amended, for the purpose of examination, inspection, or appraisement, upon a demand made on such principal within the time prescribed by the Customs Regulations, and shall on demand made within the time prescribed by the Customs Regulations redeliver or cause to be redelivered to the order of the district director of customs any of such merchandise for the purpose of marking pursuant to the provisions of section 304, Tariff Act of 1930, as amended; or, in default thereof, shall pay to said district director such amount as liquidated damages as may be demanded by him in accordance with the law and regulations not exceeding the amount of this obligation, for any breach or breaches thereof;

(7) If the said principal shall not receive into such warehouse(s) any merchandise entered for warehouse or rewarehouse therein without a proper permit from the district director of customs and without the presence of the customs officer in charge, and shall not remove or suffer to be removed any such merchandise or dutiable metal (including products partly smelted or refined) not in excess of that charged against open bonds, except in the manner provided for by law and regulations; or, in default thereof, shall pay to the district director of customs on demand all duties, taxes, charges, and exactions found legally due on the merchandise or dutiable metal (including products partly smelted or refined) so removed it being expressly understood and agreed that the liability of said principal under the bond shall extend to all cases there the merchandise or dutiable metal (including products partly smelted or refined) are lost or stolen from said warehouse(s), whether the loss or theft shall result from the fault of said principal or not; and

(8) If the said principal shall pay to the district director of customs, when demanded, all duties, taxes, and charges found legally due and unpaid on the final liquidation of such consumption entries as may be charged against this obligation; and if within five years from October 3, 1978, or five years from the date of original importation, whichever is later the said principal shall pay to the district director of customs the full amount of duties, taxes, charges, and exactions legally due upon all merchandise and dutiable metal withdrawn from warehouse for domestic consumption, and shall pay, on demand by the district director, any other duties, taxes, charges, and exactions found legally due on the merchandise or dutiable metal (including products partly smelted or refined) after withdrawal, or found to be due on merchandise or dutiable metal (including products partly smelted or refined) remaining in warehouse after expiration of such five year period; and

(9) If the said principal shall properly and lawfully enter or withdraw the merchandise or dutiable metal (including products partly smelted or refined) covered by this obligation, for bona fide exportation or for transportation, or for transportation and exportation, and shall actually furnish the district director of customs with proof that such merchandise, if entered for exportation, was exported through a customs port of exit under customs supervision and landed beyond the limits of the United States, or, if entered or withdrawn for transportation to another customs port, was delivered to the district director of customs at the port of destination and there properly entered, the proof to be filed in the form and within the time required by law and regulations, or any lawful extension thereof, or, in lieu of exportation, if the merchandise or dutiable metal (including products partly smelted or refined) shall be destroyed or abandoned within the bonded period in accordance with law and regulations, or, in default of the foregoing conditions, if the obligors shall pay to the district director of customs the full amount of duties, taxes, charges, and exactions which may be found legally due on such of the merchandise as to which there shall have been default;

Then this obligation to be void; otherwise to remain in full force and effect.

Signed, sealed, and delivered in the presence of ——————

(Name) ——————

(Address) ——————

(Name) ——————

(Address) ——————

(Principal)(Seal) ——————

(Name) ——————

(Address) ——————

(Name) ——————

(Address) ——————

(Surety)(Seal) ——————

(Name) ——————

(Address) ——————

(Name) ——————

(Address) ——————

(Surety)(Seal) ——————

[FR Doc. 80-18998 Filed 6-23-80, 8:45 am]

BILLING CODE 4810-22-M

Sunshine Act Meetings

Federal Register
Vol. 45, No. 123
Tuesday, June 24, 1980

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

CONTENTS

	Items
Chrysler Corporation Loan Guarantee Board	1
Federal Communication's	2, 3, 4
Federal Energy Regulatory Commission	5
International Trade Commission	6
National Transportation Safety Board	7
Nuclear Regulatory Commission	8
Parole Commission	9
Postal Rate Commission	10
Postal Service	11

1

CHRYSLER CORPORATION LOAN GUARANTEE BOARD.

TIME AND DATE: 9:30 a.m., June 24, 1980. The meeting may be adjourned until later in the day or adjourned from day to day as events require.

PLACE: Room 4121, Treasury Department, 15th and Pennsylvania Avenue NW., Washington, D.C. 20220.

MATTERS TO BE DISCUSSED: The Board has received an application from the Chrysler Corporation for the issuance of guarantees under the Chrysler Corporation Loan Guarantee Act (Pub. L. 96-185) (the "Act"). The Board will consider whether the Chrysler Corporation has satisfied the conditions and requirements for such Federal Assistance, as set forth in the Board's Resolutions of May 10, 1980 and the Act.

OPEN OR CLOSED: Open.

CONTACT PERSON FOR MORE INFORMATION: Brian M. Freeman, Secretary of the Board (202) 566-5888.

This notice is given as a result of Court Order. The position of the Board is that it is not subject to the Government in the Sunshine Act.

Dated: June 19, 1980.

Brian M. Freeman,

Secretary of the Board.

[S-1212-80 Filed 6-19-80; 4:35 pm]

BILLING CODE 4810-27-M

2

FEDERAL COMMUNICATIONS COMMISSION.

TIME AND DATE: 9:30 a.m., Wednesday, June 25, 1980.

PLACE: Room 856, 1919 M Street NW., Washington, D.C.

STATUS: Closed Commission meeting following the open meeting which commences at 9:30 a.m.

MATTERS TO BE CONSIDERED:

Agenda, Item Number and Subject

General—1—Establishment of the Position of Associate Bureau Chief for operations, Private Radio Bureau.

This meeting may be continued the following work day to allow the Commission to complete appropriate action.

Additional information concerning this meeting may be obtained from Edward Dooley, FCC Public Affairs Office, telephone number (202) 254-7674.

Issued: June 19, 1980.

[S-1213-80 Filed 6-20-80; 9:52 am]

BILLING CODE 6712-01-M

3

FEDERAL COMMUNICATIONS COMMISSION.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9:30 a.m., Wednesday, June 25, 1980.

PLACE: Room 856, 1919 M Street NW., Washington, D.C.

STATUS: Open Commission meeting.

CHANGES IN THE MEETING: Deletion of an item.

Agenda, Item Number, and Subject

General—4—*Title:* Petition for Rule making asking that the Commission adopt a predesignation precedure prior to Commission consideration of an investigatory report. *Summary:* Proposed Procedure would make investigatory report, witness statements, and staff recommendation available to the broadcast licensee under investigation prior to Commission consideration.

Additional information concerning this item may be obtained from Edward Dooley, FCC Public Affairs Office, telephone number (202) 254-7674.

Issued: June 19, 1980.

[S-1214-80 Filed 6-20-80; 9:53 am]

BILLING CODE 6712-01-M

4

FEDERAL COMMUNICATIONS COMMISSION.

TIME AND DATE: 9:30 a.m., Wednesday, June 25, 1980.

PLACE: Room 856, 1919 M Street NW., Washington, D.C.

STATUS: Open Commission meeting.

MATTERS TO BE CONSIDERED:

Agenda, Item Number, and Subject

General—1—*Title:* Notice of Proposed Rule making governing construction of limitations on employees' ownership of securities in Section 4(b) of the Communications Act. *Summary:* Rule making proposes new construction of 4(b) applicability to employees and their immediate families.

General—2—*Title:* Applications of Carlos Campos and Javier Navarro for Commercial Operator's licenses. *Summary:* The Commission will consider the request for review filed by Carlos Campos and Javier Navarro of an action taken by the Field Operations Bureau, denying evidentiary hearing on the issue of whether alien applicants are eligible for the class of license for which they applied. The request for the hearing had been denied by Field Operations Bureau on the ground that there are no facts or issues in dispute and the hearing would serve no useful purpose.

General—3—Renewal of the National Industry Advisory Committee (NIAC). The NIAC charter expires on July 26, 1980, and it must be renewed if the advisory committee is to continue. The NIAC submits recommendations for emergency communications plans, policies, systems, and procedures for all FCC licensed and regulated services covering emergency situations posing a threat to life and property.

General—4—*Title:* Petition for Rule making asking that the Commission adopt a predesignation procedure prior to Commission consideration of an investigatory report. *Summary:* Proposed Procedure would make investigatory report, witness statements, and staff recommendation available to the broadcast licensee under investigation prior to Commission consideration.

General—5—OPP's request for funding approval of part of FCC's fiscal year 1981 Contract Research Budget for policy research projects.

General—6—*Title:* Amendment of Parts 81 and 83 of the Commission's rules to implement the provisions of Chapter 4 of the 1974 Safety Convention pertaining to radio equipment required on compulsorily fitted vessels. *Summary:* The FCC will consider whether to adopt a Report and Order implementing the 1974 Safety of Life at Sea (SOLAS) Convention and regulations governing vessels subject to the Communications Act of 1934, as amended. These regulations will bring U.S. vessels into compliance with the 1974 SOLAS Convention and improve the safety of U.S. vessels operating in national and international waters.

Common Carrier—1—*Title:* Final Report and Order in Docket No. 18920, in the matter of establishment of policies and procedures for consideration of applications to provide specialized common carrier services in the Domestic Public Point-to-Point Microwave Radio Service and proposed amendments to Parts 21, 43, and 61 of the Commission's Rules. *Summary:* The Commission will consider the sole issue yet to be resolved in this proceeding, whether it should adopt standard terminology to be used by carriers in any tariff statements of quality and reliability factors or performance parameters to be observed by carriers engaged in providing such services.

Common Carrier—2—*Title:* Amendment of § 22.521(b) of the Commission's rules, to include Tallahassee, Florida, in the table of assignments for air-ground stations in the Domestic Public Land Mobile Radio Service. *Summary:* Commission will consider a proposed amendment to § 22.521(b) of the Commission's rules, assigning Channel 6 (base station frequency, 454.700 MHz; mobile and test station frequency, 459.700 (MHz) to Tallahassee, Florida.

Common Carrier—3—*Title:* Standard Telephone Company, petition for reconsideration of a condition in its Order and Certificate to construct and operate a CATV system. *Summary:* The Commission will consider in this matter whether to amend or delete from Petitioner's Order and Certificate, the condition that the grant is subject to the outcome of Common Carrier Docket No. 78–72, "In the Matter of MTS and WATS Market Structure."

Common Carrier—4—*Title:* Petition of the Western Union Telegraph Company for Stay Pending Judicial Review of the Commission's Policy Statement and Order in Docket No. 19660. *Summary:* This item considers the petition for stay pending judicial review of the Commission's Policy Statement and Order in Docket No. 19660 (Gateways). The issue is whether Western Union has made the showing necessary to warrant a stay under the existing case law.

Common Carrier—5—*Title:* Petition of Microband Pacific Corporation for Stay of Commission's *Memorandum Opinion and Order.* FCC 80–139. *Summary:* Microband Pacific requests the Commission stay its Order authorizing R. L. Mohr to construct a new MDS station at San Pedro, California. Microband Pacific argues that unless the Commission issues the stay as requested it will suffer irreparable financial harm.

Common Carrier—6—*Title:* Formal complaints against RCA American Communications, Inc. filed by Spanish International Network, Inc. (File No. TS 10–79), Eastern Microwave, Inc. (File No. TS 4–80), Cable News Network (File No. E 80–13) and National Christian Network (File No. E 80–15). *Summary:* The complaints raise questions concerning RCA Americom's practices in assigning transponders on its domestic satellite system to cable program suppliers. The issues include alleged violations of Sections 201–203 and 214 of the Communications Act and alleged inconsistencies with the Commission's open entry and competitive policies.

Common Carrier—7—*Title:* Petitions, filed by Home Box Office, Eastern Microwave, Inc., and Spanish International Network, seeking to reject or suspend and investigate RCA Americom's tariff proposal to conduct a lottery to allocate remaining transponders on the SATCOM F–III replacement satellite. *Summary:* The Commission will consider several petitions opposing RCA Americom's tariff proposal to conduct a lottery to allocate remaining transponders on the SATCOM F–III replacement satellite. The petitioners allege that the lottery proposal is an unreasonable practice within the meaning of Section 201(b) and unlawfully discriminatory, in violation of Section 202(a) of the Act.

Common Carrier—8—*Title:* Petitions to suspend or reject revisions to AT&T's Bell System Operating Companies Tariff FCC No. 8, Exchange Network Facilities for Interstate Access (ENFIA). *Summary:* The Commission will consider whether to grant petitions from MCI Telecommunications Corporation, Southern Pacific Communications Corporations, U.S. Telephone Communications, Inc., and United States Transmission Systems, Inc. to suspend or reject proposed increases to the AT&T ENFIA tariff now scheduled to take effect on July 1, 1980.

Common Carrier—9—*Title:* Memorandum Opinion and Order considering a Petition to Reject or Suspend and Investigate Lincoln Telephone and Telegraph Company Tariff FCC No. 1, establishing facilities for interstate access offered to other common carriers. *Summary:* The above mentioned tariff was filed in order to allow other common carriers to provide MTS/WATS–type services in the publishing carrier's service area. The question before the Commission is whether is should reject or suspend the tariff for lack of sufficient justification.

Common Carrier—10—*Title:* Manual and Procedures for the Allocation of Costs. *Summary:* This order initiates a rulemaking proceeding to prescribe a manual containing procedures to be followed by AT&T in allocating costs. This docket was established through issuance of a Notice of Inquiry in September, 1979 (73 FCC 2d 629).

Assignment and Transfer—1—*Title:* Applications to assign the licenses of stations WJAR, Providence, Rhode Island, WHIM, Providence, Rhode Island and WRLM(FM), Taunton, Massachusetts and three informal objection thereto. *Summary:* Franks Broadcasting Co. seeks to acquire the license of WRLM(FM) which it proposes to exchange for the license of WJAR which is licensed to the Outlet Co. Since the Outlet Co. is also the licensee of WJAR–TV, Providence, it also the licensee of WJAR–TV, Providence, it has requested waiver of the Commission's FM one-to-a-market rule. Franks Broadcasting also proposes to assign the license of WHIM to minority-controlled East Providence Broadcasting and has requested issuance of a tax certificate pursuant to the Commission's *Policy on Minority Ownership of Broadcasting Facilities,* 68 FCC 2d 979 (1978).

Renewal—1—*Title:* EEO Goals and Timetables. *Summary:* Agend item asking the Commission to accept the goals and timetables submitted by Station WSTU, Stuart, Florida and for the attached letter to be sent informing the licensee of the Commission's action.

Renewal—2—*Title:* Peoria Community Broadcasters, Inc. (WWCT(FM)) application for renewal of license and assignment to Chan Broadcasting Co., Inc.; Central Illinois Broadcasting Co. petition to deny Peoria's renewal application and mutually exclusive application for construction permit for WWCT(FM)'s frequency. *Summary:* Peoria, bankrupt and operating the station as debtor in possession, seeks renewal of its license and approval of assignment to Chan. Central, mutually exclusive applicant for that frequency, filed a petition to deny Peoria's renewal application alleging unauthorized transfer of control and lack of candor in Peoria's Ownership Reports. Peoria alleges that Central lacks financial qualifications, filed an incomplete application in that it lacked a transmitter site, has withheld for its own advantage information which should have been disclosed to the Commission and has made misrepresentations to the Commission. The issues before the Commission are whether a substantial and material question of fact has been raised concerning Peoria's renewal, whether Central possesses the qualifications to be a Commission licensee, and which of the applicants on a comparative basis would better serve the public interest.

Aural—1—*Title:* Application of Dick Lashbrook Corporation (WSIV–FM), Pekin, Illinois for a construction permit for modification of facilities. *Summary:* The FCC is considering WSIV–FM's request for a waiver of the Commission's minimum spacing requirements for FM stations. WRKX is the station with which WSIV–FM would be short-spaced, and it has petitioned the Commission to deny WSIV–FM's request.

Aural—2—*Title:* Memorandum Opinion and Order in re application of Ettlinger Broadcasting Corporation (File No. BPH–10,075) for a construction permit for a new FM station at Westmoreland, California and a petition for waiver of § 73.315(a) of the rules filed by applicant. *Summary:* The FCC considers the above application for a new station and applicant's petition for waiver of §§ 73.315(a) of the rules, pertaining to city coverage.

Television—1—*Title:* Application (BPCT–780720IC) for construction permit for a new commercial television station to operate on channel 27, Marion, Illinois, filed by Dennis F. Doelitzsch. *Summary:* UHF applicant is a licensee and owner of an AM and an FM station in the same market. The Grade A contour of the proposed station would encompass his aural facilities' communities of license, therefore, a one-to-a-market problem is raised. The issue before the Commission is whether the applicant has made a sufficient showing to justify Commission action under Note 8 to § 73.636 (one-to-a-market rule).

Television—2—*Title:* Applications to construct four new TV translator stations

(file Nos. BPTT-3617, 3626, 3627 and 780911IA) filed by U.P. TV Systems, Inc., are the subject of Petitions to Deny filed by Teleprompter. *Summary:* The Petitions raised questions regarding (a) use of the translators to relay the TV signals to fixed points as a substitute for common carrier in violation of § 74.731(c) of our rules; (b) concentration of control and multiple ownership questions; and (c) and the signal interference potential with respect to the channel 53 application.

Broadcast—1—*Title:* Request for Waiver of Section 74.402 of our Rules to allow Splitting of Remote Pickup N1 channels in the 450/455 MHz Band in Southern California. The Southern California Frequency Coordinating Committee has asked for waiver of Section 74.402 to allow the splitting of N1 remote pickup channels to alleviate congestion in the 450/455 MHz band in the Southern California area.

Broadcast—2—*Title:* Petition to Institute Inquiry into Various Aspects of Broadcasting (RM-3131). *Summary:* This cast involves action on a petition filed by R. P. Haviland urging the institution of an inquiry into a range of broadcast issues. The petition asks the Commission to begin an inquiry that would eventually lead to rule making and the adoption of rules, as well as to the making of recommendations to the Congress on statutory changes. Among the points which the petitioner urges the Commission to consider are: (1) The geographic distribution of radio service and the relative importance of local service versus area coverage; (2) the economic realities affecting program production; (3) techniques which could be employed to increase program choice and at the same time ensure the continued economic viability of broadcasting and networking; (4) correction of advertising "abuses;" and (5) improvement in program content on TV and radio.

Broadcast—3—*Title:* Memorandum Opinion and Order regarding NAB's petition for reconsideration of the Commission's revised EEO processing guidelines for broadcast renewal applicants, FCC 80-61, and NAB's petition for rule making to reassess the Commission's EEO regulatory program (RM-3635). *Summary:* The Commission will consider the petitions for reconsideration of its EEO processing guidelines, adopted February 13, 1980, and a related petition for rule making, both filed by the National Association of Broadcasters.

Complaints and Compliance—1—Title: Application by Hale Broadcasting Corporation licensee of Station WMTS, Murfreesboro, Tennessee, for review of Broadcast Bureau's action assessing a forfeiture for operation during unauthorized times. *Summary:* Hale Broadcasting Corporation, licensee of Station WMTS, Murfreesboro, Tennessee has requested the Commission to review the order of the Broadcast Bureau assessing a forfeiture of $2,000 for the operation of the station thirty minutes prior to the time authorized on sixteen days. Hale Broadcasting contends that the imposition of such a severe penalty in this case is inconsistent with the legislative intent of the Communications Act. The licensee argues that the Broadcast Bureau erroneously applied the "willfully or repeatedly" standard of liability, in that the violations consisted of a single, honest, harmless error which was promptly corrected. The Commission must decide whether to grant the application for review and if so, whether the forfeiture should be remitted or reduced.

Complaints and Compliance—2—*Title:* Fairness Doctrine Complaint against ABC, NBC and CBS, filed November 13, 1979 by Media Access Project (MAP) on behalf of the National Committee for Responsive Philanthropy (NCRP). *Summary:* The Commission will consider whether to grant or deny a Fairness Doctrine complaint filed by the National Committee for Responsive Philanthropy. The complaint alleges that NBC, CBS and ABC have presented a series of United Way public service announcements which address one side of a controversial issue of public importance (whether the United Way's method of collecting and distributing funds serves all elements of society), but have not presented the opposing view. The networks all claim that the announcements do not meaningfully address the issue in question. NBC and CBS state that issue as defined by the complainants would not be a controversial issue of public important even if it had veen meaningfully addressed.

This meeting may be continued the following work day to allow the Commission to complete appropriate action.

Additional information concerning this meeting may be obtained from Edward Dooley, FCC Public Affairs Office, telephone number (202) 254-7674.

Issued: June 19, 1980.

[S-1215-80 Filed 6-20-80 9:45 am]

BILLING CODE 6712-01-M

5

FEDERAL ENERGY REGULATORY COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: To be published June 23, 1980.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 10 a.m., June 25, 1980.

CHANGE IN THE MEETING: The following items have been added:

Item Number, Docket Number, and Company

M-7—RM80-11, Statement of Policy on Distributor Access to Outer Continental Shelf Gas.

RP-2—RP75-106 (Appalachian Production), Columbia Gas Transmission Corp.

Louis D. Cashell,

Acting Secretary.

[S-1219-80 Filed 6-20-80; 1:11 pm]

BILLING CODE 6450-85-M

6

[USITC SE-80-35A]

INTERNATIONAL TRADE COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: 45 FR 41112, June 17, 1980.

PREVIOUSLY ANNOUNCED TIME AND DATE OF THE MEETING: 10 a.m., Thursday, June 26, 1980.

CHANGES IN THE MEETING: Emergency action to close the meeting originally announced as open to the public.

Pursuant to the specific exemptions of 5 U.S.C. 552b(c)(4) and in conformity with 19 CFR 201.36(b)(4), Commissioners Alberger, Calhoun, Moore, Bedell, and Stern voted by action jacket SE-80-13 to hold the discussion with respect to item No. 1 [Steel jacks (Inv. 603-TA-6)—briefing] in closed session.

Commissioners Alberger, Calhoun, Moore, Bedell, and Stern also determined, pursuant to 19 CFR 201.37(b) that Commission business requires the change in the determination of the Commission to open or close this portion of the meeting and directed the issuance of this notice at the earliest practicable time.

CONTACT PERSON FOR MORE INFORMATION: Kenneth R. Mason, Secretary (202) 523-0161.

S-?

BILLING CODE 7020-02-M

7

[USITC SE-80-36]

INTERNATIONAL TRADE COMMISSION.

TIME AND DATE: 10 a.m., Tuesday, July 1, 1980.

PLACE: Room 117, 701 E Street NW., Washington, D.C. 20436.

STATUS: Open to the public.

MATTERS TO BE CONSIDERED:

1. Agenda.
2. Minutes.
3. Ratifications.
4. Petitions and complaints, if necessary.
5. Steel jacks (Inv. 603-TA-6)—vote.
6. Any items left over from previous agenda.

CONTACT PERSON FOR MORE INFORMATION: Kenneth R. Mason, Secretary (202) 523-0161.

[S-1216-80 Filed 6-20-80; 10:55 am]

BILLING CODE 7020-02-M

8

[NM-80-24]

NATIONAL TRANSPORTATION SAFETY BOARD.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: 45 FR 41113, June 17, 1980.

PREVIOUSLY ANNOUNCED TIME AND DATE OF MEETING: 9 a.m., Tuesday, June 24, 1980.

CHANGE IN MEETING: A majority of the Board has determined by recorded vote that the business of the Board requires revising the agenda of this meeting and that no earlier announcement was possible. The agenda as now revised is set forth below.

STATUS: The first two items will be open to the public; the third item will be closed under Exemption 9B of the Government in the Sunshine Act.

MATTERS TO BE CONSIDERED:

1. *Marine Accident Report*—Crane Barge C. L. DILL 10, Fire, Garden Island Bay, Mississippi River Delta, June 5, 1979, and *Recommendations* to U.S. Army Corps of Engineers, Texaco, Inc., and the C. L. Dill Co.
2. *Special Investigation Report*—Design-induced Landing Gear Retration Accidents in Beechcraft Baron, Bonanza, and Other Light Aircraft and *Recommendations* to the Federal Aviation Administration.
3. *Discussion* of Board strategy for public hearing on rail rapid transit safety which will be held on July 28 and 29, 1980.

CONTACT PERSON FOR MORE INFORMATION: Sharon Flemming, 202–472–6022.

June 20, 1980.

[S-1222-80 Filed 6-20-80; 4:02 pm]

BILLING CODE 4910-58-M

9

NUCLEAR REGULATORY COMMISSION.

DATES: June 24 and 26, 1980.

PLACE: Commissioners conference room, 1717 H Street NW., Washington, D.C.

STATUS: Open.

MATTERS TO BE CONSIDERED: Tuesday, June 24:

10 a.m.

1. Discussion of Hearing Board Report on Clearance Rule (approximately 1 hour, public meeting) (rescheduled from June 26) (replaces interim hydrogen control, which moves to June 26).

Thursday, June 26:

9:30 a.m.

1. Meeting with Representatives of the Conference of Radiation Control Program Directors Regarding the Agreement States Program (approximately 6 hours, public meeting).
2. Affirmation Session (approximately 10 minutes, public meeting).
   a. Proposed Rulemaking on reactor Siting (tenative).
   b. Petition for an Atomic Energy Act Section 105c(2) (Significant Changes).
   c. Amendments Generally Extending Time for Commission Action.
   d. NRDC Request for Hearing in Erwin (tenative).
3. Time Reserved for Discussion and Vote on Affirmation Items (if required) (approximately 15 minutes, public meeting).

1:30 p.m.

1. Briefing on Recommendations of Indian Point Task Force (approximately 2 hours, public meeting).
2. Discussion of Proposed Interim Hydrogen Control Requirements for Small Containments (approximately 6 hours, public meeting).

CONTACT PERSON FOR MORE INFORMATION: Walter Magee, (202) 634–1410.

AUTOMATIC TELEPHONE ANSWERING SERVICE FOR SCHEDULE UPDATE: (202) 634–1498.

Those planning to attend a meeting should reverify the status on the day of the meeting.

Roger M. Tweed,

Office of the Secretary.

June 19, 1980.

[S-1220-80-Filed 6-20-80; 3:16 pm]

BILLING CODE 7590-01-M

10

PAROLE COMMISSION.

[OP0401]

National Commissioners (the Commissioners presently maintaining Offices at Washington, D.C. Headquarters).

TIME AND DATE: June 18, 1980, at 9:30 a.m.

PLACE: Room 826A, 320 First Street NW, Washington, D.C. 20537.

STATUS: Closed pursuant to a vote to be taken at the beginning of the meeting.

CHANGES IN THE MEETING: On June 17, 1980, the Commission determined that the above meeting be continued to 9:30 a.m. on Wednesday, June 25, 1980, in Room 826A, 320 First Street, NW, for consideration of case referrals from Regional Commissioners. The above change is being announced at the earliest practicable time.

CONTACT PERSONS FOR MORE INFORMATION: Linda Wines Marble, Analyst (202) 724–3094.

[S-1218-80 Filed 6-20-80; 12:57 pm]

BILLING CODE 4410-01-M

11

POSTAL RATE COMMISSION.

"FEDERAL REGISTER" CITATION OF PREVIOUS ANNOUNCEMENT: 45 FR 39612, June 11, 1980.

PREVIOUSLY ANNOUNCED TIME AND DATE OF OPEN MEETING: 2 p.m., June 26, 1980.

CHANGES IN THE MEETING: Addition of the following agenda item.

1. Motion of United Parcel Service to Compel Answers in Docket R80–1.

The portion of the meeting to consider agenda item No. 1 above will be closed to the public pursuant to 5 U.S.C. § 552b (c)(10). The portion of the meeting to consider agenda item No. 2, Election of the Vice Chairman, will be open to the public.

CONTACT PERSON FOR MORE INFORMATION: Dennis Watson, Information Officer, telephone (202) 254–3880.

[S-1221-80 Filed 6-20-80; 3:20 pm]

BILLING CODE 7715-01-M

12

POSTAL SERVICE.

The Board of Governors of the United Stated States Postal Service, pursuant to its Bylaws (39 CFR 7.5) and the Government in the Sunshine Act (5 U.S.C. 552b), hereby gives notice that it intends to hold meetings at 3 p.m. on Monday, June 30, and at 9 a.m. on Tuesday, July 1, 1980, at Postal Service Headquarters, 475 L'Enfant Plaza, S.W., Washington, D.C. 20260. Except as indicated in the following paragraphs, the meetings are open to the public. The Board expects to discuss the matters stated in the agenda which is set forth below. Requests for information about the meeting should be addressed to the Secretary of the Board, Louis A. Cox, at (202) 245–4632.

On June 3, 1980, the Board of Governors voted to close to public observation its next meeting, scheduled for 3:00 P.M. on June 30, 1980. Each of the members of the Board voted in favor of closing this meeting, which is expected to be attended by the following persons: Governors Wright, Hardesty, Allen, Camp, Ching, and Sullivan; Postmaster General Bolger; and Secretary of the Board Cox.

A portion of the meeting to be closed will consist of a continuation of the discussion by the Governors of the Opinion and Recommended Decision Upon Reconsideration of the Postal Rate Commission re Electronic Mail Classification Proposal, 1978 (Commission Docket No. MC78–3), dated April 8, 1980.

A second portion of the meeting to be closed is to involve a discussion of the possible appointment of a new Deputy Postmaster General.

A third portion of the meeting to be closed is to involve a discussion of individuals in connection with a possible decision to engage independent staff assistance for the Governors.

Agenda

Monday Afternoon Session

1. Recommended Decision upon Reconsideration of the Electronic Mail Classification Proposal, 1978 (Commission Docket No. MC78-3)
(The Governors will continue consideration of the above Recommended Decision of the Postal Rate Commission. As stated above in the Notice of Meeting, the part of the meeting that will be devoted to this matter will be closed to the public.)
2. Discussion of the possible appointment of a new Deputy Postmaster General.
(The Governors and the Postmaster General will discuss possible appointment of a new Deputy Postmaster General. As stated above in the Notice of Meeting, the part of the meeting that will be devoted to this matter will be closed to the public.)
3. Discussion of individuals in connection with a possible decision to engage independent staff assistance for the Governors.
(The Board will discuss the possibility of engaging independent staff assistance for the Governors. As stated above in the Notice of Meeting, the part of the meeting that will be devoted to this matter will be closed to the public.)

Tuesday Session

1. Minutes of the previous meeting.
2. Remarks of the Postmaster General
(In keeping with its consistent practice, the Board's agenda provides this opportunity for the Postmaster General to inform the members of miscellaneous current developments concerning the Postal Service. He might report, for example, the appointment or assignment of a key official, or the effect on postal operations of unusual weather or a major strike in the transportation industry. Nothing that requires a decision by the Board is brought up under this item.)
3. Report on Operations Group Programs
(Mr. Benson, Senior Assistant Postmaster General, Operations Group, will brief the Board on Programs in the Operations Group.)
4. Report of the Regional Postmaster General
(Mr. Doran, Regional Postmaster General, will report on postal conditions in the Central Region.)
5. Report on the Status of the General Rate Proceeding pending before the Postal Rate Commission (Commission Docket No. R80-1)
(Assistant General Counsel Frances Beck will brief the Board on the current status of the Postal Rate Case.)
6. Recommended Decision of May 16, 1980, concerning Red Tag Proceeding, 1979 (Commission Docket No. MC79-3)
(The Governors will consider the above Recommended Decision of the Postal Rate Commission.)

Louis A. Cox,

Secretary.

[S-1217-80 Filed 6-20-80; 11:24 am]

BILLING CODE 7710-12-M

federal register

Tuesday
June 24, 1980

Part II

Environmental Protection Agency

Water Programs; Consolidated Permit Regulations and Technical Criteria and Standards; State Underground Injection Control Programs

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 122 and 146

[FRL 1482-1]

Water Programs; Consolidated Permit Regulations and Technical Criteria and Standards; State Underground Injection Control Programs

AGENCY: Environmental Protection Agency.

ACTION: Final Rule for Part 146 and Amendments to Part 122.

SUMMARY: The Safe Drinking Water Act requires the Environmental Protection Agency (EPA) to develop minimum requirements for State programs to protect underground drinking water sources from endangerment by the subsurface emplacement of fluids through well injection. Such regulations have been established in the recently published Consolidated Permit regulations. The regulations promulgated here today establish the technical criteria and standards for use by States and EPA in the development and implementation of such State UIC programs. Neither these regulations nor the Consolidated Permit regulations establish requirements for owners or operators of injection wells at this time, with one exception. They establish requirements for State or EPA officials to be used in developing State UIC programs which, when they become effective, will in turn establish enforceable requirements for owners or operators of injection wells.

The one exception concerns owners or operators of wells which inject hazardous waste within the meaning of the Resource Conservation and Recovery Act (RCRA). Owners or operators of such wells must achieve interim status under the Hazardous Waste Management program, even though such injection practices will ultimately be controlled under the Safe Drinking Water Act once a State UIC program becomes effective.

Subpart A of these regulations spells out certain general provisions with respect to underground sources of drinking water, the classification of injection wells, the use of the area of review concept, corrective action requirements, mechanical integrity, criteria for establishing permitting priorities, and requirements for the abandonment of Class I, II and III wells. Subparts B through F of these regulations establish technical requirements and criteria that the Director is to apply in regulating the construction, operation, monitoring and reporting of wells in Classes I through V. In the case of wells in Classes I through III, Subparts B through D also detail the information that the Director is to consider prior to the issuance of a permit.

During the final drafting of these Part 146 regulations, it became apparent that some changes to the Consolidated Permit Regulations were necessary. Six amendments involving four sections are included in this publication and are discussed in this preamble.

DATES: The regulations in this promulgation shall become effective on July 18, 1980 or thirty (30) days after their publication in the **Federal Register** (July 24, 1980), whichever is later. That date shall also be the implementation date for those portions of 40 CFR Parts 122, 123 and 124 which relate to Underground Injection Control (UIC) permits and programs (see 45 FR 33290).

The Safe Drinking Water Act allows States 270 days from the effective date of these regulations to develop programs which meet the regulatory requirements of 40 CFR Parts 122, 123, 124 and 146, and to submit such programs to EPA for approval. This period may be extended by another 270 days for good cause.

In order to assist EPA to correct typographical errors, incorrect cross-references, and similar technical errors, comments of a technical and non-substantive nature on the final regulations may be submitted until July 24, 1980. The effective date will not be delayed by consideration of such comments.

ADDRESSES: Comments of a technical and non-substantive nature should be addressed to, Thomas Belk, Chief, Ground Water Protection Branch, EPA, Office of Drinking Water (WH-550), Washington, D.C. 20460 (202) 426-3985.

FOR FURTHER INFORMATION CONTACT: Thomas Belk, Chief, Ground Water Protection Branch, Environmental Protection Agency, (202) 426-3985.

SUPPLEMENTARY INFORMATION:

Legal Authority

General

These regulations are being proposed under the authority of the Safe Drinking Water Act (the "Act" or "SDWA"), Pub. L. 93-523, December 16, 1974, as amended by Pub. L. 95-190, November 16, 1977. The Act is designed to protect the quality of drinking water in the United States.

Part A of the Act (section 1401) contains definitions. Part B (sections 1411-1416) addresses the quality of water provided by public water supplies. EPA regulations implementing Part B of the Act are codified at 40 CFR Parts 141 and 142.

The regulations below relate to Part C of the Act (sections 1421-1424), entitled "Protection of Underground Sources of Drinking Water."

Basis for Concern

The legislative history of the Act reflects the basic Congressional concerns in enacting part C of the Act:

> "* * * underground injection of contaminants is clearly an increasing problem. Municipalities are increasingly engaging in underground injection of sewage, sludge, and other wastes. Industries are injecting chemicals, by-products, and wastes. Energy production companies are using injection techniques to increase production and dispose of unwanted brines brought to the surface during production. Even government agencies, including the military, are getting rid of difficult to manage waste problems by underground disposal methods. Part C is intended to deal with all the foregoing situations insofar as they may endanger underground drinking water sources." (HR Report No. 93-1185, July 10, 1974, p. 29).

The potentially dangerous practices which Congress sought to control in 1974 continue at an ever increasing rate. EPA estimates that there are in excess of 400,000 municipal, industrial, commercial, agricultural, and domestic wells currently injecting fluids below the surface, and that there are at least 5,000 new wells of these types each year. The purpose of Part C of the Act, and of the Underground Injection Control (UIC) program, is to establish a Federal-State system of controls which will insure that such underground injection practices do not endanger drinking water sources.

Relevant Statutory Provisions

A detailed discussion of the relevant statutory provisions and legislative history appears in earlier proposals of these regulations (41 FR 36730 et seq., August 31, 1976 and 44 FR 23738 et seq., April 20, 1979). Those details need not be repeated here, but it is useful to summarize the basic scheme of Part C of the Act.

1. *Section 1421: Minimum Requirements for State Programs*—Section 1421 requires EPA to propose and promulgate regulations specifying "minimum requirements" for State programs to prevent underground injections which endanger drinking water sources. Such minimum requirements must provide for at least the following:

- A program prohibiting any underground injection which is not authorized by a State permit. EPA may, at its discretion, however, allow some or

all underground injections to be authorized by rules without case-by-case permits (section 1421(b)(1)(A)).

• Protection of underground drinking water sources.

• Inspection, monitoring, record keeping, and reporting requirements (section 1421(b)(1)(C)).

• Coverage of underground injections by Federal Agencies and underground injections by any person on property owned or leased by the United States (section 1421(b)(1)(D)).

2. *Section 1422(a): List of States*—Section 1422(a) requires EPA to list in the **Federal Register** each State for which an underground injection control program "may be necessary" to ensure that underground injections will not endanger drinking water sources. With the recent listing of the remaining 16 jurisdictions (45 FR 17632), EPA has now listed all 50 States, the District of Columbia, and the Territories and Possessions of the United States (hereafter "States"). Such listings are hereby confirmed.

One major consideration in listing all of the States and other jurisdictions as needing UIC programs is that in the next few years the Agency will embark on a broad effort to protect ground water throughout the United States. EPA wishes to avoid instances where the surface disposal of hazardous wastes is controlled or prohibited under the Hazardous Waste Management (HWM) program mandated by the Resource Conservation and Recovery Act (RCRA), Pub. L. 94–580, October 21, 1976, while the underground injection of the same hazardous waste is not regulated by effective State programs. EPA is concerned that such a situation would create undesirable incentives to avoid regulations under the Hazardous Waste Management program by disposing of those regulated wastes below the surface. By listing all the States the Agency intends to bring the disposal of hazardous waste through well injection under regulatory control in a comparable time period with the control of surface disposal of hazardous waste under the Resource Conservation and Recovery Act.

3. *Section 1422(b)(d): Development of Underground Injection Control Programs*—Once EPA has promulgated the "minimum requirements" regulations, each State will have the opportunity to develop an enforceable underground injection control program. The UIC program must be adopted after reasonable notice and public hearings, and must comply with the minimum requirements.

Each State will have 270 days from the effective date of these regulations to develop its UIC program and submit it to EPA for review. EPA may, for a good cause, extend this deadline for any State by up to an additional 270 days. The Agency does not intend to follow a liberal policy in granting extensions. "Good cause" will be limited to the need to obtain legal authority from the legislature and similar reasons.

If EPA determines that a State UIC program meets the minimum requirements of Parts 123 and 146, EPA will approve the program. The State will then be deemed to have "primary enforcement responsibility" under Part C of the Act and there will be no Federal UIC enforcement actions in that State so long as the State continues to meet its responsibilities.

If a State fails to adopt and submit a UIC program in a timely fashion, or if EPA finds that a State's UIC program fails in part or in whole to meet the minimum requirements of Parts 123 and 146, EPA is required to propose and promulgate UIC regulations to be effective in that State. In such an event, a State will not be deemed to have "primary enforcement responsibility," ("primacy") and direct Federal enforcement of the UIC program will result (section 1422 (b), (c), 1423). In addition, a State which fails to achieve full primacy within 2 years of the award of its first UIC grant loses eligibility for further Federal grants.

4. *The 1977 Amendments*—Although they do not vary the operating scheme of Part C of the Act, the 1977 amendments to the Act, Pub. L. 95–190, should be noted. In addition to allowing the 270 day extension for State submission of requests for approval of State programs (see above), they emphasize that States have jurisdiction over injection by Federal Agencies or on Federal lands within the State. Federal Agencies fall under State regulations as would any other "person" (section 1447(a)). With respect to injection wells on Indian lands, however, jurisdiction remains with EPA (section 1447(a)).

New Section 1421(b)(3) instructs EPA to allow consideration of varying geologic, hydrologic, and historic conditions among States. The Section further cautions EPA against fashioning minimum requirements regulations which would "unnecessarily disrupt" existing State underground injection control programs now being enforced. These considerations however, may not be used to compromise the overall statutory requirement to prevent endangerment to underground sources of drinking water (section 1421(b)(3)(c)). EPA believes that these regulations amply serve these interests: the regulations offer States discretion to tailor local programs to meet specific needs and to consider geologic, hydrologic, and historic conditions in fashioning rules and permit requirements.

History of Rule Making

EPA originally proposed regulations to implement Part C of the Safe Drinking Water Act on August 31, 1976 (41 FR 36730–45). That proposal included the program regulations, the technical criteria and standards, and the related grant regulations. Four hundred twenty nine (429) written sets of comments were filed and many persons commented at public hearings in Dallas, Denver, and Washington, D.C.

After careful review of those public comments, EPA determined that there were many ways that the initial proposal could be made generally more flexible and less burdensome without sacrificing the resulting environmental protection to any significant degree. Further, in the fall of 1978, the Agency decided to consolidate the regulations for its major permit programs: the Hazardous Waste Management program under the Resource Conservation and Recovery Act (RCRA); the UIC program under the Safe Drinking Water Act (SDWA); and the National Pollutant Discharge Elimination System (NPDES) under the Clean Water Act (CWA).

As a consequence of these events, the Agency took the following series of actions in 1978 and 1979. The grant regulations related to the UIC program were promulgated in final form on October 12, 1978 (43 FR 47130, *et seq.*). The initial group of 22 States needing an UIC program were listed on September 25, 1978 (43 FR 43420). In addition the UIC program regulations were reproposed in four parts on April 20 and June 14, 1979:

• 40 CFR Part 122 reproposed the regulatory framework for the UIC program.

• 40 CFR Part 123 described the elements of an approvable State program and proposed the process for EPA approval of State participation in the UIC program.

• 40 CFR Part 124 described the procedures for permit application and issuance which EPA intends to follow when it has primacy. Certain provisions of 40 CFR Part 124 would also be applicable to State UIC programs.

• 40 CFR Part 146 (being promulgated here) proposed the technical criteria and standards to be used by EPA or the State in implementing the UIC program.

Numerous written comments were received and five public hearings were held in Dallas, Washington, D.C., Chicago, Seattle, and Denver on the

Consolidated Permit regulations and Part 146. The preamble to the Consolidated Permit regulations responds to both the written and oral comments addressed to Parts 122, 123, and 124. Two hundred sets of written comments were received addressed to Part 146. These together with the oral comments received will be responded to in this preamble.

As noted in the preamble to the reproposed Part 146 (44 FR 23742), an effort has been made in the process of promulgating these regulations to reduce duplication by retaining only technical criteria and standards in Part 146 and transferring all programmatic requirements to Parts 122, 123 and 124.

It is not necessary to repeat here the requirements established and explained in the Consolidated Permit regulations. The reader is referred to 45 FR 33290. It is, however, important to emphasize that, in contrast to the 1979 proposal, the final Part 122 regulation requires owners or operators of wells used to inject hazardous waste to achieve interim status under RCRA until the controlling State UIC program becomes effective. Therefore, the totality of requirements applicable to State UIC programs are to be found in six sets of regulations.

- The UIC program grant regulations (43 FR 47130).
- 40 CFR Part 122 (45 FR 33418).
- 40 CFR Part 123 (45 FR 33456).
- 40 CFR Part 124 (45 FR 33484).
- 40 CFR Part 146 (Published here today).
- 40 CFR Part 265 (45 FR 33260).

Response to Comments

The preamble to the 1979 reproposal of Part 146 requested comments from the public in more than 20 instances. Additional comments were requested in the preamble to the Consolidated Permit regulations as well. Even though the programmatic requirements for the Underground Injection Control program are properly dealt with in the preamble to the Consolidated Permit regulations, it is desirable to discuss them at least in part here since the technical criteria and standards are an integral portion of the Underground Injection Control program. In addition, it is appropriate to err on the side of completeness, even at the risk of repetition, for the sake of a comprehensible discussion of the issues involved.

I. *Regulatory Framework*

A. Coverage of the Regulations—1. *Wells not near underground sources of drinking water.* In the preamble to the 1979 reproposal of Part 146, EPA explained that, at one point in developing these regulations, EPA considered not applying these regulations to wells that do not inject into, through, or above drinking water sources (44 FR 23740–1). The preamble went on to explain the Agency's concern that such a provision could leave an injector uncertain about whether he is or is not covered by these regulations. Furthermore, although a particular well may not be injected into, through or above a drinking water source, it could still be a potential cause of endangerment by displacing formation fluids, through a hydraulic connection, into an underground source of drinking water.

In view of these concerns, the proposal suggested applying the regulations to all injection wells regardless of their location. The preamble went on to note that one result of this decision was that off-shore injection operations would be subjected to UIC regulations. In response, a number of commenters urged that off-shore operations be excluded from the coverage of the UIC program and that wells that do not inject into, through or above a drinking water source should be given recognition in some form. EPA agrees and the final Part 122 includes two sections intended to resolve this question.

First, § 122.31(d)(2)(i) excludes injection wells located on a drilling platform or other site beyond a State's territorial waters. The rationale behind this decision is that the Safe Drinking Water Act intended the underground injection control program to be a State program. Therefore, only injection wells that fall within the boundaries of a State are included and off-shore wells which fall beyond State boundaries are excluded.

Second, a new § 122.43(a) has been added. This section states that if a well does not inject into, through or above a drinking water source, the Director has discretion to ease the area of review, construction, mechanical integrity, monitoring, operating and reporting requirements applicable to such wells. In this regard EPA contemplated excluding such wells entirely from these regulations. However, it is only prudent that as long as an injection facility has some potential to contaminate underground sources of drinking water through lateral displacement, some minimal control should be exercised over it. At a minimum, the Director should have the opportunity to assess the potential for contamination. Thus, wells that do not inject into, through or above underground source of drinking water are still covered by the UIC program, so that they can be inventoried and their potential for endangerment reviewed. However, discretion is given to the Director to determine whether any additional requirements need be applied in particular instances.

2. *The Inclusion of Class II Wells.* The overwhelming majority of people commenting on the regulations on behalf of the oil and gas industry and the State regulatory agencies suggested that EPA should not bring Class II wells (those injection wells associated with the oil and gas industry) under the UIC regulations. Commenters advanced three reasons in support of this suggestion. First of all, they contended that EPA has failed to prove extensive damage to underground sources of drinking water from Class II injection practices. Second, the commenters maintained that existing State programs have done an effective job of preventing the contamination of underground sources of drinking water through Class II practices. Third, the commenters pointed out that Section 1422(c) of the SDWA instructs EPA not to include any requirements in its UIC regulations which interfere with or impede the disposal of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or any underground injection for the secondary or tertiary recovery of oil or natural gas, unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection.

A number of commenters also argued that natural gas storage facilities should be excluded from the regulations for reasons similar to the ones cited above, and because natural gas is neither a fluid nor a contaminant within the meaning of the SDWA.

EPA has carefully reviewed these comments and concludes that injection wells involved in natural gas storage operations do constitute underground injection within the meaning of the Act, and should be subject to these regulations. Section 1421(b)(1)(A) of the SDWA states that a State program, in order to be approved under Section 1422:

> "* * * shall prohibit, effective three years after the date of the enactment of this Title any underground injection in such State which is not authorized by a permit issued by the State to authorize underground injection by rule);"

The term "underground injection" is defined in Section 1421(d) of the Act as the subsurface emplacement of fluids by well injection. In scientific usage, the term "fluids" is defined to include not only liquids that flow but also gases. Thus, reading these two provisions of the Act together, there seems to be little

question that EPA does have the authority to bring both natural gas storage wells and other injection wells related to oil and gas production under the control of the Act. A more precise statement of the issue then would seem to be the appropriate level of regulation to which such practices should be subjected.

After a careful review of the comments on this point, the Agency has decided that further easing of the requirements for gas storage wells is appropriate for several reasons. First, EPA agrees with the comments that pointed out that unlike the injection of other substances, gas is highly unlikely to result in the chemical contamination of drinking water, even if it migrates from the injection zone. Second, the Agency is persuaded by the arguments that these facilities are used to store a valuable commodity and that, therefore, the operator has a strong incentive to be able to recover the stored gas with minimal losses to the environment.

However, after a further review of the pathways of possible contamination, the Agency has concluded that the major concern is any possible contamination of underground sources of drinking water from the displacement of formation fluids when gas is stored in aquifers.

The Agency's final decision is to classify gas storage operations in Class V. As such they will be authorized by rule in satisfaction of the requirement in Section 1421(b)(1)(A) of the Act, and be subject to further study. If States, based on their assessment, recommend further regulatory controls for gas storage wells, appropriate requirements may be established in the future.

With regard to the argument concerning existing effective State programs, the Act does not set any procedures or standards for EPA to follow in deciding which States to list. The Committee Report, on the other hand (H.R. Report 93–1185, page 32), states that it was anticipated by the Committee that EPA will list all 50 States but perhaps not the District of Columbia and various territories and possessions.

Furthermore, EPA has deliberately chosen to avoid any evaluation of the quality of existing State programs or the preparation of a "report card" as the basis for the Administrator's decision to list or not to list. There are several persuasive reasons for this course of action. First of all, a significant amount of EPA resources would be consumed in the process of doing careful evaluations of all of the 50 States UIC programs as they exist today. Such a nationwide evaluation process would require years to complete, involve hundreds of EPA personnel, and cost millions of dollars of contract support funds. Secondly, such an essentially adversary relationship could easily lead to embarrassment and resentment between States and EPA. It is not likely to be conducive to the long term objective of an effective State/Federal partnership in the implementation of UIC programs.

At one point in the development of the UIC program, it was the intention of the Agency to stagger the workload by phasing in the listing of States. It was to carry out the phasing that EPA developed the system of priorities to select the States which should be listed first. Factors to be considered in establishing such priorities included those approximating the potential threat (such as the number of wells in each State) and those approximating the importance of the ground water resources (such as the percent and absolute number of people relying on ground water). The basis for establishing priorities is given a fuller explanation in the Preamble to the initial listing of 22 States (43 FR 43420).

It should be emphasized that the Agency has always intended to list all States in keeping with the congressional guidance. The priority system discussed above was always intended as a basis for identifying the States to be listed first, not as a basis for deciding which States did or did not need a program.

In the process of consolidating the Agency's major permit program, however, it became apparent that the UIC program and the Hazardous Waste Management program are related at a number of points. The Agency, therefore, accelerated the listing of States in order to apply regulatory controls under UIC and HWM in a coordinated and orderly manner.

It is inevitable that the establishment of a Federal program necessarily carries with it certain uniform monitoring, reporting and other administrative requirements. This, however, is not to say that the Agency has made the judgment that all currently existing State programs would have to change radically in order to achieve EPA approval for delegation. Indeed, mindful of the instructions of the SWDA to minimize the disruption of existing effective State programs, EPA has gone to some lengths to avoid any requirement which would force any State to seek new legislation or to seek changes in existing regulations. While it is clear that there are variations in existing State programs to control underground injection, and that these regulations will have the effect of upgrading some of the State programs, it is EPA's expectation that many if not most State programs will be able to win EPA approval with only minimal changes. The Agency looks forward to working with State staffs to develop approvable programs as expeditiously as possible.

The House Committee Report also spoke to the congressional intent in adopting the amendments instructing EPA not to set requirements which would interfere with or impede oil and gas production (H.R. Report #93–1185, p. 31):

> "This amendment prohibits regulations for State UIC programs from prescribing requirements which would interfere with production of oil or natural gas or disposal of by-products associated with such production, except that such requirements are authorized to be prescribed if essential to assure that underground sources of drinking water will not be endangered by such activity.
>
> The Committee's intent in adopting this amendment was not to require EPA to bear an impossible burden of proof as a condition of promulgation of any such regulation. Rather, the Committee sought to assure that constraints on energy production activities would be kept as limited in scope as possible while still assuring the safety of present and potential sources of drinking water. Similar provisions were adopted with respect to EPA regulations which are to be promulgated when a State fails to adopt an approvable underground injection control program.
>
> In deciding what is an "essential" requirement, the Committee intends that the types of measures referred to in the Administrator's Decision Statement Number 5 and those referred to in this report be considered to be "essential" unless the contrary could be demonstrated with respect to a specific well or injection. Moreover, in using the works "interfere with or impede" the Committee did not intend to include every regulatory requirement which would necessitate the expenditures of time, money, or effort. Rather, the Committee intended to refer to those requirements which could stop or substantially delay production of oil or natural gas."

Thus, while these UIC regulations may create additional requirements and impose additional economic costs on oil and gas producers, and while they may result in the closure of certain marginal wells, the Agency is not persuaded that these regulations would result in a substantial delay of oil or natural gas production in the meaning of the Congressional intent.

Finally, the Agency finds little merit in the arguments that it has failed to demonstrate the necessary for the UIC regulations because it has not cited numerous instances of damage to underground sources of drinking water. It should be noted that in the basis for concern expressed in the House Committee Report (quoted earlier in this Preamble) Congress had clearly

concluded that the underground injection of contaminants is an increasing problem. Numerous instructions to the Agency in the House Report No. 93–1185 would seem to indicate that the Congress was fully aware that it was enacting a preventive statute which was aimed at preventing the contamination of the Nation's ground water resources, rather than at cleaning up after the damage had occurred. As one example of this, it is interesting to note the discussion of the definition of endangering drinking water sources (H.R. Report 93–1185, page 32):

"The Committee was concerned that its definition of 'endangering drinking water sources' also be construed liberally * * * The definition would be met if the injected material were not completely contained within the well, if it may enter either a present or potential drinking water source, and if it (or some form into which it might be converted) may pose a threat to human health or render the water unfit for human consumption. In this connection, it is important to note that actual contamination of drinking water is not a prerequisite either for the establishment of the regulations or for the enforcement thereof."

Furthermore, the Agency is mindful of the fact that Section 1421(b)(1)(A) of the SDWA specifies that once a State UIC program becomes established all underground injection is considered unlawful unless authorized by the State's UIC program.

Thus, the Agency did not conduct field work to document a national file of every case of contamination by a Class II injection practice. Nor did it try to establish the percentage of the Nation's ground water which has been contaminated by specific types of injection well practices. The Agency does acknowledge a responsibility, however, not to regulate needlessly or to force the expenditure of national rersources for frivolous purposes. Therefore, the Agency did review court cases and other available material to establish that the injection practices in Class II and the other classes do have a potential for contaminating underground sources of drinking water. We believe that documenting the potential for contamination does satisfy the legal standard imposed upon the Agency by the SDWA.

B. *Test of Endangerment.* The definition of the term "endangerment" has been one of the more commented upon sections of the UIC regulations. The original 1976 proposal of the UIC regulaltions followed the language of the SDWA. Section 1421(d)(2) of the Act states:

"Underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons."

The term "contaminant" is defined in section 1401(6) as "any physical, chemical, biological or radiological substance or matter in water."

The 1976 proposal, therefore, offered the following definition:

"Underground injection endangers underground drinking water sources if (1) such injection may make it necessary for a public water system using an underground drinking water source to increase treatment of the water, or (2) if such injection might make it necessary for a public water system which uses the source in the future to use more extensive treatment of the water than would otherwise have been necessary, or (3) if such injection may otherwise adversely affect the health of persons such as by adding a substance that would make water from the source unfit for human consumption." (Section 146.1 (x), 41 FR 36737).

Numerous adverse comments were received on this suggested definition. Many believed the definition to be confusing and vague, especially the third element relating to adverse effects on the health of persons. Other commenters held that EPA had simply restated the law in different words, and that the regulations should either use the statutory definition or one that could be applied with operational precision.

In response, the 1979 reproposal avoided a formal definition of "endangerment." Rather, it attempted an operational test that could be used with some operational significance. As the Preamble discussion pointed out (44 FR 23740):

"The test in these reproposed regulations is whether injection operations will cause the migration of injected or formation fluids into an underground source of drinking water. If injection into a well can cause such migration, the owner/operator must take appropriate action to eliminate the fluid migration."

The "no migration" standard was applicable to wells in Classes I–III, which were to achieve it through the use of sound engineering practices. The proposed ban/phase out for Class IV wells was also consistent with this standard. Since no technological requirements could ensure the absence of migration from wells designed to inject into or above USDWs, this practice was to be discontinued.

The proposal recognized two exceptions to the standard. One was in the case of Class V wells. EPA had determined (and still believes) that too little is known about the practices grouped in this class to make them ripe for regulatory controls. At the same time, the Agency did want to emphasize the responsibility of the Director to take action in cases where Class V wells did pose a real problem.

The Agency believed that a more selective standard than "no migration" was appropriate to define such situations because many Class V wells, even beneficial practices such as aquifer recharge wells, are designed to inject into potential USDWs. As a consequence, § 146.53 (44 FR 23766) required the Director to act when he gained "knowledge of a Class V well which presents a significant risk to the health of persons * * *"

The other exception appeared in § 146.22(c) (33 FR 23762) which gave the Director discretion to relieve Class II wells in existing injection fields of the applicable casing and cementing requirements. One condition of granting relief was that the well injection "will not result in the migration of fluids into an underground source of drinking water so as to create a significant risk to the health of persons using the source of drinking water." This formulation was chosen because the Agency wanted to recognize the special nature of construction requirements for wells in existing injection fields. While the Agency did not believe it appropriate to grant an unconditional license to endanger USDWs, it did believe it appropriate to allow additional scope in this instance in keeping with the proviso of the SDWA to avoid interfering with or impeding oil or gas production.

Commenters agreed that the proposed scheme was less vague than the earlier definition. However, several commenters now argued that the definition was too broad and that the term "migration" must be restricted in some fashion. Others were concerned because the definition seems to include displacement through underground hydraulic connections and argued that such migration was hard to anticipate, monitor, and, in some cases, control. Some commenters suggested that the term "migration" should be modified to some term such as "harmful migration", or "migration in harmful quantities." Others urged the use of such terms as "detectable migration" or suggested the use of ambient water quality standards broader than the parameters controlled in the National Interim Primary Drinking Water Standards. Still others questioned the appropriateness of departing from the language of section 1421(d)(2) to establish less restrictive standards for

Class V and the casing and cementing requirement in Class II.

EPA appreciates these suggestions but does not believe that they would improve the usefulness of the test. The use of a broader set of water quality standards or such modifiers as "harmful" would reintroduce the unworkability of the definition that was offered in the original proposal. The use of the term "detectable" would be redundant because, by definition, a migration into underground sources of drinking water could only be ascertained if it can be measured or detected. Finally, the lateral displacement of formation fluids is one of the pathways of contamination of concern in these regulations and EPA fully intended to bring it within the scope of this definition.

Consequently, the final regulations retain the "no migration" standard for Classes I–III, although it is now stated as "movement of fluids" or "movement of injection or formation fluids." (40 CFR 122.34). The Agency intends no substantive change through the substitution of "movement" for "migration." The two terms are considered synonymous and are used interchangeably in these regulations. The Agency does not believe that it is an overly protective standard. It does not require total containment; only that any leak or displacement not reach any USDW. It has the merit of being measurable and can be achieved through the use of readily available engineering technology which many injectors already apply.

Similarly, the "significant risk" standard has been retained in § 146.22(c). The Agency still believes that this is an appropriate condition for granting relief from the Class II casing and cementing requirements.

The Agency has decided to review the ban/phase out for some Class IV wells, while retaining this approach for those injecting into USDWs. The applicable standard is one of the questions in the further consideration of certain Class IV requirements. This subject is discussed more fully below.

In the case of Class V wells, the Agency has decided to establish a standard more closely in conformance with the statutory language. 40 CFR 122.34 (c) and (d) now require the Director to act if he learns that a Class V well "may cause a violation of primary drinking water regulations" or "may be otherwise adversely affecting the health of persons." These are not deemed to be more stringent or more inclusive standards. The Agency has not reconsidered its judgment that Class V wells are not ripe for regulatory controls, and enforcemnt action by the Director is not expected to become the rule rather than the exception it was intended to be under the Class V regulatory scheme. The Agency has decided that the use of statutory language is more appropriate in this case than a standard based on "significant risk."

The explicit authority to apply permits to Class V wells is new. Again, this is not intended to make the Class V requirements more stringent. The Agency, however, realized that the reproposed regulations had failed to provide the Director with any mechanism for applying controls in the cases where action needs to be taken with regard to a Class V injector to apply for a permit is intended to remedy this oversight.

C. Aquifer Restoration vs. Protective Action. A number of commenters urged the Agency to establish explicit requirements in the regulations that would force owners or operators of wells to take action to restore the quality of an aquifer under appropriate circumstances. The Agency has carefully considered these suggestions and has chosen not to establish explicit requirements for the following reasons.

Aquifer restoration has been tried on a pilot scale in shallow aquifers in connection with certain solution mining operations. Our review of the outcome of these pilot projects persuaded the Agency that full scale attempts at aquifer restoration could be very expensive with uncertain outcomes. Certainly in cases where solution mining is accompanied by an expected subsidence or catastrophic collapse in the overlying strata, the potential benefits of an aquifer resoration attempt are questionable.

The Agency also hesitates to impose restoration requirements because it interprets the mandate of the SDWA to be a preventive one. We believe that the main thrust of these regulations should be the prevention of further contamination rather than the restoration of aquifers that may already be damaged. The Agency is very much concerned that such requirements may divert scarce resources, both Federal and State, from the task of controlling underground injection which is the mandate under the Act.

At the same time it is not the intention of these regulations to preclude the Director from requiring the restoration of aquifers if such action is appropriate in particular cases. In establishing their UIC programs, the States are free to set more stringent requirements than the minimum requirements in these regulations. In addition, new § 146.10(d) requires the owner or operator of a Class III well to submit a plan of abandonment which must demonstrate that no migration from the mining zone into underground sources of drinking water will occur after abandonment. In setting abandonment requirements, the Director is given the discretion to set such aquifer clean up and monitoring requirements as he deems necessary to insure that the abandonment plan will be effective. The Agency will continue to assess the development of technology in this area and may establish additional appropriate requirements in the future.

D. Performance Standards vs. Technical Requirements. Many commenters criticized EPA for over-regulating by attempting to set technical requirements. They urged that EPA establish the objectives that it wants to achieve and allow discretion to the State Director and the injector in achieving those objectives. At the same time, many of the requirements were critized as being too vague and allowing too much undirected discretion to the permitting authority. Such commenters urged EPA to specify more clearly precisely what the standards are.

As these conflicting comments demonstrate, the tension between performance standards and technical requirements is an inherent problem in attempting to write national regulations in a highly technical area. Supporters of performance standards argued that they are an efficient means of regulating because they allow the owner or operator to choose how he will come into compliance. This, it is argued, tends to foster the development of new technology rather than stifling it and allows the most efficient means of coming into compliance to be applied in a particular instance.

Supporters of technical requirements argue that performance standards become almost impossible to enforce. Determining compliance or lack of compliance with the objectives of the regulations becomes a matter of long, drawn-out, highly technical arguments among technical experts. Further, it is argued that both in fairness to the regulated community, and in order to make the regulations enforceable, the regulations have a responsibility to spell out clear-cut requirements that the owner or operator understands and against which compliance or the lack of it can be measured.

Precisely because a great deal is still unknown about the movement of fluids below the surface, and because the monitoring of interactions is both difficult and uncertain, the approach of the UIC regulations has been to

translate the mandate of the SDWA into straight forward "good engineering" practices such as mechanical integrity of the tubular goods and the absence of man-made communication between the injection zone and higher strata. The presumption of the regulations is that as long as an owner or operator is in compliance with the technical requirements of "good engineering" practices, endangerment of nearby underground sources of drinking water will have been avoided. In cases where migration into underground sources of drinking water still occurs, even though the technical requirements have been complied with, the Director may impose additional requirements. In general, discretion in these regulations has been allowed where it seemed appropriate and possible to do so. On balance, this still seems the best approach to the Agency and it has been retained in the regulations.

E. Permitting Sequence. Many commenters pointed out an inconsistency between proposed 40 CFR Part 122 and 40 CFR Part 146 with respect to just when in the life cycle of a well a permit had to be obtained. A more important point of confusion was that the regulations seemed to require that the Director, prior to issuing the permit, review certain information which, at least in some cases, could not be produced without injecting into the well, even though the regulations seemed to prohibit injection without a permit.

The Agency agrees that the proposed regulations were not clear on this point and has now clarified the permitting sequence. The regulations now make clear that the requirement is for a single multi-phase permit similar to the current practice in a number of States, e.g., Michigan. In the case of a new well, the owner or operator must apply for a permit, which may be issued to him after appropriate public comment and hearings, before any work to drill or convert a well begins (see 40 CFR 122.33 and 122.38(b)). The permit is to have three phases: construction, testing and stimulation; operation; and abandonment. The applicant's plans for the construction and preparation of the well, as approved by the Director, will be incorporated into the permit as permit conditions. Should the plans change in any material way, the permittee must notify the Director and obtain his concurrence to the changes. Such modifications are considered to be minor modifications and can be approved administratively without the requirement for public hearing and comment.

It is the responsibility of the owner or operator to notify the Director of the completion of each phase and to obtain the Director's written or oral permission to proceed with the next phase (see 40 CFR 122.41(c), 122.42 (a) and (f), and 146.10). The permittee must provide the Director a 13 day opportunity to conduct a physical inspection of the well before putting the well into operation. Conditions for the operation of the well will be established by the Director as part of his notification to the owner or operator that he may proceed with the next phase. The Sections of Part 146 specifying the information to be submitted by the applicant and to be considered by the Director have been modified to reflect this clarified scheme.

The owner or operator of an existing well must submit his application at the time he is required to do so by the Director in accordance with the Director's plan for re-issuing permits submitted as part of the State program to EPA for approval. The permit will apply to the operating and abandonment phases of the well's life, but may incorporate compliance schedules according to which the injector must perform such corrective actions as the Director may require.

The Agency believes there are several advantages to this approach, not the least of which is that it will minimize the changes required in the current procedures of most States. By placing the permitting decision at the beginning of the process, it assures the applicant of a decision before any major investment has been made. Since the approval to proceed to the next phase can be handled administratively, it avoids any major delays once the project has been initiated. Finally, it provides a greater degree of environmental protection by clarifying the authority of the Director to supervise the construction and testing of the well in addition to its operation and abandonment.

F. Coordination of Authorities Under SDWA, RCRA and CWA. One of the questions addressed in the consolidation of the Agency's major permit programs was the coordination of overlapping authorities over well injection. Section 3005 of RCRA states that once the Hazardous Waste Management program is established, hazardous waste may only be disposed of (including injected) in a site approved under the authority of RCRA. At the same time, Section 1421 of SDWA states that once a UIC program is established for a State, any well injection in the State is prohibited unless authorized under its UIC program. Since there are differences between SDWA and RCRA, these parallel statutory sections could subject the operator of an injection well used to dispose of hazardous waste to duplicative and possibly conflicting requirements. In keeping with its intention of reducing administrative burdens on the regulated community, the Agency offered the following resolution in the 1979 proposal of the Consolidated Permit regulations. The surface management of hazardous waste would be regulated under RCRA while injection wells would be regulated under the SDWA. The separation point would be at the cut-off valve at the well-head. A facility would have to obtain authorization under SDWA to operate the well itself. Any attendant surface facilities used to manage hazardous waste would have to be permitted under RCRA. The rationale for this proposed method of regulation was twofold: First, the technical differences between surface disposal techniques and well injection argue that the two sets of practices are appropriately regulated through differing technical requirements; second, the proposal avoided the imposition of duplicative procedural requirements on the operator of the well.

Three major comments were received on this proposed course of action. Two of them agreed in general with EPA's decision as long as the owner or operator of the well would have to complete the manifest-keeping requirements under RCRA. This was, of course, one of the conditions specified in proposed 40 CFR 122.44 and 40 CFR 146.09. The third commenter objected strongly arguing that: (1) The language of Section 3005(a) of RCRA does not allow the disposal of hazardous waste in any facility that is not permitted under RCRA; and (2) the disposal of hazardous waste should be regulated under RCRA because that Act provides a greater level of protection to the environment.

EPA has reviewed these comments with great care and rejects the general argument that the level of protection afforded the environment from the potential effects of underground injection would necessarily be greater under RCRA than under SDWA. While it is true that RCRA authorizes the Agency to protect human health and the environment from the impacts of hazardous waste disposal, the scope of this mandate is not directly relevant to well injection. The major concern from the injection of fluids is the potential danger to underground sources of drinking water, and the Agency believes it has adequate authority under SDWA to protect such sources from the effects of well injection. Futhermore, because of

technical differences in the practices, the requirements which are appropriate to surface disposal methods are not in many cases, appropriate for well injection. Indeed, the Agency would promulgate essentially the same technical requirements to regulate the well injection of hazardous wastes whether it did so under SDWA or RCRA.

In response to comments, however, the Agency has changed its approach to coordinating RCRA and SDWA authorities in three ways. First, under SDWA no enforceable requirements will apply to operators of injection wells in a State until the UIC program for that State is effective. Because of the statutory scheme of SDWA, State programs will not be established until one to two years after the minimum requirements in 40 CFR Part 122 have been promulgated. EPA agrees that, under the proposed regulatory approach, the SDWA would, therefore, not have provided a level of control equivalent to RCRA over wells used to inject hazardous waste during the interim period. Consequently, the final 40 CFR 122.23 requires that owners or operators of Class I and IV wells obtain interim status under RCRA. Certain standards for interim status are contained in 40 CFR Part 265 Subpart R which has been made applicable to such injectors. Additional standards have been proposed (see 45 FR 33280) for future inclusion in Part 265. Injectors of hazardous waste will ultimately be regulated under the SDWA. However, prior to the time a State UIC program is effective, hazardous waste injection wells may be permitted under RCRA (see 40 CFR 122.30) for a period not to exceed two years.

Second, in contrast to the proposal, injection wells will now be authorized under both RCRA and SDWA once the applicable State UIC program becomes effective. A permit by rule under RCRA (see 40 CFR 122.26) will authorize the disposal of hazardous waste into an injection well if the well has been properly authorized under SDWA. This final resolution was adopted because it satisfies the statutory language of both Acts. At the same time, the goal of minimizing procedural burdens on the regulated community will be maintained. As a practical matter the owner or operator of a well used to inject hazardous waste will still only have to obtain authorization and comply with requirements applicable to him under the UIC program. Compliance with applicable UIC requirements will be deemed to satisfy RCRA requirements as well.

A final point concerns the delegation of interim status authority to States. States will be given the option to choose whether to assume interim control over hazardous waste injection wells under RCRA and then convert to control under SDWA. Alternatively, they may leave interim regulation of such wells with EPA and accept delegation only at the time their UIC program becomes effective. If a State chooses the former method, it will be required to assume responsibility under RCRA through the same agency that will ultimately exercise the responsibility under the SDWA.

Other changes have also been made in the regulatory scheme for Class IV wells. They are discussed later in this preamble.

Injection wells, with the exception of Class II, could also be regulated either under the Clean Water Act (CWA) or the SDWA. More specifically the CWA requires that in cases where the National Pollutants Discharge Elimination permitting system (NPDES) is delegated to States, the States must have the legal authority to also control the disposal of pollutants into injection wells. The proposed Consolidated Permit regulations in § 123.74 required State NPDES permit programs to have the authority to issue permits to control the disposal of pollutants into wells.

Such a requirement could conceivably have some undesirable results. To the extent that there are differences between the CWA and the SDWA, such a requirement could, for example, require a State to develop a UIC program which meets the requirements of the SDWA and then to develop separate authorities to control well injection that meet the requirements of the CWA. In addition, this section could be read to imply that the UIC program and the NPDES program could only be delegated in concert.

In order to resolve these difficulties, final Section 40 CFR 123.72 now requires that State law provide authority to issue the permits in question and specifies that an approved UIC program satisfies this requirement for the NPDES program.

II. Major Programs Concepts

A. Well Classification. In the proposed 40 CFR Parts 122 and 146.05, the Agency proposed a revised scheme for classifying injection wells and requested comments on its appropriateness. In general, commenters agreed that this was a workable classification system. A number of commenters, however, suggested the need for further clarification. Section 146.05 of these regulations attempts to resolve the points that were raised.

First, a number of commenters pointed out that in the case of Class I and Class IV wells, part of the definition of the well involved the relationship of the well to the nearest drinking water source, without, however, specifying any distance or other limitation. The applicable definitions now specify that Class I wells must inject below the deepest formation which, within a quarter of a mile of the well bore, contains an underground source of drinking water. Conversely, Class IV wells are those that inject into or above a stratum which, within a quarter of a mile of the well, contains an underground source of drinking water. As a basis for this clarification, the Agency relied on the concept of the area of review and conformed these definitions to the minimum of one-quarter mile to be used when the area is established by the use of a fixed radius.

Second, many commenters were concerned about sand backfill wells and the possibility that, because of the nature of the injected materials, these wells could come under the classification of hazardous wastes under Class IV. This was not the result intended by the Agency. The final regulations now specify that sand backfill wells are to be considered Class V. They are to be assessed for their environmental impact and future regulations may be applied to them.

Third, some commenters suggested that the proposed regulations left some confusion over the status of non-residential septic systems. Single-family domestic sewage disposal systems are not covered under the UIC program. Multiple dwelling and industrial sewage disposal systems are generally included in Class V. Those that are used to dispose of hazardous waste fall under Class IV.

Fourth, a number of commenters suggested that disposal wells handling blowdown water discharges from gas refinery plants and similar wastes be treated not as Class I but as Class II wells. Given the nature of these operations and the chemical compositon of the injection fluids, the Agency has decided that these operations would be more appropriately regulated under Class I.

Fifth, some commenters expressed confusion over the status of injection wells used to store fluids which are used in the recovery of stored hydrocarbons. Section 146.05 clarifies that such wells are now to be treated not as salt water disposal wells, but as Class II hydrocarbon storage wells.

Sixth, during the comment period, EPA was made aware that hazardous waste may in some cases be injected in

situations other than into, through or above an USDW. Because of the definition of Class IV, these injections would, under the proposed regulations, have fallen into Class V. Commenters argued that the injection of hazardous waste merits stricter regulation than the requirements of Class V even if it is not into, through or above an USDW. The Agency agrees with this view, especially because it seeks to make the control of hazardous waste disposal under RCRA and SDWA comparable. Therefore, the injection of hazardous waste other than through Class IV wells is now included in Class I (see 40 CFR 122.32(a)).

Seventh, the proposed regulations included "nuclear" storage and disposal wells in Class I (see proposed 40 CFR 122.34, 44 FR 34282). The definition of the term "solid waste" (and therefore "hazardous waste") under RCRA may include certain kinds of radioactive waste, but specifically excludes source, special nuclear or by-product material as defined by the Atomic Energy Act of 1954, as amended. Since the SDWA does not contain a similar limitation, the Agency proposed to include the injection of such material in Class I. Few commenters addressed this aspect of the proposal, although some objected to granting States authority over these sources. The President on February 12, 1980, issued an Executive Order outlining a program to arrive at a comprehensive radioactive waste management program. Until this program is complete, and EPA has had an opportunity for full consultations with the Nuclear Regulatory Commission, the Department of Energy, and other agencies with responsibilities potentially affecting radioactive wastes, it would be premature for EPA to issue regulations concerning the disposal of radioactive wastes into Class I wells. Moreover, EPA wishes to coordinate any regulations governing sand backfill wells with regulatory measures it may undertake under the Uranium Mill Tailings Act. Accordingly, EPA has modified the classification of wells so that wells disposing of radioactive wastes below strata containing a USDW will be Class V wells.

However, the disposal of radioactive wastès into or above USDWs is an environmentally undesirable practice. Therefore, EPA has added a definition of "radioactive waste" in § 122.3 which clarifies that the term "nuclear" waste used in the proposal was intended to cover not only the radioactive wastes which are hazardous wastes under RCRA but also fission by-products and similar wastes covered under the Atomic Energy Act of 1954. The disposal of all such wastes into or above USDWs is included in Class IV and will be regulated according to the scheme promulgated for Class IV wells: those Class IV wells injecting into a USDW are prohibited; requirements for other Class IV wells will be promulgated in the fall of this year. (See the discussion of Class IV requirements below.)

Section 122.31(d) now includes specific inclusions and exclusions from the coverage of the UIC program. Notes have also been added to § 146.05 for the convenience of the reader.

B. Underground Sources of Drinking Water. Since the original proposal of the UIC regulations in 1976, an underground source of drinking water has been defined as an aquifer or its portion which either currently provides water for human consumption or is capable of yielding water containing fewer than 10,000 mg/1 of total dissolved solids (TDS). A number of commenters again objected to the reproposal of 1979 setting the standard at 10,000 mg/1 of TDS, and offered a number of alternative concentration levels. EPA has carefully reviewed these alternative suggestions and has once more decided to retain the standard of 10,000 mg/1 of TDS. None of the alternative concentrations have any superior justification in terms of current State practice, human health, or technological considerations. In the absence of any overriding argument to the contrary, the Agency will follow the standard in the House Committee Report accompanying the SDWA.

A number of other comments were offered on the scheme for designating underground sources of drinking water. Some pointed out an apparent conflict between Part 122 and Part 146, in that the former seemed to require the State Director to designate underground sources of drinking water while the latter seemed to require him to designate aquifers which were exempted from protection. Others urged the Agency to clarify the procedure for making the initial designation and the procedures whereby designation could be changed in the future. Still others pointed out that the use in the exemptions of such terms as "economically or technologically impractical" were imprecise and ought to be defined further. Finally, some argued that the exemption provided for "oil or mineral producing" aquifers seemed to imply that only areas actively being worked could receive such an exemption. They argued that the future development of mining sites could be hampered because of the uncertainty of whether or not the mining site could receive an exemption from the definition of underground source of drinking water. Therefore, they urged the use of the term "bearing" so that prospective mining sites would be assured of receiving a permit to operate, and thereby enhance their ability to obtain financing.

EPA agrees with some of these comments and disagrees with others. The final regulations attempt to clarify the definition of "underground source of drinking water" as well as the process for designation in the following way. The terms "underground source of drinking water" and "exempted aquifer" are defined in § 122.3. "Underground sources of drinking water" are aquifers or their portions which currently provide water for human consumption or which are capable of yielding water containing fewer than 10,000 mg/1 of TDS. Under § 122.35, the Director, as part of the State program he submits for approval to EPA, may identify those aquifers or aquifer portions which will be considered as underground sources of drinking water. This identification may be done by definition, description, illustration, or other means. The reason for this is to relieve the Director of the requirement for extensive underground exploration and mapping, or of supplying a level of detail with his State program submission which will force a modificaion of the State program for every minor modification in the depth or extent of the fresh water zone. As stated in § 122.31(d), an aquifer is an USDW if it fits the definition even if it has not been affirmatively identified by the Director.

An "exempted aquifer" is an aquifer or its portion which would otherwise meet the standard for an USDW but has been designated as "exempted" by the Director in conformance with § 146.04. Section 146.04 states that a Director may designate as an exempted aquifer an aquifer or aquifer portion which does not already provide water for human consumption but is capable of yielding water with a concentration of fewer than 10,000 mg/1 of TDS, if the aquifer or its portion is:

(1) Mineral, hydrocarbon, or geothermal energy producing;

(2) Situated at a depth of location which makes recovery of water for drinking water purposes economically or technologically impractical;

(3) So contaminated that it would be economically or technologically impractical to render it fit for human consumption; or

(4) Located over a Class III mining area subject to subsidence or catastrophic collapse.

The first three of these conditions have changed only in substituting the broader term "hydrocarbon" for "oil" in the first proposed criterion. The Agency has declined to change the term "producing" to "bearing" in the first condition because it did not want to open the possibility of wholesale exemption of aquifers, over large areas of the country, which become identified as being capable of producing one or another mineral. Similarly, the Agency has chosen not to define further the term "economically or technologically impractical." After considering the alternatives, the Agency decided it was more appropriate to leave the determination of what is or is not economically or technologically impractical to the discretion of the Director in the particular case.

The fourth exemption is new. It is an attempt to respond to those commenters who correctly pointed out that certain Class III mining operations necessarily involve the subsidence or collapse of strata above the injection zone. In such cases, the probability of harm to the overlying aquifers is substantial once operations are underway. The decision to protect these aquifers is more appropriately made at the time the mining operation is permitted.

In cases where the Director chooses to exempt an aquifer, he is required to submit not only detailed maps, but also sufficient justification in support of the exemption.

The Director may exempt aquifers as part of the State program he submits to EPA for approval. Therefore, the designations, by the nature of the process, are subject to public hearing and comment as well as the review and approval of EPA. The Director is free to change the designations or add to them at a later date. Such a change, however, would constitute a major modification of the approved State program and, as a major modification, is subject to public hearing and comment, as well as EPA review and approval.

C. Area of Review and Corrective Action. Most of the comments received on the revised area of review/corrective action concept contained in the reproposed 40 CFR Part 146 were generally supportive, although a number of specific suggestions were made. *First,* a number of commenters pointed out that the equation provided in the proposed § 146.06 was applicable only in certain circumstances. EPA agrees, but notes that in proposed § 146.06(c), the alternative calls only for the computation of the zone of endangering influence based upon certain parameters. The modified form of the equation provided in that section was illustrative and for the convenience of the reader. It was not intended to represent the only acceptable equation to be used in all cases.

Second, a number of commenters suggested that the applicant for a permit be given a voice in the decision of how the area of review would be determined for his well or field. EPA agrees and has added to the regulations giving the Director discretion to consult the applicant in this regard (§ 146.06). *Third,* some commenters suggested that the one-quarter mile radius be made an absolute minimum regardless of whether the zone of endangering influence was determined as fixed distance or through computation. EPA disagrees with this suggestion. In cases where the zone of endangering influence is actually less than a quarter of a mile, such a requirement would force the applicant to expend resources and do work which may not be justified by the expected benefits. *Finally,* some commenters suggested that the area of review be drawn from the edge of a field or project rather than the individual well. EPA agrees. The concept was included in the language of the proposed § 146.06(c) and has been retained in the final requirement.

Two comments were made with regard to the proposed corrective action requirement. The first suggestion was that the text of the proposed regulations seems to imply that it is up to the applicant to collect the information on the number of wells penetrating the injection zone within the area of review. The argument is that such information is kept by the State and, therefore, the requirement should be for the State, rather than for the applicant, to gather this information. The Agency agrees only in part. While it is correct that in many cases this information is in the files of the State, and, therefore, simplicity would suggest that the State should make use of this information in the review of the permit application, the Agency believes it important that the ultimate burden for providing the information necessary for an adequate review of a permit application should rest with the applicant and should not be transferred to the permitting authority. Therefore, the language of the final regulations makes it possible for the State to supply this information when, in the judgment of the Director, it is appropriate to do so. However, the final regulations do not explicitly relieve the applicant of the responsibility for making such information available when the Director deems it appropriate.

Another area of comment concerned the possible interpretation that in requiring corrective action on wells that penetrate the injection zone within the area of review, the Director may be put in a position of requiring the applicant to go onto the property of others, or to take corrective action on the property of others in order to meet the permit conditions. EPA agrees that it is inappropriate for these regulations to require an applicant to perform actions which may not be within his legal ability, as a condition or precondition of obtaining a permit. As a consequence, the corrective action requirement has been revised (§ 122.44) to provide the Director and the applicant with three options.

First, if he can arrange it with the neighboring owners and operators, the applicant may, before he begins to inject, take the corrective action prescribed by the Director and then inject at his intended injection pressure.

Second, the Director may issue a permit with a reduced injection pressure calculated so that the potential zone of endangering influence will be no bigger than the area under the control of the applicant in which the applicant can take the appropriate corrective action.

Third, the permit can be issued with the requested injection pressure but with the condition that the owner or operator must operate at a lesser pressure until such a time that he takes the corrective action required to allow a more extensive zone of endangering influence. In arriving at this resolution, EPA did not agree with suggestions that the State use its authority to force the owner or operator of the "bad" well to repair it. The Agency believes that it is not appropriate to use the authority of the State to force one individual, without his agreement, to incur expenses and effort which benefit another party. In addition, abandoned wells in the area of review also may have to be fixed. In many cases, it may not be possible to locate a responsible party.

D. Mechanical Integrity. Proposed § 146.08 defined mechanical integrity as having two parts: (1) The absence of a significant leak in the casing, tubing or packer; and (2) the absence of significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore. The proposal specified that the absence of significant leaks was to be established through the use of eight listed tests. The absence of significant fluid movement could be demonstrated either through well records demonstrating the presence of adequate cement or the result of a cement bond log, sonic log, temperature log, density log, or dual neutron log. The

proposed section further specified that the Director may allow the use of a test other than those listed upon the written approval of the Administator of EPA. The owner or operator of the well was to demonstrate the mechanical integrity of his injection well as a condition of authorization and at least every 5 years thereafter.

Virtually all aspects of this requirement received public comment. However, there does not appear to be a clear consensus in the thrust of the suggestions offered the Agency. Some commenters argued that a demonstration of mechanical integrity every 5 years is too frequent. Others argued that it is not frequent enough. Some questioned the reliability of cementing records, while others supported the use of such records and urged the Agency to go beyond its proposal by allowing the demonstration of mechanical integrity through the historical absence of contamination. Some commenters urged the Agency to rely on annular pressure tests; others disagreed. Some argued that the Director be given the discretion to specify which test he found acceptable as a demonstration of mechanical integrity. Some objected to the proviso that the Administrator approve the use of tests other than those listed in § 146.08. Others urged that such additional tests as the Director approves should be listed in the **Federal Register** for the use of others.

The majority of commenters did seem to agree in three areas. Most commenters urged the elimination of the words which seemed to require the use of more than one test to demonstrate the absence of significant leaks. Many commenters also found some fault with one or more of the tests specified by EPA in this section. Finally, in response to a request for comments in the preamble, many commenters supported the idea of a sampling approach to mechanical integrity rather than a requirement for universal demonstration.

EPA has carefully considered these comments and requested its consultant to conduct further technical analyses. Based on this work, EPA has decided to make the following changes in the final version of § 146.08.

First, EPA agrees that in order to demonstrate the absence of significant leaks in the casing, tubing, or packer of a well, any one of the specified tests is sufficient and has, therefore, eliminated the term "some combination."

Second, the analysis performed for us by Geraghty and Miller, Inc. suggested that the eight tests proposed as methods for demonstrating the absence of significant leaks were either incorrectly cited, redundant, or not particularly reliable in demonstrating the absence of leaks. Consequently, the final regulations retain only two of the eight tests listed in paragraph (b) of the proposed § 146.08. These are the monitoring of annulus pressure and pressure tests with fluid or gas.

Third, with regard to the listed tests to establish the absence of significant fluid movement in the well bore, the cement bond log, sonic log, density log, and dual neutron log have been eliminated, leaving temperature log or noise log as the specified tests. The basis for this decision is again the analysis conducted by the Agency's consultant.

Fourth, the requirement that the Administrator approve the use of tests other than those specified in § 146.08 has been retained, but in a different form. The use of alternative tests to demonstrate mechanical integrity is considered to be a major modification of the State program and must be treated as such under § 123.13. Two further points are worth discussing regarding mechanical integrity. The public comments and the work of our own consultant have raised some questions with regard to the reliability of historical well records to demonstrate the absence of fluid movement in the well bore. As a result, well records are no longer considered an acceptable method of demonstrating this aspect of mechanical integrity in the case of Class I and III wells. The use of well records has been retained for Class II wells because of the large number of wells in the Class and the statutory provision not to unduly interfere with or impede oil or natural gas production. However, the requirements for Class II wells will be subject to a mid-course evaluation. As one part of this evaluation, a sample of Class II wells, for which well records were used to demonstrate the absence of significant fluid movement in the well bore, will be required to perform the specified tests as well. This procedure will provide a comprehensive assessment of the reliability of well records and will provide a factual basis for future Agency decisions on whether to expand or eliminate the acceptability of well records to demonstrate mechanical integrity.

Finally, the preamble to the reproposed Part 146 (44 FR 23743–4) solicited comment on the possibility of requiring only a sample of wells, rather than all, to demonstrate mechanical integrity. Although many commenters supported this concept, the final regulations do not include any sampling approaches to the demonstration of mechanical integrity. Rather, the Agency decided to combine a test of the effectiveness of sampling with its decision to accept well records as a method for demonstrating the mechanical integrity only of Class II wells.

E. Area Permits. The 1979 version of the regulations proposed an area permit which would allow a number of wells of a similar purpose and construction under the control of a single owner or operator to be authorized by one permit. While most commenters approved this concept, they pointed out that the manner in which several sections of the proposal were worded seemed to imply that requirements would still have to be fulfilled on a well-by-well basis. One example of this was the information to be submitted in support of a permit application.

EPA agrees with this criticism and has clarified Part 146 throughout to make clear that a single permit for a number of wells can be applied for and obtained on an area basis. Section 122.39, dealing with area permits, has also been expanded to clarify the regulatory intent in this regard.

F. Logging and Testing Requirements. The sections of the 1979 proposal that received the most extensively adverse comments were the parallel requirements for Classes I, II, and III to conduct certain tests during the drilling and construction of wells and to report the information to the Director. Almost all commenters felt that specifying the actual logs and tests to be used was inappropriate, and, in most cases, overly inflexible. Upon consideration, the Agency agrees. These parallel sections for Classes I, II, and III have been changed. Final Part 146 requires deviation checks, but only for wells constructed with the use of pilot holes and reaming techniques. The Director is given discretion to specify the other logs and tests that may be required based upon the availability of similar data in the area of the drilling site, the construction plan and the need for additional information that may arise from time to time as the construction of the well progresses.

G. Control of Injection Pressures. The proposed regulations required the Director to establish limits on the injection pressure at the wellhead for Classes I, II, and III. In the case of Class I, the surface pressure was to be calculated so that the bottom hole pressure during injection did not propagate fractures in the injection zone and did not initiate fractures in the confining strata. For Class II, the surface pressure was to be calculated only so that the bottom hole pressure did not

initiate fractures in the confining strata. Because of the special nature of Class III operations, the injection pressure at the wellhead was to be controlled so as to prevent the migration of fluids into underground sources of drinking water.

Several commenters suggested that there be no restrictions on injection pressure. Others offered specific alternatives as to how injection pressure should be controlled and what it should be designed to prevent. In particular, representatives of the oil and gas industry argued that the wording of this requirement could cause the loss of oil reserves valued at approximately $60 billion nationwide.

Upon further consideration of this requirement, the Agency finds that the original intent of these requirements was appropriate. However, two points of clarification are appropriate to resolve the problem pointed out by the commenters. First, in the final Part 146 the terms "injection zone" and "confining zone" are defined to include a single formation, part of a formation, or a group of formations. The regulatory concern of the Agency is that between the underground source of drinking water to be protected and the injection zone, there be a relatively impermeable barrier which is not breached by the injection pressure. This barrier may be composed of a single formation or a group of formations. Secondly, the proposed regulations used the term "bottom hole pressure" inappropriately. Because the friction loss across the perforations of the casing, the injection pressure in the formation is not equal to the bottom hole pressure within the casing. The concern of the Agency is with the pressure in the formation, and the final regulations have been changed to require the calculation of pressure at the well-head so as to produce an acceptable pressure in the injection formation as opposed to the casing at the bottom of the hole.

III. Changes in Individual Well Class Requirements

A. Class I. In the original 1976 proposal, the Agency had suggested a 5-year term permit for all classes of wells regulated under the UIC program. In response to extensive comments, the 1979 reproposal substituted lifetime permits for all classes to be regulated by permits. To balance the authorization of these practices for their entire life, Part 122 established extensive review, modification, and revocation and reissuance requirements. Most commenters found these requirements to be confusing and believed them to be inappropriately extensive.

In the final Consolidated Permit regulations, the Agency decided to move in the direction of term permits. Hazardous Waste Management program permits under RCRA as well as Class I permits under UIC will be issued for a period not to exceed 10 years. There are several reasons for this decision. The fluids injected into Class I wells, in many cases, are expected to pose a high degree of risk for the environment. Therefore, a greater degree of regulation is considered appropriate. Furthermore, Class I wells are more likely to be the group of facilities that will require multiple EPA permits since many of them are used at industrial sites where hazardous waste may be generated and surface discharge of waste also occurs. Term permits for Class I wells will ease the difficulty of consolidating and integrating various EPA permits to the same owner or operator.

To balance the shorter permit term, the consolidated permit regulations now provide the permit holder greater security during the term of the permit by restricting the reasons for which the permit may be reviewed, modified or revoked.

B. Class II. In addition to the changes affecting Class II wells discussed above, several additional changes for Class II wells are reflected in the final Part 146 regulations. The first of these is a change in the casing and cementing requirements for existing wells. In the original proposal of 1976, the Agency had required that all injection wells must be cased and cemented to protect drinking water sources containing up to 3000 mg/l of TDS. A number of commenters pointed out to the Agency that such a requirement was impractical and onerous. Since there is a rough correlation between depth and the concentration of TDS in ground water, a requirement for casing and cementing to protect levels of TDS higher than previously protected essentially means that an injection well will have to be cased and cemented to a greater depth.

Based on analysis undertaken after the 1976 proposal, the Agency agreed with the commenters that in many, if not most cases, it is impossible to extend the casing in an existing well. While it is possible to add cement to a well, EPA's consultants estimated that the cost of such a requirement in existing Class II wells could run upwards of $20 billion. However, in existing injection fields, there was some question as to the environmental benefit of protecting aquifers which had not been protected previously.

As a consequence, in the 1979 reproposal, EPA included § 146.22(c). This section granted the Director the discretion not to apply the Class II casing and cementing requirements to new or existing wells in existing injection fields under three conditions: (1) That State regulations for the construction of injection wells existed prior to the State UIC programs; (2) that such requirements had been applied to the injection wells in question; and, (3) that the injection wells did not cause a significant risk to the health of persons using the impacted USDW.

EPA's intention in this section was to alleviate the casing and cementing burden for existing Class II injection wells. The Agency believed, however, that some restrictions on the discretion of the Director were appropriate. For example, the Agency did not want to condone every casing and cementing practice, regardless of its potential for contamination, or to force the Director to authorize every injection well even if it posed a significant risk to the health of persons.

Commenters on the 1979 reproposal maintained that such a grant of discretion to the Director, with its limitations, did not really solve the problem. A major concern seemed to be that a number of States do not or did not have applicable casing and cementing requirements which would satisfy the conditions of proposed § 146.22(c).

These final regulations have been changed to clarify the relief that the Agency intended to grant. Final § 146.22(c) states that the Director need not apply the casing and cementing requirements of Class II if: (1) An existing or newly converted injection well in an existing field is in compliance with whatever State requirements were applicable to that field at the time the well was constructed, and (2) the injection will not cause the movement of fluid into an USDW so as to create a significant risk to the health of persons.

Newly drilled injection wells in existing fields are to comply with the requirements the State applied to that field prior to the effective date of the UIC program (§ 146.22(d)), and may not create a significant risk to the health of persons. If a State had no requirements for casing and cementing, the Director, in accordance with § 146.22(e), is to file a plan as part of his State program application which describes the casing and cementing requirements he proposes to set for wells in existing fields. If EPA approves, the State program becomes effective, and those will be the requirements to which injection wells in existing fields must conform.

Class II injection wells in existing fields will, however, have to

demonstrate the integrity of such casing and cementing as they have.

The second change in Class II requirements concerns the conversion of wells, i.e., the practice of creating a new injection well by converting a well that had been drilled for other purposes. Many commenters pointed out that newly converted wells would have the same problems in meeting more extensive casing and cementing requirements as existing injection wells. Consequently, the application of the full Class II construction requirements to all new wells, including newly converted wells, was equivalent to prohibiting the practice.

The Agency agrees with these comments, and does not intend to prohibit the practice of converting existing wells. Consequently, newly converted wells have been included in final § 146.22(c) and (e). Whereas the proposed § 146.22(c) was limited to existing injection fields, the final relief applies to all existing fields, including those being converted to injection. Thus, the intended relief has been made available to converted wells also.

A third change concerns Class II reporting and monitoring requirements. A number of commenters pointed out that in many cases (particularly in the case of unitized enhanced recovery injection fields) monitoring is now conducted, but not on a well-by-well basis. The Agency has reviewed this question and has decided that no particular benefit is to be served by insisting on monitoring and reporting on an individual well basis, particularly since in many cases, such wells will be regulated under an area permit. Consequently, the final regulations now allow enhanced recovery injection wells to be monitored on a field basis, and the results of monitoring to be reported to the Director on the same basis.

Finally, in reviewing these regulations for promulgation, the Agency became aware of a potential problem resulting from the estimated time which might be consumed in processing permits for new wells. In many cases, the ability to produce from a new well may be contingent upon the availability of an injection well for disposing of the brine produced with the oil or gas. In existing fields, this is not expected to be a serious problem because disposal alternatives are expected to be available. However, in the case of wildcat explorations in new areas, fewer alternatives for disposal are expected to be available. Therefore, the production from a new well may have to be delayed until a permit for the construction and operation of a salt water disposal injection well is obtained. Based on our analysis, such delays could represent significant costs in terms of delayed oil and gas production.

To resolve this problem, § 122.40 of the consolidated permit regulation has been expanded. In addition to cases where imminent and substantial endangerment to human health exists, or cases in which a substantial and irretrievable loss of oil or gas resources will occur, a temporary authorization to construct and operate a salt water disposal well may be granted to avoid a substantial delay in oil or gas production. In such cases, an application for a permit must be filed, and the emergency authorization may be given until the Director acts upon the application.

C. Class III. In the preamble to the 1979 proposal of Part 146, the Agency gave notice that it had received extensive comments on the Class III requirements originally proposed in 1976. As the preamble noted, a number of the suggestions offered in response to the original proposals had been incorporated in the reproposal. However, as the preamble went on to state, (44 FR 23746) the Agency was continuing to evaluate alternatives for subcategorizing Class III requirements and was soliciting public comment on some additional fundamental changes. The public comments received on the 1979 reproposal urged the Agency to make some of these changes. The Agency agrees and has extensively revised the requirements for Class III.

Some of the following changes have already been discussed earlier in this preamble, but their impact on Class III is worth reviewing here. First of all, § 122.31(d)(2) of the final Consolidated Permit regulations lists as a specific exclusion, those wells which fall outside of the territorial waters of States. The rationale for this exclusion is that the Safe Drinking Water Act intended the UIC program to be a State and not a Federal program. When EPA promulgates and administers an UIC program, it does so in lieu of the State. Therefore, the Agency has judged it inappropriate to assert original Federal jurisdiction over offshore wells that operate beyond the territories of States. This exclusion exempts certain Class III operations from the coverage of these regulations.

A second important change is that the final § 146.04 now allows the Director to exempt from protection as underground sources of drinking water, those aquifers overlying the site of a Class III operation subject to subsidence or catastrophic collapse. This provision for exempting aquifers should be read together with final § 122.43 which states, that in cases where an injection well is not into, through, or above an underground source of drinking water, the Director may ease the conditions that he applies to a particular injection well or operation, provided that such eased requirements do not increase the risk of migration of fluids into underground sources of drinking water. This combination of provisions should make it possible to ease the burdens for Class III operations in a number of cases.

Third, one of the concerns of the comments on Class III was that the requirement that no new wells could begin to operate until they had been authorized by permit, could lead to a temporary disruption of operations while the permit was being processed. As in the reproposal, final § 122.37(a)(1) provides that existing Class III operations may be authorized under a rule until a permit is applied for and granted. However, the Section now also specifies that a Class III operator may continue normal operation, including the construction and operation of new wells, under the rule as long as he is in compliance with all applicable requirements.

Fourth, commenters were also concerned about the requirement that even under an area permit the prior approval of the Director had to be obtained before a new well could be placed into operation. As discussed above, the conditions for an area permit have been clarified in general. In addition, final § 122.39(c) now specifies that new wells may be constructed and operated under an area permit without prior approval as long as the new wells are in compliance with permit conditions, the owner or operator notifies the Director according to procedures established in the permit, and the cumulative effect of new well construction has been evaluated by the Director previously. The Agency believes that the four changes listed above should help to resolve many of the problems pointed out in the public comments.

One of the major areas on which public comment was requested in the preamble to the 1979 reproposal, was whether or not the technical requirements for Class III wells should be subcategorized. The commenters on the regulations overwhelmingly favored this course of action. However, the comments were less helpful in suggesting practical ways in which this could be done. To resolve this problem, the Agency has done considerable additional analysis to review Class III injection facilities from the perspectives

of current prevailing practice, existing regulatory requirements and potential environmental consequences. (See report of Geraghty and Miller.)

Our review looked at 9 Class III practices: Frasch sulfur mining; the solution mining of uranium, salt, and copper; in-situ combustion of oil shale, coal, lignite, and tar sands; and the extraction of geothermal energy. The similarities and differences of these nine groups of wells were compared with respect to a number of parameters. With regard to potential environmental impact, for example, 6 of the 9 practices inject into zones that may contain aquifers that would qualify as potential underground sources of drinking water under the UIC definition. In 8 of the 9 practices, injection normally occurs through overlying aquifers which would also meet the definition. With the exception of geothermal energy wells, injection pressures tend to be relatively high, and, with the exception of the Frasch process, the produced fluids could be considered hazardous in that they contain at least heavy metals. In 7 of the 9 cases, subsidence or catastrophic collapse is expected to accompany the operation.

The review of existing State controls and current practice also revealed more consistent similarities than consistent differences among these 9 types of practices. Based on this analysis, EPA has chosen not to establish requirements by subcategory of Class III.

The following changes have, however, been made in the requirements for Class III. With regard to construction requirements, the new casing and cementing standard to protect underground drinking water is applied only to new wells since a requirement for additional casing and cementing for an existing well with a life expectancy of a few months would make little sense. Existing injection wells used in the solution mining of salt and the recovery of geothermal energy, which tend to have a longer useful life, would, however, have to demonstrate mechanical integrity. The requirement for the use of corrosion resistant materials has been retained. However, it should be noted that this does not necessarily mean fiberglass, 316 stainless steel, or other exotic materials. It only means that the material used in the well must be adequate to meet the design life of the well. The performance history of the material under field conditions would be an adequate basis upon which to decide the appropriateness of construction materials. Logging and other testing requirements have already been discussed above. Deviation checks are required only in cases where construction involves a pilot hole with reaming. Other appropriate logging and testing is to be specified by the Director.

With regard to operating requirements, all new wells would have to demonstrate mechanical integrity before injection is begun. In the case of existing injection wells, only those with a longer useful life, such as the injection wells involved in the solution mining of salt and the production of geothermal energy would have to make an initial demonstration of mechanical integrity. Similarly, the periodic demonstration of mechanical integrity will apply only to the wells with longer life, i.e., salt and geothermal wells. The requirement for 5 monitoring wells has been removed, and monitoring requirements are now stated in terms of the objectives to be achieved. In the case of operations which inject into a formation which contains water with less than 10,000 mg/1 TDS, the requirement is that monitoring wells shall be completed into the injection zone and into any overlying USDWs. The monitoring wells shall be located in such a fashion as to detect any excursion of injection fluid outside the mining area. If the operation may be affected by subsidence, the monitoring wells shall be located so they will not be physically affected by the subsidence. In addition, in the case of injection wells which penetrate an underground source of drinking water in an area subject to subsidence, an appropriate number of monitoring wells is required to be completed into the underground source of drinking water to detect any migration of fluids. Again, the wells shall be located in such a fashion as to detect any migration and to be outside the physical influence of subsidence.

As noted above, the requirements have been clarified in a number of places to make them consistent with the use of area permits. For example, the information to be submitted to the Director specifies that this must be done only to the extent of establishing an adequate picture of the ore body and the subsurface geology in the mining site, but is not necessarily required in the case of each and every well.

The area of review requirement has been retained as proposed. This requirement, however, is not expected to place any undue burdens on the owner or operator. It is expected that the injector already has sufficient economic incentive to minimize the unintended leak of injection or produced fluids from the mining site. Furthermore, it should be noted that corrective action in the area of review is required only to preclude migration into drinking water sources. In cases for example, where the aquifers overlying the ore body have been designated to be exempted aquifers no corrective action may be required.

Finally, the final regulations have chosen to apply only limited aquifier restoration requirements on Class III as discussed earlier in this preamble.

D. Class IV. The coordination of RCRA and SDWA authorities in the regulation of Class I and Class IV wells used to inject hazardous wastes has been discussed earlier in this preamble. As stated there, the Agency has decided to require the operators of such wells to obtain interim status and to comply with the standards in 40 CFR Part 265 until the applicable State UIC program becomes effective.

In the final regulations, all wells which are used to inject "hazardous wastes," as defined under RCRA, are grouped into Classes I or IV. Standards for Class I wells have already been discussed above. Section 122.36 establishes, on an interim basis, a prohibition, also required for approvable State-administered programs, against the injection of hazardous waste directly into underground sources of drinking water. The prohibition is effective six months after the effective date of a State UIC program. Requirements applicable to other Class IV wells—those which inject above, but not into, USDW's—are reserved. Also reserved are additional requirements (for example, monitoring and retention of records) for Class IV wells injecting into USDW's.

Section 122.45 establishes additional requirements for operators of wells through which manifested hazardous wastes are injected. They apply to Class I wells and will apply to Class IV wells as final standards are established. This section essentially requires that the operator of such well comply with selected requirements established for hazardous waste management facilities under 40 CFR Part 122 Subpart C and 40 CFR Part 264.

The proposed standards for wells used to inject hazardous waste (122.45, 44 FR 34285, June 14, 1979) provided for a ban on the construction and operation of new Class IV wells, and a three-year phase-out of existing ones. The proposal would also have required that wells used to inject hazardous waste comply with the manifest and record-keeping requirements of the hazardous waste management regulations.

The final regulations reflect several changes from the proposal. *First*, the definition of Class IV has been narrowed. The proposal required only

that: (1) The well be owned or operated by a generator of hazardous waste, or the owner/operator of a hazardous waste management facility; and, (2) that the injection be into or above an USDW in order to be included in Class IV. Commenters correctly pointed out that this definition could embrace wells that were not in fact used to inject hazardous waste. This condition has now been added to the definition of Class IV. The definition also clarifies that the injection has to be "into or above a formation which, within one-quarter mile of the well, contains an USDW" (§ 122.32). Conversely, the injection of radioactive waste has been added. (See discussion above.)

The *second* major change from the proposal is that the requirements for Class IV wells, other than those injecting hazardous wastes into an USDW, are reserved. There are several reasons for this decision. While few commenters questioned the basic premise underlying the proposal, some questioned whether, at least in some cases, the migration of fluid into an USDW would in fact cause any adverse effects either on drinking water supplies or human health. Other commenters suggested that a well should not be banned if it overlies a deep or remote USDW which it is not likely to contaminate. As noted above, commenters also indicated their belief that the definition of Class IV was too broadly drawn, and that, therefore, the proposed standard was unnecessarily protective. The Agency has reviewed these comments and is mindful of its obligation to proceed with extraordinary care before imposing an absolute ban on any practice. The Agency's concern in fashioning the proposal was to afford protection to drinking water sources. The Agency is not contemplating any changes which would sacrifice or endanger drinking water sources people rely on. Furthermore, wells injecting hazardous wastes are also subject to RCRA which mandates a broader set of environmental concerns than drinking water. Nevertheless, there may well be portions of aquifers so deep or remote that they may never serve as drinking water sources, or conditions under which a particular injection may not have an impact on the quality of the drinking water source.

A further reason for the current approach is that regulation under RCRA and SDWA touch at several points. Facilities under Class I and Class IV overlap the class of facilities designated under RCRA as hazardous waste management facilities. It is, therefore, appropriate that technical standards under RCRA and UIC be consistent, to the extent allowable under the governing statutes, for facilities capable of causing a similar degree of environmental risk.

EPA has decided to defer issuance of permitting standards for HWM facilities until the Fall of 1980. Adoption of UIC standards now for Class IV wells could prove misleading to the States and the public because EPA might decide later this year to revise the standards to reflect policy decisions made in connection with RCRA standards. The best course is to defer the technical standards for Class IV wells which inject above USDWs until this Fall. Accordingly, we now solicit further comment on requirements for Class IV wells.

EPA has under consideration several options which would allow Class IV wells to inject, in certain circumstances. In order to assist commenters, these options are described below. After consideration of comments, EPA will publish regulations in the Fall of 1980 amending either 40 CFR Part 122, Subpart C, or 40 CFR Part 146, or both. At that time, EPA may decide to prohibit all Class IV wells as proposed, adopt any of the options discussed below, or adopt any combination or modification of the options which appears justified based upon the record, including comments received.

The definitions of an USDW and the term "endangerment" are discussed above in detail. For the proposed regulations, EPA adopted a conservative approach to the designation of USDWs. Within this regulatory approach, two alternative methods suggest themselves for expanding the range of allowable Class IV practices. The first is to attempt a more precise distinction between ground water in general and ground water that serves or can reasonably be expected to serve as a source of drinking water. Option A takes this approach.

A second possible approach is to attempt a more precise definition of the circumstances under which the presence of contaminants in an USDW may or may not cause a system to exceed national primary drinking water (NPDW) standards or otherwise adversely affect the health of persons. Option B takes the latter approach.

Option A. This option would entail modification of the definition of a USDW to decline to protect USDWs in areas adequately served by other sources. EPA is aware of areas of the country which are underlain by aquifers containing immense quantities of useable fresh water, or where surface water supplies are so plentiful that they could reasonably be expected to supply all foreseeable needs for drinking water. In such cases, EPA is willing to consider a policy which would authorize injection through Class IV wells.

In this approach, an additional basis for exemption could be added to § 146.04 that would allow the Director to decline to protect an aquifer or its portion if it "otherwise cannot reasonably be expected to serve as a source of drinking water." To justify such an exemption, the Director could be required to consider the following factors:

- Present and future availability of alternative sources of drinking water;
- Future population growth and land use patterns in the area; and
- The expected growth in the demand for drinking water.

In keeping with the revised definition noted above, such wells would fall under Class I because they would inject into exempted aquifers (i.e., not into, through or above an USDW). Injectors would apply for permits with a duration of up to ten years as specified in 40 CFR Part 146 Subpart B, with one exception. The applicant would be required to make a showing that the injection would not impact aquifers or portions of aquifers protected as USDWs. Such a showing would involve a demonstration that the injection zone is not in hydraulic connection with or that the natural flow from the injection zone is away from protected USDWs.

The application would be processed as any other Class I permit application. Under § 122.43, the Director would have the discretion to require such permit conditions as he believes necessary to protect USDWs.

Option B. This option would recognize that the injection or presence of contaminants in an USDW may not necessarily lead to drinking water supplies exceeding the NPDW standards or adverse effects on the health of persons. Based on this rationale, a more liberal approach could be taken to regulating Class IV wells if the applicant could demonstrate that the injection: (1) Is environmentally the most acceptable method of disposal; and (2) would not contaminate the portion of the aquifer from which water is drawn for drinking.

Under such an approach, the standard that the applicant would have to demonstrate would be that:

- Technology for safe disposal is not available, taking costs into account;
- Disposal by injection will be less harmful than use of other available means; and
- Technology and other means will be employed to reduce the volume and toxicity of wastes.

The applicant would be required to demonstrate that the proposed injection is the most environmentally acceptable alternative available considering technology and the cost of:

- Trucking to approved site;
- Pretreatment prior to injection;
- Treatment and surface discharge;
- Pretreatment and discharge into POTW;
- Construction of a Class I well;
- Incineration; and
- Segregation of streams and/or reduction in flow.

He would also have to demonstrate that anticipated ground water impact will not adversely affect the health of persons or violate NPDWs based on the following information:

- Injection volume and pressure;
- Life of operation;
- Depth of well;
- Direction of ground-water flow;
- Proximity to use;
- Monitoring up-gradient and down-gradient;
- Geological and hydrological data; and
- Closure plan.

There would be certain common elements under both options. Injectors would be required to obtain a permit to operate a Class IV well within one year of the effective date of the State program or close. Permits could be for a duration of 10 years, and new wells would be subject to the requirement in § 122.33 that a permit be obtained prior to the construction of a new well.

Similarly, there are certain common questions with regard to implementation under either option. The Agency solicits specific, detailed comments on these questions: *First,* do factual circumstances exist in which EPA should allow injection of hazardous waste into or above an underground source of drinking water? *Second,* if so, what information should be required of the applicant to show that the injection will not endanger drinking water sources, and what criteria should the Director use in granting or denying permits? *Third,* should new and existing Class IV wells be treated differently or alike? *Fourth,* should the decision to allow the use of a Class IV well be made as part of a statewide or regional plan (e.g., Sec. 208, land use, RCRA Sec. 4007 solid waste plan, UIC program application) or as part of the individual permit decision? *Fifth,* what factors should be considered in subdividing aquifers into relatively confined exempted areas and USDWs? *Sixth,* what procedures should be imposed to ensure full public participation in decisions to allow injection through Class IV wells? *Seventh,* what kinds of post-closure care requirements (monitoring, third-party liability, use restrictions) should be imposed on Class IV well operators? *Eighth,* are the authorities under SDWA and CWA sufficient to prevent the potential impacts of such injections or should RCRA authorities be invoked to meet environmental concerns such as aquifers discharging to streams and surface impacts on vegetation?

E. Class V. EPA received a number of comments with respect to Class V, suggesting that the two years allowed for the completion of an assessment and submission of State recommendations to EPA was insufficient. The Agency agrees with these comments. Consequently, these final regulations now allow the State three years instead of two years to complete the assessment of Class V wells and to submit recommendations for further regulation to EPA.

Amendments to Part 122

In the process of preparing the final Part 146 regulations, it became apparent that certain portions of the final consolidated permit regulations (45 FR 33290, May 19, 1980) would have to be amended to conform to the Agency's final decisions with regard to the UIC program. Four sections of Part 122 are amended as a part of this promulgation. This procedure is intended to avoid major inconsistencies between Parts 122 and 146. It is not intended to preclude further amendments that may be necessary, or to substitute for technical corrections (e.g., faulty cross references) of the consolidated permit regulations which the Agency still plans to make in the near future.

Section 122.18(c)(4)(ii). This paragraph in the final consolidated regulations required the Director to provide the Administrator with the necessary information to conduct a mid-course evaluation of the corrective action requirement as it applied to Class II wells. The Agency has decided to expand the mid-course evaluation in three ways: (1) It is to apply to Classes I and III as well as Class II; (2) it is to cover mechanical integrity in addition to corrective action; and (3) States are to provide the information every six months during the first two years of program operation rather than once at the end of two years. The amendment conforms the reporting requirement with this decision.

The Agency decided upon this course of action because we anticipate that an expanded mid-course evaluation will yield reliable information earlier than the promulgated scheme as a basis for any refinements in the UIC program requirements. This decision is discussed more fully as part of the evaluation plan described later in this preamble.

Section 122.37. This section detailed the requirements applicable to the authorization of injection wells by rule. It is revised to clear up some possible ambiguities with regard to the requirements applicable to certain types of rules. Specifically, paragraph (b) of the section may have raised questions with regard to the responsibilities of Class V injectors. Paragraphs (a) and (b) of the section have been revised extensively to clarify the Agency's intent. Paragraph (d)(1), relating to the contents of the injection well inventory is also amended. The current text inappropriately references § 146.52 which is a requirement for Class V. The revised text enumerates the information required on the national form for the inventory of injection wells (OMB #158–R0170), but does not change the substance of what is required.

Section 122.41(e). Paragraph 122.42(f) requires applicants for permits to submit a plan for plugging and abandonment, and specifies that the Director shall incorporate the approved plugging and abandonment requirements as conditions of the permit. The Agency chose this course of action because its concern for the proper abandonment of wells led it to establish such requirements as enforceable permit conditions. However, the permit terms for the UIC program may be long: up to ten years for Class I and up to the life of the well or facility for Classes II and III. Abandonment plans filed with the permit applications may easily be out of date by the time an injector is ready to close his well or facility. For the protection of both the injector and the environment, therefore, this requirement is amended by requiring the permittee to submit an updated abandment plan along with his 180-day notice. The Director is to review the updated plan, revise the relevant permit conditions as appropriate, and grant approval for the permittee to proceed with plugging and abandonment (see §§ 146.10, 146.14(c), 146.24(c) and 146.34(c)). Section 122.17(f) is amended to allow the permit to be modified to reflect this new plan as a minor modification.

Regulatory Analysis

The regulatory analysis consists of five basic sections: economic and financial profiles; alternatives considered; costs to industry and the States; impacts on the production of oil; and economic impacts on firms, regions and the economy. The cost section was entitled "Economic Impact" in the preamble to the proposed regulations. It

has been revised to show current estimates as well as to describe the reasons for change from the earlier analysis which appeared in the preamble. EPA's consultant did not include the cost associated with wells producing only gas because the percentage of injection wells associated with such wells is small in comparison with injection wells related to oil production.[1] Although the cost estimate is somewhat lower than would have resulted, had gas wells been included, EPA notes that other conventions which were adopted in the cost analysis tend to introduce possible overestimates in the overall cost of the program. To illustrate, as a result of the mid-course evaluation, changes might be made to the Regulations which would substantially reduce the cost to operators of determining the mechanical integrity of wells and performing remedial action.

Nevertheless the cost of the Regulations have been estimated as if there would be no relaxation of these requirements. In addition the Regulations allow, in 40 CFR 122.22(b)(3), the relevant authority to accept limited injection pressure in lieu of corrective action, if it can be demonstrated that the pressure of the injection zone does not exceed hydrostatic pressure at the site of any improperly completed or abandoned well within the area of review. Nevertheless, in estimating the cost of compliance, it was assumed, in all cases, that corrective action entailed physical repairs rather than pressure limitation. This assumption leads to an overestimate in the cost of the program.

Economic and Financial Profile

Overview. This section examines the impact of the regulations on operators of Class II and III wells. The relatively large number and dispersion of Class I, IV, and V wells among different industries precluded investigation of the economic impacts of regulation of these classes of wells.[2] However, the aggregate cost to operators and States have been included in the cost estimate.

On the whole, the impact of the Regulations on operators of Class II wells is expected to be relatively minor. It is estimated that a loss of crude production of about 13,000 barrels per day will result, which represents less than half of one percent of U.S. production at 1977 price and profit levels.[3] On a regional and producer level impacts will be more variable, depending upon the relative proportion of stripper wells, average stripper well production, company size and past construction practices. It is anticipated that operators in Illinois and the Mid-continent and Appalachian areas will be affected to a greater extent than other operators because these areas are characterized by poor completion practices and a large number of abandoned wells.[3a] Since production from stripper wells in these regions is relatively low, the net effect of the regulations may be the closure of those wells which produce very small amounts of oil but are likely to be the ones having potentially the greatest adverse impact on underground sources of drinking water.

Similarly the regulations will have no significant impact on Class III operators because compliance costs are relatively small, and the firms which engage in these practices are generally diversified and in sound financial condition.[4]

Oil and gas.[5] The oil and gas producing industry is comprised of a large number of firms but is dominated by a handful of vertically integrated corporations commonly known as the "majors". The majors engage in a full spectrum of activities including exploration, development, production, refining, transportation and marketing. The balance of firms in the industry, commonly known as "independents", are more diverse in structure. Although some independents engage in the same array of activities as the majors, they generally tend to focus on exploration, especially "wild catting".

Concentration in the petroleum industry is moderately high compared to other manufacturing industries. As indicated in table 1 the eight largest firms account for approximately half of industry revenues, which were $32.5 billion in 1977. Between 1973 and 1977 revenues have more than doubled. Net income, as a percent of net worth, was substantially higher in the five year period since the Arab oil embargo than the previous five year period. Despite the fluctuations in the net income/net worth ratio during the early part of the era ushered in by the embargo, it appears that the events of 1973 have reversed a general decline in this measure of profitability. Profitability appears to be increasing and the current increase in oil prices made possible by decontrol suggests that the trend will continue. (Table 2).

Table 1.—*Concentration, Oil and Gas Companies*

Firms	1973		1974		1975		1976		1977	
	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent	Revenue billions (dollars)	Percent
Largest 8	7.6	53	11.4	51	12.6	50	13.6	48	15.0	46
Next 9–32	3.8	26	6.0	27	6.8	27	7.5	26	8.7	27
All Other	3.0	21	4.9	22	6.0	23	7.3	26	8.8	27
Total	14.4	100	22.4	100	25.4	100	28.4	100	32.5	100

Source: Booz, Allen and Hamilton, Underground Injection Control Program . . ., P. II-12.

Table 2.—*Profitability of Petroleum Industry*

	Net income as a percent of net worth	
	Petroleum production and refining	Total trade
1967	12.8	13.2
1968	13.1	14.1
1969	11.9	13.5
1970	11.0	11.7
1971	11.2	11.7
1972	10.8	11.7
1973	15.6	12.7
1974	19.6	13.5
1975	13.9	13.0
1976	14.8	14.7
1977	14.0	15.0
1978	14.3	15.2

Source: Booz, Allen and Hamilton, *Underground Injection Control Program . . .*, p. II-14.

Frasch sulfur production. There are three major sources of domestically produced sulfur: (1) Recovered elemental, in which sulfur is produced as a by-product of natural gas processing and petroleum refining; (2) recovered sulfuric acid, in which sulfur is produced as a by-product of copper, lead, and zinc roasting and smelting; and (3) the Frasch process. Production by the Frasch process has declined between 1974 and 1977 while demand and prices have increased (Table 3). This decline is largely due to increases in the cost of heating water used to melt the sulfur, due to sharp increases in the price of natural gas. By the year 2000 it is possible that production by the Frasch

[1] Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program. Oil and Gas Well.* (June, 1979), p. 19.

[2] Booz, Allen and Hamilton, Inc., *Underground Injection Control Program. Industry Analysis of Class II and Class III Well Regulation.* (April 30, 1980) p. 1-2.

[3] *Ibid.*, p. III-4,5.

[3a] *Ibid.*, p. IV-3,4.

[4] *Ibid.*, p. III-14,18.

[5] For this discussion see *ibid.*, pp. II-8 to II-14.

process will be phased out, with expected increases in demand satisfied from present competing sources.[6]

The production of sulfur by the Frasch process is highly concentrated. In 1978 only five companies operating at ten sites produced sulfur by this method.[7] These companies have complete control over all phases of the production of sulfur. With one exception they are divisions of diversified companies whose sulfur sales represent, in most cases, a small portion of their total sales. These companies are financially secure, and their earnings outlook has improved owing to the growing demand for fertilizer, which they also produce and market.

Table 3.—*Sulfur Industry Data*

[Thousands of metric tons]

	1974	1975	1976	1977	1978
Domestic Production—					
Frasch	7,901	7,211	6,264	5,822	5,648
Recovered elemental	2,632	2,969	3,138	3,567	4,088
Other	886	1,079	1,305	1,169	1,439
Imports	2,150	1,897	1,727	1,977	2,177
Exports	2,663	1,352	1,270	1,178	866
Domestic Demand	10,906	11,804	11,164	11,357	12,486
Average Annual Price Per Metric Ton	$28.42	$44.91	$45.72	$44.38	$45.17

Source: Booz, Allen and Hamilton, *Underground Injection Control Program . . .*, p. II-6.

Solution Mining of Salt.[8] About 60% of domestic salt production is by the injection process. Most of the solution mining wells are located on the Gulf Coast, primarily in Texas, Louisiana, and Mississippi. The major demand for salt is by the chemical industry, which uses about half of all salt produced in the U.S. for the production of chlorine and soda ash. Consequently, demand fluctuates with the demand by the chemical industry. About thirty companies produced salt by injection method in 1978. These companies generally employ other methods as well, namely, conventional mining and evaporation of brines.

In general companies producing salt are vertically and horizontally integrated. They tend to be involved in the production of chemicals, oil and gas, minerals, metals and pharmaceuticals. It appears that salt production is of relatively minor importance to these firms.

Solution Mining of Uranium. In 1978, there were ten firms mining uranium by the in-situ process. In general these firms are large conglomerates with holdings in other minerals, as well as oil and gas production. EPA could not obtain financial information on uranium mining firms because such information is not available. Furthermore, production information is confidential, which makes it impossible to ascertain mine or company output with any degree of precision.[9] Consequently, it is not possible to provide descriptive economic and financial information on the uranium mining industry in general, or the solution mining component, in particular.

Solution Mining of Potash.[10] Potash is used primarily in fertilizer as the source of potassium. Overall domestic demand for potash has been relatively stable since 1974, but domestic production has been falling as a proportion of total use. In 1965, domestic production represented 93% of demand, but in 1978, only 37%.

There are ten companies which produce potash, but only the Texas Gulf Company uses the solution mining technique. The remaining firms employ conventional mining or recovery from surface brines. As a proportion of total domestic production, the amount represented by the solution mining of potash is minor—1.25%.

Solution Mining of Copper.[11] The solution method is used to recover copper from low grade deposits. Presently, there are no commercial in-situ sites. Three marginally profitable solution sites and one experimental site were closed in 1978 due to depressed copper prices. Despite rapid price increases recently these sites have not been reopened.

In-Situ Oil Shale Combustion.[12] There are four projects in various stages of development, but none have progressed to full commercial use. Two of them—the Geokinetics, Inc. site in Utah, and the Equity Oil Co. site in the Piceance Creek Basin, Colorado—are still in the research and development stage. The others—the Rio Blanco Oil Shale Project, and Federal Lease Tract C both in the Piceance Creek Basin—are in the development stage, with burns scheduled for 1980. Even under favorable conditions the latter project, which is the most advanced of all the sites, is not expected to produce any sizeable amount of oil until 1986.

Gasification of Coal.[13] The Federal Government has sponsored research designed to demonstrate this technology since 1973, and three privately funded ventures have been organized since 1975. At this time none has progressed to commercial production. The most advanced sites are at the field test stage. The Department of Energy does not anticipate the commercialization of either of the sites it supports before 1987.

In-Situ Tar Sands Recovery.[14] Tar sands are heavy petroleum (bitumen) which will not flow into a well bore without stimulation. Ninety-eight percent of domestic resources are located in Utah. At this time, the technical feasibility of in-situ tar sands recovery is uncertain due to the lack of geologic and reservoir data.

Geothermal Energy.[15] The major use of geothermal energy is in the production of electricity. Such production, amounting to an installed capacity of 663 megawatts, is insignificant as a proportion of total U.S. production. Expansion of the use of this source of energy is hampered by high costs of development, long delays in obtaining permits and relatively high cost compared to generation by use of oil or gas. By 1985 this source may be price-competitive with oil and gas. However, at this time, only a small number of lease holders and owners of geothermal resources have undertaken its development.

Alternatives Considered

The Safe Drinking Water Act requires EPA to develop minimum requirements for effective state programs to protect underground sources of drinking water from the subsurface emplacement of fluids through well injection. The Act, however, also requires the Agency not to prescribe requirements which interfere with or impede the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or any underground injection for the secondary or tertiary recovery of oil or natural gas unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection.

In recognition of these requirements EPA considered numerous alternatives,

[6] *Ibid.*, p. II-20.

[7] *Ibid.*, p. II-21.

[8] For this discussion see *ibid.*, pp. II-26-29.

[9] *Ibid.*, p. II—26.

[10] Generally, *ibid.*, pp. II-29 to II-32.

[11] Generally, *ibid.*, pp. II-32 to II-36.

[12] Generally, *ibid.*, pp. II-36 to II-39.

[13] Generally, *ibid.*, pp. II-39 to II-41.

[14] Generally, *ibid.*, pp. II-41.

[15] Generally, *ibid.*, pp. II-42 to II-50.

spanning the range from no regulation at all to stringent levels of protection which would cost industry tens of billions of dollars. The following discussion will provide an understanding of the alternatives which received serious consideration but were eventually rejected.

Through an understanding of the nature of the alternatives and reasons for their rejection EPA hopes to instill an appreciation for the complexity of the problem it faced and for the balance it believes was achieved in the promulgated regulations.

I. Alternatives to Regulation

The promulgated regulations are based on the concept of prevention, which EPA believes reflects the intent of Congress in enacting the Safe Drinking Water Act. Through controls on the siting, construction, operation and abandonment of injection facilities, underground sources of drinking water will be protected from endangerment. An alternative to this concept is an approach which might be termed the "restitution" approach. It entails the creation of a fund, either through insurance premiums or other sources such as general tax revenues, which would be used to rectify any damage to an aquifer. The restitution alternative was not adopted for three reasons. First, it is inconsistent with the preventive nature of the Safe Drinking Water Act which requires EPA to promulgate regulations which contain minimum requirements for effective State programs to protect underground sources of drinking water. Second, the size of such a fund would have to be based upon an estimate of risk of contamination and the future value of the aquifer, both of which are unknown. And finally, even if such estimates were available there is no known technology by which a contaminated aquifer can be economically restored.

II. Alternative Regulatory Provisions

A. Class I.—1. *Treatment of nuclear wastes.* In the 1979 proposed regulations Class I was defined as "industrial and municipal disposal wells and nuclear storage and disposal wells that inject below all underground sources of drinking water".[16] The final regulations include nuclear storage and disposal wells which inject below underground sources of drinking water in Class V. EPA still considers such wells to require careful control. However, it believes that the control of such wells should be determined as part of the overall review of the disposal of nuclear wastes initiated under the President's Program of Radioactive Waste management, as described in the Message sent to Congress on February 12, 1980. Therefore, rather than prescribe specific construction requirements which may require modification in the near future, EPA concluded that it would be preferable to assess such wells and fashion appropriate regulatory requirements, in keeping with the President's program, in the future. (Wells which inject nuclear wastes directly into underground sources of drinking water are regulated under Class IV, however).

B. Class II.—1. *Casing cemented to the surface.* The regulations require that "* * * all new drilled Class II injection wells shall be cased and cemented to prevent migration of fluids into or between underground sources of drinking water" with the specific requirements left to the discretion of the State Director upon consideration of several factors as detailed in 146.22(b). An alternative considered would have required the cementing of surface casing from the injection zone completely to the surface as a way of ensuring that there would be no fluid migration along the exterior of the casing, or communication between water bearing strata. This alternative was not adopted because such a requirement, in EPA's view, far exceeds that which is necessary to prevent fluid movement. EPA believes that such a requirement would have interfered with or impeded the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production or underground injection for the secondary or tertiary recovery of oil or natural gas without being essential to assure that underground sources of drinking water will not be endangered by such injection. To illustrate, if the Agency had required full cementing to protect underground sources of drinking water containing 3,000 ppm or less total dissolved solids, EPA estimates the cost to operators would have been roughly $20 billion over the first five years of the UIC program in 1977 prices.

2. *Interstate Oil Compact Commission (IOCC) proposal.* The promulgated Regulations do not differentiate between injection, producing and abandoned wells, based upon their age. The IOCC proposed that such a distinction be made as follows:

a. New wells and wells drilled or completed prior to 1947 would receive new permits based on mechanical integrity, area of review and remedial action;

b. Wells completed between 1962 and the time the State program goes into effect would continue under existing permits;

c. Permits for wells drilled or completed between 1947 and 1962 would be reviewed for compliance with standards prevailing since the early 1960's. Permits for wells that generally met the standards would be revalidated. Wells that clearly fall short of the standards would be re-permitted.

Many of the features of this proposal were adopted. New wells may not be constructed and operated without a permit; existing enhanced recovery wells may be operated under rule (although mechanical integrity tests are required to ensure that they remain sound); wells injecting in an existing field need only comply with standards for casing and cementing in existence at the time of drilling of such wells. Hence some of the major features of the IOCC proposal were adopted. It was not adopted in toto because under (b) it would have allowed wells completed between 1962 and the time the UIC program went into effect to be operated even if they were not mechanically sound. While EPA agrees that older wells may be more likely to fail owing to corrosion and other problems, it also believes that many newer wells may be subject to leakage and fluid migration due to the use of cement of insufficient quality, poor workmanship, a corrosive environment, human error, or other factors.

3. *Area of review alternatives.* Because of the high concentration of producing and abandoned wells in existing oil fields the overall cost to operators of the UIC program is largely determined by the extent of the area of review and nature of testing and remedial action required on wells within it. EPA devoted considerable effort to the identification and evaluation of alternative approaches. In its deliberations, EPA considered:

a. Applying it to all injection wells, both enhanced recovery and disposal, new and existing;

b. Applying it to new injection and existing disposal wells;

c. Requiring the radius to be a minimum of ½ mile of a new enhanced recovery or disposal well if the zone of endangering influence is not determined by the use of the Theis or similar equation;

d. An ad-hoc area of review, as practiced in Texas and Louisiana, and;

e. Eliminating the area of review requirement entirely.

Had alternative (a) been selected it would have required that virtually every injection, producing, and abandoned well of record in the United States be examined and, if necessary, either

[16] 44 FR 23740, April 20, 1979.

repaired, abandoned, or reabandoned within five years of the date the program became effective. Considering that there were about 1.2 million abandoned wells of record, 505,000 producing and 119,000 injection wells at the end of 1976, plus a net increase of some 25,000 new injection wells during the first five years of the program, EPA concluded that so comprehensive a requirement would have unduly impeded oil and gas production.

Option (b) was discarded for the same reason. Although fewer wells would have been reviewed within the first five years EPA believed that it would have unduly interfered with or impeded oil and gas production without being essential to assure that underground sources of drinking water will not be endangered. Similiarly alternative (c) was rejected for the same reason. Had the one half mile radius for the area of review been adopted, 171,000 producing wells and 302,000 abandoned wells would have been evaluated, and 20,000 repaired. At the one fourth mile radius there is a reduction of some 77,000 producing and abandoned wells in the area of review. At the smaller radius, the number of producing and abandoned wells needing remedial action is approximately 17,000 compared to about 20,000 at the ½ mile radius.

The ad-hoc alternative (d) would require the testing and appropriate remedial action to wells in the area of review of a new diposal well only if the regulatory authority received a complaint within the ten days of the filing of a permit application. While its low cost makes it appealing, this option was rejected because it would have provided for remedial action to faulty wells only after environmental damage had become visible.

Alternative (e) was rejected because even though the injection well was sound, other nearby wells could still serve as pathways for potential endangerment.

Radii less than ¼ mile were not considered because actual computations by EPA of the zone of endangering influence indicate that, in most instances, the appropriate distance is less than ¼ mile. Setting the radius at ¼ mile thereby ensures that all wells within the zone of endangering influence will be examined.

4. *Other alternatives to reduce or spread out program costs.* a. Sampling a small portion of wells for mechanical integrity. Testing and reporting the results of mechanical integrity tests on injection wells accounts for approximately $96 million of total program costs. EPA considered random sampling as an alternative to testing of all wells. This approach was not adopted because data essential to the design of the sample, e.g., the different sampling strata to sample and expected failure rates, are not available. A random sample would provide an estimate of failure rates but would fail to locate all defective wells. [16a]

b. *Assessment/Postponement.* This option would postpone the date by which permits are required by about three years while the States planned and conducted an assessment of injection practices. The data base resulting from this approach would then be used to formulate a regulatory program. This alternative was rejected for two reasons. First, the assessment would have required an expensive survey in each state and would not provide a valid test of the area-of-review concept. Second, the program would have been delayed three years, which was judged by EPA to be unacceptable.

c. *Exempting stripper-related injection wells.* Approximately three-quarters of all producing wells are strippers, which are wells producing ten or fewer barrels of oil per day. It appeared that exempting from regulation injection wells associated with strippers would achieve the dual objective of reducing program costs substantially while sparing the least productive wells the burden of the cost of compliance. Unfortunately, the very reason that enables the savings in program costs also weighs against the adoption of this alternative. To exclude three-quarters of all producing wells from any kind of review would undermine the effectiveness of the program for two reasons. First, strippers number among them some of the oldest wells drilled in the U.S. Old stripper wells are not drilled to current standards and are the ones most likely to endanger underground sources of drinking water. Second, because of their numbers and widespread distribution entire regions of the country will be left unprotected if injection wells associated with strippers are exempted.

d. *Exempting injection wells with an open annulus from pressure testing.* The promulgated regulations require pressure testing of all injection wells for casing leaks. Where the annulus is enclosed, the cost of such a test is estimated to be thirty dollars.[17] However, if a well does not have an enclosed annulus the cost of testing is estimated to be $1500.[17] Over the first five years of the program the cost of testing wells with an open annulus is estimated to be $65 million, and affects about 43,000 wells. EPA considered eliminating the testing requirement, but decided to retain it because of the large number of such wells and their potential for widespread contamination.

5. *Other, more stringent alternatives.* As discussed under (1) and (3) above, more stringent alternatives rejected were: Continuous cementing from the injection zone to the surface; area of review for all injection wells, and a half-mile, rather than quarter mile, area of review. Following are three additional alternatives which were considered by EPA. Each would have imposed more stringent requirements than those promulgated:

a. *Continuous monitoring of injection pressure, volume and flow rate.* Unlike the continuous monitoring required for Class I and III wells, such monitoring was considered but rejected for Class II because the injected fluid, being less toxic and corrosive than that of Class I and III wells, does not require constant surveillance. In addition, the Agency believes that the cost of continuous monitoring would have been excessive in view of the potential for harm to human health.

b. *Absolute construction ban without a permit.* In the case of a non-controversial application EPA estimates that the process will require about 105 days over and above current State permit processing times. For wildcat operations EPA believes that such a delay would be particularly expensive and would have unduly interfered with or impeded oil and gas production. Consequently, the promulgated regulations allowed the issuance of temporary emergency permits if it can be demonstrated that "a substantial delay in production of oil or gas resources will occur unless temporary emergency permit is granted to a new Class II well and the temporary authorization will not result in the movement of fluids into an underground source of drinking water." [18]

c. *Extending coverage to wells storing hydrocarbons in a gaseous state.* The April, 1979 proposed regulations included all forms of hydrocarbon storage under the definition of Class II.[19] Wells storing hydrocarbons which are a gas at standard temperature and pressure have been excluded from Class II in the promulgated regulations

[16a] Booz, Allen and Hamilton, *A Study of Sampling Procedures as Applied to the Mechanical Integrity Testing of Injection Wells.* (April 30, 1980), Executive Summary, pp. 1,2.

[17] Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program, Oil and Gas Wells.* (June, 1979), p. 96.

[18] 40 CFR 122.40(a)(3).

[19] 44 FR 23758, April 20, 1979 and 44 FR 122.34(b), June 14, 1979.

because gas is highly unlikely to result in the chemical contamination of drinking water even if it migrates from the injection zone. In addition such wells may be properly maintained owing to strong economic incentives to prevent loss of the stored gas. These wells have been transferred to Class V for further study.

C. In response to comments that Class III wells were too diverse to be covered by common requirements, EPA undertook a detailed evaluation of their physical characteristics and potential for contamination of underground sources of drinking water in order to determine if subclassification of Class III wells was appropriate.[20]

The review looked at 9 Class III practices: Frasch sulfur mining; the solution mining of uranium, salt, and copper; in-situ combustion of oil shale, coal, lignite, and tar sands; and the extraction of geothermal energy. The similarities and differences of these nine groups of wells were compared with respect to a number of parameters.[21] With regard to potential environmental impact, for example, 6 of the 9 practices inject in zones that may contain aquifiers that would qualify as potential underground sources of drinking water under the UIC definition. In 8 of the 9 practices, injection normally occurs through overlying aquifiers which would also meet the definition. With the exception of geothermal energy wells, injection pressures tend to be relatively high, and, with the exception of the Frasch process, the produced fluids could be considered hazardous in that they contain at least heavy metals. In 7 of the 9 cases, subsidence or catastrophic collapse is expected to accompany the operation.

The review of existing State controls and current practice also revealed more consistent similarities than consistent differences among these 9 types of practices. In addition, the theoretically preferable criterion cannot be translated into operational terms. According to EPA's consultant, "perhaps the most logical way to subclassify the Class III wells, would be in terms of the relative threats to the ground-water environment posed by different practices." [22] However the Agency's consultant also concluded that the " * * * overall threat to the ground-water environment that might be posed by a particular type of injection well in Class III depends to a large degree on the site-specific hydrogeologic situation." [23] The agency cannot develop consistent National Standards based upon diverse, local, hydrogeologic factors. Therefore, EPA has chosen not to subclassify Class III. However, in recognition of the relatively short service life of wells other than salt solution and geothermal,[24] EPA concluded that the mechanical integrity testing requirements for certain existing wells in Class III should be relaxed.

Consequently, prior to granting approval for the operation of a Class III well, the operator is required to demonstrate mechanical integrity only for all new Class III wells and existing salt and geothermal wells. In addition, only the operators of salt solution mining and geothermal wells are required to demonstrate mechanical integrity every five years.[25]

Two, more stringent alternatives were considered for the abandonment of Class III wells, notably those relating to uranium mining: Aquifer restoration, and containment of injected fluids. The restoration alternative was not adopted because the technology is still in the experimental stage. Since EPA cannot evaluate the effectiveness of this technology it concluded that it was premature to require it now as a National minimum requirement. However the Director is given the discretion to require aquifer restoration on a case-by-case basis.[26] As for the containment alternative, the Agency concluded that because of the long decay time of radioactive substances, containment would require monitoring and testing of water quality for hundreds of years, which the Agency does not believe to be administratively feasible at this time.

D. Classes IV and V. Four alternative approaches were formulated for regulation of wells which inject directly into or above underground sources of drinking water: [27]

1. Within the UIC regulations, require a permit program for at least some of these practices;

2. Within the UIC regulations, require the states to assess the threat of contamination from these wells and submit a detailed state plan to EPA;

3. Withdraw consideration of these wells from the UIC regulations and study them in a separate national assessment; and

4. Within the UIC regulations, require state assessment of these wells coupled with regulatory control over the most potentially harmful practices. The main features of alternative number 1 are:

- The Director would have the discretion to ban immediately those categories of practices which present an unreasonable risk to health and to ban, after an appropriate period of time, all categories of practices for which economically feasible alternatives exist;
- The Director would determine, for those practices not banned, which practices in the state should be regulated by permit rather than by rule;
- Exemptions would be allowed based upon criteria such as toxicity and/or volume, hydrogeologic characteristics, and population in the area relying on the affected underground sources of drinking water;
- The Director would impose monitoring, record-keeping and reporting requirements for each permit. In addition, the director would require public notification for each permit before its issuance, and require that the injector periodically show that the well continues to be the best environmental means of disposing of the waste.

This approach would have provided maximum protection of underground drinking water souces within the shortest time frame, and would have been consistent with other Subparts of the UIC regulations. It was not adopted because a substantial effort would have been required to locate individual wells that are typically hidden from view. In addition, it is impossible to argue with certainty that technological alternatives to current practices are economically feasible for all shallow disposal and recharge well practices. Considering the absence of a complete characterization of wells, it is possible that some permit requirements would be established without a thorough understanding of all elements of operations such as volume and toxicity, of injected fluids, costs and alternatives.

The main features of alternative number 2 are:

- The Director would compile an inventory, including number, location, and use of these wells and determine the toxicity and volume of the injected fluids;
- The Director would develop and compile hydrogeologic data such as location of the aquifers, aquifer yield, ground-water quality, ground-water movement and ground-water use;
- The Director would develop data on present and future population and industrialization, emphasizing the dependence upon ground-water and the protection of public health;

[20] Geraghty and Miller, Inc., *Development of Procedures for Subclassification of Class III Injection Wells.* (April 30, 1980).

[21] *Ibid.*, p. 8.

[22] *Ibid.*, p. VI.

[23] *Ibid.*, p. VII.

[24] *Ibid.*, p. 8.

[25] 40 CFR 146.34(b)(2) and 40 CFR 146.33(b)(3).

[26] 40 CFR 146.10(d).

[27] For a full discussion of these alternatives, see Temple, Barker and Sloane, Inc., *Analysis of Cost. Underground Injection Control Regulations. Class I and Class III Wells. Class IV and Class V Wells.* (May, 1979), Part 2, Appendix B.

• The Director would consider the technological alternatives available to existing practices; and

• The Director would assess the risk to underground sources of drinking water and would submit a State plan to cover new and existing injection wells.

The advantages of this alternative are, the study would be mandatory, being required by regulation; provision could be made for the Director to take action in the event cases of endangerment are uncovered during the course of the study and there would be a greater degree of uniformity in several important aspects of the study, such as scope; methodology; and data quality. The major disadvantages to this approach, which led to its rejection by the Agency, is that it is time consuming and would allow extremely dangerous practices to continue on a widespread basis while the problem was studied further.

The third alternative is similar to the second, except that the study would be voluntary. The same type of information would be collected; however, the alternative would suffer from the same disadvantages as the former alternative. In addition, the Director might not have the authority to ban dangerous practices which are uncovered. Consequently, the Agency rejected this approach as well.

The fourth alternative was selected by EPA. It combines regulation of the most dangerous practices (Class IV) with further study of those believed to be of less immediate concern (generally, those wells in Class V). Under alternative number four, the injection of hazardous wastes directly into an underground source of drinking water after six months following approval or promulgation of any UIC program for a State, is prohibited. The control of injection of hazardous wastes above USDWs is reserved until the Fall.

Cost of Compliance

Most States already regulate the underground injection of fluids in some manner or to some degree. State personnel are already assigned to work on the control of injection wells, and owners and operators of injection wells must meet existing State requirements. Nevertheless, the UIC regulations will cause both States and industry to commit resources to the protection of underground sources of drinking water in addition to their current level of effort.

EPA's best estimate is that these regulations will result in incremental costs of approximately $775 million, expressed in 1977 prices, to all 57 States and Territories and the regulated community in the first five years of program operation (Table 4 provides a summary). This estimate includes costs only for developing and conducting the assessment of Class V wells and does not try to guess the impact of immediate closures or the eventual regulatory requirements. In addition, no attempt was made to anticipate the changed requirements that may result from the mid-course evaluation of the area of review requirement, or from the review of a sample of wells which were permitted on the basis of cementing records. This is because EPA does not have a sufficient basis for projecting the number of wells which will require remedial action.

Table 4.—*Summary of Five-Year Incremental Costs of UIC Regulation*

[In thousands of 1977 dollars]

	Non-recurring	Recurring	Total
Industry:			
Class I	5,025	463	5,488
Class II	565,094	4,006	569,100
Class III	5,698	560	6,258
Class IV	1,100	162,300	163,400
Subtotal	576,917	167,329	744,246
State:			
Class I	875	2,535	3,410
Class II	9,855	7,560	17,415
Class III	709	1,230	1,939
Class IV	389	858	1,247
Class V	7,200		7,200
Subtotal	19,028	12,183	31,211
Total	595,945	179,512	775,457

In this study price levels which existed in 1977 were used to estimate the cost of the UIC program. The use of "constant" prices is a commonly used convention which enables one to ascertain the physical amount of goods and services, or "real" resources, devoted to compliance because it eliminates the influence of changes in prices. For other types of analysis, such as projecting expenditures and revenues in a given year, it would be appropriate to use prices expected to prevail during the time period of interest. If it is desired to express the cost estimates in terms of "current" prices it would be necessary either to project the level of each unit price, or to construct a price index which would be used to convert the aggregate cost estimates from 1977 to other price levels. Such an endeavor is beyond the scope of this analysis. However, in the judgment of EPA's consultant, increases in costs suggest that the annual rate of price level increase for activities associated with oil drilling and production is roughly on the order of 20% per year.[28]

Consequently a rough estimate of the cost of the UIC program in general, and Class II in particular, in 1980 prices, may be obtained by adjusting costs upward by 50%. The total cost of the Regulations in 1980 prices would be on the order of $1.2 billion, or about $230 million per year.

It should be emphasized that the estimate is largely a function of the size of the environmental problem. The cost to industry, in 1977 prices, of carrying out the fixed requirements—permit application, permit issuance, inspection, surveillance, monitoring, testing, reporting, etc.[29]—is estimated to be $191 million, or $38 million annually for the first five years. This is, in a sense, the fixed cost of the regulations. The remainder, $553 million, is the estimated cost, in the first five years, of repairing leaky injection wells, replugging wells improperly abandoned in the first place, and re-cementing improperly completed producing wells in the area of review. For Class IV, these costs include the pretreatment of hazardous waste and shipment to approved hazardous waste management facilities. These are the variable costs which directly depend upon the number of problem wells. If the environmental problem is more or less extensive than estimated by EPA in this analysis, this portion of the cost would vary accordingly and potentially widely.

Of the total $775 million estimated cost, about $744 million falls on industry. The total incremental State burden is estimated to be about $31 million over five years or about $6 million annually.

The cost of regulating Class II injection wells, $569 million to industry over five years, clearly dominates both State and industry costs. However, this class also has the largest number of wells (2 million) potentially affected by the regulations.

The following discussion provides details of the cost estimates by class of well. The sections are organized into industry estimates and State estimates. They also discuss nonrecurring and recurring costs. Nonrecurring costs include such one-time activities as inventorying wells in the area of review, taking appropriate remedial action, and repermitting existing wells. Demonstrations of mechanical integrity are also treated as one-time costs because the second round of tests will not take place in the first five year

[28] *In Geraghty and Miller, Inc., Development of Procedures and Costs for Proper Abandonment and Plugging of Injection Wells* (April 30, 1980), p. IV–5, the cost of abandoning a 3,000 foot well used either for oil and gas storage or production is $8,600. In order to estimate the cost of abandonment in 1977 prices, EPA's consultant, Booz, Allen and Hamilton, reduced this to $5,000, which indicates a growth rate of approximately 20% per year *(Underground Injection Control Program Class II Well Incremental Compliance Cost Refinements*, p. 18).

[29] 40 CFR 122.45.

period. Recurring costs include such periodically required activities as monitoring, reporting, and enforcement.

Class I Wells. 1. *Industry Costs.* A demonstration of mechanical integrity will be required of operators but flexibility is provided in the choice of test for demonstrating it. Unit costs can range from $5,000 to $35,000 [30] per test. The total cost of mechanical integrity testing for the UIC program is estimated to be in the range of $675,000 to $4.5 million.[31]

Appropriate remedial work is prescribed for defective wells and may vary from $17,500 to $100,000.[32] Total incremental repair costs for the class are estimated to range from $53,000 to $300,000.[33]

The average number of new wells being constructed each year is estimated at twenty.[34] Since all States now have permitting requirements at least as stringent as the UIC requirements, new construction will incorporate the new design criteria contained in these regulations and no incremental construction costs are expected to result.[35]

Additional reporting requirements have been estimated to cost $300 per well per year for new and existing deep disposal wells.[36] Total recurring costs are estimated to be $463,000 over five years.[37]

2. *State Costs.* The regulations require collection and review of data on a quarterly basis for each site subject to the regulations. Six work-hours per submission per site has been employed in the estimation of costs for this activity.[38] EPA estimates that the submission of reports to the Agency will require one hour of preparation per site per quarter.

The total costs of the requirements in Class I appear in Table 5. The increase in industry and state costs since the proposed regulations is due to a revision in the number of existing wells, based upon a new survey of the well population.[39]

Class II Wells. Class II wells include injection wells associated with oil and gas production, and hydrocarbon storage, except gaseous natural gas storage wells. The conceptual scheme for estimating incremental costs involves the identification of unit costs for the activities required by the proposed regulations and multiplying those by the estimated number of wells requiring each kind of action. Several changes have been made to the cost of compliance based upon comments received and further analysis performed by EPA. On net balance cost to operators is lower than the previous estimate, primarily due to lower costs of remedial action. This results from the recognition that certain wells will be abandoned rather than reparied. A reconciliation of changes in costs from those appearing in the April 20, 1979, Preamble follows:

Table 5.—*Incremental Five Year Program Costs, Class I Wells*

[In thousands of 1977 dollars]

	Nonrecurring	Recurring	Total
Industry:			
Mechanical Integrity Test	675–4, 725		675–4,725
Remedial Action	53–300		53–300
Monitoring and Reporting		463	
Subtotal	728–5,025	463	1,191–5,488
State:			
Program Development	52–127		52–127
Program Hearings	39		39
Permit Existing Wells	298–593		298–593
Permit Hearings	116		116
Quarterly Review		545	545
Quarterly Report		130	130
Annual Report		50–245	50–245
Enforcement		830–1,615	830–1,615
Subtotal	505–875	1,555–2,535	2,060–3,410
Total	1,233–5,900	2,018–2,998	3,251–8,898

Source: Temple, Barker and Sloane, Inc., *Underground Injection Control Regulations. Analysis of State Program Costs: Class I Wells.* (May 15, 1980) p. 6.

1. *Sampling for fluid migration (+$4.5 million).* The proposed regulations permitted the submission of cementing records as a demonstration of mechanical integrity. However, EPA's contractor advised the Agency that "existing well records have limited use in determining the adequacy of the cement sheath outside of a well casing".[40] For certain existing Class II wells, the absence of fluid migration will be based on well records. A sample of these wells will be tested in order to ascertain if reliance upon well records was adequate as an indicator of the mechanical integrity of the well. The costs of this requirement are based upon a sample of 3,000 injection wells nationwide.

2. *Initial reporting of test results—existing enhanced recovery wells (+$2.5 million).* In the case of new injection wells and existing disposal wells test results are reported in the permit application. However, existing enhanced recovery injection wells may be covered by rule, but no provision was made for reporting test results to the State Director. This omission has been corrected by attributing to operators of wells covered by rule, a cost of $25 per report.

3. *Financial responsibility (+$5.0 million).* The April 1979 reproposal did not include the cost, to operators of existing enhanced recovery wells, of securing a well closure bond. Costs for such wells were estimated in the same fashion as costs for existing disposal well operators.

4. *Unit permitting cost (+$2.2 million).* In EPA's earlier analysis the unit cost of permit application used in table XIV–1 [41] to calculate the five-year cost to industry was inconsistent with the unit cost which should have been used, as calculated in Chapter XI.[42] Previously the cost for permitting new salt water disposal (SWD), new enhanced recovery and existing SWD wells was $620; $367 and $240, respectively. The correct unit costs are $675; $422 and $262, respectively.

5. *Changes accruing to well closure and injection wells not put in service ($−92.8 million).* In EPA's earlier estimate it was assumed that wells would either be repaired, or abandoned and redrilled, depending on the type of well. In the current analysis the results of the production impact analysis have been integrated into the cost analysis.[43] The cost model now recognizes that the predicted number of new enhanced recovery (ER) wells will be reduced by 2,470 as a result of the evaluation of the area of review. It is estimated that the

[30] Temple, Barker and Sloane, *op.cit.*, Part I, p. II–10.

[31] Geraghty and Miller, Inc., *Economic Analysis, Class I Rehabilitation.* (April 30, 1980).

[32] Temple, Barker and Sloane, *op.cit.*, Part I, p. II–11.

[33] Geraghty and Miller, *op.cit.*, Part I, p. II–5.

[34] Temple, Barker, and Sloane, *op.cit.*, Part I, p. II–5.

[35] Ibid., Part I, p. II–12.

[36] Ibid., Part I, p. II–12.

[37] Geraghty and Miller, *op.cit.*, p. 14.

[38] Temple, Barker and Sloane, *op. cit.*, Part I, p. III–6.

[39] Geraghty and Miller, *op. cit.*, p. 9.

[40] Geraghty and Miller, Inc., *Mechanical Integrity Testing of Injection Wells.* (April 30, 1980), p. 9.

[41] Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program. Oil and Gas Wells. (June, 1979), p. 196.*

[42] *Ibid.*, p. 159.

[43] Booz, Allen and Hamilton, *op. cit.*, pp. 16 ff.

evaluation will show (1) a producing well needing remedial action; (2) an abandoned well requiring reabandonment; or (3) both (1) and (2). It is judged that the anticipated production will not warrant the required expenditures to repair an estimated 2,220 abandoned wells and 88 producing wells. The operator will therefore choose not to place the new ER wells in service, thereby avoiding the cost of remedial action to wells in the area of review. Savings, relative to EPA's earlier costs estimate, amount to $70.8 million. Similarly, forty new (i.e., converted) ER wells will require remedial action but will be abandoned rather than repaired. This reduces EPA's earlier cost estimated by $1.0 million.

EPA estimates that fifteen new salt water disposal wells will not be placed in service due to the need to repair both a producing and abandoned well in the area of review. Fifteen abandoned wells and a like number of producing wells will not be repaired, resulting in a reduction of $750 thousand from EPA's earlier estimate.

In addition, (a) 590 existing ER and 500 existing SWD wells will be abandoned rather than repaired. When the cost of abandoning the injection and associated producing wells is taken into account, the "savings" over EPA's earlier cost estimate is estimated to be $18.9 million; and (b) seventy five existing SWD wells will be abandoned rather than repaired, at a net "savings" of $150,000.

Finally, the abandonment of wells and decision not to put new injection wells into service results in savings in the cost of permitting, reporting the results of mechanical integrity tests and obtaining plugging bonds. These "indirect" savings total $1.2 million.

Table 6 shows a reconciliation of the earlier Class II cost estimate and the current one. In all cases where a well was abandoned rather than repaired, the cost of its abandonment was properly considered in the calculation of the "savings" over EPA's prior cost estimate.

1. *Industry Costs.*—Incremental non-recurring costs of compliance to operators are estimated to be $565 million over the first five year period. Of this total $20 million are for the preparation of permit applications, and $149 million are the cost associated with determining the nature and extent of corrective action. The bulk of these costs, $396 million, is the estimated cost of the corrective work itself.

Table 6.—*Reconciliation of Current and Previous Class II industry Costs*

[Thousands of 1977 dollars]

1. April, 1979 estimate [1]	$647,000
2. Alaska	+700
3. Initial reporting of test results for existing ER wells	+2,500
4. Plugging bond, existing ER wells	+5,000
5. Correction, unit cost of permitting	+2,200
6. Random sampling for fluid migration	+4,500
7. Production impact analysis	−192,800
8. Current cost estimate	569,000

[1] Arthur D. Little, Inc., Cost of Compliance. Proposal Underground *Injection Control Program. Oil and Gas Wells.* (June, 1979) pp. 196–200. Includes recurring costs.

Source: Booz, Allen and Hamilton, Inc., *Underground Injection Control Program Class II Well Incremental Compliance Cost Refinements.* (April 30, 1980), p. 33.

In estimating the cost of corrective action the unit cost of reabandoning a well was taken as $20,000. EPA reviewed the validity of this estimate since the proposal by surveying costs of reabandonment experienced by operators and state regulatory agencies between 1975 and 1979 in Louisiana, Michigan and Texas. After adjusting for changes in price levels EPA's consultant concluded that $20,000 represented a reasonable average of the considerable range of unit costs uncovered by the survey.[44]

On the average, industry will experience one-time costs of some $113 million per year over a five-year period. These estimates assume the current requirements for Class II and do not try to anticipate the outcome of the mid-course evaluation regarding the area of review requirement.

In addition to the one-time costs associated with existing wells, there are incremental costs which producers will incur each year to collect and report monitoring data. The total recurring costs attributable to the regulation are estimated at $4 million over five years or about $800,000 per year. (Table 7).

A note of caution is warranted regarding the correct interpretation of the costs to Class II operators. First, it was assumed in the estimating methodology that the area of review would be ¼ mile in all cases. EPA believes that this assumption results in an overstatement of industry costs because the area of review, when calculated by a mathematical formula as permitted by the regulations, will probably be substantially less than ¼ mile in most cases. This means that the number of producing and abandoned wells subject to testing, correction and reporting requirements is substantially less than the number ascertained through the use of the ¼ mile assumption.

[44] Booz, Allen and Hamilton, *op. cit.*, p. 11.

Table 7.—*Incremental Five-Year Costs to Producers, Class II Wells*

[Thousands of 1977 dollars]

NON-RECURRING:	
Evaluation of Construction:	
Previously Abandoned Wells	12,600
Producing Wells	28,200
Injection Wells*	108,500
Subtotal	149,300
Corrective Action:	
Previously Abandoned Wells	258,100
Producing Wells	38,500
Injection Wells	85,400
Abandon injection wells and associated producing wells	13,800
Subtotal	395,800
Permit Application	20,100
Subtotal, non-recurring	565,200
RECURRING:	
Monitoring and Reporting	4,000
Total	569,000

*Includes plugging bond for existing enhanced recovery wells.

Note.—Does not add to total due to rounding.

2. *State Costs.*—The estimate of the incremental costs to States, of implementing the proposed UIC control program for Class II, is based on an estimate of the total effort that will be required in oil-producing States to enforce the proposed Federal regulations. The amount currently spent on UIC programs by these States was then subtracted from the total, yielding the incremental costs.[45]

It is estimated that oil-producing states will incur total costs of $38 million over a five year period. Of this, $16 million will be one-time costs to re-permit existing disposal wells and other start-up costs. The remaining $22 million will cover the permitting of new wells, monitoring and enforcement, and general overhead. Since current State spending projected for five years equals $20.7 million, incremental costs over five years are $17 million or $3.5 million annually (Table 8).

Class III Wells. Special process mining is, in most instances, a developing technology already operating under some State controls. There are about 8,000 wells but a relatively small number of sites at the present time.[46] Consequently, the costs of compliance are estimated to be small and the impact on the industry to be negligible.

Table 8.—*Incremental Five-Year Costs to States, Class II Wells*

[Thousands of 1977 dollars]

Non-recurring:	
Ground Water Inventory	2,174
Permit Existing Disposal Wells	7,810
Permit New Wells	4,505
Other	2,072
Subtotal	16,560

[45] Arthur D. Little, Inc., *op. cit.*, p. 183.

[46] Geraghty and Miller, *op. cit.*, p. 4.

Table 8.—*Incremental Five-Year Costs to States, Class II Wells*—Continued

[Thousands of 1977 dollars]

Recurring:	
Overhead	5,590
Enforcement	13,802
Monitoring Reports	2,203
Subtotal	21,595
Total State Cost	38,155
Less: Current State Spending	−20,740
Total Incremental State Cost	17,415
Recurring	7,650
Non-recurring	9,855

Source: Arthur D. Little, Inc., *Cost of Compliance. Proposed Underground Injection Control Program. Oil and Gas Wells.* (June, 1979), p. 193, and U.S. Environmental Protection Agency, *Class II State Cost* (May, 1980).

1. *Industry Costs.*—The total incremental cost to industry of complying with Class III requirements is estimated to be $6.3 million for the first five years, or about $1.3 million annually. Of this, about $5.7 million are nonrecurring costs mainly associated with the test for mechanical integrity and repair of faulty wells. The remaining half-million dollars are the cost of monitoring and reporting.[47]

The States of Texas and Louisiana account for all current Frasch process sulfur mining. There are ten mine fields with approximately 500 wells in the two States. The average useful life of a Frasch well is about one year. Since this practice was started eighty years ago, approximately 35,000 wells have been drilled.[48]

The total one-time permitting expenses for the ten fields will be approximately $34,000, and reporting costs, $15,000 over five years.

There are eighty operating salt solution mining sites in the United States, principally in Texas, Louisiana, Michigan, New York, Ohio, and Kansas, containing approximately one thousand wells. Permit applications expenses for the thirty fields are estimated to total $204,000 and incremental annual reporting requirement expenses are estimated at $165,000 over five years. The total one-time cost of mechanical integrity testing is estimated to be one-half million dollars.

One operating field with 18 wells (17 injection and one extraction) for the solution mining of potash exists in Moab, Utah.[49] Permit application requirements for the site will involve a one-time cost of $30,000.[50] There will be no costs for integrity testing of the injection wells, as all abandoned wells in the field are thought to be adequately plugged.[51] Therefore no cost will be incurred by the operator for reviewing nearby wells. There will be recurring incremental costs of $100,000 for reporting over a five year period.

Summaries of the one-time costs and annual recurring costs to industry are presented in Table 9.

2. *State Costs.*—The regulations require collection and review of data on a quarterly basis for each site subject to the regulations. Seven hours per submission per site has been employed in estimating state costs. The submission of an annual report to EPA will require 3 to 35 work days per State to comply with the regulations, depending on the number of permits issued, quarterly reports reviewed, and other regulatory activities.

Table 9.—*Incremental Five-Year Costs to Industry, Class III*

[In thousands of 1977 dollars]

	Permitting	Mechanical integrity test	Monitoring wells	Remedial action	Total
Non-recurring:					
In-situ gasification	10	0	0	0	10
Uranium leaching	60	0	0	0	60
Geothermal	10	0	0	0	10
In-situ copper leaching	31	0	300	0	331
Frasch sulfur mining	34	0	0	0	34
Solution mining of salt	204	519	3,000	1,500	5,223
Solution mining of potash	30	0	0	0	30
Subtotal	379	519	3,300	1,500	5,698

	Monitoring	Reporting	Total
Recurring:			
In-situ gasification	0	11	11
Uranium leaching	0	53	53
Geothermal	0	9	9
In-situ copper leaching	18	9	27
Frasch sulfur mining	0	15	15
Solution mining of salt	180	165	345
Solution mining of potash	0	100	100
Subtotal	198	362	560
Total	N/A	N/A	6,258

N/A = Not Applicable.

Source: Environmental Protection Agency. *Class III Cost Analysis.* (May 1980).

The State program costs for all States to comply with this Subpart of the regulations are estimated to be $1.9 million over five years as shown in Table 10.

Class IV Wells. Until an underground injection facility receives an UIC permit issued pursuant to the Safe Drinking Water Act it is subject to the interim status requirements of the Resource Conservation and Recovery Act.[52] The Agency adopted this approach because the UIC program does not have the equivalent of an interim status period when owners or operators who dispose of hazardous waste by underground injection are subject to Federally enforceable standards. Enforcement of environmental controls under the UIC program must await: the development by states of programs for primary enforcement responsibility; the approval or disapproval of those programs by EPA; and the development of UIC programs by EPA in States which fail to develop and implement adequate programs for primary enforcement responsibility. EPA does not believe that UIC primary enforcement programs will be in place in all States on the effective date of these interim status regulations. Therefore, in order to provide control over underground injection of hazardous waste during the interim status period, as contemplated by RCRA, it is necessary to regulate underground injection under 40 CFR 265, Subpart R.

Table 10.—*Incremental Five-Year Costs to States, Class III Wells*

[In thousands of 1977 dollars]

	Total
Non-recurring:	
Developing state programs	72
Program hearings	23
Permitting existing sites	536
Permit hearings	78
Subtotal	709
Recurring:	
Quarterly Review	285
Annual Report	130
Enforcement	815
Subtotal	1,230
Total	1,939

Source: Environmental Protection Agency. *Class III Cost Analysis.* (May 1980).

[47] Environmental Protection Agency, *Class III Cost Analysis* (May, 1980).

[48] Temple, Barker and Sloane, *op. cit.*, Part I, p. II–23.

[49] *Ibid.*, Part I, p. II–27.

[50] *Ibid.*, Part I, p. III–6.

[51] *Ibid.*, Part I, p. III–8.

[52] 45 FR 33176.

Once an UIC program is promulgated by a state, Class IV wells which inject hazardous waste directly into an underground source of drinking water will be prohibited.[53] This prohibition is effective six months after the affective date of the program. Requirements for Class IV wells which inject above an underground source of drinking water are reserved.

Preliminary analysis, based on limited field work, suggests that there are between 5,000–10,000 wells that will meet the definition of Class IV. The "best estimate" is 7,500 wells.

In estimating costs EPA's consultant based its analysis on the expectation that large disposers—those injecting more than one thousand gallons per day—will pretreat their waste stream to remove the hazardous components, then transport the sludge to an off-site facility. Small disposers it is assumed, will transport the entire waste stream without prior treatment.[54] In revising the cost estimate to conform with the promulgated regulations EPA followed this convention.[55] In addition, EPA included costs for monitoring of injection fluids and quarterly reporting to the Director in order to present the costs of a comprehensive regulatory program. Such monitoring and reporting is not now required, but under consideration. To illustrate, one of the options for which the Agency has requested comments, in connection with permitting standards for hazardous waste management facilities, would require a demonstration that the anticipated impact upon groundwater" * * * will not adversely affect the health of persons or violate NPDWR based on the following information:

Injection volume and pressure * * *
Direction of ground water flow * * *
Monitoring up-gradient and down-gradient." [56]

It is expected that the cost to industry in the first five years of program operation will total $163 million. State costs are estimated at $1.2 million over this period.[57]

Class V Wells. Generally, wells falling into this class inject nonhazardous fluids into or above formations that contain underground sources of drinking water. Owners or operators of such wells are to notify the Director of the existence of any well under his control meeting the definition of Class V, and submit certain information within one year of the effective date of the UIC program. Within three years of such effective date the Director is to: submit certain information; assess the contamination potential of Class V wells; assess the available corrective alternatives and their environmental and economic consequences; and make recommendations for the most appropriate regulatory approaches and for remedial actions, where appropriate.[58]

Nonrecurring State costs for Class V wells are related to establishing the assessment program while annual costs relate to compiling, categorizing and analyzing the information collected. It is estimated that this effort will cost $5.2 to $7.2 million over a five year period.

Production Impact

Class II

EPA followed a seven step approach to the estimate of the impact of the Regulations on oil production.[59]

1. Determine the cost of compliance for each event combination.
2. Calculate the break-even point for each event combination.
3. Calculate the probability for each event combination.
4. Determine the expected value of fraction of wells shut down or unrealized, i.e., those producing below break-even point.
5. Determine the expected value of fraction of production lost due to shut down/unrealized wells.
6. *Number of wells shut down* = total number of wells under regulation × (sum of expected values of fraction of wells shut down/unrealized.
7. *Lost production* = total production from wells under regulation × (sum of expected value of fraction of lost production).

Previously, EPA estimated that approximately 12,000 barrels of oil per day would not be produced as a result of the regulations.[60] In the interim EPA's contractor reviewed the analysis and made several important changes.[61] First, the profit per barrel was revised from four to six dollars because the rapidly increasing price of crude oil rendered the earlier profit figure obsolete. Second, the capital recovery period was revised from ten years for all wells, to one and one-half years for new ones, and three for existing wells, to more accurately reflect current industry practice. This change represents a substantially more stringent assumption regarding the required profitability of associated producing wells when evaluated against the cost incurred in compliance with the Regulations. Third, the discount rate used in the calculation of the present value of future profits was increased from 10% to 13%. Again, this represents a more stringent criterion for determining whether the expenditure of funds in compliance with the Regulations is justified on the basis of future profits. All of the changes except that relating to profits tended to increase the impact on production compared to EPA's previous estimate.

The combined effect of those changes was to increase the estimate of production loss from 12,000 to 13,300 barrels per day (BPD).[62] The impact associated with each category of injection well is presented in Table 11. It is to be noted that the estimate of lost production is closely tied to profit rates, the distribution of profit per barrel among wells, and payback period. If profits are assumed to increase from six to ten dollars per barrel, which EPA believes to be a reasonable assumption, the estimated loss in production attributable to the regulations declines from thirteen thousand to five thousand BPD.[63] If, instead of applying a uniform profit of $6 per barrel, it is assumed that one-third of all wells earn $4 per barrel and two-thirds earn $10 per barrel, the loss in oil production increases from thirteen thousand to twenty thousand BPD.[64] If the required payback period is decreased from one and one-half to one year for new wells, and from three to two years for existing wells, the loss in production amounts to 29,000 BPD.[65]

[53] 40 CFR 122.36.
[54] *Ibid.*, Part II, p. III–5.
[55] U.S. Environmental Protection Agency, *Class IV Cost Analysis* (May 1980).
[56] 45 FR 33332.
[57] Environmental Protection Agency, *Class IV Cost Analysis* (May 1980).
[58] 40 CFR 146.51; 40 CFR 146.52.
[59] Booz, Allen and Hamilton, Inc., *Re-estimation of Impacts of Proposed Underground Injection Control Regulations on Crude Oil Production.* (April 30, 1980), Attachment 3, p. 11.
[60] 44 FR 23 758, April 20, 1979.
[61] Generally, Booz, Allen and Hamilton, *Re-estimation of Impacts . . .*, p. III–3.
[62] *Ibid.*, p. III–2.
[63] *Ibid.*, p. III–3.
[64] *Ibid.*, p. III–8.
[65] *Ibid.*, p. III–3.

Table 11.—*Production Loss Related to Type of Injection Well Subject to Regulation*

Type of well	Injection wells		Associated producing wells		Associated production loss (thousands BPD)		
	Shut-in	Not put into service	Shut-in	Not coverted to enhance recovery	Shut-in wells	Enhanced recovery not put into service	Total
Existing enhanced recovery	1,090	.....	1,090	.....	2.4	.....	2.4
Existing salt water disposal	75	.....	300	.....	.4	.....	.4
New enhanced recovery	40	2,470	.....	2,510	.....	10.3	10.3
New salt water disposal	.....	15	.....	60	.....	.2	.2
Totals	1,205	2,485	1,390	2,570	2.8	10.5	13.3

Source: Booz, Allen and Hamilton, *Reestimation of Impacts of Proposed Underground Injection Control Regulations on Crude Oil Production.* (April 30, 1980), p. III–4.

In the aggregate the regulations are expected to have little effect on profits, prices, production, or employment. Imported oil prices are determined by the Organization of Petroleum Exporting Countries (OPEC), and domestic "new" oil is priced accordingly. With the expiration of controls on "old" oil in 1981, all domestically produced oil will be priced according to OPEC levels. Therefore it is reasonable to expect that the cost of compliance will be absorbed by oil firms.[66] In 1977 revenues of the oil industry were $32.5 billion.[67] The average annual cost of $113 million attributable to the regulations represents about one third of one percent of total revenues.

Based upon overall output per employee productivity figures, the loss of 13,300 barrels per day suggests a maximum potential reduction in employment of 600 employees. In practice the number of positions actually eliminated may approach zero, for two reasons: First, almost all of the lost production accrues to future wells not put into service. Since they are not yet in existence there are no existing jobs eliminated. Second, the remaining lost production of 2,700 BPD is distributed among fifteen hundred producing wells. Considering the widely dispersed impact it appears that few, if any, current jobs will be lost.[68]

On a regional level the impact will be more variable. In general, regions with (1) a higher proportion of stripper wells, (2) wells producing at a relatively low output, (3) a large number of abandonments, and (4) poor completion and abandonment practices, will be affected more than regions not so characterized. Based upon these types of considerations it appears that the impact of the regulations will be felt to a greater extent in the Illinois and Appalachian Basins. The least likely regions to experience an impact are the Rocky Mountain and the Gulf Coast. Between these extremes will fall California, East Texas and the Permian Basin.[69]

Class III[70]

The potential impact of the regulations is not expected to be significant, for the following reasons:

(1) For most industries the production from the sites subject to the regulations account for only a small proportion of domestic supply;

(2) For salt and Frasch sulfur production, compliance costs are relatively small; and

(3) Firms engaging in solution mining are diversified.

No loss of employment is expected to be caused by compliance with the regulations.

Reporting Impacts

Reporting requirements apply to all permit holders under Classes I and III, and to owners or operators of wells authorized by permit or rule under Class II. Owners or operators of Class II wells are to report once each year, while owners or operators of Class I and III wells are to report quarterly. Although not presently required, reporting costs have also been estimated for Class IV operators, as discussed earlier.

Total annual costs to owners and operators of Class I, II, and III wells are estimated to be $468,000. Owners and operators of Class IV wells are estimated to incur costs in the first year only of approximately $600,000 in submitting monitoring reports. They will not incur reporting costs beyond the first year because these wells are banned after six months from the time the UIC program becomes effective.

The State will review these reports. It will, in turn, make three types of reports to EPA: (1) Quarterly reports on the compliance status of major facilities (Classes I and IV) once the State program is effective; (2) annual reports on the operation of its program; and (3) "mid-course correction" reports, as described in the following section on program evaluation.

Annual State costs for the review of monitoring data for Classes I, II, and III, and for the submission of the quarterly and annual reports to EPA, are estimated to be about $1.0 million per year. These are recurring annual costs and do not include a cost of $221,000 incurred by the States during the first year only, to review Class IV monitoring reports. It is expected that the mid-course correction reports will require an insignificant amount of time to prepare, and no cost has been included for them.

EPA will review the quarterly and annual reports from the 57 jurisdictions at an estimated cost of $18,000 per year.

In summary, reporting costs during the first five years of program operation total $8.2 million, as follows:

- Owner/operators, $2.9 million.
- States, $5.2 million.
- EPA, $90 thousand.

Reporting costs are presented in additional detail in Table 12.

Evaluation Plan

In the preamble to the reproposed regulations,[71] EPA summarized its plan for evaluation of the UIC program and indicated it would provide a more detailed plan on promulgation. The discussion below summarizes the Agency's plan in this area.

EPA would like to be able to target the UIC requirements to those well types and geologic, geographic or hydrologic conditions, that have the greatest potential for groundwater contamination. EPA will evaluate the program and, based on its findings, may adjust the requirements of the UIC program.

[71] 44 FR 23752, April 20, 1979.

Table 12.—*Reporting Costs*

	Well class			
	I	II	III	IV
Well owner/operator:				
Reporting monitoring data:				
Reporting frequency per year	4	1	4	4
Unit time (hours)	8	1	8–16	4
Unit cost (dollars)	75	11–18	75–150	40
Number of wells/sites	[1]309	25,200	142	[2]7,500
Total cost per year ($ thousands)	23	378	67	[2]600
State:				
Review monitoring reports:				
Number reviewed per year	1,236	25,200	568	[2]15,000
Unit time (hours)	6	1	7	1
Unit cost (dollars)	90	18	105	15
Total cost per year ($ thousands)	109	454	60	[2]221
Quarterly report to EPA on compliance status:				
Number submitted per year	96	n.a.	n.a.	114
Unit time (hours)	18	n.a.	n.a.	40
Unit cost (dollars)	270	n.a.	n.a.	580
Total cost per year ($ thousands)	26	n.a.	n.a.	66
Annual report to EPA on program operation:				
Unit time (hours)	30–140	160	108	160
Unit cost (dollars)	400–2,000	2,400	1,625	2,400
Total cost per year ($ thousands)	10–49	77	26	137

[66] Booz. Allen and Hamilton. *Underground Injection Control Program. Industry Analysis of Class II and Class III Well Regulation.* (April 30, 1980), p. III–3.

[67] *Ibid.*, p. II–12.

[68] Booz. Allen and Hamilton. *Underground Injection Control Program. Industry Analysis . . .* (p. IV–2).

[69] *Ibid.*, p. 2: IV–4.

[70] *Ibid.*, p. III–14 ff.

Table 12.—*Reporting Costs*—Continued

	Well class			
	I	II	III	IV
Environmental Protection Agency:				
Review of quarterly report on compliance status:				
Number received	96	n.a.	n.a.	114
Unit time (hours)	4	n.a.	n.a.	4
Unit cost (dollars)	40	n.a.	n.a.	40
Total cost per year ($ thousands)	4	n.a.	n.a.	5
Review of Annual Report on Program Operation:				
Number reviewed	24	32	16	57
Unit time (hours)	4	16	4	4
Unit cost (dollars)	40	160	40	40
Total cost per year ($ thousands)	1	5	1	2

[1] The average number of wells in States which do not presently require reporting.

[2] Only two reports will be submitted since it is assumed that all injections of hazardous waste ceases within six months. Hence, there are no Class IV reporting costs to injectors after the first year.

n.a. = Not applicable.

The Agency evaluated two approaches for directly measuring the improvement in ground-water quality that would result from implementation of the UIC program and concluded that neither was a viable method of evaluating the program. The first approach was based on the drilling of monitoring wells in the immediate vicinity of a random sample of injection wells to determine the ambient ground-water quality. Because the expected failure rates (i.e., the fraction of wells expected to fail a mechanical integrity test) are small (estimated at 2–3% for Class II wells, for example) large sample sizes would be needed to measure the effect reliably. It was estimated that the Agency would need to sample 200 injection wells to measure the failure rates and a much larger sample, perhaps 1,000, to make inferences about what categories of wells are most likely to fail. Using the conservative assumption that at least two monitoring wells would generally be needed for each injection well, and that the cost of drilling a monitoring well would be on the order of $20,000, the total costs for the well drilling alone would be $8 million to sample 200 injection wells and $40 million to sample 1,000 wells. In addition to its extremely high cost, this approach has two other serious drawbacks. It provides no information on the effect of nearby wells in the area of review on groundwater or on the effectiveness of the UIC program in abating pollution from these wells. It also would not provide valid data on the effectiveness of the UIC program in ensuring that leaking injection wells are repaired. To obtain data on ground-water quality before and after program implementation, the sample on which the evaluation would be based would have to be drawn and known to the program managers before the program takes effect. There would, therefore, be no way to ensure that the treatment of the sampled injection wells was representative of the State programs as a whole. For these reasons, this approach was rejected.

The second direct approach that EPA evaluated is based on analysis of water from existing water wells (or other wells, such as existing monitoring wells) that happen to be located near injection wells. If a sample of such wells showed a significantly higher rate of contamination, for example by salinity, than a sample of wells further from injection wells, one could conclude that the injections wells were likely to be a cause of contamination. Similarly, if the rate of contamination were reduced after implementation of the UIC program, one could conclude that it had been effective. This approach would avoid the necessity of drilling monitoring wells, but it suffers from a number of serious drawbacks which have led EPA to reject it as well. First, it would be necessary in each case to perform a ground-water modeling exercise to determine whether contamination, if it existed, would have reached a given water well. Methods and data to do this routinely with sample sizes of hundreds or thousands do not exist. Second, we would not know when the contamination might have begun, so we would not know how far the plume of contamination would have traveled even if we have an adequate ground-water flow model for the area. Third, existing water wells would in many cases not be drawing from the depths and strata which may have been contaminated. Fourth, where contamination has in fact reached a water well, the well might well have been closed down without an adequate record, introducing an inherent bias. Fifth, it would be impossible to distinguish between contamination from an injection well and contamination from a nearby brine pit (perhaps abandoned). Sixth, it is not clear whether the population of injection wells with water wells located nearby is statistically representative of injection wells as a whole.

EPA also evaluated the possibility of using surface resistivity methods as part of an evaluation scheme to determine from the surface whether contamination had occurred. The evaluation included a field test of the method in an area where contamination by a Class II well had been alleged. EPA concluded that, at its present stage of development, the results of the method are not clear enough for routine use in a broad scale evaluation.

Because of the lack of valid and feasible means of evaluating the effect of the UIC program directly on ground-water quality, EPA has been forced in its evaluation plans to rely on an indirect set of measures of the need for and the effectiveness of the program. EPA will use the observed failure rates as its major evaluation tool. EPA will evaluate these failure rates and, based on its findings, make appropriate changes in the regulations.

Any such changes would be accomplished through amendments of these regulations and would involve full opportunity for public comment. EPA also would expect that the implementation of the UIC program would lead to an increased public awareness of the potential impacts of well injection on groundwater and hence to an increase in the number of reported cases of alleged contamination and to investigation and resolution of these incidents, thus improving the available data base on the direct impacts of injection wells on ground-water quality.

In addition to analysis of failure rates, EPA will also evaluate the administrative effectiveness of the program—whether permits are being issued as required, whether corrective action is in fact occurring when problems are discovered, and so forth.

The mechanisms which EPA will use to carry out these evaluations are the following:

For Classes I, II, III, IV, and V. Quarterly or annual reporting is required of both the owners and operators of wells and the States with primary enforcement responsibility for the program. This periodic reporting will allow the periodic assessment of the efficiency of the program in terms of whether the permits are being issued on such schedule, what the rate of permit violations are and whether the rates are increasing or decreasing, and whether State programs are performing adequately as measured by the conditions of State primacy.

In addition, the following will be required for specific categories of wells:

For injection wells in Classes I, II, and certain Class III wells. the regulations'

major requirements are periodic mechanical integrity tests and evaluation of wells in the area of review. EPA will conduct a "mid-course" evaluation of these two requirements on an ongoing basis as the Agency collects data from the States based on the first two years of program operations. The evaluation will provide information on the potential environmental problem posed by injection wells lacking mechanical integrity and by abandoned and producing wells that penetrate the zone of endangering influence associated with injection wells. It will also yield information on the costs and benefits of corrective action and analyze alternatives to the current requirement.

For other categories of Class III wells, the scheme presented above is not appropriate because the applicable regulatory requirements are quite different; these will be evaluated on a case-by-case basis.

For Class IV wells, EPA's evaluation will center on whether such wells are in fact identified and phased out when this is required by the regulations.

Evaluation of the UIC program's effectiveness with respect to *Class V wells* is premature at this time.

EPA considered several alternatives on the timing of the data submission and for "mid-course" evaluation of the requirement for mechanical integrity testing and for the area of review. The considerations that were balanced included the burden on the States in supplying the data, the desire to make any needed corrections in the regulations as quickly as possible, and the need for a sufficiently large and representative sample of data. The reproposal provided for submission of data after the first year of operation of the State programs. Concern developed, however, that one year's operation might be an arbitrary limit. It would be unrepresentative because it is too short for two reasons: (1) Practical experience with program implementation indicates that an initial period of time is required during which both program staff and the regulated community gains experience with the new procedures and requirements; and (2) because five years are allowed for mechanical integrity tests for existing injection wells (where required), it is likely that relatively few of these actions will occur in the first year. Conversely, one year's operation may not provide enough data with which to conduct a statistically valid evaluation of the area of review and mechanical integrity portions of the regulation.

The Agency, therefore, selected an alternative which it believes is an appropriate compromise. The requirements for the evaluation of the major provisions applicable to Classes I, II, and certain Class III wells are specified in 40 CFR 122.18(c)(4)(ii) and 146.

The State Director is to submit this data during the first two full years of operation of the State program, at six-month intervals. The data is to include information on the hydrogeological environment, the numbers and types of wells in the area of review and any remedial action required by the Director, and the results of mechancial integrity tests conducted pursuant to the regulations.

This alternative ensures the data will cover a representative period of program operation and also enable EPA to begin to develop data analysis procedures and to draw appropriate conclusions about program effectiveness as soon as it gets a large enough sample of data.

The Agency originally proposed to apply the evaluation of mechancial integrity and area of review requirements solely to Class II wells because it was here that major questions about the requirements had been raised. After further consideration, the Agency decided to evaluate the requirements for Class I and certain Class III wells for which the requirements are similar.

OMB Review

The sections of these regulations pertaining to recordkeeping and reporting will be submitted to the Office of Management and Budget for review in light of the requirements of the Federal Reports Act, 44 U.S.C. Sec. 3501 *et seq.*

(Secs. 1421, 1422, 1423, 1431, 1445, 1447, 1450, Safe Drinking Water Act, as amended, 42 U.S.C. 300(f) et seq.)

Douglas M. Costle,

Administrator.

June 17, 1980.

Part 146 is added to Title 40 to read as set forth below:

PART 146—UNDERGROUND INJECTION CONTROL PROGRAM: CRITERIA AND STANDARDS

Subpart A—General Provisions

Sec.

146.01 Applicability and scope.
146.02 Law authorizing these regulations.
146.03 Definitions.
146.04 Criteria for exempted aquifers.
146.05 Classification of injection wells.
146.06 Area of review.
146.07 Corrective action.
146.08 Mechanical integrity.
146.09 Criteria for establishing permitting priorities.
146.10 Plugging and abandoning Class I–III wells.

Subpart B—Criteria and Standards Applicable to Class I Wells

146.11 Applicability.
146.12 Construction requirements.
146.13 Operating, monitoring and reporting requirements.
146.14 Information to be considered by the Director.
146.15 Mid course evaluation requirements.

Subpart C—Criteria and Standards Applicable to Class II Wells

146.21 Applicability.
146.22 Construction requirements.
146.23 Operating, monitoring, and reporting requirements.
146.24 Information to be considered by the director.
146.25 Mid course evaluation requirements.

Subpart D—Criteria and Standards Applicable to Class III Wells

146.31 Applicability.
146.32 Construction requirements.
146.33 Operating, monitoring and reporting requirements.
146.34 Information to be considered by the Director.
146.35 Mid course evaluation requirements.

Subpart E—Criteria and Standards Applicable to Class IV Injection Wells

Subpart F—Criteria and Standards Applicable to Class V Injection Wells

146.51 Applicability.
146.52 Inventory and Assessment.

Authority: Secs. 1421, 1422, 1423, 1431, 1445, 1447, and 1450 of the Safe Drinking Water Act, as amended, 42 U.S.C. 300(f) et. seq.

Subpart A—General Provisions

§ 146.01 Applicability and scope.

(a) This Part sets forth technical criteria and standards for the Underground Injection Control Program. This part should be read in conjunction with 40 CFR Parts 122, 123, and 124 which also apply to UIC programs. 40 CFR Part 122 defines the regulatory framework of EPA administered permit programs. 40 CFR Part 123 describes the elements of an approvable State program and procedures for EPA approval of State participation in the permit programs. 40 CFR Part 124 describes the procedures the Agency will use for issuing permits under the covered programs. Certain of these procedures will also apply to State-administered programs as specified in 40 CFR Part 123.

(b) Upon the approval, partial approval or promulgation of a State UIC program by the Administrator, any underground injection which is not authorized by the Director by rule or by permit is unlawful.

§ 146.02 Law authorizing these regulations.

The laws authorizing these regulations and all other UIC program regulations are referenced in 40 CFR part 122. They include Sections 1421, 1422, 1423, 1431, 1445, 1447 and 1450 of the Public Health Service Act as amended by the Safe Drinking Water Act ("SDWA") (Pub. L. 93–523) and by the SDWA Amendments of 1977 (Pub. L. 95–190).

§ 146.03 Definitions.

The following definitions apply to the underground injection control program.

Abandoned well means a well whose use has been permanently discontinued or which is in a state of disrepair such that it cannot be used for its intended purpose or for observation purposes.

Administrator means the Administrator of the United States Environmental Protection Agency, or an authorized representative.

Application means the EPA standard national forms for applying for a permit, including any additions, revisions or modifications to the forms; or forms approved by EPA for use in approved States, including any approved modifications or revisions. For RCRA, application also includes the information required by the Director under § 122.25 (contents of Part B of the RCRA application).

Aquifer means a geological formation, group of formations, or part of a formation that is capable of yielding a significant amount of water to a well or spring.

Area of review means the area surrounding an "injection well" described according to the criteria set forth in § 146.06.

Casing means a heavy metal (steel or iron) pipe or tubing of varying diameter and weight, lowered into a borehole during or after drilling in order to support the sides of the hole and thus prevent the walls from caving, to prevent loss of drilling mud into porous ground, or to prevent water, gas, or other fluid from entering the hole.

Catastrophic collapse means the sudden and utter failure of overlying "strata" caused by removal of underlying materials.

Cementing means the operation whereby a cement slurry is pumped into a drilled hole and/or forced behind the casing.

Confining bed means a body of impermeable or distinctly less permeable material stratigraphically adjacent to one or more aquifers.

Confining zone means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone.

Contaminant means any physical, chemical, biological, or radiological substance or matter in water.

Director means the Regional Administrator or the State Director, as the context requires, or an authorized representative. When there is no approved State program, and there is an EPA administered program, "Director" means the Regional Administrator. When there is an approved State program, "Director" normally means the State Director. In some circumstances, however, EPA retains the authority to take certain actions even where there is an approved State program. (For example, when EPA issued an NPDES permit prior to the approval of a State program, EPA may retain jurisdiction over that permit after program approval, see § 123.69.) In such cases, the term "Director" means the Regional Administrator and not the State Director.

Disposal well means a well used for the disposal of waste into a subsurface stratum.

Effective date of a UIC program means the date that a State UIC program is approved or established by the Administrator.

Environmental Protection Agency ("EPA") means the United States Environmental Protection Agency.

EPA means the United States "Environmental Protection Agency."

Exempted aquifer means an aquifer or its portion that meets the criteria in the definition of "underground source of drinking water" but which has been exempted according to the procedures of § 122.35(b).

Existing injection well means an "injection well" other than a "new injection well."

Facility or activity means any "HWM facility," UIC "injection well," NPDES "point source," or State 404 dredge and fill activity, or any other facility or activity (including land or appurtenances thereto) that is subject to regulation under the RCRA, UIC, NPDES, or 404 programs.

Fault means a surface or zone of rock fracture along which there has been displacement.

Flow rate means the volume per time unit given to the flow of gases or other fluid substance which emerges from an orifice, pump, turbine or passes along a conduit or channel.

Fluid means material or substance which flows or moves whether in a semisolid, liquid, sludge, gas, or any other form or state.

Formation means a body of rock characterized by a degree of lithologic homogeneity which is prevailingly, but not necessarily, tabular and is mappable on the earth's surface or traceable in the subsurface.

Formation fluid means "fluid" present in a "formation" under natural conditions as opposed to introduced fluids, such as drilling mud.

Generator means any person, by site location, whose act or process produces hazardous waste identified or listed in 40 CFR Part 261.

Ground water means water below the land surface in a zone of saturation.

Hazardous waste means a hazardous waste as defined in 40 CFR 261.3.

Hazardous Waste Management facility ("HWM facility") means all contiguous land, and structures, other appurtenances, and improvements on the land used for treating, storing, or disposing of hazardous waste. A facility may consist of several treatment, storage, or disposal operational units (for example, one or more landfills, surface impoundments, or combination of them).

HWM facility means "Hazardous Waste Management facility."

Injection well means a "well" into which "fluids" are being injected.

Injection zone means a geological "formation", group of formations, or part of a formation receiving fluids through a well.

Lithology means the description of rocks on the basis of their physical and chemical characteristics.

Owner or operator means the owner or operator of any facility or activity subject to regulation under the RCRA, UIC, NPDES, or 404 programs.

Packer means a device lowered into a well which can be expanded to produce a water-tight seal.

Permit means an authorization, license, or equivalent control document issued by EPA or an "approved State" to implement the requirements of this part and Parts 122, 123 and 124. Permit does not include RCRA interim status (§ 122.23), UIC authorization by rule (§ 122.37), or any permit which has not yet been the subject of final agency action, such as a "draft permit" or a "proposed permit."

Plugging means the act or process of stopping the flow of water, oil, or gas in "formations" penetrated by a borehole or "well."

Plugging record means a systematic listing of permanent or temporary abandonment of water, oil, gas, test, exploration and waste injection wells, and may contain a well log, description of amounts and types of plugging material used, the method employed for plugging, a description of formations which are sealed and a graphic log of the well showing formation location,

formation thickness, and location of plugging structures.

Pressure means the total load or force per unit area acting on a surface.

Radioactive Waste means any waste which contains radioactive material in concentrations which exceed those listed in 10 CFR Part 20, Appendix B, Table II, Column 2, or exceed the "Criteria for Identifying and Applying Characteristics of Hazardous Waste and for Listing Hazardous Waste" in 40 CFR Part 261, whichever is applicable.

RCRA means the Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act of 1976 (Pub. L. 94–580, as amended by Pub. L. 95–609, 42 U.S.C. 6901 et seq.).

SDWA means the Safe Drinking Water Act (Pub. L. 95–523, as amended by Pub. L. 95–190, 42 U.S.C. 300(f) *et seq.).*

Site means the land or water area where any facility or activity is physically located or conducted, including adjacent land used in connection with the facility or activity.

Sole or principal source acquifer means an aquifer which has been designated by the Administrator pursuant to sections 1424 (a) or (e) of the SDWA.

State Director means the chief administrative officer of any State or interstate agency operating an approved program, or the delegated representative of the State Director. If responsibility is divided among two or more State or interstate agencies, "State Director" means the chief administrative officer of the State or interstate agency authorized to perform the particular procedure or function to which reference is made.

Stratum (plural *strata*) means a single sedimentary bed or layer, regardless of thickness, that consists of generally the same kind of rock material.

Subsidence means the lowering of the natural land surface in response to: Earth movements; lowering of fluid pressure; removal of underlying supporting material by mining or solution of solids, either artificially or from natural causes; compaction due to wetting (Hydrocompaction); oxidation of organic matter in soils; or added load on the land surface.

Surface casing means the first string of well casing to be installed in the well.

Total dissolved solids ("TDS") means the total dissolved (filterable) solids as determined by use of the method specified in 40 CFR Part 136.

UIC means the Underground Injection Control program under Part C of the Safe Drinking Water Act, including an "approved program."

Underground injection means a "well injection."

Underground source of drinking water ("USDW") means an "aquifer" or its portion:

(1)(i) Which supplies drinking water for human consumption; or

(ii) In which the ground water contains fewer than 10,000 mg/1 "total dissolved solids;" and

(2) Which is not an "exempted aquifer."

USDW means "underground source of drinking water."

Well means a bored, drilled or driven shaft, or a dug hole, whose depth is greater than the largest surface dimension.

Well injection means the subsurface emplacement of fluids through a bored, drilled or driven well; or through a dug well, where the depth of the dug well is greater than the largest surface dimension.

Well log means a log obtained from a well, showing such information as resistivity, radioactivity, spontaneous potential, and acoustic velocity as a function of depth.

Well plug means a watertight and gastight seal installed in a borehole or well to prevent movement of fluids.

Well record means a concise statement of the available data regarding a well, such as a scout ticket; a full history or day-by-day account of a well, from the day the well was surveyed to the day production ceased.

Well stimulation means several processes used to clean the well bore, enlarge channels, and increase pore space in the interval to be injected thus making it possible for wastewater to move more readily into the formation, and includes (1) surging, (2) jetting, (3) blasting, (4) acidizing, (5) hydraulic fracturing.

Well monitoring means the measurement, by on-site instruments or laboratory methods, of the quality of water in a well.

§ 146.04 Criteria for exempted aquifers.

An aquifer or a portion thereof which meets the criteria for an "underground source of drinking water" in § 146.03 may be determined under 40 CFR 122.35 to be an "exempted aquifer" if it meets the following criteria:

(a) It does not currently serve as a source of drinking water; and

(b) It cannot now and will not in the future serve as a source of drinking water because:

(1) It is mineral, hydrocarbon or geothermal energy producing;

(2) It is situated at a depth or location which makes recovery of water for drinking water purposes economically or technologically impractical;

(3) It is so contaminated that it would be economically ot technologically impractical to render that water fit for human consumption; or

(4) It is located over a Class III well mining area subject to subsidence or catastrophic collapse.

§ 146.05 Classification of injection wells.

Injection wells are classified as follows:

(a) *Class I.* (1) Wells used by generators of hazardous wastes or owners or operators of hazardous waste management facilities to inject hazardous waste, other than Class IV wells.

(2) Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

(b) *Class II.* Wells which inject fluids:

(1) Which are brought to the surface in connection with conventional oil or natural gas production;

(2) For enhanced recovery of oil or natural gas; and

(3) For storage of hydrocarbons which are liquid at standard temperature and pressure.

(c) *Class III.* Wells which inject for extraction of minerals or energy, including:

(1) Mining of sulfur by the Frasch process;

(2) Solution mining of minerals;

Note.—Solution mining of minerals includes sodium chloride, potash, phosphate, copper, uranium and any other mineral which can be mined by this process.

(3) in-situ combustion of fossil fuel: and

Note.—Fossil fuels includes coal, tar sands, oil shale and any other fossil fuel which can be mined by this process.

(4) recovery of geothermal energy to produce electric power.

Note.—Class III wells include the recovery of geothermal energy to produce electric power but do not include wells used in heating or aquaculture which fall under Class V.

(d) *Class IV.* Wells used by generators of hazardous wastes or of radioactive wastes, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous wastes or radioactive wastes into or above a formation which within one quarter mile of the well contains an underground source of drinking water.

(e) *Class V.* Injection wells not included in Class I, II, III, or IV.

Note.—Class V wells includes:

(1) Air conditioning return flow wells used to return to the supply aquifer the water used for heating or cooling in a heat pump;

(2) Cesspools or other devices that receive wastes, which have an open bottom and sometimes have perforated sides. The UIC requirements do not apply to single family residential cesspools;

(3) Cooling water return flow wells used to inject water previously used for cooling;

(4) Drainage wells used to drain surface fluid, primarily storm runoff, into a subsurface formation;

(5) Dry wells used for the injection of wastes into a subsurface formation;

(6) Recharge wells used to replenish the water in an aquifer;

(7) Salt water intrusion barrier wells used to inject water into a fresh water aquifer to prevent the intrusion of salt water into the fresh water;

(8) Sand backfill wells used to inject a mixture of water and sand, mill tailings or other solids into mined out portions of subsurface mines;

(9) Septic system wells used:

(i) To inject the waste or effluent from a multiple dwelling, business establishment, community or regional business establishment septic tank; or

(ii) For a multiple dwelling, community or regional cesspool. The UIC requirements do not apply to single family residential waste disposal systems;

(10) Subsidence control wells (not used for the purpose of oil or natural gas production) used to inject fluids into a non-oil or gas producing zone to reduce or eliminate subsidence associated with the overdraft of fresh water;

(11) Wells used for the storage of hydrocarbons which are gases at standard temperature and pressure;

(12) Geothermal wells used in heating and aquaculture;

(13) Nuclear disposal wells.

§ 146.06 Area of Review.

The area of review for each injection well or each field, project or area of the State shall be determined according to either paragraph (a) or (b) of this section. The Director may solicit input from the owners or operators of injection wells within the State as to which method is most appropriate for each geographic area or field.

(a) *Zone of endangering influence.* The zone of endangering influence shall be that area the radius of which is the lateral distance from an injection well, field or project in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid into an underground source of drinking water. Computation of the zone of endangering influence may be based upon the parameters listed below and should be calculated for an injection time period equal to the expected life of the injection well or pattern. The following modified Theis equation illustrates one form which the mathematical model may take.

BILLING CODE 6560-01-M

$$r = \left(\frac{2.25\ K\ H\ t}{S\ 10^{X}} \right)^{1/2}$$

where:

$$X = \frac{4\pi KH \left(h_w - h_{b_o} \times SpG_b \right)}{2.3\ Q}$$

r = Radius of endangering influence from injection well (length)

K = Hydraulic conductivity of the injection zone (length/time)

H = Thickness of the injection zone (length)

t = Time of injection (time)

S = Storage coefficient (dimensionless)

Q = Injection rate (volume/time)

h_{b_o} = Observed original hydrostatic head of injection zone (length) measured from the base of the lowest underground source of drinking water

h_w = Hydrostatic head of underground source of drinking water (length) measured from the base of the lowest underground source of drinking water

SpG_b = Specific gravity of fluid in the injection zone (dimensionless)

π = 3.142 (dimensionless).

BILLING CODE 6560-01-C

The above equation is based on the following assumptions:

(1) The injection zone is homogenous and isotropic;

(2) The injection zone has infinite areal extent;

(3) The injection well penetrates the entire thickness of the injection zone;

(4) The well diameter is infinitesimal compared to "r" when injection time is longer than a few minutes; and

(5) The emplacement of fluid into the injection zone creates instantaneous increase in pressure.

Other models may be used as appropriate for different situations encountered in the field or where the model assumptions match more closely those situations.

(b) *Fixed Radius.* A fixed radius around the well, field or project of not less than one-fourth (¼) mile may be used. In determining the fixed radius, the following factors shall be taken into consideration: Chemistry of injected and formation fluids; hydrogeology; population and ground-water use and dependence; and historical practices in the area.

(c) If the area of review is determined by a mathematical model pursuant to paragraph (a) of this section, the permissible radius is the result of such calculation even if it is less than one-fourth (¼) mile.

§ 146.07 Corrective Action.

In determining the adequacy of corrective action proposed by the applicant under 40 CFR 122.44 and in determining the additional steps needed to prevent fluid movement into underground sources of drinking water, the following criteria and factors shall be considered by the Director:

(a) Toxicity and volume of the injected fluid;

(b) Toxicity of native fluids or by-products of injection;

(c) Potentially affected population;

(d) Geology;

(e) Hydrology;

(f) History of the injection operation;

(g) Completion and plugging records;

(h) Abandonment procedures in effect at the time the well was abandoned; and

(i) Hydraulic connections with underground sources of drinking water.

§ 146.08 Mechanical Integrity

(a) An injection well has mechanical integrity if:

(1) There is no significant leak in the casing, tubing or packer; and

(2) There is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore.

(b) One of the following tests must be used to evaluate the absence of significant leaks under paragraph (a)(1) of this section.

(1) Monitoring of annulus pressure; or

(2) Pressure test with liquid or gas.

(c) One of the following methods must be used to determine the absence of significant fluid movement under paragraph (a)(2) of this section:

(1) For Class II only, well records demonstrating the presence of adequate cement to prevent such migration; or

(2) The results of a temperature or noise log.

(d) The Director may allow the use of a test to demonstrate mechanical integrity other than those listed in paragraphs (b) and (c)(2) of this section with the written approval of the Administrator. To obtain approval, the Director shall submit a written request to the Administrator, which shall set forth the proposed test and all technical data supporting its use. The Administrator shall approve the request if it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator shall be published in the **Federal Register** and may be used in all States unless its use is restricted at the time of approval by the Administrator.

(e) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director shall apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director shall review monitoring and other test data submitted since the previous evaluation.

§ 146.09 Criteria for Establishing Permitting Priorities.

In determining priorities for setting times for owners or operators to submit applications for authorization to inject under the procedures of § 122.38 or § 123.4(g), the Director shall base these priorities upon consideration of the following factors:

(a) Injection wells known or suspected to be contaminating underground sources of drinking water;

(b) Injection wells known to be injecting fluids containing hazardous contaminants;

(c) Likelihood of contamination of underground sources of drinking water;

(d) Potentially affected population;

(e) Injection wells violating existing State requirements;

(f) Coordination with the issuance of permits required by other State or Federal permit programs;

(g) Age and depth of the injection well; and

(h) Expiration dates of existing State permits, if any.

§ 146.10 Plugging and Abandoning Class I–III Wells.

(a) Prior to abandoning Class I–III wells the well shall be plugged with cement in a manner which will not allow the movement of fluids either into or between underground sources of drinking water.

(b) Placement of the cement plugs shall be accomplished by one of the following:

(1) The Balance Method;

(2) The Dump Bailer Method; or

(3) The Two-Plug Method.

(c) The well to be abandoned shall be in a state of static equilibrium with the mud weight equalized top to bottom, either by circulating the mud in the well at least once or by a comparable method prescribed by the Director, prior to the placement of the cement plug(s).

(d) The plugging and abandonment plan required in 40 CFR 122.42(f) and 122.41(e) shall, in the case of a Class III well field which underlies or is in an aquifer which has been exempted under 40 CFR 146.04, also demonstrate that no movement of contaminants from the mined zone into an underground source of drinking water will occur. The Director shall prescribe aquifer cleanup and monitoring where he deems it necessary and feasible to insure that no migration of contaminants from the mined zone into an underground source of drinking water will occur.

Subpart B—Criteria and Standards Applicable to Class I Wells

§ 146.11 Applicability.

This subpart establishes criteria and standards for underground injection control programs to regulate Class I wells.

§ 146.12 Construction Requirements.

(a) All Class I wells shall be sited in such a fashion that they inject into a formation which is beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.

(b) All Class I wells shall be cased and cemented to prevent the movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the

well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, and axial loading;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluid, formation fluids, and temperatures;

(6) Lithology of injection and confining intervals; and

(7) Type or grade of cement.

(c) All Class I injection wells, except those municipal wells injecting non-corrosive wastes, shall inject fluids through tubing with a packer set immediately above the injection zone, or tubing with an approved fluid seal as an alternative. The tubing, packer, and fluid seal shall be designed for the expected service.

(1) The use of other alternatives to a packer may be allowed with the written approval of the Director. To obtain approval, the operator shall submit a written request to the Director, which shall set forth the proposed alternative and all technical data supporting its use. The Director shall approve the request if the alternative method will reliably provide a comparable level of protection to underground sources of drinking water. The Director may approve an alternative method solely for an individual well or for general use.

(2) In determining and specifying requirements for tubing, packer, or alternatives the following factors shall be considered:

(i) Depth of setting;

(ii) Characteristics of injection fluid (chemical content, corrosiveness, and density);

(iii) Injection pressure;

(iv) Annular pressure;

(v) Rate, temperature and volume of injected fluid; and

(vi) Size of casing.

(d) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class I wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a qualified log analyst and submitted to the Director. At a minimum, such logs and tests shall include:

(1) Deviation checks on all holes constructed by first drilling a pilot hole, and then enlarging the pilot hole by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling.

(2) Such other logs and tests as may be needed after taking into account the availability of similar data in the area of the drilling site, the construction plan, and the need for additional information, that may arise from time to time as the construction of the well progresses. In determining which logs and tests shall be required, the following logs shall be considered for use in the following situations:

(i) For surface casing intended to protect underground sources of drinking water:

(A) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and

(B) A cement bond, temperature, or density log after the casing is set and cemented.

(ii) For intermediate and long strings of casing intended to facilitate injection:

(A) Resistivity, spontaneous potential, porosity, and gamma ray logs before the casing is installed;

(B) Fracture finder logs; and

(C) A cement bond, temperature, or density log after the casing is set and cemented.

(e) At a minimum, the following information concerning the injection formation shall be determined or calculated for new Class I wells:

(1) Fluid pressure;

(2) Temperature;

(3) Fracture pressure;

(4) Other physical and chemical characteristics of the injection matrix; and

(5) Physical and chemical characteristics of the formation fluids.

§ 146.13 Operating, Monitoring and Reporting Requirements.

(a) *Operating Requirements.* Operating requirements shall, at a minimum, specify that:

(1) Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone, initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.

(3) Unless an alternative to a packer has been approved under § 146.12(c), the annulus between the tubing and the long string of casings shall be filled with a fluid approved by the Director and a pressure, also approved by the Director, shall be maintained on the annulus.

(b) *Monitoring Requirements.* Monitoring requirements shall, at a minimum, include:

(1) The analysis of the injected fluids with sufficient frequency to yield representative data of their characteristics;

(2) Installation and use of continuous recording devices to monitor injection pressure, flow rate and volume, and the pressure on the annulus between the tubing and the long string of casing;

(3) A demonstration of mechanical integrity pursuant to § 146.08 at least once every five years during the life of the well; and

(4) The type, number and location of wells within the area of review to be used to monitor any migration of fluids into and pressure in the underground sources of drinking water, the parameters to be measured and the frequency of monitoring.

(c) *Reporting Requirements.* Reporting requirements shall, at a minimum, include:

(1) Quarterly reports to the Director on:

(i) The physical, chemical and other relevant characteristics of injection fluids;

(ii) Monthly average, maximum and minimum values for injection pressure, flow rate and volume, and annular pressure; and

(iii) The results of monitoring prescribed under subparagraph (b)(4) of this section.

(2) Reporting the results, with the first quarterly report after the completion, of:

(i) Periodic tests of mechanical integrity;

(ii) Any other test of the injection well conducted by the permittee if required by the Director; and

(iii) Any well work over.

§ 146.14 Information to be Considered by the Director.

This section sets forth the information which must be considered by the Director in authorizing Class I wells. For an existing or converted new Class I well the Director may rely on the existing permit file for those items of information listed below which are current and accurate in the file. For a newly drilled Class I well, the Director shall require the submission of all the information listed below. For both existing and new Class I wells certain maps, cross-sections, tabulations of wells within the area of review and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting

agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit all the information in this Section must be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class I well to operate or the construction or conversion of a new Class I well the Director shall consider the following:

(1) Information required in 40 CFR 122.4 and 122.38(c);

(2) A map showing the injection well(s) for which a permit is sought and the applicable area of review. Within the area of review, the map must show the number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells and other pertinent surface features including residences and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;

(3) A tabulation of data on all wells within the area of review which penetrate into the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;

(4) Maps and cross sections indicating the general vertical and lateral limits of all underground sources of drinking water within the area of review, their position relative to the injection formation and the direction of water movement, where known, in each underground source of drinking water which may be affected by the proposed injection;

(5) Maps and cross sections detailing the geologic structure of the local area;

(6) Generalized maps and cross sections illustrating the regional geologic setting;

(7) Proposed operating data:

(i) Average and maximum daily rate and volume of the fluid to be injected;

(ii) Average and maximum injection pressure; and

(iii) Source and an analysis of the chemical, physical, radiological and biological characteristics of injection fluids;

(8) Proposed formation testing program to obtain an analysis of the chemical, physical and radiological characteristics of and other information on the receiving formation;

(9) Proposed stimulation program;

(10) Proposed injection procedure;

(11) Engineering drawings of the surface and subsurface construction details of the system;

(12) Contingency plans to cope with all shut-ins or well failures so as to prevent migration of fluids into any underground source of drinking water;

(13) Plans (including maps) for meeting the monitoring requirements in § 146.13(b);

(14) For wells within the area of review which penetrate the injection zone but are not properly completed or plugged, the corrective action proposed to be taken under 40 CFR 122.44;

(15) Construction procedures including a cementing and casing program, logging procedures, deviation checks, and a drilling, testing, and coring program; and

(16) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well as required by 40 CFR 122.42(a).

(b) Prior to granting approval for the operation of a Class I well the Director shall consider the following information:

(1) All available logging and testing program data on the well;

(2) A demonstration of mechanical integrity pursuant to § 146.08;

(3) The actual operating data;

(4) The results of the formation testing program;

(5) The actual injection procedure;

(6) The compatibility of injected waste with fluids in the injection zone and minerals in both the injection zone and the confining zone; and

(7) The status of corrective action on defective wells in the area of review.

(c) Prior to granting approval for the plugging and abandonment of a Class I well the Director shall consider the following information:

(1) The type and number of plugs to be used;

(2) The placement of each plug including the elevation of the top and bottom;

(3) The type and grade and quantity of cement to be used;

(4) The method for placement of the plugs; and

(5) The procedure to be used to meet the requirements of § 146.10(c).

§ 146.15 Mid-course evaluation requirements.

In compliance with 40 CFR 122.18(c)(4)(c)(ii) the data to be submitted on each Class I permit at six month intervals during the first two years of operation of the State program shall at a minimum include the following:

(a) The data required in § 146.14(a)(1);

(b) The data required in § 146.14(a)(3) including, under location, the distance and direction from the injection well;

(c) The depth to the top and bottom of any USDW;

(d) The distance to the nearest down-gradient water supply well;

(e) A description of the geology and hydrology of the area;

(f) The construction characteristics of the well;

(g) The corrective action proposed as well as that performed;

(h) The type and results of all mechanical integrity tests reported to the Director; and

(i) Any reporting to the Director under § 122.41(d).

Subpart C—Criteria and Standards Applicable to Class II Wells

§ 146.21 Applicability.

This subpart establishes criteria and standards for underground injection control programs to regulate Class II wells.

§ 146.22 Construction requirements.

(a) All new Class II wells shall be sited in such a fashion that they inject into a formation which has confining zones that are free of known open faults or fractures within the area of review.

(b) All Class II injection wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, and axial loading;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluid and formation fluids;

(6) Lithology of injection and confining zones; and

(7) Type and grade of cement.

(c) The requirements in paragraph (b) of this section need not apply to existing or newly converted Class II wells located in existing fields if:

(1) Regulatory controls for casing and cementing existed for those wells at the time of drilling and those wells are in compliance with those controls; and

(2) Well injection will not result in the movement of fluids into an underground

source of drinking water so as to create a significant risk to the health of persons.

(d) The requirements in paragraph (b) of this section need not apply to newly drilled wells in existing fields if:

(1) They meet the requirements of the State for casing and cementing applicable to that field at the time of submission of the State program to the Administrator; and

(2) Well injection will not result in the movement of fluids into an underground source of drinking water so as to create a significant risk to the health of persons.

(e) Where a State did not have regulatory controls for casing and cementing prior to the time of the submission of the State program to the Administrator, the Director need not apply the casing and cementing requirements in paragraph (b) of this section if he submits as a part of his application for primacy, an appropriate plan for casing and cementing of existing, newly converted, and newly drilled wells in existing fields, and the Administrator approves the plan.

(f) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class II wells. A descriptive report interpreting the results of these logs and tests shall be prepared by a qualified log analyst and submitted to the Director. At a minimum, these logs and tests shall include:

(1) Deviation checks on all holes constructed by first drilling a pilot hole and then enlarging the pilot hole, by reaming or another method. Such checks shall be at sufficiently frequent intervals to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.

(2) Such other logs and tests as may be needed after taking into account the availability of similar data in the area of the drilling site, the construction plan, and the need for additional information that may arise from time to time as the construction of the well progresses. In determining which logs and tests shall be required the following shall be considered by the Director in setting logging and testing requirements:

(i) For surface casing intended to protect underground sources of drinking water:

(A) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and

(B) A cement bond, temperature, or density log after the casing is set and cemented.

(ii) For intermediate and long strings of casing intended to facilitate injection:

(A) Resistivity, spontaneous potential, porosity, and gamma ray logs before the casing is installed;

(B) Fracture finder logs; and

(C) A cement bond, temperature, or density log after the casing is set and cemented.

(g) At a minimum, the following information concerning the injection formation shall be determined or calculated for new Class II wells:

(1) Fluid pressure;

(2) Temperature;

(3) Fracture pressure;

(4) Other physical and chemical characteristics of the injection zone; and

(5) Physical and chemical characteristics of the formation fluids.

§ 146.23 Operating, monitoring, and reporting requirements.

(a) *Operating Requirements.* Operating requirements shall, at a minimum, specify that:

(1) Except during well stimulation for enhanced recovery wells, injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone. In no case, shall injection pressure initiate fractures in the confining zone or cause the movement of injection or formation fluids into an underground source of drinking water.

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore shall be prohibited.

(b) *Monitoring Requirements.* Monitoring requirements shall, at a minimum, include:

(1) Monitoring of the nature of injected fluids at time intervals sufficiently frequent to yield data representative of their characteristics;

(2) Monitoring of injection pressure, flow rate, and cumulative volume at least with the following frequencies:

(i) Weekly for produced fluid disposal operations;

(ii) Monthly for enhanced recovery operations;

(iii) Daily during the injection of liquid hydrocarbons and injection for withdrawal of stored hydrocarbons; and

(iv) Daily during the injection phase of cyclic steam operations;

(3) A demonstration of mechanical integrity pursuant to § 146.08 at least once every five years during the life of the injection well;

(4) Maintenance of the results of all monitoring until the next permit review (see 40 CFR 122.42(e)); and

(5) Hydrocarbon storage and enhanced recovery may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.

(c) *Reporting Requirements.*

(1) Reporting requirements shall, at a minimum include an annual report to the Director summarizing the results of the monitoring required under paragraph (b) of this section. Previously submitted information may be included by reference.

(2) Owners or operators of hydrocarbon storage and enhanced recovery projects may report on a field or project basis rather than an individual well basis where manifold monitoring is used.

§ 146.24 Information to be considered by the director.

This section sets forth the information which must be considered by the Director in authorizing Class II wells. Certain maps, cross-sections, tabulations of wells within the area of review, and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this Section is to be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class II well to operate or the construction or conversion of a new Class II well the Director shall consider the following:

(1) Information required in 40 CFR 122.4 and 122.38(c);

(2) A map showing the injection well(s) for which a permit is sought and the applicable area of review. Within the area of review, the map must show the number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes and water wells. The map should also show faults, if known or suspected. Only wells of public record are required to be included on this map. This requirement does not apply to existing Class II wells; and

(3) A tabulation of data on all wells within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any

additional information the Director may require. This requirement does not apply to existing Class II wells.

(4) Proposed operating data:

(i) Average and maximum daily rate and volume of fluids to be injected;

(ii) Average and maximum injection pressure; and

(iii) Source, and an analysis of the chemical, physical, radiological and biological characteristics of the injection fluid;

(5) Appropriate geological data on the injection zone and confining zones including lithologic description, geological name, thickness, depth and lateral extent;

(6) Geologic name, lateral extent and depth to top and bottom of all underground sources of drinking water which may be affected by the injection;

(7) Engineering drawings of the surface and subsurface construction details of the system;

(8) Proposed formation testing program;

(9) Proposed stimulation program;

(10) Proposed injection procedure;

(11) Contingency plans to cope with all shut-ins or well failures so as to prevent migration of contaminating fluids into any underground source of drinking water;

(12) Plans for meeting the monitoring requirements of § 146.23(b);

(13) In the case of new injection wells, the corrective action proposed to be taken by the applicant under 40 CFR 122.44;

(14) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well as required by 40 CFR 122.42(g).

(b) Prior to granting approval for the operation of a Class II well the Director shall consider the following information:

(1) All available logging and testing program data on the well;

(2) A demonstration of mechanical integrity pursuant to § 146.08;

(3) The actual operating data;

(4) The results of the formation testing program;

(5) The actual injection procedure; and

(6) For new wells the status of corrective action on defective wells in the area of review.

(c) Prior to granting approval for the plugging and abandonment of a Class II well the Director shall consider the following information:

(1) The type, and number of plugs to be used;

(2) The placement of each plug including the elevation of top and bottom;

(3) The type, grade, and quantity of cement to be used;

(4) The method of placement of the plugs; and

(5) The procedure to be used to meet the requirements of § 146.10(c).

§ 146.25 Mid-course evaluation requirements.

(a) In compliance with 40 CFR 122.18(c)(4)(C)(ii) the data to be submitted on each new Class II permit at six months intervals during the first two years of operation of the State program shall at a minimum include the following:

(1) The data required in § 146.24(a)(1);

(2) The data required in § 146.24(a)(3) including, under location, the distance and direction from the injection well;

(3) The depth to the top and bottom of any USDW;

(4) The distance to the nearest down-gradient water supply well;

(5) A description of the geology and hydrology of the area;

(6) The construction characteristics of the well;

(7) The corrective action proposed as well as that performed; and

(8) Any reporting to the Director under § 122.41(d).

(b) The Director shall also submit the type and results of all Mechanical Integrity tests reported on existing wells and new (conversion only) wells during the first two years of operation.

(c) The Director shall require a temperature log or noise log, on a sample of Class II wells in cases where operators submitted cementing records to meet the requirement of § 146.08(c). The wells to be tested shall be chosen by a formal random selection procedure. The sampling shall be done on a field or pool basis and be statistically representative of the wells in that field or pool. At a minimum, the sample size for each State shall be 100 wells or 5 percent of the number of Class II injection wells in the State whichever is smaller. At least half of the wells tested must be existing wells.

Subpart D—Criteria and Standards Applicable to Class III Wells

§ 146.31 Applicability.

This subpart establishes criteria and standards for underground injection control programs to regulate Class III wells.

§ 146.32 Construction requirements.

(a) All new Class III wells shall be cased and cemented to prevent the migration of fluids into or between underground sources of drinking water. The casing and cement used in the construction of each newly drilled well shall be designed for the life expectancy of the well. In determining and specifying casing and cementing requirements, the following factors shall be considered:

(1) Depth to the injection zone;

(2) Injection pressure, external pressure, internal pressure, axial loading, etc.;

(3) Hole size;

(4) Size and grade of all casing strings (wall thickness, diameter, nominal weight, length, joint specification, and construction material);

(5) Corrosiveness of injected fluids and formation fluids;

(6) Lithology of injection and confining zones; and

(7) Type and grade of cement.

(b) Appropriate logs and other tests shall be conducted during the drilling and construction of new Class III wells. A descriptive report interpreting the results of such logs and tests shall be prepared by a qualified log analyst and submitted to the Director. The logs and tests appropriate to each type of Class III well shall be determined based on the intended function, depth, construction and other characteristics of the well, availability of similar data in the area of the drilling site and the need for additional information that may arise from time to time as the construction of the well progresses. At a minimum, such logs and tests shall include deviation checks conducted on all holes where pilot holes and reaming are used, at sufficiently frequent intervals to assure that vertical avenues for fluid migration in the form of diverging holes are not created during drilling.

(c) Where the injection zone is a water bearing formation, the following information concerning the injection zone shall be determined or calculated for new Class III wells:

(1) Fluid pressure;

(2) Temperature;

(3) Fracture pressure;

(4) Other physical and chemical characteristics of the injection zone;

(5) Physical and chemical characteristics of the formation fluids; and

(6) Compatibility of injected fluids with formation fluids.

(d) Where the injection formation is not a water bearing formation, the information in paragraph (c)(3) of this section must be submitted.

(e) Where injection is into a formation which contains water with less than 10,000 mg/l TDS monitoring wells shall be completed into the injection zone and into any underground sources of drinking water above the injection zone which could be affected by the mining

operation. These wells shall be located in such a fashion as to detect any excursion of injection fluids, process by-products, or formation fluids outside the mining area or zone. If the operation may be affected by subsidence or catastrophic collapse the monitoring wells shall be located so that they will not be physically affected.

(f) Where injection is into a formation which does not contain water with less than 10,000 mg/l TDS, no monitoring wells are necessary in the injection stratum.

(g) Where the injection wells penetrate an USDW in an area subject to subsidence or catastrophic collapse an adequate number of monitoring wells shall be completed into the USDW to detect any movement of injected fluids, process by-products or formation fluids into the USDW. The monitoring wells shall be located outside the physical influence of the subsidence or catastrophic collapse.

(h) In determining the number, location, construction and frequency of monitoring of the monitoring wells the following criteria shall be considered:

(1) The population relying on the USDW affected or potentially affected by the injection operation;

(2) The proximity of the injection operation to points of withdrawal of drinking water;

(3) The local geology and hydrology;

(4) The operating pressures and whether a negative pressure gradient is being maintained;

(5) The toxicity and volume of the injected fluid, the formation water, and the process by-products; and

(6) The injection well density.

§ 146.33 Operating, monitoring, and reporting requirements.

(a) *Operating Requirements.* Operating requirements prescribed shall, at a minimum, specify that:

(1) Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure in the injection zone during injection does not initiate new fractures or propagate existing fractures in the injection zone, initiate fractures in the confining zone or cause the migration of injection or formation fluids into an underground source of drinking water; and

(2) Injection between the outermost casing protecting underground sources of drinking water and the well bore is prohibited.

(b) *Monitoring Requirements.* Monitoring requirements shall, at a minimum, specify:

(1) The analyses of the physical and chemical characteristics of the injected fluid with sufficient frequency to yield representative data on its characteristics;

(2) Installation and use of continuous recording devices to monitor the injection pressure, flow rate and volume;

(3) Demonstration of mechanical integrity pursuant to § 146.08 at least once every five years during the life of the well for salt solution mining and geothermal wells only;

(4) Weekly monitoring of fluid level and the parameters chosen to measure water quality in the injection zone; and

(5) Quarterly monitoring of wells adjacent to the injection site to detect any migration from the injection zone into an USDW.

(6) All Class III wells may be monitored on a field or project basis rather than an individual well basis by manifold monitoring. Manifold monitoring may be used in cases of facilities consisting of more than one injection well, operating with a common manifold. Separate monitoring systems for each well are not required provided the owner/operator demonstrates that manifold monitoring is comparable to individual well monitoring.

(c) *Reporting Requirements.* Reporting requirements shall, at a minimum, include:

(1) Quarterly reporting to the Director on required monitoring;

(2) Results of mechanical integrity and any other periodic test required by the Director reported with the first regular quarterly report after the completion of the test; and

(3) Monitoring may be reported on a project or field basis rather than individual well basis where manifold monitoring is used.

§ 146.34 Information to be considered by the Director.

This section sets forth the information which must be considered by the Director in authorizing Class III wells. Certain maps, cross sections, tabulations of wells within the area of review, and other data may be included in the application by reference provided they are current, readily available to the Director (for example, in the permitting agency's files) and sufficiently identified to be retrieved. In cases where EPA issues the permit, all the information in this section must be submitted to the Administrator.

(a) Prior to the issuance of a permit for an existing Class III well or area to operate or the construction of a new Class III well the Director shall consider the following:

(1) Information required in 40 CFR 122.4 and 122.38(c);

(2) A map showing the injection well(s) for which the permit is sought and the applicable area of review. Within the area of review, the map must show the number, or name, and location of all producing wells, injection wells, abandoned wells, dry holes, surface bodies of water, mines (surface and subsurface), quarries, public water systems, water wells and other pertinent surface features including residences and roads. The map should also show faults if known or suspected. Only information of public record is required to be included on this map;

(3) A tabulation of data on all wells within the area of review which penetrate the proposed injection zone. Such data shall include a description of each well's type, construction, date drilled, location, depth, record of plugging and completion, and any additional information the Director may require;

(4) Maps and cross sections indicating the vertical and lateral limits of all underground sources of drinking water within the area of review, their position relative to the injection formation, and the direction of water movement, where known, in every underground source of drinking water which may be affected by the proposed injection;

(5) Maps and cross sections detailing the geologic structure of the local area;

(6) Generalized map and cross sections illustrating the regional geologic setting;

(7) Proposed operating data:

(i) Average and maximum daily rate and volume of fluid to be injected;

(ii) Average and maximum injection pressure; and

(iii) Source and an analysis of the chemical, physical, biological and radiological characteristics of the injection fluid.

(8) Proposed formation testing program to obtain an analysis of the physical, chemical and radiological characteristics of the receiving formation;

(9) Proposed stimulation program;

(10) Proposed injection procedure;

(11) Engineering drawings of the surface and subsurface construction details of the system;

(12) Plans (including maps) for meeting the monitoring requirements of § 146.33(b);

(13) Expected changes in pressure, native fluid displacement, direction of movement of injection fluid;

(14) Contingency plans to cope with all shut-ins or well failures so as to prevent the migration of contaminating fluids into underground sources of drinking water;

(15) A certificate that the applicant has assured, through a performance bond or other appropriate means, the resources necessary to close, plug or abandon the well as required by 40 CFR 122.42(9); and

(16) The corrective action proposed to be taken under 40 CFR 122.44.

(b) Prior to granting approval for the operation of a Class III well the Director shall consider the following information:

(1) All available logging and testing data on the well;

(2) A satisfactory demonstration of mechanical integrity for all new wells and for all existing salt solution and geothermal wells pursuant to § 146.08.

(3) The actual operating data;

(4) The results of the formation testing program;

(5) The actual injection procedures; and

(6) The status of corrective action on defective wells in the area of review.

(c) Prior to granting approval for the plugging and abandonment of a Class III well the Director shall consider the following information:

(1) The type and number of plugs to be used;

(2) The placement of each plug including the elevation of the top and bottom;

(3) The type, grade and quantity of cement to be used;

(4) The method of placement of the plugs, and

(5) The procedure to be used to meet the requirements of § 146.10(c).

§ 146.35 Mid-course evaluation requirements.

In compliance with 40 CFR 122.18(c)(4)(C)(ii) the data to be submitted on each Class III permit at six month intervals during the first two years of operation of the State program shall at a minimum include the following:

(a) The data required in § 146.14(a)(i);

(b) The data required in § 146.34(a)(3) including, under location, the distance and direction from the injection well;

(c) The depth to the top and bottom of any USDW;

(d) The distance to the nearest down-gradient water supply well;

(e) A description of the geology and hydrology of the area;

(f) The construction characteristics of the well;

(g) The type and results of all mechanical integrity tests reported to the Director during the first two years of the program; and

(h) Any reporting to the Director under § 122.41(d).

Subpart E—Criteria and Standards Applicable to Class IV Injection Wells [Reserved]

Subpart F—Criteria and Standards Applicable to Class V Injection Wells

§ 146.51 Applicability.

This subpart sets forth Criteria and Standards for underground injection control programs to regulate all injection not regulated in Subparts B, C, D, and E.

(a) Generally, wells covered by this Subpart inject non-hazardous fluids into or above formations that contain underground sources of drinking water. It includes all wells listed in § 146.05(e) but is not limited to those types of injection wells.

(b) It also includes wells not covered in Class IV that inject radioactive materials listed in 10 CFR Part 20, Appendix B, Table II, Column 2, and injection wells used to store hydrocarbons which are gases at standard temperature and pressure.

§ 146.52 Inventory and Assessment.

(a) The owner or operator of any Class V well shall, within one year of the effective date of an underground injection control program, notify the Director of the existence of any well meeting the definitions of Class V under his control, and submit the inventory information required in 40 CFR 122.37(c)(1).

(b) Within three (3) years of approval of the State program the Director shall complete and submit to EPA a report containing:

(1) The information on the construction features of Class V wells, and the nature and volume of the injected fluids;

(2) An assessment of the contamination potential of the Class V wells using hydrogeological data available to the State;

(3) An assessment of the available corrective alternatives where appropriate and their environmental and economic consequences; and

(4) Recommendations both for the most appropriate regulatory approaches and for remedial actions where appropriate.

PART 122—MARINE SANITATION DEVICE STANDARD

2. 40 CFR is amended by revising Part 122 as follows:

§ 122.18 [Amended]

a. Section 122.18 is amended by deleting paragraph (c)(4)(ii) and substituting in lieu thereof the following:

* * * * *

(c) * * *

(4) * * *

(ii) In addition to complying with the requirements of paragraph (c)(4)(i) of this section, the Director shall provide the Administrator, on February 28th and August 31st of each of the first two years of program operation, the information required in 40 CFR 146.15, 146.25, and 146.35.

§ 122.37 [Amended]

b. Section 122.37 is amended by deleting paragraph (a) and substituting in lieu therefore the following:

(a) *Types of underground injection which may be authorized by rule.* The Director may authorize underground injection by rule as outlined in this paragraph.

(1) Injection into exisiting Class I, II (except existing enhanced recovery and hydrocarbon storage), and III wells may be authorized by rule for periods up to five years from the date of approval or promulgation of the UIC program. All such wells must be issued permits within the five year period.

(i) Rules under paragraph (a)(1) of this section shall specify that the authorization to inject shall exprire:

(A) Upon the effective date of the permit or permit denial, if a permit application has been filed in a timely manner as specified in § 122.38(b)(1);

(B) If a permit application has not been filed in a timely manner as specified in § 122.38(b)(1); or

(C) Unless a complete permit application is pending, not later than five years after the approval or promulgation of the UIC program.

(ii) Notwithstanding the prohibition in § 122.33, rules under paragraph (a)(1) of this section authorizing Class II and Class III operations or projects in existing injection fields may allow them to continue normal operations until permitted, including construction and operation of new injection wells as part of the operation, provided the owner or operator maintains compliance with all applicable requirements.

(iii) Rules under paragraph (a)(1) of this section shall apply, and ensure compliance no later than one year after authorization by such rules, with the following requirements applicable to permittees, except the terms "permit" and "permittee" shall be read to include rules and those authorized by rule:

(A) Section 122.41(a)—(exemption from rule where authorized by temporary permits);

(B) Section 122.41(b)—(retention of records);

(C) Section 122.41(d)—(reporting within 24 hours);

(D) Section 122.41(e)—(180 days notice of abandonment);

(E) Sections 122.42(f) and 146.10—(plugging and abandonment);

(F) Operating, monitoring, and reporting requirements (except mechanical integrity) under § 146.13 (Class I), § 146.23 (Class II) and § 146.33 (Class III);

(G) Section 122.42(g)—(financial responsibility); and

(H) Section 122.45(c)—(requirements for wells injecting hazardous waste) applicable to class I wells injecting hazardous waste only.

(2) Injection into existing Class II enhanced recovery and hydrocarbon storage wells may be authorized by rule for the life of the well or project.

(i) Such rules promulgated by the Director shall apply the following requirements applicable to Class II permittees, except that the terms "permit" and "permittee" shall be read to include rules and those authorized by rule:

(A) Section 122.41(a)—(exemption from rule where authorized by temporary permit);

(B) Section 122.41(b)—(retention of records);

(C) Section 122.41(d)—(reporting within 24 hours);

(D) Section 122.41(e)—(180 days notice of abandonment);

(E) Sections 122.42(f) and 146.10—(plugging and abandonment);

(F) Section 122.42(g)—(financial responsibility);

(G) Section 146.08—(mechanical integrity);

(H) Section 146.22—(construction requirements); and

(I) Section 146.23—(operating, monitoring and reporting requirements).

(ii) Such rules shall establish compliance schedules for achieving the construction requirements no later than three years and other requirements no later than one year after authorization.

(3) Injection into existing Class IV wells injecting directly into USDWs may be authorized for a period not to exceed six months after approval or promulgation of the UIC program. Such rules shall apply the requirements of § 122.45(c).

(4) Injection into Class V wells may be authorized by rule until requirements under future regulations become applicable.

c. Section 122.37 is further amended by deleting paragraph (b) and re-lettering paragraphs (c), (d) and (e) as paragraphs (b), (c) and (d).

d. Section 122.27 is further amended by deleting new paragraph (c)(1) and substituting in lieu thereof the following:

* * * * *

(c) * * *

(1) *Contents.* As part of the inventory, the Director shall require at least the following information:

(i) Facility name and location;

(ii) Name and address of legal contact;

(iii) Ownership of facility;

(iv) Nature and type of injection wells; and

(v) Operating status of injection wells.

(Note.—This information is requested on national form "Inventory of Injection Wells," OMB No. 158–R0170).

§ 122.41 [Amended]

e. Section 122.41 is amended by adding a new sentence at the end of paragraph (e) as follows:

* * * * *

(e) * * * With the notice, the permittee shall submit a revised plugging and abandonment plan updated as appropriate in compliance with § 122.42(f) and § 146.10.

§ 122.17 [Amended]

f. Section 122.17(f) is amended by adding a new paragraph (3) as follows:

(f) * * *

(3) Amend a plugging and abandonment plan which has been updated under § 122.41(e).

[FR Doc. 80–18963 Filed 6–2–80; 8:45 am]

BILLING CODE 6560–01–M

federal register

Tuesday
June 24, 1980

Part III

Environmental Protection Agency

Primary Nonferrous Smelter Orders; National Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 57

[FRL 1488-2]

Primary Nonferrous Smelter Orders; National Rules

AGENCY: Evironmental Protection Agency (EPA).

ACTION: Final rules.

SUMMARY: These rules establish the minimum required contents of initial primary nonferrous smelter orders (NSOs) issued under section 119 of the Clean Air Act, and the criteria and procedures EPA will use in issuing NSOs and in evaluating NSOs issued by States. Under section 119, NSOs may be granted to eligible smelters by States, with EPA approval, or by EPA. An NSO permits a smelter to use interim constant control technology in combination with dispersion techniques to maintain the national ambient air quality standards NAAQS) for sulfur dioxide, instead of complying with its state implementation plan (SIP) emission limitation. These rules apply only to initial NSOs, which may extend through January 1, 1983. Second NSOs, extending through January 1, 1988, may also be granted but are not covered by these rules.

DATES: These rules are effective July 24, 1980. Judicial review of these rules may be obtained by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit on or before August 25, 1980.

ADDRESSES: Docket Number DSSE-78-1, which contains the documents upon which these rules are based, is open for public inspection and copying between 8 A.M. and 4 P.M. Monday through Friday at:
U.S. Environmental Protection Agency, Central Docket Section, Room 2902, Waterside Mall, 401 M Street, S.W., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: David Rochlin, Division of Stationary Source Enforcement (EN-341), 401 M Street, S.W., Washington, D.C. 20460 (202) 755-2542

SUPPLEMENTARY INFORMATION:

The remainder of this notice discusses the basis and purpose, background, and contents of the rules promulgated today. This notice also responds to the major comments on the proposed regulations and explains the reasons for major changes in the promulgated rules from the proposed regulations. EPA has also prepared a Response to Comments document, which contains more detailed responses on a number of issues raised by commenters, and addresses certain comments of less major importance. That document is part of the basis and purpose of this rulemaking, and is available in the rulemaking docket and at the address stated above. Except where changes have been made in the rules, the contents of the notice accompanying EPA's proposal of these rules should also be considered a part of the basis and purpose of the final rules.

Background

On January 31, 1979, EPA proposed national rules to implement new section 119 of the Clean Air Act (44 FR 6284). Corrections of the proposal were published on February 27, 1979 (44 FR 11096). The rules proposed a new Part 57 of the Code of Federal Regulations and included criteria for deciding whether a smelter is eligible for an NSO. Under the proposal, a smelter would have been found eligible if the Administrator determined, based on the financial information submitted in the smelter owner's application, that the smelter could not afford the control equipment necessary for it to meet its SIP emission limitation for sulfur dioxide. The proposed rules also provided for the establishment of certain minimum interim requirements to ensure that the smelter's emissions would not result in violations of the NAAQS for sulfur dioxide. These requirements included the use of dispersion-dependent techniques (tall stacks and supplementary control systems), the evaluation and control of fugitive emissions, the assumption of legal liability by the smelter for violations of the NAAQS in the areas affected by its emissions, and related monitoring and reporting requirements. The proposed rules also would have required the efficient use of an interim level of continuous emission reduction technology, and would have established criteria and procedures for a waiver of that requirement for any smelters without such controls which would be forced to close by the imposition of the interim control requirement.

Smelters receiving first NSOs would also have been required to conduct or participate in research and development projects to develop improved means for meeting SIP requirements. The regulations would have allowed a temporary suspension of SIP requirements during the processing of NSO applications, and provided procedures for that processing.

EPA received comments on the proposed rules from companies operating smelters, from people living in the vicinity of smelters, and from other interested members of the public. Public hearings were held on the proposal in Tucson, Arizona; Seattle, Washington; and Arlington, Virginia. Twenty-seven written submissions were received during the comment period, and twenty-two persons testified at the hearings. EPA considered all written and oral comments in developing the final regulations.

Basis and Purpose of the Final Regulations

Although the basic approach and framework of the final rules follows that of the proposed rules, a number of changes have been made as a result of public comment. The following discussion is organized to correspond to the rules, and contains a summary of the major comments, the Administrator's responses to those comments, and an explanation of the changes.

I. Subpart A—General

A. Eligibility of Smelters for Initial NSOs

The proposed criteria and procedures for determining whether a smelter is eligible for a first NSO received more comment than any other aspect of the proposed rules. Under the proposal, a smelter operator would have been required to submit specified technical and financial information to EPA at the time of an application for an NSO. EPA would then have determined, using a particular financial test, whether the smelter could afford the equipment necessary to meet its state implementation plan (SIP) emission limitation for sulfur dioxide. A smelter found unable to afford that equipment would have been considered eligible for an NSO, assuming it met certain other basic criteria. If the smelter had applied to the State for the NSO, EPA would have transmitted its finding on affordability to the State, before the State issued the NSO.

This approach to the eligibility determinations was opposed in comments by many of the large corporate smelter operators. The main arguments made by these companies were that EPA lacked the authority to adopt either any financial test or a single financial test for determining whether it is economically feasible for a smelter to meet its SIP emission limit, that the test proposed by EPA is the wrong one, and that the information requirements for the test are too burdensome.

1. *Does EPA have the authority to use any financial test in determining whether smelters are eligible for NSOs?*

The Kennecott Copper Corporation argued in substance that EPA has no authority to consider the affordability of any equipment beyond existing acid

plants in making the eligibility determination required by section 119(b)(3). According to this comment, any smelter now using an acid plant should be found eligible for an NSO if it is not currently meeting its SIP emission limit, irrespective of whether it can afford the additional equipment necessary to meet that emission limit.

This comment is wholly at odds with the congressional scheme and intent underlying section 119. First, it conflicts with the plain meaning of the statute. The comment advocates an industry-wide finding that no more than existing acid plants are adequately demonstrated to be reasonably availabile yet section 119(b)(3) explicitly calls for a smelter-by-smelter determination. That subsection also clearly calls for an evaluation of the affordability of the control technology (or "means of emission limitation") which would enable the smelter to meet its SIP emission limit, with no mention of the smelter's existing controls. The Administrator believes that if Congress had intended the existence of an acid plant to be the focus of the determination, it would have said so explicitly, as it did in section 119(d)(4). Kennecott's reading would, in addition, make meaningless the interim constant control requirement of section 119(d)(1)(C). In short, under the statutory scheme, a smelter is eligible for an NSO only until it can afford the necessary constant controls, and it ordinarily must use an acid plant in the interim. Kennecott's reading would create another scheme entirely.

Second, Kennecott's reading of section 119(b)(3) is inconsistent with the existing policy Congress adopted in enacting section 119. In enacting section 119, Congress intended to adopt the main elements of EPA's existing smelter program.[1] Under that program, smelters were eligible on an interim basis to use dispersion techniques instead of meeting their SIP emission limits only if the immediate imposition of the full constant control requirements was not economically feasible. This determination was smelter-specific. The only industry-wide determination was that the use of sulfuric acid plants on all strong sulfur dioxide gas streams was reasonably available control technology for *every* smelter, *i.e.* it was a minimum requirement applicable to all smelters as a condition of the interim use of dispersion techniques. The policy always required the adoption of further controls as advances in technology made them economically feasible.

Allowing smelters to use dispersion techniques instead of constant controls, irrespective of the economic need of a particular smelter to do so, would also have been diametrically opposed to the direction Congress took for all other sources in the 1977 amendments to the Clean Air Act. In the new section 123 of the Act, Congress expressed strong disapproval of dispersion techniques, and explicitly prohibited all other sources from using dispersion techniques in lieu of constant controls to meet national ambient air quality standards. Constant control emission limitations must be met by other sources irrespective of the economic or technological feasibility of doing so,[2] and section 120, also enacted in 1977, imposes severe economic penalties for noncompliance with those emission limitations. To read section 119, a provision intended to respond to problems of economic and technical feasibility, as allowing all smelters to use dispersion techniques instead of constant controls *irrespective of economic feasibilty* would give inadequate recognition to the basis thrust of the 1977 amendments and the underlying congressional intent.

Such a reading would also ignore the widely varying circumstances of the various smelters. The process technology now in use at American smelters ranges from the most antiquated to the most advanced in the world, and sulfur dioxide control levels range from zero to more than ninety percent. The meteorological and terrain conditions which determine the smelters' emission limitations also vary widely among the smelters, and the amount of further control required to meet emission limits varies widely with those conditions. The economic vitality of the different smelters also diverges widely, as a result of differences in smelting costs, mining costs, labor costs, location, and the like. As a result, the financial ability of a given smelter to meet its SIP emission limitation cannot be accurately calculated based simply on its existing control level. To do so would ignore these vital differences in circumstances, and make the eligibility determination meaningless.

Finally, basing the eligibility determination simply on the existence of an acid plant would ignore advances in technology, contrary to the intent of Congress. Although it did not appear to EPA several years ago that many smelters would be able to afford the further control technology that was then technically feasible, there have been significant advances in the cost-effectiveness of available process and control technology with its increased use domestically and abroad. For example, when EPA proposed new source performace standards (NSPS) for copper smelters in 1974, only one kind of flue gas desulfurization system (DMA scrubbing) was examined, and its use was not proposed as a basis for the standards. Information in the rulemaking docket, however, shows that significant advances in smelting sulfur dioxide weak stream control have occurred in Canada, Europe, and Japan. Basing eligibility solely on acid plants would ignore these developments, contrary both to the technology-forcing character of the Act as a whole, and to the provisions of section 119 itself. The Administrator believes that had Congress intended to exclude consideration of technical advances and key eligibility under section 119 to a single technology, it would have done so explicitly.

2. *Does section 119 permit the Administrator to adopt a single financial test for determining whether a smelter can afford the equipment necessary to meet its SIP emission limit?*

Certain companies commented that EPA lacks the authority under section 119 to prescribe the use of a particular financial test for determining whether a smelter can afford the equipment needed to meet its SIP emission limit. According to these commenters, EPA may not adopt a single financial test both because it had not done so before the adoption of section 119, and because Congress intended the Agency merely to review affordability determinations made by the State. In the Administrator's view, these assertions raise two basic questions.

(a) First, did Congress intend the States to make a finding on affordability before the final determination by EPA? Under the proposed rules, the States would have had no role in determining whether particular smelters could afford the equipment necessary to meet their SIP emission limits. Various commenters argued that Congress intended the States to make an initial finding on affordability when smelters applied to the States for NSOs. The Administrator has concluded that these comments have merit, and that the proposed rules gave inadequate attention to this question.

Upon examination, the Administrator believes that Congress intended the States to evaluate the smelters' applications and to make initial findings on affordability. This view is based primarily on sections 119(a)(1) and 119(a)(2)(C). Under section 119(a)(1), the

[1] This program is discussed in more detail below.

[2] *Union Electric Co.* v. *EPA*, 427 U.S. 246 (1976).

Administrator is to hold a hearing on the question of reasonably available control technology for a smelter if he disapproves a State's NSO. Under section 119(a)(2)(C), any NSO must be accompanied by a statement of the findings upon which it is based. The Administrator believes that eligibility is one of the findings intended to be included in that statement.

These provisions, and the right of a State to issue an NSO, can only be meaningful if the State makes an initial finding on eligibility. The final rules therefore provide for the submission of the relevant information to the States as part of the NSO application and for the States to make initial findings.

(b) Second, does section 119 preclude EPA from establishing a single, uniform set of criteria for making the determinations required by section 119(b)(3)? The proposed rules contained a specific set of financial criteria that would be used by the Administrator in making the affordability determinations required of him by section 119(b)(3). The comments of the companies argued that EPA could not adopt *any* single, uniform set of criteria for making that judgment, either because the Agency had not published such a test before enactment of section 119, or because Congress intended to allow the States to make the determination according to whatever criteria they chose.

These arguments plainly miscontrue the meaning and intent of section 119. As most commenters acknowledged, under section 119(b)(3) eligibility for an NSO is contingent on the affordability of the necessary controls, *"as determined by the Administrator."* The inclusion of this provision in the statutory criteria for eligibility shows that Congress intended EPA to make an independent judgment in reviewing a State's finding on affordability, and not to confine its review under section 119(a)(1) of State-issued NSOs to whether the State had made *some* finding on affordability. This conclusion is supported by the provisions of section 119(a)(1) itself, requiring EPA to hold a hearing when its determination differed from a State's. That provision would have no substance unless EPA were obligated to make its own determination.[3]

If EPA is to make its own determinations, the only remaining question is whether the Agency may prescribe a set of uniform criteria for determining what circumstances constitute an inability to afford the necessary equipment. The Administrator believes that, contrary to the companies' arguments, he is fully authorized to establish such criteria in these rules.

First, section 301(a) of the Act empowers the Administrator to prescribe any rules necessary for carrying out his duties under the Act. Congress specifically contemplated the exercise of this authority to promulgate rules governing the NSO program, and therefore enacted judicial review and procedural provisions (sections 307(b)(1) and 307(d)(1)(G)) applicable to these rules. Given the great importance of eligibility determinations, and given the Administrator's obligation to make those determinations independently in issuing NSOs and in reviewing State-issued NSOs, it does not seem likely that Congress intended to prohibit the Administrator from establishing in advance the criteria and procedures he will use in making affordability determinations. The Administrator believes that if Congress had intended to do so, the statute would contain some evidence of that.

Second, the fact that EPA had not previously published financial criteria for making that determination in as much detail as in these rules does not suggest that Congress intended to prohibit it from doing so. As many commenters noted, Congress intended in enacting section 119 to ratify the main elements of EPA's existing policy in this area. Under that policy, the financial basis for eligibility was that requiring the immediate installation of the necessary technology at a particular smelter was not economically feasible.

This financial criterion was also expressed by the phrase "economically unreasonable." In enacting section 119, however, Congress did not even confine the Administrator's discretion by using those terms, as it could have; instead, it left the Administrator free to exercise his discretion as necessary, telling him simply to make the determination "taking into account the cost of compliance * * *"[4]

The need to assure consistent and accurate treatment to the various smelters in making those determinations is a third persuasive reason for the Administrator's view that these national rules should contain the uniform, detailed criteria and procedures that EPA will use for making the affordability determinations.[5]

The creation of some economic criteria obviously cannot be avoided. Even if they are not established in these rules, they will be established on an *ad hoc*, incremental basis as EPA evaluates NSO applications or NSOs submitted for approval by the States. In the Administrator's judgment, however, such an incremental process of establishing criteria would not result in affordability determinations that are either accurate or consistent.

This judgment is based on the Agency's experience with the smelter program that Congress has adopted in section 119. This experience shows that detailed information and specific, uniform procedures are necessary to make informed and consistent judgments about the ability of applicant smelters to afford the necessary control technology. This is due to the integrated relation of many smelters to mining and refining facilities under the same or related ownership. This integration necessitates the use of detailed disaggregated data to ascertain true costs and transfer values in the absence of actual market values. The size and complexity of the multinational corporations which operate most American smelters can, in the absence of disaggregated data, obscure the financial relationship and value of a smelter to the corporation. Differences in the way various companies aggregate data into financial categories can also result in inaccurate application of any financial analysis unless the data are first disaggregated. Indeed, the Administrator believes that his earlier failure to apply these detailed procedures to all smelters uniformly may have delayed compliance with SIP requirements by some smelters which can afford to do so.

The Administrator therefore believes that it is a reasonable exercise of his discretion to specify in advance the financial criteria and procedures he will use to determine eligibility. This also allows States and smelter owners to know in advance how EPA's determinations will be made, and to avoid EPA disapproval of State-issued NSOs due to inadequate affordability demonstrations.

3. *Has EPA chosen an appropriate means of taking into account the cost of further controls?*

A number of companies commented that the Net Income Test proposed by EPA was inappropriate for "taking into account the cost of compliance" as required by section 119(b)(3). The significant comments in this area were made jointly by Asarco and Magma. According to these comments, Congress intended EPA to take cost into account in a specific way: by protecting against any significant decrease in profitability, sales, or mining activity. Asarco,

[3] *Kennecott Copper Corp.* v. *Train*, 572 F.2d 1349 (9th Cir. 1978).

[4] EPA did in fact use financial tests similar to the Net Income Test to determine the feasibility of requiring compliance with SIP emission limits at certain smelters under the Agency's existing policy.

[5] Cf. section 301(a)(2) of the Act.

Magma, and Phelps Dodge therefore urged EPA to adopt the "Replacement Test" contained in the Asarco/Magma comments instead of the Net Income Test.

After careful and detailed consideration, the Administrator has decided to retain the Net Income Test, with certain modifications, in the final rules. This decision is based both on his view of the intent of Congress and on the related conclusion that certain features of the Replacement test, in comparison to the Net Income test, as modified, make it fundamentally unsuitable as a financial eligibility test under section 119(b)(3).

(*a*) *What did Congress intend?* The Asarco/Magma comments argue that Congress did not intend the Administrator to exercise his discretion in "taking into account the cost of compliance" under section 119(b)(3), but instead intended that he consider cost in a specific way: by protecting against any significant decrease in profitability, sales, or mining activity. According to these comments, this reading of section 119 is mandated by its legislative history, showing that Congress intended those tests because EPA had adopted them and because they were needed to protect the industry from foreign competition.

The Administrator believes that these comments seriously misread the statute and are incompatible with the congressional intent. First, the Asarco/Magma argument is inconsistent with the statutory language itself. Section 119(b)(3) simply tells the Administrator to take the cost of compliance "into account," leaving to his discretion the specific manner of doing so. Previous judicial interpretation of similar language in the Act indicates that such language does not imply any specific method of considering costs, see, *Portland Cement Association v. Train*, 486 F.2d 375 (D.C. Cir. 1973), *cert. denied*, 417 U.S. 921 (1974), and it is well-established generally that such language does not entail a particular kind or weight of consideration of the named factor. See, *Kleppe v. Sierra Club*, 427 U.S. 390, 410 n. 21 (1976); *Aberdeen & Rockfish R. Co. v. SCRAP*, 422 U.S. 289, 319 (1975); *Vermont Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 558 (1978); *New York v. United States*, 331 U.S. 284, 347–349 (1947).

If Congress had intended that the Administrator apply a specific test, such as that suggested by Asarco/Magma, it could easily have said so, as it did under section 119(d)(2). There, Congress specified that waivers of the interim constant control requirement are to be available only when "such requirement would be so costly as to necessitate permanent or prolonged temporary cessation of operations of the smelter." In the Administrator's view, the contrast in specificity between these two provisions of the same section is too marked to be ignored.

The Administrator's interpretation of section 119 (b)(3) is based equally on his understanding of the congressional intent underlying section 119. As the Asarco/Magma comments recognize, that intent, clearly expressed in the legislative history of section 119, was to adopt the main elements of EPA's existing smelter policy. This is evident from the House Report,[6] which explained that the intent of the provision which was enacted as section 119 was to "confirm the authority of the EPA to pursue the Agency's present smelter policy, and (to) support the holding in *Kennecott Copper Corp. v. EPA*, 526 F.2d 1149 (9th Cir. 1975), *cert. den.* 425 U.S. 935 (1976)."

The Asarco/Magma assertion that eligibility for the use of supplementary control systems (SCS)[7] under EPA's existing smelter policy was based on a decrease in profitability, sales, or mining activity is simply wrong. The policy permitted a smelter to use SCS on an interim basis if immediate compliance with its SIP emission was economically infeasible,[8] i.e., if the smelter could not support the expenditure and keep operating. This was explicitly recognized in the *Kennecott* case endorsed by the House committee. In that case, the court specifically stated that EPA's policy was to permit the interim use of dispersion techniques when full constant controls were not "economically feasible,"[9] and quoted the following statement by EPA as explaining the meaning of feasibility:

> "[T]he selective use of Supplementary Control Systems * * * to attain and maintain the ambient standards is consistent with the Clean Air Act when the only alternatives are permanent production curtailment, shutdown, or delays in the attainment of the national standards * * *.
>
> * * * * * *
>
> EPA will approve such measures as intermittent production curtailment and use of dispersion techniques, including tall stacks, as an addition to available constant control measures, *until such time as the treatment of weak gas streams can be accomplished through reasonable retrofit control techniques. Evaluation of the availability of constant control techniques which may be developed in the future will be made using the same criteria as were used in developing these regulations. Namely, (Supplementary Control Systems) will continue to be allowed where permanent production curtailment, shutdown, or delays in attainment of national standards are the only other alternatives.* 40 FR 5508, 5510 (Feb. 6, 1975)."

526 F. 2d 1151–1152, n. 13 (emphasis added).[10]

This policy had its roots in 1972, in EPA's earliest proposed SIP rulemaking for a number of western powerplants and smelters. EPA stated that techniques such as intermittent production curtailment were not sufficiently reliable to be acceptable as permanent means of control, and that by July 31, 1977, the final attainment date for the smelters involved, those smelters would be expected to meet their SIP emission limitations through the use of scrubbers or process changes where necessary. The Agency also stated, however, that until that date, smelters which could not meet their emission limits through the use of sulfuric acid plants treating all strong streams could use SCS as a supplement to such acid plants. Active interim efforts to develop improved technology were also required. 37 FR 15094–15095 (July 27, 1972).

EPA further amplified this policy about a year later, in proposing amendments to 40 CFR Part 51. 38 FR 25697 (September 14, 1973). The Agency stated there that as a result of further evaluation of the reliability of the use of SCS by isolated sources of sulfur dioxide, it would permit the use of SCS by powerplants and smelters under certain circumstances beyond applicable SIP attainment date deadlines. It was here that the fundamental test of eligibility for the use of SCS was first established: the selective use of SCS would be allowed only "in cases where permanent production curtailment, shutdown, or delays in attainment of the national standards are the only other alternatives." 38 FR 25698. Although

[6] H.R. Rep. No. 95–294, 95th Cong., 1st Sess. at 61 and 67–68. The Senate Report also expresses an intent to ratify EPA's existing smelter policy. S. Rep. No. 95–127, 95th Cong., 1st Sess. at 25.

[7] Supplementary Control Systems (SCS) are also sometimes called Intermittent Control Systems (ICS), in recognition that they operate through intermittent production curtailment.

[8] Where EPA performed detailed analysis of the economic feasibility of full constant controls under its existing policy, it used an opportunity cost test related to the Net Income Test, and did not focus on profitability. A detailed financial analysis was performed for the Asarco Tacoma and Anaconda smelters.

[9] 526 F.2d at 1151.

[10] Permanent production curtailment or shutdown would occur where no other technically feasible means of reducing emissions on a constant basis existed, or where technically feasible controls were not economically feasible. Delays in attainment of standards would occur where technically and economically feasible controls could not be installed by the attainment date in the state implementation plan.

EPA believed that most smelters would prove eligible, each candidate source was required to demonstrate its eligibility on a case-by-case basis, and was required to conduct research to develop improved controls. *Id.* In the interim, each source was also required to apply available technology fully; in the case of smelters, available technology was at least the treatment of strong gas streams by sulfuric acid plants. *Id.*

The basis for EPA's concern about smelters was that

> Many existing nonferrous smelters would require emission reductions in excess of 90 percent in order to avoid violations of the national standards for sulfur dioxide during all adverse meteorological conditions. Constant emission limitation techniques capable of achieving this degree of emission reduction are not available for every smelter. The alternatives in most cases will be either to close these facilities (or drastically curtail production), or apply supplementary control systems. *Id.*

It is evident, therefore, that the focus of the Agency's policy was from its inception on the ability of these facilities to continue operating, not on underwriting their existing level of profits. As the Administrator put it in that 1973 publication, "it does not appear to be in the public interest to require shutdown or permanent curtailment of production for existing sources which could temporarily use supplementary control systems to attain and maintain the national standards." *Id.*

EPA continued to adhere to this policy in proposing Nevada SIP regulations which were the subject of the *Kennecott* case cited by the House Report. 39 FR 38104 (October 29, 1974). The Agency again stated there that SCS could be used on a temporary basis to meet ambient standards "when the only alternatives are permanent production curtailment, shutdown, or delays in the attainment of the national standards." 39 FR 38105. EPA also applied the other elements of the policy, i.e., the smelter was required (1) to treat all strong (converter) gas streams in an acid plant, (which EPA believed was required by *N.R.D.C. v. EPA*, 489 F. 2d 390 (5th Cir. 1974), in which the court held that dispersion techniques could be allowed only if full constant control was infeasible and if the maximum control achievable was used in the interim); (2) to assume liability for violations of NAAQS in the area affected by its emissions; and (3) to conduct research to develop improved controls.

EPA reiterated the policy's basis for eligibility and its interim requirements in promulgating the Nevada plan. 40 FR 5508 (February 6, 1975).[11] It was this policy which was before the Ninth Circuit and the Congress, and this was the policy specifically endorsed by both. The policy focused on the feasibility of full constant controls, not the effects on a smelter's profits. The suggestion by Asarco/Magma that EPA should now shift its focus to profitability would therefore represent dramatic change in the policy ratified by Congress.[12]

The Asarco/Magma assertions that the EPA smelter policy in effect when section 119 was enacted was based on profitability ignore this actual administrative history of the policy. Instead, the assertions are based on a reference in the House Report to certain statements made by EPA in promulgating new source performance standards (NSPS) for copper, lead, and zinc smelters. H.R. Rep. No. 95–294, supra at 63. In explaining why the NSPS smelter standards were not based on the use of scrubbing, EPA stated that the costs of using scrubbers on new smelters were too large for such smelters to absorb without a significant decrease in profitability, a loss in sales due to price increases, or a decrease in mining activity if the costs were passed back to the mines. See 41 FR 2332, 2334 (January 15, 1976).

The Adminstrator does not regard the House Report's reference (at page 63) to this discussion from the NSPS preamble as an implicit direction to construct a profitability test of financial eligibility under section 119(b)(3). The Committee's intention as discussed above and as expressly stated in the House Report, was to "confirm the authority of the EPA to pursue the Agency's present smelter policy, and support the holding in *Kennecott*." H.R. Rep. No. 95–294, supra at 61. The passage on page 63 is used simply to illustrate the context of the problem being addressed by section 119. The passage itself actually says in fact that "[t]he difficulties inolved are highlighted" in the NSPS publication.

In addition, the NSPS preamble language alluded to was intended by EPA to refer solely to projected financial effects on *new* smelters of requiring various possible controls. The analysis performed for those NSPS purposes was not formulated to evaluate the effects of requiring controls on any existing smelter, and an altogether different kind of analysis, one in which profitability would not have a comparable role, would be required to do so.[13] The Committee's reference to this language is therefore relevant only to new sources and should not be viewed as expressing an intention that EPA use any particular test of eligibility in the different circumstances relevant to existing sources.[14]

The conclusion that this passage in the House Report was simply intended to illustrate the overall circumstances facing the industry is reinforced, finally, by the Report's quotation, on page 63 immediately following the NSPS discussion, of certain excerpts from EPA's Stack Height Increase Guideline. Significantly, after stating that "[r]etrofitting existing smelters involves additional problems," the Report quotes portions of the Guideline discussing those problems as a basis for granting increased stack height credit, *not for premitting the use of SCS*, the main feature of both EPA's existing smelter policy and section 119. The Report thus fails even to suggest a link between profitability and the existing Agency-SCS policy for smelters. The Administrator therefore believes that, in light of the overall administrative and legislative history of section 119, and of the 1977 Amendments as a whole,[15] Congress intended EPA to exercise discretion in taking cost into account, and did not intend to specify profitability as the financial criterion of a smelter's eligibility for an NSO.

(b) *Is the "Replacement Test" a more appropriate measure of the economic feasibility of requiring full constant controls than EPA's Net Income Test?* The Asarco/Magma comments also argue that EPA should not only base eligibility on smelter profitability, but should do it in a particular way. These two companies, joined by the Phelps Dodge Corporation, urge EPA to discard the Net Income Test and adopt instead the "Replacement Test" contained in the Asarco/Magma comments. These

[11] EPA also adhered to this policy in proposing regulations for the Arizona SIP. 40 FR 49362 (October 22, 1975). The policy was also stated again, in part, in the Agency's Stack Height Increase Guideline, 41 FR 7450; (February 18, 1976). It should be noted, however, that the major focus of the Guideline was the amount of credit to be granted in SIPs for the use of tall stacks, not the use of SCS.

[12] It should also be noted that the suggestion that EPA focus on profitability, sales levels, and the levels of mining activity is internally inconsistent; these factors might be affected in contradictory ways by any given eligibility test.

[13] See note 8, above. In brief, this is because the NSPS analysis quoted is based on a hypothetical new smelter of hypothetical size and configuration at an assumed location, while the analysis of an existing smelter would be based on its existing cost structure, size, configuration, and location. Also, as discussed more fully below, the nature of the decision facing investors in a new facility is very different from that facing the management of an existing source.

[14] See also note 21 below.

[15] The overall policy of the Clean Air Act in this regard and the policy implications of adopting a test based on profitability are discussed further below, in connection with the Asarco/Magma "Replacement Test."

comments assert that the Replacement Test is a more appropriate measure of the economic feasibility of requiring full constant controls than is the Net Income Test.

The Asarco/Magma comments label as the primary defect of the Net Income Test its use of Liquidation (salvage) value as the measure of a candidate smelter's capital base.[16] According to these comments, an adequate net present value test of whether a smelter can afford to invest in necessary emission controls would instead use the facility's replacement value, as defined in the Replacement Test proposed by Asarco/Magma.

After careful and detailed consideration, however, the Administrator has concluded that the use of replacement value as a measure of capital base would be wholly inappropriate for use in an eligibility test under section 119, and that the use of liquidation value is far preferable under the circumstances. This view stems from four fundamental flaws in the Replacement Test: (1) Its inability to require compliance at strong smelters while ensuring against the closure of marginal smelters, (2) its failure to take into account the required nature of the pollution control investment in evaluating a smelter's ability to support that investment, (3) its consequent distortion of the evaluation of economic feasibility through its focus on an illusory opportunity; and (4) its implicit reversal of the basic social and economic policy of the Clean Air Act.

(1) *The Basic Purpose of the Eligibility Test is Not Accomplished by the Use of Replacement Value.*

In choosing an eligibility test for taking the cost of compliance into account under section 119(b)(3), EPA sought to follow Congress' intent that the Agency apply the same basic criteria as it had under its existing smelter policy. As discussed above, that policy permitted deferral of full SIP compliance and the interim use of SCS if immediate compliance with required SIP measures was not economically feasible for a particular smelter. An acceptable test thus must not only require compliance at financially strong smelters, but must also protect against smelter closures that could be brought about by the immediate imposition of control requirements at marginal smelters. The proposed eligibilty test chosen for section 119, therefore, was intended to evaluate the consequences of requiring immediate compliance, and to determine whether immediate compliance was economically feasible.

The Agency's proposed eligibility test [the Net Income Test] does this through the use of "net present value" cash flow analysis. The Net Income Test is a modified form of "opportunity cost" or "closure" test, a standard tool for evaluating the feasibility of a *required* investment. An opportunity cost test simulates the response of the operators or investors to such a requirement by comparing the value to them of their options and assuming that they will act to maximize the return on their investments. The opportunity cost test thus compares the value of making the investment in the smelter and continuing operation with the value of liquidating the firm's investment in the smelter and investing the proceeds elsewhere. The required investment would be deemed feasible (i.e., net present value is positive) under an opportunity cost test only if the firm would earn more by installing the equipment (and making any other expenditures for modernization, for maintenance, for compliance with other Government regulations, and the like) and continuing to operate the smelter than by liquidating its investment in the smelter and placing the proceeds in another investment opportunity open to the firm.[17]

The Net Income Test devised by the Agency provides more protection for marginal smelters than would a strict opportunity cost test. It does this by allowing a smelter operator to deduct all remaining depreciation on its assets from its projected future net cash flow before determining whether it can afford the pollution control expenditure. By deducting depreciation as well as the future expenditures noted above, this procedure deliberately understates the value of the smelter's future earnings, and provides an additional financial cushion to the smelter operator. Although section 119 does not require the Administrator to provide this additional relief, he has made the policy decision to do so in order to ensure, in light of the impossibility of making absolutely accurate projections, that marginal smelters Congress would have expected to be eligible for NSOs will not be found ineligible on "close calls." The Administrator believes this decision to be within the discretion afforded by section 119(b)(3), and consistent with the intent of Congress.

This kind of test fully protects the viability of the industry. It ensures that the investments will not be required unless they are economically feasible, and therefore that existing smelters will continue to operate and modernize as they would in the absence of SIP requirements. In addition, the test protects against a loss in sales by finding a smelter eligible unless it can support the investment *without* raising its prices above prevailing levels. The test's assumption in valuing the earning power of any smelter—and thus all American smelters—that domestic metal prices are constrained by worldwide production, supply, and demand also protects against foreign competition in determining feasibility.

The Asarco/Magma comments suggest that, in judging whether the smelter can afford to make the investment, EPA use the replacement cost of the smelter (as defined in the Replacement Test contained in the companies' comments) instead of liquidation value as the basis for comparison (in the net present value calculation) with the worth of the smelter's future earnings. Replacement value is, however, fundamentally unsuitable for this purpose, because it fails to accomplish the basic purpose of the eligibility test: identifying those smelters at which immediate compliance with SIP emission limits is not economically feasible, while requiring compliance at those smelters which can now afford controls.

This defect results from the failure of the Replacement Test to examine either the actual situation of the smelter or the actual alternatives facing the smelter operator. Because it examines the cost of constructing a *hypothetical* replica of the existing smelter, replacement cost is insensitive to the *actual* physical state of the smelter. The use of replacement cost also ignores the actual technological alternatives available to the smelter operator, as well as the ability of new technology to achieve production cost savings.

As a result of these features, as well as other undesirable properties, the Replacement Test is unable to simulate the decision of a smelter operator faced with a required investment. It is therefore incapable of distinguishing between those smelters that are able to afford compliance and those that cannot. Indeed, for the reasons discussed above, the Replacement Test would almost inevitably demonstrate an inability to afford the required investment, irrespective of the smelter's actual physical condition, the size of the

[16] The comments also discuss problems of foreign competition and the levels of sales and mining activity as factors in congressional intent, but do not suggest any specific deficiencies in the Net Income Test related to these factors, apart from the asserted need to focus on industry profitability.

[17] These proceeds of liquidation can be referred to as the "capital base" against which the adequacy of the projected future returns from making the investment and continuing operations at the smelter can be measured.

investment actually needed to achieve compliance, or the actual or projected returns to investors.[18]

The use of liquidation (salvage) value in the net present value analysis, by contrast, suffers none of these drawbacks. It clearly indicates a smelter's ability to support a required investment. By explicitly recognizing the liquidation value of the smelter's assets as well as the value of future operations, the Net Income Test is able to value realistically each of the smelter's actual options and assess the actual financial consequences of a required investment. For these reasons alone, the Replacement Test cannot reasonably be viewed as a serious option for an eligibility test.

(2) *The Replacement Test Distorts the Evaluation of Economic Feasibility by Ignoring the Required Nature of the Investment.*

The Replacement Test is also unsuitable as an eligibility test because it inherently distorts the evaluation of economic feasibility by ignoring the basic characteristic of the pollution control investment: its required, involuntary nature. It is of central relevance in formulating a test of the economic feasibility of requiring pollution control that the investment would be made not because it is economically attractive to do so, but because it is required by law. If pollution control equipment were financially productive from the firm's viewpoint, it presumably would long since have been installed and the Clean Air Act might not be needed.

In evaluating the consequences of requiring that investment, therefore, it is necessary to recognize that only two options would be available to a smelter operator faced with the requirement: to make the investment required for compliance and continue operating, or to liquidate its investment in the facility and invest the money elsewhere at a higher rate of return. This contrasts to the situation where it is desirable to install new production equipment, where the options to be examined for maximizing return include continued operation without the new equipment. An eligibility test for section 119 must recognize this basic difference and must examine the consequences of a *requirement* that the control equipment be installed.

The Replacement Test, instead, asks in effect whether in the absence of any technical or legal impetus for doing so, it would make financial sense to invest in pollution control equipment at the existing smelter. This is because pollution control investment: Its required, involuntary nature. It is of central relevance in formulating a test of the economic feasibility of requiring pollution control that the investment would be made not because it is economically attractive to do so, but because it is required by law. Obviously, if pollution control equipment were financially productive from the firm's viewpoint, it would long since have been installed and the Clean Air Act might not be needed.

In evaluating the consequences of requiring that investment, therefore, it is necessary to recognize that only two options would be available to a smelter operator faced with the requirement: To make the investment required for compliance and continue operating, or to liquidate its investment in the facility and invest the money elsewhere at a higher rate of return. This contrasts to the situation where it is desirable to install new production equipment, where the options to be examined for maximizing return include continued operation without the new equipment. An eligibility test for section 119 must recognize this basic difference and must examine the consequences of a *requirement* that the control equipment be installed.

The Replacement Test, instead, asks in effect whether in the absence of any technical or legal impetus for doing so, it would make financial sense to invest in pollution control equipment at the existing smelter. This is because the Replacement Test conditions investment in pollution control on whether such investment will not detract from the facility's "value" as an ongoing entity, as represented by its replacement value (defined as the current cost of creating equivalent production capacity). This means that only if pollution control investment would yield at least as much as the company's other productive investment opportunities, and would return at least as much as required to secure financing from investors, would the existing smelter be presumed able to afford pollution control investment.

In conditioning the requirement to install nonproductive control equipment on a finding that it will earn as much return as production equipment, however, the Replacement Test implicitly assumes that the smelter operator has the option of making the investment decision on purely financial grounds, free of any legal obligation to control the smelter's emissions. This ignores the mandatory nature of the investment, and fundamentally distorts the nature of the evaluation to be made under section 119: Whether the smelter is capable of supporting a *required* investment. The Replacement Test therefore asks the wrong question for evaluating the consequences of requiring the investment to be made. By asking the wrong question, the Replacement Test also biases the evaluation of feasibility; since the pollution control investment, by its largely non-productive nature, will generally lower the value of the facility as an ongoing entity, the Replacement Test will therefore indicate that no investment in pollution control is feasible.

(3) *The Replacement Test Distorts the Evaluation of Economic Feasibility by Focusing on an Illusory Opportunity.*

The Replacement Test further distorts the evaluation of economic feasibility by focusing on an illusory opportunity. Given the assumed goal of maximizing shareholder wealth, a smelter operator facing a pollution control investment requirement must choose, from among the opportunities facing it, that option which would most benefit shareholder wealth. These options are, conceptually: (1) Installing the required equipment and continue operating; or (2) liquidating the investment in the smelter and investing the money elsewhere (which may include selling the smelter to a new operator).[19]

Realizing the replacement value of the smelter (as defined by the SEC), however, is not an option available to the smelter operator; replacement value is an artificial measure of value, not an economic measure of value. No one would offer that amount for the right to operate the smelter. As the Asarco/Magma comments note, the most a third party would offer for the smelter would be the net present value of the smelter's future cash flows, taking account of pollution control costs.

By focusing on an illusory opportunity, the Replacement Test thus further distorts the evaluation of economic feasibility. The Net Income Test, by contrast, focuses on the actual opportunities facing the smelter, and provides a better measure of eligibility.

(4) *The Replacement Test Implicitly Reverses the Basic Social and Economic Policy of the Clean Air Act.*

Finally, the Asarco/Magma comments urge that replacement value to used in

[18] Replacement value need not be used in the net present value analysis to account for inflation and the need to periodically replace or modernize equipment. The Net Income Test accounts for both: Inflation is taken into account by indexing future costs in calculating the net present value of future cash flows; the need to replace equipment is accounted for by the allowance for sustaining capital expenditures in that calculation.

[19] More detail on this point is provided in the Supplemental Response to Comments document in the docket.

the net present value analysis because liquidation value does not provide an adequate rate of return to the debt and equity capital invested in the smelter. This comment, however, is based on an erroneous view of the purpose of section 119. The purpose of an NSO is to defer compliance with SIP emission limitations if it is not economically feasible for the smelter to install the necessary controls now. Sources other than smelters, by contrast, must install the controls necessary to comply with SIP emission limitations, even if that investment would cause a source to close.

The Asarco/Magma comments urge that EPA attribute to Congress an unspoken intent to alter retroactively the position of investors in smelters, making them unique among investors in the American economy. Under the Replacement Test, no smelter would be found able to afford the investment for new controls until all prior investors in the smelter had been paid the return on their investments that they had hoped for.[20] This fundamentally reverses the actual investment decision that has faced investors in smelters since 1970, and still faces investors in every other American industry. The actual situation they faced, and others still face, is that as a result of the Clean Air Act, compliance expenditures had a prior claim on a facility's earnings. Thus, the prices and terms on which the investments were made (*i.e.*, the cost of capital) reflected prospective compliance requirements, and represented judgments about the amount of the earnings that would remain after those expenditures. These investors took a deliberate risk, and had no assurance that smelter earnings would be as great as they had hoped. To say now that, even though the smelter can make the control expenditure and keep operating, the available funds should be used first to guarantee the profits of prior investors, would be wholly inconsistent not only with the way capital markets operate and the position of all other investors, but also with the bases on which those investors themselves acted in making the investments.

The general requirement to comply with SIP emission limitations has existed since the 1970 Clean Air Act became law. Debt and Equity investments in industrial facilities since then have had to take these compliance requirements into account. Since investors have known of these requirements, their judgments about the likely return on and risk associated with these investments have necessarily reflected the prospect of required compliance. They have known, in other words, that the compliance requirements of the Clean Air Act were a cost of doing business, and that the return on their investments depended on a facility's ability to cover more than this and other legitimate business costs. This, of course, is simply how capital markets operate.

Some investments have proven to be unwise, and have not—whether because of various regulatory requirements, bad management, market forces, or other factors—earned the expected rate of return. In some cases, the investments themselves have been only partly repaid, such as when a facility closes or a firm is reorganized in bankruptcy. These risks are part of the normal operation of the business and financial community, and are reflected in the interest rates on loans and the prices of stocks and bonds. These pricing mechanisms reflect investor judgments about the comparative prospects of the various firms and industries, taking into account all known factors which may affect those prospects. Indeed, it is the basic purpose of the securities laws to ensure public knowledge of all the factors which would be relevant to making appropriate pricing and investment decisions.

The existence of these risks does not affect the long-term viability of an industry unless they are so great that no investors can be found that are willing to operate and modernize existing facilities and build new ones, under whatever circumstances may exist in that industry. As to existing facilities, accepted principles of financial analysis demonstrate that there will be investors willing to make the required expenditures and continue operating the facilities if their net present value under an opportunity cost (closure) test is positive. Imposition of the requirement will therefore not threaten the continued operation of the facility, although it may prevent previous investors from realizing the gains on their investments for which they had hoped. This prospect, however, was one of which they were aware in making their investment, and was reflected in the price or terms on which it was made.[21]

The most fundamental policy of the Clean Air Act is that public health expenditures be internalized as costs of doing business and have a prior claim on a facility's earnings. The Administrator does not believe that Congress intended a radical change in that policy for smelters. The use of the Replacement Test would make such a radical change, yet would do no more than the Net Income Test to assure the continued operation of American smelters. Adoption of the Replacement Test would therefore go far beyond the discretion provided the Administrator to take the costs of compliance into account, and must be rejected.

4. *Is EPA's test too burdensome?* Several companies commented that Appendix A to the regulations required a burdensome amount of information for purposes of performing the eligibility test. In light of these comments, the Administrator has, where possible, reduced the required information.

The Administrator's basic approach to validating the financial analyses and data is to require applicants to disaggregate data to levels that can be either independently certified or assessed. For example, the cash proceeds from liquidation are to be independently estimated for major components (e.g., land) according to a standard format and certified. Likewise, major cost components are to be identified and cost component totals are to be further broken into puts and their prices. For example, energy costs are to be identified and the average price of each major fuel and its consumption must be reported. Data must be disaggregated this way because detection of errors in highly aggregated data is nearly impossible. These errors could otherwise result in massive distortions in the final results of the analyses.

Based on the public comments, however, the Administrator has substantially reduced the data submission requirements. The consolidated accounts table which Phelps Dodge argued would be extraordinary expensive to prepare has been eliminated. All tables that refer to "baseline" financial performance (i.e.,

[20] Because the test uses the cost of a new, controlled facility, it would actually reserve considerably more of the smelter's earnings for prior investors than they actually expected to earn. It should also be noted that the concept of "profitability" itself, in terms of the relevant capital base, is very different for evaluating whether a new smelter will be built from evaluating the effects of requiring additional controls on an existing smelter. For a new smelter, profitability is value of its future cash flow (taking the cost of capital into account) is positive, the Net Income Test does turn on the "profitability" of the new investment to the same extent that EPA's NSPS analysis turns on the profitability of new source construction.

[21] Evaluating whether investors will finance new facilities requires the use of a different capital base than that used for evaluating compliance costs. This would be more along the lines suggested by Asarco/Magma consultants Citibank and Scott. However, section 119 and its eligibility test apply only to existing smelters, and to the extent that their comments address the effects of a particular eligibility test on new smelter construction, they are irrelevant.

without further emission controls) have been eliminated because, after careful reexamination, the Administrator believes that the burden of preparing these tables outweighs their contribution to validating the analyses.

The Administrator believes, however, that the remaining data requirements are necessary for reaching accurate results and for ensuring the integrity of the process. This view is based on the Agency's experience with analyses of smelters under the existing smelter policy. In performing those tests, EPA found that the quality of the production cost and revenue information used was inadequate for reaching accurate results, primarily because it was neither obtained directly from the companies' books nor presented in a way that allowed the smelter to be viewed in terms of its real economic worth to the company.[22] The Agency has therefore concluded that information of the kind found in Appendix A as promulgated—detailed company data presented on a uniform "stand alone" basis for all smelters—is necessary. The Administrator did decide to require applicants to provide more detail in the projected data. This detail allows direct comparison of the historical and forecast [22a] data and facilitates independent analysis.

The Administrator recognizes that the remaining burden on the companies, though reduced, is still not trivial. This burden, however, is also not undue. The granting of an NSO is an air quality management decision of great significance, given the amount of additional sulfur dioxide a smelter will be permitted to emit. In addition, an NSO may permit the deferral of expenditures of up to hundreds of millions of dollars. Finally, the companies themselves are among the largest and most sophisticated in the nation, conducting business in many parts of the world. Judged in this context, the magnitude of the burden is reasonable.

B. The Designation of Certain FGD (Scrubbing) Systems as Adequately Demonstrated Technology

EPA's proposed rules would have designated as adequately demonstrated technology, for purposes of evaluating eligibility for an NSO, the following systems: (a) The acid plant and associated process technology underlying EPA's new source performance standards for copper, lead, and zinc smelters (40 CFR Part 60, Subparts P, Q, and R); and (b) magnesium oxide sulfur dioxide concentration, lime/limestone scrubbing, and Cominco ammonia scrubbing. EPA also stated that it was considering designating the Flakt-Boliden sodium citrate concentration system as adequately demonstrated.

Comments were received in two areas. First, certain commenters argued that it was improper under section 119(b)(3) for EPA to consider any technological questions on an industry-wide basis without considering economic factors at the same time, or that some additional proceeding was required by section 119(d)(4). Second, various comments questioned the technical basis for considering these systems adequately demonstrated.

1. *Is it proper for EPA to make a finding as to technological feasibility in this rulemaking?* The main thrust of the comments in this area was that it was somehow improper for EPA to "bifurcate" the technical from the economic aspects of eligibility determinations under section 119(b)(3). This contention is based on a misunderstanding of EPA's action and the intent of that section.

As discussed in detail above, the intent of section 119 is to adopt the main elements of EPA's existing smelter policy. This includes the conditions under which a smelter may use SCS to meet NAAQS and defer compliance with its SIP emission limitations. Thus under section 119(b)(3), as under the existing policy, EPA must determine whether it is economically and technically feasible for a particular smelter to meet those SIP requirements. This determination involves three findings: (1) Whether there is technology in existence which has been adequately demonstrated for the purpose; (2) whether that technology can be applied at the smelter in question; and (3) whether it is economically feasible for the smelter to install and operate it. A smelter would be eligible for an NSO if any of those questions were answered in the negative.

Section 119(b)(3) specifies that the overall eligibility decision is to be smelter-specific. It does not, however, indicate how the decision is to be made, but rather leaves that to the Administrator's discretion. In proposing to designate certain systems as adequately demonstrated, the Administrator was simply exercising that discretion to inform interested members of the public that he regards those systems as technically proven to the extent necessary to base eligibility decisions on their possible use. This kind of finding is inherently industrywide, since the finding is based on the systems' use at sources other than the NSO applicant. The comments do not offer any reason why this is improper, and the Administrator knows of none.[23]

The comments argue, however, that this does not take costs or site-specific factors into account as required by section 119(b)(3). This comment misunderstands the Agency's action. Inherent in the finding that a system is adequately demonstrated is the fact that the cost of the system is within the range that *some* smelter was able to afford. This is because the finding is based on its actual use at an existing smelter. Beyond this, however, section 119(b)(3) requires consideration of the economic feasibility of the system for the applicant smelter itself (unless the Administrator makes a finding that it is reasonably available to all smelters, as he did for acid plants under the existing EPA policy). The NSO rules do not, therefore, ignore the costs of these systems, but rather evaluate whether a particular system is economically feasible for the applicant smelter. Since this determination is inherently smelter-specific, and since it cannot be made without knowing which systems to evaluate, it is impossible *not* to "bifurcate" the technical and economic decisions.

Site-specific technical as well as economic factors are also considered under the final rules. Under § 57.102(b)(3), a smelter operator may show that even an adequately demonstrated system which it can afford is not "applicable" to the smelter because its use would be technically unreasonable for reasons specific to that site. Thus the eligibility determination includes each of the elements that Congress specified, and the

[22] See, 123 Cong. Rec. S13700, Col. 2 (August 4, 1977) (daily ed.) (Statement of Senator Muskie).

[22a] In proposing these rules, EPA indicated that it would provide projected indices (forecasts) of various relevant economic factors for use in performing the analyses required by Appendix A. Although a portion of this information was placed in the docket either before or shortly after proposal, the balance of the indices did not become available, and consequently were not placed in the docket, until shortly before the promulgation of these rules. See, section 307(d)(4)(B)(i) of the Act. These are the indices identified in paragraphs 2.4 (d), (e), and (g) of the Instructions portion of Appendix A as promulgated today. Because this provided only a brief opportunity for comment before promulgation of these rules, the Administrator will consider any objection to this material submitted in a petition for reconsideration within sixty days of today to be based on grounds "arising after the period for public comment" within the meaning of section 307(d)(7)(B) of the Act.

[23] The proposal gave specific and adequate notice of the Administrator's intent to designate those systems as adequately demonstrated for eligibility purposes. See 44 FR at 6287–6288, 6296, and 6317–6318. Indeed, the specific comments received on these proposed designations belie any contention that the notice was deficient.

Administrator finds nothing in the comments to suggest that his exercise of discretion to make the inherently non-site-specific determination of general technical feasibility in this rulemaking is improper.

Concern was also expressed that making this finding somehow required further proceedings under section 119(d)(4), or that making the finding in this rulemaking is inconsistent with that provision. This contention also reflects misunderstanding of the statutory provision and the Agency's action. Section 119(d)(4) is in no way relevant to eligibility for an NSO, but rather governs the nature of the interim controls that may be required in an NSO once granted. The Administrator recognizes that a further proceeding would be necessary to require weak gas stream controls as interim controls in an NSO, and does not intend this rulemaking to pre-empt such a further proceeding on the economic feasibility or site-specific applicability of such interim controls under section 119(d)(4). The only effect of this rulemaking is to establish that the designated systems are technically feasible (adequately demonstrated) in an industrywide sense, not that they are applicable or reasonably available to any or all smelters.

2. *Are these systems adequately demonstrated?* Comments in this area focused exclusively on the scrubbing and concentration systems. After careful consideration of these comments, EPA is today finalizing its proposed determination that certain of this technology is adequately demonstrated.

In its proposal, EPA also said it was considering designating the Flakt-Boliden sodium citrate concentration system as adequately demonstrated. EPA is not finalizing this proposed determination, pending the results of further experience with this promising technology, which should be available shortly.

(a) *Background.* The major pyrometallurgical steps for copper, lead, and zinc generate great quantities of sulfur dioxide (SO_2), some of which is emitted in gas streams too dilute for the practical use of acid plants for treatment. One means for removing SO_2 from these gas streams is flue gas desulfurization (FGD). In an FGD process, the gas stream is mixed in a vessel with a substance that combines with the SO_2 in the gas. The clean ("scrubbed") gas is discharged from the vessel, and the collected SO_2 is retained with the reacting substance for subsequent treatment or disposal. Regenerative FGD systems produce SO_2 as a more concentrated gas which can then be made into liquid SO_2, sulfuric acid, or sulfur which can be sold or used. Nonregenerative FGD systems essentially neutralize the SO_2 as a waste solid or sludge, which then must be disposed.

The Administrator's judgments regarding the scrubbing and concentration systems listed here are primarily based on their actual use at copper, lead, and zinc smelters. In addition, EPA has applied its experience with FGD systems used to control offgases from utility boilers. This transfer of technology experience is proper, studies show, provided there is some adjustment in operating conditions.

Lime/limestone processes have been extensively used in Japan (since 1971, in some cases) to treat offgas from lead, zinc and copper smelters. Lime/limestone scrubbing operations examined by EPA engineers include the Onahama Smelting and Refining Company (reverberatory furnace offgas), Mitsubishi Naoshima Lead-Copper Smelters (blast furnace and weak stream sinter machine offgas), Hosokura Lead-Zinc Smelter (blast furnace offgas and lead smelter acid plant tailgas), and the Toho Zinc Chirgirishima Lead Smelter (lead smelter, acid plant tailgas, sinter machine weak gas and blast furnace offgas). In addition, numerous other lead and zinc smelters use lime/limestone scrubbers for various offgas processes. This technology is also currently in operation for many utility offgas streams. In fact, lime/limestone systems account for over 90 percent of scrubbers operating on utilities. Based on extensive operating experience in this industry, it has been determined that these systems can operate at 90 percent SO_2 removal or greater with at least 90 percent operability.

Similarly, the magnesium oxide SO_2 concentration system (MgO system) has been satisfactorily operated for two years on reverberatory offgas at the Onahama Smelter. In the United States, the MgO system has been under commercial scale evaluation since 1972. In 1975, after much analysis, EPA concluded that the MgO system was currently available for power plants. 40 FR 42045, 42049 (September 10, 1979). The concentrated stream produced by the MgO system retains product flexibility since it can be used to make liquid SO_2, sulfuric acid, or elemental sulfur. It can provide over 98 percent control for a reverberatory furnace.

Finally, the Cominco ammonia system, which produces ammonium sulfate as well as concentrated SO_2 offgas, has been successfully used for weak stream SO_2 control. The Cominco, Trail, B.C. lead/zinc smelter facility operates three ammonia-based FGD systems to remove SO_2 from the lead plant sinter machine offgas, zinc plant roaster offgas and zinc plant acid plant tailgas. Reliability and minimal downtime for maintenance characterize the FGD facilities at Cominco. Ammonia scrubbing has also been used to treat sulfuric acid plant tail gas at various locations in the United States.

(b) *General Comments.* General comments questioned whether the scrubbing systems were applicable to smelters in the Southwest because the technology has been applied only at plants located close to waterways providing unlimited amounts of water for scrubbing and cooling. EPA studies show, however, that access to large amounts of water is not a special requirement for these systems and should not impede application of this technology to smelters in the Southwest.

Since the Onahama and Cominco smelters have access to a large water supply, no attempt was made to conserve water usage, and therefore the water use figures for these smelters do not reflect the savings that can result when water conservation is a design objective. Such conservation is illustrated by a molybdenum roaster in Arizona which is currently operating a lime slurry SO_2 control system using a continuous 4 percent bleed to a tailings pond where 50 to 80 percent of the water is recovered for reuse. Generally speaking, a new scrubbing system would, as a maximum, increase water usage for a smelter only from 10 to 20 percent. Analysis reveals this increase would not be prohibitive for smelters, just as it has not been prohibitive for power plants in these areas.

The Administrator has already determined (44 FR 33594, June 11, 1979) that, for power plants, an FGD system uses less than 10 percent of the water consumed (Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Standard, EPA–450/2–78–007a) and that it will not be a controlling factor in the siting of new utility plants. Indeed, there has been extensive use of the lime/limestone system and to a lesser extent the MgO system at utility power plants throughout the United States and the world in areas where large amounts of water are unavailable.

Moreover, a 1976 report on the application of absorption-based SO_2 control systems to certain United States primarily copper smelters (SO_2 Control Processes for Nonferrous Smelters, EPA–600/2–76–008) indicates that most of the copper smelters, including those in the Southwest, have adequate water

supplies available. Thus an FGD system's rate of water consumption is not apt to be a factor limiting its application to smelters, even those in the Southwest.

(c). *Comments on Lime/Limestone Scrubbing.* One commenter suggested there might be scale-up problems with lime/limestone scrubbing because the Japanese systems are "small." The Onahama smelter in Japan, however, is currently operating a full-scale lime/limestone system that is actually handling over 70,000 scfm of gas at an SO_2 concentration of 2 to 2.5 percent. These reverberatory furnaces are full-scale systems. With sufficient sealing of ductwork and equipment in domestic smelters, offgases from a copper smelter reverberatory furnace could be reduced to 70,000 scfm. Thus, there would be no need to scale-up the Onahama system; it could be applied directly. If the SO_2 concentration is lower, as would occur with a calcine charge furnace, it would actually be easier to implement a design because less SO_2 would be absorbed. Lime/limestone systems are, of course, commercially available for full-scale commercial operation on coal-fired utility boilers.

Another commenter suggested that the lime/limestone system might be infeasible because the high degree of process control necessary to prevent scaling and plugging is not often possible under the fluctuating conditions normally encountered in reverberatory smelting. EPA has determined, however, that techniques applicable to reverberatory smelting have been devised and used successfully in recent years that effectively solve both the scaling and the plugging problems.

The tendency of both calcium sulfite and calcium sulfate to form scale in the absorber, mist eliminator, and ancillary tanks, pumps, and pipes has been an operating problem of the lime/limestone system. The Japanese, however, have experienced and solved scaling problems with their lime/limestone system. Between 1968 and 1972 the Hiroshima Technical Institute conducted a $5,000,000 program to investigate the scaling problem occurring on the scrubber and mist eliminator of the lime/limestone pilot plant.

Results showed that the unsaturated sulfite scale was easy to remove, but the sulfate was very difficult. Preparation and operating conditions of the absorbent were found to be critical and required the proper range of pH, temperature, concentration, construction material of the scrubber, liquid to gas ratio (L/G), and prevention of mist carryover through the eliminator. Most of this work was reported in 1971, including the development of the seed crystal technique.

The seed crystal technique provides a sacrificial surface for crystal precipitation greatly reducing and controlling deposition on absorber surfaces. It has been found that scaling or crystallization of the calcium sulfate occurs as either many small crystals, as a layer on the surface of equipment, or as layered buildup on seed crystals. If the formation of the calcium sulfate can be controlled to a rate below the rate of crystallization on the seed crystals, then the scaling will preferentially go to these seed crystals. However, if the calcium sulfate rate of formation exceeds the rate of crystallization on the seed crystals or if there are not sufficient seed crystals present, then scaling will occur on the surface of the equipment or many small additional crystals will be formed. Thus, for a given solubility of calcium sulfate, the concentration of calcium sulfate in the liquid phase must be maintained. This can be done by controlling either the L/G in the absorber or the flow rate of the seed crystals to the absorption circuit. The lower the SO_2 concentration, the less scaling that will occur.

The design of the internal conditions of the system is critical because of the scaling problem and the fluctuation of the SO_2 concentration. There has not been any problem with operation of the gypsum system within the range of fluctuations occurring at the Onahama smelter. However, detailed design considerations must be optimum to provide a flexible system. Selecting optimum slurry velocities in the piping and proper instrumentation are critical.

Design and operation of the absorption towers at Onahama have also reduced scaling formation. Two plastic grid packed absorbers in series are used. Their external shell is made of steel plates lined with synthetic resin. The grid packing has large openings to minimize plugging and pressure drop.

The design of the absorber and operating L/G are critical to minimize scaling. It is important to obtain an internal configuration producing an operating condition that prevents the slurry from stagnating and ensuring that all the inner surfaces of the absorber are sufficiently sprayed or covered with the absorbing solution. This covering will avoid any pH variation which could occur locally and thereby provide a condition for scale generation.

These and other process techniques are summarized in Flue Gas Desulfurization at the Bunker Hill Company, Kellogg, Idaho (EPA–330/2–79–011), Feasibility of Primary Copper Smelter Weak Sulfur Dioxide Steam Control (EPA–68–03–2398), and Electric Utility Steam Generating Units: Background Information for Proposed SO_2 Emission Standards (EPA–450/2–78–700a), all of which are in the docket.

Plugging caused by deposition of solids on equipment surfaces has sometimes restricted the passage of liquids or gas in limestone systems, but this problem, like scaling, has largely been solved in recent years as limestone scrubbing has undergone intense development in the utility industry. Maintenance of proper liquid velocities and elimination of areas where solids can settle has minimized plugging, as has careful control of raw material particle size, screening of the slurry, and reduction of the overall amount of solids.

A number of comments concerned problems relating to disposal of the solid waste generated by the lime/limestone system. Specifically, Phelps Dodge Corporation questioned whether sufficient space existed to dispose of waste at its Ajo, Douglas and Morenci smelters. ASARCO voiced similar concern about its smelters at El Paso, Hayden, and Tacoma. EPA acknowledges that the lime/limestone system may be inapplicable in a few cases due to site-specific constraints on disposal options. On the basis of extensive use, demonstration programs, research, and development, however, EPA has determined that problems of solid waste disposal from lime/limestone FGD systems can in most cases be solved.

In 1975, EPA announced its decision that sludge produced by lime/limestone systems at power plants can be fixated and disposed of in an environmentally acceptable manner at reasonable cost. 40 FR 42045 (September 10, 1975). See, also, 42 FR 61541 (December 5, 1977). This decision was in response to a remand ordered by the court in *Essex Chemical Corporation, et al.* v. *Ruckelshaus,* 486 F.2d 427 (D.C. Cir. 1973), and followed an extensive reevaluation of sludge disposal that included national hearings, an agency panel report, and two independent contractor studies.

A number of reports in this docket also discuss the disposal of by-products from non-regenerable FGD systems, among them are: Economics of Disposal of Lime/Limestone Scrubbing Wastes: Untreated and Chemically Treated Wastes (EPA–600/7–78–023a), Control of Waste and Water Pollution from Coal-fired Power Plants: Second R & D Report (EPA–600/7–78–224), and Disposal of By-products from Nonregenerable Flue Gas Desulfurization Systems: Final Report (EPA–600/7–79–046). Other reports in

the docket also discuss disposal of wastes from lime/limestone systems. These reports show that disposal options include conversion of the sludge to gypsum (which can be sold or disposed on or off the site), ponding in indigenous clay soil, ponding with a flexible liner or liner of impervious soil, ponding with underdrainage, surface or deep mine disposal, ocean disposal, and chemical treatment with landfilling. In addition, processes now available transform mixtures of lime or limestone sludge, fly ash, additives, and aggregates into high strength road base usable in primary highways, airport runways, trucking terminals, etc. Other possible sludge applications include synthetic aggregate suitable for producing sintered structural shapes and asphaltic concrete, mineral wool, soil amendment, mineral recovery, sulfur extraction, and polluted water treatment.

Most smelters, it has been determined, have space readily available for disposal of the solid waste product. For the Phelps Dodge smelters, the acres per year required for disposal (liberally calculated) would be 18.5 at Morenci, 13 at Douglas, and 5.5 at Ajo. Morenci has a tailings pond that covers nearly 2,560 acres plus available wasteland. Douglas also has wasteland available. Ajo has a tailings pond of approximately 1,920 acres, a waste dump of over 640 acres, and 640 acres of additional wasteland. Consequently, in none of these areas would waste disposal appear to be a problem. As for ASARCO, Hayden has a sufficient space for waste disposal with a tailings pond of over 640 acres and an additional area with available wasteland. The Tacoma and El Paso smelters may have less room for disposal. In any case, a source owner or operator has the opportunity to demonstrate that the lime/limestone system is inapplicable because site specific reasons make its use technically unreasonable.

As noted, lime/limestone systems can produce gypsum for sale or easy disposal off- or on-site. The Onahama smelter converts waste sludge to gypsum for sale to wallboard manufacturers. In fact, in 1978 the lime/limestone process producing usable gypsum was used in Japan more than any other FGD system. At the beginning of 1978 over 500 major FGD plants having a combined capacity of 90,000,000 m^3/hr. were operational in Japan. Nearly 50 percent of this plant capacity used the lime/limestone process producing usable gypsum.

One commenter opined that gypsum produced by domestic smelters would not be marketable because, unlike Japan, this country has large deposits of relatively high-grade gypsum. Recent studies show, however, that the cost of salable gypsum produced by lime/limestone systems can be competitive with domestically mined crude gypsum if appropriate cost avoidance credits are taken for chemical treatment and disposal. Moreover, waste converted to gypsum can be disposed of easily.

This country imported 7.7 million tons of gypsum in 1972 and the anticipated figure for 1979 is 8.3 million tons. These imports, which occur even though large, mineable quantities exist in New York, Michigan, Iowa, and Texas, come primarily from Nova Scotia, Canada, and go primarily to wallboard manufacturers, especially in the East. Gypsum has also been used in agriculture as a soil additive, as a retarder in cement, and as a paint pigment.

Experience in Japan and elsewhere indicates that gypsum crystal size used in a lime/limestone system can be controlled to produce stronger and lighter weight wallboard than mined gypsum. The potential for producing a superior product, plus the large imports, show the high potential for sales of gypsum. Smelter-produced gypsum would compete directly with natively mined gypsum, especially in the West where it is mined in several states. The sale price of gypsum mined in the West and its shipping cost would dictate the price at which smelter-produced gypsum could successfully compete in the market.

A number of EPA-sponsored studies have examined the estimated costs of producing wallboard-grade gypsum from lime/limestone systems. They conclude that the cost of salable gypsum produced by these systems can be competitive with domestically mined crude gypsum if appropriate cost avoidance credits are taken for chemical treatment and disposal. For example, one such report entitled Control of Waste and water Pollution from Coal-fired Power Plants: Second R & D Report (EPA–600/7–78–224) estimated engineering costs considering two basic processes: A tail-end system incorporating an oxidation tower, which approximates the Japanese processes, and an integrated system, which represents the pilot plant installation at Research Triangle Park, North Carolina, and is being tested at the TVA Shawnee plant with its 10-MWe venturi and spray tower scrubber. The estimates illustrate the range of costs for salable-grade gypsum produced from SO_2 abatement processes.

The study concluded that the potential selling cost of gypsum produced in the integrated systems results in generally favorable economic trends relative to chemical and disposal costs of dry wastes. Also, significant cost reductions can be achieved by improving limestone utilization from 65 to 100 percent. For tail-end systems operating with 100 percent limestone utilization, gypsum production for sale is marginally competitive.

Gypsum also has advantages in terms of disposal. Gypsum is suitable for landfill because, when it is discharged in a slurry form to a waste pond, it precipitates relatively easily in small volumes, thus reducing the required pond size. In the case of truck transportation, gypsum can be handled with great ease.

One commenter suggested that this difficulty in removing water from (dewatering) sulfite crystals makes the lime/limestone system infeasible. However, dewatering sulfate crystals is much easier and, as noted, so is the dewatering of gypsum effluent, which is considered current state-of-the-art.

A final comment on solid waste disposal claimed that Japanese success in solving this problem should be discounted because it was contingent on disposal of wastes directly to the ocean. Consultants hired by EPA who scrutinized the Japanese smelters were, however, unable to discover a single instance where solid waste was disposed of directly to the ocean. Instead, wastewater systems in Japan, including the one at the Onahama smelter, were specifically treated to remove impurities before the water was returned to the ocean.

Thus, on the basis of its extensive and successful use, both domestically and abroad, the Administrator determines that lime/limestone scrubbing is adequately demonstrated technology. Full-scale use of lime/limestone scrubbing has led to the identification and solution of problems such as scaling, plugging, and sludge disposal.

(c) *Comments on Magnesium Oxide Sulfur Dioxide Concentration.* The MgO system is a wet scrubbing regenerable process that differs from the lime/limestone process in two basic ways: the magnesium sulfite produced when SO_2 is absorbed form the flue gas can be calcined to recover the SO_2 in concentrated from, and during calcining the magnesium oxide (MgO) is regenerated and can be recycled. The process produces a marketable product with no sludge to dispose. It requires only a small chemical makeup.

ASARCO commented that Japanese success with the MgO systems is

inapposite for U.S. smelters because (1) the MgO used at the Onahama was (inexpensively) recovered from seawater and produced in a nearby plant, (2) the magnesium would have to be replaced more frequently at domestic smelters, and (3) waste materials from Onahama were sluiced directly to the ocean, which is not possible in this country.

As explained above, cost is peripheral to whether a technology is adequately demonstrated; thus, what matters is not whether magnesium is more expensive in the United States, but whether it is available here. The record shows that it is available. Furthermore, there is no reason why domestic smelters would need more replacement magnesium than at Onahama. In fact, the MgO system at the Boston Edison Mystic Station lost only 0.10 lb MgO/lb SO_2. As for disposal, neither the companies' comments nor EPA's information establish that waste from the Onahama MgO system was dumped directly in the ocean. In any event, only a small quantity of MgO is generated for disposal and it is highly unlikely that any smelter could not find a dump area large enough to last many years. Phelps Dodge opined that the MgO system would be infeasible in the Southwest because it is energy intensive and wastes water. Studies show, however, that although energy and water consumption may be major costs of the MgO system, they do not make the system infeasible.

In addition to its use at the Onahama smelter in Japan, the MgO system has been used in three full size electric utility installations in the United States—the Mystic Station of Boston Edison, the Dickerson Station of Potomac Electric Power, and the Eddystone Station of Philadelphia Electric. A commenter noted that the Mystic and Dickerson Stations have shut down and the Eddystone Station has experienced reduced operability. The commenter asks whether problems with the MgO system are the cause.

Both the oil-fired MgO system at Mystic and the coal-fired one at Dickerson were prototype units built to demonstrate that the MgO system was technically feasible and to determine major areas for improvement. Each achieved these purposes.

The Mystic Station, for example, logged 4000 hours of running time during its operations (it was shut down in June 1974 at the completion of the contract) and demonstrated that it could meet the process guarantees of 90 percent removal of the inlet SO_2, that the magnesia could be regenerated and recycled, and that 98 percent sulfuric acid of good quality could be recovered from the SO_2 removed from the flue gas. No plugging or scaling occurred. Equipment problems and malfunctions were frequent during the test period, especially in the dryer and calciner systems, but they were corrected before completion of the program. The unit worked best during its last 4 months when operability (hours of FGD operation divided by hours of boiler operation) was about 80 percent and would have been higher but for a two-week outage of the offsite sulfuric acid plant. From April 12 to May 10, 1974, the system achieved 100 percent operability.

The Onahama smelter MgO system, which operated for over 2 years is not currently used. The reason is that the sulfuric acid market in Japan is not as good as the gypsum market, and the lime/limestone system is therefore used instead. There has been no evidence that the MgO system had low availability.

The Eddystone facility, which is currently in operation using a MgO system, had to be temporarily shut down in January, 1976, because Olin Chemical closed the acid plant serving the MgO calciner. The regeneration equipment was moved to Essex Chemical, Newark, New Jersey. The Eddystone FGD system operated only a short time, but it removed more than 90 percent of the SO_2. Although initial operability was low, the main problems were with ancillary equipment; the major equipment (scrubbers and absorber, etc.) worked properly.

Philadelphia Electric's confidence in its MgO system is shown by its current construction of a second unit at Eddystone. The first unit was designed for 1,200,000 acfm at 300° F and an SO_2 concentration of 1400 ppm. The second is designed for 1,270,000 acfm under the same conditions. These two units were designed and built by United Engineers of Philadelphia, which is currently designing an MgO system of 2,200,000 acfm at 300° F and SO_2 concentration of 2500 ppm for the TVA Johnsville Station in Tennessee. Basic-Chemico has also designed and built MgO systems and currently offers this service to industry.

This domestic experience with the MgO system, as well as its use at the Onahama smelter, form the basis of the Administrator's decision that this technology is adequately demonstrated. The MgO system has been demonstrated to efficiently recover inlet SO_2 with regeneration of the MgO for recycling and recovery of the SO_2 for feed to a conventional smelter acid plant. Magnesium is available domestically, and although energy and water consumption may be major costs of a MgO system in the Southwest, this does not undermine the Administrator's finding, which is based on an industry-wide examination of technical feasibility.

(d) *Comments on Cominco Ammonia Scrubbing System.* Removal of SO_2 from gas streams by ammonia-based scrubbing has been studied intermittently since the 1880's. Ammonia-based processes are not amenable to throw-away operation because of the cost of ammonia and the solubility and nitrogen value (with chemical oxygen demand) of ammonium salts. The Cominco ammonia scrubbing system can achieve high efficiencies of SO_2 removal over a wide range of SO_2 concentrations. Since the absorbent is a solution rather than a slurry, there are no scaling or plugging problems in the process.

One problem with ammonia scrubbing systems is that the carryover of ammonium salts and other compounds can cause a highly visible plume to occur when the scrubbed gas is discharged from the stacks. The plume is partly attributable to gas-phase reactions of ammonia, SO_2, and water forming ammonium sulfite, which, due to its small size, is not efficiently removed by a conventional mist eliminator. The Cominco smelter at Trail, B.C., solved the plume formation problem at the zinc plant by using a Brinks mist eliminator to filter stack gas prior to discharge. The Cominco smelter also reported adequate control of the plume when operating with low liquid temperature to reduce the ammonia and SO_2 losses, and pretreating the gas before the absorbers. In conjunction with Catalytic, Inc., the Cominco smelter has conducted pilot tests to study the plume formation problem further, and personnel now feel that they will largely eliminate this problem.

One commenter alleged that the Cominco ammonia system is infeasible because the ammonium sulfate product is highly soluble and cannot be properly stockpiled in areas that are subject to rainfall. Handling of ammonium sulfate in the fertilizer industry shows, however, that this material is safe and easily storeable. The Cominco lead and zinc smelter in western Canada and the New Brunswick lead smelter in eastern Canada both produce ammonium sulfate and successfully handle it under rigorous conditions (rain and snow).

Other comments questioned whether ammonia would be available given its dependence on natural gas. Studies show, however, that there will be an adequate supply of ammonia. Moreover, the scarcity or expense of natural gas would not preclude the availability of an

adequate supply since feedstocks other than natural gas could be used.

Most of the ammonia produced at present is based on steam reforming of natural gas. Although any hydrocarbon could be used, natural gas has the advantages of a high hydrogen to carbon ratio and a high purity as received at the plant. Other potential hydrogen feedstocks include petroleum fractions, such as naptha and fuel oil, as well as coal.

A commerical process to produce hydrogen based on coal instead of natural gas or naptha called the Bosch process has been known for over 50 years. It calls for passing steam over highly heated carbon (coal) in the presence of a suitable catalyst.

The Bosch process has not been used in recent years on a commercial level because the natural gas process has been less costly and more reliable. Should this change, the coal process could be used to produce hydrogen based on its previous commercial use. In anticipation of such a change, the Tennessee Valley Authority's National Fertilizer Center is currently working on an ammonia-from-coal project scheduled for startup in mid–1980.

At present, there is no shortage of ammonia in this country or throughout the world. In 1978, 59 domestic companies operated ammonia plants at 93 locations with a total operating design capacity of 22 million short tons a year. A recent EPA report, Impact of Ammonia Utilization by NO_x Flue Gas Treatment Process (EPA–600/7–79–011), concluded that normal growth of the ammonia market could accommodate even an assumed wide-spread use of an ammonia-intensive flue gas treatment system for the removal of nitrogen oxides from power plant stack gas.

Worldwide, ammonia is now in oversupply. A great deal of new ammonia capacity has come on stream, much of it in countries with plentiful supplies of low cost natural gas. For example, the Soviet Union increased its exports of ammonia to this country from zero in 1977 to 315,000 short tons in 1978; large imports of ammonia from the Soviet Union are expected to continue in future years.

Finally, it is noteworthy that the Cominco smelter manufactures its own ammonia, and has since 1940, by using nitrogen from liquid air distillation and hydrogen from electrolysis of water.

A final comment on the Cominco ammonia scrubbing system was whether Arizona smelters would have an adequate market for the ammonium sulfate generated. Although this comment is not strictly relevant to whether the system is adequately demonstrated, it does appear that ammonium sulfate will likely prove marketable, the sale price being dependent on its nitrogen content.

There has been no difficulty in selling the ammonium sulfate produced at the Cominco smelter a Trail, B.C. It is currently sold to Cominco American Corp., Spokane, Washington, and Cominco Ltd., Calgary, Alberta, and is marketed as fertilizer in the northwest United States and various areas of Canada.

The value of ammonium sulfate as a fertilizer stems from the nitrogen it contains. Nitrogen is the primary fertilizer element required for all growing crops. On a per ton basis, it is true that ammonium sulfate contains less nitrogen (21 percent) than for example ammonium nitrate (34 percent) or urea (46 percent). Ammonium sulfate will continue to be used as a fertilizer, however, if the price (per unit of nitrogen) is set at a level that compares favorably with other fertilizers. Also, with the availability of sulfuric acid at smelters, ammonium phosphate fertilizer can be produced. This product can also be sold in the fertilizer market.

Thus the Administrator has determined that ammonia scrubbing is adequately demonstrated technology. It has been used successfully on reverberatory furnance offgases and at the Cominco, Trail, B.C., lead/zinc smelter. This technology can achieve high efficiencies of SO_2 removal with no scaling, plugging, or waste disposal problems. The visible plume problem has been solved, and adequate supplies of ammonia will be available irrespective of natural gas supplies.

(e) *Conclusion.* After considering their feasibility, energy, and nonair quality health and environmental effects, the Administrator is today designating as adequately demonstrated technology, for purposes of evaluating eligibility for an NSO, the following systems: (a) The acid plant and associated process technology underlying EPA's new source performance standards for copper, lead, and zinc smelters (40 CFR Part 60, Subparts, P, Q, and R); and (b) magnesium oxide sulfur dioxide concentration, lime/limestone scrubbing, and ammonia scrubbing. Thus, eligibility determinations should consider their possible use.

These designations are based on analyses of the actual use of the several systems by smelters and power plants. The comments questioning the technical basis for designating these systems adequately demonstrated present no problems not identified and, for the most part, solved in the course of the systems' use.

C. Molybdenum Roasters

EPA specifically invited comment in its proposal on whether molybdenum roasters should be considered eligible for NSOs. Only one commenter, a corporation engaged in molybdenum roasting, responded to EPA's invitation. It argued that molybdenum roasting at older, smaller facilities confronts the same economic and technical problems in SO_2 control as found in the copper, lead and zinc industries. Therefore, the commenter concluded, Congress intended molybdenum smelting to be within the scope of section 119.

The legislative and administrative history, however, clearly points to the opposite conclusion, and, accordingly, the section 119 regulations promulgated today permit NSOs to be issued only to copper, lead, and zinc smelters. As discussed above, Section 119, which does not define "primary nonferrous smelter," was based on the existing EPA policy for smelters. This EPA policy never treated molybdenum roasters as nonferrous smelters. EPA's new source performance standards for primary nonferrous smelters did not include molybdenum roasters, either. Because the smelter-related EPA actions before Congress when it enacted section 119 did not include molybdenum roasters, and because molybedenum roasters had not been the subject of concern in formulating any of those actions, the Administrator has concluded that Congress did not contemplate their inclusion in section 119. This view is also supported by the fact that Congress repeatedly stressed that the relief provided by section 119 was exceptional and intended only for a unique category of sources. See, e.g., 123 Cong. Rec. S13699 (August 4, 1977) (daily ed.). This interpretation is further confirmed by Congress' itemization of only copper, lead, zinc, silver, and gold smelters in discussing the NSO legislation. S. Rep. No. 94–717, 94th Cong., 2nd Sess. 17 (1976); S. Rep. No. 95–127, supra, at 25.[24]

D. Enforcement of NSO Provisions

Several comments asserted that the proposed regulations made inadequate provision for the enforcement of NSOs

[24] The question has also been raised of whether smelters should be eligible for NSOs due to an inability to capture (as opposed to "controlling" or "treating") fugitive emissions. The final regulations reflect the Administrator's view that Congress intended section 119 to deal only with the weak gas stream *control* problems of smelters (which may include the need to treat captured fugitive emissions), and did not intend eligibility for NSOs to be based on the infeasibility of *capturing* fugitive emissions. Problems with fugitive emissions capture are not peculiar to smelters, were not the basis for EPA's smelter/SCS policy, and did not underlie the enactment of section 119.

in various respects. One group of comments suggested that EPA should require more assurance that the states issuing NSOs would have an adequate plan and adequate resources to enforce the provisions of its NSOs.

The Administrator has concluded that certain of these suggestions have merit, and has modified § 57.107 of the regulations accordingly. First, a provision has been added under which EPA may require additional assurances that State plans for NSO enforcement are adequate. Under another new provision suggested by the comments, a State may condition the granting of an NSO to a smelter operator upon the payment of a fee by the smelter operator to the State to defray the cost of enforcing the NSO. The Administrator believes this provision is "necessary to maximize the reliability and enforceability" of supplementary control system (SCS) operation within the meaning of section 119(d)(1)(C), in light of the large burden that enforcement of NSO SCS requirements will place on the limited resources of most State and local agencies. The Administrator also believes that it is appropriate to explicitly authorize this condition as a matter of federal law, since the NSO Program itself is federal in nature. This interpretation of section 119(d)(1)(C) is explicitly supported by the legislative history of the section. See, 123 *Cong. Rec.* S13699–13700 (August 4, 1977) (daily ed.) (statement of Senator Muskie).

Certain commenters also argued that the ambient monitoring systems used under NSOs should be owned by the issuing agency, not the smelter operator. In the Administrator's view, however, what is important is not ownership but reliability and accuracy of the ambient monitors used to detect possible NAAQS violations. As a practical matter, EPA believes that acceptable reliability and accuracy will be assured by the operational requirements of § 57.402(a)(3), and by the requirement that officials of the issuing agency have free access to the equipment for checking and calibration. A requirement that records of ambient monitor calibration and maintenance be kept has been added to § 57.404 for this purpose. This approach gives the issuing agency advantages comparable to owning the monitors, without the additional burden of purchasing and operating the monitors. Since the smelter operator benefits greatly from receiving an NSO, and since it must operate SCS monitors anyway, placing this burden on the operator seems reasonable. The states remain free, of course, to require more or redundant monitors, under whatever financing and operating arrangements they deem appropriate.

II. Subpart B—The Application

A. Effect of Application on SIP Requirements

The proposed regulations provided that NSO applications submitted within two weeks of the effective date of these regulations would have the effect of suspending the applicable federal sulfur dioxide SIP requirements (emission limitations and schedules of compliance) during completion and processing of the application. One commenter argued that EPA should not limit this effect to applications submitted within two weeks, on the ground that this limitation would be a disincentive to smelters which might otherwise attempt to meet existing SIP emission limitations first, and only apply for an NSO if they were unable to meet those emission limitations. The Administrator agrees. Congress apparently did not intend to limit the time during which applications could be made, and smelters which might be able to meet SIP emission limitations should be encouraged to try to do so without jeopardizing their opportunity to apply for an NSO on the same terms as other smelters. Section 57.202 has been modified accordingly.

Another commenter urged that the time given for the completion of NSO applications not be limited to ninety days in all cases. EPA agrees that there may be an occasional situation in which more time for completion of the application is justified. On the other hand, since SIP requirements are suspended during this period, the period must be as short as possible and must not provide any incentive for delay. Section 57.202 has therefore also been modified to give the Administrator discretion to extend the ninety-day period. The Administrator intends to do so only in unusual circumstances, and believes that ninety days is sufficient to complete an application, especially in light of the time which has already elapsed since the proposal of these regulations.

Concern was also expressed that the suspension of the SIP requirements not affect their state law status. The intent of the phrase "federal SIP emission limitation for sulfur dioxide" in both the proposed and the final regulations is limited to the federal law aspects of those requirements (emission limitations and schedules of compliance), and is not intended to affect their enforceability as a matter of state law.

B. Confidentiality

Some commenters expressed concern that the confidential information contained in the application might be released improperly by EPA. The Administrator has concluded, however, that the Agency's procedures for the treatment of confidential information fully protect that information. EPA has recently reviewed these procedures in view of the increased amount of confidential information it now receives under various statutes, including the Toxic Substances Control Act. The Agency has, as a result, amended the provisions of 40 CFR Part 2 to assure the full protection of confidential information consistent with applicable legal requirements. See, 43 FR 39997 (September 8, 1978). These provisions fully protect this information from disclosure by EPA to competitors.[25]

III. Subpart C—Constant Controls and Related Requirements

A. Constant Controls

Subpart C of the proposed regulations would have required a smelter receiving an NSO to operate its existing constant control equipment at its maximum feasible efficiency and to correct any serious deficiencies in the design or operation of the system which result in significant decreases in its overall efficiency or availability. In addition, no smelter would be permitted to emit strong gas streams directly to the atmosphere without treatment, except when a malfunction necessitated bypassing the acid plant.

Asarco/Magma and Phelps Dodge submitted the major comments on these requirements. The thrust of these comments was that, with respect to interim constant controls, Congress had merely intended that existing controls continue to be operated, and that EPA's proposed interim constant control provisions were therefore unreasonable. In effect, the companies urged that they should not only be exempt from any control of their weak sulfur dioxide gas streams, but that they should also not be required to correct even gross deficiencies in the operation or maintenance of their existing acid plants. In addition, the smelters argued that they should be free to bypass the control equipment whenever process

[25] This protection is not undermined by 40 CFR 2.301(g), under which EPA may release certain confidential material when the material is relevant to a proceeding under the Clean Air Act. That provision is required by section 114(c) of the Act. Under EPA's regulations, however, the material could only by released if it was in the public interest to do so, and only after an opportunity for the company to comment on, and judicially contest its release.

equipment produced strong gas streams in excess of the acid plant's capacity or whenever the acid plant has been shut down for maintenance, even though such maintenance is predictable far in advance. According to the companies, this is required by subsections (d)(1) and (d)(4) of section 119, and by its legislative history.

The Administrator disagrees, and believes that these comments misconstrue the statute and the congressional intent. EPA's existing smelter policy addressed the principal control problem facing nonferrous smelters: controlling the weak gas streams produced by certain of their processes. There was no need for the policy to provide relief for the strong gas streams produced by other processes, because they have long been readily treatable in acid plants. Under EPA's policy, the use of SCS in lieu of the treatment of weak streams was therefore conditioned on the control of all strong gas streams by acid plants. As the Asarco/Magma comments note, bypassing during periods of excess gas or for scheduled maintenance was not permitted.[26]

Congress codified the constant control provisions of the Agency's policy in section 119(d), both as to weak streams and strong streams. The House Report not only explicitly endorses EPA's overall policy,[27] it also quotes [28] specifically from EPA's Stack Height Increase Guideline, which explains that the interim constant control required is "control of all strong gas streams through properly operated and maintained double contact acid plants (or single contact acid plants where single contact acid plants are already on line)." [29] This requirement for the full and efficient treatment of strong streams is embodied in section 119(d)(1)(C), requiring the use of interim constant controls.

This reading of the congressional intent is further confirmed by the formal explanation of the provisions of the 1977 Conference bill presented to the Senate by Senator Muskie, chairman of the conference committee. In that statement, he described the interim constant control requirement as

> "intended to mean an acid plant which: First, was designed to achieve an optimum level of SO_2 control at the site where it is located; and second, is properly operated and maintained at that site. Where acid plants now in use do not measure up to this standard, it is intended that such acid plants will be upgraded to a level which EPA determines to be optimum either on a smelter-by-smelter or industry-wide basis." [30]

The companies also commented that Congress intended section 119(d)(4) as a reversal of the EPA policy requiring that existing acid plants fully and efficiently treat the smelters' strong streams. For several reasons, the Administrator believes that section 119(d)(4) instead represents a codification of the Agency's policy that weak stream control systems, such as scrubbers, would not be required until they were found to be economically and technically feasible for a smelter.

First, the interim constant control requirement is imposed by section 119(d)(1)(C), not by section 119(d)(4). The only reference to costs in connection with this requirement is found in subsection (d)(2), which allows the requirement to be waived in the case of a smelter having *no* existing acid plant, if installation of the acid plant would force the smelter to close.[31] The fact that the "adequately demonstrated to be reasonably available" language and hearing requirement of subsection (d)(4) are parallel to the provisions of subsections (b)(3), (c)(1), and (e), all of which deal with the weak stream controls that would ultimately allow compliance with the SIP emission limit, is further evidence that subsection (d)(4) relates to additional weak stream controls. Moreover, since Congress knew that acid plants would be the means of compliance with the interim control requirement,[32] it would have been pointless to require hearings on the availability of acid plants to the smelting industry under subsection (d)(4).

A contrary reading of section 119 would also improperly ignore the context in which the section was enacted and the policies Congress sought to further. As discussed more fully in the preamble to the proposed NSO rules, Congress was acting against the backdrop of years of litigation over SIPs by the utility and smelting industries concerning the role of feasibility and the use of SCS and tall stacks in lieu of constant controls on weak streams in SIPs. In the 1977 Amendments, Congress resolved any remaining uncertainty by rejecting the use of dispersion and explicitly requiring that constant controls be used irrespective of feasibility. This action was prompted by mounting concern over health and environmental effects of increased atmospheric loading and transport of sulfur dioxide. See generally, H.R. Rep. No. 95–294, *supra* at 81–94. Because of the particular weak stream control problems facing some smelters, Congress did grant limited relief through section 119 from immediate compliance with the full constant control SIP requirements that would otherwise have applied. There is no indication whatever in the statute or its legislative history, however, that Congress intended to relieve smelters of their existing obligations under the EPA policy and the Act to use available technology—acid plants—to treat their strong gas streams fully and efficiently. To have done so, indeed, would have been a fundamental departure from both the EPA policy and the overall policy on constant controls contained in the 1977 Amendments.

The more modest SIP constant control requirement for smelters found in EPA's policy specified that all strong gas streams be fully and efficiently treated in acid plants. Recognizing that the costs associated with this commonly used technology were much lower than those required for weak stream control, and in view of the judicial decisions affirming the constant control imperatives of the Act, the EPA policy treated the acid plant requirement as an absolute industry-wide minimum, as to which compliance costs were not relevant. The consideration of economic feasibility was instead reserved for the weak stream controls to be required in the future.

That Congress likewise intended section 119(d)(4) to refer to future weak stream controls is clear not only from its endorsement of the Ninth Circuit's

---

[26] *See*, 40 FR 49371 (October 22, 1975) (proposed SIP provisions for Arizona smelters).

[27] H.R. Rep. No. 95–294, *supra* at 61.

[28] *Id.* at 63

[29] 41 FR at 7452 (February 18, 1976). The Asarco/Magma comments argue that, in quoting EPA's statement of the interim control requirement in the Stack Height Increase Guideline, the House Committee did not intend to endorse the requirement for increased acid plant capacity to treat strong streams fully, because the Report's quotation ends before the sentence: "Where increased acid plant capacity is required to treat presently untreated strong gas streams, RACT for such gas streams must be double contact acid plants." This sentence, however, merely explains what kind of acid plant must be used when additional capacity is required; it is the prior sentence, quoted by the Committee, that actually creates the requirement for the "control of *all* strong gas streams" (emphasis added).

[30] 123 Cong. Rec. S13699 (August 4, 1977) (daily ed.).

[31] This provision, included for the benefit of the copper smelters operated by Kennecott at McGill, Nevada and Phelps Dodge at Douglas, Arizona, represents the only major substantive departure by section 119 from the EPA policy.

[32] H.R. Rep. No. 95–294, *supra* at 62; H.R. Rep. No. 95–564, *supra* at 138. Asarco/Magma also urge that the interim control requirement was directed solely at the attainment of NAAQS. This is incorrect. Since Congress clearly envisioned that smelters under NSOs would attempt to protect standards through the use of SCS, the Administrator believes that the congressional purpose in requiring the use of interim constant was the same as that underlying the other constant controls requirement of the Act: limiting total SO_2 emissions into the atmosphere.

Kennecott opinion,[33] but also from the House Report's explanation of the (d)(4) provision. That explanation is immediately preceded by a quotation from EPA's Stack Height Increase Guideline, discussing the distinction between technically feasible weak stream control (scrubbers) and the reasonably available controls represented by acid plants on strong streams. The Administrator reads the Committee's explanation, which is based on this quoted distinction, as confirming his interpretation that (d)(4) is addressed to additional constant control systems for controlling weak streams, not to the interim acid plant requirement.

Finally, even if the costs imposed by the interim control requirements were relevant, the Administrator does not believe that they are unreasonable. As EPA explained in the preamble to the proposed regulations, the requirement for the correction of serious deficiencies is not intended to require the upgrading of acid plants except where a deficiency in the design of a component or in the operation or maintenance of the plant results in a significant decrease in the overall efficiency or availability of the acid plant.[34]

Likewise, the prohibition of emitting strong gas streams in excess of the volume capacity of an acid plant directly to the atmosphere is reasonable. In the preamble to the proposed regulations, EPA noted that most smelters' acid plants are capable of treating the full volume of strong streams generated by process equipment. The comments on this provision suggested only three smelters at which excess gas was even a problem: Asarco's Hayden and Tacoma smelters, and the Magma smelter. Magma asserts that while its acid plant was designed to handle the full gas volume produced by Magma's converters, leakage in the flue system results in a gas volume reaching the acid plant which exceeds its capacity, thus necessitating bypassing or production cutbacks. As EPA noted in the preamble to the proposal, however, this excess gas can be reduced or eliminated by improved maintenance to reduce inleakage to the flue system. This view was confirmed by information gathered at EPA's public hearings, at which a Magma employee stated that maintenance on the flues serving the acid plant was never a high priority at the smelter, and that as a result the flues were allowed to develop holes "as big as a man." Also included in the docket at the time of proposal was testimony by the manager of Asarco's Hayden smelter to the effect that the smelter's acid plant was designed to handle the full volume of gas generated by the smelter's converters, and that improved maintenance would be able to eliminate the inleakage into the flue system which was necessitating bypassing there. Asarco's comments establish nothing to the contrary. The Administrator believes that it is reasonable to require these smelters, like all other air pollution sources in the nation, to perform the maintenance necessary to permit their pollution control equipment to operate according to its design. The Administrator also notes that smelters do have the option of upgrading their acid plant capacity to handle the full volume of strong gas generated by their production equipment.[35]

Another commenter urged that bypassing be permitted when an acid plant has cooled below autothermal operational temperature as the result of an SCS curtailment. The Administrator recognizes that if an acid plant is not receiving gas for a prolonged period of time it can cool to such an extent that some period of warm-up is required before efficient gas treatment is again feasible. SCS curtailments are usually short enough, however, that such cooling will not occur if the acid plant is sealed off at the time the gas feed ends. It is also feasible, and good pollution control practice, to prevent undue cooling or to reheat the plant prior to restarting the process through the use of auxiliary heat or SO_2 injection. The proposed regulations have therefore been modified to permit NSOs to allow bypassing where an acid plant has received no gas during a prolonged curtailment, but only if smelter-specific NSO provisions are included requiring a smelter to show that it could not reasonably have avoided significant cooling through the use of the practices noted above.

Finally, the companies objected to the prohibition on bypassing strong streams directly to the atmosphere during scheduled or planned maintenance of acid plants, such as the screening of catalyst. The companies assert that Congress intended to prohibit such a requirement, and that it would cause a significant amount of production to be lost.

For the reasons discussed in Section A above, the Administrator believes that Congress intended to ratify EPA's policy requiring full treatment of strong gas streams, rather than to limit the policy as the comments suggest. In addition, none of these comments demonstrated that the production foregone during scheduled maintenance could not, as EPA suggested in the proposal, be rescheduled at other times. This maintenance, unlike repairs of malfunctions, can be schedued far in advance, and production levels at other times can be increased to compensate for that amount not produced during planned maintenance. The comments also did not dispute that many smelters already schedule shutdowns or reduce production rates for maintenance of production equipment, during which maintenance can also be carried out on acid plants. The Administrator also notes that the need for catalyst screening, the primary type of planned maintenance, can be reduced significantly by improvements in the particulate pre-cleaning portion of the acid plant. This also reduces the amount of production that must be rescheduled.

One main basis on which the comments urged that bypassing be allowed during planned maintenance was that the NAAQS would be protected by the use of SCS anyway, and that the bypass prohibition was therefore not justified as an interim measure necessary for meeting NAAQS.[36] The Administrator disagrees. As Congress clearly recognized, supplementary control systems are at best of questionable reliability. With the limited number of monitors the systems use and the complex terrain in which many smelters are located, it is quite possible that standards may be violated because of the absence of a monitor at a

[33] *Kennecott Copper Corp.* v. *EPA*, 526 F. 2d 1149 (1975).

[34] EPA gave as an example of a serious deficiency the use of heat exchangers inadequate to sustain efficient autothermal operation over the range of gas strengths and volumes routinely generated by process equipment. The Agency recognizes that smelter acid plants are not designed to handle gas strengths averaging below about 3.5% SO_2, and did not intend to imply to the contrary. Heat exchangers should, however, be adequate to handle the average gas strengths actually received by the acid plant.

[35] Asarco also stated that the existing constant control system (acid plant and liquid SO_2 plant) at its Tacoma smelter was not designed to handle all the strong streams (converter gas) routinely produced there, and that a prohibition on bypassing excess gas would result in large production losses there. The Administrator notes that the Assistant Manager of the Tacoma smelter informed EPA in 1976 that the system *was* designed to provide sufficient capacity to process all converter gas, and that the technical problems which had resulted in bypassing were then being resolved. A study of the acid plant performed for EPA also confirmed that its capacity could be upgraded and that certain serious deficiencies could be overcome without unreasonable expense. In any event, the Administrator does not believe that Congress intended to exempt smelters from the established requirement to control all strong gas streams simply because existing acid plant capacity or inferior plant design may have to be augmented or upgraded at a particular smelter.

[36] No emperical support for this contention was provided.

particular location of high sulfur dioxide concentration under a given set of local meteorological conditions. The significance of this problem is greatly increased when the smelter operates without its interim constant controls, resulting in higher average ambient SO_2 concentration. The reliability of a particular SCS is therefore appreciably undermined during such operations.

This was confirmed by testimony at EPA's public hearing in Tucson indicating that sulfur dioxide emissions from the Phelps Dodge Douglas, Arizona smelter, which operates without sulfur dioxide controls, may cause excessive ambient concentrations of sulfur dioxide at locations not monitored by the smelter's SCS network. The Administrator believes, therefore, that the prohibition on bypassing during planned maintenance is a condition necessary to maximize the reliability and enforceability of the interim SCS measures used to protect NAAQS within the meaning of section 119(d)(1)(C).

Finally, the Administrator does not believe that permitting strong streams to be emitted directly to the atmosphere during maintenance that has been planned in advance is consistent with the requirement of section 119(d)(1)(C) that smelters under NSOs operate using *continuous* controls unless they have received waivers under section 119(d)(2). To do so would permit smelters, on a routine and planned basis, to operate with supplementary controls alone. The Administrator believes that Congress did not intend to allow use of dispersion techniques alone, because it was ratifying EPA's existing policy on the issue, because of the limited reliability of supplementary controls, and because it wanted to limit total atmospheric loading of sulfur dioxide. Considering the number of smelters which may receive NSOs, particularly in the southwestern U.S., permitting operation without controls during planned maintenance would result in the excess emission of a very large amount of additional sulfur dioxide each year. This cannot be reconciled either with the congressional intent to limit total atmospheric loading, or with the intent reflected in the provisions of the 1977 Clean Air Act Amendments especially affecting that part of the country, such as prevention of significant deterioration and visibility protection. Rescheduling production, by comparison, would allow the removal of up to 99% of the SO_2 in these strong streams, which would otherwise be emitted without treatment.

B. *Monitoring.* Proposed § 57.305(a)(2) of the regulations would have required "continuous" monitoring of ducts used to bypass gases around required constant controls, and stated that this "monitoring shall be adequate to disclose the time of the bypass, its duration, and the *approximate* volume of gas bypassed" (emphasis added). EPA received two conflicting comments on this provision. A smelter wrote that it could not accurately measure the volume in the bypass stack, and an air pollution control agency wrote that such volume should be measured precisely and that therefore EPA should delete the word "approximate."

The purpose of the monitoring requirement in proposed § 57.305(a)(2) was to give a means for determining whether there was compliance with the bypass provisions of an NSO. This purpose does not require a precise measurement of the volume of gas bypassed; rather, any instrument or device that reveals with a reasonable certainty the extent bypass ducts are open would be sufficient. To clarify this intent, EPA has deleted the word "continuous" from § 57.305(a)(2). In short, whether a monitor is sufficient under this subsection depends on whether it can reliably indicate whether there is compliance with the bypass provisions of the NSO. Although a disclosure of the "approximate" volume of gas bypassed satisfies this purpose, a state may require a more precise measurement if it desires.

EPA emphasizes, as it did in the preamble to the proposed regulations, 44 FR 6291–2, that the primary purpose of the monitoring requirement in § 57.404 is not to determine compliance, but to facilitate the development of improved SCS curtailment criteria and improve understanding of the effects of the smelter's emissions by using specific quantitative emission data to construct more accurate models of the effects of those emissions. The usefulness of the information for modeling purposes would remain substantial even if problems in continuously monitoring stack gas volumetric flow rate do initially occur. These problems should largely be overcome as smelter operators and vendors gain additional experience using these monitors.

The State of Arizona commented that continuous emission monitors should be subject to a redundancy requirement. After consideration of this comment, EPA has decided that while a strict redundancy requirement is not necessary, a requirement of high data recovery is important for purposes of compliance determinations. Therefore, EPA is amending proposed § 57.305(a)(i) by adding this sentence: "Failure of the monitors to record 95% of the 15-minute periods in any 30-day period shall constitute a violation of the NSO." EPA believes this requirement is "necessary to maximize the reliability and enforceability of * * * interim measures." Section 119(d)(1)(c)(i). It is also reasonable. The State of Arizona, in setting sulfur dioxide emission limitations for copper smelters, found that Kennecott's Hayden smelter achieved a rate of more than 95% data recovery over the last two years when there was no data recovery requirement in effect. EPA also believes that currently available monitors can be highly reliable if operated and maintained properly. This is discussed more fully in the Supplemental Response to Comments document in the docket.

IV. Subpart D—Supplementary Control System Requirements

A. Size of the Designated Liability Area

Under the proposed regulations, a smelter operator would be required to operate a supplementary control system (SCS) in a way that prevents all violations of the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide within the smelter's designated liability area (DLA). The DLA is the area within which the smelter's emissions could cause or contribute to violations of NAAQS, and the smelter operator would be required to consent to liability for most violations of standards within the DLA as a condition of receiving the NSO. The proposed regulations provided presumptive DLA radii, based on the emission rates of the smelters without consideration of any constant controls in use. The regulations also permitted the smelter operator to show in its NSO application that other DLA boundaries were more appropriate under actual local terrain and meteorological conditions.

EPA received many comments concerning the size of the DLA. Credible comments made both in writing and at the public hearings indicated that under some terrain and meteorological conditions the proposed size of the DLAs and the number of monitors required were inadequate to protect standards. This was the thrust of comments made by a number of persons living at various distances from the Phelps Dodge copper smelter at Douglas, Arizona. According to these comments, there are recurring incidents of SO_2 concentrations of appreciable severity attributable to the smelter's emissions. The Douglas smelter operates without any constant controls for sulfur dioxide, but employs an SCS that appears to be

basically consistent with the proposed regulations. The Administrator has therefore concluded that some change is needed in the Subpart D regulations to deal with this kind of situation.

Smelter operators and the State of Arizona, however, argued that the proposed DLA radii were too large. In considering changes to the proposed Subpart D regulations, the Administrator has given considerable weight to Arizona's comments, both because Arizona is likely to be enforcing more SCS programs than any other state, and because Arizona has more experience to date than any other state in administering these programs. After considering all pertinent comments, the Administrator has concluded that, as explained below, the Subpart D regulations should be revised both to reduce the size of the presumptive DLA radii, and to provide a means for detecting and remedying excess concentrations at locations not served by SCS monitors. These revisions are intended to respond to both sorts of comments described above.

As to DLA size, the Administrator notes initially that because the radii in the table in § 57.402(c) were based on general (*i.e.*, not site-specific) modeling, that section permitted a smelter operator to demonstrate that different DLA boundaries are appropriate under conditions specific to a given site. This provision is being retained, and EPA believes that it remains the best method available.

A number of considerations, however, support the reduction of the presumptive DLA radii. First, as Arizona points out, the principal emissions that the NSO is intended to deal with are uncontrolled weak streams. The strong streams are required to be controlled through interim constant controls operated at their maximum feasible efficiency. Except during malfunctions, therefore, weak stream emissions will be the primary contributor to total smelter emissions. Second, SCS ambient air quality monitors are required to be located at points of high SO_2 concentrations. Since these points will generally be within DLAs established on the basis of controlled emissions, little is gained towards protecting standards by including a large amount of unmonitored area in the DLA beyond those monitors.

Finally, as Arizona notes, basing DLAs on uncontrolled emissions could create overlapping DLAs among as many as four smelters in Arizona. This could make enforcement of NSO provisions difficult in these areas of overlap, contrary to the basic purpose of having DLAs. Although the Administrator believes that the proposed regulations addressed this problem reasonably, he agrees that if it is possible to eliminate the problem without undermining the SCS–DLA mechanism, it would make that mechanism more enforceable. The final regulations therefore provide that the presumptive DLA is to be determined based on emissions at the rate associated with the smelter's maximum production capacity, assuming compliance with the interim control emission limit, rather than on the smelter's total potential uncontrolled emissions.[37] According to the comments of Arizona and others, this leaves only the overlap between the adjacent Asarco and Kennecott smelters at Hayden, Arizona. The proposed regulations dealing with the overlapping DLAs are being retained as necessary for that situation or other possible overlaps.

To deal with the problem of excessive concentrations at areas without SCS monitors, the regulations have been revised to require that as part of the continuing review of the SCS under § 57.402(f) the smelter operator conduct an active program to determine whether standards are being exceeded at points without monitors either within or outside of the DLA. This program would be expected to include at least the use of mobile monitors,[38] modelling, and the conscientious investigation of possible excess concentrations reported by the public. If a violation of NAAQS were discovered through this program, a monitor would be required at that location as part of the SCS network, with corresponding meteorological information acquisition capability as well.

B. Effects of the Consent to Liability

As the Administrator stated in the preamble to the proposed regulations, SCS can be a reliable and enforceable means of preventing violations of NAAQS only if the smelter operator is clearly responsible for all violations of ambient standards in the areas affected by the smelter's emissions. This view is abundantly supported by the legislative history of section 119,[39] by EPA's existing smelter program and by judicial precedent. See, *Bunker Hill Co. v. EPA*, 572 F.2d 1286 (9th Cir. 1977). The only significant comment on the requirement for consent to liability for violations of NAAQS in the DLA was that it was unnecessary because it would be easy for the issuing agency to establish that an isolated source was responsible for violations in its vicinity. The Administrator continues to believe, however, that the enforceability of an SCS depends heavily on the smelter operator's assumption of clear legal responsibility for any violations in the area affected by the smelter's emissions. The assumption of liability provides that smelter operator with a strong incentive to design the SCS procedures and to operate the system in a way that will prevent any violations of standards, and provides the issuing agency an effective and direct means of taking whatever enforcement actions may be necessary to remedy violations should they occur. The Administrator also notes that the commenters questioning the assumption of liability concede that it is only the smelter itself which *could* be causing violations in a DLA; requiring that concession to be made formally as a condition for using SCS therefore does not seem an unreasonable burden.

Several comments asserted that the assumption of liability should not include criminal liability under section 113(c) of the Act. The Administrator intended the consent to preclude disputing the fact that violations of the NAAQS in the DLA were caused by the smelter's emissions, and thus violated the NSO. Under section 113(c), however, only NSO violations which were committed "knowingly" are criminally enforceable. Section 57.403 has therefore been modified to allow the smelter operator to contest during criminal enforcement proceedings whether violations were committed "knowingly."

Comments also asserted the need to modify the circumstances under which a smelter could show that a violation in its DLA was due to the emissions of another source in excess of that source's "maximum permissible emissions" as defined in § 57.402(e)(2). EPA agrees that the fugitive emissions of another source may cause violations in a smelter's DLA under the circumstances present in Hayden, Arizona, where Asarco and Kennecott operate adjacent smelters. EPA does not believe that this problem is pertinent to any other location. The Agency does recognize, however, that violations resulting from fugitive emissions cannot always be prevented through the use of SCS. The regulations have therefore been modified to require not only that the

[37] This will be a rate greater than the plant-wide emission limit if that limit is measured on a long-term (*e.g.*, weekly or monthly) basis, since production rates can be greater for the shorter durations corresponding to the NAAQS than for longer periods such as a week or month.

[38] This requirement replaces the mobile monitor required by proposed § 57.402(a)(2). The conduct of the continuing review will still be supervised by the issuing agency.

[39] See, *e.g.*, H.R. Rep. No. 95–294, *supra* at 62; 123 Cong. Rec. S13700 (August 4, 1977) (daily ed.) (statement of Sen. Muskie).

SCS be designed to deal with fugitive emissions from another source to the extent possible, but also to allow a smelter operator to show that a given violation resulted from another source's fugitive emissions despite the smelter operator's adherence to the SCS manual provisions applicable to the situation.

Certain commenters also urged that the regulations be revised to allow a showing that violations resulted from excess emissions of another source during a malfunction, where there are no applicable SIP limits, or where another source's emission limit is wholly inadequate to protect the NAAQS. The Administrator does not believe any of these exceptions would be appropriate. Contrary to the views expressed by some commenters, emissions in excess of a federally-approved or promulgated SIP emission limitation *do* violate that emission limit even if they result from a malfunction. The proposed regulations therefore already account for this situation, and would permit a smelter operator to show that such excess emissions were responsible for the violation.

The absence of a SIP emission limit, or an adequate emission limit, provides no basis for allowing violations in a DLA to be excused, in the Administrator's view. The basic premise on which the use of SCS is based is that the smelter is the sole major source of sulfur dioxide emissions in its area, and therefore that the smelter's emission curtailments can be relied upon to prevent violations of the NAAQS. If another source in the area emits enough sulfur dioxide to invalidate this assumption, the use of SCS should not be permitted and an NSO could not be granted. The provisions of the proposed regulations allowing a smelter operator to show that a given violation was due to the excess emissions of another source were also predicated on the assumption that such a source was ordinarily of consistently low emissions, and that only under very unusual circumstances could its excess emissions result in a violation of NAAQS before the smelter could curtail its emissions to compensate. Similarly, then, if this assumption is not valid in a particular case an NSO should not be issued. Whether a source in the vicinity of a smelter is controlled tightly enough under the SIP to allow the validation of these assumptions is, moreover, an air quality management decision within the discretion of the State, and one over which EPA has little influence. See, *Train v. NRDC,* 421 U.S. 60 (1975); cf. section 119(d)(1)(A). If the State does not choose to impose and enforce a SIP emission limit tight enough to validate the assumptions underlying the use of SCS, that is within its discretion, and an NSO cannot be granted.

C. Maintenance of Pay

Several commenters suggested that EPA include some provision in the regulations to ensure that production curtailments due to SCS did not result in worker lay-offs or pay reductions. Under section 110(a)(6) of the Act, state implementation plans are required to include the provision that a smelter operator may not temporarily reduce the pay of any empolyee due to SCS curtailments under an NSO. The Administrator agrees that Congress intended to link sections 110(a)(6) and 119, and has therefore included a new § 57.109 in the final regulations providing that he will not approve or issue an NSO for a smelter in any state for which he has not approved or promulgated a provision satisfying the requirements of section 110(a)(6).

V. Subpart E—Fugitive Emission Evaluation and Control

Fugitive emissions, in contrast to stack emissions, are emitted at low elevations and cause or contribute to ambient violations primarily in the immediate vicinity of the source. SCS emission curtailments, which at many smelters are initiated in response to monitors sited to measure primarily the effects of stack emissions, often fail to prevent violations resulting from fugitive emissions. The proposed NSO regulations required the use of interim measures to deal with this problem. EPA received comments on this proposed requirement and, in response, has carefully reconsidered it and, where appropriate, made changes.

One comment was that EPA had authority to control fugitive emissions only in a SIP, and not in an NSO. This follows from the assertions that a fugitive emission control is not an "emission limitation," and that the sole purpose of section 119 was to postpone the ultimate emission limitation on stack emissions because "no means of emission limitation" has been adequately demonstrated to be reasonably available. Sections 119(b)(3), (c)(2).

Although the Administrator agrees that eligibility for an NSO is to be based solely on the problems of complying with the SIP stack emission limitation, this contention ignores the explicit and unmistakeable mandate Congress gave the Administrator in section 119(d)(1)(A) to require "use (of) such interim measures for the period during which (an NSO) is in effect as may be necessary in (his) judgment * * * to assure attainment and maintenance of the national primary and secondary standards during such period." See also H.R. Rep. No. 95–294, 95th Cong., 1st Sess. 62 (1977). Since fugitive emissions from smelters can result in violations of the ambient standards, their control as a condition of an NSO is appropriate. In addition, interim control measures for fugitive emissions are necessary because while SIPs may include controls for fugitive emissions, it is likely that a smelter's configuration under an NSO will be different from the final compliance configuration assumed in setting the SIP controls.

The proposal required a smelter receiving an NSO to study its fugitive emissions problem unless it was able to show at the time of its application for an NSO that fugitive emissions have no significant effect on ambient air quality in its DLA. The study would have consisted of at least six months of ambient monitoring around the smelter to determine the sources and effects of fugitive emissions of sulfur dioxide, total suspended particulates (TSP), arsenic, and lead.

The only comment received directly pertinent to the monitoring requirement was from the State of Arizona, which stated that it was desirable to measure arsenic, lead, and TSP, as well as SO_2, but queried how the requirement was authorized. Section 119(d)(1)(B)(i) requires interim measures to include "such monitoring as the Administrator determines may be necessary." Monitoring for arsenic, lead, and TSP, as well as SO_2, is necessary to enable the smelter operators, EPA, and state agencies to devise or evaluate control strategies for fugitive emissions of SO_2 that will be compatible with existing or probable EPA and OSHA requirements for the control of process and fugitive emissions of all these pollutants. Indeed, the smelting industry voiced considerable concern during pre-proposal discussion about the potential for conflicting technologies for SO_2 and these other pollutants. In order to develop practicable controls, then, it was necessary to require monitoring for all these pollutants. The final regulations tailor the monitoring requirements more closely to the probable results by requiring monitoring for arsenic only at copper smelters and monitoring for lead only at lead and zinc smelters.[40]

The proposal required that a report on this study, with its minimum six months of monitoring, be completed within 10

[40] Arsenic is found primarily in copper ores. Zinc ores often contain substantial quantities of lead.

months of the effective date. Then, within 60 days, the smelter would have had to submit for approval a fugitive emission control plan. If this plan called for control of fugitive emissions through the use of engineering techniques (as opposed to SCS), certain increments of progress had to be submitted for approval within 60 days of the plan's approval.

A commenter submitted that the provision for compliance schedules relating to control through engineering should be omitted because the time reasonably required to let contracts and complete compliance plainly will vary from smelter to smelter depending on the nature of the controls required. Instead, this commenter would have each applicant include for approval by EPA a schedule of compliance in the smelter's compliance plan.

In light of all these comments, the Administrator has modified the final regulations in several ways. The goal of the study has been more clearly specified as assessing the sources of significant fugitive emissions from the smelter and their effects on ambient air quality. The specification of six months as the minimum time for monitoring required in the study has been deleted to allow the issuing agency to tailor the study more carefully to the actual conditions at the smelter. In many cases, the Administrator expects that the monitoring will continue for longer than six months. Correspondingly, the time for the submission of the results of the study is to be fixed by the individual NSOs. Finally, the increments of progress required in fugitive emission control plans have been modifed considerably, as discussed below in connection with other compliance schedule requirements.

VI. Subpart F—Research and Development

EPA proposed to require each smelter owner to agree, as a condition of receiving an NSO, to commit reasonable resources to a research and development project designed to produce more effective means of meeting the smelter's SIP emission limitation. The proposal set out criteria for approval of a proposed project, the main goal being to insure that taken together, projects conducted under NSOs (as well as independently) should result in technology that will allow all smelters to meet their emission limitations as soon as possible, but in no event later than January 1, 1988, when second NSOs expire. EPA received and has considered several comments on this part of the proposal, some of which resulted in changes as discussed below.

One commenter objected to EPA's asserted assumption of sole responsibility for the approval of research and development projects. This commenter noted that the Conference Committee deleted the House bill's requirement that smelters commit to research and develop "such resources *as the Administrator determines* to be reasonable" (emphasis added) and substituted the requirement for committment of "reasonable resources to research and development of appropriate emission control technology," as section 119(d)(1)(C)(ii) provides. This change in wording does not, however, indicate that EPA has little or no authority for judging what constitutes a "reasonable" research and development commitment.

The House bill did not have a separate section parallelling section 119 of the Act; rather, the NSO provisions were part of a section of the House bill dealing with delayed compliance orders. See section 121 of H.R. 6161 as passed, 95th Cong., 1st Sess. (1977). The Conference Committee, while adopting the basic format from the House bill, separated treatment of NSOs and delayed compliance orders, and in doing so partially rewrote the House bill's provisions to accommodate this reorganization. The commenter notes one such change. Nowhere, however, is there an indication that a substantive change was intended to revoke the Administrator's authority to pass on the approvability of research proposals. This is confirmed by the plain language of section 119(d)(1)(C)(ii) which says "*The Administrator* shall condition the use of any interim measures" (emphasis added) on a smelter's commitment of "reasonable resources to research and develop * * * appropriate emission control technology." This mandate to the Administrator would be meaningless if he was without authority to determine whether proposed resources were "reasonable" and emission control technology was "appropriate." See also, section 119(a)(1)(B).

Proposed § 57.602(b) said that where EPA was not the issuing agency, the smelter must submit its research proposal to EPA at the time it submits the proposal to the issuing agency. This provision may have been misleading, however, since EPA did intend the States to have a role in initially determining the approvability of a research proposal. To reflect this, the regulations promulgated today modify proposed § 57.602(b) to give the issuing agency and the applicant the option simultaneously to submit the research proposal to EPA and the issuing agency. For the convenience of either, if EPA receives a proposal it will certify whether in the judgment of the Administrator the research proposal is approvable.

As one of the criteria for judging the approvability of a research proposal, EPA proposed to examine "whether the proposed level of funding for the project is consistent with the research and development expenditure levels found in other industries." Today's promulgation clarifies that the relevant comparison is to pollution control research expenditure levels in other industries.

Two smelter owners submitted that this criterion should not be given "heavy reliance" because Congress, in enacting section 119, recognized the unique, marginal economic status of the nonferrous industry. In any event, these commenters say, such comparisons should not be based on a report entitled "Characteristics of Nonferrous Smelter Research and Development Efforts," Item No. II–A–5(b) in the docket, because it fails adequately to disaggregate data relating to nonferrous smelters. Other commenters, including lung associations, environmental groups, and academicians felt that smelters should be required to spend research money above the levels in other industries because of the smelter industry's historical lack of commitment to, and at times downright evasion of, pollution control. These commenters stressed that EPA must be in a position to insist that research projects not be shams, and several suggested that an industry-wide commitment of $35 million would be appropriate.

EPA shares the desire that section 119(d)(1)(C)(ii)'s mandate for the commitment of "reasonable" pollution control research be followed in fact. Acting on this desire, EPA contracted before proposal with Energy Analysis Associates, which concluded (in a report filed as number II–A–5 in the docket) that, although one could develop specific criteria to measure whether a commitment is "reasonable," a general, practical formula yielding a "reasonable" level of commitment could not be developed. EPA then hired Development Planning and Research Associates to investigate the amounts that other industries spent on pollution control research. That study, which is filed as number II–A–5(b) in the docket, shows that the nonferrous smelter industry has historically made the smallest expenditures on pollution control research of any major industry, even though smelters generate disproportionate amounts of pollution on a per unit basis. EPA is aware of, and

will take into consideration, the limits of this study. The Administrator has concluded, however, that this comparison is appropriate as one of several criteria in implementing Congress' call for reasonable pollution control research projects and in administering the Clean Air Act on an even-handed basis.

This comparison is not, however, the only criterion. Among the additional factors the Administrator will consider in assessing any proposed project are: (a) The likelihood that the project will result in more effective means of emission limitation applicable to the smelter and the industry; (b) the probability that the project will improve environmental and occupational control of pollutants other than sulfur dioxide; (c) the possible effects of the project on energy conservation; and (d) other non-air quality health and environmental effects. In assessing the adequacy of a particular project, EPA will also consider the current level of sulfur dioxide control at the smelter as well as the resources of the corporation operating the smelter. EPA's emphasis is on pollution control rather than on process changes that may incidentally yield some control improvement. As explained in the proposed rule's preamble, it will ordinarily be necessary to propose projects involving at least pilot-scale operations to secure project approval.

One commenter contended that the proposed research requirement would be unenforceable through the Act's section 304 citizen suit provision because of "vagueness," but EPA's specific, detailed criteria for judging approvability belies this contention. As noted, a rigid formula for determining what is "reasonable" was attempted, but found impracticable. The regulations are flexible enough to allow for serious though differing research proposals, but specific enough to allow for enforcement and fulfillment of congressional intent. In addition to the specific approvability criteria, for example, the regulations provide that the smelter owner's research proposal must include a fully documented supporting analysis and an evaluation of the consistency of the proposed project with the approvability criteria, as well as the proposed project's specific design, time required for implementation, capital and other costs, expected benefits, evaluation criteria, and supervising agents. Independent engineering reports are required on the completion of each significant stage of the project where the smelter conducts its own research, and each applicant must consent to the access of each issuing agency to the project as it develops. In this way EPA insures that research projects are not shams, but are "reasonable" commitments that appear likely to produce significant pollution control gains for the smelter or the industry. The terms of a research project required in an NSO would also be enforceable under section 304.

Finally, one commenter wrote that EPA should require annual progress reports, as well as reports on each significant stage, so that projects which appear to be failing will be caught early. Today's promulgation incorporates this suggestion.

VII. Subpart G—Compliance Schedules

The proposed regulations required that compliance with each NSO provision be achieved as expeditiously as practicable and set forth the maximum intervals EPA believed were consistent with this requirement. EPA established these intervals on the "worst case" assumption that a smelter would not begin to comply with its NSO requirements until the NSO's effective date. 44 FR 6293, 6302–6303.

Several smelter owners commented that the compliance schedules for fugitive controls and reconstruction of the acid plants were too short. The regulations have been modified in light of these comments to allow a smelter to submit its own compliance schedule for control of fugitive emissions. This schedule must require the necessary measures to be completed as expeditiously as practicable, and must be approved by the issuing agency and EPA as an amendment of the NSO. Similarly, EPA is modifying the interim constant control compliance schedule requirement proposed in § 57.702 to allow the smelter owner to demonstrate that more than the proposed amount of time is necessary due to special circumstances. EPA emphasizes, however, that only circumstances that are in fact special will justify a final compliance date more than 14 months beyond the NSO's effective date. In most cases, compliance "as expeditiously as possible" will take less than 14 months. Not only was the 14 month interval based on a "worst case" assumption, as explained, but, as noted elsewhere in this preamble, EPA does not intend wide-scale upgrading of the acid plants as a matter of course.

VIII. Subpart H-Waiver of Interim Constant Control Requirements

Subpart H of the proposed regulations set out the procedures and criteria governing the granting of a waiver of interim constant control requirements where such interim controls would "necessitate" closures for at least one year. Several comments were received on these procedures and criteria, but no change has been made.

One commenter wrote that waiver candidates should not have to submit Appendix A. Appendix A is required from all smelter owners applying for an NSO, and therefore the applicant which also seeks a waiver from interim constant control incurs no additional burden in attaching a completed Appendix A to its waiver request. As explained above, the information specified in Appendix A is necessary to determine, as required by section 119(b)(3), whether the smelter can afford the technology necessary for it to meet its SIP emission limit. It is also necessary to determine, as required by section 119(d)(2), whether the cost of interim controls would necessitate closure of the smelter for at least one year.

Another commenter stated that the public notice provisions regarding waiver requests should apply to action on NSO applications as well. EPA intends to follow the procedures used in evaluating a SIP in proposing to approve an NSO. This involves publishing notice of proposed action in the **Federal Register**, allowing time for submission of written comments, and publishing notice of final action with a response to major comments. These notice procedures comply with the law and enable the public to be informed regarding EPA's action on a request for an NSO. EPA anticipates that the State will hold a hearing on any NSO applications it evaluates.

A State commented that any hearing on a waiver request should be held in the State where the smelter is located. EPA believes the location of the hearing is a decision for the Presiding Officer, who should consider such factors as the convenience to potential hearing witnesses and the State in deciding on an appropriate location.

Finally, a commenter wrote that the regulations should give anyone the opportunity to appear at a hearing and make a statement. As discussed in the preamble to the proposed regulations, the regulations expedite both pre-hearing procedures and final decisions on waiver requests (in part to enable the Administrator to meet the time limit prescribed by Congress), while providing applicants and other interested persons a full opportunity to present pertinent information and views. In particular a would-be hearing participant must file with the Hearing Officer (1) a written request containing certain information necessary for

scheduling, and (2) written comments. Although written comments will constitute the bulk of the evidence submitted at the hearing, "any" person who has filed a request to appear at the hearing may request the Presiding Officer to allow such person to submit all or part of his main comments orally at the hearing in place of written comments. This request must be granted within one week if the Presiding Officer "finds that such person will be prejudiced if he is required to submit such comments in written form." Section 57.805(d)(2). Thus the regulations do give anyone the opportunity to make a statement at a hearing when it is in his interest to do so.

Note.—The Environmental Protection Agency has determined that this notice does not contain a significant regulation requiring a regulatory analysis under Executive Order 12044.

(Secs. 110, 114, 119, and 301 of the Clean Air Act, as amended (42 U.S.C. 7410, 7414, 7419, and 7601), and sec. 406 of Pub. L. 95–95)

Dated: June 13, 1980.

Douglas M. Costle,

Administrator.

The Administrator establishes a new Part 57 in Title 40 of the Code of Federal Regulations, to read as follows:

PART 57—PRIMARY NONFERROUS SMELTER ORDERS

Subpart A—General

Sec.

57.101 Purpose and scope.
57.102 Eligibility.
57.103 Definitions.
57.104 Amendment of the NSO.
57.105 Submittal of required plans, proposals, and reports.
57.106 Expiration date.
57.107 The State agency's transmittal to EPA.
57.108 Comparable existing SIP provisions.
57.109 Maintenance of pay.
57.110 Reimbursement to state or local agency.
57.111 Severability of provisions.

Subpart B—The Application

57.201 Where to apply.
57.202 How to apply.
57.203 Contents of the application.

Subpart C—Constant Controls and Related Requirements

57.301 General requirements.
57.302 Performance level of interim constant controls.
57.303 Total plant-wide emission level.
57.304 Bypass, excess emissions, and malfunctions.
57.305 Compliance monitoring and reporting.

Subpart D—Supplementary Control System Requirements

57.401 General requirements.
57.402 Elements of the supplementary control system.
57.403 Consent to liability.
57.404 Measurements, records, and reports.
57.405 Formulation, approval, and implementation of requirements.

Subpart E—Fugitive Emission Evaluation and Control

57.501 General requirement.
57.502 Evaluation.
57.503 Control measures.

Subpart F—Research and Development Requirements

57.601 General requirements.
57.602 Approval of proposal.
57.603 Criteria for approval.
57.604 Evaluation of projects.
57.605 Consent.
57.606 Confidentiality.

Subpart G—Compliance Schedule Requirements

57.701 General requirements.
57.702 Compliance with constant control emission limitation.
57.703 Compliance with the supplementary control system requirements.
57.704 Compliance with fugitive emission evaluation and control requirements.

Subpart H—Waiver of Interim Requirement for Use of Continuous Emission Reduction Technology

57.801 Purpose and scope.
57.802 Request for waiver.
57.803 Issuance of tentative determination; notice.
57.804 Request for hearing; request to participate in hearing.
57.805 Submission of written comments on tentative determination.
57.806 Presiding officer.
57.807 Hearing.
57.808 Opportunity for cross examination.
57.809 Ex parte contacts.
57.810 Filing of briefs, proposed findings, and proposed recommendation.
57.811 Recommended decision.
57.812 Appeal from or review of recommended decision.
57.813 Final decision.
57.814 Administrative record.
57.815 State notification.
57.816 Effect of negative recommendation.

Appendix A—Primary Nonferrous Smelter Order (NSO) Application

Authority: Secs. 110, 114, 119, 301, Clean Air Act, as amended (42 U.S.C. 7410, 7414, 7419, and 7601); sec. 406 of Pub. L. 95–95.

Subpart A—General

§ 57.101 Purpose and scope.

(a) *Applicability of the regulations.* The regulations in Subparts A through H govern:

(1) The eligibility of smelters for a first Primary Nonferrous Smelter Order (NSO) under section 119 of the Clean Air Act;

(2) The procedures through which a first NSO can be approved or issued by EPA; and

(3) The minimum contents of each first NSO required for EPA issuance or approval under section 119. Subparts I *et seq.*, will contain NSOs in effect for individual smelters.

(b) *State authority to adopt more stringent requirements.* Nothing in this part shall preclude a State from imposing more stringent requirements, as provided by Section 116 of the Clean Air Act.

§ 57.102 Eligibility.

(a) A primary copper, lead, or zinc smelter is eligible for an NSO if it meets the following conditions:

(1) The smelter was in existence and operating on August 7, 1977;

(2) The smelter is subject to an approved or promulgated sulfur dioxide (SO_2) State Implementation Plan (SIP) stack emission limitation which is adequate to ensure that National Ambient Air Quality Standards (NAAQS) for SO_2 are achieved without the use of any unauthorized dispersion techniques; and

(3) The Administrator determines, based on a showing by the smelter owner, that no means of emission limitation applicable to the smelter which would enable it to comply with its SIP stack emission limitation for SO_2 has been adequately demonstrated to be reasonably available (taking into account the cost of compliance, nonair quality health and environmental impact, and energy considerations).

(b) For the purposes of this section:

(1) The following means of emission limitation shall be considered *adequately demonstrated* for copper, lead, and zinc smelters (taking into account nonair quality health and environmental impact and energy considerations, but not the cost of compliance):

(i) The sulfuric acid plant and associated process technology underlying EPA's new source performance standards for primary copper, lead, and zinc smelters (40 CFR Part 60, Subparts P, Q, and R);

(ii) Magnesium oxide concentration (scrubbing);

(iii) Lime/limestone scrubbing; and

(iv) Ammonia scrubbing.

(2) An applicable means of emission limitation which would enable a smelter to comply with its SIP emission limitation for SO_2 shall be considered *reasonably available* to the smelter (taking into account the cost of compliance) if the information submitted under §§ 57.107(a) and 57.203(b) (plus any necessary supplemental information) shows, according to the criteria, procedures, and tests contained in Appendix A to this part, that (after

the installation of the system) the sum of the present value of the smelter's future net income plus its terminal value would exceed the smelter's liquidation (salvage) value.

(3) For the purposes of this section, each adequately demonstrated means of emission limitation which would enable a smelter to comply with its SIP emission limitation for SO_2 shall be considered *applicable* to the smelter unless the smelter operator demonstrates that the use of a particular system at that smelter is technically unreasonable, *for reasons specific to that site.*

§ 57.103 Definitions.

(a) *The Act* means the Clean Air Act, as amended.

(b) *Active use* refers to an SO_2 constant control system installed at a smelter before August 7, 1977 and not totally removed from regular service by that date.

(c) *Adequate SO_2 emission limitation* means an SIP stack emission limitation which was approved or promulgated by EPA as adequate to attain and maintain the NAAQS in the areas affected by the stack emissions without the use of any unauthorized dispersion technique.

(d) *Administrative Law Judge* means an administrative law judge appointed under 5 U.S.C. 3105 (see also 5 CFR Part 930, as amended by 37 FR 16787), and is synonymous with the term "Hearing Examiner" as formerly used in Title 5 of the United States Code.

(e) The *Administrator* means the Administrator of the United States Environmental Protection Agency, or the Administrator's authorized representative.

(f) *Ambient air* shall have the meaning given by 40 CFR 50.1(e), as that definition appears upon promulgation of this subpart, or as hereafter amended.

(g) *Ambient air quality* refers only to concentrations of sulfur dioxide in the ambient air, unless otherwise specified.

(h) *An approved measure* refers to one contained in an NSO which is in effect.

(i) *Assistant Administrator for Air, Noise & Radiation* means the Assistant Administrator for Air, Noise & Radiation of the United States Environmental Protection Agency.

(j) *Assistant Administrator for Enforcement* means the Assistant Administrator for Enforcement of the United States Environmental Protection Agency.

(k) *Constant controls, control technology,* and *continuous emission reduction technology* mean systems which limit the quantity, rate, or concentration of emissions of air pollutants on a continuous basis.

(l) *Effective date of an NSO* means the effective date listed in the **Federal Register** publication of EPA's issuance or approval of an NSO.

(m) *EPA* and the *Agency* means the Administrator of the United States Environmental Protection Agency, or the Administrator's authorized representative.

(n) *Fugitive emissions* means any air pollutants emitted to the atmosphere other than from a stack.

(o) *Issuance* of an NSO means the final transmittal of the NSO pursuant to § 57.107(a) by an issuing agency (other than EPA) to EPA for approval, or the publication of an NSO issued by EPA in the **Federal Register.**

(p) *Issuing agency,* unless otherwise specifically indicated, includes both EPA and the state or local air pollution control agency to which a smelter's owner has applied for an NSO, or which has issued the NSO. Any showings or demonstrations required to be made under this part to the issuing agency are subject to independent determinations by EPA.

(q) *Judicial Officer* means an attorney who is a permanent or temporary employee of the United States Environmental Protection Agency.

(r) *Malfunction* means any unanticipated and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor design, poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions. A malfunction exists only for the minimum time necessary to implement corrective measures.

(s) *Maximum production capacity* means either the maximum demonstrated rate at which a smelter has produced its principal metallic final product under the process equipment configuration and operating procedures prevailing on or before August 7, 1977, or a rate which the smelter is able to demonstrate by calculation is attainable with existing process equipment. The rate may be expressed as a concentrate feed rate to the smelter.

(t) *NAAQS* and *National Ambient Air Quality Standards,* unless otherwise specified, refer only to the National Primary and Secondary Ambient Air Quality Standards for sulfur dioxide.

(u) *Scheduled maintenance* means any periodic procedure, necessary to maintain the integrity or reliability of emissions control performance, which can be anticipated and scheduled in advance. In sulfuric acid plants, it includes among other items the screening or replacement of catalyst, the re-tubing of heat exchangers, and the routine repair and cleaning of gas cleaning equipment.

(v) *Smelter owner* and *operator* mean the owner or operator of the smelter, without distinction.

(w) *Supplementary control system* (SCS) means any technique for limiting the concentration of a pollutant in the ambient air by varying the emissions of that pollutant according to atmospheric conditions. For the purposes of this part, the term supplementary control system does not include any dispersion technique based solely on the use of a stack the height of which exceeds good engineering practice (as determined under regulations implementing section 123 of the Act).

(x) *Unauthorized dispersion technique* refers to any dispersion technique which, under section 123 of the Act and the regulations promulgated pursuant to that section, may not be used to reduce the degree of emission limitation otherwise required in the applicable SIP.

(y) Unless otherwise specified in this part, all terms shall have the same meaning given them by the Act.

§ 57.104 Amendment of the NSO.

An NSO shall be amended whenever necessary for compliance with the requirements and purposes of this part.

(a) *Issuance of amendment.* A state or local issuing agency may issue an amendment of any NSO it has issued. Any amendment issued by a State or local issuing agency shall be subject to approval by EPA to the same extent as was the original NSO. Any smelter owner may apply to the agency which originally issued its NSO for an amendment of the NSO at any time. Such an application shall be accompanied by whatever documentation is required by that agency (or EPA) to support the requested amendment.

(b) *Revision of SCS Manual.* Operation in accordance with the revised provisions of an SCS operational manual (see § 57.402(e)) shall not be considered a violation of an NSO while the application for approval of those revisions as NSO amendments is pending before the issuing agency (or EPA) for approval: *Provided,* That:

(1) no violations of NAAQS occur in the smelter's Designated Liability Area during that time; and

(2) the smelter operator has not been informed by the issuing agency or EPA that its application is not adequately documented, unless such deficiency has been remedied promptly.

(c) *Termination or revocation.* This section shall not apply to termination or revocation of NSOs, or to a requirement for the use of additional systems of continuous emission reduction technology under section 119(d)(4) of the Act.

§ 57.105 Submittal of Required Plans, Proposals, and Reports.

The failure of a smelter owner to submit any plan, report, document or proposal as required by its NSO or by this part shall constitute a violation of its NSO.

§ 57.106 Expiration Date.

Each NSO shall state its expiration date. No first NSO shall expire later than January 1, 1983.

§ 57.107 The State or Local Agency's Transmittal to EPA.

(a) *Content and bases of the State or local agency's NSO.* Issuance of an NSO by a State or local agency shall be completed by the issuing agency's transmittal to the appropriate EPA Regional Office of:

(1) The text of the NSO;

(2) The application submitted by the smelter owner, except for Appendix A to this part, any correspondence between the issuing agency and the applicant relating to the NSO, and any material submitted in support of the application;

(3) A concise statement of the State or local agency's findings and their bases; and

(4) Any documentation or analyses prepared by or for the issuing agency in support of the NSO.

(b) *The State or local agency's enforcement plan.* The transmittal under paragraph (a) of this section shall be accompanied by a description of the issuing agency's plans for monitoring compliance with and enforcement of the NSO. The transmittal shall also include a description of the resources which will be used to implement those plans. If the enforcement plans appear inadequate, EPA may require additional assurances that the NSOs will be adequately enforced.

§ 57.108 Comparable Existing SIP Provisions.

Notwithstanding any other provision of this part, an NSO may contain provisions to which the affected smelter is subject under the applicable EPA-approved state implementation plan (SIP) for sulfur dioxide in lieu of the corresponding provisions which would otherwise be required under this part if the Administrator determines that those SIP provisions are substantially equivalent to the corresponding NSO provisions which would otherwise be required, and if the Administrator determines that the smelter is in substantial compliance with those SIP provisions. For the purposes of this section, provisions to which the affected smelter is subject under the applicable EPA-approved State Implementation Plan are those which became effective before the smelter owner applied for the NSO.

§ 57.109 Maintenance of Pay.

The Administrator will not approve or issue an NSO for any smelter unless he has approved or promulgated SIP provisions which are applicable to the smelter and which satisfy the requirements of section 110(a)(6) of the Clean Air Act.

§ 57.110 Reimbursement to State or local agency.

As a condition of issuing an NSO, any issuing agency may require the smelter operator to pay a fee to the State or local agency sufficient to defray the issuing agency's expenses in issuing and enforcing the NSO.

§ 57.111 Severability of provisions.

The provisions promulgated in this part and the various applications thereof are distinct and severable. If any provision of this part or the application thereof to any person or circumstances is held invalid, such invalidity shall not affect other provisions, or the application of such provisions to other persons or circumstances, which can be given effect without the invalid provision of application.

Subpart B—The Application

§ 57.201 Where to apply.

Any eligible smelter may apply for an NSO to the appropriate EPA Regional Office or to the appropriate State or local air pollution control agency.

(a) When application is made to EPA, all parts of the application required to be submitted under this subpart shall be sent directly to the Director, Division of Stationary Source Enforcement (EN-341), U.S. Environmental Protection Agency, 401 M St. S.W., Washington, D.C. 20460, Attention: Confidential Information Unit. In addition, the smelter owner shall send a copy of the application, except that part required to be submitted under § 57.203(b) (eligibility), directly to the appropriate EPA Regional Office.

(b) When application is made to the appropriate State or local agency, the smelter owner shall submit one complete copy of all parts of the application required to be submitted under this subpart to that agency, in *addition* to the application requirements contained in § 57.201(a), above. If the smelter owner is requesting an advance eligibility determination pursuant to § 57.203(b), such request must be made in writing and shall accompany the copy of the application being sent to the Director of the Division of Stationary Source Enforcement of the Environmental Protection Agency.

(c) If the smelter owner is requesting a waiver of the interim constant control requirement of § 57.301, such request must be sent directly to the Director, Division of Stationary Source Enforcement, at the time of application, in accordance with § 57.802.

§ 57.202 How to apply.

(a) *Letter of intent.* To initiate an application for an NSO, the owner or operator of a smelter shall send a letter of intent to an appropriate air pollution control agency. The letter of intent shall contain a statement of the owner's intent to apply for an NSO, and an agreement to provide any information required under this part. The letter of intent shall be signed by a corporate official authorized to make such commitments. Upon receipt of any letter of intent by the issuing agency, the SIP emission limitation for sulfur dioxide, as to that applicant, shall be deemed suspended for 90 days. The 90 day period may be extended for good cause at the discretion of the Administrator.

(b) *Complete application.* (1) Within the period referred to in paragraph (a) of this section, the smelter owner shall submit its completed application pursuant to § 57.201. Receipt of all parts of a substantially complete application postmarked within the original or extended application period shall be deemed to continue the suspension of the SIP emission limitation for SO_2 until the issuing agency issues or declines to issue an NSO. This suspension shall in all cases terminate, however, 90 days after receipt of the substantially completed application, unless extended for good cause at the discretion of the Administrator. If, in the Administrator's judgment, a good faith effort has been made to submit a complete application, additional time may be granted to allow for correction of minor deficiencies.

(2) If an issuing agency transmits an NSO to EPA for approval before the expiration of the suspension of the federal SIP emission limitation, the suspension shall continue until EPA approves or disapproves the NSO. Such action shall be taken by EPA within 90 days of receipt of a transmittal under § 57.107.

§ 57.203 Contents of the application.

(a) *Claim of confidentiality.* The smelter owner may make a business confidentiality claim covering all or part of the information in the NSO application in accordance with 40 CFR Part 2, Subpart B (41 FR 36906 *et seq.*, September 1, 1976, as amended by 43 FR 39997 *et. seq.*, September 8, 1978). A claim is effective only if it is made at the time the material is submitted to the issuing agency or EPA. A claim shall be made by attaching to the information a notice of confidentiality. Information claimed as confidential will be handled by EPA under the provisions of 40 CFR Part 2, Subpart B. If no claim accompanies the information, it may be made available to the public without further notice.

(b) *Eligibility information.* Each smelter owner shall make the showing required by § 57.102(a)(3) by completing and submitting Appendix A to this part and any necessary supplemental information to the issuing agency as a part of its application. Any smelter owner or State may, at its option, simultaneously submit this material to EPA for an advance eligibility determination.

(c) *Current operating information.* A complete NSO application shall also contain the following information:

(1) A process flow diagram of the smelter, including current process and instrumentation diagrams for all processes or equipment which may emit or affect the emission of sulfur dioxide; the characteristics of all gas streams emitted from the smelter's process equipment (flow rates, temperature, volumes, compositions, and variations over time); and a list of all monitoring data and strip charts, including all data, charts, logs or sheets kept with respect to the operation of any process equipment which may emit or affect the emission of sulfur dioxide;

(2) The smelter's maximum daily production capacity (as defined in § 57.103(s)), as of August 7, 1977; the operational rate (in pounds of charge per hour) of each major piece of process equipment when the smelter is operating at that capacity; and the smelter's average and maximum daily production rate for each product, co-product, or by-product, by year, for the past 2 years;

(3) The optimal conversion efficiency of any acid plant or other sulfur dioxide control system under the normal process operating conditions (excluding malfunctions) most conducive to optimal conversion efficiency;

(4) The average conversion efficiency of any acid plant or other sulfur dioxide control system during normal process operations (excluding malfunctions), by month, during the past 2 years;

(5) The percent of the time the acid plant or other control system was available for service during each month for the past 2 years, excluding down-time for scheduled maintenance, and a full explanation of any major or recurring problems with the system during that time;

(6) The frequency and duration of times during the past 2 years when the SO_2 control system was unavailable because of scheduled maintenance of the system;

(7) A description of all scheduled, periodic shut downs of the smelter during the past 2 years, including their purpose, frequency and duration; and the same information with respect to unscheduled shutdowns;

(8) The gas volume, rates, and SO_2 concentration which the control system was actually designed to accommodate, taking into account any modifications made after its installation;

(9) The average monthly sulfur balance across the process and control equipment, including fugitive emissions, for the past 2 years; and

(10) A description of engineering techniques now in use at the smelter to prevent the release of fugitive emissions into the atmosphere at low elevations.

(d) *The smelter owner's proposals.* The smelter owner shall submit as part of its application draft NSO provisions which would implement the requirements of Subparts C through G of this part. The issuing agency may use these proposals as the basis for any NSO that may be granted, or may modify these proposals in any way it deems necessary in order to comply with the requirements of this part.

(e) *Additional information.* The smelter owner shall designate in its application a corporate officer responsible and authorized to supply supplemental technical and economic information and explanations as required by the issuing agency during the formulation of the NSO. Failure to supply such information and explanations shall constitute a failure to submit a complete application.

(f) *Request for a waiver of constant controls.* Any request for a waiver of the interim constant control requirement of § 57.301 shall be made in accordance with § 57.802. The criteria and procedures for granting the waiver are governed by Subpart H of this part.

Subpart C—Constant Controls and Related Requirements

§ 57.301 General Requirements.

Each NSO shall require an interim level of sulfur dioxide constant controls to be operated at the smelter, unless a waiver of this requirement has been granted to the owner under Subpart H of this part. Except as otherwise provided in § 57.304, the interim constant controls shall be properly operated and maintained at all times. The NSO shall require the following gas streams to be treated by interim constant controls:

(a) In copper smelters, off-gases from fluidized bed roasters, flash furnances, NORANDA reactors, electric furnaces and copper converters;

(b) In lead smelters, off-gases from the front end of the sintering machine and any other sinter gases which are re-circulated;

(c) In zinc smelters, off-gases from multi-hearth roasters, flash roasters and fluidized bed roasters; and

(d) In all smelters, any other process streams which were regularly or intermittently treated by constant controls at the smelter as of August 7, 1977.

§ 57.302 Performance Level of Interim Constant Controls.

(a) *Maximum feasible efficiency.* Each NSO shall require: that the smelter operate its interim constant control systems at their maximum feasible efficiency, including the making of any improvements necessary to correct the effects of any serious deficiencies; that the process and control equipment be maintained in the way best designed to ensure such operation; and that process operations be scheduled and coordinated to facilitate treatment of process gas streams to the maximum possible extent. Maximum feasible efficiency shall be expressed in the NSO in the form of a limitation on the concentration of SO_2 in the tail gas of each individual control system in combination with an appropriate averaging period, as provided below in paragraphs (b) and (c) of this section.

(b) *The limitation level for SO_2 concentration in the control system tail gas.* The level at which the concentration limitation is set shall take into account fluctuations in the strength and volume of process off-gases to the extent that those fluctuations affect the SO_2 content of the tail gas and cannot be avoided by improved scheduling and coordination of process operations. The limitation shall exclude the effect of any increase in emissions caused by process or control equipment malfunction. The limitation shall take into account

unavoidable catalyst deterioration in sulfuric acid plants, but may prescribe the frequency of catalyst screening or replacement. The NSO shall also prohibit the smelter owner from using dilution air to meet the limitation.

(c) *Averaging period.* (1) The averaging period shall be derived in combination with the concentration limitation and shall take into account the same factors described in paragraph (b). The averaging periods established under this paragraph should generally not exceed the following:

(i) For sulfuric acid plants on copper smelters, 12 hour running average;

(ii) For sulfuric acid plants on lead smelters, 6 hour running average;

(iii) For sulfuric acid plants on zinc smelters, 2 hour running average;

(iv) For dimethylaniline (DMA) scrubbing units on copper smelters, 2 hour running average.

(2) A different averaging period may be established if the applicant demonstrates that such a period is necessary in order to account for the factors described in paragraph (b) of this section: *Provided,* That the period is enforceable and satisfies the criteria of paragraph (a) of this section.

(d) *Improved performance.* (1) The performance level representing maximum feasible efficiency for any existing control system (*e.g.,* a sulfuric acid plant or a DMA scrubber) shall require the correction of the effects of any serious deficiencies in the system. For the purpose of this paragraph, at least the following problems shall constitute serious deficiencies in acid plants:

(i) Heat exchangers and associated equipment inadequate to sustain efficient, autothermal operation at the average gas strengths and volumes received by the acid plant during routine process equipment operation;

(ii) Failure to completely fill all available catalyst bed stages with sufficient catalyst;

(iii) Inability of the gas pre-treatment system to prevent unduly frequent plugging or fouling (deterioration) of catalyst or other components of the acid plant; or

(iv) Blower capacity inadequate to permit the treatment of the full volume of gas which the plant could otherwise accommodate, or in leakage of air into the flues leading to the plant, to the extent that this inadequacy results in bypassing of gas around the plant.

(2) Notwithstanding any contrary provisions of § 57.304(c) (malfunction demonstration), no excess emissions (as defined in § 57.304(a)) shall be considered to have resulted from a malfunction in the constant control system if the smelter owner has not upgraded serious deficiencies in the constant control system in compliance with the requirements of § 57.302(d)(1), unless the smelter owner demonstrates under § 57.304(c) that compliance with those requirements would not have affected the magnitude of the emission.

(e) *Multiple control devices.* (1) At any smelter where off-gas streams are treated by various existing control systems (*e.g.,* multiple acid plants or a DMA scrubber and an acid plant), the NSO shall require the use of those systems in the combination that will result in the maximum feasible net SO_2 removal.

(2) To the extent that compliance with this requirement is demonstrated by the smelter operator to result in excess emissions during unavoidable start up and shut down of the control systems, those excess emissions shall not constitute violations of the NSO.

§ 57.303 Total Plantwide Emission Limitation.

(a) *Calculation of the emission limitation.* Each NSO shall contain a requirement limiting the total allowable emissions from the smelter to the level which would have been associated with production at the smelter's maximum production capacity (as defined in § 57.103(s)) as of August 7, 1977. This limitation shall be expressed in units of mass per time and shall be calculated as the sum of uncontrolled process and fugitive emissions, and emissions from any control systems (operating at the efficiency prescribed under § 57.302). These emission rates may be derived from either direct measurements or appropriately documented mass balance calculations.

(b) *Compliance with the emission limitation.* Each NSO shall require the use of specific, enforceable testing methods and measurement periods for determining compliance with the limitation established under paragraph (a) of this section.

§ 57.304 Bypass, Excess Emissions and Malfunctions.

(a) *Definition of excess emissions.* For the purposes of this subpart, any emissions greater than those permitted by the NSO provisions established under § 57.302 (performance level of interim constant controls) or § 57.303 (plantwide emission limitation) of this subpart shall constitute excess emissions. Emission of any gas stream identified under § 57.301 (a), (b), (c), or (d) of this subpart that is not treated by a sulfur dioxide control system shall also constitute an excess emission under this subpart.

(b) *The excess emission report.* Each NSO shall require the smelter to report all excess emissions to the issuing agency, as provided in § 57.305(b). The report shall include the following:

(1) Identity of the stack or other emission points where the excess emissions occurred;

(2) Magnitude of the excess emissions expressed in the units of each applicable emission limitation, as well as the operating data, documents, and calculations used in determining the magnitude of the excess emissions;

(3) Time and duration of the excess emissions;

(4) Identity of the equipment causing the excess emissions;

(5) Nature and cause of such excess emissions;

(6) Steps taken to limit the excess emissions, and when those steps were commenced;

(7) If the excess emissions were the result of a malfunction, the steps taken to remedy the malfunction and to prevent the recurrence of such malfunction; and

(8) At the smelter owner's election, the demonstration specified in paragraph (c) of this section.

(c) *Malfunction demonstration.* Except as provided in § 57.302(e)(2) or in paragraph (d) or (e) of this section, any excess emission shall be a violation of the NSO unless the owner demonstrates in the excess emissions report required under paragraph (b) of this section that the excess emission resulted from a malfunction (or an unavoidable start up and shut down resulting from a malfunction) and that:

(1) The air pollution control systems, process equipment, or processes were at all times maintained and operated, to the maximum extent practicable, in a manner consistent with good practice for minimizing emissions;

(2) Repairs were made as expeditiously as practicable, including the use of off-shift labor and overtime;

(3) The amount and duration of the excess emissions were minimized to the maximum extent practicable during periods of such emissions; and

(4) The excess emissions were not part of a recurring pattern indicative of serious deficiencies in, or inadequate operation, design, or maintenance of, the process or control equipment.

(d) *Scheduled maintenance exception.* Excess emissions occuring during scheduled maintenance shall not constitute violations of the NSO to the extent that:

(1) The expected additional annual sulfur dioxide removal by any control system (including associated process changes) for which construction had not

commenced (as defined in 40 CFR 60.2(g) and (i)) as of August 7, 1977, and which the smelter owner agrees to install and operate under Subpart F, would have offset such excess emissions if the system had been in operation throughout the year in which the maintenance was performed;

(2) The system is installed and operated as provided in the NSO provisions established under Subpart F; and

(3) The system performs at substantially the expected efficiency and reliability subsequent to its initial break-in period.

(e) An NSO may provide that excess emissions which occur during acid plant start-up as the result of the cooling of acid plant catalyst due to the unavailability of process gas to an acid plant during a prolonged SCS curtailment are not excess emissions. If the NSO does so provide, it shall also require the use of techniques or practices designed to minimize these excess emissions, such as the sealing of the acid plant during prolonged curtailments, the use of auxiliary heat or SO_2 injected during the curtailment, or the preheating of the acid plant before start-up of the process equipment it serves.

§ 57.305 Compliance monitoring and reporting.

(a) *Monitoring.* (1) Each NSO shall require compliance with the control system performance requirements established pursuant to this subpart to be determined through the use of continuous monitors for measuring SO_2 concentration.

(i) Such monitors must be installed, operated and maintained in accordance with the performance specifications and other requirements contained in Appendix D to 40 CFR Part 52 or Part 60. The monitors must take and record at least one measurement of SO_2 concentration from the effluent of each control system in each 15 minute period. Failure of the monitors to record at least 95% of the 15-minute periods in any 30-day period shall constitute a violation of the NSO.

(ii) The sampling point shall be located at least 8 stack diameters (diameter measured at sampling point) downstream and 2 diameters upstream from any flow disturbance such as a bend, expansion, constriction, or flame, unless another location is approved by the Administrator.

(iii) The sampling point for monitoring emissions shall be in the duct at the centroid of the cross section if the cross sectional area is less than 4.645m^2 (50 ft^2) or at a point no closer to the wall than 0.914m (3 ft) if the cross sectional area is 4.645m^2 (50 ft^2) or more. The monitor sample point shall be in an area of small spatial concentration gradient and shall be representative of the concentration in the duct.

(iv) The measurement system(s) installed and used pursuant to this paragraph shall be subject to the manufacturer's recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless the manufacturer specifies or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed. Records of these procedures shall be made which clearly show instrument readings before and after zero adjustment and calibration.

(v) The use of manual source testing methods (equivalent to 40 CFR Part 60, Appendix A) may also be specified as an acceptable additional (but not alternative) method for making compliance determinations.

(2) Each NSO shall require the monitoring of any ducts or flues used to bypass gases, required under this subpart to be treated by constant controls, around the smelter's sulfur dioxide constant control system(s) for ultimate discharge to the atmosphere. Such monitoring shall be adequate to disclose the time of the bypass, its duration, and the approximate volume of gas bypassed.

(b) *Reporting.* (1) Each NSO shall require that the smelter maintain a record of all measurements required under paragraph (a) of this section. Results shall be summarized monthly and shall be submitted to the issuing agency within 15 days after the end of each month. The smelter owner shall retain a record of such measurements for the duration of the NSO and for as long thereafter as may be necessary for the purpose of including such records in an application for a second NSO.

(2) Each NSO shall require that the smelter maintain a record of all measurements and calculations required under § 57.303(b). Results shall be summarized on a monthly basis and shall be submitted to the issuing agency to 6-month intervals. The smelter owner shall retain a record of such measurements and calculations for the duration of the NSO and for as long thereafter as may be necessary for the purposes of including such information in an application for a second NSO.

(3) The report required under § 57.304(b) shall accompany the report required under paragraph (b)(1) of this section.

Subpart D—Supplementary Control System Requirements

§ 57.401 General requirement.

Except as provided in Subpart E, each NSO shall require the smelter owner to prevent all violations of the NAAQS in the smelter's designated liability area (DLA) through the operation of an approved supplementary control system (SCS).

§ 57.402 Elements of the supplementary control system.

Each supplementary control system shall contain the following elements:

(a) *Air quality monitoring network.* An approvable SCS shall include the use of appropriate ambient air quality monitors to continuously measure the concentration of sulfur dioxide in the air in the smelter's DLA.

(1) The monitors shall be located at all points of expected high SO_2 concentrations necessary to anticipate and prevent possible violations of NAAQS anywhere in the smelter's DLA. The determination of the locations where such concentrations may occur shall take into account all recorded or probable meteorological and operating conditions (including bypassing of control equipment), as well as the presence of other sources of SO_2 significantly affecting SO_2 concentrations in the DLA.

(2) The number and location of sites shall be based on dispersion modeling, measured ambient air quality data, meteorological information, and the results of the continuing review required by paragraph (f) of this section. The system shall include the use of at least 7 fixed monitors unless the issuing agency determines, on the basis of a demonstration by the smelter owner, that the use of fewer monitors would not limit coverage of points of high SO_2 concentration or otherwise reduce the capability of the smelter owner to prevent all violations of the NAAQS in the smelter's DLA.

(3) All monitors shall be continuously operated and maintained and shall meet the performance specifications contained in 40 CFR Part 53. The monitors shall be capable of routine real time measurement of maximum expected SO_2 concentrations for the averaging times of SO_2 NAAQS.

(b) *Meteorological network.* The SCS must have a meteorological assessment capability adequate to predict and identify local conditions requiring emission curtailment to prevent possible violations of the NAAQS. The meteorological assessment capability shall provide all forecast and current information necessary for successful use

of the SCS operational manual required by paragraph (e) of this section.

(c) *Designated liability area.* The system shall be required to prevent all violations of the NAAQS within the smelter's DLA. The DLA of any smelter is the area within which the smelter's emissions may cause or significantly contribute to violations of the NAAQS for SO_2 when the smelter is operating at its maximum production capacity under any recorded or probable meteorological conditions. The boundaries of that area shall be specified in the NSO.

(1) Unless an acceptable demonstration is made under paragraph (c)(2) of this section, the DLA shall be a circle with a center point at the smelter's tallest stack and a minimum radius as given in the following table:

Radius for SO_2 Emissions at Maximum Production Capacity.*

Emission rate in tons per hour	Emission Rate in grams per sec.	Radius in kilometers
16 or less	4,000 or less	11
24	6,000	16
32	8,000	24
40	10,000	32
48 or more	12,000 or more	40

*Maximum emission rates for periods not to exceed 24 hours.

Minimum radii may be determined from the table by linear interpolation.

(2) The NSO may provide for a DLA with different boundaries if the smelter owner can demonstrate through the use of appropriate dispersion modeling and ambient air quality monitoring data that the smelter's controlled emissions could not cause or significantly contribute to a violation of the NAAQS beyond the boundaries of such a different area under any recorded or probable meteorological conditions.

(3) A violation of the NAAQS in the DLA of any smelter shall constitute a violation of that smelter's NSO, unless the issuing agency determines on the basis of a showing by the smelter owner that the smelter owner had taken all emission curtailment action indicated by the SCS operational manual and that the violation was caused in significant part by:

(i) Emissions of another source(s) which were in excess of the maximum permissible emissions applicable to such source(s),

(ii) Fugitive emissions of another source(s), or

(iii) Except as provided by § 57.703(a), the smelter's own fugitive emissions: *Provided,* That the smelter is in compliance with all requirements of or under subpart E of this Part.

(4) For the purposes of this section, maximum permissible emissions for other sources are the highest of:

(i) SIP emission limitation

(ii) Orders in effect under section 113(d) of the Clean Air Act; or

(iii) Compliance date extensions under former section 119 of the Clean Air Act (relating to coal conversions).

(d) *Overlapping designated liability areas.* Notwithstanding any other provisions of this subpart, the following requirements shall apply whenever the designated liability areas of 2 or more smelters do, or may, overlap:

(1) in the case of any NSO applicant that would have a DLA which would overlap with the DLA of any other smelter that has applied for an NSO or has an NSO in effect, the NSO applicant shall include in its application an enforceable joint plan, agreed to by such other smelter(s). In determining whether a joint plan is required, the NSO applicant shall calculate its DLA according to the table in paragraph (c)(1) of this section. The DLA of the other smelter shall be calculated according to the table in paragraph (c)(1) unless the other smelter has an NSO in effect, in which case the boundaries in that NSO shall be used. The enforceable joint plan shall provide for:

(i) Emission curtailment adequate to ensure that the NAAQS will not be violated in any areas of overlapping DLAs; and

(ii) Conclusive prospective allocation of legal liability in the event that the NAAQS are violated in the area of overlapping DLAs.

Such plans may, but need not, include the operation of a joint SCS system. Each NSO shall require adherence by the NSO applicant owner to the joint plan for emission curtailment and allocation of liability, unless the issuing agency determines, pursuant to the provisions of paragraph (c)(2) of this section, that the NSO applicant's DLA does not overlap with that of any other smelter.

(2) In the case of any NSO applicant that would have a DLA which would overlap with the DLA of any other smelter whose owner has not applied for an NSO (and does not have an NSO in effect), the NSO applicant's submittal shall contain a written consent, signed by a corporate official empowered to do so. The consent shall state that if, at any time thereafter, the owner of the other smelter applies for an NSO, and the other smelter's DLA would overlap with the NSO applicant's DLA, the NSO applicant will negotiate and submit an enforceable joint plan for emission curtailment and allocation of liability (as described in paragraph (d)(1) of this section). In determining whether it is necessary to submit such a consent, each smelter's DLA shall be calculated according to the table set forth in paragraph (c)(1) of this section. The consent shall state that a joint plan shall be submitted within 90 days of the issuing agency's notification to the NSO applicant of receipt of the other smelter's letter of intent, unless the issuing agency determines that the DLAs do not overlap. Failure of the NSO applicant to submit such a plan shall constitute grounds for denial of its NSO application or a violation of an effective NSO, as applicable.

(e) *The SCS operational manual.* Each NSO shall require the smelter to be operated in accordance with the provisions of an SCS operational manual approved by the issuing agency. The SCS operational manual shall describe the circumstances under which, the extent to which, and the procedures through which emissions shall be curtailed to prevent violations of the NAAQS in the smelter's DLA. Failure to curtail emissions when and as much as indicated by the manual or to follow the provisions of the manual implementing the requirements of subparagraph (3) of this paragraph shall constitute a violation of the NSO.

(1) The operational manual shall prescribe emission curtailment decisions based on the use of real time information from the air quality monitoring network dispersion model estimates of the effect of emissions on air quality, and meteorological observations and predictions.

(2) The operational manual shall also provide for emission curtailment to prevent violation of the NAAQS within the smelter's DLA which may be caused in part by stack emissions, and to the extent practicable fugitive emissions, from any other source (unless that other source is a smelter subject to an NSO).

(3) The SCS operational manual shall include (but not be limited to):

(i) A clear delineation of the authority of the SCS operator to require all other smelter personnel to implement the operator's curtailment decisions;

(ii) The maintenance and calibration procedures and schedules for all SCS equipment;

(iii) A description of the procedures to be followed for the regular acquisition of all meteorological information necessary to operate the system;

(iv) The ambient concentrations and meteorological conditions that will be used as criteria for determining the need for various degrees of emission curtailment;

(v) The meteorological variables as to which judgments may be made in

applying the criteria stated pursuant to subparagraph (e)(3)(iv) of this section;

(vi) The procedures through which and the maximum time period within which a curtailment decision will be made and implemented by the SCS operator;

(vii) The method for immediately evaluating the adequacy of a particular curtailment decision, including the factors to be considered in that evaluation;

(viii) The procedures through which and the time within which additional necessary curtailment will immediately be effected; and

(ix) The procedures to be followed to protect the NAAQS in the event of a mechanical failure in any element of the SCS.

(f) *Continuing review and improvement of the SCS.* Each NSO shall require the smelter owner to conduct an active program to continuously review the design and operation of the SCS to determine what measures may be available for improving the performance of the system. Among the elements of this program shall be measures to locate and examine possible places both inside and outside the DLA where unmonitored NAAQS violations may be occurring. Such measures shall include the use of modelling as appropriate and mobile ambient air quality monitors, following up on information and complaints from members of the public, and other appropriate activities. The NSO shall also require the submission of a semi-annual report to the issuing agency detailing the results of this review and specifying measures implemented to prevent the recurrence of any violations of NAAQS.

§ 57.403 Written consent.

(a) *The consent.* The NSO shall include a written consent, signed by a corporate official empowered to do so, in the following form:

As a condition of receiving a Primary Nonferrous Smelter Order (NSO) under section 119 of the Clean Air Act for the smelter operated by (*name of company*) at (*location*), the undersigned official, being empowered to do so, consents for the company as follows:

(1) In any judicial or administrative proceeding to enforce the NSO, the company will not contest:

(a) Liability for any violation of the National Ambient Air Quality Standards for sulfur dioxide in the smelter's designated liability area (DLA), except on the ground that a determination under 40 CFR 57.402(c)(3) was clearly wrong; or

(b) The conclusive allocation of liability under NSO provisions satisfying 40 CFR 57.402(d)(1) between the company's smelter and any other smelter(s) for any violation of the National Ambient Air Quality Standards for sulfur dioxide in an area of overlapping DLAs.

(2) The issuing agency (as defined in 40 CFR 57.103) will be allowed unrestricted access at reasonable times to inspect, verify calibration of, and obtain data from ambient air quality monitors operated by the company under the requirements of the NSO.

(b) *Rights not waived by the consent.* This consent shall not be deemed to waive:

(1) Any right(s) to judicial review of any provisions of an NSO that are otherwise available to the smelter owner or operator under section 307(b) of the Clean Air Act; or

(2) The right to contest, in any forum, that any violation of an NSO was committed "knowingly" within the meaning of section 113(c) of the Clean Air Act.

§ 57.404 Measurements, records, and reports.

(a) *Measurements.* Each NSO shall require the smelter owner to install, operate, and maintain a measurement system(s) for continuously monitoring sulfur dioxide emissions and stack gas volumetric flow rates in each stack (except a stack used exclusively for bypassing control equipment) which could emit 5 percent or more of the smelter's total potential (uncontrolled) hourly sulfur dioxide emissions.

(1) Such monitors shall be installed, operated, and maintained in accordance with the performance specifications and other requirements contained in Appendices D and E to 40 CFR Part 52. The monitors must take and record at least one measurement of sulfur dioxide concentration and stack gas flow rate from the effluent of each affected stack in each fifteen-minute period. (The NSO shall require the smelter operator to devise and implement any procedures necessary for compliance with these performance specifications.

(2) The sampling point shall be located at least eight stack diameters (diameter measured at sampling point) downstream and two diameters upstream from any flow disturbance such as a bend, expansion, constriction, or flame, unless another location is approved by the Administrator.

(3) The sampling point for monitoring emissions shall be in the duct at the centroid of the cross section if the cross sectional area is less than 4.645 m^2 (50 ft^2) or at a point no closer to the wall than 0.914m (3ft.) if the cross sectional area is 4.645 m^2 (50 ft^2) or more. The monitor sample point shall be in an area of small spatial concentration gradient and shall provide a sample which is representative of the concentration in the duct.

(4) The measurement system(s) installed and used pursuant to this paragraph shall be subject to the manufacturer's recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless the manufacturer specifies or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed. Records of these procedures shall be made which clearly show instrument readings before and after zero adjustment and calibration.

(5) The results of such monitoring, calibration, and maintenance shall be submitted in the form and with the frequency specified in the NSO.

(b) *Records.* Each NSO shall require the smelter owner to maintain records of the air quality measurements made, meteorological information acquired, emission curtailment ordered (including the identity of the persons making such decisions), and calibration and maintenance performed on SCS monitors during the operation of the SCS. These records shall be maintained for the duration of the NSO, and for as long thereafter as may be necessary for purposes of applying for a second NSO, and shall be furnished to the issuing agency upon request.

(c) *Reports.* Each NSO shall require the smelter owner to:

(1) Submit a monthly summary indicating all places and times at which the NAAQS for SO_2 were violated in the smelter's DLA, and stating the SO_2 concentrations at such times;

(2) Immediately notify EPA and the state agency any time concentrations of SO_2 in the ambient air in the smelter's DLA reaches 0.3 part per million (800 micrograms/cubic meter), 24-hour average, or exceed the warning stage in any more stringent emergency plan in the applicable state implementation plan; and

(3) Make such other reports as may be specified in the NSO.

§ 57.405 Formulation, approval, and implementation of requirements.

(a) *SCS content of the application.* The requirements of § 57.203(d) shall be satisfied with respect to this subpart as follows:

(1) Each NSO application shall include a complete description of any supplementary control system in operation at the smelter at the time of application and a copy of any SCS operational manual in use with that system.

(2) Each NSO application shall contain proposed NSO provisions for

compliance with the requirements of §§ 57.401, 57.402 (c), (d), and (f), 57.403, 57.404, and 57.405(b)(2).

(3) Each NSO application shall include a specific plan for the development of a system fulfilling the requirements of § 57.402 (a), (b), and (e) (covering air quality monitoring network, meteorological network, and the SCS operational manual).

(b) *SCS content of the order.* (1) Each NSO shall include an approved version of the plan described in paragraph (a)(3) of this section and shall provide increments of progress towards its completion.

(2) Each NSO shall require the submission of a final report evaluating the performance and adequacy of the SCS developed pursuant to the approved plan. The report shall include:

(i) A detailed description of how the criteria that form the basis for particular curtailment decisions were derived;

(ii) A complete description of each SCS element listed in § 57.402 (a) through (d) (covering monitoring, meteorology, and the DLA), and an explanation of why the elements fulfill the requirements of those sections;

(iii) A reliability study demonstrating that the SCS will prevent violations of the NAAQS in the smelter's DLA at all times. The reliability study shall include a comprehensive analysis of the system's operation during one or more three-month seasonal periods when meteorological conditions creating the most serious risk of NAAQS violations are likely to occur; and

(iv) A copy of the current SCS operational manual.

(c) *Amendment of the NSO.* Each NSO shall be amended, after the submission of the final report required under paragraph (b)(2) of this section, to reflect the most current approved elements of the SCS and to fulfill all other requirements of this subpart. Each NSO shall also be subsequently amended (as provided in § 57.104) whenever necessary as a result of the program required by § 57.402(f) or to reflect improved SCS operating procedures or other system requirements.

Subpart E—Fugitive Emission Evaluation and Control

§ 57.501 General Requirement.

Each NSO shall require the smelter owner to use such control measures as may be necessary to ensure that the smelter's fugitive emissions do not result in violations of the NAAQS for SO_2 in the smelter's DLA.

§ 57.502 Evaluation.

(a) *Evaluation at the time of application.* Any smelter owner may demonstrate at the time of application for an NSO that the smelter's SO_2 fugitive emissions will not cause or significantly contribute to violations of the NAAQS in the smelter's DLA. If such demonstration is not made, the smelter owner shall submit the design and workplan for a study adequate to assess the sources of significant fugitive emissions from the smelter and their effects upon ambient air quality.

(b) *Evaluation during the first 6 months of the NSO.* The design and workplan of the study shall be approved by the issuing agency and included in the NSO. The study shall commence upon the date when the NSO becomes effective, and an analysis of its results shall be submitted to the issuing agency within the time provided by the NSO. The study shall include an appropriate period during which the ambient air shall be monitored to determine the impact of fugitive emissions of sulfur dioxide, arsenic (at copper smelters only), lead (at lead and zinc smelters only), and total suspended particulates on the ambient air quality in the smelter's DLA.

§ 57.503 Control measures.

The NSO of any smelter subject to the requirements of § 57.502(b) shall be amended as provided in § 57.704(d) to implement the requirement of § 57.501. Measures required to be implemented may include:

(a) *Additional supplementary control.* The use of the supplementary control system, if the additional use of the system does not interfere with the smelter owner's ability to meet the requirements of Subpart D; and

(b) *Engineering and maintenance techniques.* The use of engineering and maintenance techniques to detect and prevent leaks and capture and vent fugitive emissions through appropriate stacks. These techniques include but are not limited to:

(1) For reactors, installation and proper operation of primary hoods;

(2) For roasters, installation and proper operation of primary hoods on all hot calcine transfer points;

(3) For furnaces, installation and proper operation of primary hoods on all active matte tap holes, matte launders, slag skim bays, and transfer points;

(4) For converters, installation and proper operation of primary hoods for blowing operations, and where appropriate, secondary hoods for charging and pouring operations;

(5) For sintering machines, installation and proper operation of primary hoods on the sinter bed, all hot sinter ignition points, all concentrate laydown points, and all hot sinter transfer points;

(6) For blast furnaces, installation and proper operation of primary hoods on all active slag and lead bullion furnace tap holes and transfer points;

(7) For dross reverberatory furnaces, installation and proper operation of primary hoods on all active charging and discharging points;

(8) Maintenance of all ducts, flues and stacks in a leak-free condition to the maximum extent possible;

(9) Maintenance of all process equipment under normal operating conditions in such a fashion that out-leakage of fugitive gases will be prevented to the maximum extent possible;

(10) Secondary or tertiary hooding on process equipment where necessary; and

(11) Partial or complete building evacuation as appropriate.

Subpart F—Research and Development Requirements

§ 57.601 General requirement.

Each NSO shall require the smelter to conduct or participate in a specific research and development program designed to develop more effective means of compliance with the sulfur dioxide control requirements of the applicable state implementation plan than presently exist.

§ 57.602 Approval of proposal.

(a) *The smelter owner's proposal.* The smelter owner's NSO application shall include a proposed NSO provision for implementing the requirement of § 57.601, a fully documented supporting analysis of the proposed program, and an evaluation of the consistency of the proposed program with the criteria listed in § 57.603. The application shall also specify:

(1) The design and substantive elements of the research and development program, including the expected amount of time required for their implementation;

(2) The annual expected capital, operating, and other costs of each element in the program;

(3) The smelter's current production processes, pollution control equipment, and emissions which are likely to be affected by the program;

(4) Potential or expected benefits of the program;

(5) The basis upon which the results of the program will be evaluated; and

(6) The names, positions, and qualifications of the individuals

responsible for conducting and supervising the project.

(b) *EPA approval.* If the issuing agency will not be EPA, the smelter owner or the issuing agency may also submit to EPA the information specified in paragraph (a) of this section at the same time the information is submitted to the issuing agency. As soon as possible after the receipt of the information described in paragraph (a) of this section, EPA shall certify to the issuing agency and to the applicant whether or not in the judgment of the Administrator the smelter owner's final proposals are approvable.

(c) *Optional preproposal.* The smelter owner may, at its option, submit to EPA for its approval and comment a preproposal generally describing the project the owner intends to propose under paragraph (a) of this section. A preproposal may be submitted to EPA at any time prior to the submission of a proposal under paragraph (a) of this section. As soon as possible after the receipt of a preproposal, EPA shall certify to the applicant (and to any other issuing agency, as applicable) whether or not the project would be approvable. This certification may include comments indicating necessary modifications which would make the project approvable.

§ 57.603 Criteria for approval.

The approvability of any proposed research and development program shall be judged primarily according to the following criteria:

(a) The likelihood that the project will result in the use of more effective means of emission limitation by the smelter within a reasonable period of time;

(b) Whether the proposed funding and staffing of the project appear adequate for its successful completion;

(c) Whether the proposed level of funding for the project is consistent with the research and development expenditure levels for pollution control found in other industries;

(d) The potential that the project may yield industrywide pollution control benefits;

(e) Whether the project may also improve control of other pollutants of both occupational and environmental significance;

(f) The potential effects of the project on energy conservation; and

(g) Other non-air quality health and environmental considerations.

§ 57.604 Evaluation of projects.

In any case where the proposed research and development project is to be conducted wholly by one or more smelter owners, the owner's proposal shall include a provision for the employment of a qualified independent engineering firm to evaluate and prepare written reports at least annually and, in any case, on each completed significant stage of the program. In any other case, the proposal shall contain a provision for the preparation of such reports by the person conducting any portion of the project. All reports required by this paragraph shall be submitted to EPA and also to the issuing agency if it is not EPA.

§ 57.605 Consent.

Each NSO shall incorporate by reference a binding written consent, signed by a corporate official empowered to do so, requiring the smelter owner to:

(a) Carry out the approved research and development program;

(b) Grant each issuing agency and their contractors access to any information or data employed or generated in the research and development program, including any process, emissions, or financial records which such agency determines are needed to evaluate the technical or economic merits of the program;

(c) Grant physical access to representatives and contractors of each issuing agency to each facility at which such research is conducted;

(d) Grant the representatives and contractors of EPA and the issuing agency reasonable access to the persons conducting the program on behalf of the smelter owner for discussions of progress, interpretation of data and results, and any other similar purposes as deemed necessary by any issuing agency.

§ 57.606 Confidentiality.

The provisions of section 114 of the Act and 40 CFR Part 2 shall govern the confidentiality of any data or information provided to EPA under this subpart.

Subpart G—Compliance Schedule Requirements

§ 57.701 General requirements.

Each NSO shall require the smelter owner to meet all of the requirements of the NSO as expeditiously as practicable. All NSO requirements shall be immediately effective, except to the extent that the owner is able to demonstrate the necessity for additional time. For requirements not immediately effective, the NSO shall provide increments of progress and schedules for compliance. The schedules set forth in this subpart represent the most expeditious compliance practicable only for those smelters which do not currently have the equipment or systems required by this part.

§ 57.702 Compliance with constant control emission limitation.

Where necessary, each NSO shall require the smelter owner to submit to the issuing agency, within 30 days of the effective date of the NSO, a proposed scheduled for compliance with the requirements of Subpart C. No final compliance date shall extend beyond 14 months of the effective date of the NSO, except: For a smelter having no constant controls installed on the effective date, or where the smelter operator demonstrates that special circumstances require more time. The schedule shall include the following increments of progress:

(a) The date by which contracts will be let or purchase orders issued to accomplish any necessary performance improvements;

(b) The date for initiating on-site construction or installation of necessary equipment;

(c) The date by which on-site construction or installation of equipment is to be completed; and

(d) The date for achievement of final compliance with emission limitations.

§ 57.703 Compliance with the supplementary control system requirements.

(a) *Operations of existing SCS.* Each NSO shall require the immediate operation of any existing supplementary control system and the assumption of liability for violations of the NAAQS at existing monitor sites.

(b) *Compliance schedule where no SCS exists.* Where necessary, the NSO shall also require compliance with the requirements of Subpart D to be achieved according to the following schedule:

(1) Within 6 months after issuance of the NSO the smelter shall install all operating elements of the system, begin operating the system, complete all other measures specified in its approved SCS development plan, and begin compliance with the requirements of § 57.404.

(2) Within 9 months thereafter the smelter shall submit the SCS Report, assume liability for all violations of the NAAQS within its designated liability area, and comply with all other requirements of Subpart D.

§ 57.704 Compliance with fugitive emission evaluation and control requirements.

(a) *Plan for fugitive emission control.* The NSO shall provide that within a reasonable period after the submission

of the report on the fugitive emission control study required by § 57.502(b), the smelter owner shall submit to the issuing agency for its approval a proposed fugitive emission control plan, including increments of progress, for compliance with the requirements of §§ 57.501 and 57.503.

(b) *SCS Report.* If the fugitive emission control plan submitted under paragraph (a) of this section proposes to meet the requirements of §§ 57.501 and 57.503 through the additional use of a supplementary control system, the plan shall demonstrate that the use of supplementary controls at that smelter to prevent violations of the NAAQS resulting from fugitive emissions is practicable, adequate, reliable, and enforceable. The plan shall contain increments of progress providing for completion of the implementation of each additional measure, and for corresponding compliance with the requirements of paragraphs (b) and (c) of § 57.404, within four months of approval of the plan by the issuing agency. The plan shall also provide that within three months after completion of implementation of those additional measures, the smelter shall fully comply with the requirements of §§ 57.401 and 57.501 (including the assumption of liability for violations of NAAQS within its designated liability area), and shall submit an additional SCS report for the approval of the issuing agency. This additional final report shall correspond to that submitted under § 57.40(b)(2), except that it need not contain the 3 month study described in § 57.405(b)(2)(iii).

(c) *NSO amendment.* The amendments of the NSO required under § 57.503 shall be effected by the issuing agency as follows:

(1) With respect to the additional use of SCS, upon approval or promulgation of the plan submitted under paragraph (a) of this section and upon approval or promulgation of the requirements for the system described in the additional SCS Report under paragraph (a) of this section;

(2) With respect to the additional use of engineering techniques, upon approval or promulgation of the compliance schedule required by paragraph (a) of this section.

Subpart H—Waiver of Interim Requirement for Use of Continuous Emission Reduction Technology

§ 57.801 Purpose and scope.

(a) This subpart shall govern all proceedings for the waiver of the interim requirement that each NSO provide for the use of constant controls.

(b) In the absence of specific provisions in this subpart, and where appropriate, questions arising at any stage of the proceeding shall be resolved at the discretion of the Presiding Officer or the Administrator, as appropriate.

§ 57.802 Request for waiver.

(a) *General.* (1) Each smelter owner requesting a waiver shall compete, sign and submit Appendix A to this part. Copies of Appendix A may be obtained from any EPA Regional Administrator, or from the Director, Division of Stationary Source Enforcement (EN–341), United States Environmental Protection Agency, 401 M Street, SW., Washington, D.C. 20460. Claims of confidentially shall be made as provided in § 57203.

(2) The smelter owner shall append to the completed and signed Appendix A full copies of all documents, test results, studies, reports, scientific literature and assessments required by Appendix A. To the extent that the material consists of generally available published material, the smelter owner may cite to the material in lieu of appending it to Appendix A. The smelter owner shall specifically designate those portions of any documents relied upon and the facts or conclusions in Appendix A to which they relate.

(b) *Effect of submitting incomplete application.* (1) The Administrator, or a person designated by him to review applications for waivers, may advise the smelter owner in writing whenever he determines that additional information is needed in order to make the waiver eligibility determinations required by Section 119(d)(2) of the Act. The smelter owner shall promptly supply such information. All additional information requested under this paragraph and filed in the manner required by paragraph (d) shall be deemed part of Appendix A.

(2) Failure to comply with the requirements of paragraphs (a) and (b)(1) of this section shall be grounds for denial of the requested waiver.

(c) *Time for requesting waivers.* Any request for a waiver must be submitted to the Administrator by the smelter owner at the time of the initial application for an NSO from the State or the Administrator, as the case may be.

(d) *Submission of request.* A copy of Appendix A (plus attachments) which has been completed for the purpose of requesting a waiver of constant control requirements shall be filed with the Administrator, addressed as follows:

Director, Division of Stationary Source Enforcement (EN–341), U.S. Environmental Protection Agency, 401 M St., SW., Washington, D.C. 20460, Attn: Confidential Information Unit.

(e) *Eligibility.* No smelter shall be eligible for consideration under this subpart unless no constant controls were installed at that smelter as of August 7, 1977.

(f) *Criteria for Decision.* The Administrator shall grant or approve a waiver, whichever is appropriate, for any eligible smelter as to which he finds, in accordance with the methods and procedures specified in Appendix A, that:

(1) The sum of the present value of the smelter's future net cash flow (after installation of interim constant control equipment) plus its terminal value would be less than the smelter's liquidation (salvage) value; or

(2) The smelter's average variable costs at all relevent levels of production (after installation of interim constant control equipment) would exceed the weighted average price of smelter output for one year or more.

§ 57.803 Issuance of tentative determination; notice.

(a) *Tentative determination.* (1) The EPA staff shall formulate and prepare:

(i) A "Staff Computational Analysis," using the financial information submitted by the smelter owner under § 57.802 to evaluate the economic circumstances of the smelter for which the waiver is sought;

(ii) A tentative determination as to whether an interim requirement for the use of constant controls would be so costly as to necessitate permanent or prolonged temporary cessation of operations at the smelter for which the waiver is requested. The tentative determination shall contain a "Proposed Report and Findings" summarizing the conclusions reached in the Staff Computational Analysis, discussing the estimated cost of interim controls, and assessing the effect upon the smelter of requiring those controls. The tentative determination shall also contain a proposed recommendation that the waiver be granted or denied, based upon the Proposed Report and Findings, and stating any additional considerations supporting the proposed recommendation. This tentative determination shall be a public document.

(2) In preparing the Proposed Report and Findings, the EPA staff shall attempt to the maximum extent feasible to avoid revealing confidential information which, if revealed, might damage the legitimate business interests of the applicant. The preceding sentence notwithstanding, the tentative determination shall be accompanied by a listing of all materials considered by EPA staff in developing the tentative

determination. Subject to the provisions of § 57.814(a), full copies of all such materials shall be included in the administrative record under § 57.814, except that, to the extent the material consists of published material which is generally available, full citations to that material may be given instead.

(b) *Public notice.* Public notice of EPA's tentative determination to grant or deny an application for a waiver shall be given by:

(1) Publication at least once in a daily newspaper of general circulation in the area in which the smelter is located; and

(2) Posting in the principal office of the municipality in which the smelter is located.

(c) *Individual notice.* Individual notice of EPA's tentative determination to grant or deny an application for a waiver shall be mailed to the smelter owner by certified mail, return receipt requested, and to the air pollution control agency for the State in which the smelter is located.

(d) *Request for individual notice.* EPA shall mail notice of its tentative determination to grant or deny an application for waiver to any person upon request. Each such request shall be submitted to the Administrator in writing, shall state that the request is for individual notice of tentative determination to grant or deny any application for a waiver under section 119(d) of the Clean Air Act, and shall describe the notice or types of notices desired (*e.g.*, all notices, notices for a particular Region, notices for a particular State, notice for a particular city).

(e) *Form of notice.* The notice of tentative determination required to be distributed under paragraphs (b), (c), and (d) of this section shall include, in addition to any other materials, the following:

(1) A summary of the information contained in Appendix A;

(2) The tentative determination prepared under paragraph (a) of this section: *Provided,* That, except in the case of the smelter owner, a summary of the basis for the grant or denial of the waiver may be provided in lieu of the formal determinations required by paragraph (a)(1) of this section;

(3) A brief description of the procedures set forth in § 57.804 for requesting a public hearing on the waiver request, including a statement that such request must be filed within 30 days of the date of the notice;

(4) A statement that written comments on the tentative determination submitted to EPA within 60 days of the date of the notice will be considered by EPA in making a final decision on the application; and

(5) The location of the administrative record and the location at which interested persons may obtain further information on the tentative determination, including a copy of the index to the record, the tentative determination prepared under paragraph (a) of this section, and any other non-confidential record materials.

§ 57.804 Request for hearing; request to participate in hearing.

(a) *Request for hearing.* Within 30 days of the date of publication or receipt of the notice required by § 57.803, any person may request the Administrator to hold a hearing on the tentative determination by submitting a written request containing the following:

(1) Identification of the person requesting the hearing and his interest in the proceeding;

(2) A statement of any objections to the tentative determination; and

(3) A statement of the issues which such person proposes to raise for consideration at such hearing.

(b) *Grant or denial of hearing; notification.* Whenever (1) the Administrator has received a written request satisfying the requirements of paragraph (a) of this section which presents genuine issues as to the effect on the smelter of the requirement for use of constant controls, or (2) the Administrator determines in his discretion that a hearing is necessary or appropriate, the Administrator shall give written notice of his determination to each person requesting such hearing and the smelter owner, and shall provide public notice of his determination in accordance with § 57.803(b). If the Administrator determines that a request filed under paragraph (a) of this section does not comply with the requirements of paragraph (a) or does not present genuine issues, he shall give written notice of his decision to deny a hearing to the person requesting the hearing.

(c) *Form of notice of hearing.* Each notice of hearing disseminated under paragraph (b) of this section shall contain:

(1) A statement of the time and place of the hearing;

(2) A statement identifying the place at which the official record on the application for waiver is located, the hours during which it will be open for public inspection, and the documents contained in the record as of the date of the notice of hearing;

(3) The due date for filing a written request to participate in the hearing under paragraph (d) of this section;

(4) The due date for making written submissions under § 57.805; and

(5) The name, address, and office telephone number of the hearing Clerk for the hearing.

(d) *Request to participate in hearing.* Each person desiring to participate in any hearing granted under this section, including any person requesting such a hearing, shall file a written request to participate with the Hearing Clerk by the deadline set forth in the notice of hearing. The request shall include:

(1) A brief statement of the interest of the person in the proceeding;

(2) A brief outline of the points to be addressed;

(3) An estimate of the time required; and

(4) If the request is submitted by an organization, a nonbinding list of the persons to take part in the presentation. As soon as practicable, but in no event later than two weeks before the scheduled date of the hearing, the Hearing Clerk shall make available to the public and shall mail to each person who asked to participate in the hearing a hearing schedule.

(e) *Effect of denial of or absence of request for hearing.* If no request for a hearing is made under this section, or if all such requests are denied under paragraph (b) of this section, the tentative determination issued under § 57.803 shall be treated procedurally as if it were a recommended decision issued under § 57.811(b)(2), except that for purposes of §§ 57.812 and 57.813 the term "hearing participant" shall be construed to mean the smelter owner and any person who submitted comments under § 57.803(e)(4).

§ 57.805 Submission of written comments on tentative determination.

(a) *Main comments.* Each person who has filed a request to participate in the hearing shall file with the Hearing Clerk no later than 30 days before the scheduled start of the hearing (or such other date as may be set forth in the notice of hearing) any comments which he has on the request for waiver and EPA's tentative determination, based on information which is or reasonably could have been available to that person at the time.

(b) *Reply comments.* Not later than two weeks after a full transcript of the hearing becomes available (or such other date as may be set forth in the notice of hearing), each person who has filed a request to participate in the hearing shall file with the Hearing Clerk any comments he may have on:

(1) Written comments submitted by other participants pursuant to paragraph (a) of this section;

(2) Written comments submitted in response to the notice of hearing;

(3) Material in the hearing record; and

(4) Material which was not and could not reasonably have been available prior to the deadline for submission of main comments under paragraph (a) of this section.

(c) *Form of comments.* All comments should be submitted in quadruplicate and shall include any affidavits, studies, tests or other materials relied upon for making any factual statements in the comments.

(d) *Use of comments.* (1) Written comments filed under this section shall constitute the bulk of the evidence submitted at the hearing. Oral statements at the hearing should be brief, and restricted either to points that could not have been made in written comments, or to emphasizing points which are made in the comments, but which the participant believes can be more forcefully urged in the hearing context.

(2) Notwithstanding the foregoing, within two weeks prior to either deadline specified by paragraph (a) of this section for the filing of main comments, any person who has filed a request to participate in the hearing may file a request with the Presiding Officer to submit all or part of his main comments orally at the hearing in lieu of submitting written comments. The Presiding Officer shall, within one week, grant such request if he finds that such person will be prejudiced if he is required to submit such comments in written form.

§ 57.806 Presiding Officer.

(a) *Assignment of Presiding Officer.* (1) The Administrator shall, as soon as practicable after the granting of a request for hearing under § 57.803:

(i) Appoint a Presiding Officer to chair the hearing panel, who shall be either the Assistant Administrator for Air and Waste Management or the Assistant Administrator for Enforcement; or

(ii) Request that the Chief Administrative Law Judge assign an Administrative Law Judge as Presiding Officer. The Chief Administrative Law Judge shall thereupon make the assignment.

(2) If all parties to the hearing waive their right to have the Agency or an Administrative Law Judge preside at the hearing, the Administrator shall appoint an EPA employee having the qualifications of a Judicial Officer as defined in § 57.103 to serve as Presiding Officer.

(b) *Powers and duties of Presiding Officer.* It shall be the duty of the Presiding Officer to conduct a fair and impartial hearing, assure that the facts are fully elicited, and avoid delay. The Presiding Officer shall have authority to:

(1) Chair and conduct administrative hearings held under this subpart;

(2) Administer oaths and affirmations;

(3) Receive relevant evidence: *Provided,* That the administrative record, as defined in § 57.814, shall be received in evidence;

(4) Consider and rule upon motions, dispose of procedural requests, and issue all necessary orders;

(5) Hold conferences for the settlement or simplification of the issues or the expediting of the proceedings; and

(6) Do all other acts and take all measures necessary for the maintenance of order and for the efficient, fair and impartial conduct of proceedings under this subpart.

§ 57.807 Hearing.

(a) *Composition of hearing panel.* The Presiding Officer shall preside at the hearing held under this subpart. An EPA panel shall also take part in the hearing. In general, the membership of the panel shall consist of EPA employees having special expertise in areas related to the issues to be addressed at the hearing, including economists and engineers. For this reason, the membership of the panel may change as different issues are presented for discussion.

(b) *Additional hearing participants.* Either before or during the hearing, the Presiding Officer, after consultation with the panel, may request that a person not then scheduled to participate in the hearing (including an EPA employee or a person identified by any scheduled hearing participant as having knowledge concerning the issues raised for discussion at the hearing) make a presentation or make himself available for cross-examination at the hearing.

(c) *Questioning of hearing participants.* The panel members may question any person participating in the hearing. Cross-examination by persons other than panel members shall not be permitted at this stage of the proceeding except where the Presiding Officer determines, after consultation with the panel, that circumstances compel such cross-examination. However, persons in the hearing audience, including other hearing participants, may submit written questions to the Presiding Officer for the Presiding Officer to ask the participants, and the Presiding Officer may, after consultation with the panel, and in his sole discretion, ask these questions.

(d) *Submission of additional material.* Participants in the hearing shall submit for the hearing record such additional material as the hearing panel may request within 10 days following the close of the hearing, or such other period of time as is ordered by the Presiding Officer. Participants may also submit additional information for the hearing record on their own accord within 10 days after the close of the hearing.

(e) *Transcript.* A verbatim transcript shall be made of the hearing.

§ 57.808 Opportunity for Cross-examination.

(a) *Request for cross-examination.* After the close of the panel hearing conducted under this part, any participant in that hearing may submit a written request for cross-examination. The request shall be received by EPA within one week after a full transcript of the hearing becomes available and shall specify:

(1) The disputed issue(s) of material fact as to which cross-examination is requested. This shall include an explanation of why the questions at issue are factual, rather than of an analytical or policy nature; the extent to which they are in dispute in the light of the record made thus far, and the extent to which and why they can reasonably be considered material to the decision on the application for a waiver; and

(2) The person(s) the participant desires to cross-examine, and an estimate of the time necessary. This shall include a statement as to why the cross-examination requested can be expected to result in full and true disclosure resolving the issue of material fact involved.

(b) *Order granting or denying request for cross-examination.* As expeditiously as practicable after receipt of all requests for cross-examination under paragraph (a) of this section, the Presiding Officer, after consultation with the hearing panel, shall issue an order either granting or denying each such request, which shall be disseminated to all persons requesting cross-examination and all persons to be cross-examined. If any request for cross-examination is granted, the order shall specify:

(1) The issues as to which cross-examination is granted;

(2) The persons to be cross-examined on each issue;

(3) The persons allowed to conduct cross-examination;

(4) Time limits for the examination of witnesses; and

(5) The date, time and place of the supplementary hearing at which cross-examination shall take place. In issuing this ruling, the Presiding Officer may determine that one or more participants have the same or similar interests and that to prevent unduly repetitious cross-examination, they should be required to

choose a single representative for purposes of cross-examination. In such a case, the order shall simply assign time for cross-examination by that single representative without identifying the representative further.

(c) *Supplementary hearing.* The Presiding Officer and at least one member of the original hearing panel shall preside at the supplementary hearing. During the course of the hearing, the Presiding Officer shall have authority to modify any order issued under paragraph (b) of this section. A verbatim transcript shall be made of this hearing.

(d) *Alternatives to cross-examination.* (1) No later than the time set for requesting cross-examination, a hearing participant may request that alternative methods of clarifying the record (such as the submittal of additional written information) be used in lieu of or in addition to cross-examination. The Presiding Officer shall issue an order granting or denying such request at the time he issues (or would have issued) an order under paragraph (b) of this section. If the request is granted, the order shall specify the alternative provided and any other relevant information (*e.g.*, the due date for submitting written information).

(2) In passing on any request for cross-examination submitted under paragraph (a) of this section, the Presiding Officer may, as a precondition to ruling on the merits of such request, require that alternative means of clarifying the record be used whether or not a request to do so has been made under the preceding paragraph. The person requesting cross-examination shall have one week to comment on the results of utilizing such alternative means, following which the Presiding Officer, as soon as practicable, shall issue an order granting or denying such person's request for cross-examination.

§ 57.809 Ex parte communications.

(a) *General.* (1) No interested person outside the Agency or member of the Agency trial staff shall make or knowingly cause to be made to any member of the decisional body an *ex parte* communication relevant to the merits of the proceedings.

(2) No member of the decisional body shall make or knowingly cause to be made to any interested person outside the Agency or member of the Agency trial staff an *ex parte* communication relevant to the merits of the proceedings.

(b) *Effect of receipt of ex parte communication.* (1) A member of the decisional body who receives or who makes or knowingly causes to be made a communication prohibited by this subsection shall place in the record all written communications or memoranda stating the substance of all oral communications together with all written responses and memoranda stating the substance of all oral responses.

(2) Upon receipt by any member of the decisionmaking body of an *ex parte* communication knowingly made or knowingly caused to be made by a party or representative of a party in violation of this section, the person presiding at the stage of the hearing then in progress may, to the extent consistent with justice and the policy of the Clean Air Act, require the party to show cause why its claim or interest in the proceedings should not be dismissed, denied, disregarded, or otherwise adversely affected on account of such violation.

(c) *Definitions.* For purposes of this section, the following definitions shall apply:

(1) "Agency trial staff" means those Agency employees, whether temporary or permanent, who have been designated by the Agency as available to investigate, litigate, and present the evidence, arguments and position of the Agency in the evidentiary hearing or non-adversary panel hearing. Appearance as a witness does not necessarily require a person to be designated as a member of the Agency trial staff;

(2) "Decisional body" means any Agency employee who is or may reasonably be expected to be involved in the decisional process of the proceeding including the Administrator, Judicial Officer, Presiding Officer, the Regional Administrator (if he does not designate himself as a member of the Agency trial staff), and any of their staff participating in the decisional process. In the case of a non-adversary panel hearing, the decisional body shall also include the panel members whether or not permanently employed by the Agency;

(3) "*Ex parte* communication" means any communication, written or oral, relating to the merits of the proceeding between the decisional body and an interested person outside the Agency or the Agency trial staff which was not originally filed or stated in the administrative record or in the hearing. *Ex parte* communications do not include:

(i) Communications between Agency employees other than between the Agency trial staff and the member of the decisional body;

(ii) Discussions between the decisional body and either:

(A) Interested persons outside the Agency, or;

(B) The Agency trial staff *if* all parties have received prior written notice of such proposed communications and have been given the opportunity to be present and participate therein.

(4) "Interested person outside the Agency" includes the smelter owner, any person who filed written comments in the proceeding, any person who requested the hearing, any person who requested to participate or intervene in the hearing, any participant or party in the hearing and any other interested person not employed by the Agency at the time of the communications, and the attorney or record for such persons.

§ 57.810 Filing of Briefs, Proposed Findings, and Proposed Recommendations.

Unless otherwise ordered by the Presiding Officer, each hearing participant may, within 20 days after reply comments are submitted under § 57.805(b), or if a supplemental hearing for the purpose of cross-examination has been held under § 57.808(c), within 20 days after the transcript of such supplemental hearing becomes available, or if alternative methods of clarifying the record have been used under § 57.808(d), within 20 days after the alternative methods have been employed, file with the Hearing Clerk and serve upon all other hearing participants proposed findings and proposed recommendations to replace in whole or in part the findings and recommendations contained in the tentative determination. Any such person may also file, at the same time, a brief in support of his proposals, together with references to relevant pages of transcript and to relevant exhibits. Within 10 days thereafter each participant may file a reply brief concerning alternative proposals. Oral argument may be held at the discretion of the Presiding Officer on motion of any hearing participant or sua sponte.

§ 57.811 Recommended Decision.

As soon as practicable after the conclusion of the hearing, one or more responsible employees of the Agency shall evaluate the record for preparation of recommended decision and shall prepare and file a recommended decision with the Hearing Clerk. The employee(s) preparing the decision will generally be members of the hearing panel and may include the Presiding Officer. Such employee(s) may consult with and receive assistance from any member of the hearing panel in drafting a recommended decision and may also delegate the preparation of the recommended decision to the panel or to

any member or members of it. This decision shall contain the same elements as the tentative determination. After the recommended decision has been filed, the Hearing Clerk shall serve a copy of such decision on each hearing participant and upon the Administrator.

§ 57.812 Appeal From or Review of Recommended Decision.

(a) *Exceptions.* (1) Within 20 days after service of the recommended decision, any hearing participant may take exception to any matter set forth in such decision or to any adverse order or ruling of the Presiding Officer prior to or during the hearing to which such participant objected, and may appeal such exceptions to the Administrator by filing them in writing with the Hearing Clerk. Such exceptions shall contain alternative findings and recommendations, together with references to the relevant pages of the record and recommended decision. A copy of each document taking exception to the recommended decision shall be served upon every other hearing participant. Within the same period of time each party filing exceptions shall file with the Administrator and shall serve upon all hearing participants a brief concerning each of the exceptions being appealed. Each brief shall include page references to the relevant portions of the record and to the recommended decision.

(2) Within 10 days of the service of exceptions and briefs under paragraph (a)(1) of this section, any hearing participant may file and serve a reply brief responding to exceptions or arguments raised by any other hearing participant together with references to the relevant portions of the record, recommended decision, or opposing brief. Reply briefs shall not, however, raise additional exceptions.

(b) *Sua sponte review by the Administrator.* Whenever the Administrator determines sua sponte to review a recommended decision, notice of such intention shall be served upon the parties by the Hearing Clerk within 30 days after the date of service of the recommended decision. Such notice shall include a statement of issues to be briefed by the hearing participants and a time schedule for the service and filing of briefs.

(c) *Scope of appeal or review.* The appeal of the recommended decision shall be limited to the issues raised by the appellant, except when the Administrator determines that additional issues should be briefed or argued. If the Administrator determines that briefing or argument of additional issues is warranted, all hearing participants shall be given reasonable written notice of such determination to permit preparation of adequate argument.

(d) *Argument before the Administrator.* The Administrator may, upon request by a party or sua sponte, set a matter for oral argument. The time and place for such oral argument shall be assigned after giving consideration to the convenience of the parties.

§ 57.813 Final Decision.

(a) *After review.* As soon as practicable after all appeal or other review proceedings have been completed, the Administrator shall issue his final decision. Such a final decision shall include the same elements as the recommended decision, as well as any additional reasons supporting his decisions on exceptions filed by hearing participants. The final decision may accept or reject all or part of the recommended decision. The Administrator may consult with the Presiding Officer, members of the hearing panel or any other EPA employee in preparing his final decision. The Hearing Clerk shall file a copy of the decision on all hearing participants.

(b) *In the absence of review.* If no party appeals a recommended decision to the Administrator and if the Administrator does not review it sua sponte, he shall be deemed to have adopted the recommended decision as the final decision of the Agency upon the expiration of the time for filing any exceptions under § 57.812(a).

(c) *Timing of judicial review.* For purposes of judicial review, final Agency action on a request for a waiver of the interim requirement that each NSO provide for the use of constant controls shall not occur until EPA approves or disapproves the issuance of an NSO to the source requesting such a waiver.

§ 57.814 Administrative Record.

(a) *Establishment of record.* (1) Upon receipt of request for a waiver, an administrative record for that request shall be established, and a Record and Hearing Clerk appointed to supervise the filing of documents in the record and to carry out all other duties assigned to him under this subpart.

(2) All material required to be included in the record shall be added to the record as soon as feasible after its receipt by EPA. All material in the record shall be appropriately indexed. The Hearing Clerk shall make appropriate arrangements to allow members of the public to copy all non-confidential record materials during normal EPA business hours.

(3) Confidential record material shall be indexed under (2). Confidential record material shall, however, be physically maintained in a separate location from public record material.

(4) Confidential record material shall consist of the following:

(i) Any material submitted pursuant to § 57.802 for which a proper claim of confidentiality has been made under section 114(c) of the Act and 40 CFR Part 2; and

(ii) The Staff Computational Analysis prepared under § 57.803.

(b) *Record for issuing tentative determination.* The administrative record for issuing the tentative determination required by § 57.803 shall consist of the material submitted under § 57.802 and any additional materials supporting the tentative determination.

(c) *Record for acting on requests for cross-examination.* The administrative record for acting on requests for cross-examination under § 57.808 shall consist of the record for issuing the tentative determination, all comments timely submitted under §§ 57.803(e)(4) and 57.805, the transcript of the hearing, and any additional material timely submitted under § 57.807(d).

(d) *Record for preparation of recommended decision.* The administrative record for preparation of the recommended decision required by § 57.811 shall consist of the record for acting on requests for cross-examination, the transcript of any supplementary hearing held under § 57.808(c), any materials timely submitted in lieu of or in addition to cross-examination under § 57.808(d), and all briefs, proposed findings of fact and proposed recommendations timely submitted under § 57.810.

(e) *Record for issuance of final decision.* (1) Where no hearing has been held, the administrative record for issuance of the Administrator's final decision shall consist of the record for issuing the tentative determination, any comments timely submitted under § 57.803(e)(4), any briefs or reply briefs timely submitted under § 57.812(a) through (c), and the transcript of any oral argument granted under § 57.812(d).

(2) Where a hearing has been held, the administrative record for issuance of the Administrator's final decision shall consist of the record for preparation of the recommended decision, any briefs or reply briefs submitted under § 57.812(a) through (c), and the transcript of any oral argument granted under § 57.812(d).

§ 57.815 State Notification.

The Administrator shall give notice of the final decision in writing to the air

pollution control agency of the State in which the smelter is located.

§ 57.816 Effect of Negative Recommendation.

No waiver of the interim requirement for the use of constant controls shall be granted by the Administrator or a State in the absence of a positive recommendation by the Administrator that such a waiver be granted.

Appendix A—Primary Nonferrous Smelter Order (NSO) Application

Instructions

1. *General Instructions*

1.1 Purpose of the Application
1.2 NSO Economic Capability Tests
1.3 Confidentiality
1.4 Data Entry
1.5 Use of Exhibits

2. *NSO Financial Reporting Overview*

2.1 Revenue and Cost Assignment
2.2 Transfer Prices on Affiliated Party Transactions
2.3 Forecasting Requirements
2.4 EPA Furnished Forecast Data
2.5 Applicant Generated Forecasts
2.6 Depreciation

Detailed Instructions for Each Schedule

A.1 Constant Controls Forecast Summary
A.2 Interim Controls Forecast Summary
B.1 Historical Profit and Loss Summary
B.1.a Supplemental Historical Revenue Data
B.1.b Supplemental Historical Cost Data
B.2 Historical Capital Investment Summary
B.2.a Cash Proceeds from Liquidation
C.1 Constant Controls Forecast Profit and Loss Summary
C.1.a Supplemental Constant Controls Revenue Data
C.1.b Supplemental Constant Controls Cost Data
C.2 Constant Controls Sustaining Capital Investment Summary
D.1 Interim Controls Forecast Profit and Loss Summary
D.1.a Supplemental Interim Controls Revenue Data
D.1.b Supplemental Interim Controls Cost Data
D.2 Interim Controls Sustaining Capital Investment Summary

1. *General Instructions*

1.1 *Purpose of the Application*

This application provides financial reporting schedules and the accompanying instructions for EPA's determination of eligibility for a nonferrous smelter order (NSO), and for a waiver of the interim constant controls requirement of an NSO. Although the determination of eligibility for an NSO is prerequisite for the determination of a waiver, Appendix A, as a matter of convenience to applicants, includes both the NSO and waiver tests and reporting schedules.

In order to support an NSO eligibility determination, the applicant must submit operating and financial data as specified by the schedules included in this application. Specific instructions for completing each schedule are provided in subsequent sections of the instructions. In general, applicants must provide:

(a) Annual income statements, balance sheets and supporting data covering the five most recent fiscal years for the smelter for which the NSO is requested.

(b) Forecasts of operating revenues, operating costs, net income from operations and capital investments for the firm's smelter operations subject to this application, on the basis of anticipated smelter operations after installing additional pollution control facilities required to comply with the smelter's SIP emission limitations.

(c) For smelters applying for a waiver of interim constant controls, forecasts of operating revenues, operating costs, and capital investments for the firm's smelter operations prepared on the basis of anticipated smelter operations after installing additional pollution control facilities required to comply with interim constant control requirements.

1.2 *NSO Economic Capability Tests*

EPA will evaluate eligibility for an NSO or for a waiver of the interim constant control requirement by the following tests of an applicant's economic capability to undertake additional pollution control expenditures. The test for NSO eligibility employs a present value approach for determining an applicant's economic capability to implement a system of constant control technology that will achieve full compliance with SIP emission limitations. The tests for the waiver of the interim constant control requirements employ variable costing and discounted cash flow standards for evaluating an applicant's economic capability to implement those requirements. The period of analysis for these tests shall be 1980 through 1986, inclusive or yearly to include a period of two full years following completion and startup of the pollution control system. All references to 1980 to 1986 shall be interpreted accordingly and all additional years shall be reported.

1.2.1 *Net Income Test.* Each applicant must establish that firm is not economically capable of implementing a system of production and/or constant control technology that will achieve full compliance with SIP emission limitation standards.

Inadequate economic capability is defined in this test as an inability to undertake the required installation of new, or modification to existing production and/or constant control facilities without reducing the present value of the smelters net income and terminal value below the smelter's current salvage value under an orderly plan of liquidation.

1.2.2 *Temporary Waiver from Interim Controls.* Applicants that do not have an existing constant controls system may apply for a waiver from requirements for the interim controls. Applicants will be eligible for a temporary waiver from the interim constant control requirement if they can establish pursuant to the procedures in this application that the imposition of such control requirements would economically necessitate closure of the smelter facility for a period of one year or longer. The economic justification for a non-permanent closure under this temporary waiver test is defined as a situation in which the smelter's projected operating revenues for one or more years within the forecast period are inadequate to cover variable operating costs anticipated after installing the required interim control technology. Temporary waivers will be granted for only the period of time over which applicants can establish an inability by the firm to cover its variable operating costs. Interim control waiver requests based on the smelter's projected inability to earn adequate income after installation of interim pollution control equipment will be subject to the permanent waiver test.

1.2.3 *Permanent Waiver from Interim Controls.* Applicants without an existing constant controls system will be eligible for a full waiver from the interim use of such controls if they can establish pursuant to the procedure in this application that an imposition of interim control requirements would necessitate permanent closure of the smelter. Economic justification for a permanent closure is defined as a situation in which the present value of future cash flows anticipated from the smelter after installing the required interim control technology are less than the smelter's current salvage value under an orderly plan of liquidation.

1.2.4 *EPA Contact for NSO Inquiries.* Inquiries concerning this portion of the requirements for NSO application should be addressed to David M. Rochlin, Environmental Protection Agency, EN 341, 401 M Street SW., Washington, D.C. 20460.

1.2.5 *Certification.* The NSO Certification Statement must be signed by an authorized officer of the applicant firm.

1.3 *Confidentiality*

Applicants may request that information contained in this

application be treated as confidential. Agency regulations concerning claims of confidentiality of business information are contained in 40 CFR Part 2, Subpart B (41 FR 36902 *et seq.*, September 1, 1976, as amended by 43 FR 39997 *et seq.*, September 8, 1978). The regulations provide that a business may, if it desires, assert a business confidentiality claim covering part or all of the information furnished to EPA. The claim must be made at the same time the applicable information is submitted. The manner of asserting such claims is specified in 40 CFR 2.203(b). Information covered by such a claim will be handled by the Agency in accordance with procedures set forth in the Subpart B regulations. No information will be disclosed by EPA as to which a claim of confidentiality has been made except to the extent of and in accordance with 40 CFR Part 2, Subpart B. However, if no claim of confidentiality is made when information is furnished to EPA, the information may be made available to the public without notice to the business.

1.4 *Data Entry*

1.4.1 *Rounding.* All amounts (including both dollar values and physical units) reported in the schedules and exhibits accompanying this application must be rounded to the nearest thousand and expressed in thousands of dollars or units unless otherwise indicated in the instructions.

1.4.2 *Estimates.* Where an applicant's records cannot produce the specific data required by this application, the use of estimates will be allowed if a meaningful estimate can be made without significant distortion of the reported results. Data estimates must be supported by attaching on a separate sheet of paper as a part of Exhibit B an explanation identifying where such estimates are used and showing explicitly how the estimates were made.

1.4.3 *Missing Data.* Applicants must provide, where applicable, all operating and financial data requested by this application. Only substantially complete applications can be accepted for processing by the Agency. Questions concerning data entries for which information is not provided by, or cannot reasonably be estimated from, the applicant's existing accounting records should be addressed to the EPA Contact for NSO Inquiries.

1.5 *Use of Exhibits*

In addition to data required by the schedules included in this application, the following information must be attached as exhibits.

1.5.1 *Exhibit A.* Background information on the firm's organizational structure and its associated accounting and financial reporting systems for primary nonferrous activities. This information should include, where applicable, the firm's:

(a) Operating association with and ownership control in consolidated subsidiaries, unconsolidated subsidiaries, joint ventures and other affiliated companies.

(b) Organizational subdivision of its primary nonferrous activities into profit centers, cost centers and/or related financial reporting entities employed to control the operation of its mines, concentrators, smelters, refineries and other associated facilities.

(c) Material and product flows among the smelter subject to this NSO application, other integrated facilities and its affiliated suppliers and/or customers. In the case of integrated facilities, applicants should provide process flow diagrams depicting the operating interrelationships among its mines, concentrators, smelters, refineries and other integrated facilities. For both integrated and nonintegrated facilities, applicants also should describe the proportion contributed to its primary nonferrous activities by material purchases from and product sales to affiliated suppliers and customers.

(d) Annual operating capacity over the five most recent fiscal years for the smelter subject to this application and the firm's other nonferrous facilities. Operating capacity should be defined in terms of the total quantity of throughput that could have been processed with the available facilities after giving appropriate allowance to normal downtime requirements for maintenance and repairs. Operating capacity data also should consider both capacity balancing requirements among processing steps and annual processing yield rates attainable for each facility.

(e) Weighted average analysis of concentrates processed and tonnage produced annually over each of the five most recent fiscal years by the smelter subject to this application. The operators of integrated facilities also should provide annual data over the five-year period on both the sources of and a weighted average analysis of concentrates and ores processed and tonnage produced by individual profit centers.

(f) Accounting system and policies for recording investment expenditures, operating revenues, operating costs and income taxes associated with its primary nonferrous activities. Applicants also should provide a complete description of allocation techniques employed for assigning investments, revenues, costs and taxes to individual profit, cost or departmental centers for which costs are accumulated. Applicants should further indicate the relationship of cost and/or departmental accounting entities to the firm's established profit centers.

(g) Annual and five-year operating and capital expenditure plans (or budgets) by individual nonferrous profit center. These documents should include previous plans prepared for the five preceding fiscal years as well as the current one-year and five-year operating and capital expenditure plans. At least the current one-year and five-year plans should provide a specific breakdown of investment expenditures and operating costs associated with the operation and maintenance of each profit center's existing and proposed pollution control facilities.

1.5.2 *Exhibit B.* Supplemental description and explanation of items appearing in the financial reporting schedules.

1.5.3 *Exhibit C.* Financial data documentation. Applicants must document annual balance sheet, income statement and supporting data reported for the firm's preceding five fiscal years or for that portion of the past five years during which the firm engaged in smelter operations. This documentation should be provided by attaching to the application:

(a) SEC 10–K reports filed by the parent corporation and its unconsolidated subsidiaries for each of the preceding five fiscal years.

(b) Certified financial statements prepared (a) on a consolidated basis for the parent corporation and its consolidated subsidiaries and (b) for the firm's unconsolidated subsidiaries and affiliates. This requirement may be omitted for those years in which SEC 10–K reports have been attached to this Exhibit.

(c) Business Segment Information reports filed with the Securities and Exchange Commission by the firm and its unconsolidated subsidiaries for each of the preceding five years (as available).

2. *NSO Financial Reporting Overview*

2.1 *Revenue and Cost Assignment.* The amounts assigned to operations of the smelter subject to this NSO application should include (1) revenues and costs directly attributable to the smelter's operating activities and (2) indirect operating costs shared with other segments of the firm to the extent that a specific causal and beneficial relationship can be identified for the

allocation of such costs to the smelter. Do not allocate revenues and costs associated with central administrative activities for which specific causal and beneficial relationships to the activities of the smelter cannot be established. Nonallocable items include, but are not restricted to, amounts such as dividend and interest income on centrally administered portfolio investments, central corporate administrative office expenses and interest on long-term debt financing arrangements. Provide a detailed explanation of amounts classified as nontraceable on a separate schedule and attach as part of Exhibit B.

2.2 *Transfer Prices on Affilitated Party Transactions.* Certain transactions by the smelter subject to an NSO application may reflect sales to or purchases from "affiliated" customers or suppliers with whom the smelter has a common bond of ownership and/or managerial control. In preparing this application, affiliated party transactions shall be defined as transactions with any entity that the firm, or its owners, controls directly or indirectly either through an ownership of 10 percent or more of the entity's voting interests or through an exercise of managerial responsibility. Applicants must attach as part of Exhibit B supporting schedules explaining the pricing policies established on affilitated party transactions incorporated in the financial reporting schedules.

Prices on inter-segment material and product transfers within a firm, or on external purchases from and sales to other affiliated suppliers and customers, may differ from the prices on comparable transactions with unaffiliated suppliers and customers. In this event, applicants also should present in the Exhibit B supporting schedules and incorporate in the NSO financial reporting schedules appropriate adjustments for restating affiliated party transactions. Affiliated party transactions should be restated at either (a) equivalent prices on comparable transactions with unaffiliated parties if such price quotations can be obtained or (b) prices that provide the selling entity with a normal profit margin above its cost of sales if a meaningful comparison with unaffiliated transaction prices cannot be established. A "normal" profit margin should be defined as the gross operating profit per dollar of operating revenue that will provide an after-tax rate of return on permanent capital (long-term assets less current liabilities) of no more than eight percent.

2.3 *Forecasting Requirements.* Applicants must provide the Agency with financial forecasts (Schedules C.1 and C.2) covering the period from fiscal years 1980 through 1986 or yearly to include a period of two full years following completion and startup of the pollution control system. All references to 1980 to 1986 shall be interpreted accordingly and all additional years shall be reported reflecting applicant expectations about future smelter operations if additional constant controls are required to comply with SIP sulfur dioxide emission limitations.

Applicants requesting either a temporary or permanent waiver from interim constant control requirements also must provide an additional set of financial forecasts (Schedule D.1 and D.2) reflecting anticipated smelter operations with the installation of such controls.

It is recognized that some line items may be the same under both cases. On the other hand, production interruptions or curtailments due to the installation of additional pollution control facilities may require adjustments to certain revenue and cost estimates in the respective control cases. The installation of additional pollution control facilities that involve process changes in the smelter's operations also may require specific forecasts by applicants of associated impacts on incremental operating revenues and costs.

Applicants should make their financial forecasts in terms of nominal dollar estimates. Forecasts of selected parameters provided by EPA will furnish guidelines to an applicant in preparing part of the required cost and revenue estimates. In particular, refined copper, zinc and lead price indices provided in nominal-dollar terms should be used directly by the applicant as given—i.e., the stipulated price estimates should not be inflated. In all cases applicants should disclose the index applied to their revenue and cost forecasts.

2.4 *EPA Furnished Forecast Data:* In making projections of the period 1980 through 1986, applicants should, except as noted below, use the following indices provided by EPA. These indices are available in the rulemaking docket, or from the INFORMATION CONTACT noted in the **Federal Register**. The indices are:

(a) Aggregate industry production of copper, lead and zinc.

(b) Average capacity utilization factors for primary nonferrous metal producers.

(c) Refined prices for copper, lead and zinc.

(d) Wage indices for manufacturing labor. These indices are to be used only for estimating wage increases after the expiration of the applicant's current labor agreements.*

(e) Gross National Product price deflator.*

(f) Weighted average cost of capital for nonferrous metal producers. The applicant may, in lieu of this estimate, use its own weighted cost of capital estimate, provided that it is generated according to accepted financial theory and is fully documented as part of Exhibit B.

(g) Energy Price Indices. The applicant should use the index in Table 3 * for the appropriate product and year to calculate the rate of price increase for each energy product for the period following the expiration of existing contracts. Where contracts expire during the calendar year, prices should be calculated by rounding to the nearest quarter and interpolating to the next calendar year if necessary. The applicant may use instead any reasonable projection made by its own supplier of that energy product, providing the projection is fully documented as part of Exhibit B. EPA or supplier indices are to be used by the applicant only for periods after the expiration of current contracts.

2.5 *Applicant Generated Forecasts:* Within the specified limitations, applicants may employ any reasonable method of forecasting by-product, co-product and other prices not provided by the Agency. The method selected should be explained and unit prices or costs provided where applicable. The forecast elements should be compatible with an applicant's historical cost and revenue elements to permit direct comparisons of historical and forecasted data. Applicants should attach as part of Exhibit B appropriate schedules explaining variances between forecasted and historical unit costs for the smelter.

An acceptable method of forecasting by-product (e.g., gold and silver) prices would be to (a) compute an average of the 1978 constant-dollar equivalents to a by-product's 1973–1979 prices and (b) inflate the average price by the forecasted general rate of inflation for each successive year over the 1980–1986 forecast period. Similarly, concentrate prices could be estimated by applying forecasts of the appropriate refined price index to typical contractual terms indicated for 1979 purchases from unaffiliated suppliers.

---

* This information appears in "Energy Price Indices, Manufacturing Wages Indices, and Gross National Product Deflators, 1980–1986," an EPA report available in the docket or from the INFORMATION CONTACT listed in the **Federal Register** notice.

To the maximum extent practicable, by-product, co-product and (when applicable) unaffiliated concentrate prices should be stated at market prices adjusted to f.o.b. smelter. Adjustments to these pricing bases should be made to reflect differences in grades and types of production. All adjustments should be consistent with expected sales, grades and types of concentrate processes. Applicants should attach as part of Exhibit B schedules describing and explaining the methods used to forecast these revenue and cost items and the adjustments required for these revenue and cost forecasts.

Applicants should explain fully any changes from the historical data that are required to forecast labor productivity, ore/concentrate grade and composition, materials and energy consumption per unit of output, yield rates and other physical input/output relationships.

Existing contractual terms should be used in forecasting those sales or input costs or prices to which the applicant is committed by contracts. The use of contract-dictated prices should be disclosed and supported by attaching as part of Exhibit B the terms and duration of labor and other supplier arrangements.

Cost of compliance estimates need not be to the accuracy of final design/bid estimates; feasibility grade estimates will be acceptable. Updated cost of compliance estimates used in internal five year plans or specially prepared internal estimates of costs of compliance will generally be satisfactory.

2.6 *Depreciation.* Depreciation refers to that used for Federal Income Tax purposes.

Constant Controls Forecast Summary—Schedule A.1

General

All applicants must complete this schedule and its supporting schedules under the conditions where the applicant would undertake sufficient additional investment in pollution control facilities to achieve full compliance with Agency emission limitation standards.

Line 01—Net Income from Operations. Enter for each year from 1980 through 1986 the amount reported in Schedule C.1, Line 25.

Line 02—Constant Controls Capital Investment. Enter the estimated capital outlays for constant controls in the years which outlays would be made. These values shall correspond to the investment estimates shown in the supporting schedules for Line 18 of Schedule C.1. Changes in working capital investment due to investment constant controls facilities may be added to the capital investment estimates shown in Schedule C.1.

Line 03—Sustaining Capital. Enter for each year from 1979 through 1985, the amounts reported in Schedule C.2, Line 07.

Line 04—Total. Enter the sum of Line 02 and Line 03 for each year.

Line 05—Adjusted Cash Flow Projections. Enter for each year from 1979 through 1985 the difference between amounts reported on Line 01 and 04.

Line 06—Discount Factors. Enter the discount factor for each year from 1979 through 1985 corresponding to the weighted cost of capital as furnished by EPA or estimated by the applicant pursuant to the instructions under Section 2.5.

Line 07—Present Value of Future Cash Flows. Enter for each year from 1979 through 1985 the product of Line 05 times Line 06.

Line 08—Terminal Value. Enter under the total column, the estimated terminal value of the smelter. This shall be computed by capitalizing the forecasted net income plus after-tax interest expense on long-term debt (Schedule C.1, Line 23) from operations for 1986 by the historical cost of capital as furnished by EPA. Specifically, multiply net income plus the after-tax interest expense on long term debt for the last year by year forecast by 10.6.

Line 09—Discount Factor. Enter the appropriate discount factor corresponding to the weighted cost of capital as furnished by EPA or estimated by the Applicant pursuant to instructions under Section 2.5.

Line 10—Present Value of Terminal Salvage Value. Enter the product of Line 08 times Line 09.

Line 11—Present Value of Future Cash Flows. Enter the sum of amounts previously reported on Line 07 for 1979 through 1985.

Line 12—Total Present Value. Enter the sum of Line 10 plus Line 11.

Line 13—Current Salvage Value. Enter the amount reported in Schedule B.2.a, Line 17 if the value is greater than zero. If the value is zero or less enter zero.

Line 14—Net Present Value. Enter the difference between Line 12 and 13. Applicants reporting a negative net present value will be eligible for a waiver from full compliance with constant control standards for SIP sulfur dioxide emission limitations. Applicants that do not have an existing system of constant control technology also must complete Schedule A.2 and Schedule D.1 and D.2 to determine their eligibility for a temporary or permanent waiver from interim control requirements.

Interim Controls Forecast Summary—Schedule A.2

General

Applicants that do not have an existing system of constant control technology must complete this schedule and its supporting schedules if they want to request a waiver from interim control requirements.

Line 01—Gross Operating Profit. Enter for each year from 1980 through 1986, the amount reported in Schedule D.1, Line 14. Applicants will be eligible for a temporary waiver from the interim development of constant control technology for sulfur dioxide emissions if the reported gross operating profit is a negative value for one or more years during the 1980 through 1986 forecast period. Applicants also should complete parts B and C of Schedule A.2 to determine eligibility for a permanent waiver from interim-control requirements.

Line 02—Net Income from Operations. Enter for each year from 1980 through 1986 the amount reported in Schedule D.1, Line 25.

Lines 03 and 04—Depreciation and Amortization. Enter for each year from 1980–1986 the amounts reported in Schedule D.1, Lines 18 and 19.

Line 05—Operating Cash Flow. Enter for each year from 1980–1986 the total of amounts reported on Lines 02 through 04.

Line 06—Interim Controls Capital Investment. Enter the estimated capital outlays for interim controls for the years during which outlays would be made. These values shall correspond to the investment estimates shown in the supporting schedules for Line 18 of Schedule D.1. Changes in working capital investment due to investment in interim controls facilities may be added to the capital investment estimates shown in Schedule D.1.

Line 07—Sustaining Capital. Enter for each year from 1980–1986, the amounts reported in Schedule D.2, Line 07.

Line 08—Total. Enter the sum of Line 06 and Line 07 for each year.

Line 09—Net Cash Flow Projections. Enter for each year from 1980 through 1986 the difference between the amounts reported on Line 05 and 08.

Line 10—Discount Factors. Enter the discount factor for each year from 1980–1986 corresponding to the weighted cost of capital as furnished by EPA or estimated by the applicant pursuant to the instructions under Section 2.5.

Line 11—Present Value of Future Cash Flows. Enter for each year from

1980–1986, the product of Line 09 times Line 10.

Line 12—Terminal Value. Enter under the Total column, the estimated terminal value of the smelter. This shall be computed by capitalizing the forecasted net income plus after-tax interest expense on long-term debt (Schedule D.1, Line 23) from operations for 1986 by the historical cost of capital as furnished by EPA. Specifically, multiply net income plus after-tax interest expense on long-term debt for the last year of the year by forecast by 10.6.

Line 13—Discount Factor. Enter the appropriate discount factor corresponding to the weighted cost of capital as furnished by EPA or estimated by the applicant pursuant to instructions under Section 2.5.

Line 14—Present Value of Terminal Salvage Value. Enter the product of Line 12 times Line 13.

Line 15—Present-Value of Future Cash Flows. Enter the sum of amounts previously reported on Line 11 for 1980–1986.

Line 16—Total Present Value. Enter the sum of Line 14 plus Line 15.

Line 17—Current Salvage Value. Enter the amount reported in Schedule B.2.a, Line 17, if the value is greater than zero. If the value is zero or less, enter zero.

Line 18—Net Present Value. Enter the difference between amounts reported on Lines 16 and 17. Applicants reporting a negative net present value will be eligible for a permanent waiver from interim use of a constant control system for sulfur dioxide emissions.

Historical Profit and Loss Summary—Schedule B.1

General

Report annual revenues, costs and income taxes assignable to operation of the smelter subject to this NSO application. Assignable revenues and costs should include only the results of transactions either (1) directly associated with smelter operations or (2) for which the applicant can establish a causal and beneficial relationship with smelter operations pursuant to instructions in Section 2.1. The annual data requested in this schedule should be reported for each of the five fiscal years immediately preceding the year in which this application is filed or for that portion of the five-year period during which the firm engaged in smelter operations.

Line 01—Primary Metal Sales. Enter for each fiscal year the amount reported in Schedule B.1.a., Line 40.

Line 02—Co-Product and By-Product Sales. Report annual revenues, net of returns and allowances, derived from smelter sales and/or transfers of co-products and by-products to both unaffiliated and affiliated customers. Attach as part of Exhibit B a supporting schedule for each major co-product and by-product component of smelter revenues. Segregate the revenues reported by major co-product and by-product components into their unaffiliated customer and affiliated customer elements. Report for each component's unaffiliated and affiliated customer revenue elements the (1) average grade of product sold, (2) actual quantity sold, (3) average price per unit and (4) total smelter revenues. Also show for each product line any adjustments required to restate transfer prices and explain the basis for such adjustments. Refer to the NSO Financial Reporting Overview Section 2.2 on "Transfer Prices on Affiliated Party Transactions" for instructions on the restatement of affiliated customer revenues.

Line 03—Tolling Service Revenues. Enter for each year the amount reported in Schedule B.1.a., Line 53.

Line 04—Other Operating Revenues. Report annual revenues directly associated with smelter operations that have not previously been reported on Lines 01 through 03. Attach as part of Exhibit B a schedule showing the types and amounts of sales reported as other operating revenue. The following non-operating revenue and income items should *not* be included as other operating revenue or as a part of revenues reported on Line 01 through 03.

- Royalties, licensing fees and other income from intangibles
- Interest and dividend income on portfolio investments
- Equity in income (loss) of unconsolidated subsidiaries and affiliates
- Gain (loss) from discontinued operations and disposal of property
- Minority interest adjustment to consolidated subsidiary income.
- Extraordinary items.

Line 05—Total Operating Revenue. Enter the total of amounts reported on Lines 01 through 04 for each year.

Line 06—Concentrates Processed. Report the cost of concentrates processed and sold or transferred to unaffiliated and affiliated customers from Schedule B.1.b, Line 13. Concentrates purchased from unaffiliated suppliers should be valued at the actual prices paid. Concentrates purchased from affiliated suppliers should be valued at or, if necessary, restated to equivalent prices quoted by unaffiliated suppliers. If prices used to report revenues are c.i.f. and concentrate costs are f.o.b. smelter, all transportation charges paid on the seller's or buyer's account should be excluded from smelter expense. Attach as part of Exhibit B supporting schedules showing the:

- Annual value of concentrate purchases classified according to purchases from unaffiliated and affiliated suppliers.
- Cost of sales adjustments to concentrate purchases for net annual additions to or withdrawals from concentrate inventories, freight-in on concentrate purchases and inventory spoilage.
- Impact on cost of sales for restating, where applicable, the cost of concentrate purchases from affiliated suppliers to the equivalent prices paid to unaffiliated suppliers.
- Volumes, grades and net prices of concentrate purchases from unaffiliated and affiliated suppliers by type of concentrate purchased.
- Volumes, grades and net prices associated with toll concentrates processed by type of concentrate.

Line 07—Other Materials Costs. Report annual costs incurred for flux, refractories, coke and other materials used by the smelter in its processing of concentrates. Materials purchased from unaffiliated suppliers should be valued at the actual prices paid after adjustment for transportation costs incurred. Materials purchased from affiliated suppliers should be valued at or, if necessary, restated to equivalent prices quoted by unaffiliated suppliers. Include in Exhibit B supporting schedules showing the:

- Annual value of material purchases classified according to purchases from unaffiliated and affiliated suppliers.
- Cost of sales adjustments to material purchases for net annual additions to or withdrawals from material inventories, freight costs on material purchases and inventory loss.
- Impact on cost of sales for restating, where applicable, the costs of material purchases from affiliated suppliers to equivalent prices paid to unaffiliated suppliers.
- Classification of other material costs by major cost factors for each cost component that exceeds 20 percent of any line item in the cost of sales schedule.

Line 08—Production Labor Costs. Report in each column total direct labor costs incurred by the smelter for processing purchased and toll concentrates, Schedule B.1.b, Line 18. Include in Exhibit B supporting schedules showing the:

- Manhours and wage rates for major labor classifications.

• Potential impact on wage rates of provision in the smelter's current labor contracts.

• Explanation of major variances observed in direct labor costs over the five-year period as a result of factors such as strikes or new labor contracts.

Line 09—Energy Costs. Enter the totals for the five fiscal years reported in Schedule B.1.b, Line 34.

Line 10—Pollution Control Costs. Report in each column expenses incurred for operating and maintaining pollution control facilities. All by-product credits associated with pollution control facility operations should be eliminated and reported on Line 02. Depreciation and amortization charges against the smelter's pollution control facilities should be reported separately on Line 18. Attach as part of Exhibit B supporting schedules showing the:

• Major pollution control cost elements with their values classified according to direct and indirect cost factors.

• Techniques used to allocate indirect pollution control costs to major cost pools.

Line 11—Production Overhead. Report the total costs for indirect labor, indirect materials and other production overhead costs associated with the smelter for each year. Attach as part of Exhibit B a schedule showing annual overhead costs by major cost components associated with the smelter's operations. For each cost component, where appropriate, identify the quantity and unit price element of overhead costs.

Line 12—Other Production Costs. Report annual smelter overhead and other production costs not previously reported on Lines 06 through 11. By-product credits, if any, should be eliminated and reported on Line 02 as operating revenues. Attach as part of Exhibit B supporting schedules showing the:

• Major cost elements classified according to direct and indirect production costs.

• Disaggregation of major overhead cost components into their fixed and variable cost elements.

• Allocation techniques used in assigning indirect overhead costs to the major cost components.

• Elements of overhead costs represented by purchases from affiliated suppliers and adjustments, if any, required to restate these costs on the basis of equivalent prices paid to unaffiliated suppliers.

Line 13—Total Cost of Sales. Enter the total of amounts reported on Lines 06 through 12 for each year.

Line 14—Gross Operating Profit. Enter the amount reported on Line 05 minus the amount reported on Line 13 for each year.

Line 15—Selling, General & Administrative (SG&A) Expenses. Report SG&A expenses attributable to the smelter's annual operating activities. Exclude those operating costs to be reported separately on Lines 16 through 21 and those costs for which causal and beneficial relationships to the smelter cannot be established. Attach as part of Exhibit B supporting schedules (1) segregating SG&A expenses by major expense components, (2) classifying the major expense components according to those costs incurred directly by smelter operations and costs allocated to the smelter from indirect cost pools and (3) explaining the basis used for indirect cost allocations.

Line 16—Taxes, Other Than Income Tax. Report all taxes (exclusive of Federal, state, local and foreign income taxes) assignable to the smelters operations. Attach as part of Exhibit B, a schedule that (1) segregates these operating taxes by major component, (2) classifies each component according to direct and indirect cost elements, and (3) explains the basis used for indirect cost allocations.

Line 17—Exploration and Research Costs. Report exploration and research costs (exclusive of capitalized costs reported in Schedule B.2) that are assignable to the smelter's annual operations. Attach as part of Exhibit B a schedule (1) segregating exploration and research costs by major expense components, (2) classifying each expense component according to direct and indirect cost elements and (3) explaining the basis used for indirect cost allocations.

Line 18—Pollution Control Depreciation and Amortization. Report annual depreciation and amortization charges attributable to the smelter's investment in pollution control facilities and equipment. Reported charges should be computed in accordance with depreciation and amortization methods adopted for tax reporting purposes by the firm. Attach as part of Exhibit B a schedule segregating the smelter's pollution control and nonpollution control facility investments into major depreciable asset components. Describe for each asset component the (1) depreciation method adopted for tax reporting purposes, (2) annual depreciation and amortization charges by applicable fiscal year, (3) classification of annual charges into direct and indirect cost elements and (4) basis used for indirect cost allocations.

Line 19—Other Facility Depreciation and Amortization. Report annual depreciation and amortization charges (exclusive of charges reported on Line 18) assignable to the smelter's operations. Refer to Line 18 instructions for additional reporting requirements.

Line 20—Interest on Short-Term Debt. Report interest expense and associated financial charges for each year on current liabilities in accordance with the assignment instructions in Section 2.1. Do not include interest on the portion of long-term debt due within the current year for each reporting period.

Line 21—Miscellaneous Operating Expenses. Report any additional expenses assignable to the smelter's annual operations. Attach as part of Exhibit B a schedule (1) segregating these additional expenses into major expense components, (2) classifying each expense component according to costs incurred directly by the smelter and costs allocated to the smelter from indirect cost pools and (3) explaining the basis used for indirect cost allocations.

Line 22—Total Other Operating Expenses. Enter the total of amounts reported on Lines 15 through 21 for each year.

Line 23—Income from Operations. Enter the amount reported on Line 14 minus the amount reported on Line 22 for each year.

Line 24—Gain/(Loss) from Disposition of Property. Report net gains or losses recognized during each year from disposition of property, plant and equipment. Report such gains or losses in accordance with the firm's normal practice for certified financial statement reporting. If such gains or losses are not significant and are classified otherwise, no reclassification need be made. A note to this effect must be included in Exhibit B.

Line 25—Miscellaneous Income and Expenses. Report minority interest in income, foreign currency translation effects, and other non-operating income and expenses directly assignable to the smelter and not recognized elsewhere on this schedule. Report such items in accordance with the accounting methods used for certified financial reporting purposes.

Line 26—Total Other Income and Expenses. Enter the algebraic sum of amounts reported on Lines 24 through 25 for each year.

Line 27—Net Taxable Income. Enter the amount reported on Line 23 minus the amount reported on Line 26 for each year.

Supplemental Historical Revenue Data—Schedule B.1.a

General

Report annual product sales and associated operating revenues, net of returns and allowances, from smelter sales and/or transfers of copper, lead and zinc products and tolling services to both unaffiliated and affiliated customers. Revenues from affiliated customer sales should be stated or, if necessary, restated at prices equivalent to those received on comparable sales to unaffiliated customers. Refer to the NSO Financial Reporting Overview discussion of "Transfer Prices on Affiliated Party Transactions" for instructions on the restatement of affiliated customer revenues.

Lines 01, 14 and 27—Primary Nonferrous Product Sales. Report in thousands of tons the total quantity of copper, lead and zinc products sold in each respective fiscal year.

Lines 02, 15 and 28—Unaffiliated Customer Sales. Report in thousands of tons the respective quantities of copper, lead and zinc product sales to unaffiliated customers during each fiscal year.

Lines, 03, 16 and 29—Unaffiliated Customer Revenues. Report in thousands of dollars the total operating revenues derived from smelter sales of copper, lead and zinc to unaffiliated customers during each fiscal year.

Lines 04, 17 and 30—Unaffiliated Customer Prices. Report the average unit price, computed as operating revenues reported on Lines 03, 16 and 29 divided by the quantities reported on Lines 02, 15 and 28, respectively, received on smelter sales of copper, lead and zinc to unaffiliated customers during each fiscal year.

Lines 05, 18 and 31—Average Product Quality Grade. Report the average quality rating assigned to copper, lead and zinc products purchased by the smelter's unaffiliated customers.

Lines 06, 19 and 32—Affiliated Customer Sales. Report in thousands of tons the respective quantities of copper, lead and zinc product sales to affiliated customers during each fiscal year.

Lines 07, 20 and 33—Affiliated Customer Revenues. Report in thousands of dollars the total operating revenues derived from smelter sales of copper, lead and zinc to affiliated customers during each fiscal year.

Lines 08, 21 and 34—Affiliated Customer Prices. Report the average unit price, computed as operating revenues reported on Lines 07, 20 and 33 divided by the quantities reported on Lines 06, 19 and 32, respectively, received on smelter sales of copper, lead and zinc to affiliated customers during each fiscal year.

Lines 09, 22 and 35—Average Product Quality Grade. Report the average quality rating assigned to copper, lead and zinc products purchased by the smelter's affiliated customers.

Lines 10, 23 and 36—Total Primary Product Revenues. Report total operating revenues derived from the smelter's sales to unaffiliated and affiliated customers of copper (Lines 03 + 07), lead (Lines 16 + 20) and zinc (Lines 29 + 33) during each fiscal year.

Lines 11, 24 and 37—Transfer Price Adjustments. Report operating revenue adjustments required to equate affiliated customer transfer prices with unaffiliated customer market prices on smelter sales of copper, lead and zinc during each fiscal year. Attach as part of Exhibit B an explanation of the method used for restating transfer prices where such adjustments are necessary.

Lines 12, 25 and 38—Other Revenue Adjustments. Report sales returns and allowances and other adjustments applicable to the smelter's revenues derived from copper, lead and zinc product sales. Attach as part of Exhibit B a schedule reporting the types and amounts of such adjustments.

Lines 13, 26 and 39—Adjusted Product Revenues. Enter the algebraic sums of Lines 10 through 12 for adjusted copper sales (Line 13), Lines 23 through 25 for adjusted lead sales (Line 26) and Lines 36 through 38 for adjusted zinc sales (Line 39).

Line 40—Primary Metal Revenues. Enter for each fiscal year the sum of Lines 13, 26 and 39.

Line 41—Toll Concentrates Processed. Report in thousands of tons the total quantity of toll concentrates processed during each fiscal year.

Lines 42 to 45—Unaffiliated Customer Toll Revenues. Report for each fiscal year the quantity of toll concentrates processed for unaffiliated customers (Line 42), total operating revenues derived from this processing (Line 43), average price charged per ton of concentrate processed (Line 44 = Line 43/42) and the average quality rating assigned to toll concentrates processed for unaffiliated customers (Line 45).

Lines 46 to 49—Affiliated Customer Toll Revenues. Report for each fiscal year the quantity of toll concentrates processed for affiliated customers (Line 46), total operating revenues derived from such processing (Line 47), average price charged per ton of concentrate processed (Line 48 = Line 47/46) and the average quality rating (Line 49) assigned to toll concentrates processed for affiliated customers.

Line 50—Tolling Service Revenues. Enter for each fiscal year the total of amounts reported on Lines 43 and 47.

Line 51—Transfer Price Adjustments. Report operating revenue adjustments required to equate affiliated customer transfer prices with market prices charged to unaffiliated customers on the smelter's tolling services. Attach as part of Exhibit B an explanation of the method used for restating transfer prices where such adjustments are necessary.

Line 52—Other Revenue Adjustments. Report other adjustments applicable to the smelter's tolling service revenues. Attach as part of Exhibit B a schedule reporting the types and amounts of such adjustments.

Line 53—Adjusted Tolling Service Revenues. Enter for each fiscal year the total of amounts reported on Lines 50 through 52.

Line 54—Co-Product Revenues. Report the net revenues for each year from sales of co-products derived from the smelter's operations. Attach as part of Exhibit B a schedule showing by individual type of co-product, the quantity produced and sold, market price per unit of sales and total revenues derived from the co-product sales.

Line 55—Pollution Control By-product Revenues. Report revenues from the sale of by-products derived from operation of the smelter's pollution control facilities. Attach as part of Exhibit B a schedule showing by type of by-product produced, the quantity of output, market price received per unit of output sold and total revenue derived from the by-product sales.

Line 56—Other By-product Revenues. Report revenues from the sales of gold, silver, and other by-products derived from the smelter's operations. Attach as part of Exhibit B a schedule providing additional documentation as specified in the instructions for Line 55.

Line 57—Total Co-product and By-product Revenues. Enter for each year the total of Lines 54 through 56.

Supplemental Historical Cost Data—Schedule B.1.b

General

Report annual costs and input quantities for smelter operations by line item under each column for the years indicated by this schedule.

Line 01—Total Quantity Purchased. Report for each year the total quantity of concentrates purchased by the smelter. This will be sum of Lines 02 and 06. Do not include the quantity of toll concentrates.

Line 02—Quantity Purchased. Report for each year the total quantity of concentrates purchased from

unaffiliated suppliers by the smelter. Attach as a part of Exhibit B a description of the types and grades of these concentrates. Do not include the quantity of toll concentrates.

Line 03—Concentrate Cost. Report for each year the outlays paid to unaffiliated suppliers for concentrates. Attach as part of Exhibit B an explanation of the method or methods used in determining these outlays and relationship between concentrate prices and the types and grades of concentrates purchased from unaffiliated suppliers.

Line 04—Average Unit Price. Report for each year the average unit price paid for purchases of concentrates from unaffiliated suppliers. Generally, this value will be equivalent to Line 03 divided by Line 02. If this equivalency does not hold, attach as a part of Exhibit B an explanation of the variance.

Line 05—Average Concentrate Grade. Report for each year the average concentrate grade of concentrates purchased from unaffiliated suppliers. Attach as part of Exhibit B an explanation of this average. The average should correspond to the average price reported in Line 04.

Line 06—Quantity Purchases. Report for each year the total quantity of concentrates purchased from affiliated suppliers by the smelter. Attach as part of Exhibit B a description of the types and grades of these concentrates. Do not include the quantity of toll concentrates.

Line 07—Concentrate Cost. Report for each year the actual outlays paid to affiliated suppliers for concentrates. Attach as part of Exhibit B an explanation of the method or methods used in determining these outlays and relationship between concentrate prices and the types and grades of concentrates purchased from affiliated suppliers. Do not reflect any adjustments to market prices here.

Line 08—Average Unit Price. Report for each year the average unit price paid for purchases of concentrates from affiliated suppliers. Generally, this value will be equivalent to Line 07 divided by Line 06. If this equivalency does not hold, attach as part of Exhibit B an explanation of the variance.

Line 09—Average Concentrate Grade. Report for each year the average concentrate grade of concentrates purchased from affiliated suppliers. Attach as part of Exhibit B an explanation of this average. The average should correspond to the average price reported in Line 08.

Line 10—Total Concentrate Costs. Enter the sum of Line 03 and Line 07 for each year.

Line 11—Transfer Price Adjustments. Enter the amounts required to adjust outlays paid to affiliated suppliers to market value. Attach as part of Exhibit B a description of and the computations of any required cost adjustments.

Line 12—Other Cost Adjustments. Enter the amounts of any other cost adjustments required such as freight or allowances. Attach as part of Exhibit B the identification and the derivation of these adjustments.

Line 13—Adjusted Concentrate Cost. Enter for each year the adjusted concentrate cost reflecting the adjustments reported in Lines 11 and 12.

Line 14—Direct Labor Hours. Report for each year the quantity of direct labor hours required to support the processing levels previously reported. Attach as part of Exhibit B an explanation of the labor productivity factors involved.

Line 15—Average Hourly Wage Rate. Report for each year the average wage rate paid per unit of direct labor input. Attach as part of Exhibit B a description of direct labor cost factors under existing labor contracts and an explanation of the method or methods used to determine wage rates.

Line 16—Total Wage Payments. Enter for each year the product of Lines 14 and 15.

Line 17—Supplemental Employee Benefits. Report adjustments required to direct labor costs for other employee compensation under supplemental benefit plans. Attach as part of Exhibit B a description of such plans and their costs and an explanation of the method or methods used to determine such costs.

Line 18—Total Production Labor Cost. Enter for each year the total of Lines 16 and 17.

Lines 19, 22, 25, 28 and 31—Energy Quantities. Report for each year the quantity of energy by type required to support the processing levels reported in the smelter's revenue. Attach as part of Exhibit B, an explanation of energy use factors and qualities considered in determining the smelters energy requirements.

Lines 20, 23, 26, 29 and 32—Unit Prices. Report for each year the a price paid per unit of energy input by type of energy. Attach as part of Exhibit B, a description of the energy price factors under existing energy contracts and an explanation of the method or methods used to determine unit energy prices.

Lines 21, 24, 27, 30 and 33—Total Payments. Enter the products of quantity and prices paid for electricity (Lines 19 × 20), natural gas (Lines 22 × 23), coal (Lines 25 × 26), fuel oil (Lines 28 × 29), and other (Lines 31 × 32).

Line 34—Total Energy Costs. Enter for each year the total of Lines 21, 24, 27, 30 and 33.

Historical Capital Investment Summary—Schedule B.2

General

Report annual end-of-period asset investments and current liabilities associated during the fiscal years reported in Schedule B.1 with operation of the smelter subject to this NSO application.

The amounts assigned to the subject smelter should include both (1) investments and liabilities directly identifiable with the smelter's operating activities and (2) asset investments shared with other segments to the extent that a specific causal and beneficial relationship can be established for the inter-segment allocation of such investments. Do not allocate to the smelter the costs of assets maintained for general corporate purposes. Provide a detailed explanation of amounts classified as nontraceable on a separate schedule and attach as part of Exhibit B.

Applicants shall also restate trade receivables and payables for transfer price adjustments on the smelter's transactions with affiliated customers.

Line 01—Cash on Hand and Deposit. Report total cash balances assignable to the smelter's operations at the end of each fiscal year on the basis of causal and beneficial relationships with total corporate activities. Attach as part of Exhibit B an explanation of the basis used for allocation.

Line 02—Temporary Cash Investments. Report temporary cash investments in time deposits or other short-term securities. Include only those investments either held by the smelter to meet current-period tax payments and other budgeted expenditures specifically identifiable with the smelters continued operation. Exclude any temporary cash investments for which no specific future outlay requirement can be identified.

Attach as part of Exhibit B a schedule classifying temporary cash investments according to identifiable budgeted expenditure requirements.

Lines 03 and 04—Net Trade Receivables. Report trade accounts and notes, net of reserves for uncollectible items, assignable to the smelter in relation to its unaffiliated (Line 03) and affiliated (Line 04) customer sales and transfers. Trade receivables reported by the smelter as due from affiliated customers should be stated or, if necessary, restated on credit terms equivalent to those received by unaffiliated customers on a sale of comparable products. Attach as part of

Exhibit B a schedule showing adjustments in the smelter's receivables investments required to equate trade credit terms extended to affiliated and unaffiliated customers.

Lines 05 and 06—Inventory Investments. Report respective end-of-period investments in raw material, work-in-process and finished good inventories held to support the smelter's production and sale of products (Line 05) and associated inventories of other materials and supplies (Line 06). Inventory purchases from affiliated suppliers should be stated or, if necessary, restated at market prices prevailing on purchases from unaffiliated suppliers. Attach as part of Exhibit B a schedule (1) describing whether inventories have been valued on a last-in-first-out (LIFO), first-in-first-out (FIFO) or other cost allocation process, (2) describing the smelter's transfer pricing policies on inventory purchases from affiliated suppliers and (3) presenting adjustments required in reported inventory investments to reflect restatements of transfer prices on purchases from affiliated suppliers.

Line 07—Other Current Assets. Report prepaid expenses, deferred charges, non-trade notes and accounts receivable, and other assets classified as current for certified financial statement reporting purposes that are assignable to the smelter's operations. Attach as part of Exhibit B a schedule classifying these other current assets according to their types and amounts.

Line 08—Total Current Assets. Enter the total of amounts reported on Lines 01 through 07 for each fiscal year.

Lines 09 to 14—Property, Plant and Equipment. Report by individual line item property, plant and equipment investments assignable to smelter operations for each fiscal year. Include in gross facility investments at the end of each period both (1) property, plant and equipment directly associated with the smelter's operations and (2) facilities shared with other operating segments to the extent that a causal and beneficial relationship can be established for the inter-segment allocation of such facility investments.

Attach as part of Exhibit B a schedule reporting by individual line item the annual capital expenditures on additional property, plant and equipment investments in the smelter's operations. Further classify these annual capital expenditures into both (1) investments required to maintain the smelter versus investments in smelter expansion and improvement and (2) direct facility versus joint-use facility investments. Explain the method used for allocating capital expenditures on joint-use facilities to the smelter's operations. Refer to Line 17 instructions for additional reporting requirements on the smelter's facility investments.

Line 15—Total Smelter Investment. Enter the total of amounts reported on Lines 09 through 14 for each fiscal year.

Line 16—Accumulated Depreciation and Amortization. Report accumulated depreciation, amortization and other valuation charges recorded for certified financial statement reporting purposes in relation to smelter investment as reported on Line 15. Other valuation charges are defined in Financial Accounting Standards Board (FASB) Statement No. 19 as losses recognized in connection with an impairment in the value of an unimproved property below its acquisition cost. Refer to Line 17 instructions for additional reporting requirements on smelter facility investments.

Line 17—Net Smelter Investment. Enter the amount reported on Line 15 minus the amount reported on Line 16 for each fiscal year. Attach as part of Exhibit B a schedule classifying gross facility investments, accumulated depreciation, amortization charges, and net facility investments by major pollution control and non-pollution control components. Identify for each asset component the direct versus joint-use investments assigned to the smelter and explain the basis used to allocate amounts associated with joint-use facilities to the smelter.

Line 18—Other Non-Current Assets. Report other assets assignable to the smelter's operations for each fiscal year. Attach as part of Exhibit B a schedule reporting by type and amount the major components of such investments.

Line 19—Total Smelter Capital Investment. Enter the total of amounts reported on Lines 08, 17 and 18 for each fiscal year.

Lines 20 and 21—Trade Accounts and Notes Payable. Report trade accounts and notes due on the smelter's purchases from unaffiliated suppliers (Line 20) and on its inter-segment transfers or purchases from affiliated suppliers (Line 21) Trade payables reported by the smelter as due to affiliated suppliers should be stated or, if necessary, restated on terms equivalent to those received from unaffiliated suppliers on a purchase of comparable materials. Attach as part of Exhibit B a schedule showing adjustments required on the smelter's trade payables to equate trade credit terms received from affiliated and unaffiliated suppliers.

Line 22—Other Expense Accruals. Report payments classified as current for salaries and wages, other employee benefits, operating taxes and related operated expenses assignable to the smelter's operations during each fiscal year. Attach as part of Exhibit B a schedule classifying by type and amount the major components of such accruals.

Line 23—Current Notes Payable. Report payments due to nontrade creditors on short-term financing arrangements directly associated with the smelter's operations. Exclude current installments due on long-term debt financing arrangements, notes due to officers and directors, intersegment loans or advances and loans or advances from affiliated operating segments.

Line 24—Other Current Liabilities. Report other nontrade payables classified as current obligations assignable to the smelter's operations.

Line 25—Total Current Liabilities. Enter the total of amounts reported on Lines 20 through 24 for each fiscal year.

Line 26—Net Smelter Capital Investment. Enter the amount reported on Line 19 minus the amount reported on Line 25 for each fiscal year.

Cash Proceeds From Liquidation—Schedule B.2.a

General

Applicants should determine the current salvage value of their existing investment in the smelter as the net proceeds that could be derived through an orderly liquidation of the smelter's assets. The net cash proceeds should be reported after an appropriate allowance for disposal costs, contractual claims against the smelter (e.g., labor termination penalties), and income tax effects on the corporation of such liquidation costs.

The applicant must stipulate the most advantageous alternative market (use) for the smelter's facilities. Generally, this market will be:

- Secondary market for used plant and equipment.
- Sale for scrap.
- Abandonment where the disposal cost exceeds scrap value.

The current net salvage value should be disaggregated into the same property, plant and equipment asset groups reported under the historical capital investment summary, Schedule B.2.

Line 01—Current Assets. Enter in Columns 1 and 2, the value of total current assets shown in Line 08 of Schedule B.2 (Historical Capital Investment Summary) for 1978. No gain or loss should be reported in Columns 3 through 5 for the liquidation of current asset investments.

Lines 02–07—Property Plant and Equipment. Enter in Column 1 the

appraised liquidation value (in terms of pretax cash proceeds) of the smelter by asset group. This estimate should be certified by a qualified third party professional appraiser and shall represent the best use and highest alternative value of these assets. The liquidation value of any assets which are jointly used by the smelter and other operating segments shall be excluded if, upon closure of the smelter, such assets would continue in service for the non-smelter activity.

In Column 2, report the net book value of these assets for which liquidation values have been reported in Column 1. The reported values should correspond with amounts reported for 1978 in lines 09 through 15 in Schedule B.2 as adjusted for appropriate eliminations of joint-use facilities and reconciliation to a net book value as reported for income taxes. Attach as part of Exhibit B supporting schedules showing all adjustments and conversion of net book value as reported on the financial statements to net book value, that would be used for income tax purposes.

Compute Column 3 as Column 1 less Column 2. The gain (or loss) shown in Column 3 shall be segregated into ordinary income and capital gains components subject to taxation pursuant to applicable income tax rules. Enter ordinary income in Column 4 and capital gains in Column 5.

Line 08—Total Smelter Investment. Enter the sum of lines 02 through 07 for each of the columns.

Line 09—Other Non-current Assets. In Column 1, report the appraised value of other non-current assets in accordance with the instructions for Line 18, Schedule B.2, *except* that any joint asset(s) that would continue in the event of smelter liquidation shall be excluded. This estimate shall be certified by a qualified third party professional appraiser.

In Column 2, report the net book value of the non-current assets directly corresponding to those assets included in the liquidation value estimated under Column 1.

The remaining columns shall be completed in accordance with the instructions given above for Lines 02 to 06.

Line 10—Total Smelter Value. Enter the sum of Lines 01, 08 and 09.

Line 11—Total Current Liabilities. Report in both Columns 1 and 2, the value of total current liabilities shown in Line 25 of Schedule B.2 for 1978.

Line 12—Gross Liquidation Value. Line 10 less Line 11.

Line 13—Liquidation Costs. In Columns 1, 3 and 4, report the value of any liquidation costs such as labor contract termination penalties, severance pay and related costs, associated with closure of the smelter.

Line 14—Taxable Gain (or Loss). Enter in Columns 4 and 5, the differences between Line 12 less Line 13.

Line 15—Income Tax Rate. Enter the sum of the Federal, state and local marginal tax rates of the firm for ordinary income and capital gains in columns 4 and 5, respectively. Attach as part of Exhibit B a schedule detailing the estimated marginal tax rate by taxing entity.

Line 16—Income Tax on Gain (or Loss). In Columns 4 and 5, enter the product of Line 14 multiplied by the marginal income tax rates reported in Line 15. In Column 1 enter the sum of Column 4 plus Column 5.

Line 17—After-Tax Cash Proceeds. Line 12 less Lines 13 and 16. This computation applies to Column 1 only.

Constant Controls Forecast Profit and Loss Summary—Schedule C.1

General

Report annual forecasts of operating revenues, operating costs and income taxes anticipated during calendar years 1980 through 1986 from operation of the smelter subject to this NSO application. These *constant controls forecasts should be based on an assumption that the applicant immediately implements a program of additional pollution control facility investments sufficient to achieve full compliance* with the smelter's SIP stack emission limitations for sulfur dioxide.

The assumed investment program should be based on whichever adequately demonstrated system, applicable to the smelter, that would be most economically beneficial subsequent to installation of the system. For this purpose, adequately demonstrated systems include the technology underlying EPA's new source performance standards for copper, lead and zinc smelters (40 CFR Part 60, Subparts P, Q and R) and the following control systems: Magnesium oxide concentration, lime/limestone scrubbing and ammonia scrubbing.

Copper smelters which will process concentrates containing an average of 1,000 pounds per hour or more of arsenic during the forecast period should assume that they will be required to use best engineering techniques to control fugitive emissions of arsenic. All smelters should assume that they will be required to install whatever technically feasible equipment is necessary to reduce their process and fugitive emissions of lead enough to achieve a concentration of 1.5 micrograms per cubic meter (mg/m^3) on a 90-day average basis in the ambient air by January 1, 1985. All smelters should also assume that they will be required to meet all other regulatory requirements in effect at the time the application is made.

Line 01—Primary Metal Sales Revenue. Enter the totals reported in Schedule C.1.a, Line 40.

Line 02—Co-product and By-product Sales Revenue. Enter the totals reported in Schedule C.1.a, Line 57.

Line 03—Tolling Service Revenues. Enter the totals reported in Schedule C.1.a, Line 53.

Line 04—Other Operating Revenues. Report operating revenues anticipated from sources not accounted for under Lines 01 through 03. Refer to instructions for Line 04 in Schedule B.1 for items that should not be included in "other" operating revenues. Attach as part of Exhibit B a schedule showing annual amounts forecasted by individual revenue component for "other" operating revenues associated with the smelter's forecast constant controls operations. Identify in the supporting schedule any differences in the "other" revenue components reported in Schedules B.1 and C.1 and explain the reasons for such differences.

Line 05—Total Operating Revenues. Report the total of amounts reported under Lines 01 through 04.

Line 06—Concentrate Costs. Enter the totals reported in Schedule C.1.b, Line 13.

Line 07—Other Material Costs. Report total costs forecasted for flux, refractories, coke and other materials directly associated with the smelter's processing of concentrates. Attach as part of Exhibit B a schedule showing the annual amounts forecasted by major material cost components. For each cost component, identify the forecasted quantity and unit price elements of material cost and explain the basis for forecasting these quantity and price elements. Identify in the supporting schedule any differences in the "other" material cost components shown in Schedules B.1 and C.1 and explain the reasons for such differences.

Line 08—Production Labor Costs. Enter the totals reported for the years 1980 through 1986 in Schedule C.1.b, Line 18.

Line 09—Energy Costs. Enter the totals reported for the years 1980 through 1986 in Schedule C.1.b, Line 34.

Line 10—Pollution Control Costs. Report the total costs forecasted for expenses identifiable with operation and maintenance of the additional pollution control equipment and facilities to achieve constant controls.

By-product credits associated with operation of the pollution control facilities should be eliminated from the cost accounts and reclassified to Schedule C.1.a, Line 55. Attach a schedule as part of Exhibit B classifying pollution control costs by major cost components. Explain the basis used for estimating each of the cost components.

Line 11—Production Overhead Costs. Report the total costs forecasted for indirect labor, indirect materials and other production overhead costs associated with the smelter's constant controls forecasts. Attach as part of Exhibit B a schedule showing annual overhead costs projected by major cost components associated with the smelter's operations. For each cost component, where appropriate, identify the forecasted quantity and unit price elements of overhead costs and explain the basis for estimating these quantity and price elements. Also identify in the supporting schedule any differences in production overhead cost classifications used in Schedules B.1 and C.1 and explain the reasons for such differences.

Line 12—Other Production Costs. Report other forecasted production costs not previously reported on Lines 06 through 11. Attach as part of Exhibit B supporting schedules showing the basis of the forecasts.

Line 13—Total Cost of Sales. Report the sum of operating costs reported on Lines 06 through 12.

Line 14—Gross Operating Profit. Report the difference between Line 05 minus Line 13.

Line 15—Selling, General and Administrative Expenses. Report the total costs forecasted for administrative, marketing and general corporate overhead functions that directly or indirectly support the smelter's operations. Refer to the NSO Financial Reporting Overview for a general discussion of indirect cost allocations from overhead cost pools. Attach as part of Exhibit B a schedule classifying selling, general and administrative expenses into major cost components. Indicate whether each component represents costs directly assignable to the smelter or indirect costs allocated from other business segments to the smelter. Explain the basis used for estimating the amount of expected costs included in each component and the basis used for allocating indirect cost elements to the smelter. Identify and explain any differences in the selling, general and administrative cost classification used in Schedules B.1 and C.1.

Line 16—Taxes, Other than Income Taxes. Report the total costs forecasted for property taxes and associated levies paid to governmental units by or for the benefit of the firm's smelter operations. Attach as part of Exhibit B a schedule classifying operating taxes by major cost components. Indicate whether each cost component represents costs directly assignable to the smelter or indirect costs allocated from overhead cost pools. Explain the basis used for estimating the costs included in each component and the basis for allocating indirect taxes to the smelter. Identify and explain any differences in the component classifications used in Schedules B.1 and C.1.

Line 17—Exploration and Research Costs. Report the total estimates of costs incurred directly by or for the benefit of the smelter operations. Attach as part of Exhibit B a schedule classifying the costs by major direct and indirect cost components. Explain the basis for estimating the costs assigned to each component. Identify and explain any differences in pro forma versus historical cost classifications used in Schedules B.1 and C.1.

Line 18—Pollution Control Facility Depreciation and Amortization. Report the estimates of depreciation and amortization charges associated with the smelter's forecasted investment in constant controls pollution control equipment and facilities. Attach as part of Exhibit B supporting schedules classifying pollution control facilities by major assets or asset groups. For each facility component, indicate the depreciation or amortization method that would be reported for tax purposes. Based on that method, report the original cost of the component assets, undepreciated balance of the component assets, the remaining depreciable life and the annual depreciation or amortization charge. Indicate for each asset component whether the depreciation and amortization charges represent direct cost assignments or indirect cost allocations to the smelter.

Line 19—Other Smelter Facility Depreciation and Amortization. Report the pro forma estimates of depreciation and amortization charges associated with the smelter's investment in equipment and facilities other than those classified as pollution control facilities. Attach as part of Exhibit B supporting schedules prepared according to the instructions for Line 18 above.

Line 20—Interest on Short-Term Debt. Report the estimates of interest and other financing charges on forecasted short-term obligations as classified in the smelter's current liabilities on Schedule B.2. Interest and associated financing charges on long-term debt should *not* be included as an expense identifiable with the smelter's operations. Attach as part of Exhibit B a schedule showing the interest-bearing, short-term debt contracts identifiable with the smelter's operations, the interest rate projected for these contracts and the estimated annual interest charges. Identify and explain any differences in the forecasted versus historical classification in Schedules B.1 and C.1 of short-term debt contracts identifiable with the smelter operations.

Line 21—Miscellaneous Operating Expenses. Report only the total operating expenses associated with or allocated to the smelter that cannot be appropriately classified in one of the preceding line items. Attach as part of Exhibit B a schedule showing the classification of these residual operating expenses into major cost components. Explain the basis used for forecasting the cost under each component. Identify each cost component in terms of direct or indirect cost and explain the basis used for allocating the indirect costs to smelter operations. Identify and explain any differences in the forecasted versus historical cost classifications included in Schedules B.1 and C.1.

Line 22—Total Other Operating Expenses. Enter the sum of operating costs reported on Lines 15 through 21.

Line 23—Income From Operations. Report the balance obtained by subtracting Line 22 from Line 14.

Line 24—Income Taxes. Multiply income from operations by the sum of the Federal, state and local marginal tax rates. Attach as part of Exhibit B a schedule detailing the estimated marginal tax rate by taxing entity.

Line 25—Net Income from Operations. Report the balance obtained by subtracting Line 24 from Line 23.

Supplemental Constant Controls Revenue Data—Schedule C.1.a

General

Report forecasts detail of annual indicated operating revenue factors anticipated during the years 1980 through 1986 from operation of the smelter subject to this NSO application. These details shall support the summary revenue forecasts reported on Schedule C.1. Report forecasted information required for each item in a manner consistent with the instructions for Schedule B.1.a. Attach as part of Exhibit B schedules to (1) explain the methods used to make the required forecasts, (2) explain differences, if any, between historical trends and the forecasts and (3) data and information to support the forecasts. The forecast revenue total in Schedule C.1.a shall correspond to those reported on Schedule C.1.

Supplemental Constant Controls Cost Data—Schedule C.1.b

General

Report forecasts of annual indicated operating cost factors anticipated during the years 1980 through 1986 from operation of the smelter subject to this NSO application. These details shall support the summary cost forecasts on Schedule C.1. Report forecasted information required for each item in a manner consistent with the instructions for Schedule B.1.b. Attach as part of Exhibit B schedules to (1) explain the methods used to make the required forecasts, (2) explain differences, if any, between historical trends and the forecasts and (3) data information to support the forecasts. The forecast cost totals in Schedule C.1.b shall correspond to those reported on Schedule C.1.

Constant Controls Sustaining Capital Investment Summary—Schedule C.2

General

The applicant should estimate and report, in Schedule C.2, yearly sustaining capital outlays for maintenance of the smelter's existing productive capability. These estimates should be forecast under the assumption that full compliance with SIP emission limitations for SO_2 will be achieved. Major elements of these outlays should be disclosed, as well as the total of such outlays. Estimates shall be restricted to those items which will be capitalized for tax purposes. These outlays shall primarily be for plant replacement, although outlays for improvements and expansion may be included to the extent that improvements and/or expansion, exclusive of required pollution control outlays, can be justified as economically feasible. Estimates of sustaining capital shall exclude any incremental investment for constant control requirements. Sustaining capital investments in facilities shared with other operating segments shall be allocated in accordance with the instructions given below.

Estimates of sustaining capital shall be compatible with productive capacity and pollution control requirements underlying the operating revenue and cost forecasts incorporated in Schedule C.1.

Lines 01 to 06—Sustaining Capital. Report by individual line item property, plant and equipment sustaining capital investments assignable to smelter operations for each fiscal year. Include both (1) property, plant and equipment directly associated with the smelter's operations and (2) facilities shared with other operating segments to the extent that a causal and beneficial relationship can be established for the intersegment allocation of such facility investments.

Attach as part of Exhibit B a schedule disclosing by individual line item the major elements of annual capital expenditures for sustaining capital. Further classify these annual capital expenditures into both (1) investments required to maintain the smelter versus investments in smelter expansion and improvements and (2) direct facility versus joint-use facility investments. Explain the method used for allocating capital expenditures on joint-use facilities to the smelter's operations.

Line 07—Total Smelter Sustaining Capital. Enter the total of amounts reported on Lines 01 through 06 for each fiscal year. Transfer the reported total for each year to Schedule A.1, Line 03.

Interim Controls Forecast Profit and Loss Summary—Schedule D.1

General

Report annual forecasts of operating revenues, operating costs and income taxes for the years 1980 through 1986 from operation of the smelter, subject to this controls waiver application. These interim controls *forecasts should be based on an assumption that the applicant immediately implements a program of interim controls.*

The assumed investment program should be based on the installation and operation of a well-designed double-absorption sulfuric acid plant to treat all strong gas streams. The interim controls projection may, but need not, account for other regulatory requirements on the same basis as for other applicants. If this is done, however, it should be assumed that the SO_2 controls are also in an interim controls configuration.

Report forecasted information required by each individual line item in a manner consistent with the instructions for Schedule C.1. Attach as part of Exhibit B supporting schedules describing and explaining any differences between Schedule B.1 and the estimates reported in Schedule D.1. Transfer the appropriate amounts reported for each year from this Schedule to Schedule A.2.

Supplemental Interim Controls Revenue Data—Schedule D.1.a

General

Report forecasted revenue information for each line item in a manner consistent with the instructions for Schedules B.1.a and C.1.a.

Supplemental Interim Controls Cost Data—Schedule D.1.b

General

Report forecasted cost information for each line item in a manner consistent with the instructions for Schedules B.1.g and C.1.b.

Interim Controls Sustaining Capital Investment Summary—Schedule D.2

General

The applicant should estimate and report in Schedule D.2 yearly sustaining capital outlays compatible with productive capacity and control requirements underlying the revenue and cost forecasts reported on Schedule D.1. Report forecasted sustaining capital outlays for each line item in a manner consistent with the instructions for Schedule C.2.

EPA

Environmental Protection Agency

Primary Nonferrous Smelter Order Application

Part I—IDENTIFICATION INFORMATION

1. Firm name
2. Street/Box/RFD
3. City
4. State
5. Zip Code
6. IRS Employer Identification No.
7. SEC 1934 Act Registration Number
8. Smelter Iden.
9. Street/Box/RFD
10. City
11. State
12. Zip Code
13. Contact Person
14. Title
15. Street/Box/RFD
16. Telephone
17. City
18. State
19. Zip Code

Part II—CERTIFICATION

I certify that the information provided herein and appended hereto is true and accurate to the best of my knowledge. I understand that this information is being required, in part, under the authority of Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Name
Title
Signature
Date

Schedule A.1.—*Constant Controls Forecast Summary*

[Smelter Identification]

	1980	1981	1982	1983	1984	1985	1986	Total
A. Operating cash flow projection:								
1. Net income from operation.....01								XXXXX
2. Capital expenditure projections:								
a. Constant controls.....02								XXXXX
b. Sustaining capital.....03								XXXXX
c. Total.....04								XXXXX
3. Adjusted cash flow projections...05								XXXXX
4. Discount factors.....06								XXXXX
5. Present value of future cash flows.....07								XXXXX
B. Net present value:								
1. Terminal value.....08								
2. Discount factor.....09								
3. Present value of terminal salvage value.....10								
4. Present value of future adjusted.....								
5. Cash flows.....11								
6. Total present value.....12								
7. Current salvage value.....13								
8. Net present value.....14								

Schedule A.2.—*Interim Controls Forecast Summary*

[Smelter Identification]

	1980	1981	1982	1983	1984	1985	1986	Total
A. Gross operating profit.....01								XXXXX
B. Operating cash flow projection:								
1. Net income from operations.....02								XXXXX
2. Depreciation and amortization:								
a. Pollution control facilities.....03								XXXXX
b. Other smelter facilities.....04								XXXXX
3. Operating cash flow.....05								XXXXX
4. Capital expenditure projections:..								
a. Interim controls.....06								XXXXX
b. Sustaining capital.....07								XXXXX
c. Total.....08								XXXXX
5. Net cash flow projections.....09								XXXXX
6. Discount factors.....10								XXXXX
7. Present value of future cash flow.....11								XXXXX
C. Net present value:								
1. Terminal value.....12								
2. Discount factor.....13								
3. Present value of terminal salvage value.....14								
4. Present value of future cash flows.....15								
5. Total present value.....16								
6. Current salvage value.....17								
7. Net present value.....18								

Schedule B.1.—*Historical Profit and Loss Summary*

[Smelter Identification]

	1975	1976	1977	1978	1979
A. Operating revenues:					
1. Primary metal sales.....01					
2. Coproduct and byproduct sales.....02					
3. Tolling service revenues.....03					
4. Other operating revenues.....04					
5. Total operating revenues.....05					
B. Cost of sales:					
1. Concentrates processed.....06					
2. Other materials.....07					
3. Production labor.....08					
4. Energy costs.....09					
5. Pollution control cost.....10					
6. Production overhead.....11					
7. Other production costs.....12					
8. Total cost of sales.....13					
C. Gross operating profit.....14					
D. Other operating expenses:					
1. Selling, general and administrative.....15					
2. Taxes, other than income tax.....16					
3. Exploration and research costs.....17					
4. Depreciation and amortization:					
a. Pollution control facilities.....18					
b. Other smelter facilities.....19					
5. Interest on short term debt.....20					
6. Miscellaneous operating expenses.....21					
7. Total other operating expenses.....22					
E. Income from operations.....23					
F. Other income and (expense):					
1. Gain/(loss) on disposition of property.....24					
2. Miscellaneous other income and (expense).....25					
3. Total other income and (expense).....26					
G. Net taxable income.....27					

Schedule B.1.a.—*Supplemental Historical Revenue Data*

[Segment Identification]

		1975	1976	1977	1978	1979
A. Copper product sales:						
1. Total quantity sold	01					
2. Unaffiliated customer sales:						
a. Quantity sold	02					
b. Operating revenue	03					
c. Average unit price	04					
d. Average product grade	05					
3. Affiliated customer sales:						
a. Quantity sold	06					
b. Operating revenue	07					
c. Average unit price	08					
d. Average product grade	09					
4. Adjusted copper revenues:						
a. Total copper revenues	10					
b. Transfer price adjustment	11					
c. Other revenue adjustments	12					
d. Adjusted copper revenues	13					
B. Lead product sales:						
1. Total quantity sold	14					
2. Unaffiliated customer sales:						
a. Quantity sold	15					
b. Operating revenue	16					
c. Average unit price	17					
d. Average product grade	18					
3. Affiliated customer sales:						
a. Quantity sold	19					
b. Operating revenue	20					
c. Average unit price	21					
d. Average product grade	22					
4. Adjusted lead revenues:						
a. Total lead revenues	23					
b. Transfer price adjustment	24					
c. Other revenue adjustments	25					
d. Adjusted lead revenues	26					
C. Zinc product sales:						
1. Total quantity sold	27					
2. Unaffiliated customer sales:						
a. Quantity sold	28					
b. Operating revenue	29					
c. Average unit price	30					
d. Average product grade	31					
3. Affiliated customer sales:						
a. Quantity sold	32					
b. Operating revenue	33					
c. Average unit price	34					
d. Average product grade	35					
4. Adjusted zinc revenue:						
a. Total zinc revenues	36					
b. Transfer price adjustment	37					
c. Other revenue adjustments	38					
d. Adjusted zinc revenues	39					
D. Primary metal revenues	40					
E. Tolling service revenues:						
1. Total toll concentrates processed	41					
2. Unaffiliated customer revenues:						
a. Concentrates processed	42					
b. Operating revenue	43					
c. Average unit price	44					
d. Average product grade	45					
3. Affiliated customer revenues:						
a. Concentrates processed	46					
b. Operating revenue	47					
c. Average unit price	48					
d. Average product grade	49					
4. Adjusted tolling service revenues:						
a. Total tolling service revenue	50					
b. Transfer price adjustment	51					
c. Other revenue adjustments	52					
d. Adjusted tolling service revenues	53					
F. Coproduct and byproduct sales:						
1. Total coproduct revenues	54					
2. Total byproduct revenues:						
a. Pollution control facilities	55					
b. Other smelter processing	56					
3. Total coproduct and byproduct revenues	57					

Schedule B.1.b.—*Supplemental Historical Cost Data*

[Smelter Identification]

		1975	1976	1977	1978	1979
A. Concentrate costs:						
1. Total quantity purchased	01					
2. Unaffiliated purchases:						
a. Quantity purchased	02					
b. Concentrate cost	03					
c. Average unit price	04					
d. Average concentrate grade	05					

Schedule B.1.b.—*Supplemental Historical Cost Data—Continued*

[Smelter Identification]

		1975	1976	1977	1978	1979
3. Affiliated purchases:						
a. Quantity purchased	06					
b. Concentrate cost	07					
c. Average unit price	08					
d. Average concentrate grade	09					
4. Adjusted concentrate costs:						
a. Total concentrate costs	10					
b. Transfer price adjustment	11					
c. Other cost adjustments	12					
d. Adjusted concentrate cost	13					
B. Production labor cost:						
1. Direct labor hours	14					
2. Average hourly wage rate	15					
3. Total wage payments	16					
4. Supplemental employee benefits	17					
5. Total production labor cost	18					
6. Affiliated customer revenues						
C. Energy costs:						
1. Electricity:						
a. Quantity in kilowatt hours	19					
b. Price per kWh	20					
c. Total electricity payments	21					
2. Natural gas:						
a. Quantity in mcf	22					
b. Price per mcf	23					
c. Total natural gas payments	24					
3. Coal:						
a. Quantity per tons	25					
b. Price per ton	26					
c. Total coal payments	27					
4. Fuel oil:						
a. Quantity in gallons	28					
b. Price per gallon	29					
c. Total fuel oil payments	30					
5. Other (specify):						
a. Quantity (specific units)	31					
b. Price per unit	32					
c. Total payments	33					
6. Total energy costs	34					

Schedule A.—*Constant Controls Forecast Summary*

[Smelter Identification]

	1980	1981	1982	1983	1984	1985	1986	Total

Schedule B.2.—*Historical Capital Investment Summary*

[Smelter Identification]

		1975	1976	1977	1978	1979
A. Current assets:						
1. Cash on hand and deposit	01					
2. Temporary cash investments	02					
3. Trade receivables, net						
a. Unaffiliated customers	03					
b. Affiliated customers	04					
4. Inventories						
a. Raw materials and products	05					
b. Other materials and supplies	06					
5. Other current assets	07					
6. Total current assets	08					
B. Property, plant and equipment:						
1. Land	09					
2. Buildings and improvements	10					
3. Machinery and equipment	11					
4. Transportation equipment	12					
5. Pollution control facilities	13					
6. Other fixed assets	14					
7. Total smelter investment	15					
8. Less: Accumulated depreciation and amortization	16					
9. Net smelter investment	17					
C. Other noncurrent assets	18					
D. Total smelter capital investment	19					
E. Current liabilities:						
1. Trade accounts and notes payable						
a. Unaffiliated suppliers	20					
b. Affiliated suppliers	21					
2. Other expense accruals	22					
3. Notes payable, current	23					
4. Other current liabilities	24					
5. Total current liabilities	25					
G. Net smelter capital investment	26					

Schedule B.2.a.—*Cash Proceeds From Liquidation*

[Smelter Identification]

		(1) Estimated liquidation value	(2) Reported net book value	(3) Total gain (loss)	(4) Gain (loss) subject to taxation as— Ordinary income	(5) Capital gain
A. Total current assets	01			XXXXX	XXXXX	XXXXX
B. Property, plant and equipment:						
1. Land	02					
2. Buildings and improvements	03					
3. Machinery and equipment	04					
4. Transportation equipment	05					
5. Pollution control facilities	06					
6. Other fixed assets	07					
7. Total	08					
C. Other Noncurrent assets	09					
D. Total smelter value	10					
E. Total current liabilities	11			XXXXX	XXXXX	XXXXX
F. Gross liquidation value	12					
G. Liquidation costs	13		XXXXX			XXXXX
H. Net Taxable Gain (or loss)	14	XXXXX	XXXXX	XXXXX		
I. Income tax rate	15	XXXXX	XXXXX	XXXXX		
J. Income tax on gain (loss)	16		XXXXX	XXXXX		
K. After tax cash proceeds from liquidation	17		XXXXX	XXXXX	XXXXX	XXXXX

Schedule C.1.—*Constant Controls Forecast Profit and Loss Summary*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
A. Operating revenues:								
1. Primary metal sales	01							
2. Coproduct and byproduct sales	02							
3. Tolling service revenues	03							
4. Other operating revenues	04							
5. Total operating revenues	05							
B. Cost of sales:								
1. Concentrates	06							
2. Other materials	07							
3. Production labor	08							
4. Energy costs	09							
5. Production overhead	10							
6. Pollution control costs	11							
7. Other production costs	12							
8. Total cost of sales	13							
C. Gross Operating Profit	14							
D. Other operating expenses:								
1. Selling, general and administrative	15							
2. Taxes, other than income	16							
3. Exploration and research costs	17							
4. Depreciation and amortization								
a. Pollution control facilities	18							
b. Other smelter facilities	19							
5. Interest on short-term debt	20							
6. Miscellaneous operating expenses	21							
7. Total other operating expenses	22							
E. Income from operations	23							
F. Income taxes	24							
G. Net income from operations	25							

Schedule C.1.a.—*Supplemental Constant Controls Revenue Data*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
A. Forecasted copper product sales:								
1. Total quantity sold	01							
2. Unaffiliated customer sales:								
a. Quantity sold	02							
b. Operating revenue	03							
c. Average unit price	04							
d. Average product grade	05							
3. Affiliated customer sales:								
a. Quantity sold	06							
b. Operating revenue	07							
c. Average unit price	08							
d. Average product grade	09							
4. Adjusted copper revenues:								
a. Total copper revenues	10							
b. Transfer price adjustment	11							
c. Other revenue adjustments	12							
d. Adjusted copper revenues	13							

Schedule C.1.a.—*Supplemental Constant Controls Revenue Data—Continued*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
B. Forecasted lead product sales:								
1. Total quantity sold	14							
2. Unaffiliated customer sales:								
a. Quantity sold	15							
b. Operating revenue	16							
c. Average unit price	17							
d. Average product grade	18							
3. Affiliated customer sales:								
a. Quantity sold	19							
b. Operating revenue	20							
c. Average unit price	21							
d. Average product grade	22							
4. Adjusted lead revenues:								
a. Total lead revenues	23							
b. Transfer price adjustments	24							
c. Other revenue adjustments	25							
d. Adjusted lead revenues	26							
C. Forecasted zinc product sales:								
1. Total quantity sold	27							
2. Unaffiliated Customer sales:								
a. Quantity sold	28							
b. Operating revenue	29							
c. Average unit price	30							
d. Average product grade	31							
3. Affiliated customer sales:								
a. Quantity sold	32							
b. Operating revenue	33							
c. Average unit price	34							
d. Average product grade	35							
4. Adjusted zinc revenue:								
a. Total zinc revenues	36							
b. Transfer price adjustment	37							
c. Other revenue adjustments	38							
d. Adjusted zinc revenues	39							
D. Forecasted primary metal revenues								
E. Forecasted tolling service revenues:								
1. Total toll concentrates processed	40							
2. Unaffiliated customer revenues:								
a. Concentrates processed	41							
b. Operating revenue	42							
c. Average unit price	43							
d. Average product grade	44							
3. Affiliated customer revenues:								
a. Concentrates processed	45							
b. Operating revenue	46							
c. Average unit price	47							
d. Average product grade	48							
4. Adjusted tolling service revenues:								
a. Total tolling service revenues	49							
b. Transfer price adjustments	50							
c. Other revenue adjustments	51							
d. Adjusted tolling service revenue	52							
F. Co-product and by-product sales:								
1. Total co-product revenues	55							
2. Total by-product revenues from:								
a. Pollution control facilities	56							
b. Other smelter processing	57							
3. Total co-product and byproduct revenues	58							

Schedule C.1.b. —*Supplemental Constant Controls Revenue Data*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
A. Forecasted concentrate costs:								
1. Total quantity purchased	01							
2. Unaffiliated purchases:								
a. Quantity purchased	02							
b. Concentrate cost	03							
c. Average unit price	04							
d. Average concentrate grade	05							
3. Affiliated purchases:								
a. Quantity purchased	06							
b. Concentrate cost	07							
c. Average unit price	08							
d. Average concentrate grade	09							
4. Adjusted concentrate costs:								
a. Total concentrate costs	10							
b. Transfer price adjustment	11							
c. Other cost adjustments	12							
d. Adjusted concentrate cost	13							
B. Forecasted production labor cost:								
1. Direct labor hours	14							
2. Average hourly wage rate	15							
3. Total wage payments	16							
4. Supplemental employee benefits	17							
5. Total production labor cost	18							

Schedule C.1.b. —*Supplemental Constant Controls Revenue Data—Continued*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
C. Forecasted Energy Costs:								
1. Electricity:								
a. Quantity in kilowatt hours	19							
b. Price per kwh	20							
c. Total electricity payments	21							
2. Natural gas:								
a. Quantity in mcf	22							
b. Price per mcf	23							
c. Total natural gas payments	24							
3. Coal:								
a. Quantity per tons	25							
b. Price per ton	26							
c. Total coal payments	27							
4. Fuel oil:								
a. Quantity in gallons	28							
b. Price per gallon	29							
c. Total fuel oil payments	30							
5. Other (specify):								
a. Quantity (specific units)	31							
b. Price per unit	32							
c. Total payments	33							
6. Total energy costs	34							

Schedule C.2.—*Constant Controls Sustaining Capital Investment Summary*

[Smelter Identification]

Sustaining capital		1980	1981	1982	1983	1984	1985	1986
1. Land	01							
2. Buildings and improvements	02							
3. Machinery and equipment	03							
4. Transportation equipment	04							
5. Pollution control facilities	05							
6. Other fixed assets	06							
7. Total smelter sustaining capital	07							

Schedule D.1.—*Interim Controls Forecast Profit and Loss Summary*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
A. Operating revenues:								
1. Primary metal sales	01							
2. Co-product and by-product sales	02							
3. Tolling service revenues	03							
4. Other operating revenues	04							
5. Total operating revenues	05							
B. Cost of sales:								
1. Concentrates	06							
2. Other materials	07							
3. Production labor	08							
4. Energy costs	09							
5. Pollution control costs	10							
6. Production overhead	11							
7. Other production costs	12							
8. Total cost of sales	13							
C. Gross operating profit	14							
D. Other operating expenses:								
1. Selling, general and administrative	15							
2. Taxes, other than income tax	16							
3. Exploration and research costs	17							
4. Depreciation and amortization:								
a. Pollution control facilities	18							
b. Other smelter facilities	19							
5. Interest on short-term debt	20							
6. Miscellaneous operating expenses	21							
7. Total other operating expenses	22							
E. Income from operations	23							
F. Income taxes	24							
G. Net income from operations	25							

Schedule D.1.a.—*Supplemental Constant Controls Revenue Data*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
A. Forecasted copper product sales:								
1. Total Quantity Sold	01							
2. Unaffiliated customer sales:								
a. Quantity sold	02							
b. Operating revenue	03							

Schedule D.1.a.—*Supplemental Constant Controls Revenue Data—Continued*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
c. Average unit price	04							
d. Average product grade	05							
3. Affiliated customer sales:								
a. Quantity sold	06							
b. Operating revenue	07							
c. Average unit price	08							
d. Average product grade	09							
4. Adjusted copper revenues								
a. Total copper revenues	10							
b. Transfer price adjustment	11							
c. Other revenue adjustments	12							
d. Adjusted copper revenues	13							
B. Forecasted lead product sales:								
1. Total quantity sold	14							
2. Unaffiliated customer sales:								
a. Quantity sold	15							
b. Operating revenue	16							
c. Average unit price	17							
d. Average product grade	18							
3. Affiliated customer sales:								
a. Quantity sold	19							
b. Operating revenue	20							
c. Average unit price	21							
d. Average product grade	22							
4. Adjusted lead revenues:								
a. Total lead revenues	23							
b. Transfer price adjustments	24							
c. Other revenue adjustments	25							
d. Adjusted lead revenues	26							
C. Forecasted zinc product sales:								
1. Total quantity sold	27							
2. Unaffiliated customer sales:								
a. Quantity sold	28							
b. Operating revenue	29							
c. Average unit price	30							
d. Average product grade	31							
3. Affiliated customer sales:								
a. Quantity sold	32							
b. Operating revenue	33							
c. Average unit price	34							
d. Average product grade	35							
4. Adjusted zinc revenue:								
a. Total zinc revenues	36							
b. Transfer price adjustment	37							
c. Other revenue adjustments	38							
d. Adjusted zinc revenues	39							
D. Forecasted primary metal revenues	40							
E. Forecasted tolling services revenues:								
1. Total toll concentrates processed	41							
2. Unaffiliated customer revenues:								
a. Concentrates processed	42							
b. Operating revenue	43							
c. Average unit price	44							
d. Average product grade	45							
3. Affiliated customer revenues:								
a. Concentrates processed	46							
b. Operating revenue	47							
c. Average unit price	48							
d. Average product grade	49							
4. Adjusted tolling service revenues:								
a. Total tolling service revenue	50							
b. Transfer price adjustment	51							
c. Other revenue adjustments	52							
d. Adjusted tolling service revenues	53							
F. Co-product and by-product sales:								
1. Total coproduct revenues	54							
2. Total byproduct revenues from:								
a. Pollution control facilities	55							
b. Other smelter processing	56							
3. Total coproduct and byproduct revenues	57							

Schedule D.1.b.—*Supplemental Constant Controls Revenue Data*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
A. Forecasted concentrate costs:								
1. Total quantity purchased	01							
2. Unaffiliated purchases:								
a. Quantity purchased	02							
b. Concentrate cost	03							
c. Average unit price	04							
d. Average concentrate grade	05							
3. Affiliated purchases:								
a. Quantity purchased	06							
b. Concentrate cost	07							
c. Average unit price	08							
d. Average concentrate grade	09							

Schedule D.1.b.—*Supplemental Constant Controls Revenue Data—Continued*

[Smelter Identification]

		1980	1981	1982	1983	1984	1985	1986
4. Adjusted concentrate costs:								
a. Total concentrate costs	10							
b. Transfer price adjustment	11							
c. Other cost adjustments	12							
d. Adjusted concentrate cost	13							
B. Forecasted production labor cost:								
1. Direct Labor Hours	14							
2. Average Hourly Wage Rate	15							
3. Total Wage Payments	16							
4. Supplemental Employee Benefits	17							
5. Total Production Labor Cost	18							
C. Forecasted energy costs:								
1. Electricity:								
a. Quantity in kilowatt hours	19							
b. Price per kwh	20							
c. Total electricity payments	21							
2. Natural gas:								
a. Quantity in mcf	22							
b. Price per mcf	23							
c. Total natural gas payments	24							
3. Coal:								
a. Quantity per tons	25							
b. Price per ton	26							
c. Total coal payments	27							
4. Fuel oil:								
a. Quantity in gallons	28							
b. Price per gallon	29							
c. Total fuel oil payments	30							
5. Other (specify):								
a. Quantity (specific units)	31							
b. Price per unit	32							
c. Total payments	33							
6. Total energy costs	34							

Schedule D.2.—*Constant Controls Sustaining Capital Investment Summary*

[Smelter Identification]

Sustaining capital		1980	1981	1982	1983	1984	1985	1986
1. Land	01							
2. Buildings and improvements	02							
3. Machinery and equipment	03							
4. Transportation equipment	04							
5. Pollution control facilities	05							
6. Other fixed assets	06							
7. Total smelter sustaining capital	07							

[FR Doc. 80-18984 Filed 6-23-80; 8:45 am]

BILLING CODE 6560-01-M

federal register

Tuesday
June 24, 1980

Part IV

Department of Education

National Direct Student Loan; College Work-Study; Supplemental Educational Opportunity Grant; Guaranteed Student Loan; and Basic Educational Opportunity Grant Programs; Student Assistance General Provisions

DEPARTMENT OF EDUCATION

45 CFR Parts 168, 174, 175, 176, 177, and 190

Student Assistance General Provisions; National Direct Student Loan Program; College Work-Study Program; Supplemental Educational Opportunity Grant Program; Guaranteed Student Loan Program; and Basic Educational Opportunity Grant Program

AGENCY: Department of Education.

ACTION: Final Regulations.

SUMMARY: These regulations modify regulations published in 1979 which implement part A, subparts 1 and 2, and parts B, C, E, and F of Title IV of the Higher Education Act of 1965, as amended. They govern the operation of the National Direct Student Loan, College Work-Study, Supplemental Educational Opportunity Grant, Guaranteed Student Loan, and Basic Educational Opportunity Grant programs.

The modifications in the regulations for these programs are intended to alleviate administrative burdens at participating institutions of higher education, eliminate inequities affecting student applicants, and make several technical changes to correct or clarify the language of certain provisions in the regulations.

DATES: Effective Date: These regulations are expected to take effect 45 days after they are transmitted to the Congress. Regulations are usually transmitted to the Congress several days before they are published in the **Federal Register.** The effective date is changed by statute if the Congress disapproves the regulations or takes certain adjournments. If you want to know the effective date of these regulations, call or write the Department of Education contact person.

Comments

Although these revisions are being published as final regulations, the Secretary is soliciting comment on them. Comments may be submitted at the commenter's convenience; no closing date is specified.

FOR FURTHER INFORMATION CONTACT: William L. Moran, Bureau of Student Financial Assistance, Room 4318, ROB–3, 400 Maryland Avenue, S.W., Washington, D.C. 20202. Telephone (202) 472–4300.

SUPPLEMENTARY INFORMATION: In 1979 the Office of Education published new regulations for five of the title IV student aid programs: Basic Educational Opportunity Grant Program—January 25, 1979; Campus-based Programs, (National Direct Student Loan, College Work-Study, Supplemental Educational Opportunity Grant)—August 13, 1979; and Guaranteed Student Loan Program—September 17, 1979.

Additionally, on September 28, 1979, regulations were published containing general provisions relating to all Title IV student assistance programs. These regulations, based on section 497A of the Higher Education Act of 1965, establish minimum standards regarding audits, financial responsibility, and administrative capability for participating institutions.

All of these regulations have now been in effect for a number of months. During the intervening period of time since their publication a number of issues have been raised which necessitate changes in the regulations. These changes are intended to improve program operations in a number of areas. They are outlined in detail in the following summary.

Summary of Major Issues: Description of Proposed Revisions to Title IV Student Aid Program Regulations

1. *A revision in the definition of a "six month training program" in the Basic Grant regulations in order to reestablish eligibility for some previously eligible programs which were inadvertently made ineligible by the January 25, 1979 regulations.*

Until February 27, 1979, the date the comprehensive revision to the Basic Grant regulations published on January 25, 1979, took effect, the Basic Grant regulations defined an eligible program as, among other things, a program of at least six months duration. As a result, institutions whose programs were six calendar months in length were allowed to participate in the program. When the Basic Grant regulations were revised in 1979, the definition of a six month training program was added. The definition was identical to the one that had been in effect for several years under the campus-based programs, Supplemental Educational Opportunity Grant, College Work-Study, and National Direct Student Loan. Under this definition a six month training program was defined in terms of the education provided, i.e., 600 clock hours, 16 semester hours, or 24 quarter hours, rather than the length of time a particular program lasted.

It has come to the Secretary's attention that there are institutions offering six month programs that previously participated in the Basic Grant program that can no longer participate because these programs are not 600 clock hours, 16 semester hours, or 24 quarter hours in length. Further, the Secretary believes that for many of these programs, the course content and work load requirements may be considered equal to the course content and work load requirements of several approved (600 clock hour, 16 semester hour, or 24 quarter hour) programs. The Secretary's opinion in this regard is in many cases buttressed by a similar determination by the accrediting association that accredits these programs. Therefore, the Secretary has decided to amend the definition of a six month program, retroactive to February 27, 1979, by adding the following provision. The Secretary will consider a training program of less than 600 clock hours, 16 semester hours or 24 quarter hours to be a "six month training program" if the Secretary determines that the course content and student work load requirements support that determination and the accrediting agency that accredits the program certifies that the program is comparable to a 600 clock hour, 16 semester hour or 24 quarter hour program.

In the interest of consistency, identical changes are also being made in the campus-based program regulations.

2. *A revision in the Basic Grant regulations to provide a means for a student who has missed the March 15 application deadline to receive a grant on the basis of his or her Student Eligibility Report (SER) for the subsequent award period.*

In administering a program which serves several million applicants annually, experience has shown that application and correction deadlines must be established and adhered to without exception if a processing system of this magnitude is to function. The Basic Grant application deadline has been established as March 15 of the award period for which the grant is to be used. And, applications may be submitted over a period of about fourteen months. For example, applications for the 1979–80 award period (July 1, 1979–June 30, 1980) were available beginning in *January 1979,* and could be submitted to the processor as late as *March 15, 1980.*

In spite of this extended period of time during which applications are available, some students invariably miss the deadline. This problem has been of particular concern to institutions measuring progress in clock hours which have a number of courses beginning after March 15. They contend that often prospective students may not have decided before March 15 to attend school and, thus, would not have filed

for a Basic grant. Then, if those students decide to enroll after March 15, but before July 1, they will not be able to receive a grant for the portion of their study occurring before July 1—the beginning of the subsequent award period.

This problem has been alleviated without changing the deadline. Prior to the January 25, 1979 regulations, a student's Basic Grant was pro-rated if he or she was enrolled in a term that occurred in two award periods. That is, the student was paid out of the first award period for the period of time that occurred in that award period, and out of the second award period for the period of time that occurred in the second award period. The regulations published on January 25, 1979 required an institution which used terms and measured progress in credit hours to pay a student for a term that occurred in two award periods as if it occurred entirely in one award period. Thus, only one SER was used, the one for the award period in which the term was considered to have occurred, and the amount of eligibility used was subtracted from the student's total eligibility for that award period.

The pre-January 1979 rule remained in effect for institutions which measure progress in clock hours and for institutions which measure progress in credit hours but do not use terms. However, the current amendment of § 190.65 extends the January 25, 1979 rule to these two types of institutions. To make this possible technically, the definition of a payment period in § 190.2a(e) is also amended to allow a payment period for those types of institutions to occur in two award periods. (Under the January 25, 1979 regulation, this was not the case.) Consequently, if the payment period for a student at an institution which measures progress in clock hours occurs in two award periods, the institution must consider that payment period as occurring entirely in one or the other of those two award periods.

As a result, if a student enrolls in an institution that measures progress in clock hours on April 15, 1980, and the student's first payment period is scheduled to end around July 15, 1980, the institution will have to treat that payment period as occurring in the 1979–80 award period, or in the 1980–81 award period. Thus, if the student failed to file his 1979–80 application to have his "eligibility index" detemined by the March 15, 1980, deadline, the institution could still pay him for the work performed between April 15 and June 30 by considering the entire payment period as occurring in the 1980–81 award period. Of course, the student would have to file an application for the 1980–81 award period and the institution would have to consider that payment period as occurring in the 1980–81 award period for all of its students whose payment period begins on the same day.

The definition of a payment period was changed for institutions that do not use terms (usually clock hour institutions) as follows:

1. The payment period for a full-time student is generally one-half of that student's academic year if his or her program of study is at least one academic year.

2. The payment period for a full-time student is one half of that student's program of study if his or her program of study is less than one academic year.

3. For a part-time student, the institution first determines the period of time it would take a full-time student to complete one academic year or the program of study if it is less than one academic year. The institution would then determine the number of clock hours the part-time student would complete in that time period. The student's first payment period would be the period of time the student would need to complete one-half of those clock hours. The second payment period would be the period of time needed to complete the other half of the clock hours.

Examples:

1. For a full-time student in a clock hour institution in a program of study of at least one academic year, where the academic year is 900 clock hours, the student's first payment period would be the period of time it would take the student to complete 450 clock hours. The student's second payment period would be the period of time it would take to complete the remaining 450 clock hours.

2. For a full-time student in a clock hour institution in a program of study of 800 clock hours (i.e., less than one academic year), the student's first payment period is the period of time it would take to complete 400 clock hours. The student's second payment period would be the period of time needed to complete the remaining 400 clock hours.

3. For a part-time student in a clock hour institution in a program of study of at least one academic year, where the academic year is 900 clock hours, the institution would first determine the period of time it would take a full-time student to complete 900 clock hours and would then determine the number of clock hours the part-time student would finish in that period.

If the student was scheduled to complete 450 clock hours in that period, the student's first payment period is the period of time needed to complete 225 clock hours. The second payment period is the period of time needed to complete the second 225 clock hours.

4. For a part-time student in a clock hour institution in a program of less than one academic year, the institution would use the steps set forth in example 3, except that the period of reference would be the period of time that a full-time student would take to complete that course of study, rather than to complete the academic year. Thus, if the student were scheduled to complete 300 clock hours in the period of time that a full-time student would complete 600 hours (for a 600 hour program), the student's first payment period is the period of time needed to complete 150 clock hours. The second payment period is the period of time needed to complete the second 150 clock hours.

For clock hour institutions participating in the Basic Grant Program under the Regular Disbursement System, this change has been made applicable to terms which occur in both the 1979–80 and 1980–81 award periods. However, because of Department of Education contractual restraints, it will not become effective until a later date for clock hour institutions that participate under the Alternate Disbursement System.

The above explanation and examples relate to institutions with two payment periods. If an institution wishes to have three payment periods the payment periods would be one-third, rather than one-half, of an academic year or of a program of study that is less than an academic year. Similar rules would apply to institutions with a greater number of payment periods.

3. *A change in the definition of a half-time student to more realistically reflect half-time status, especially at institutions offering evening programs.*

This change is intended to reinstitute minimum hour requirements for half-time status which existed in previous Basic Grant regulations. Prior to the effective date of the January 25, 1979 regulations, the following minima for half-time student status were set forth in Basic Grant regulations:

(i) 6 semester hours or 6 quarter hours per academic term for institutions utilizing semester, trimester, or quarter hour systems; (ii) 12 semester hours or 18 quarter hours per school year for institutions which measure progress in terms of credit hours but which do not utilize semester, trimester, or quarter systems; or (iii) 12 clock hours per week for institutions which utilize clock hours to measure progress.

The minima for full-time status were as follows:

(i) 12 semester hours or 12 quarter hours per academic term for institutions utilizing semester, trimester, or quarter hour systems; (ii) 24 semester hours or 36 quarter hours per school year for institutions which measure progress in terms of such credit hours but which do not utilize semester, trimester, or quarter systems; or (iii) 24 clock hours per week for institutions which utilize clock hours to measure progress.

In the January 25, 1979 regulations, the full-time minima in the former regulations were retained. The half-time definition was revised, however, to provide that half-time status is "at least half the work load of a full-time student."

This change had a negative effect on some institutions where a full-time program exceeded the minimum requirements while the half-time program met but did not exceed the minimum requirements for half-time under the old regulations. This situation exists most frequently at institutions measuring progress in clock hours with full-time programs during the day and part-time programs in the evenings. In instances of this nature, a full-time program may be forty clock hours per week while the half-time program is twelve. Under the old regulations, half-time status of twelve hours would be acceptable. However, under the current regulations, twenty clock hours per week is necessary for half-time status when the full-time program requires forty hours per week.

Our revision in the regulations reestablishes the previous minima for half-time status and accommodates those who contend that it is unrealistic to expect half-time status always to be at least one-half of the full-time workload, especially when the full-time program may be offered in the day while the half-time program is offered in the evening.

4. *Provide that an unnotarized statement of educational purpose may be used in lieu of the current requirement of a notarized affidavit of educational purpose.*

This revision eliminates a requirement that is a burden on both students and institutions and that in some instances requires the student to pay a fee. Section 1746 of Title 28 of the United States Code provides that whenever, under Federal law, an affidavit is necessary, an unsworn declaration, subscribed as true under penalty of perjury, will be equally valid. Thus, applicable provisions of the Guaranteed Loan, Basic Grant, and campus-based regulations are being amended to provide that an institution may obtain an unnotarized statement of educational purpose from a student in lieu of an affidavit.

5. *Technical revisions to the Guaranteed Student Loan Program regulations published on September 17, 1979.*

The following changes in the GSLP regulations published on September 17, 1979, are being made in order to clarify the meaning of certain provisions and to eliminate certain duties previously imposed on program participants.

(a) Delete the rule under § 177.401(b)(7)(ii) that requires a guarantee agency to require its lenders to send GSLP checks directly to the student when the student is attending a foreign school.

(b) Change the phrase "during the first fiscal year" contained in § 177.407(b)(2)(ii)(A) to read "during the first twelve months" to be more consistent with section 428(f)(1)(C) of the Higher Education Act, which exempts guarantee agencies from certain minimum spending requirements under the administrative cost allowance for "the first year" of the agency's eligibility.

(c) Correct § 177.513(b) to require that a lender report an assignment of loans under the FISLP only if the right to receive interest benefits or special allowance has been assigned. This correction is consistent with current policy.

(d) Correct a cross-reference in § 177.516(a)(1)(ii).

(e) Revise § 177.601(b) (2) and (3) to make clear that the evidence of loan denial by a commercial lender is required only for an undergraduate student who has not previously obtained a loan made or originated by the school from which the student currently is seeking to obtain a loan.

(f) Amend § 177.607 (f) and (g) to establish one set of rules for how a school must process a late disbursement check, whether the check arrives after the end of the period for which the loan was intended or during that period but after the student has withdrawn. Also, amend § 177.509(g) to clarify the lender's role regarding late disbursement under the FISLP.

(g) Clarify § 177.611, so that the formula for determining the school-lender's default ratio includes the principal amount of loans that went into default during the year for which the ratio is being determined. This conforms to section 435(g)(3) of the Higher Education Act of 1965, as amended, which refers to loans in default during "each such year."

6. *Revisions in the financial aid transcript requirement published in the regulations setting forth general provisions on fiscal and administrative standards (45 CFR 168.14).*

When the fiscal and administrative standards regulations were published on September 28, 1979, we solicited public comment on their content, as we had done with the August 10, 1978, notice of proposed rulemaking on which these regulations were based. Although comments have been received on practically all sections of these regulations, the majority of the comments have been directed to § 168.14, the requirement that an institution maintain, and forward to another institution upon request, a transcript listing the Title IV financial aid a student has received at the former institution. The correspondence we have received and our discussions with members of the financial aid community indicate that serious difficulties may arise from several of the requirements included in § 168.14.

The financial aid transcript requirement, as it appeared in the September 28 regulations, had two main objectives:

(a) To prevent awards exceeding the statutory maxima, in those programs having statutory maxima, by ensuring that a financial aid administrator will know the amounts of aid a transfer student has received at institutions he or she previously attended, and

(b) To prevent a student from receiving any Title IV assistance if he or she is in default on a Title IV loan or owes a repayment on a Title IV grant received for study at an institution that student previously attended.

The financial aid community has expressed several major concerns about the financial aid transcript requirement. They are listed below followed by our proposed revision of the regulation to accommodate those concerns:

(a) *Issue:* The possibility exists that an eligible student may be unable to receive Title IV aid in a timely manner solely because his of her former institution is slow in forwarding the requested transcript to the institution where the student is currently enrolled. In this case, the student would be penalized in a situation over which neither he nor his or her current institution has any control. Furthermore, in the case of a GSL, some additional administrative problems would occur affecting both the lenders and the guarantee agencies, by allowing a check to be held until a transcript arrived. For example, determinations would have to be made about: (1) How long an institution could hold a check which had

been disbursed by a non-school lender before having to return it to that lender; (2) whether the check that a student never received due to lack of a transcript would be handled as a cancelled loan or a loan paid in full; (3) whether insurance premiums for these loans would have to be refunded to lenders by the guarantee agencies; and (4) whether lenders would be required to reinvestigate a student's eligibility prior to completely denying the loan to a student whose transcript never arrived.

Revision: The regulations provide that an institution may disburse Title IV funds to a student for one payment period without a financial aid transcript if the transcript, or a notice that the transcript will not be forthcoming has not been provided in a timely manner. But no subsequent payments (other than GSL's when the institution is *not* the lender) may be made until the institution receives the transcript or a letter from the student's previous institution which states that the transcript will not be forthcoming for specified reasons other than the student's default on a loan or liability for a refund on a grant.

The revised regulation will also provide that all GSLP funds may be released to a student who has enrolled, as required by that program's regulations (45 CFR Part 177), except that if the institution is a GSLP lender under the FISLP program or a guarantee agency program, it must withhold disbursement of any GSLP funds to a GSLP borrower in accordance with the provisions which apply to the other Title IV programs.

This revision is being made, due to the complications that could arise if the requirement for withholding of GSLP loans were made applicable to all institutions. We feel that it will be consistent with the other transcript requirements to limit the provision's applicability, at least for the present, to institutions that can actually make GSLP loans.

(b) *Issue:* Some information required by the current regulation to be on the financial aid transcript may already be available through other sources. The processing systems of the agencies which insure Guaranteed Student Loans have a mechanism for rejecting applications when statutory loan limits have been reached or when a student is in default on a loan previously insured by that insuring agency.

We anticipate that within the near future the tracking systems which monitors the amount of Basic Grant eligibility a student has used will be able to report *in a more timely fashion* the cumulative amount of eligibility a student has used up to the current award period. If this information is available through the central processor, it would be unnecessary to require institutions to collect on the transcript information on cumulative Basic Grant eligibility used. Thus, the transcript would need to include only the amount of eligibility used within the award period when a student is transferring to ensure that the student's Scheduled Award for that award period is not exceeded.

Revision: To eliminate requirements that institutions collect information that will be available from other sources, we are eliminating the requirement that Guaranteed Student Loan information and cumulative Basic Grant information be included on the transcript. The regulation will therefore only require the institution to provide information concerning the amounts of loan funds advanced for each award period under the NDSL program, the amount of grant funds disbursed for each award period under the SEOG program, and the amounts of Basic Grant disbursements and Scheduled Awards for the award period in which a student transfers.

(c) *Issue:* The current transcript regulation requires transcripts from every student who has attended a previous institution before Title IV aid can be disbursed to that student, without regard to the number of hours for which the student was enrolled at the previous institution or whether the student was enrolled in a foreign institution.

Revision: The regulation is being revised to provide that the transcript is required only if the student received a Supplemental Grant or National Defense/Direct Student Loan at the institution or a Basic Grant in the award period in which the transcript request was made.

(d) *Issue:* A number of institutions have indicated that the November 8, 1979 effective date of the fiscal and administrative standards regulations has created an administrative burden with regard to the implementation of the transcript requirement. They have indicated that this requirement could much more easily be put into effect if its implementation were postponed until the beginning of the coming award year.

Revision: To eliminate the administrative burden caused by implementing the transcript requirement in the middle of the award year, the former regulation is revoked retroactive to November 8, 1979, its original effective date, and the revised transcript requirements are made effective July 1, 1980.

7. *Removal of the Guaranteed Student Loan Program from the formula for distributing repayments of cash disbursements made directly to a student in the fiscal and administrative standards regulations (45 CFR 168.21(c)).*

Section 168.21 of the fiscal and administrative standards regulations sets forth formulae to be used in determining amounts to be returned to Title IV programs when (a) an institutional refund is due to a student, and (b) a portion of a cash payment is to be returned by the student because the student has left school before the end of the term for which that disbursement was made. The formula for determining the distribution of an institutional refund can be applied readily to all Title IV programs. However, the formula for determining the distribution of a portion of a cash disbursement returned by the student has the potential for conflicting with or complicating certain requirements in effect for the Guaranteed Student Loan Program.

Revision: To eliminate this potential for conflicting requirements, we are deleting Guaranteed Student Loan funds from all requirements for determining the distribution of a repayment of a portion of a cash disbursement.

8. *Technical revisions to the regulations establishing institutional fiscal and administrative standards (45 CFR Part 168 Subpart B).*

We are making the following additional changes in the institutional fiscal and administrative standards regulations, published on September 28, 1979. These revisions are necessary in order to clarify the meaning of certain provisions, to add nomenclature that was inadvertently omitted, and to correct errors that were made when the regulations were drafted.

These changes are:

(a) Amend the audit and recordkeeping requirements contained in § 168.12(a) to include the biennial audit and five year record retention requirements. These provisions, currently included in applicable program regulations, were inadvertently omitted from the September 28, 1979 standards regulations.

(b) Explicitly provide the Secretary with access to an institution's records reflecting transactions with any financial institution with which it deposits or has deposited Title IV funds.

(c) Eliminate, under § 168.15(f), the applicability of the bonding requirement for public institutions which are components of State governments and are already bonded by their respective States. As amended, the bonding requirement will require only private nonprofit and proprietary postsecondary educational institutions to obtain and

maintain a fidelity bond to protect the Government's interest.

(d) Redraft § 168.18(a), "Change in ownership or control," to make clear that § 168.18 also applies to the acquisition, by an eligible institution, of a previously eligible institution.

9. *Addition of the definition of a "postsecondary vocational institution."*

The Higher Education Technical Amendments of 1979 provided for a new type of eligible institution, the "postsecondary vocational institution." Program regulations have been amended to incorporate this new type of institution.

The definition of a postsecondary vocational institution has several unique elements for a public institution. It may admit as regular students only high school graduates or their equivalent; it must be fully accredited; and it must have been providing a training program for two years before it is eligible to participate in any Title IV program.

Proposed regulations to be published in the near future. In addition to the regulation revisions described above, the Department of Education is planning to propose two additional changes which will be published as a notice of proposed rulemaking with a solicitation of public comment.

One of these proposed changes will be a deletion of the requirement that an institution document on a student-by-student basis "ability to benefit from the training offered" for those students it admits who are beyond the age of compulsory school attendance but do not have a high school diploma or the equivalent. The proposed regulation will also provide that the institution should develop and apply reasonable criteria for determining ability to benefit which are consistent with generally used standards of the educational community.

The second proposed regulation on which public comment will be solicited concerns deferment of Guaranteed Student Loan repayments for students engaged in rehabilitation training programs. Under a provision of the Middle Income Student Assistance Act (Pub. L. 95–566) a disabled borrower may defer repayment on a loan if he or she is engaged in a rehabilitation program approved by the Secretary. The notice of proposed rulemaking will submit for public comment a listing of criteria under which rehabilitation programs can receive the Secretary's approval.

Waiver of Notice of Proposed Rulemaking. The regulatory changes made respond to comments received from the financial aid community which pointed out problems and concerns with some of the provisions of the six student financial aid regulations published by the Office of Education in 1979. In addressing these concerns, the Secretary has liberalized provisions to enable institutions and students who previously participated in the Basic Grant Program to continue to do so. The Secretary has also liberalized the Basic Grant regulations to accommodate students who previously were unable to receive a grant in a year because they started classes too late in that year, lessened the administrative burden on institutions with regard to the financial aid transcript, and insured that the regulations conform to changes in the law pertaining to the Guaranteed Student Loan program and the law pertaining to notarized affidavits of educational purpose. Finally, other changes of a technical nature were also made.

Accordingly, in view of the nature of the changes as described above, the Secretary finds that the publication of a proposed rule in this instance would be unnecessary, impracticable and contrary to the public interest within the meaning of 5 U.S.C. 553(b), and is publishing these rules as final regulations.

Dated: June 19, 1980.

Steven A. Minter,

Acting Secretary of Education.

(Catalog of Federal Domestic Assistance Numbers: Basic Educational Opportunity Grant Program, 13.539; National Direct Student Loan Program, 13.471; College Work-Study Program, 13.463; Supplemental Educational Opportunity Grant Program, 13.418; Guaranteed Student Loan Program, 13.460; State Student Incentive Grant Program, 13.548)

PART 168—STUDENT ASSISTANCE GENERAL PROVISIONS

Subpart B of Part 168 of Title 45 of the Code of Federal Regulations is amended as follows:

1. The title of Part 168 is amended to read as follows: STUDENT ASSISTANCE GENERAL PROVISIONS.

1a. In § 168.12, paragraph (a) is amended and paragraph (b)(3) is added to read as follows:

§ 168.12 Audits, records and examination.

(a) If an institution participates in the National Direct Student Loan (45 CFR Part 174), College Work-Study (45 CFR Part 175), Supplemental Educational Opportunity Grant (45 CFR Part 176), Guaranteed Student Loan (45 CFR Part 177), or Basic Educational Opportunity Grant (45 CFR Part 190) Programs, it shall comply with the regulations for those programs concerning (1) fiscal and accounting systems, (2) biennial audits of institutional transactions, (3) program and fiscal recordkeeping, and (4) record retention.

(b) * * *

(3) Upon written request, an institution shall give the Secretary access to all program and fiscal records, including records reflecting transactions with any financial institution with which it deposits or has deposited any title IV funds.

(20 U.S.C. 1088f–1.)

* * * * *

§ 168.14 [Revoked]

2. Section 168.14 is revoked, retroactive to November 8, 1979.

3. Effective July 1, 1980, a new § 168.14 is added to read as follows:

§ 168.14 Financial aid transcript.

(a)(1) *Disbursing money only after receiving a transcript—general rule.* If informed by a student that he or she attended another eligible institution on at least a half-time basis, the institution the student is currently attending shall not disburse any title IV funds (other than Guaranteed Student Loan checks where the institution is not the lender) to that student before obtaining a properly signed financial aid transcript from the institution or institutions the student previously attended, unless the other institution or institutions each indicate, in writing that they are not required to provide a transcript under the provisions of paragraph (b) or paragraph (c)(2) or (c)(3) of this section. The student's current institution may disburse title IV funds on the basis of such a written notice or notices.

(2) *Limited exception to the general rule.* The institution the student is currently attending may disburse title IV funds to a student for one payment period if it does not receive in a timely manner the requested transcript or a written notice that the transcript will not be forthcoming as provided in paragraph (d) of this section.

(b) *Providing a transcript—general rule.* (1) Upon request, an institution shall provide to another institution a financial aid transcript for a current or former student who received, while attending the institution—

(i) A Basic Grant during the award period in which the request for the transcript is made;

(ii) A Supplemental Grant; or

(iii) A National Direct Student Loan.

(2) The institution shall honor a request for a transcript from a student or the institution the student is attending or planning to attend.

(3) The institution shall provide the transcript in a timely manner.

(4) The transcript must be signed by an official authorized by the institution to sign such transcripts.

(c) *Exceptions to the general rule in paragraph (b) of this section.* An institution does not have to provide the requested transcript if—

(1) The subject student—

(i) Is in default on any title IV loan made or received for attendance at that institution; or

(ii) Owes a refund on any title IV grant received for attendance at that institution;

(2) The transcript would only include information based on records that the institution is no longer required to keep under the record retention regulations referred to under § 168.12(a); or

(3) The institution participates in the Basic Grant Program under the Alternate Disbursement System and does not also participate in the Supplemental Grant or National Direct Student Loan program in the award period in which the request for the transcript is received.

(d) *Notifying the student's new institution in a timely manner that the transcript is not forthcoming.* If an institution has been requested to provide a transcript but is not required to do so according to paragraph (b) or paragraph (c) of this section, it must notify the student's new institution in writing in a timely manner that the transcript will not be forthcoming and specify the reason for the refusal.

(e) *Information included in a student's financial aid transcript.* A student's financial aid transcript shall include, with respect to any year for which the institution is required to keep that student's financial aid records, at least the following information—

(1) The student's name and social security number;

(2) Whether the student was independent or dependent, for the last award year in which aid was received;

(3) For the award period in which the request for the transcript is made, the student's Scheduled Basic Grant and the amount of Basic Grant funds disbursed to the student,

(4) The amount of Supplemental Grants disbursed to the student during each award year;

(5) The amount of National Direct Student Loans advanced to the student during each award year;

(6) Whether the student is in default on—

(i) A National Direct Student Loan made by the institution, or

(ii) A Guaranteed Student Loan the student received for attendance at the institution if the institution is aware of the default status, and

(7) Whether the student owes a refund on—

(i) A Basic or Supplemental Grant for attendance at the institution, or

(ii) A State Student Incentive Grant received for attendance at the institution, if the institution is aware that the student owes the refund.

(20 U.S.C. 1088f–1.)

4. In § 168.15, paragraph (f)(1) is amended to read as follows:

§ 168.15 Factors of financial responsibility.

* * * * *

(f)(1)(i) An otherwise eligible institution shall obtain and keep current adequate fidelity bond coverage in order to protect the Government's interest in the title IV funds it receives as a trustee.

(ii) However, a public institution that is bonded by the State against the type of losses described in paragraph (f)(2) of this section does not have to obtain additional fidelity bond coverage.

* * * * *

5. In § 168.18, paragraph (a) is amended to read as follows:

§ 168.18 Change in ownership or control.

(a) An eligible institution, or a previously eligible institution that participated in any title IV program, that changes ownership resulting in a change in control is not considered by the Secretary to be the same institution unless—

(1) The new owner agrees to be liable, or the old and new owners agree to be jointly and severally liable, for all improperly spent title IV funds provided to the institution before the effective date of the change;

(2) The new onwer agrees—

(i) To abide by the institution's refund policy in effect before the effective date of the change for students who were enrolled before the effective date, and

(ii) To honor all student enrollment contracts that were signed by the institution before the effective date of the change; and

(3) The institution submits individual statements for both new and former owners listing their assets, liabilities, and net worth, and either—

(i) A profit and loss statement and balance sheet for the institution's latest complete fiscal year, or

(ii) An audit for the institution's latest complete fiscal year prepared by a certified or licensed public accountant; and

(4) The institution submits additional financial documents if requested by the Secretary because the financial information provided under subparagraph (3) is insufficient.

* * * * *

(20 U.S.C. 1088f–1.)

6. Section 168.21 is amended to read as follows:

§ 168.21 Distribution formula for institutional refunds and repayments of cash disbursements made directly to the student.

(a) *Institutional refunds to title IV programs.* (1) If a refund is due to a student under the institution's refund policy and the student received financial aid under any title IV student financial aid program other than the College Work-Study Program, a portion of the refund shall be returned to the title IV program(s).

(2) Except as provided in paragraph (a)(3) of this section the institution shall multiply the institutional refund by the following fraction to determine the portion of the refund to be returned to the title IV program(s):

$$\frac{\text{total amount of title IV aid (exclusive of work earnings) awarded for the payment period}}{\text{total amount of aid (exclusive of work earnings) awarded for the payment period}}$$

(3) If a student has received Basic Grant funds at the institution under the Alternate Disbursement System,

(i) The institution shall use the following fraction in lieu of the fraction in paragraph (a)(2) of this section to determine the portion of the refund to be returned to the title IV programs (other than the Basic Grant program.)

$$\frac{\text{total amount of title IV aid (exclusive of work earnings and Basic Grant funds) awarded for the payment period}}{\text{total amount of aid (exclusive of work earnings and Basic Grant funds) awarded for the payment period}}$$

(ii) the institution shall notify the Secretary of the amount of money that it is returning to the title IV program according to paragraph (a)(3)(i) of this section.

(b) *Distribution among the title IV programs.* (1) The institution shall develop written policies allocating the title IV portion of the refund to the various title IV programs from which the student received aid. These policies shall be applied on a consistent basis to all students receiving title IV funds.

(2) The portion of a refund allocated to a program may not exceed the amount a student received from that program.

(3) As provided in 45 CFR 177.610 of the Guaranteed Student Loan Program regulations, the institution shall return to the student's lender any portion of a

refund which is allocable to a loan made under the Guaranteed Student Loan Program.

(c) *Distribution of repayments of cash disbursements made directly to the student for non-institutional costs.* (1) Any cash that an institution disbursed to a student for a payment period under any title IV program other than the College Work-Study or Guaranteed Student Loan program becomes an overpayment if before the first day of classes of that payment period the student officially withdraws, drops out, or is expelled.

(2) An institution shall determine, under paragraph (c)(3) of this section, whether any cash it disbursed to a student for a payment period under any title IV program other than the College Work-Study or Guaranteed Student Loan program amounts to an overpayment if the student withdraws, drops out, or is expelled on or after the first day of classes of that payment period.

(3) In determining whether a student received an overpayment for purposes of paragraph (c)(2) of this section, and the amount of that overpayment, the institution shall subtract from the cash disbursed to the student for non-institutional costs, the non-institutional costs that were to be paid by the disbursement for the portion of the payment period during which the student was enrolled. Non-institutional educational costs may include, but are not limited to, room and board (if not contracted for with the institution), books and supplies, transportation and miscellaneous expenses.

(4) If a student drops out, the institution shall use the last recorded day of class attendance by the student as the end of the student's enrollment. However, if it is unable to document the student's last day of attendance, any cash it disbursed to that student for that payment period is an overpayment.

(5) The institution shall multiply the overpayment by the following fraction to determine the portion of the overpayment to be returned to the title IV program(s):

total amount of title IV aid (exclusive of work earnings and Guaranteed Student Loans) awarded for the payment period—

total amount of aid (exclusive of work earnings and Guaranteed Student Loans) awarded for the payment period

(d) *Distribution among the title IV programs.* (1) The institution shall develop written policies allocating the title IV portion of the overpayment owed by the student to the various title IV programs from which the student received aid. These policies shall be applied on a consistent basis to all students receiving title IV aid.

(20 U.S.C. 1088f–1.)

PART 174—NATIONAL DIRECT STUDENT LOAN PROGRAM

Part 174 of Title 45 of the Code of Federal Regulations is amended as follows:

1. In § 174.2a, the introductory sentence is amended and paragraphs (e) and (f) are added, to read as follows:

§ 174.2a Institution of higher education.

An institution of higher education is a public, private nonprofit, proprietary, or postsecondary vocational institution.

* * * * *

(e) In lieu of the credit or clock hour requirements of paragraphs. (d)(1) and (d)(2) of this section, the Secretary may determine that an institution offers a six-month program of training if—

(1) He or she determines that the institution's course content and student work load requirements support that determination, and

(2) The accrediting association that accredits the institution certifies that the program offered by the institution is equal in course content and student work load to the comparable clock or credit hour program described in paragraph (d) of this section.

*(f) *A postsecondary vocational institution* is a public or other nonprofit educational institution which—

(1) Is in a State;

(2) Admits as regular students only persons who—

(i) Have a high school diploma, or

(ii) Have the recognized equivalent of a high school diploma;

(3) Is legally authorized to provide an education program beyond secondary education in the State in which the institution is physically located;

(4) Provides at least a six-month program of training to prepare students for gainful employment in a recognized occupation;

(5) Is accredited by a nationally recognized accrediting agency or association; and

(6) Has been in existence for at least two years. The Secretary considers an institution to have been in existence for two years if it is legally authorized to provide, and has provided, a training program on a continuous basis to prepare students for gainful employment in a recognized occupation during the 24 months (except for normal vacation periods) preceding the date of application for eligibility.

(20 U.S.C. 1141(a); 20 U.S.C. 1088(b) (3) and (4).)

(2) In § 174.2b paragraph (b)(4) is amended to read as follow:

§ 174.2b Eligible Program.

* * * * *

(b) * * *

(4) Is, for a proprietary institution or a postsecondary vocational institution, at least a six-month program leading to a certificate or degree, which prepares students for gainful employment in a recognized occupation. (A six month training program is defined in § 174.2a (d) and (e)).

(20 U.S.C. 1141(a), 1088(b) (3) and (4).)

3. In § 174.16, paragraph (i) is amended to read as follows:

§ 174.16 Making and disbursing loans.

* * * * *

(i)(1) An institution may not disburse loan funds to a student unless the student affirms or declares that he or she will use the loan solely for educational expenses in connection with attendance at the institution.

(2) The student may satisfy this requirement by filing either—

(i) A notarized affidavit, or

(ii) A written statement.

(3) The statement or the affidavit must be on a form approved by the Secretary. Forms approved for this purpose are set forth in Appendix E.

* * * * *

(20 U.S.C. 1088g; 28 U.S.C. 1746)

4. Appendix E is added to read as follows:

Appendix E—Affidavit of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan or Guaranteed Student Loan programs solely for expenses related to attendance at

_____.

(Name of Institution)

I understand that I am responsible for repaying any funds that I receive which cannot reasonably be attributed to meeting my educational expenses related to attendance at

_____.

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

_____

Signature (Sign only in presence of a Notary)

Academic period covered by award(s)

——— 19——— to ——— 19———

Month Year Month Year

Subscribed and sworn before me this —— day of ———, 19——

My commission expires: _____

_____

(Signature of Notary Public)

_____

(Address of Notary Public)

Statement of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan, or Guaranteed Student Loan programs solely for expenses related to attendance at

_____.

(Name of Institution)

I understand that I am responsible for repaying any funds I receive which cannot reasonably be attributed to meet my educational expenses at

_____.

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

I declare under penalty of perjury that the foregoing is true and correct.

Signature _____

Date _____

Academic period covered by award(s)

_____, 19____ to _____, 19____

Month Year Month Year

PART 175—COLLEGE WORK-STUDY AND JOB LOCATION AND DEVELOPMENT PROGRAM

Part 175 of Title 45 of the Code of Federal Regulations is amended as follows:

1. In § 175.2, the introductory sentence is amended and paragraphs (e) and (f) are added, to read as follows:

§ 175.2a Institution of higher education.

An institution of higher education is a public, private nonprofit, proprietary, or postsecondary vocational institution.

* * * * *

(e) In lieu of the credit or clock hour requirements of paragraphs (d)(1) and (d)(2) of this section, the Secretary may determine that an institution offers a six-month program of training if—

(1) He or she determines that the institution's course content and student work load requirements support that determination, and

(2) The accrediting association that accredits the institution certifies that the program offered by the institution is equal in course content and student work load to the comparable clock or credit hour program described in paragraph (d) of this section.

(f) *A postsecondary vocational institution* is a public or other nonprofit educational institution which—

(1) Is in a State;

(2) Admits as regular students only persons who—

(i) Have a high school diploma, or

(ii) Have the recognized equivalent of a high school diploma;

(3) Is legally authorized to provide an education program beyond secondary education in the State in which the institution is physically located;

(4) Provides at least a six-month program of training to prepare students for gainful employment in a recognized occupation;

(5) Is accredited by a nationally recognized accrediting agency or association; and

(6) Has been in existence for at least two years. The Secretary considers an institution to have been in existence for two years if it is legally authorized to provide, and has provided, a training program on a continuous basis to prepare students for gainful employment in a recognized occupation during the 24 months (except for normal vacation periods) preceding the date of application for eligibility.

(20 U.S.C. 1085(b), and 1088(b)(3) and (4).)

2. In § 175.2b the introductory sentence and paragraph (b)(4) are amended to read as follows:

§ 175.2b Eligible program.

An eligible program in an institution of higher education is a program of education or training that—

* * * * *

(b) * * *

(4) Is, for a proprietary institution or a postsecondary vocational institution, at least a six-month program leading to a certificate or degree, which prepares students for gainful employment in a recognized occupation. (A six month program is defined in § 175.2a(d) and (e)).

(20 U.S.C. 1141(a) and 1088(b)(3) and (4).)

3. Section 175.9(b)(1) is amended to read as follows:

§ 175.9 Student eligibility.

* * * * *

(b) * * *

(1) Satisfies the conditions under paragraphs (a)(1), (a)(2), (a)(4), and (a)(5);

4. Section 175.16(d) is amended to read as follows:

§ 175.16 Payments to students.

* * * * *

(d)(1) An institution may not pay a student College Work-Study wages unless the student affirms or declares that he or she will use those wages solely for educational expenses in connection with attendance at the institution.

(2) The student may satisfy this requirement by filing either—

(i) A notarized affidavit, or

(ii) A written statement.

(3) The statement or the affidavit must be on a form approved by the Secretary. Forms approved for this purpose are set forth in Appendic C.

* * * * *

(20 U.S.C. 1088g; 28 U.S.C. 1746)

5. Appendix C is added to read as follows:

Appendix C—Affidavit of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan or Guaranteed Student Loan programs solely for expenses related to attendance at

_____.

(Name of Institution)

I understand that I am responsible for repaying any funds that I receive which cannot reasonably be attributed to meeting my educational expenses related to attendance at

_____.

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

_____

Signature (Sign only in presence of a Notary)

Academic period covered by award(s)

_____ 19____ to _____ 19____

Month Year Month Year

Subscribed and sworn before me this ____ day of _____, 19____

My commission expires: _____

_____

(Signature of Notary Public)

_____

(Address of Notary Public)

Statement of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan, or Guaranteed Student Loan programs solely for expenses related to attendance at

_____.

(Name of Institution)

I understand that I am responsible for repaying any funds I receive which cannot reasonably be attributed to meeting my educational expenses at

_____.

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

I declare under penalty of perjury that the foregoing is true and correct.

Signature _____

Date: _____

Academic period covered by award(s)

_____, 19____ to _____, 19____

Month Year Month Year

PART 176—SUPPLEMENTAL EDUCATIONAL OPPORTUNITY GRANT PROGRAM

Part 176 of Title 45 of the Code of Federal Regulations is amended as follows:

1. In § 176.2a, the introductory sentence is amended and paragraphs (e) and (f) are added to read as follows:

§ 176.2a Institution of higher education.

An institution of higher education is a public, private nonprofit, proprietary or postsecondary vocational institution.

* * * * *

(e) In lieu of the credit or clock hour requirements of paragraphs (d)(1) and (d)(2), the Secretary may determine that an institution offers a six-month program of training if—

(1) He or she determines that the institution's course content and student work load requirements support that determination, and

(2) The accrediting association that accredits the institution certifies that the program offered by the institution is equal in course content and student work load to the comparable clock or credit hour program described in paragraph (d) of this section.

(f) *A postsecondary vocational institution* is a public or other non-profit educational institution which—

(1) Is in a State;

(2) Admits as regular students only persons who—

(i) Have a high school diploma, or

(ii) Have the recognized equivalent of a high school diploma;

(3) Is legally authorized to provide an education program beyond secondary education in the State in which the institution is physically located;

(4) Provides at least a six-month program of training to prepare students for gainful employment in a recognized occupation;

(5) Is accredited by a nationally recognized accrediting agency or association; and

(6) Has been in existence for at least two years. The Secretary considers an institution to have been in existence for two years if it is legally authorized to provide, and has provided, a training program on a continuous basis to prepare students for gainful employment in a recognized occupation during the 24 months (except for normal vacation periods) preceding the date of application for eligibility.

(20 U.S.C. 1141(a), 20 U.S.C. 1088(b) (3) and (4).)

2. In § 176.2b, paragraph (b)(4) is amended to read as follows:

§ 176.2b Eligible program.

* * * * *

(b) * * *

(4) Is, for a proprietary institution or a postsecondary vocational institution, at least a six-month program leading to a certificate or degree, which prepares students for gainful employment in a recognized occupation. (A six-month program is defined in § 176.2a (d) and (e).)

(20 U.S.C. 1141(a) and 1088(b) (3) and (4).)

3. Section 176.16(h) is amended to read as follows:

§ 176.16 Payment of grant.

* * * * *

(h)(1) An institution may not pay a Supplemental Educational Opportunity Grant unless the student affirms or declares that he or she will use the grant solely for educational expenses in connection with attendance at the institution.

(2) The student may satisfy this requirement by filing either—

(i) A notarized affidavit, or

(ii) A written statement.

(3) The statement or the affidavit must be on a form approved by the Secretary. Forms approved for this purpose are set forth in Appendix B.

* * * * *

(20 U.S.C. 1088g; 28 U.S.C. 1746.)

4. Appendix B is added to read as follows:

Appendix B—Affidavit of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan or Guaranteed Student Loan programs solely for expenses related to attendance at

_____.

(Name of Institution)

I understand that I am responsible for repaying any funds that I receive which cannot reasonably be attributed to meeting my educational expenses related to attendance at

_____.

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

_____

Signature (Sign only in presence of a Notary)

Academic period covered by award(s)

_____, 19____ to _____, 19____

Month Year Month Year

Subscribed and sworn before me this ____ day of _____, 19____

My commission expires: _____

_____

(Signature of Notary Public)

_____

(Address of Notary Public)

Statement of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan, or Guaranteed Student Loan programs solely for expenses related to attendance at

_____.

(Name of Institution)

I understand that I am responsible for repaying any funds I receive which cannot reasonably be attributed to meeting my educational expenses at

_____.

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

I declare under penalty of perjury that the foregoing is true and correct.

Signature _____

Date: _____

Academic period covered by award(s)

_____, 19____ to _____, 19____

Month Year Month Year

PART 177—GUARANTEED STUDENT LOAN PROGRAM

Part 177 of Title 45 of the Code of Federal Regulations is amended as follows:

1. In § 177.200 under the definition of "Vocational school", paragraph (a)(2)(ii) is amended to read as follows:

§ 177.200 General definitions.

Vocational school:

(a) * * *

(2) * * *

(ii) Has the ability to benefit from the training offered. A school shall develop criteria for determining a student's ability to benefit from the training offered.

* * * * *.

2. In § 177.201 paragraph (a)(1)(ii) is amended to read as follows:

§ 177.201 Eligible student.

(a) * * *

(1) * * *

(ii) If enrolled or accepted for enrollment in a vocational school, the student must be attending neither elementary nor secondary school and have the ability to benefit from the training offered, as required under the definition of "Vocational school" in § 177.200.

* * * * *

3. Section 177.203 is amended to read as follows:

§ 177.203 Affidavit or statement of educational purpose.

(a)(1) No loan may be insured under this program unless the student affirms or declares that he or she will use the loan proceeds solely for costs of attendance at the school the student is or will be attending.

(2) The student may satisfy this requirement by filing either—

(i) A notarized affidavit; or

(ii) A written statement.

(3) The statement or the affidavit must be in a form approved by the Secretary.

(b) the student must file the affidavit or statement with the lender. The lender shall retain a copy of the affidavit or

statement as required in § 177.408(a) or § 177.519(a).

(20 U.S.C. 1082, 1088g; 28 U.S.C. 1746)

4. In § 177.401 paragraphs (b)(5)(ii)(A) and (b)(7)(ii) are amended to read as follows:

§ 177.401 Basic agreement.

* * * * *

(b) * * *
(5) * * *
(ii) * * *

(A) An affidavit or statement, described in § 177.203, that the loan will be used for the cost of attendance;

* * * * *

(7) * * *

(ii) By the lender sending all loan checks to the school for delivery to the borrower.

* * * * *

5. In § 177.407 paragraph (b)(2)(ii)(A) is amended to read as follows:

§ 177.407 Administrative cost allowances for guarantee agencies.

* * * * *

(b) * * *
(2) * * *
(ii) * * *

(A) The spending minimum described in paragraph (b)(2)(i) for the administrative costs of collection of loans and preclaim assistance for default prevention does not apply during the first twelve months in which the agency is eligible to receive the advance; and

* * * * *

6. In § 177.509 paragraph (g)(4)(i) is amended and paragraph (g)(4)(iii) is added to read as follows:

§ 177.509 Due diligence in making and disbursing a loan.

* * * * *

(g) * * *

(4) *Late disbursements.* (i) Under certain circumstances a lender, with the prior approval of the Secretary, may disburse a FISLP loan after a borrower has ceased to be enrolled on at least a half-time basis or after the expiration date of the insurance commitment.

* * * * *

(iii) If the lender, after receiving the Secretary's prior approval, makes a late disbursement, the lender shall give notice of that approval to the school at the time it sends the loan check to the school.

(20 U.S.C. 1077, 1080, 1082, 1083, 1085)

7. In § 177.513 paragraph (b)(2)(i) is amended to read as follows:

§ 177.513 Assignment of a FISLP loan.

* * * * *

(b) * * *
(2) * * *

(i) Notify the Secretary of the assignment if the right to receive interest benefits and special allowance payments has been assigned; and

* * * * *

8. In § 177.516 paragraph (a)(1)(ii)(A) is amended to read as follows:

§ 177.516 Procedures for filing claims.

(a) * * *
(1) * * *

(ii)(A) If the lender has exercised the option (under § 177.509(e)(3)) of including a provision in the promissory note which requires the borrower to execute a repayment schedule not later than 120 days prior to the beginning of the repayment period, and the borrower has not executed a schedule by that date, despite compliance by the lender with § 177.510(b)(1)(ii), the 120-day period begins 120 days prior to the beginning of the repayment period.

* * * * *

9. In § 177.601 paragraphs (b)(2) and (b)(3) are amended to read as follows:

§ 177.601 Agreement between the Secretary and a school that makes or originates loans.

* * * * *

(b) * * *

(2) The school will inform any undergraduate student who has not previously obtained a loan that was made or originated by the school and who seeks to obtain such a loan that he or she must first make a good faith effort to obtain a loan from a commerical lender.

(3)(i) The school will not make or originate a loan for an academic period to a student described in paragraph (b)(2) of this section until the student provides the school with evidence of denial of a loan by a commercial lender for the same academic period. Evidence acceptable for this purpose is described in paragraph (c) of this section.

(ii) In determining whether a school has complied in good faith with this requirement, the Secretary may take into consideration any patterns reflected by the letters of denial or students' sworn statements referred to in paragraph (c) of this section that indicate that the school has not given sufficient counseling to students to first seek loans from a commercial lender. An example of an unacceptable pattern would be if all denials of loans to a school's students were made by a small number of lenders.

* * * * *

§ 177.603 [Revoked]

10. Section 177.603 is revoked.

11. In § 177.607 paragraph (g) is deleted and paragraph (f) is amended to read as follows:

§ 177.607 The student's loan check.

* * * * *

(f) *Processing a late disbursement check.* (1) For purposes of this paragraph, a loan check is considered a late disbursement check if the school receives the student's loan check from the lender either—

(i) After the expiration of the academic period for which the loan was intended (the expiration date of the insurance commitment); or

(ii) Prior to the expiration of the academic period for which the loan was intended but after the student ceased to be enrolled at the school on at least a half-time basis.

(2) If the late disbursement check is accompanied by a notice from the lender that the late disbursement has been approved by the Secretary or the appropriate guarantee agency, the school shall follow the applicable procedure described in paragraph (c) or (d) of this section.

(3) If the late disbursement check is not accompanied by the notice described in paragraph (f)(2) of this section, the school shall—

(i) Return the check to the lender within 30 days of its determination that one of the conditions described in paragraph (f)(1) of this section exists;

(ii) Send with the check—

(A) A notice that one of the conditions described in paragraph (f)(1) of this section exists; and

(B) If applicable, information concerning the student's date of withdrawal and costs of attendance owed the school for the period the student was enrolled on at least a half-time basis;

(iii) Advise the student that the lender may, in accordance with § 177.509(g)(4) or similar rules established by the guarantee agency, redisburse funds for the student's costs of attendance incurred before the existence of one of the conditions described in paragraph (f)(1) of this section.

(20 U.S.C. 1078, 1082)

12. In § 177.611 paragraph (b)(1)(i) is amended to read as follows:

§ 177.611 Termination of a school's lending eligibility.

* * * * *

(b) * * *
(1) * * *

(i) The original principal amount of loans the school has ever made that went into default during that period.

* * * * *

PART 190—BASIC EDUCATIONAL OPPORTUNITY GRANT PROGRAM

Part 190 of Title 45 of the Code of Federal Regulations is amended as follows:

1. In § 190.2, the definitions of half-time student and three-quarter-time student are amended to read as follows:

§ 190.2 General definitions.

* * * * *

Half-time student. (a) An enrolled student who is carrying half-time academic work load—as determined by the institution—which amounts to at least half the work load of the appropriate minimum requirement outlined in the definition of a full-time student. (See definition of full-time student.)

(b) A student enrolled solely in a program of study by correspondence who is carrying a work load of at least 12 hours of preparation of work per week. However, regardless of the work load, no student enrolled solely in correspondence study will be considered more than a half-time student.

* * * * *

Three-quarter-time student. An enrolled student who is carrying a three-quarter-time academic work load—as determined by the institution—which amounts to at least three quarters of the work load of the appropriate minimum requirement outlined in the definition of a full-time student. (See definition of full-time student.)

* * * * *

2. In § 190.2a, paragraphs (a)(2)(iv), (e) and (f) are amended and paragraph (g) is added, to read as follows:

§ 190.2a Special terms.

(a) *Eligible program.* * * *

(2) * * *

(iv) Is, for a proprietary or postsecondary vocational institution, at least a six-month program leading to a certificate or degree, which prepares students for gainful employment in a recognized occupation. (A six-month program is defined in § 190.3(d) and (e).)

* * * * *

(e) *Payment period for an institution using the Regular Disbursement System that does not use academic terms.* (1) An institution participating in the Basic Grant program under the Regular Disbursement System (RDS institution) that does not use semesters, trimesters, quarters, or other academic terms must have at least two payment periods for each academic year, or for each program which is less than an academic year.

(2) For a full-time student whose educational program is one academic year—

(i) The first payment period is the period of time in which the student completes the first half of his or her academic year (in credit or clock hours), and

(ii) The second payment period is the period of time in which the student completes the second half of that academic year.

(3) For a full-time student whose educational program is more than one academic year, the first and second payment periods shall be calculated under paragraph (e)(2) of this section. For subsequent academic years, or fractions of academic years, each payment period shall be the period of time in which the student completes—

(i) One-half of the academic year, or

(ii) The remaining hours in the student's educational program, whichever is to be completed first.

(4) For a full-time student whose educational program is LESS than an academic year—

(i) The first payment period is the period of time in which the student completes the first half of his or her educational program (in credit or clock hours), and

(ii) The second payment period is the period of time in which the student completes the second half of that educational program.

(5) The payment period for an eligible part-time student shall be calculated as follows:

(i) Determine the length of time it would take a full-time student in the program to complete one academic year or a program of less than one academic year, as appropriate.

(ii) The first payment period is the period of time in which the part-time student completes half the work (in credit or clock hours) he or she is scheduled to complete in the period referred to in paragraph (e)(5)(i) of this section.

(iii) The second payment period begins when the first payment period ends and ends when the student completes the other half of the work that he or she was scheduled to complete in the period referred to in paragraph (e)(5)(i) of this section.

(iv) Each subsequent payment period begins when the previous period ends and ends when the part-time student completes—

(A) Half the work he or she is scheduled to complete during the period of time referred to in paragraph (e)(5)(i) of this section, or

(B) The remaining hours of his or her educational program, whichever is completed first.

(6) If an RDS institution chooses to have more than two payment periods in an academic year or in a program of less than an academic year, the rules set forth in paragraphs (e)(2) through (e)(5) of this section shall be modified to reflect the number of payment periods. For example, if an institution chooses to have three payment periods for an academic year, each payment period shall correspond, for a full-time student, to one-third of the academic year.

(7) This paragraph (e) of this section is effective as of March 1, 1980.

(f) *Payment period for an institution using the Regular Disbursement System that uses academic terms.* (1) For an RDS institution that uses semesters, trimesters, quarters or other academic terms, the payment period is the semester, trimester, quarter or other academic term.

(2) If a student's progress is measured in clock hours, a student may not be paid for a subsequent payment period until he or she finishes the hours of the previous payment period for which the student has already been paid.

(3) This paragraph is effective as of March 1, 1980.

(g) *Payment period for an institution using the Alternate Disbursement System.* A payment period for an institution participating in the Basic Grant program under the Alternate Disbursement System (ADS institution) shall be calculated as follows:

(1) If an ADS institution uses semesters, trimesters, quarters or other academic terms and measures progress in credit hours, the payment period is the semester, trimester, quarter or other academic term.

(2) If an ADS institution measures progress in clock hours, or measures progress in credit hours but does not use academic terms, it shall have at least two payment periods. The payment periods shall be calculated as follows:

(i) If the student's academic year is within one award period and the student's educational program is at least one academic year—

(A) The first payment period is the period of time in which the student completes the first half of his or her academic year, and

(B) The second payment period is the period of time in which the student completes the second half of his or her academic year.

(ii) If the student's academic year is NOT within one award period or the student's educational program is LESS than a full academic year—

(A) The first payment period is the period of time in which the student completes the first half of the hours he or she is scheduled to complete within the award period, and

(B) The second payment period begins when the first payment period ends and ends when the student completes all hours he or she was scheduled to complete between the beginning of the second payment period and June 30.

(iii) A student with incompleted hours for the second payment period of any award period may complete them during the following award period. In this case, if the student's educational program is more than an academic year, the first payment period of the new award period begins when the student finishes all carried over hours for which he or she was paid.

3. In § 190.3, the introductory sentence is amended and paragraphs (e) and (f) are added, to read as follows:

§ 190.3 Institution of higher education.

An institution of higher education is a public, private nonprofit, proprietary, or postsecondary vocational institution.

* * * * *

(e)(1) In lieu of the credit or clock hour requirements of paragraphs (d)(1) and (d)(2) of this section, the Secretary may determine that an institution offers a six-month program of training if—

(i) He or she determines that the institution's course content and student work load requirements support that determination, and

(ii) The accrediting association that accredits the institution certifies that the program offered by the institution is equal in course content and student work load to the comparable clock or credit hour program described in paragraph (d) of this section.

(2) This paragraph (e) of this section is effective as of February 27, 1979.

(f) *A postsecondary vocational institution* is a public or other nonprofit educational institution which—

(1) Is in a State;

(2) Admits as regular students only persons who—

(i) Have a high school diploma, or

(ii) Have the recognized equivalent of a high school diploma;

(3) Is legally authorized to provide an education program beyond secondary education in the State in which the institution is physically located;

(4) Provides at least a six-month program of training to prepare students for gainful employment in a recognized occupation;

(5) Is accredited by a national recognized accrediting agency or association; and

(6) Has been in existence for at least two years. The Secretary considers an institution to have been in existence for two years if it is legally authorized to provide, and has provided, a training program on a continuous basis to prepare students for gainful employment in a recognized occupation during the 24 months (except for normal vacation periods) preceding the date of application for eligibility.

(20 U.S.C. 1141(a), 20 U.S.C. 1088(b) (3) and (4).)

4. In § 190.64, paragraph (c) is amended, to read as follows:

§ 190.64 Calculation of a Basic Grant for a payment period.

* * * * *

(c) Notwithstanding paragraphs (a) and (b) of this section—

(1) A student may not receive a Basic Grant if the amount which the student would receive, projected on the basis of a full academic year, would be less than either $200 at full funding or $50 at less than full funding; and

(2) The amount of a student's award for an award period may not exceed his or her Scheduled Basic Grant award for that award period.

5. Section 190.65 is amended to read as follows:

§ 190.65 Calculation of a Basic Grant for a payment period which occurs in two award periods.

A student who enrolls in a payment period which is scheduled to occur in two award periods shall be paid in accordance with the following rules—

(a)(1) The entire payment period will be considered to occur within one award period.

(2) The institution will determine the award period in which the payment period will be placed.

(3) The determination made in paragraph (a)(2) of this section must be the same for all Basic Grant recipients for all payment periods in a program which begin on the same day.

(4) If the institution places the payment period in the first award period, it must pay the student with funds from the first award period.

(5) If the institution places the payment period in the second award period, it must pay the student with funds from the second award period.

(b) The institution may not make a payment which will result in the student receiving more than his/her Scheduled Basic Grant award for that award period.

(c)(1) If a term-based institution offers a series of mini-sessions which occurs in two award periods, the combined sessions will be treated as one term. A student may not receive more than one term's award for completing any combination of these sessions.

(2) For such mini-sessions, a term-based institution must determine the student's enrollment status for the entire term. That enrollment status will be based upon—

(i) The total number of credits enrolled for in all sessions if that number is known when the award is calculated, or

(ii) A projected number of credits based upon the credits enrolled for in the first session, if the number of credits to be taken in subsequent sessions is unknown when the award is calculated.

(20 U.S.C. 1070a.)

6. Section 190.79 is revised to read as follows:

§ 190.79 Educational purpose declaration.

(a) An institution may not pay a Basic Grant unless the student affirms or declares that he or she will use the grant solely for educational expenses in connection with attendance at the institution.

(b) The student may satisfy this requirement by filing either—

(1) A notarized affidavit, or

(2) A written statement.

(c) The statement or the affidavit must be on a form approved by the Secretary. Forms approved for this purpose are set forth in Appendix A.

(20 U.S.C. 1088g; 28 U.S.C. 1746.)

6. Appendix A is added to read as follows:

Appendix A—Affidavit of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan or Guaranteed Student Loan programs solely for expenses related to attendance at

(Name of Institution)

I understand that I am responsible for repaying any funds that I receive which cannot reasonably be attributed to meeting my educational expenses related to attendance at

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

Signature (Sign only in presence of a Notary)

Academic period covered by award(s)

19 to 19

Month Year Month Year

Subscribed and sworn before me this day of , 19

My commission expires: _____

_____
(Signature of Notary Public)

_____
(Address of Notary Public)

Statement of Educational Purpose

I affirm that I will use any funds I receive under the Basic Educational Opportunity Grant, Supplemental Educational Opportunity Grant, College Work-Study, National Direct Student Loan or Guaranteed Student Loan programs solely for expenses related to attendance at

(Name of Institution)

I understand that I am responsible for repaying any funds that I receive which cannot reasonably be attributed to meeting my educational expenses related at

(Name of Institution)

I further understand that the amount of any repayment is based on regulations published by the Secretary of Education.

I declare under penalty of perjury that the foregoing is true and correct.

Signature _____

Date: _____

Academic period covered by award(s)

, 19 to , 19

Month Year Month Year

[FR Doc. 80-19003 Filed 6-23-80; 8:45 am]

BILLING CODE 4110-02-M

federal register

Tuesday
June 24, 1980

Part V

Department of Education

Basic Educational Opportunity Grant Program; Final Regulations

DEPARTMENT OF EDUCATION

45 CFR Part 190

Basic Educational Opportunity Grant Program

AGENCY: Department of Education.

ACTION: Final Regulations.

SUMMARY:

1. The Action Being Taken

The Secretary is amending the regulations for the 1980–81 Family Contribution Schedules for the Basic Educational Opportunity Grant Program.

2. The Circumstances That Created the Need for the Action

The regulations are being amended because of administrative policy decisions reflecting concerns expressed by the financial aid community about the treatment of dependent student income.

3. The Intended Effect of the Action

The regulation will allow a number of dependent students from poor families—who currently are not eligible for Basic Grants because of their own income—to qualify for that aid.

EFFECTIVE DATE: Generally regulations are expected to take effect 45 days after they are transmitted to Congress. Regulations are usually transmitted to Congress several days before they are published in the **Federal Register.** However, since this regulation applies to Basic Grants made for the period of July 1, 1980 through June 30, 1981, when the regulation becomes effective, it will apply retroactively to July 1, 1980.

FOR FURTHER INFORMATION CONTACT: William Moran, Chief, Basic Grant Policy Section, or Brian Kerrigan, Basic Grant Program Specialist, Division of Program Development, ROB–3, Room 4318, 400 Maryland Avenue SW., Washington, D.C. 20202. Telephone No. (202) 472–4300.

SUPPLEMENTARY INFORMATION:

Waiver of Notice of Proposed Rulemaking

This regulatory change has been made in response to comments received from students and others in the financial aid community. The commenters expressed concern over inequities that were arising as a result of the treatment of dependent student income in the Basic Grant Family Contribution Schedule for the 1980–81 award period that was published in the **Federal Register** of April 30, 1980.

The Secretary has addressed most of these concerns in the revision to the Family Contribution Schedule and has in this regulation, eliminated the major inequities in the treatment of the income of dependent student income.

The changes made in this regulation will affect the calculation of Basic Grant awards for the 1980–81 award period which begins on July 1, 1980. Because the Secretary is correcting a problem in the current regulations and because time is of the essence, the Secretary finds that the publication of a proposed rule in this instance would be unnecessary, impracticable and contrary to the public interest within the meaning of 5 U.S.C. 553(b), and is publishing this rule as a final regulation.

General Background

From the inception of the Basic Grant Program through the 1979–80 award period, the earned income of dependent students was not considered in determining eligibility for a Basic Grant. For purposes of income assessment, only the income of the dependent student's parents was taken into account. Over the years the program received considerable criticism for ignoring this potential student resource. This issue has been of particular concern to the House Committee on Intergovernmental Relations. In responding to this criticism, the Office of Education proposed, in a notice of proposed rulemaking (NPRM) published on July 26, 1979, to assess dependent student income in determining Basic Grant eligibility for the 1980–81 award period. Copies of that NPRM were mailed to participating postsecondary institutions and to various education organizations, and public comment was solicited. Additionally, a Congressional hearing was held on the proposed regulations. Relatively few comments were received on the proposal to assess dependent student income. And, of those which were received, the response to the proposal was mixed. There was not strong or overwhelming opposition to the proposal. Thus, when the final 1980–81 Family Contribution Schedules were drafted, the assessment of dependent student income was included in the formula.

However, after the publication of the final regulation, the financial aid community voiced increased dissatisfaction with the treatment of dependent student income. It became apparent that the assessment of dependent student income—as outlined in the April 30 publication of the final regulations—worked inequitably for a number of students. Thus, the assessment of dependent student income in the calculation of a student's eligibility for a Basic Grant has caused many students and other concerned individuals in the financial aid community to request that the Department of Education reconsider its position with respect to that aspect of the eligibility formula.

Summary of the Issue

The current regulation on the assessment of dependent student income, as published on April 30, 1980, is as follows:

§ 190.34a Computation of the expected family contribution for a dependent student from the effective student income

(a) Determine the student's discretionary income by deducting from the effective student income the relevant dependent student offset.

Dependent Student Offset

Single student	$2,650
Married student	3,850

(b) If the student's discretionary income is a positive amount, multiply it by one of the following figures to determine the expected contribution from effective student income:

(1) 75 percent for the single dependent student, or

(2) 25 percent for the married dependent student.

If the student's discretionary income is negative, there is no expected contribution from the effective student income.

(20 U.S.C. 1070a(a)(3)(B))

In incorporating the assessment of dependent student income into the formula, we originally anticipated that eight to ten percent of the dependent students would have sufficient income for that income to be assessed. However, current data indicates that approximately 15 percent of the dependent student population is being affected. Some of these dependent students have fairly large incomes of their own, but come from impoverished families. As such, they often use much of their earnings to help support those families and, thus do not have as much money available for educational expenses as might otherwise be expected.

With respect to these students, we are issuing an emergency final regulation to change the treatment of dependent student income.

The revision to the current regulation will increase the appropriate dependent student offset in those instances where parental income is so low that it produces negative discretionary income. "Negative discretionary income", under the Basic Grant Family Contribution Schedule, is produced when the sum of the offsets against income provided in § 190.34 plus the federal taxes paid by the parents exceeds the parents' income. In the current regulation the parents' negative discretionary income is used as

an offset against any contribution from parental assets. (See § 190.35(d).) Under this revision the amount of negative discretionary income that will not be used as an offset against assets will be added to the normal dependent student offset.

For example, if the parental effective family income is $10,000 (adjusted gross income of $11,000 and Federal income tax paid of $1,000) and the sum of the family size offset and other offsets equals $12,000, the parents would have a negative discretionary income of $2,000 ($10,000 of income minus $12,000 of offsets).

If the parents have less than $25,000 in net assets, there would be no contribution from parental assets. Thus, none of the negative $2,000 would be used to offset the normal contribution from parental assets (§ 190.35). Therefore, the entire $2,000 amount of negative discretionary income would be added to the normal dependent student offset (either $2,650 or $3,850). This would make the dependent student offset for a married dependent student in this example $5,850 ($3,850+$2,000=$5,850.) That $5,850 figure would be subtracted from the dependent student income figure before the 25 percent assessment step is performed. For a single dependent student in this example, a $4,650 offset would be subtracted from dependent student income before the 75 percent assessment step is performed ($2,650+$2,000=$4,650).

Citation of Legal Authority

A citation of statutory or other legal authority is placed in parentheses on the line following each substantive provision of these regulations.

(Catalog of Federal Domestic Assistance No. 13.539, Basic Educational Opportunity Grant Program)

Dated: June 19, 1980.

Steven A. Minter,

Acting Secretary of Education.

Subpart C of Part 190 of Title 45 of the Code of Federal Regulations is amended as follows:

Existing § 190.34a is revoked as of July 1, 1980, and effective July 1, 1980, a new § 190.34a is added as follows:

§ 190.34a Computation of the expected family contribution for a dependent student from the effective student income.

The expected family contribution for a dependent student from effective student income is calculated as follows:

(a) Determine the student's discretionary income by deducting from the effective student income the relevant dependent student offset.

(1) Where the parental discretionary income is positive, the offset is as follows:

Dependent Student Offset

Single student	$2,650
Married student	3,850

(2) Where the parental discretionary income is negative, the relevant offset in subparagraph (1) of this paragraph is increased by the amount of that negative parental discretionary income minus any amount of the negative parental discretionary income that will be used as an offset against the contribution from parental assets in § 190.35(d).

(b) If the student's discretionary income is a positive amount, multiply it by one of the following figures to determine the expected contribution from effective student income:

(1) 75 percent for the single dependent student, or

(2) 25 percent for the married dependent student.

If the student's discretionary income is negative, there is no expected contribution from the effective student income.

(20 U.S.C. 1070a(a)(3)(B))

[FR Doc. 80-19004 Filed 6-23-80; 8:45 am]

BILLING CODE 4110-02-M