



State of Utah

Department of  
Environmental Quality

Dianne R. Nielson, Ph.D.  
*Executive Director*

DIVISION OF AIR QUALITY  
Richard W. Sprott  
*Director*

**Air Quality Board**  
John M. Veranth, *Chair*  
Ernest E. Wessman, *Vice-Chair*  
Nan Bunker  
Stead Burwell  
Jerry D. Grover  
James R. Horrocks  
Scott Lawson  
Dianne R. Nielson  
Wayne M. Samuelson  
JoAnn B. Seghini  
Don Sorensen  
Richard W. Sprott,  
*Executive Secretary*

JON M. HUNTSMAN, JR.  
*Governor*

GARY HERBERT  
*Lieutenant Governor*

DAQ-070-06

**UTAH AIR QUALITY BOARD MEETING**

**DRAFT AGENDA**

**Wednesday, November 1, 2006**  
**1:30 p.m.**

168 North 1950 West (Bldg #2) Room 101

- I. Call-to-Order.
- II. Date of the Next Air Quality Board Meeting: December 6, 2006.
- III. **Approval of the Minutes for September's Board Meeting.**
- IV. **Ballot Transportation Proposition - Presented by LaVar Webb.**
- V. **Appointment of Temporary Executive Secretary. Presented by Christian Stephens.**
- VI. Appointment of Hearing Officer for A-1 Restoration. Presented by Christian Stephens.
- VII. **Propose for Public Comment: Amend R307-210, Stationary Sources; Amend R307-220, Emission Standards: Plan for Designated Facilities and Add New Section IV, Plan for Mercury Emissions at Coal-Fired Electric Generating Units; Add New Rule R307-224, Mercury Emission Standards: Coal-Fired Electric Generating Units; and Add New Rule R307-424, Permits: Mercury Requirements for Electric Generating Units. Presented by Bill Reiss.**
- VIII. **Propose for Public Comment: New State Implementation Plan Section XXII, Interstate Transport, and R307-110-36. Presented by Jan Miller.**
- IX. **Propose for Public Comment: R307-214-2, Incorporate by Reference Updates to Various Subparts of 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAPS), MACT Standards. Presented by Eileen Brennan.**

- X. Informational Items
  - A. PM Standard Update. Presented by Mat Carlile and Bill Reiss.
  - B. Compliance. Presented by Bryce Bird.
  - C. HAPS. Presented by Robert Ford.
  - D. Monitoring. Presented by Bob Dalley.

In compliance with the American with Disabilities Act, individuals with special needs (including auxiliary communicative aids and services) should contact Charlene Lamph, Office of Human Resources at (801) 536-4413 (TDD 536-4414).

**UTAH AIR QUALITY BOARD MEETING**  
**September 6, 2006**

**DRAFT MINUTES**

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**I. Call to Order**

John Veranth called the meeting to order at 1:32:58 PM.

Board members present

Nan Bunker, Stead Burwell, Jerry Grover, Jim Horrocks, Dianne R Nielson, Joann Seghini, Don Sorensen, and John Veranth.

Executive Secretary: Cheryl Heying acting for Rick Sprott.

Board members excused:

Ernest Wessman, Scott Lawson and Wayne Samuelson.

**II. Date of the Next Air Quality Board Meeting**

October 4, 2006 will be set as a tentative date for the next Board meeting.

Mr. Veranth stated that next year's tentative schedule for the Air Quality Board meetings will be the first Wednesday of every month except the March meeting will be held on the 14th and the July meeting will be held the 11<sup>th</sup>.

- Ms. Bunker made the motion to approve the tentative schedule. Mr. Sorensen seconded and the Board approved unanimously.

**III. Approval of the Minutes for August 2, 2006 Board Meeting**

- Mr. Grover made the motion to approve August 2, 2006 minutes. Mr. Horrocks seconded and the Board approved unanimously.

**IV. Final Adoption: Amend R307-415-4(2), Operating Permits - Source Category Exemptions - Addition of Five Area Source Exemptions. Presented by Robert Grandy.**

Mr. Grandy stated that at the June 15, 2006 Board meeting, amendments in R307-415-4(2) were proposed for public comment. The comment period was open July 1-31, and no comments were received. The staff recommends that R307-415-4(2) be adopted as proposed.

- Mr. Grover made the motion to adopt R307-415-4(2) as proposed. Ms. Bunker seconded and the Board approved unanimously.

**V. Proposed for Public Comment: Operating Permit Program Fee for Fiscal Year 2008. Presented by Dave Beatty.**

Mr. Beatty stated that Title V of the Clean Air Act Amendments of 1990 (CAAA) requires the State of Utah to develop an Operating Permit Program (OPP) to include a fee system which is to be used to fund all direct and indirect costs associated with administering the OPP. As part of the fee development process, the fee is included as part of the Department's fee schedule each fall. A public comment period will be held to allow an opportunity for interested parties to comment on the Department fee schedule and a public hearing will be scheduled during October 2006. Notice of the comment period and public hearing will be provided in the Legal Notices section of the major newspapers in the state. The staff recommends that the Board submit as part of the Department's fee schedule, a proposed fee of \$46.44/ton for the operating permit program for fiscal year 2008.

Ms. Nielson asked what EPA has established as a fee on the federal level. Mr. Beatty stated that comes out the end of September and the current fee is approximately \$40.50. Mr. Grover asked if this was ongoing budget not to include one-time expenditures. Mr. Beatty stated that it includes salary increases and decrease in emissions. Ms. Nielson wanted to remind the Board that every year at the end of the state budget cycle if there is an overage or underage it carries over o the next year. Ms. Nielson asked that when EPA establishes the federal fee that the Board be provided that information. Ms. Kathy Van Dame of the Clean Air Coalition stated that she would like to find a different structure for the Operating Permit Program Fee. Mr. Beatty stated that a task force has been together and would like to meet the end of September with the interest group to see if they can come up with a new way for the program. Mr. Horrocks would like to be updated on appropriate mile stones. Mr. Beatty would like the Board's input as well.

- Mr. Horrocks made the motion to propose for public comment the Operating Permit Program Fee for Fiscal Year 2008. Ms. Bunker seconded and the Board approved unanimously.

**VI. Propose for Public Comment: 8-Hour Ozone Maintenance Provisions for Salt Lake and Davis Counties, to replace Section IX.D of the Utah State Implementation Plan (SIP). Amend R307-110-13 to reflect this change. Presented by Robert Clark.**

Mr. Clark stated that the staff recommends that the 8-hour ozone maintenance plan be proposed for public comment and that 307-110-13 be amended to reflect this change.

- Mr. Grover made the motion to propose for public comment: 8-Hour Ozone Maintenance Provisions for Salt Lake and Davis Counties, to replace Section IX.D of the Utah State Implementation Plan (SIP). Amend R307-110-13 to reflect this change. Ms. Bunker seconded and the Board approved unanimously.

**VII. Propose for Public Comment: Amend R307-320, Davis, Salt Lake and Utah Counties, and Ogden City: Employer-Based Trip Reduction Program; R307-325, Davis and Salt Lake Counties and Ozone Nonattainment or Maintenance Areas: Ozone Provisions;**

**R307-326, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Control of Hydrocarbon Emissions; R307-327, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Petroleum Liquid Storage; R307-328, Davis, Salt Lake, Utah and Weber Counties and Ozone Nonattainment Areas: Gasoline Transfer and Storage; R307-335, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Degreasing and Solvent Cleaning Operations; R307-340, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Surface Coating Operations; R307-341, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Cutback Asphalt; R307-342, Davis, Salt Lake, Utah and Weber Counties and Ozone Nonattainment Areas: Qualification of Contractors and Test Procedures for Vapor Recovery Systems for Gasoline Delivery Tanks; R307-343, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Emissions Standards for Wood Furniture Manufacturing Operations; and R307-101-2, Definitions. Presented by Robert Clark.**

Mr. Clark stated that the staff recommends that R307-320, 325, 326, 327, 328, 335, 340, 341, 342, 343, and 101-2 be proposed for public comment, as amended.

- Mr. Grover made the motion to Propose for Public Comment: Amend R307-320, Davis, Salt Lake and Utah Counties, and Ogden City: Employer-Based Trip Reduction Program; R307-325, Davis and Salt Lake Counties and Ozone Nonattainment or Maintenance Areas: Ozone Provisions; R307-326, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Control of Hydrocarbon Emissions; R307-327, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Petroleum Liquid Storage; R307-328, Davis, Salt Lake, Utah and Weber Counties and Ozone Nonattainment Areas: Gasoline Transfer and Storage; R307-335, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Degreasing and Solvent Cleaning Operations; R307-340, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Surface Coating Operations; R307-341, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Cutback Asphalt; R307-342, Davis, Salt Lake, Utah and Weber Counties and Ozone Nonattainment Areas: Qualification of Contractors and Test Procedures for Vapor Recovery Systems for Gasoline Delivery Tanks; R307-343, Davis and Salt Lake Counties and Ozone Nonattainment Areas: Emissions Standards for Wood Furniture Manufacturing Operations; and R307-101-2, Definitions. Mr. Sorensen seconded and the Board approved unanimously.

**VIII. Propose for Public Comment: Deletion of R307-332 from the Air Quality Rules. Presented by Robert Clark.**

Mr. Clark stated that no substantive changes have been made. The only changes are grammatical errors, outdated terminology and moved definitions to proper place within the rules. The staff recommends that R307-332 be deleted.

- Mr. Sorensen made the motion to Propose for Public Comment: Deletion of R307-332 from the Air Quality Rules. Ms. Bunker seconded and the Board approved unanimously.

**IX. Informational Items**

- A. Open Meetings Act Presentation: Presented by Fred Nelson.
  - B. Clean Air Mercury Rule (CAMR); Status Report. Presented by Mat Carlile.
  - C. State Implementation Plan for 110 (a)(2)(d) of the Clean Air Act. Presented by Colleen Delaney.
  - D. Compliance. Presented by Jeff Dean.
  - E. HAPS. Presented by Robert Ford.
  - F. Monitoring. Presented by Bob Dalley.
- Mr. Dalley went over the latest air quality monitoring data.

Meeting adjourned at 2:44 PM

## **The Rail & Roads Campaign** **Improving Mobility in Salt Lake and Utah Counties**

### **The Transportation Need**

The Wasatch Front is facing a very real transportation crisis. Despite major improvements -- including the reconstruction of I-15 several years ago and the success of TRAX light rail -- the region's transportation needs are growing faster than our ability to meet them. One primary reason for this is population growth. Utah is one of the fastest growing states in the country, doubling the average national growth rate through the 1990s. The population boom continues, with another one million people projected along the Wasatch Front by 2030. And 75% of our population growth is coming from within, as our children and grandchildren seek to stay and enjoy the educational, economic and quality of life opportunities Utah offers.

Utahns are also driving more. From 1990 to 2002, vehicle miles traveled increased by 66 percent. This is almost twice the rate of population growth (36 percent), and severely outpaced increases in highway capacity (12 percent). At these growth rates, the amount of time we spend delayed in traffic congestion will *triple* in the next 25 years.

Increased congestion poses a significant threat to Utah's current and future economic vitality. Traffic congestion increases the cost of doing business with longer delivery times, reduced productivity, lost time of employees stuck in traffic, less efficient travel and increased fuel usage. As the cost of doing business goes up, the increases are passed along to customers in the form of higher prices for goods and services.

Growing congestion and increased business costs reduce Utah's competitiveness with other regions and negatively impacts our economic growth. Transportation and mobility is one of the primary factors businesses evaluate when considering where to locate, and having an efficient, multi-modal transportation system will help keep Utah attractive and competitive. For example, in the Denver area, the Chamber of Commerce reports that new business prospects have tripled since voters passed *FasTracks*, a \$4 billion program of rail projects to be completed by 2016.

Investing in our transportation infrastructure will also help fuel Utah's future economic growth. A study conducted by the Bureau of Business and Economic Research at the University of Utah titled, *Economic and Demographic Impacts of Federal Financed Transportation Infrastructure on the Wasatch Front*, determined that building recommended highway and transit projects could bring as much as \$4.2 billion in additional federal money to Utah by 2030. That \$4.2 billion will create almost 4,000 new jobs and add \$212 million to the state's economy each year.

We must address our transportation needs sooner, not later, in order to protect Utah's economy and quality of life. Building an efficient highway and transit system will increase mobility, improve air quality, strengthen major employment centers, increase Utah's economic competitiveness with other regions, bolster our local economy and generate additional revenue to fund other state programs.

### **An Opportunity to Act**

This election season, thanks to years of work by local governments and the Utah Legislature, voters in Salt Lake and Utah counties have an opportunity to do something about the transportation crisis. By voting for Proposition 3 in Salt Lake County and for the rail and roads Opinion Question in Utah County, a significant infusion of funding will flow to highway corridor preservation, FrontRunner commuter rail, expansion of TRAX light rail, and other highway projects.

A positive vote on the two ballot proposals will mean an additional quarter-cent sales tax will be invested in transportation infrastructure. It will be an on-going, growing source of revenue for transportation, amounting to billions of dollars over many years.

### **Years of Research and Study**

The Nov. 7 vote is the culmination of long study and effort by elected officials from the Legislature, the Wasatch Front Regional Council (WFRC) and the Mountainland Association of Governments (MAG). Local officials have studied the serious transportation needs facing the region, with an eye to build a region-wide rail transit system, along with critical highway projects. The officials created the "Transit 2030" committee, which over a two-year period identified top-priority highway and transit projects that were ultimately adopted into the Long Range Plan in 2003.

The elected officials on the Transit 2030 committee also evaluated available funding alternatives to complete the critical highway and transit projects identified. With respect to transit, the first phase of the WFRC and MAG long-range plans identify \$2.1 billion needed to build the projects by 2015. Current revenue sources will generate only \$600 million, leaving \$1.5 billion in unfunded needs.

The committee carefully studied and evaluated many possible funding sources for both highways and transit. With input from UDOT, UTA, the Utah League of Cities and Towns, elected officials evaluated the potential revenue and ramifications from:

- Gas taxes
- Sales tax on fuel
- Impact fees on roads
- Real estate taxes
- Property taxes
- Inflationary component to gas tax
- Vehicle registration / license fees
- Registration fees based on vehicle miles traveled
- Special Improvement Districts
- Sales taxes

### **The Legislature Examines the Need**

Meanwhile, the Transportation Planning Task Force was created by the Legislature during the 2003 General Session with H.B. 310 "Transportation Planning Task Force." For two years, the Task Force studied transportation issues and needs statewide and on November 10, 2004, made its final report to the Transportation Interim Committee. The report articulated several fundamental principles to guide transportation policy decision making, including:

- **Funding Diversification:** over-reliance on a few traditional funding sources will not produce the revenue needed nor spread the tax burden fairly – the state must broaden the base for which transportation systems are funded.
- **Transit Funding:** transit is a necessary transportation option. Currently authorized revenue tools, including sales tax and property tax, should be exercised before new revenue sources are considered.
- **Funding Stability:** transportation projects require stable and reliable long-term transportation funding that can be clearly identified by policy makers and transportation planners.

### **The Business Community Gets Involved**

The Salt Lake Chamber of Commerce, recognizing the link between transportation and economic development, has engaged the business community in finding and advocating solutions. In November 2004, the Chamber announced its five *Economic Strategic Initiatives*, identifying transportation as one of its critical priorities to foster economic, cultural and social growth. Recommending the expedited construction of highway and transit projects, on November 23, 2004 the Chamber adopted a *Resolution on Mobility*, pledging its "partnership with the Utah Legislature in identifying funding solutions to our mobility problems."

On December 15, 2004, the Chamber hosted a "Mobility Summit," which was attended by more than 200 local business, political and community leaders. Chamber President Lane Beattie, local pollster Dan Jones and West Valley City Mayor Dennis Nordfelt outlined the growing crisis and the need to

find the funding to build critical transportation projects. Rich Walje, Executive Vice President of Utah Power, and Keith Rattie, President and CEO of Questar Corporation emphasized the increasing costs of business due to congestion and the need to find solutions.

A year later, in October 2005, Governor Huntsman's office hosted a second Transportation Summit, attended by more than 150 political, business and community leaders. Members of Utah's Congressional delegation, the Legislature, local government, Chambers of Commerce, transportation agencies and other stakeholders participated in a discussion of Utah's transportation crisis and the unfunded highway and transit needs. Results of an informal online survey conducted by the Governor's office in anticipation of the summit reported that 82% of respondents are concerned about transportation and 83% support expanding transit.

The Salt Lake Chamber also created The 2015 Alliance whose mission is to accelerate the build-out of key transportation projects by 2015, rather than 2030. The Alliance commissioned an independent study, confirming the need to boost transportation funding for priority projects or risk a diminished quality of life and reduced economic vitality.

## **The Legislature Acts**

### **Crucial Highway Projects**

#### **The Success of Transit**

In 2005, a record number of Utahns used transit. More than 36 million trips were taken last year on UTA's bus, light rail, paratransit and vanpool services. The last time transit ridership was at this level was post-World War II, when a record peak of 33 million trips was recorded in 1946.

Largely fueling these record-breaking ridership levels is the success of light rail. Since the first TRAX line opened in December 1999, ridership is exceeding projections by more than double. The Sandy/Salt Lake Line and the University Line - originally projected to carry a combined total of 21,000 daily riders - are currently carrying more than 55,000 riders each weekday.

TRAX ridership continues to see double-digit increases each year. In 2005, ridership increased 13.5% over 2004, providing almost 13 million rides. And as the cost of gasoline skyrocketed through the summer and fall of 2005, UTA saw a dramatic increase in ridership as people turned to transit as a less expensive option. The number of average weekday passengers on TRAX rose 20 percent in October, 45 percent in November and 46 percent in December, compared to the corresponding months the previous year. The high ridership has continued into 2006: year-to-date through April, TRAX ridership is up 35% over the same months last year.

These ridership figures demonstrate that transit is having an effect on mobility and congestion. A comparison of light rail ridership with traffic counts on I-15 reveals that TRAX is carrying approximately 20% percent of weekday work trips to downtown Salt Lake City. During peak commute hours, that equals one lane of traffic on I-15. And in more defined markets, light rail is making an even greater impact, currently accounting for 30 percent of weekday student trips to the University of Utah, 50% of employees at the LDS Church Office Building, and 60% of employees at Beneficial Life.

#### **The Projects & Schedule**

The first phase of the WFRC Long Range Plan in Salt Lake County includes four light rail projects: the Mid-Jordan Line, the West Valley Line, the Airport Line and the Draper extension. The sales tax increase approved in 2000 by voters in Salt Lake, Davis and Weber Counties provided funding to

complete these four projects in 30 years. But with a desire among local elected officials to accelerate the projects, it is possible these lines could be in operation by 2014 if funding is provided.

**Mid-Jordan Line**

- 10.1 miles
- Eight proposed stations
- 15-minute frequency
- Projected ridership of 25,000-30,000 in 2025
- If accelerated: open for service in 2010
- Estimated cost: \$335 - \$370 million

**Airport Line**

- 5.5 miles
- Five proposed stations
- Extends from Delta Center to Airport
- Projected ridership of 6,000-9,000 in 2025
- If accelerated: open for service in 2013
- Estimated cost: \$250 - \$290 million

**West Valley Line**

- 5.1 miles
- Four proposed stations
- 15-minute frequency
- Projected ridership of 9,000-12,000 in 2025
- If accelerated: open for service in 2012
- Estimated cost: \$250 - \$290 million

**Draper Extension**

- 7.0 miles
- Stations to be determined
- Extends from TRAX in Sandy to Draper
- Projected ridership of 7,000–10,000 in 2025
- If accelerated: open for service in 2014
- Estimated cost: \$235 - \$260 million

As local elected officials have been studying options for accelerating projects in the Long Range Plan, UTA has responded by moving forward with the necessary environmental, engineering and design work. The preliminary environmental and engineering work is almost complete on these projects, and if funding is approved to accelerate the plan, all four projects could be *under construction within one year and open for service by 2014*, significantly accelerating the schedule as follows:

	<u>Current Funding</u>	<u>Increased Funding</u>
• Mid-Jordan Line	2014	<b>2010</b>
• West Valley Line	2021	<b>2012</b>
• Airport Line	2030	<b>2013</b>
• Draper Extension	2025	<b>2014</b>

Under the accelerated schedule, the cost to build the four projects is approximately \$1.25 billion. Current estimates indicate this will save taxpayers \$610 million (50%) in construction costs.

**Conclusion: Pay Now or Pay Later**

The transportation needs are real. The Wasatch Front population is projected to double by 2030. In a September 2005 poll conducted by Dan Jones & Associates, 74% of Salt Lake County residents stated that “traffic congestion is a serious problem.” Eighty-one percent (81%) said “traffic congestion is getting worse.” At current funding levels, congestion will triple in the next 25 years. Our economic growth will be affected as business costs increase, productivity decreases and Utah becomes a less desirable place for businesses to locate.

The benefits of investing in transportation are also real. Funding to purchase top-priority highway rights-of-way is desperately needed, especially for the Mountain View Corridor. Highway mitigation projects in Utah County are crucial to prepare for I-15 rebuild in the county.

With increased funding, the four light rail projects in Salt Lake County can be operational by 2014. Accelerating the transit projects will reduce construction costs by 50%, saving taxpayers more than \$600 million. The TRAX system will more than double, with 28 miles of new light rail. A majority of Salt Lake County residents will be within three miles of a rail line, and bus routes will be realigned to better serve other areas and support the light rail system. These transit projects will provide transportation options to residents, and the increased mobility will support our economic growth and help maintain Utah’s quality of life.

Community leaders have come to the table. Much work has been done over the past few years as local and state elected officials, the business community, planning organizations, transportation planners and other stakeholders have partnered in an unprecedented fashion to identify critical highway and transit needs and develop viable funding solutions.

Now the public can weigh in by voting on Nov. 7.

STATE OF UTAH  
OFFICE OF THE ATTORNEY GENERAL



MARK L. SHURTLEFF  
ATTORNEY GENERAL

RAYMOND A. HINTZE  
Chief Deputy

*Protecting Utah • Protecting You*

KIRK TORGENSEN  
Chief Deputy

September 28, 2006

Dianne R. Nielson  
Executive Director  
Utah Department of Environmental Quality  
168 North 1950 West  
P.O. Box 144810  
Salt Lake City, UT 84114-4810

Re: Appointment of Air Quality Staff During Executive Secretary's Temporary Absences

Dear Executive Director Nielson:

With the administrative duties incumbent on the Executive Secretary of the Utah Air Quality Board, on occasion the Executive Secretary is unable to be present to perform his responsibilities. Consequently, the Division of Air Quality (DAQ) would benefit from the appointment of another DAQ staff member to exercise temporarily the Executive Secretary's authority. I have outlined below the legal authority that I believe supports this approach to carrying forward the Division's responsibilities.

The Executive Director has authority to ensure that the Department of Environmental Quality accomplishes its mission to "provide effective, coordinated management of state environmental concerns" and "safeguard public health and quality of life by protecting and improving environmental quality . . ." Utah Code Ann. § 19-1-102(2)-(3). In this position, the Executive Director oversees the Department's divisions and the Executive Secretaries of the environmental quality boards.


To assist in that endeavor, the Utah Conservation Act states that "[t]he executive secretary shall be appointed by the executive director, with the approval of the board, and shall serve under the administrative direction of the executive director." Utah Code Ann. § 19-2-107. Therefore, the Executive Secretary serves under the administrative direction of the Executive Director. The Executive Director also has the authority to "make policies not inconsistent with law for the internal administration and government of the department, [and] the conduct of its employees . . ."

Due to personal or other matters, on occasion the Executive Secretary is unable to be present. To account for such instances, Executive Secretary Richard Sprott requests that the Board appoint Cheryl Heying (DAQ Planning Branch Manager) to act as Executive Secretary in his absence. The authority to "make policies . . . for the internal administration of the department" extends to the appointment of Ms. Heying to exercise the Executive Secretary's authority on a temporary basis.

Executive Secretary Sprott also requests that this matter be placed as an action item on the November Air Quality Board meeting agenda, as the appointment will require the Air Quality Board's approval.

Should you have any questions, please do not hesitate to call me at (801) 536-4137.

Sincerely,



Christian C. Stephens  
Assistant Attorney General

cc: . . . Richard Sprott, Executive Secretary, Utah Division of Air Quality  
Fred G Nelson, Assistant Attorney General



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DAQ-074-06

MEMORANDUM

**TO:** Utah Air Quality Board

**THROUGH:** Richard W. Sprott

**FROM:** Bill Reiss

**DATE:** November 1, 2006

**SUBJECT:** Propose for Public Comment; Amend R307-210, Stationary Sources; Amend R307-220, Emission Standards: Plan for Designated Facilities and Add New Section IV, Plan for Mercury Emissions at Coal-Fired Electric Generating Units; Add New Rule R307-224, Mercury Emission Standards: Coal-Fired Electric Generating Units; and Add New Rule R307-424, Permits: Mercury Requirements for Electric Generating Units.

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**Background:**

On May 18, 2005 EPA released its Clean Air Mercury Rule (CAMR) to address airborne mercury emissions from Electric Generating Units (EGUs.) The rule generally applies to any stationary coal-fired boiler, serving a generator with nameplate capacity of more than 25 megawatts.

The CAMR has been structured as part of the New Source Performance Standards (NSPS.) Any new unit (commencing construction after January 30, 2004) will be required to meet emission limits for mercury in the revised NSPS.

In order to address pre-existing units that would otherwise have been affected by the rule, Utah must prepare what is called a Designated Facilities Plan (DFP or the Plan). The Plan must demonstrate that, beginning in 2010, mercury emissions from all of the affected EGUs under the State's jurisdiction will be no greater than the mercury emission budgets allocated to Utah under the CAMR.

The CAMR program will take place in two phases, reflecting a two-tiered reduction in nation-wide mercury emissions from an estimated 48 tons in 1999. Phase one will begin in 2010 and run through 2017. Under Phase one, EPA will issue a total number of mercury allowances equal to 38 tons. Phase two begins

in 2018. Under Phase two, EPA will reduce the number of allowances to a corresponding nationwide emission rate of 15 tons per year.

Utah's allowances under the CAMR will be 0.506 tons per year in Phase one and 0.200 tons per year in Phase two. As a point of comparison, EPA estimates that EGUs in Utah emitted 0.142 tons of mercury in 1999. Utah's budgets do not include emissions from Deseret Generation and Transmission (the Bonanza plant.) Rather, the Ute Indian Tribe has jurisdiction over that facility. The Utes are also given a budget under the CAMR.

EPA has proposed a "model rule" to satisfy the compliance element of the Designated Facilities Plan. The model rule is essentially a national cap and trade program. Sources within each state or tribal area could exceed this budget if they were to secure enough extra allowances to cover the overage.

States and tribes are free to participate in this national trading program or not. Should they choose not to take part, the DFP would have to outline alternative means of keeping the mercury emissions from these pre-existing facilities within the budgets allocated to that state or tribe. Presumably, this alternative means would involve emission limits and, like the model trading rule, would include provisions for monitoring, recordkeeping and reporting.

### **Today's Proposal:**

Utah Division of Air Quality (DAQ) has drafted a suite of rules intended to implement a comprehensive strategy to address mercury emissions from EGUs.

This strategy includes participation in EPA's nationwide cap and trade program, with overall goals of reducing mercury emissions from an estimated 48 tons per year nationwide to 38 tons per year by 2010 and 15 tons per year by 2018.

It also includes state-only provisions which establish minimum performance criteria for existing EGUs and require offset for potential increases in mercury emissions.

The proposal is reflected in four separate rules as well as the Designated Facilities Plan. Each of these has been included in the packet, and a brief description is provided below:

R307-224 "Mercury Emission Standards: Coal-Fired Electric Generating Units" In this rule, Utah is proposing to incorporate by reference much of EPA's model rule which establishes a cap and trade program to ensure that mercury emissions from EGUs will remain in compliance with the emission budgets established for the State of Utah. Some parts of the model rule have specifically not been incorporated by reference.

"Designated Facilities Plan for Mercury (Hg) Emissions at Coal Fired Electric Generating Units" This Plan (or DFP) is required under 40 CFR 60.24 to address mercury emissions at qualifying coal-fired electric generating units that were in existence prior to EPA's new regulations under the New Source Performance Standards. Those parts of the model rule that have specifically not been incorporated by reference in R307-224 are addressed here in the DFP.

R307-220 "Emission Standards: Plan for Designated Facilities" In this rule, Utah incorporates by reference the entirety of its Designated Facilities Plan. The DFP includes sections covering: Municipal Solid Waste Landfills (Section I), Hospital, Medical, Infectious Waste Incinerators (Section II), Small

Municipal Waste Combustion Units (Section III), and now at R307-220-5 a new “Section IV, Coal-Fired Electric Generating Units”

R307-210 “Stationary Sources” In this rule, Utah incorporates by reference all of 40 CFR 60, Standards of Performance for New Stationary Sources. Much of EPA’s federal rulemaking with regard to mercury emissions from EGUs appears in part 60, and not all of it is contained in the Model Rule (which is subpart HHHH.) Subpart HHHH is specifically not incorporated by R307-210.

R307-424 “Permits: Mercury Requirements for Electric Generating Units” In this rule, Utah seeks to establish state-wide requirements for mercury emissions at coal-fired electric generating units. As proposed, the rule contains two distinct provisions: 1) a requirement that any existing EGU exceeding 1,500 MMbtu/hr (heat input capacity) meet certain emission rates or control efficiencies, and 2) an offset requirement for permitting increases in mercury emissions.

**Recommendation:**

DAQ staff recommends that the Utah Air Quality Board propose the attached rules and the Designated Facilities Plan for public comment.

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UTAH STATE PLAN  
FOR  
IMPLEMENTATION OF EMISSION CONTROLS FOR  
EXISTING DESIGNATED FACILITIES

**SECTION IV, PLAN FOR  
MERCURY EMISSIONS AT  
COAL-FIRED ELECTRIC GENERATING UNITS  
Implementation of 40 CFR 60 Subpart HHHH**

**Adopted by the Air Quality Board  
February 7, 2007**

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1 **A. Introduction**

2

3 A federal plan to reduce mercury (Hg) emissions from coal fired electric generating units (EGUs)  
4 has been promulgated as a revision to the New Source Performance Standards, under the  
5 authority of section 111 of the Clean Air Act.

6 Emission standards for mercury emissions have been included at 40 CFR 60 subpart Da, and will  
7 apply to any applicable source which commences construction after January 30, 2004.

8 Subpart B of 40 CFR 60 requires a Designated Facilities Plan (DFP or the Plan) to address  
9 sources to which subpart Da would have applied had construction not commenced prior to the  
10 applicable date. This document is Utah’s Plan to meet the requirements of subpart B.

11 As part of a nationwide control strategy, each state has been allocated an annual mercury budget  
12 for each of two program phases: 2010 through 2017, and 2018 and thereafter.

13 The Designated Facilities Plan required under paragraph (h)(1) of 40 CFR 60.24 is to contain  
14 emission standards and compliance schedules that will result in compliance with the State’s  
15 annual EGU mercury budget. It must also require EGUs to comply with the monitoring, record  
16 keeping, and reporting provisions of 40 CFR part 75 with regard to mercury emissions, and show  
17 that the State has adequate legal authority to adopt and require such elements.

18 The EPA has presented subpart HHHH (the “Model Rule”) as a means to implement a national  
19 trading program for mercury allowances, and thereby meet the required elements of a DFP. If a  
20 state adopts regulations substantively identical to subpart HHHH, incorporates such subpart by  
21 reference into its regulations, or adopts regulations that differ substantively from such subpart  
22 only in terms of its allowance allocation and notification provisions, then the State’s Plan will be  
23 automatically approved as meeting the requirements related to compliance with the annual  
24 mercury budgets.

25 R307-224 directly incorporates much of subpart HHHH. This Plan supplements the incorporated  
26 elements of subpart HHHH and specifies allocation and notification provisions for the mercury  
27 allowances to be used in the cap and trade program. This Plan itself is incorporated by reference  
28 at R307-220-5.

29 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS), including subpart Da,  
30 is incorporated by reference into the Utah Administrative Code at R307-210.

31 Together, R307-210, R307-224, and this Plan (incorporated into the rules at R307-220) regulate  
32 mercury emissions from any coal-fired electric generating unit (EGU) as defined in 40 CFR 60.24  
33 serving a generator greater than 25 megawatts nameplate capacity.

1 **B. Departures from the Model Rule**

2 **1. Portions of HHHH Incorporated by Reference at R307-224.**

3 The following sections of 40 CFR Part 60, subpart HHHH (the Model Rule) effective on June 9,  
4 2006, have been adopted and incorporated by reference into the Utah Administrative Code in  
5 R307-224-2.

6 \* Hg Budget Trading Program General Provisions

7 Sections 60.4101 through 60.4108

8 \* Hg Designated Representative for Hg Budget Sources

9 Sections 60.4110 through 60.4114

10 \* Permits

11 Sections 60.4120 through 60.4124

12 \* Hg Allowance Allocations

13 Section 60.4142, paragraphs (c)(2) through (c)(4)

14  
15 These paragraphs outline the procedures for obtaining Hg allowances from  
16 the new unit set-aside. The designated representative must submit a  
17 written request for such allowances, in an amount not exceeding the unit's  
18 emissions for the prior control period, and the permitting authority will  
19 then review the request and make allowances as appropriate.

20 \* Hg Allowance Tracking System

21 Sections 60.4151 through 60.4157

22 \* Hg Allowance Transfers

23 Sections 60.4160 through 60.4162

24 \* Monitoring and Reporting

25 Sections 60.4170 through 60.4176

26

27 **2. Portions of HHHH Specifically Not Incorporate by Reference.**

28 The following sections of 40 CFR Part 60, subpart HHHH, effective on June 9, 2006, specifically  
29 have **not** been adopted and incorporated by reference into the Utah Administrative Code.

1 Hg Allowance Allocations

2 Section 60.4140; State Trading Budgets

3

4 This section includes mercury budgets for each of the affected States and  
5 Tribes for control periods in each phase of the program.

6

7 Section 60.4141; Timing Requirements for:

8

9

paragraph (a)

10

11

By 2006, the model rule requires the permitting authority to declare to  
12 the Administrator the number of mercury allowance allocations for  
13 2010-2014 (not including new unit set-aside allowances.)

14

15

paragraph (b)

16

17

By 2008 and every year thereafter, the model rule requires the  
18 permitting authority to declare to the Administrator the number of  
19 mercury allowance allocations it will issue for the control period 6  
20 years hence (not including new unit set-aside allowances.) If the  
21 permitting authority fails to make this declaration, the Administrator  
22 shall make certain assumptions regarding such issuance.

23

24

paragraph (c)

25

26

In 2010 and every year thereafter, the model rule requires the  
27 permitting authority to declare to the Administrator the number of  
28 mercury allowances to be issued from the new unit set-aside. If the  
29 permitting authority fails to make this declaration, the Administrator  
30 shall make certain assumptions regarding such issuance.

31

32

Section 60.4142; Hg Allowance Allocations

33

34

paragraph (a)

35

36

In this paragraph, the model rule outlines procedures for determining  
37 the baseline heat input for both new and existing EGUs. This then  
38 becomes the basis for allocating mercury allowances.

1 paragraph (b)

2  
3 In this paragraph, the model rule directs the permitting authority to  
4 allocate, to the EGUs, 95 percent of the State’s mercury budget for the  
5 control periods in 2010-2014, and 97 percent in 2015 and beyond.

6  
7 paragraph (c)(1)

8  
9 In this paragraph, the model rule directs the permitting authority to set  
10 aside the remaining 5 / 3 percent of the State’s mercury budget (for the  
11 control periods in 2010-2014 and the control periods in 2015 and  
12 beyond respectively) for distribution to new units.

13  
14 paragraph (d)

15  
16 In this paragraph, the model rule stipulates that, if there are any  
17 unallocated mercury allowances remaining in the new unit set-aside,  
18 the permitting authority would allocate them to the established units on  
19 the basis of heat input.

20  
21 **3. Substitutions for Portions of HHHH Not Incorporated by Reference.**

22  
23 Instead, the following shall apply.

24  
25 **(a) State Trading Budget**

26 The Utah State trading budget for annual allocations of Hg allowances for each of the control  
27 periods in 2010 through 2017 shall be 0.506 tons (16,192 oz.) The Utah State trading budget for  
28 annual allocations of Hg allowances for each of the control periods thereafter shall be 0.200 tons  
29 (6,400 oz.)

30 **(b) Notification of Hg Allowance Allocations**

31 (i) By November 17, 2006, the Permitting Authority will submit to the Administrator the  
32 Hg allowance allocations, in a format prescribed by the Administrator and in accordance  
33 with (e) below and (c) below, for the control periods in 2010, 2011, and 2012.

34 (ii) By October 31, 2009, the Permitting Authority will submit to the Administrator the  
35 Hg allowance allocations, in a format prescribed by the Administrator and in accordance  
36 with (e) below and (c) below, for the control periods in 2013, 2014 and 2015.

37 (iii) By October 31, 2010 and October 31 of each year thereafter, the Permitting  
38 Authority will submit to the Administrator the Hg allowance allocations, in a format  
39 prescribed by the Administrator and in accordance with (e) below and:

1 (A) in accordance with (c) below, for the control period in the sixth year after  
2 the year of the deadline for submission under this section; and

3 (B) in accordance with (d) below, for the control period in the year of the  
4 applicable deadline for submission under this section.

5 (iv) If the Permitting Authority fails to submit to the Administrator the Hg allowance  
6 allocations in accordance with (b)(ii) or (b)(iii) above, the Administrator will assume that  
7 the allocations of Hg allowances for the applicable control period are the same as for the  
8 control period that immediately precedes the applicable control period, except that:

9 (A) if the applicable control period is in 2018, the Administrator will assume  
10 that the allocations equal the allocations for the control period in 2017 multiplied  
11 by a factor of (6400/16192), and

12 (B) any Hg budget unit that would be otherwise allocated Hg allowances under  
13 (c) below as well as under (d) for the applicable control period will be assumed  
14 to be allocated no Hg allowances under (d).

15 **(c) Hg Allowance Allocations**

16 (i) For each control period in 2010 and thereafter, the Permitting Authority will allocate  
17 to all Hg budget units that have a baseline heat input, as determined under (e) below, a  
18 total amount of Hg allowances equal to 90 percent for a control period in 2010 through  
19 2017, and 90 percent for a control period in 2018 and thereafter, of the amount of ounces  
20 of Hg emissions in the Utah State trading budget under (a) above, except as provided in  
21 (d)(iii).

22 (ii) The Permitting Authority will allocate Hg allowances to each Hg Budget unit under  
23 (c)(i) above in an amount determined by multiplying the total amount of Hg allowances  
24 allocated under (c)(i) above by the ratio of the baseline heat input of such Hg Budget unit  
25 to the total amount of baseline heat input of all such Hg Budget units and rounding to the  
26 nearest whole allowance (ounce) as appropriate.

27 **(d) Hg Allowance Allocations: New Unit Set-Aside**

28 (i) The Permitting Authority will establish a separate new unit set-aside for each  
29 control period. Each new unit set-aside will be allocated Hg allowances equal to  
30 10 percent for a control period in 2010 through 2017, and 10 percent for a control  
31 period in 2018 and thereafter, of the amount of ounces of Hg emissions in the  
32 State trading budget under (a).  
33

34 (ii) For each control period in 2010 and thereafter, the Permitting Authority will  
35 allocate Hg allowances to Hg Budget units that commenced operation on or after  
36 January 1, 2001, and do not yet have a baseline heat input, as determined under  
37 (e) below, in accordance with R307-224-2 (1)(b).  
38

1 (iii) If, after completion of the procedures under R307-224-2 (1)(b), any  
2 unallocated Hg allowances remain in the new unit set-aside for the control period,  
3 the permitting authority will allocate these allowances to each budget unit that  
4 was allocated Hg allowances under (c)(i) above using the procedure described in  
5 (c)(ii).

6 **(e) Hg Allowance Allocations: Basis for Distribution**

7 (i) The baseline heat input (in MMBtu) used with respect to Hg allowance allocations  
8 under (c) above for each Hg Budget unit commencing operation before January 1, 2001,  
9 will be the average of the three highest amounts of the unit's control period heat input,  
10 resulting from the combustion of coal, within the rolling five-year period concluding  
11 December 31<sup>st</sup> of the year prior to the year in which such allocations are to be made.

12 (ii) The baseline heat input (in MMBtu) used with respect to Hg allowance allocations  
13 under (c) above for each Hg Budget unit commencing operation on or after January 1,  
14 2001, and operating each calendar year during a period of five or more consecutive  
15 calendar years, will be the average of the three highest amounts of the unit's total  
16 converted control period heat input, resulting from the combustion of coal, over the first  
17 such five years. A unit's converted control period heat input for a calendar year is equal  
18 to whichever of the following is applicable:

19  
20 (A) Except as provided in (B) or (C) below, the control period gross electrical  
21 output of the generator or generators served by the unit multiplied by 7.9  
22 MMBtu/MW-hr. If a generator is served by 2 or more units, then the gross  
23 electrical output of the generator will be attributed to each unit in proportion to  
24 the unit's share of the total control period heat input of such units for the year; or

25 (B) For a unit that is a boiler and has equipment used to produce electricity and  
26 useful thermal energy for industrial, commercial, heating, or cooling purposes  
27 through the sequential use of energy, the total heat energy (in MMBtu) of the  
28 steam produced by the boiler during the control period, divided by 0.8; or

29 (C) For a unit that is a combustion turbine and has equipment used to produce  
30 electricity and useful thermal energy for industrial, commercial, heating, or  
31 cooling purposes through the sequential use of energy, the control period gross  
32 electrical output of the enclosed device comprising the compressor, combustor,  
33 and turbine multiplied by 3.413 MMBtu/MW-hr, plus the total heat energy (in  
34 MMBtu) of the steam produced by any associated heat recovery steam generator  
35 during the control period multiplied by 0.8.

36 (iii) For the purpose of determining allocations of Hg allowances, a unit's control period  
37 heat input for a calendar year under (e)(i) above and a unit's total ounces of Hg emissions  
38 under R307-224-2 (1)(b) will be determined in accordance with 40 CFR part 75 to the  
39 extent that the unit was otherwise subject to the requirements of part 75 for that year. To  
40 the extent that the unit was not otherwise subject to the requirements of part 75 for that  
41 year, this information will be based on the best available data reported to the executive  
42 secretary for the unit.

1 **C. The Clean Air Mercury Rule (CAMR)**

2 Utah has incorporated most of the model rule by reference into its Administrative Code.

3 As of this date (November 1, 2006), EPA has yet to include the amendments that comprise the  
4 CAMR in the Code of Federal Regulations. Instead it appears in the various Federal Register  
5 notices cited below.

6 **1. Final Rule**

7 Standards of Performance for New and Existing Stationary Sources: Electric Steam Generating  
8 Units (the Clean Air Mercury Rule) (70 FR 28606, May 18, 2005.)

9 This final rule includes revisions to title 40, chapter I parts 60 (New Source Performance  
10 Standards), 72 (Permits Regulation), and 75 (Continuous Emission Monitoring) of the Code of  
11 the Federal Regulations.

12 The model rule itself appears as part of this rulemaking at 40 CFR 60 subpart HHHH (70 FR,  
13 page 28657).

14 **2. Notice of Reconsideration**

15 Notice of Reconsideration of Final Rule and Request for Public Comment Regarding the May 18,  
16 2005 Final Clean Air Mercury Rule (70 FR 62213, October 28, 2005.)

17 This was published in response to seven specific issues, raised in four petitions, concerning the  
18 final rule.

19 **3. Final Rule; Notice of Final Action on Reconsideration**

20 Final Rule; Notice of Final Action on Reconsideration (71 FR 33388, June 9, 2006.)

21 This final action resulted in one clarification and two revisions to the CAMR.

22 The applicability to the CAMR was clarified in the definition of Electric Generating Unit. This  
23 determination was applied consistently in two locations: 40 CFR 60.24(h)(8) and subpart HHHH,  
24 40 CFR 60.4104.

25 The two changes that were made relate to:

26 \* the unit-level Hg emission allocations within the 2010 phase I statewide Hg  
27 emission budgets. This change affected minor changes to the budgets for seven  
28 states.

1           \* the statistical analysis used for the NSPS limits in subpart Da. EPA did not  
2           revise its statistical basis for the analysis, but did correct several arithmetic errors  
3           effectively revising most of the proposed limits.

**Electronic Code of Federal Regulations (e-CFR)****BETA TEST SITE****e-CFR Data is current as of October 6, 2006****Title 40: Protection of Environment****[PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES](#)**[Browse Previous](#) | [Browse Next](#)**Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978****Source:** 44 FR 33613, June 11, 1979, unless otherwise noted.**§ 60.40Da Applicability and designation of affected facility.**

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

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

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

(b) Heat recovery steam generators that are associated with stationary combustion turbines burning fuels other than 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average and that meet the applicability requirements of subpart KKKK of this part are not subject to this subpart. Heat recovery steam generators and the associated stationary combustion turbine(s) burning fuels containing 75 percent (by heat input) or more synthetic-coal gas on a 12-month rolling average are subject to this part and are not subject to subpart KKKK of this part. This subpart will continue to apply to all other electric utility combined cycle gas turbines that are capable of combusting more than 73 MW (250 MMBtu/h) heat input of fossil fuel in the heat recovery steam generator. If the heat recovery steam generator is subject to this subpart and the combined cycle gas turbine burn fuels other than synthetic-coal gas, only emissions resulting from combustion of fuels in the steam-generating unit are subject to this subpart. (The combustion turbine emissions are subject to subpart GG or KKKK, as applicable, of this part).

(c) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels, shall not bring that unit under the applicability of this subpart.

(d) Any change to an existing steam generating unit originally designed to fire gaseous or liquid fossil fuels, to accommodate the use of any other fuel (fossil or nonfossil) shall not bring that unit under the applicability of this subpart.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49453, Sept. 16, 1998. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9876, Feb. 27, 2006; 71 FR 33399, June 9, 2006]

**§ 60.41Da Definitions.**

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

*Anthracite* means coal that is classified as anthracite according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388–77 (incorporated by reference—see §60.17).

*Available purchase power* means the lesser of the following:

(a) The sum of available system capacity in all neighboring companies.

(b) The sum of the rated capacities of the power interconnection devices between the principal company and all neighboring companies, minus the sum of the electric power load on these interconnections.

(c) The rated capacity of the power transmission lines between the power interconnection devices and the electric generating units (the unit in the principal company that has the malfunctioning flue gas desulfurization system and the unit(s) in the neighboring company supplying replacement electrical power) less the electric power load on these transmission lines.

*Available system capacity* means the capacity determined by subtracting the system load and the system emergency reserves from the net system capacity.

*Bituminous coal* means coal that is classified as bituminous according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004) (incorporated by reference, see §60.17).

*Boiler operating day* for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. For units constructed, reconstructed, or modified after February 28, 2005, *boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

*Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004) (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal, coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart.

*Coal-fired electric utility steam generating unit* means an electric utility steam generating unit that burns coal, coal refuse, or a synthetic gas derived from coal either exclusively, in any combination together, or in any combination with other fuels in any amount.

*Coal refuse* means waste products of coal mining, physical coal cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

*Cogeneration*, also known as “combined heat and power,” means a steam-generating unit that simultaneously produces both electric (or mechanical) and useful thermal energy from the same primary energy source.

*Combined cycle gas turbine* means a stationary turbine combustion system where heat from the turbine exhaust gases is recovered by a steam generating unit.

*Dry flue gas desulfurization technology* or *dry FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a dry powder material. This definition includes devices where the dry powder material is subsequently converted to another form. Alkaline slurries or solutions used in dry FGD technology include, but are not limited to, lime and sodium.

*Duct burner* means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

*Electric utility combined cycle gas turbine* means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

*Electric utility company* means the largest interconnected organization, business, or governmental entity that generates electric power for sale (e.g., a holding company with operating subsidiary companies).

*Electric utility steam-generating unit* means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale. For the purpose of this subpart, net-electric output is the gross electric sales to the utility power distribution system minus purchased power on a 12-month rolling average. Also, any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is considered in determining the electrical energy output capacity of the affected facility.

*Electrostatic precipitator* or *ESP* means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper.

*Emergency condition* means that period of time when:

(a) The electric generation output of an affected facility with a malfunctioning flue gas desulfurization system cannot be reduced or electrical output must be increased because:

(1) All available system capacity in the principal company interconnected with the affected facility is being operated, and

(2) All available purchase power interconnected with the affected facility is being obtained, or

(b) The electric generation demand is being shifted as quickly as possible from an affected facility with a malfunctioning flue gas desulfurization system to one or more electrical generating units held in reserve by the principal company or by a neighboring company, or

(c) An affected facility with a malfunctioning flue gas desulfurization system becomes the only available unit to maintain a part or all of the principal company's system emergency reserves and the unit is operated in spinning reserve at the lowest practical electric generation load consistent with not causing significant physical damage to the unit. If the unit is operated at a higher load to meet load demand, an emergency condition would not exist unless the conditions under (a) of this definition apply.

*Emission limitation* means any emissions limit or operating limit.

*Emission rate period* means any calendar month included in a 12-month rolling average period.

*Federally enforceable* means all limitations and conditions that are enforceable by the Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or 40 CFR 51.18 and 40 CFR 51.24.

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

*Gaseous fuel* means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

*Gross output* means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus 75 percent of the useful thermal output measured relative to ISO conditions that is not used to generate additional electrical or mechanical output (i.e., steam delivered to an industrial process).

*24-hour period* means the period of time between 12:01 a.m. and 12:00 midnight.

*Integrated gasification combined cycle electric utility steam generating unit* or *IGCC* means a coal-fired electric utility steam generating unit that burns a synthetic gas derived from coal in a combined-cycle gas turbine. No coal is directly burned in the unit during operation.

*Interconnected* means that two or more electric generating units are electrically tied together by a network of power transmission lines, and other power transmission equipment.

*ISO conditions* means a temperature of 288 Kelvin, a relative humidity of 60 percent, and a pressure of 101.3 kilopascals.

*Lignite* means coal that is classified as lignite A or B according to the American Society of Testing and Materials' (ASTM) Standard Specification for Classification of Coals by Rank D388-77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

*Natural gas* means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835–87, 91, 97, or 03a (incorporated by reference, see §60.17).

*Neighboring company* means any one of those electric utility companies with one or more electric power interconnections to the principal company and which have geographically adjoining service areas.

*Net system capacity* means the sum of the net electric generating capability (not necessarily equal to rated capacity) of all electric generating equipment owned by an electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) plus firm contractual purchases that are interconnected to the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*Noncontinental area* means the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

*Petroleum* means crude oil or petroleum or a fuel derived from crude oil or petroleum, including distillate, residual oil, and petroleum coke.

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

(a) For particulate matter is:

(1) 3,000 ng/J (7.0 lb/million Btu) heat input for solid fuel; and

(2) 73 ng/J (0.17 lb/million Btu) heat input for liquid fuels.

(b) For sulfur dioxide is determined under §60.50Da(b).

(c) For nitrogen oxides is:

(1) 290 ng/J (0.67 lb/million Btu) heat input for gaseous fuels;

(2) 310 ng/J (0.72 lb/million Btu) heat input for liquid fuels; and

(3) 990 ng/J (2.30 lb/million Btu) heat input for solid fuels.

*Potential electrical output capacity* is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

*Principal company* means the electric utility company or companies which own the affected facility.

*Resource recovery unit* means a facility that combusts more than 75 percent non-fossil fuel on a quarterly (calendar) heat input basis.

*Responsible official* means responsible official as defined in 40 CFR 70.2.

*Solid-derived fuel* means any solid, liquid, or gaseous fuel derived from solid fuel for the purpose of creating useful heat and includes, but is not limited to, solvent refined coal, liquified coal, and gasified coal.

*Spare flue gas desulfurization system module* means a separate system of sulfur dioxide emission control equipment capable of treating an amount of flue gas equal to the total amount of flue gas generated by an affected facility when operated at maximum capacity divided by the total number of nonspare flue gas desulfurization modules in the system.

*Spinning reserve* means the sum of the unutilized net generating capability of all units of the electric utility company that are synchronized to the power distribution system and that are capable of immediately accepting additional load. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

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

*Subbituminous coal* means coal that is classified as subbituminous A, B, or C according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, or 98a (incorporated by reference—see §60.17).

*System emergency reserves* means an amount of electric generating capacity equivalent to the rated capacity of the single largest electric generating unit in the electric utility company (including steam generating units, internal combustion engines, gas turbines, nuclear units, hydroelectric units, and all other electric generating equipment) which is interconnected with the affected facility that has the malfunctioning flue gas desulfurization system. The electric generating capability of equipment under multiple ownership is prorated based on ownership unless the proportional entitlement to electric output is otherwise established by contractual arrangement.

*System load* means the entire electric demand of an electric utility company's service area interconnected with the affected facility that has the malfunctioning flue gas desulfurization system plus firm contractual sales to other electric utility companies. Sales to other electric utility companies (e.g., emergency power) not on a firm contractual basis may also be included in the system load when no available system capacity exists in the electric utility company to which the power is supplied for sale.

*Wet flue gas desulfurization technology* or *wet FGD* means a sulfur dioxide control system that is located downstream of the steam generating unit and removes sulfur oxides from the combustion gases of the steam generating unit by contacting the combustion gases with an alkaline slurry or solution and forming a liquid material. This definition applies to devices where the aqueous liquid material product of this contact is subsequently converted to other forms. Alkaline reagents used in wet FGD technology include, but are not limited to, lime, limestone, and sodium.

[44 FR 33613, June 11, 1979, as amended at 48 FR 3737, Jan. 27, 1983; 63 FR 49453, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 66 FR 18551, Apr. 10, 2001; 70 FR 28652, May 18, 2005. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9876, Feb. 27, 2006; 71 FR 33400, June 9, 2006]

**§ 60.42Da Standard for particulate matter.**

(a) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

(c) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of this section, any gases that contain particulate matter in excess of either:

(1) 18 ng/J (0.14 lb/MWh) gross energy output; or

(2) 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

(d) As an alternative to meeting the requirements of paragraph (c) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, may elect to meet the requirements of this paragraph. On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator subject to the provisions of this subpart shall not cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, any gases that contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel, and

(2) 0.1 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.9 percent reduction) for an affected facility for which construction or reconstruction commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel, or

(3) 0.2 percent of the combustion concentration determined according to the procedure in §60.48Da(o)(5) (99.8 percent reduction) for an affected facility for which modification commenced after February 28, 2005 when combusting solid fuel or solid-derived fuel.

[44 FR 33613, June 11, 1979. Redesignated at 70 FR 51268, Aug. 30, 2005, as amended at 71 FR 9877, Feb. 27, 2006]

**§ 60.43Da Standard for sulfur dioxide.**

(a) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid fuel or solid-derived fuel and for which construction, reconstruction, or modification commenced before or on February 28, 2005, except as provided under paragraphs (c), (d), (f) or (h) of this section, any gases that contain sulfur dioxide in excess of:

(1) 520 ng/J (1.20 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 30 percent of the potential combustion concentration (70 percent reduction), when emissions are less than 260 ng/J (0.60 lb/million Btu) heat input.

(b) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts liquid or gaseous fuels (except for liquid or gaseous fuels derived from solid fuels and as provided under paragraphs (e) or (h) of this section) and for which construction, reconstruction, or modification commenced before or on February 28, 2005, any gases that contain sulfur dioxide in excess of:

(1) 340 ng/J (0.80 lb/million Btu) heat input and 10 percent of the potential combustion concentration (90 percent reduction), or

(2) 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/million Btu) heat input.

(c) On and after the date on which the initial performance test required to be conducted under §60.8 is complete, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility which combusts solid solvent refined coal (SRC-I) any gases which contain sulfur dioxide in excess of 520 ng/J (1.20 lb/million Btu) heat input and 15 percent of the potential combustion concentration (85 percent reduction) except as provided under paragraph (f) of this section; compliance with the emission limitation is determined on a 30-day rolling average basis and compliance with the percent reduction requirement is determined on a 24-hour basis.

(d) Sulfur dioxide emissions are limited to 520 ng/J (1.20 lb/million Btu) heat input from any affected facility which:

(1) Combusts 100 percent anthracite,

(2) Is classified as a resource recovery unit, or

(3) Is located in a noncontinental area and combusts solid fuel or solid-derived fuel.

(e) Sulfur dioxide emissions are limited to 340 ng/J (0.80 lb/million Btu) heat input from any affected facility which is located in a noncontinental area and combusts liquid or gaseous fuels (excluding solid-derived fuels).

(f) The emission reduction requirements under this section do not apply to any affected facility that is operated under an SO<sub>2</sub> commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(g) Compliance with the emission limitation and percent reduction requirements under this section are both determined on a 30-day rolling average basis except as provided under paragraph (c) of this section.

(h) When different fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

(1) If emissions of sulfur dioxide to the atmosphere are greater than 260 ng/J (0.60 lb/million Btu) heat input

$$E_s = (340x + 520y) / 100 \text{ and}$$

$$\%P_s = 10$$

(2) If emissions of sulfur dioxide to the atmosphere are equal to or less than 260 ng/J (0.60 lb/million Btu) heat input:

$$E_s = (340x + 520y) / 100 \text{ and}$$

$$\%P_s = (10x + 30y) / 100$$

where:

$E_s$  is the prorated sulfur dioxide emission limit (ng/J heat input),

$\%P_s$  is the percentage of potential sulfur dioxide emission allowed.

$x$  is the percentage of total heat input derived from the combustion of liquid or gaseous fuels (excluding solid-derived fuels)

$y$  is the percentage of total heat input derived from the combustion of solid fuel (including solid-derived fuels)

(i) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of this section, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(j) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that burns 75 percent or more (by heat input) coal refuse on a 12-month rolling average basis, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (j)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(2) For an affected facility for which reconstruction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

(i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,

(ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or

(iii) 6 percent of the potential combustion concentration (94 percent reduction) on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:

- (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis,
- (ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis, or
- (iii) 10 percent of the potential combustion concentration (90 percent reduction) on a 30-day rolling average basis.

(k) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, and that is located in a noncontinental area, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (k)(1) and (2) of this section.

(1) For an affected facility that burns solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of 520 ng/J (1.2 lb/MMBtu) heat input on a 30-day rolling average basis.

(2) For an affected facility that burns other than solid or solid-derived fuel, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain sulfur dioxide in excess of if the affected facility or 230 ng/J (0.54 lb/MMBtu) heat input on a 30-day rolling average basis.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6663, Feb. 14, 1989; 54 FR 21344, May 17, 1989; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9877, Feb. 27, 2006]

**§ 60.44Da Standard for nitrogen oxides.**

(a) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility, except as provided under paragraphs (b) and (d) of this section, any gases which contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of the following emission limits, based on a 30-day rolling average, except as provided under §60.48Da(j)(1):

(1) *NOx emission limits.*

Fuel type	Emission limit for heat input	
	ng/J	(lb/ million Btu)
-----		
Gaseous fuels:		
Coal-derived fuels.....	210	0.50
All other fuels.....	86	0.20
Liquid fuels:		
Coal-derived fuels.....	210	0.50
Shale oil.....	210	0.50

All other fuels.....	130	0.30
Solid fuels:		
Coal-derived fuels.....	210	0.50
Any fuel containing more than 25%, by weight, (\1\ ) coal refuse.....	(\1\ )	(\1\ )
Any fuel containing more than 25%, by weight, lignite if the lignite is mined in North Dakota, South Dakota, or Montana, and is combusted in a slag tap furnace\2\.....	340	0.80
Any fuel containing more than 25%, by weight, lignite not subject to the 340 ng/J heat input emission limit\2\.....		
Subbituminous coal.....	210	0.50
Bituminous coal.....	260	0.60
Anthracite coal.....	260	0.60
All other fuels.....	260	0.60

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 \1\ Exempt from NOX standards and NOX monitoring requirements.  
 \2\ Any fuel containing less than 25%, by weight, lignite is not  
 prorated but its percentage is added to the percentage of the  
 predominant fuel.

*(2) NOx reduction requirement.*

Fuel type	Percent reduction of potential combustion concentration
Gaseous fuels.....	25
Liquid fuels.....	30
Solid fuels.....	65

(b) The emission limitations under paragraph (a) of this section do not apply to any affected facility which is combusting coal-derived liquid fuel and is operating under a commercial demonstration permit issued by the Administrator in accordance with the provisions of §60.47Da.

(c) Except as provided under paragraph (d) of this section, when two or more fuels are combusted simultaneously, the applicable standard is determined by proration using the following formula:

$$E_n = [86 w + 130x + 210 y + 260 z + 340 v] / 100$$

where:

$E_n$  is the applicable standard for nitrogen oxides when multiple fuels are combusted simultaneously (ng/J heat input);

w is the percentage of total heat input derived from the combustion of fuels subject to the 86 ng/J heat input

standard;

x is the percentage of total heat input derived from the combustion of fuels subject to the 130 ng/J heat input standard;

y is the percentage of total heat input derived from the combustion of fuels subject to the 210 ng/J heat input standard;

z is the percentage of total heat input derived from the combustion of fuels subject to the 260 ng/J heat input standard; and

v is the percentage of total heat input delivered from the combustion of fuels subject to the 340 ng/J heat input standard.

(d)(1) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 200 ng/J (1.6 lb/MWh) gross energy output, based on a 30-day rolling average, except as provided under §60.48Da(k).

(2) On and after the date on which the initial performance test required to be conducted under §60.8 is completed, no existing source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which reconstruction commenced after July 9, 1997, but before or on February 28, 2005, any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 65 ng/J (0.15 lb/MMBtu) heat input, based on a 30-day rolling average.

(e) On and after the date on which the performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of this section.

(1) For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

(2) For an affected facility for which reconstruction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of either:

(i) 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, or

(ii) 47 ng/J (0.11 lb/MMBtu) heat input on a 30-day rolling average basis.

(3) For an affected facility for which modification commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of either:

- (i) 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or
- (ii) 65 ng/J (0.15 lb/MMBtu) heat input on a 30-day rolling average basis.

(f) On and after the date on which the performance test required to be conducted under §60.8 is completed, the owner or operator of an IGCC subject to the provisions of this subpart that burns liquid fuel as a supplemental fuel and for which construction, reconstruction, or modification commenced after February 28, 2005, shall meet the requirements specified in paragraphs (f)(1) through (3) of this section.

(1) The owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided for in paragraphs (f)(2) and (3) of this section.

(2) When burning liquid fuel exclusively or in combination with synthetic gas derived from coal such that the liquid fuel contributes 50 percent or more of the total heat input to the combined cycle combustion turbine, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of 190 ng/J (1.5 lb/MWh) gross energy output on a 30-day rolling average basis.

(3) In cases when during a 30-day rolling average compliance period liquid fuel is burned in such a manner to meet the conditions in paragraph (f)(2) of this section for only a portion of the 30-day period, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO<sub>2</sub>) in excess of the computed weighted-average emissions limit based on the proportion of gross energy output (in MWh) generated during the compliance period for each of emissions limits in paragraphs (f)(1) and (2) of this section.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49453, Sept. 16, 1998; 66 FR 18551, Apr. 10, 2001; 66 FR 42610, Aug. 14, 2001. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006]

#### **§ 60.45Da Standard for mercury.**

(a) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of this section that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) of this section are based on a 12-month rolling average using the procedures in §60.50Da(h).

(1) For each coal-fired electric utility steam generating unit that burns only bituminous coal, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $20 \times 10^{-6}$  pound per megawatt hour (lb/MWh) or 0.020 lb/gigawatt-hour (GWh) on an output basis. The International System of Units (SI) equivalent is 0.0025 nanograms per joule (ng/J).

(2) For each coal-fired electric utility steam generating unit that burns only subbituminous coal:

(i) If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain

Hg in excess of  $66 \times 10^{-6}$  lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

(ii) If your unit is located in a county-level geographical area receiving less than or equal to 25 in/yr mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $97 \times 10^{-6}$  lb/MWh or 0.097 lb/GWh on an output basis. The SI equivalent is 0.0122 ng/J.

(3) For each coal-fired electric utility steam generating unit that burns only lignite, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $175 \times 10^{-6}$  lb/MWh or 0.175 lb/GWh on an output basis. The SI equivalent is 0.0221 ng/J.

(4) For each coal-burning electric utility steam generating unit that burns only coal refuse, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of  $16 \times 10^{-6}$  lb/MWh or 0.016 lb/GWh on an output basis. The SI equivalent is 0.0020 ng/J.

(5) For each coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks (*i.e.*, bituminous coal, subbituminous coal, lignite) or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the monthly unit-specific Hg emissions limit established according to paragraph (a)(5)(i) or (ii) of this section, as applicable to the affected unit.

(i) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse, you must not discharge into the atmosphere any gases from a new affected source that contain Hg in excess of the computed weighted Hg emissions limit based on the proportion of energy output (in British thermal units, Btu) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total Btu or megawatt hours contributed by all fuels burned during the compliance period.

$$EL_b = \frac{\sum_{i=1}^n EL_i (HH_i)}{\sum_{i=1}^n HH_i} \quad (\text{Eq. 1})$$

Where:

$EL_b$  = Total allowable Hg in lb/MWh that can be emitted to the atmosphere from any affected source being averaged under the blending provision.

$EL_i$  = Hg emissions limit for the subcategory  $i$  (coal rank) that applies to affected source, lb/MWh.

$HH_i$  = Electricity output from affected source during the production period related to use of the corresponding subcategory  $i$  (coal rank) that falls within the compliance period, gross MWh generated by the electric utility steam generating unit.

$n$  = Number of subcategories (coal ranks) being averaged for an affected source.

(ii) If you operate a coal-fired electric utility steam generating unit that burns a blend of coals from different coal ranks or a blend of coal and coal refuse together with one or more non-regulated,

supplementary fuels, you must not discharge into the atmosphere any gases from the unit that contain Hg in excess of the computed weighted Hg emission limit based on the proportion of electricity output (in MWh) contributed by each coal rank burned during the compliance period and its applicable Hg emissions limit in paragraphs (a)(1) through (4) of this section as determined using Equation 1 of this section. You must meet the weighted Hg emissions limit calculated using Equation 1 of this section by calculating the unit emission rate based on the total Hg loading of the unit and the total megawatt hours contributed by both regulated and nonregulated fuels burned during the compliance period.

(b) For each IGCC electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain Hg emissions in excess of  $20 \times 10^{-6}$  lb/MWh or 0.020 lb/GWh on an output basis. The SI equivalent is 0.0025 ng/J. This Hg emissions limit is based on a 12-month rolling average using the procedures in §60.50Da(g).

[70 FR 28653, May 18, 2005. Redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 33400, June 9, 2006]

#### **§ 60.46Da [Reserved]**

#### **§ 60.47Da Commercial demonstration permit.**

(a) An owner or operator of an affected facility proposing to demonstrate an emerging technology may apply to the Administrator for a commercial demonstration permit. The Administrator will issue a commercial demonstration permit in accordance with paragraph (e) of this section. Commercial demonstration permits may be issued only by the Administrator, and this authority will not be delegated.

(b) An owner or operator of an affected facility that combusts solid solvent refined coal (SRC-I) and who is issued a commercial demonstration permit by the Administrator is not subject to the SO<sub>2</sub> emission reduction requirements under §60.43Da(c) but must, as a minimum, reduce SO<sub>2</sub> emissions to 20 percent of the potential combustion concentration (80 percent reduction) for each 24-hour period of steam generator operation and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(c) An owner or operator of a fluidized bed combustion electric utility steam generator (atmospheric or pressurized) who is issued a commercial demonstration permit by the Administrator is not subject to the SO<sub>2</sub> emission reduction requirements under §60.43Da(a) but must, as a minimum, reduce SO<sub>2</sub> emissions to 15 percent of the potential combustion concentration (85 percent reduction) on a 30-day rolling average basis and to less than 520 ng/J (1.20 lb/million Btu) heat input on a 30-day rolling average basis.

(d) The owner or operator of an affected facility that combusts coal-derived liquid fuel and who is issued a commercial demonstration permit by the Administrator is not subject to the applicable NO<sub>x</sub> emission limitation and percent reduction under §60.44Da(a) but must, as a minimum, reduce emissions to less than 300 ng/J (0.70 lb/million Btu) heat input on a 30-day rolling average basis.

(e) Commercial demonstration permits may not exceed the following equivalent MW electrical generation capacity for any one technology category, and the total equivalent MW electrical generation capacity for all commercial demonstration plants may not exceed 15,000 MW.

Technology	Pollutant	Equivalent electrical capacity (MW electrical output)
Solid solvent refined coal (SRC I).....	SO2	6,000-10,000
Fluidized bed combustion (atmospheric)...	SO2	400-3,000
Fluidized bed combustion (pressurized)...	SO2	400-1,200
Coal liquification.....	NOX	750-10,000
Total allowable for all technologies.....		15,000

[44 FR 33613, June 11, 1979. Redesignated at 70 FR 28653, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005]

**§ 60.48Da Compliance provisions.**

(a) Compliance with the particulate matter emission limitation under §60.42Da(a)(1) constitutes compliance with the percent reduction requirements for particulate matter under §60.42Da(a)(2) and (3).

(b) Compliance with the nitrogen oxides emission limitation under §60.44Da(a) constitutes compliance with the percent reduction requirements under §60.44Da(a)(2).

(c) The particulate matter emission standards under §60.42Da, the nitrogen oxides emission standards under §60.44Da, and the Hg emission standards under §60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

(d) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:

- (1) Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
- (2) Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and
- (3) Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under §60.43Da for any period of operation lasting from

24 hours to 30 days when:

- (i) Any one flue gas desulfurization module is not operated,
  - (ii) The affected facility is operating at the maximum heat input rate,
  - (iii) The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and
  - (iv) The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.
- (e) After the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.
- (f) For the initial performance test required under §60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under §60.43Da and the nitrogen oxides emission limitation under §60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.
- (g) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:
- (1) Compliance with applicable 30-day rolling average SO<sub>2</sub> and NO<sub>x</sub> emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO<sub>2</sub> and NO<sub>x</sub> for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO<sub>x</sub> only), or emergency conditions (SO<sub>2</sub>) only.
  - (2) Compliance with applicable SO<sub>2</sub> percentage reduction requirements is determined based on the average inlet and outlet SO<sub>2</sub> emission rates for the 30 successive boiler operating days.
  - (3) Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.
- (h) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under §§60.43Da and 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.
- (i) *Compliance provisions for sources subject to §60.44Da(d)(1), (e)(1), or (f).* The owner or

operator of an affected facility subject to §60.44Da(d)(1) or (e)(1) shall calculate NO<sub>x</sub> emissions by multiplying the average hourly NO<sub>x</sub> output concentration, measured according to the provisions of §60.49Da(c), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(j) *Compliance provisions for duct burners subject to §60.44Da(a)(1).* To determine compliance with the emissions limits for NO<sub>x</sub> required by §60.44Da(a) for duct burners used in combined cycle systems, either of the procedures described in paragraph (j)(1) or (2) of this section may be used:

(1) The owner or operator of an affected duct burner shall conduct the performance test required under §60.8 using the appropriate methods in appendix A of this part. Compliance with the emissions limits under §60.44Da(a)(1) is determined on the average of three (nominal 1-hour) runs for the initial and subsequent performance tests. During the performance test, one sampling site shall be located in the exhaust of the turbine prior to the duct burner. A second sampling site shall be located at the outlet from the heat recovery steam generating unit. Measurements shall be taken at both sampling sites during the performance test; or

(2) The owner or operator of an affected duct burner may elect to determine compliance by using the continuous emission monitoring system specified under §60.49Da for measuring NO<sub>x</sub> and oxygen and meet the requirements of §60.49Da. Data from a CEMS certified (or recertified) according to the provisions of 40 CFR 75.20, meeting the QA and QC requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used. The sampling site shall be located at the outlet from the steam generating unit. The NO<sub>x</sub> emission rate at the outlet from the steam generating unit shall constitute the NO<sub>x</sub> emission rate from the duct burner of the combined cycle system.

(k) *Compliance provisions for duct burners subject to §60.44Da(d)(1) or (e)(1).* To determine compliance with the emission limitation for NO<sub>x</sub> required by §60.44Da(d)(1) or (e)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(1) The owner or operator of an affected duct burner used in combined cycle systems shall determine compliance with the applicable NO<sub>x</sub> emission limitation in §60.44Da(d)(1) or (e)(1) as follows:

(i) The emission rate (E) of NO<sub>x</sub> shall be computed using Equation 1 of this section:

$$E = [(C_{sg} \times Q_{sg}) - (C_{te} \times Q_{te})] / (O_{sg} \times h) \quad (\text{Eq. 1})$$

Where:

E = emission rate of NO<sub>x</sub> from the duct burner, ng/J (lb/Mwh) gross output

C<sub>sg</sub> = average hourly concentration of NO<sub>x</sub> exiting the steam generating unit, ng/dscm (lb/dscf)

C<sub>te</sub> = average hourly concentration of NO<sub>x</sub> in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Q<sub>sg</sub> = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

$Q_{te}$  = average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

$O_{sg}$  = average hourly gross energy output from steam generating unit, J (Mwh)

$h$  = average hourly fraction of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner

(ii) Method 7E of appendix A of this part shall be used to determine the  $NO_x$  concentrations ( $C_{sg}$  and  $C_{te}$ ). Method 2, 2F or 2G of appendix A of this part, as appropriate, shall be used to determine the volumetric flow rates ( $Q_{sg}$  and  $Q_{te}$ ) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

(iii) The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

(iv) Compliance with the applicable  $NO_x$  emission limitation in §60.44Da(d)(1) or (e)(1) is determined by the three-run average (nominal 1-hour runs) for the initial and subsequent performance tests.

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the applicable  $NO_x$  emission limitation in §60.44Da(d)(1) or (e)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate ( $E$ ) of  $NO_x$  shall be computed using Equation 2 of this section:

$$E = (C_{sg} \times Q_{sd}) / O_{cc} \text{ (Eq. 2)}$$

Where:

$E$  = emission rate of  $NO_x$  from the duct burner, ng/J (lb/Mwh) gross output

$C_{sg}$  = average hourly concentration of  $NO_x$  exiting the steam generating unit, ng/dscm (lb/dscf)

$Q_{sg}$  = average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

$O_{cc}$  = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under §60.49Da for measuring  $NO_x$  and oxygen shall be used to determine the average hourly  $NO_x$  concentrations ( $C_{sg}$ ). The continuous flow monitoring system specified in §60.49Da(l) shall be used to determine the volumetric flow rate ( $Q_{sg}$ ) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under §60.49Da(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy

output from the entire combined cycle unit (Occ), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in §60.49Da(l), determine the mass rate (lb/hr) of NO<sub>x</sub> emissions by installing, operating, and maintaining continuous fuel flowmeters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NO<sub>x</sub> shall be computed using Equation 3 of this section:

$$E = (ERsg \times Hcc) / Occ \text{ (Eq. 3)}$$

Where:

E = emission rate of NO<sub>x</sub> from the duct burner, ng/J (lb/Mwh) gross output

ERsg = average hourly emission rate of NO<sub>x</sub> exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(3) When an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

(i) Determine compliance with the applicable NO<sub>x</sub> emissions limits by measuring the emissions combined with the emissions from the other unit(s) utilizing the common steam turbine; or

(ii) Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under this part.

(l) Compliance provisions for sources subject to §60.45Da. The owner or operator of an affected facility subject to §60.45Da (new sources constructed or reconstructed after January 30, 2004) shall calculate the Hg emission rate (lb/MWh) for each calendar month of the year, using hourly Hg concentrations measured according to the provisions of §60.49Da(p) in conjunction with hourly stack gas volumetric flow rates measured according to the provisions of §60.49Da(l) or (m), and hourly gross electrical outputs, determined according to the provisions in §60.49Da(k). Compliance with the applicable standard under §60.45Da is determined on a 12-month rolling average basis.

(m) *Compliance provisions for sources subject to §60.43Da(i)(1)(i) or (j)(1)(i).* The owner or operator of an affected facility subject to §60.43Da(i)(1)(i) or (j)(1)(i) shall calculate SO<sub>2</sub> emissions by multiplying the average hourly SO<sub>2</sub> output concentration, measured according to the provisions of §60.49Da(b), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k).

(n) *Compliance provisions for sources subject to §60.42Da(c)(1).* The owner or operator of an

affected facility subject to §60.42Da(c)(1) shall calculate particulate matter emissions by multiplying the average hourly particulate matter output concentration, measured according to the provisions of §60.49Da(t), by the average hourly flow rate, measured according to the provisions of §60.49Da(l), and divided by the average hourly gross energy output, measured according to the provisions of §60.49Da(k). Compliance with the emission limit is determined by calculating the arithmetic average of the hourly emission rates computed for each boiler operating day.

(o) *Compliance provisions for sources subject to §60.42Da(c)(2) or (d).* Except as provided for in paragraph (p) of this section, the owner or operator of an affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, shall demonstrate compliance with each applicable emission limit according to the requirements in paragraphs (o)(1) through (o)(5) of this section.

(1) Conduct an initial performance test according to the requirements in §60.50Da to demonstrate compliance by the applicable date specified in §60.8(a) and, thereafter, conduct the performance test annually, and

(2) An owner or operator must use opacity monitoring equipment as an indicator of continuous particulate matter control device performance and demonstrate compliance with §60.42Da(b). In addition, baseline parameters shall be established as the highest hourly opacity average measured during the performance test. If any hourly average opacity measurement is more than 110 percent of the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test. The new baseline shall not exceed the opacity limit specified in §60.42Da(b), and

(3) An owner or operator using an ESP to comply with the applicable emission limits shall use voltage and secondary current monitoring equipment to measure voltage and secondary current to the ESP. Baseline parameters shall be established as average rates measured during the performance test. If a 3-hour average voltage and secondary current average deviates more than 10 percent from the baseline level, the owner or operator will conduct another performance test within 60 days to demonstrate compliance. A new baseline is established during each stack test, and

(4) An owner or operator using a fabric filter to comply with the applicable emission limits shall install, calibrate, maintain, and continuously operate a bag leak detection system according to paragraphs (o)(4)(i) through (viii) of this section.

(i) Install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(ii) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with the guidance provided in EPA-454/R-98-015, September 1997.

(iii) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(iv) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(v) The bag leak detection system must be equipped with a device to continuously record the

output signal from the sensor.

(vi) The bag leak detection system must be equipped with an alarm system that will sound automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard by plant operating personnel. Corrective actions must be initiated within 1 hour of a bag leak detection system alarm. If the alarm is engaged for more than 5 percent of the total operating time on a 30-day rolling average, a performance test must be performed within 60 days to demonstrate compliance.

(vii) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(viii) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors, and

(5) An owner or operator of a modified affected source electing to meet the emission limitations in §60.42Da(d) shall determine the percent reduction in particulate matter by using the emission rate for particulate matter determined by the performance test conducted according to the requirements in paragraph (o)(1) of this section and the ash content on a mass basis of the fuel burned during each performance test run as determined by analysis of the fuel as fired.

(p) As an alternative to meeting the compliance provisions specified in paragraph (o) of this section, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of this section.

(1) The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of this section by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

(2) Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in §60.49Da(v).

(3) The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under §60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph (p)(1) of this section, whichever is later.

(4) Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

(5) At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90

percent of all operating hours on a 30-day rolling average.

(i) At least two data points per hour shall be used to calculate each 1-hour arithmetic average.

(ii) [Reserved]

(6) The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under §60.13(e)(2) of subpart A of this part.

(7) All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph (j)(5) of this section are not met.

(8) When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 63 FR 49454, Sept. 16, 1998; 66 FR 18552, Apr. 10, 2001; 66 FR 31178, June 11, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9878, Feb. 27, 2006; 71 FR 33400, June 9, 2006]

#### **§ 60.49Da Emission monitoring.**

(a) Except as provided for in paragraphs (t) and (u) of this section, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

(b) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:

(1) Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.

(2) For a facility that qualifies under the numerical limit provisions of §60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.

(3) An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under

paragraph (b)(1) of this section.

(c)(1) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or

(2) If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.51Da. Data reported to meet the requirements of §60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(d) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

(e) The continuous monitoring systems under paragraphs (b), (c), and (d) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(f)(1) For units that began construction, reconstruction, or modification on or before February 28, 2005, the owner or operator shall obtain emission data for at least 18 hours in at least 22 out of 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(2) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of this section.

(g) The 1-hour averages required under paragraph §60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under §60.13(b). At least two data points must be used to calculate the 1-hour averages.

(h) When it becomes necessary to supplement continuous monitoring system data to meet the minimum data requirements in paragraph (f) of this section, the owner or operator shall use the reference methods and procedures as specified in this paragraph. Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Method 6 shall be used to determine the SO<sub>2</sub> concentration at the same location as the SO<sub>2</sub> monitor. Samples shall be taken at 60-minute intervals. The sampling time and sample volume for each sample shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Each sample represents a

1-hour average.

(2) Method 7 shall be used to determine the NO<sub>x</sub> concentration at the same location as the NO<sub>x</sub> monitor. Samples shall be taken at 30-minute intervals. The arithmetic average of two consecutive samples represents a 1-hour average.

(3) The emission rate correction factor, integrated bag sampling and analysis procedure of Method 3B shall be used to determine the O<sub>2</sub> or CO<sub>2</sub> concentration at the same location as the O<sub>2</sub> or CO<sub>2</sub> monitor. Samples shall be taken for at least 30 minutes in each hour. Each sample represents a 1-hour average.

(4) The procedures in Method 19 shall be used to compute each 1-hour average concentration in ng/J (1b/million Btu) heat input.

(i) The owner or operator shall use methods and procedures in this paragraph to conduct monitoring system performance evaluations under §60.13(c) and calibration checks under §60.13(d). Acceptable alternative methods and procedures are given in paragraph (j) of this section.

(1) Methods 3B, 6, and 7 shall be used to determine O<sub>2</sub>, SO<sub>2</sub>, and NO<sub>x</sub> concentrations, respectively.

(2) SO<sub>2</sub> or NO<sub>x</sub> (NO), as applicable, shall be used for preparing the calibration gas mixtures (in N<sub>2</sub>, as applicable) under Performance Specification 2 of appendix B of this part.

(3) For affected facilities burning only fossil fuel, the span value for a continuous monitoring system for measuring opacity is between 60 and 80 percent and for a continuous monitoring system measuring nitrogen oxides is determined as follows:

Fossil fuel	Span value for nitrogen oxides (ppm)
Gas.....	500
Liquid.....	500
Solid.....	1,000
Combination.....	500 (x+y)+1,000z

where:

x is the fraction of total heat input derived from gaseous fossil fuel,

y is the fraction of total heat input derived from liquid fossil fuel, and

z is the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (b)(3) of this section for burning combinations of fossil fuels are rounded to the nearest 500 ppm.

(5) For affected facilities burning fossil fuel, alone or in combination with non-fossil fuel, the span value of the sulfur dioxide continuous monitoring system at the inlet to the sulfur dioxide control device is 125 percent of the maximum estimated hourly potential emissions of the fuel fired, and the outlet of the sulfur dioxide control device is 50 percent of maximum estimated hourly potential emissions of the fuel fired.

(j) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 6, Method 6A or 6B (whenever Methods 6 and 3 or 3B data are used) or 6C may be used. Each Method 6B sample obtained over 24 hours represents 24 1-hour averages. If Method 6A or 6B is used under paragraph (i) of this section, the conditions under §60.46(d)(1) apply; these conditions do not apply under paragraph (h) of this section.

(2) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be 1 hour.

(3) For Method 3, Method 3A or 3B may be used if the sampling time is 1 hour.

(4) For Method 3B, Method 3A may be used.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under §60.44Da(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 75 percent of the gross thermal output (measured relative to ISO conditions) of the process steam measured in accordance with paragraph (k)(2) of this section.

(l) The owner or operator of an affected facility demonstrating compliance with an output-based standard under §60.42Da, §60.43Da, §60.44Da, or §60.45Da shall install, certify, operate, and maintain a continuous flow monitoring system meeting the requirements of Performance Specification 6 of appendix B and procedure 1 of appendix F of this subpart, and record the output of the system, for measuring the flow of exhaust gases discharged to the atmosphere; or

(m) Alternatively, data from a continuous flow monitoring system certified according to the requirements of 40 CFR 75.20, meeting the applicable quality control and quality assurance requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23, may be used.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements

specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

(o) The owner or operator of a duct burner, as described in §60.41Da, which is subject to the NO<sub>x</sub> standards of §60.44Da(a)(1), (d)(1), or (e)(1) is not required to install or operate a continuous emissions monitoring system to measure NO<sub>x</sub> emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

(p) The owner or operator of an affected facility demonstrating compliance with an Hg limit in §60.45Da shall install and operate a continuous emissions monitoring system (CEMS) to measure and record the concentration of Hg in the exhaust gases from each stack according to the requirements in paragraphs (p)(1) through (p)(3) of this section. Alternatively, for an affected facility that is also subject to the requirements of subpart I of part 75 of this chapter, the owner or operator may install, certify, maintain, operate and quality-assure the data from a Hg CEMS according to §75.10 of this chapter and appendices A and B to part 75 of this chapter, in lieu of following the procedures in paragraphs (p)(1) through (p)(3) of this section.

(1) The owner or operator must install, operate, and maintain each CEMS according to Performance Specification 12A in appendix B to this part.

(2) The owner or operator must conduct a performance evaluation of each CEMS according to the requirements of §60.13 and Performance Specification 12A in appendix B to this part.

(3) The owner or operator must operate each CEMS according to the requirements in paragraphs (p)(3)(i) through (iv) of this section.

(i) As specified in §60.13(e)(2), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(ii) The owner or operator must reduce CEMS data as specified in §60.13(h).

(iii) The owner or operator shall use all valid data points collected during the hour to calculate the hourly average Hg concentration.

(iv) The owner or operator must record the results of each required certification and quality assurance test of the CEMS.

(4) Mercury CEMS data collection must conform to paragraphs (p)(4)(i) through (iv) of this section.

(i) For each calendar month in which the affected unit operates, valid hourly Hg concentration data, stack gas volumetric flow rate data, moisture data (if required), and electrical output data (*i.e.*, valid data for all of these parameters) shall be obtained for at least 75 percent of the unit operating hours in the month.

(ii) Data reported to meet the requirements of this subpart shall not include hours of unit startup, shutdown, or malfunction. In addition, for an affected facility that is also subject to subpart I of part 75 of this chapter, data reported to meet the requirements of this subpart shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

(iii) If valid data are obtained for less than 75 percent of the unit operating hours in a month, you

must discard the data collected in that month and replace the data with the mean of the individual monthly emission rate values determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(iv) Notwithstanding the requirements of paragraph (p)(4)(iii) of this section, if valid data are obtained for less than 75 percent of the unit operating hours in another month in that same 12-month rolling average cycle, discard the data collected in that month and replace the data with the highest individual monthly emission rate determined in the last 12 months. In the 12-month rolling average calculation, this substitute Hg emission rate shall be weighted according to the number of unit operating hours in the month for which the data capture requirement of §60.49Da(p)(4)(i) was not met.

(q) As an alternative to the CEMS required in paragraph (p) of this section, the owner or operator may use a sorbent trap monitoring system (as defined in §72.2 of this chapter) to monitor Hg concentration, according to the procedures described in §75.15 of this chapter and appendix K to part 75 of this chapter.

(r) For Hg CEMS that measure Hg concentration on a dry basis or for sorbent trap monitoring systems, the emissions data must be corrected for the stack gas moisture content. A certified continuous moisture monitoring system that meets the requirements of §75.11(b) of this chapter is acceptable for this purpose. Alternatively, the appropriate default moisture value, as specified in §75.11(b) or §75.12(b) of this chapter, may be used.

(s) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (s)(1) through (6) of this section.

(1) Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (*e.g.*, on or downstream of the last control device);

(2) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;

(3) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations, relative accuracy test audits (RATA), etc.);

(4) Ongoing operation and maintenance procedures in accordance with the general requirements of §60.13(d) or part 75 of this chapter (as applicable);

(5) Ongoing data quality assurance procedures in accordance with the general requirements of §60.13 or part 75 of this chapter (as applicable); and

(6) Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

(t) The owner or operator of an affected facility demonstrating compliance with the output-based emissions limitation under §60.42Da(c)(1) shall install, certify, operate, and maintain a continuous

monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section. An owner or operator of an affected source demonstrating compliance with the input-based emission limitation under §60.42Da(c)(2) may install, certify, operate, and maintain a continuous monitoring system for measuring particulate matter emissions according to the requirements of paragraph (v) of this section in lieu of the requirements in §60.48Da(o).

(u) An owner or operator of an affected source that meets the conditions in either paragraph (u)(1) or (2) of this section is exempted from the continuous opacity monitoring system requirements in paragraph (a) of this section and the monitoring requirements in §60.48Da(o).

(1) A continuous monitoring system for measuring particulate matter emissions is used to demonstrate continuous compliance on a boiler operating day average with the emissions limitations under §60.42Da(a)(1) or §60.42Da(c)(2) and is installed, certified, operated, and maintained on the affected source according to the requirements of paragraph (v) of this section.

(2) The affected source burns only oil that contains no more than 0.15 weight percent sulfur or liquid or gaseous fuels that when combusted without sulfur dioxide emission control, have a sulfur dioxide emissions rate equal to or less than or equal to 65 ng/J (0.15 lb/MMBtu) heat input.

(v) The owner or operator of an affected facility using a continuous emission monitoring system measuring particulate matter emissions to meet requirements of this subpart shall install, certify, operate, and maintain the continuous monitoring system as specified in paragraphs (v)(1) through (v)(3).

(1) The owner or operator shall conduct a performance evaluation of the continuous monitoring system according to the applicable requirements of §60.13, Performance Specification 11 in appendix B of this part, and procedure 2 in appendix F of this part.

(2) During each relative accuracy test run of the continuous emission monitoring system required by Performance Specification 11 in appendix B of this part, particulate matter and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the continuous emission monitors and conducting performance tests using the following test methods.

(i) For particulate matter, EPA Reference Method 5, 5B, or 17 shall be used.

(ii) For oxygen (or carbon dioxide), EPA Reference Method 3, 3A, or 3B, as applicable shall be used.

(3) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with procedure 2 in appendix F of this part. Relative Response Audit's must be performed annually and Response Correlation Audits must be performed every 3 years.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 55 FR 18876, May 7, 1990; 63 FR 49454, Sept. 16, 1998; 65 FR 61752, Oct. 17, 2000; 66 FR 18553, Apr. 10, 2001. Redesignated and amended at 70 FR 28653, 28654, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9880, Feb. 27, 2006]

#### **§ 60.50Da Compliance determination procedures and methods.**

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as

reference methods and procedures the methods in appendix A of this part or the methods and procedures as specified in this section, except as provided in §60.8(b). Section 60.8(f) does not apply to this section for SO<sub>2</sub> and NO<sub>x</sub>. Acceptable alternative methods are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the particulate matter standards in §60.42Da as follows:

(1) The dry basis F factor (O<sub>2</sub>) procedures in Method 19 shall be used to compute the emission rate of particulate matter.

(2) For the particulate matter concentration, Method 5 shall be used at affected facilities without wet FGD systems and Method 5B shall be used after wet FGD systems.

(i) The sampling time and sample volume for each run shall be at least 120 minutes and 1.70 dscm (60 dscf). The probe and filter holder heating system in the sampling train may be set to provide an average gas temperature of no greater than 160 ±14 °C (320 ±25 °F).

(ii) For each particulate run, the emission rate correction factor, integrated or grab sampling and analysis procedures of Method 3B shall be used to determine the O<sub>2</sub> concentration. The O<sub>2</sub> sample shall be obtained simultaneously with, and at the same traverse points as, the particulate run. If the particulate run has more than 12 traverse points, the O<sub>2</sub> traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O<sub>2</sub> traverse points. If the grab sampling procedure is used, the O<sub>2</sub> concentration for the run shall be the arithmetic mean of the sample O<sub>2</sub> concentrations at all traverse points.

(3) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(c) The owner or operator shall determine compliance with the SO<sub>2</sub> standards in §60.43Da as follows:

(1) The percent of potential SO<sub>2</sub> emissions (%P<sub>s</sub>) to the atmosphere shall be computed using the following equation:

$$\%P_s = [(100 - \%R_f) (100 - \%R_g)] / 100$$

where:

%P<sub>s</sub> = percent of potential SO<sub>2</sub> emissions, percent.

%R<sub>f</sub> = percent reduction from fuel pretreatment, percent.

%R<sub>g</sub> = percent reduction by SO<sub>2</sub> control system, percent.

(2) The procedures in Method 19 may be used to determine percent reduction (%R<sub>f</sub>) of sulfur by such processes as fuel pretreatment (physical coal cleaning, hydrodesulfurization of fuel oil, etc.), coal pulverizers, and bottom and flyash interactions. This determination is optional.

(3) The procedures in Method 19 shall be used to determine the percent SO<sub>2</sub> reduction (%R<sub>g</sub>) of any SO<sub>2</sub> control system. Alternatively, a combination of an "as fired" fuel monitor and emission rates measured after the control system, following the procedures in Method 19, may be used if

the percent reduction is calculated using the average emission rate from the SO<sub>2</sub> control device and the average SO<sub>2</sub> input rate from the "as fired" fuel analysis for 30 successive boiler operating days.

(4) The appropriate procedures in Method 19 shall be used to determine the emission rate.

(5) The continuous monitoring system in §60.49Da(b) and (d) shall be used to determine the concentrations of SO<sub>2</sub> and CO<sub>2</sub> or O<sub>2</sub>.

(d) The owner or operator shall determine compliance with the NO<sub>x</sub> standard in §60.44Da as follows:

(1) The appropriate procedures in Method 19 shall be used to determine the emission rate of NO<sub>x</sub>.

(2) The continuous monitoring system in §60.49Da(c) and (d) shall be used to determine the concentrations of NO<sub>x</sub> and CO<sub>2</sub> or O<sub>2</sub>.

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of §§2.1 and 2.3 of Method 5B may be used in Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent is saturated or laden with water droplets.

(2) The F<sub>c</sub> factor (CO<sub>2</sub>) procedures in Method 19 may be used to compute the emission rate of particulate matter under the stipulations of §60.46(d)(1). The CO<sub>2</sub> shall be determined in the same manner as the O<sub>2</sub> concentration.

(f) Electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

(g) For the purposes of determining compliance with the emission limits in §60.45Da, the owner or operator of an electric utility steam generating unit which is also a cogeneration unit shall use the procedures in paragraphs (g)(1) and (2) of this section to calculate emission rates based on electrical output to the grid plus half of the equivalent electrical energy in the unit's process stream.

(1) All conversions from Btu/hr unit input to MW unit output must use equivalents found in 40 CFR 60.40(a)(1) for electric utilities (*i.e.*, 250 million Btu/hr input to an electric utility steam generating unit is equivalent to 73 MW input to the electric utility steam generating unit); 73 MW input to the electric utility steam generating unit is equivalent to 25 MW output from the boiler electric utility steam generating unit; therefore, 250 million Btu input to the electric utility steam generating unit is equivalent to 25 MW output from the electric utility steam generating unit).

(2) Use the Equation 1 of this section to determine the cogeneration Hg emission rate over a specific compliance period.

$$ER_{\text{cogen}} = \frac{M}{(V_{\text{grid}} + 0.75 \times V_{\text{process}})} \quad (\text{Eq. 1})$$

Where:

$ER_{\text{cogen}}$  = Cogeneration Hg emission rate over a compliance period in lb/MWh;

$E$  = Mass of Hg emitted from the stack over the same compliance period (lb);

$V_{\text{grid}}$  = Amount of energy sent to the grid over the same compliance period (MWh); and

$V_{\text{process}}$  = Amount of energy converted to steam for process use over the same compliance period (MWh).

(h) The owner or operator shall determine compliance with the Hg limit in §60.45Da according to the procedures in paragraphs (h)(1) through (3) of this section.

(1) The initial performance test shall be commenced by the applicable date specified in §60.8(a). The required continuous monitoring systems must be certified prior to commencing the test. The performance test consists of collecting hourly Hg emission data (lb/MWh) with the continuous monitoring systems for 12 successive months of unit operation (excluding hours of unit startup, shutdown and malfunction). The average Hg emission rate is calculated for each month, and then the weighted, 12-month average Hg emission rate is calculated according to paragraph (h)(2) or (h)(3) of this section, as applicable. If, for any month in the initial performance test, the minimum data capture requirement in §60.49Da(p)(4)(i) is not met, the owner or operator shall report a substitute Hg emission rate for that month, as follows. For the first such month, the substitute monthly Hg emission rate shall be the arithmetic average of all valid hourly Hg emission rates recorded to date. For any subsequent month(s) with insufficient data capture, the substitute monthly Hg emission rate shall be the highest valid hourly Hg emission rate recorded to date. When the 12-month average Hg emission rate for the initial performance test is calculated, for each month in which there was insufficient data capture, the substitute monthly Hg emission rate shall be weighted according to the number of unit operating hours in that month. Following the initial performance test, the owner or operator shall demonstrate compliance by calculating the weighted average of all monthly Hg emission rates (in lb/MWh) for each 12 successive calendar months, excluding data obtained during startup, shutdown, or malfunction.

(2) If a CEMS is used to demonstrate compliance, follow the procedures in paragraphs (h)(2)(i) through (iii) of this section to determine the 12-month rolling average.

(i) Calculate the total mass of Hg emissions over a month ( $M$ ), in pounds (lb), using either Equation 2 in paragraph (h)(2)(i)(A) of this section or Equation 3 in paragraph (h)(2)(i)(B) of this section, in conjunction with Equation 4 in paragraph (h)(2)(i)(C) of this section.

(A) If the Hg CEMS measures Hg concentration on a wet basis, use Equation 2 below to calculate the Hg mass emissions for each valid hour:

$$E_k = K C_k Q_k t_k \quad (\text{Eq. 2})$$

Where:

$E_h$  = Hg mass emissions for the hour, (lb)

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/ $\mu$ gm-scf

$C_h$  = Hourly Hg concentration, wet basis, ( $\mu$ gm/scm)

$Q_h$  = Hourly stack gas volumetric flow rate, (scfh)

$t_h$  = Unit operating time, *i.e.*, the fraction of the hour for which the unit operated. For example,  $t_h = 0.50$  for a half-hour of unit operation and 1.00 for a full hour of operation.

(B) If the Hg CEMS measures Hg concentration on a dry basis, use Equation 3 below to calculate the Hg mass emissions for each valid hour:

$$E_k = K C_k Q_k t_k (1 - B_{ws}) \quad (\text{Eq. 3})$$

Where:

$E_h$  = Hg mass emissions for the hour, (lb)

$K$  = Units conversion constant,  $6.24 \times 10^{-11}$  lb-scm/ $\mu$ gm-scf

$C_h$  = Hourly Hg concentration, dry basis, ( $\mu$ gm/dscm)

$Q_h$  = Hourly stack gas volumetric flow rate, (scfh)

$t_h$  = Unit operating time, *i.e.*, the fraction of the hour for which the unit operated

$B_{ws}$  = Stack gas moisture content, expressed as a decimal fraction (*e.g.*, for 8 percent H<sub>2</sub>O,  $B_{ws} = 0.08$ )

(C) Use Equation 4, below, to calculate  $M$ , the total mass of Hg emitted for the month, by summing the hourly masses derived from Equation 2 or 3 (as applicable):

$$M = \sum_{k=1}^n E_k \quad (\text{Eq. 4})$$

Where:

$M$  = Total Hg mass emissions for the month, (lb)

$E_h$  = Hg mass emissions for hour "h", from Equation 2 or 3 of this section, (lb)

$n$  = The number of unit operating hours in the month with valid CEM and electrical output data, excluding hours of unit startup, shutdown and malfunction

(ii) Calculate the monthly Hg emission rate on an output basis (lb/MWh) using Equation 5, below.

For a cogeneration unit, use Equation 1 in paragraph (g) of this section instead.

$$ER = \frac{M}{P} \quad (\text{Eq. 5})$$

Where:

ER = Monthly Hg emission rate, (lb/MWh)

M = Total mass of Hg emissions for the month, from Equation 4, above, (lb)

P = Total electrical output for the month, for the hours used to calculate M, (MWh)

(iii) Until 12 monthly Hg emission rates have been accumulated, calculate and report only the monthly averages. Then, for each subsequent calendar month, use Equation 6 below to calculate the 12-month rolling average as a weighted average of the Hg emission rate for the current month and the Hg emission rates for the previous 11 months, with one exception. Calendar months in which the unit does not operate (zero unit operating hours) shall not be included in the 12-month rolling average.

$$E_{avg} = \frac{\sum_{i=i}^{12} (ER)_i n_i}{\sum_{i=i}^{12} n_i} \quad (\text{Eq. 6})$$

Where:

$E_{avg}$  = Weighted 12-month rolling average Hg emission rate, (lb/MWh)

$(ER)_i$  = Monthly Hg emission rate, for month "i", (lb/MWh)

n = The number of unit operating hours in month "i" with valid CEM and electrical output data, excluding hours of unit startup, shutdown, and malfunction

(3) If a sorbent trap monitoring system is used in lieu of a Hg CEMS, as described in §75.15 of this chapter and in appendix K to part 75 of this chapter, calculate the monthly Hg emission rates using Equations 3 through 5 of this section, except that for a particular pair of sorbent traps,  $C_h$  in Equation 3 shall be the flow-proportional average Hg concentration measured over the data collection period.

(i) Daily calibration drift (CD) tests and quarterly accuracy determinations shall be performed for Hg CEMS in accordance with Procedure 1 of appendix F to this part. For the CD assessments, you may use either elemental mercury or mercuric chloride ( $\text{Hg}^0$  or  $\text{HgCl}_2$ ) standards. The four quarterly accuracy determinations shall consist of one RATA and three measurement error (ME) tests using  $\text{HgCl}_2$  standards, as described in section 8.3 of Performance Specification 12-A in appendix B to this part (note:  $\text{Hg}^0$  standards may be used if the Hg monitor does not have a converter). Alternatively, the owner or operator may implement the applicable daily, weekly, quarterly, and annual quality assurance (QA) requirements for Hg CEMS in appendix B to part 75 of this chapter, in lieu of the QA procedures in appendices B and F to this part. Annual RATA of

sorbent trap monitoring systems shall be performed in accordance with appendices A and B to part 75 of this chapter, and all other quality assurance requirements specified in appendix K to part 75 of this chapter shall be met for sorbent trap monitoring systems.

[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989; 55 FR 5212, Feb. 14, 1990; 65 FR 61752, Oct. 17, 2000. Redesignated and amended at 70 FR 28653, 28655, May 18, 2005, and further redesignated and amended at 70 FR 51268, Aug. 30, 2005; 71 FR 9881, Feb. 27, 2006; 71 FR 33400, June 9, 2006]

**§ 60.51Da Reporting requirements.**

(a) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

(b) For sulfur dioxide and nitrogen oxides the following information is reported to the Administrator for each 24-hour period.

(1) Calendar date.

(2) The average sulfur dioxide and nitrogen oxide emission rates (ng/J or lb/million Btu) for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

(3) Percent reduction of the potential combustion concentration of sulfur dioxide for each 30 successive boiler operating days, ending with the last 30-day period in the quarter; reasons for non-compliance with the standard; and, description of corrective actions taken.

(4) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 18 hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(5) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction (NO<sub>x</sub> only), emergency conditions (SO<sub>2</sub> only), or other reasons, and justification for excluding data for reasons other than startup, shutdown, malfunction, or emergency conditions.

(6) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(7) Identification of times when hourly averages have been obtained based on manual sampling methods.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(c) If the minimum quantity of emission data as required by §60.49Da is not obtained for any 30 successive boiler operating days, the following information obtained under the requirements of

§60.48Da(h) is reported to the Administrator for that 30-day period:

(1) The number of hourly averages available for outlet emission rates ( $n_o$ ) and inlet emission rates ( $n_i$ ) as applicable.

(2) The standard deviation of hourly averages for outlet emission rates ( $s_o$ ) and inlet emission rates ( $s_i$ ) as applicable.

(3) The lower confidence limit for the mean outlet emission rate ( $E_o^*$ ) and the upper confidence limit for the mean inlet emission rate ( $E_i^*$ ) as applicable.

(4) The applicable potential combustion concentration.

(5) The ratio of the upper confidence limit for the mean outlet emission rate ( $E_o^*$ ) and the allowable emission rate ( $E_{std}$ ) as applicable.

(d) If any standards under §60.43Da are exceeded during emergency conditions because of control system malfunction, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating if emergency conditions existed and requirements under §60.48Da(d) were met during each period, and

(2) Listing the following information:

(i) Time periods the emergency condition existed;

(ii) Electrical output and demand on the owner or operator's electric utility system and the affected facility;

(iii) Amount of power purchased from interconnected neighboring utility companies during the emergency period;

(iv) Percent reduction in emissions achieved;

(v) Atmospheric emission rate (ng/J) of the pollutant discharged; and

(vi) Actions taken to correct control system malfunction.

(e) If fuel pretreatment credit toward the sulfur dioxide emission standard under §60.43Da is claimed, the owner or operator of the affected facility shall submit a signed statement:

(1) Indicating what percentage cleaning credit was taken for the calendar quarter, and whether the credit was determined in accordance with the provisions of §60.50Da and Method 19 (appendix A); and

(2) Listing the quantity, heat content, and date each pretreated fuel shipment was received during the previous quarter; the name and location of the fuel pretreatment facility; and the total quantity and total heat content of all fuels received at the affected facility during the previous quarter.

(f) For any periods for which opacity, sulfur dioxide or nitrogen oxides emissions data are not

available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(g) For Hg, the following information shall be reported to the Administrator:

(1) Company name and address;

(2) Date of report and beginning and ending dates of the reporting period;

(3) The applicable Hg emission limit (lb/MWh); and

(4) For each month in the reporting period:

(i) The number of unit operating hours;

(ii) The number of unit operating hours with valid data for Hg concentration, stack gas flow rate, moisture (if required), and electrical output;

(iii) The monthly Hg emission rate (lb/MWh);

(iv) The number of hours of valid data excluded from the calculation of the monthly Hg emission rate, due to unit startup, shutdown and malfunction; and

(v) The 12-month rolling average Hg emission rate (lb/MWh); and

(5) The data assessment report (DAR) required by appendix F to this part, or an equivalent summary of QA test results if the QA of part 75 of this chapter are implemented.

(h) The owner or operator of the affected facility shall submit a signed statement indicating whether:

(1) The required continuous monitoring system calibration, span, and drift checks or other periodic audits have or have not been performed as specified.

(2) The data used to show compliance was or was not obtained in accordance with approved methods and procedures of this part and is representative of plant performance.

(3) The minimum data requirements have or have not been met; or, the minimum data requirements have not been met for errors that were unavoidable.

(4) Compliance with the standards has or has not been achieved during the reporting period.

(i) For the purposes of the reports required under §60.7, periods of excess emissions are defined as all 6-minute periods during which the average opacity exceeds the applicable opacity standards under §60.42Da(b). Opacity levels in excess of the applicable opacity standard and the date of such excesses are to be submitted to the Administrator each calendar quarter.

(j) The owner or operator of an affected facility shall submit the written reports required under this

section and subpart A to the Administrator semiannually for each six-month period. All semiannual reports shall be postmarked by the 30th day following the end of each six-month period.

(k) The owner or operator of an affected facility may submit electronic quarterly reports for SO<sub>2</sub> and/or NO<sub>x</sub> and/or opacity and/or Hg in lieu of submitting the written reports required under paragraphs (b), (g), and (i) of this section. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.

[44 FR 33613, June 11, 1979, as amended at 63 FR 49454, Sept. 16, 1998; 64 FR 7464, Feb. 12, 1999. Redesignated and amended at 70 FR 28653, 28656, May 18, 2005, and further redesignated and amended at 70 FR 51268, 51269, Aug. 30, 2005]

#### **§ 60.52Da Recordkeeping requirements.**

The owner or operator of an affected facility subject to the emissions limitations in §60.45Da or §60.46Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of §60.7(f).

[70 FR 28656, May 18, 2005. Redesignated and amended at 70 FR 51268, 51269, Aug. 30, 2005]

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# Electronic Code of Federal Regulations (e-CFR)

**BETA TEST SITE**

**e-CFR Data is current as of October 6, 2006**

## **Title 40: Protection of Environment**

### **PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES**

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#### **Subpart HHHH—Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units**

**Source:** 70 FR 28657, May 18, 2005, unless otherwise noted.

#### **Hg Budget Trading Program General Provisions**

##### **§ 60.4101 Purpose.**

This subpart establishes the model rule comprising general provisions and the designated representative, permitting, allowance, and monitoring provisions for the State mercury (Hg) Budget Trading Program, under section 111 of the Clean Air Act (CAA) and §60.24(h)(6), as a means of reducing national Hg emissions. The owner or operator of a unit or a source shall comply with the requirements of this subpart as a matter of Federal law only if the State with jurisdiction over the unit and the source incorporates by reference this subpart or otherwise adopts the requirements of this subpart in accordance with §60.24(h)(6), the State submits to the Administrator one or more revisions of the State plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of this subpart in accordance with §60.24(h)(6), then the State authorizes the Administrator to assist the State in implementing the Hg Budget Trading Program by carrying out the functions set forth for the Administrator in this subpart.

##### **§ 60.4102 Definitions.**

The terms used in this subpart shall have the meanings set forth in this section as follows:

*Account number* means the identification number given by the Administrator to each Hg Allowance Tracking System account.

*Acid rain emissions limitation* means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

*Acid Rain Program* means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

*Administrator* means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

*Allocate or allocation* means the determination by the permitting authority or the Administrator of the amount of Hg allowances to be initially credited to a Hg Budget unit or a new unit set-aside under §§60.4140 through 60.4142.

*Allowance transfer deadline* means, for a control period, midnight of March 1, if it is a business day, or, if March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a Hg allowance transfer must be submitted for recordation in a Hg Budget source's compliance account in order to be used to meet the source's Hg Budget emissions limitation for such control period in accordance with §60.4154.

*Alternate Hg designated representative* means, for a Hg Budget source and each Hg Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with §§60.4110 through 60.4114, to act on behalf of the Hg designated representative in matters pertaining to the Hg Budget Trading Program.

*Automated data acquisition and handling system or DAHS* means that component of the continuous emission monitoring system (CEMS), or other emissions monitoring system approved for use under §§60.4170 through 60.4176, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required §§60.4170 through 60.4176.

*Boiler* means an enclosed fossil-or other fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

*Bottoming-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

*CAIR NOX Annual Trading Program* means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of part 96 of this chapter and §51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

*CAIR NOX Ozone Season Trading Program* means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of part 96 of this chapter and §51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

*CAIR SO2 Trading Program* means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of part 96 of this chapter and §51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

*Clean Air Act or CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

*Coal* means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)<sup>1</sup> (incorporated by reference, see §60.17).

*Coal-derived fuel* means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

*Coal-fired* means combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year.

*Cogeneration unit* means a stationary, coal-fired boiler or stationary, coal-fired combustion turbine:

- (1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and
- (2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity:

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less than 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

*Combustion turbine means:*

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

*Commence commercial operation* means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in §60.4105.

(i) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §60.4105, for a unit that is not a Hg Budget unit under §60.4104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a Hg Budget unit under §60.4104.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1) or (2) of this definition as appropriate.

*Commence operation* means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in §60.4105.

(i) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in §60.4105, for a unit that is not a Hg Budget unit under §60.4104 on the date the unit commences operation as defined in paragraph (1) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a Hg Budget unit under §60.4104.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (e.g., repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1) or (2) of this definition as appropriate.

*Common stack* means a single flue through which emissions from 2 or more units are exhausted.

*Compliance account* means a Hg Allowance Tracking System account, established by the Administrator for a Hg Budget source under §§60.4150 through 60.4157, in which any Hg allowance allocations for the Hg Budget units at the source are initially recorded and in which are

held any Hg allowances available for use for a control period in order to meet the source's Hg Budget emissions limitation in accordance with §60.4154.

*Continuous emission monitoring system* or *CEMS* means the equipment required under §§60.4170 through 60.4176 to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of Hg emissions, stack gas volumetric flow rate, stack gas moisture content, and oxygen or carbon dioxide concentration (as applicable), in a manner consistent with part 75 of this chapter. The following systems are the principal types of CEMS required under §§60.4170 through 60.4176:

- (1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);
- (2) A Hg concentration monitoring system, consisting of a Hg pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of Hg emissions in units of micrograms per dry standard cubic meter ( $\mu\text{gm/dscm}$ );
- (3) A moisture monitoring system, as defined in §75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent  $\text{H}_2\text{O}$ .
- (4) A carbon dioxide monitoring system, consisting of a  $\text{CO}_2$  concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the  $\text{CO}_2$  concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of  $\text{CO}_2$  emissions, in percent  $\text{CO}_2$ ; and
- (5) An oxygen monitoring system, consisting of an  $\text{O}_2$  concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of  $\text{O}_2$ , in percent  $\text{O}_2$ .

*Control period* means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

*Emissions* means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the Hg designated representative and as determined by the Administrator in accordance with §§60.4170 through 60.4176.

*Excess emissions* means any ounce of mercury emitted by the Hg Budget units at a Hg Budget source during a control period that exceeds the Hg Budget emissions limitation for the source.

*General account* means a Hg Allowance Tracking System account, established under §60.4151, that is not a compliance account.

*Generator* means a device that produces electricity.

*Gross electrical output* means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

*Heat input* means, with regard to a specified period of time, the product (in MMBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/MMBtu and multiplied by the

fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the Hg designated representative and determined by the Administrator in accordance with §§60.4170 through 60.4176 and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

*Heat input rate* means the amount of heat input (in MMBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in MMBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

*Hg allowance* means a limited authorization issued by the permitting authority or the Administrator under §§60.4140 through 60.4142 to emit one ounce of mercury during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the Hg Budget Trading Program. An authorization to emit mercury that is not issued under the provisions of a State plan that adopt the requirements of this subpart and are approved by the Administrator in accordance with §60.24(h)(6) shall not be a "Hg allowance."

*Hg allowance deduction* or *deduct Hg allowances* means the permanent withdrawal of Hg allowances by the Administrator from a compliance account in order to account for a specified number of ounces of total mercury emissions from all Hg Budget units at a Hg Budget source for a control period, determined in accordance with §§60.4150 through 60.4157 and §§60.4170 through 60.4176, or to account for excess emissions.

*Hg allowances held* or *hold Hg allowances* means the Hg allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with §§60.4150 through 60.4162, in a Hg Allowance Tracking System account.

*Hg Allowance Tracking System* means the system by which the Administrator records allocations, deductions, and transfers of Hg allowances under the Hg Budget Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

*Hg Allowance Tracking System account* means an account in the Hg Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of Hg allowances.

*Hg authorized account representative* means, with regard to a general account, a responsible natural person who is authorized, in accordance with §60.4152, to transfer and otherwise dispose of Hg allowances held in the general account and, with regard to a compliance account, the Hg designated representative of the source.

*Hg Budget emissions limitation* means, for a Hg Budget source, the equivalent in ounces of the Hg allowances available for deduction for the source under §60.4154(a) and (b) for a control period.

*Hg Budget permit* means the legally binding and Federally enforceable written document, or portion of such document, issued by the permitting authority under §§60.4120 through 60.4124, including any permit revisions, specifying the Hg Budget Trading Program requirements applicable to a Hg Budget source, to each Hg Budget unit at the source, and to the owners and operators and the Hg designated representative of the source and each such unit.

*Hg Budget source* means a source that includes one or more Hg Budget units.

*Hg Budget Trading Program* means a multi-state Hg air pollution control and emission reduction program approved and administered by the Administrator in accordance with this subpart and §60.24(h)(6), as a means of reducing national Hg emissions.

*Hg Budget unit* means a unit that is subject to the Hg Budget Trading Program under §60.4104.

*Hg designated representative* means, for a Hg Budget source and each Hg Budget unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with §§60.4110 through 60.4114, to represent and legally bind each owner and operator in matters pertaining to the Hg Budget Trading Program.

*Life-of-the-unit, firm power contractual arrangement* means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

- (1) For the life of the unit;
- (2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or
- (3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

*Lignite* means coal that is classified as lignite A or B according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004);<sup>1</sup> (incorporated by reference, see §60.17).

*Maximum design heat input* means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady-state basis, such decreased maximum amount as specified by the person conducting the physical change.

*Monitoring system* means any monitoring system that meets the requirements of §§60.4170 through 60.4176, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

*Nameplate capacity* means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady-state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

*Operator* means any person who operates, controls, or supervises a Hg Budget unit or a Hg Budget source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

*Ounce* means  $2.84 \times 10^7$  micrograms. For the purpose of determining compliance with the Hg Budget emissions limitation, total ounces of mercury emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with §§60.4170 through 60.4176, but with any remaining fraction of an ounce equal to or greater than 0.50 ounces deemed to equal one ounce and any remaining fraction of an ounce less than 0.50 ounces deemed to equal zero ounces.

*Owner* means any of the following persons:

(1) With regard to a Hg Budget source or a Hg Budget unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a Hg Budget unit at the source or the Hg Budget unit;

(ii) Any holder of a leasehold interest in a Hg Budget unit at the source or the Hg Budget unit; or

(iii) Any purchaser of power from a Hg Budget unit at the source or the Hg Budget unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such Hg Budget unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the Hg allowances held in the general account and who is subject to the binding agreement for the Hg authorized account representative to represent the person's ownership interest with respect to Hg allowances.

*Permitting authority* means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the Hg Budget Trading Program in accordance with §§60.4120 through 60.4124 or, if no such agency has been so authorized, the Administrator.

*Potential electrical output capacity* means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

*Receive or receipt of* means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

*Recordation, record, or recorded* means, with regard to Hg allowances, the movement of Hg allowances by the Administrator into or between Hg Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

*Reference method* means any direct test method of sampling and analyzing for an air pollutant as specified in §75.22 of this chapter.

*Repowered* means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

*Serial number* means, for a Hg allowance, the unique identification number assigned to each Hg allowance by the Administrator.

*Sequential use of energy* means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

*Source* means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the CAA, a "source," including a "source" with multiple units, shall be considered a single "facility."

*State* means:

(1) For purposes of referring to a governing entity, one of the States in the United States, the District of Columbia, or, if approved for treatment as a State under part 49 of this chapter, the Navajo Nation or Ute Indian Tribe that adopts the Hg Budget Trading Program pursuant to §60.24(h)(6); or

(2) For purposes of referring to geographic areas, one of the States in the United States, the District of Columbia, the Navajo Nation Indian country, or the Ute Tribe Indian country.

*Subbituminous* means coal that is classified as subbituminous A, B, or C, according to the American Society of Testing and Materials (ASTM) Standard Specification for Classification of Coals by Rank D388–77, 90, 91, 95, 98a, or 99 (Reapproved 2004)<sup>1</sup> (incorporated by reference, see §60.17).

*Submit or serve* means to send or transmit a document, information, or correspondence to the person specified in accordance with the applicable regulation:

(1) In person;

(2) By United States Postal Service; or

(3) By other means of dispatch or transmission and delivery. Compliance with any “submission” or “service” deadline shall be determined by the date of dispatch, transmission, or mailing and not the date of receipt.

*Title V operating permit* means a permit issued under title V of the CAA and part 70 or part 71 of this chapter.

*Title V operating permit regulations* means the regulations that the Administrator has approved or issued as meeting the requirements of title V of the CAA and part 70 or 71 of this chapter.

*Topping-cycle cogeneration unit* means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

*Total energy input* means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

*Total energy output* means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

*Unit* means a stationary coal-fired boiler or a stationary coal-fired combustion turbine.

*Unit operating day* means a calendar day in which a unit combusts any fuel.

*Unit operating hour or hour of unit operation* means an hour in which a unit combusts any fuel.

*Useful power* means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

*Useful thermal energy* means, with regard to a cogeneration unit, thermal energy that is:

- (1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;
- (2) Used in a heat application (e.g., space heating or domestic hot water heating); or
- (3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

*Utility power distribution system* means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

### **§ 60.4103 Measurements, abbreviations, and acronyms.**

Measurements, abbreviations, and acronyms used in this part are defined as follows:

Btu—British thermal unit.

CO<sub>2</sub>—carbon dioxide.

H<sub>2</sub>O—water.

Hg—mercury.

hr—hour.

kW—kilowatt electrical.

kWh—kilowatt hour.

lb—pound.

MMBtu—million Btu.

MWe—megawatt electrical.

MWh—megawatt hour.

NO<sub>x</sub>—nitrogen oxides.

O<sub>2</sub>—oxygen.

ppm—parts per million.

scfh—standard cubic feet per hour.

SO<sub>2</sub>—sulfur dioxide.

yr—year.

**§ 60.4104 Applicability.**

(a) Except as provided in paragraph (b) of this section:

(1) The following units in a State shall be Hg Budget units, and any source that includes one or more such units shall be a Hg Budget source, subject to the requirements of this subpart and subparts BB through HH of this part: Any stationary, coal-fired boiler or stationary, coal-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) If a stationary boiler or stationary combustion turbine that, under paragraph (a)(1) of this section, is not a Hg Budget unit begins to combust coal or coal-derived fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become a Hg Budget unit as provided in paragraph (a)(1) of this section on the first date on which it both combusts coal or coal-derived fuel and serves such generator.

(b) The units in a State that meet the requirements set forth in paragraphs (b)(1)(i) or (b)(2) of this section shall not be Hg Budget units:

(1)(i) Any unit that is a Hg Budget unit under paragraph (a)(1) or (2) of this section:

(A) Qualifying as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(B) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(ii) If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and meets the requirements of paragraph (b)(1)(i) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become an Hg Budget unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (b)(1)(i)(B) of this section.

(2) Any unit that is an Hg Budget unit under paragraph (a)(1) or (2) of this section, is a solid waste incineration unit combusting municipal waste, and is subject to the requirements of:

(i) A State Plan approved by the Administrator in accordance with subpart Cb of part 60 of this chapter (emissions guidelines and compliance times for certain large municipal waste combustors);

(ii) Subpart Eb of part 60 of this chapter (standards of performance for certain large municipal waste combustors);

(iii) Subpart AAAA of part 60 of this chapter (standards of performance for certain small municipal waste combustors);

(iv) A State Plan approved by the Administrator in accordance with subpart BBBB of part 60 of this chapter (emission guidelines and compliance times for certain small municipal waste combustion units);

(v) Subpart FFF, of part 62 of this chapter (Federal Plan requirements for certain large municipal waste combustors); or

(vi) Subpart JJJ of part 62 of this chapter (Federal Plan requirements for certain small municipal waste combustion units).

[71 FR 33400, June 9, 2006]

#### **§ 60.4105 Retired unit exemption.**

(a)(1) Any Hg Budget unit that is permanently retired shall be exempt from the Hg Budget Trading Program, except for the provisions of this section, §60.4102, §60.4103, §60.4104, §60.4106(c)(4) through (8), §60.4107, and §§60.4150 through 60.4162.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the Hg Budget unit is permanently retired. Within 30 days of the unit's permanent retirement, the Hg designated representative shall submit a statement to the permitting authority otherwise responsible for administering any Hg Budget permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

(3) After receipt of the statement under paragraph (a)(2) of this section, the permitting authority will amend any permit under §§60.4120 through 60.4124 covering the source at which the unit is located to add the provisions and requirements of the exemption under paragraphs (a)(1) and (b) of this section.

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any mercury, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate Hg allowances under §§60.4140 through 60.4142 to a unit exempt under paragraph (a) of this section.

(3) For a period of 5 years from the date the records are created, the owners and operators of a unit exempt under paragraph (a) of this section shall retain at the source that includes the unit, records demonstrating that the unit is permanently retired. The 5-year period for keeping records may be extended for cause, at any time before the end of the period, in writing by the permitting authority or the Administrator. The owners and operators bear the burden of proof that the unit is permanently retired.

(4) The owners and operators and, to the extent applicable, the Hg designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the Hg Budget Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the Hg designated representative of the source submits a complete Hg Budget permit application under §60.4122 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the unit resumes operation.

(6) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the Hg designated representative submits a Hg Budget permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the Hg designated representative is required under paragraph (b)(5) of this section to submit a Hg Budget permit application for the unit; or

(iii) The date on which the unit resumes operation, if the Hg designated representative is not required to submit a Hg Budget permit application for the unit.

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under §§60.4170 through 60.4176, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

#### **§ 60.4106 Standard requirements.**

(a) *Permit Requirements.* (1) The Hg designated representative of each Hg Budget source required to have a title V operating permit and each Hg Budget unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete Hg Budget permit application under §60.4122 in accordance with the deadlines specified in §60.4121(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a Hg Budget permit application and issue or deny a Hg Budget permit.

(2) The owners and operators of each Hg Budget source required to have a title V operating permit and each Hg Budget unit required to have a title V operating permit at the source shall have a Hg Budget permit issued by the permitting authority under §§60.4120 through 60.4124 for the source and operate the source and the unit in compliance with such Hg Budget permit.

(3) The owners and operators of a Hg Budget source that is not required to have a title V operating permit and each Hg Budget unit that is not required to have a title V operating permit are not required to submit a Hg Budget permit application, and to have a Hg Budget permit, under §§60.4120 through 60.4124 for such Hg Budget source and such Hg Budget unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the Hg designated representative, of each Hg Budget source and each Hg Budget unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§60.4170 through 60.4176.

(2) The emissions measurements recorded and reported in accordance with §§60.4170 through 60.4176 shall be used to determine compliance by each Hg Budget source with the Hg Budget emissions limitation under paragraph (c) of this section.

(c) *Mercury emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each Hg Budget source and each Hg Budget unit at the source shall hold, in the source's compliance account, Hg allowances available for compliance deductions for the control period under §60.4154(a) in an amount not less than the ounces of total mercury emissions for the control period from all Hg Budget units at the source, as determined in accordance with §§60.4170 through 60.4176.

(2) A Hg Budget unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under §60.4170(b)(1) or (2).

(3) A Hg allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the Hg allowance was allocated.

(4) Hg allowances shall be held in, deducted from, or transferred into or among Hg Allowance Tracking System accounts in accordance with §§60.4160 through 60.4162.

(5) A Hg allowance is a limited authorization to emit one ounce of mercury in accordance with the Hg Budget Trading Program. No provision of the Hg Budget Trading Program, the Hg Budget permit application, the Hg Budget permit, or an exemption under §60.4105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A Hg allowance does not constitute a property right.

(7) Upon recordation by the Administrator under §§60.4150 through 60.4162, every allocation, transfer, or deduction of a Hg allowance to or from a Hg Budget unit's compliance account is incorporated automatically in any Hg Budget permit of the source that includes the Hg Budget unit.

(d) *Excess emissions requirements.* (1) If a Hg Budget source emits mercury during any control period in excess of the Hg Budget emissions limitation, then:

(i) The owners and operators of the source and each Hg Budget unit at the source shall surrender the Hg allowances required for deduction under §60.4154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ounce of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the Hg Budget source and each Hg Budget unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under §60.4113 for the Hg designated representative for the source and each Hg Budget unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under §60.4113 changing the Hg designated representative.

(ii) All emissions monitoring information, in accordance with §§60.4170 through 60.4176, provided that to the extent that §§60.4170 through 60.4176 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Hg Budget Trading Program.

(iv) Copies of all documents used to complete a Hg Budget permit application and any other submission under the Hg Budget Trading Program or to demonstrate compliance with the requirements of the Hg Budget Trading Program.

(2) The Hg designated representative of a Hg Budget source and each Hg Budget unit at the source shall submit the reports required under the Hg Budget Trading Program, including those under §§60.4170 through 60.4176.

(f) *Liability.* (1) Each Hg Budget source and each Hg Budget unit shall meet the requirements of the Hg Budget Trading Program.

(2) Any provision of the Hg Budget Trading Program that applies to a Hg Budget source or the Hg designated representative of a Hg Budget source shall also apply to the owners and operators of such source and of the Hg Budget units at the source.

(3) Any provision of the Hg Budget Trading Program that applies to a Hg Budget unit or the Hg designated representative of a Hg Budget unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the Hg Budget Trading Program, a Hg Budget permit application, a Hg Budget permit, or an exemption under §60.4105 shall be construed as exempting or excluding the owners and operators, and the Hg designated representative, of a Hg Budget source or Hg Budget unit from compliance with any other provision of the applicable, approved State implementation plan, a Federally enforceable permit, or the CAA.

#### **§ 60.4107 Computation of time.**

(a) Unless otherwise stated, any time period scheduled, under the Hg Budget Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the Hg Budget Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the Hg Budget Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

#### **§ 60.4108 Appeal procedures.**

The appeal procedures for decisions of the Administrator under the Hg Budget Trading Program shall be the procedures set forth in part 78 of this chapter. The terms "subpart HHHH of this part," "§60.4141(b)(2) or (c)(2)," "§60.4154," "§60.4156," "§60.4161," "§60.4175," "Hg allowances," "Hg Allowance Tracking System Account," "Hg designated representative," "Hg authorized account representative," and "§60.4106" apply instead of the terms "subparts AA through II of part 96 of this chapter," "§96.141(b)(2) or (c)(2)," "§96.154," "§96.156," "§96.161," "§96.175," "CAIR NO<sub>x</sub> allowances," "CAIR NO<sub>x</sub> Allowance Tracking System account," "CAIR designated representative," "CAIR authorized account representative," and "§96.106."

### **Hg Designated Representative for Hg Budget Sources**

#### **§ 60.4110 Authorization and Responsibilities of Hg designated representative.**

(a) Except as provided under §60.4111, each Hg Budget source, including all Hg Budget units at the source, shall have one and only one Hg designated representative, with regard to all matters under the Hg Budget Trading Program concerning the source or any Hg Budget unit at the source.

(b) The Hg designated representative of the Hg Budget source shall be selected by an agreement binding on the owners and operators of the source and all Hg Budget units at the source and shall act in accordance with the certification statement in §60.4113(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under §60.4113, the Hg designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the Hg Budget source represented and each Hg Budget unit at the source in all matters pertaining to the Hg Budget Trading Program, notwithstanding any agreement between the Hg designated representative and such owners and operators. The owners and operators shall be bound by any decision or order

issued to the Hg designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No Hg Budget permit will be issued, no emissions data reports will be accepted, and no Hg Allowance Tracking System account will be established for a Hg Budget unit at a source, until the Administrator has received a complete certificate of representation under §60.4113 for a Hg designated representative of the source and the Hg Budget units at the source.

(e)(1) Each submission under the Hg Budget Trading Program shall be submitted, signed, and certified by the Hg designated representative for each Hg Budget source on behalf of which the submission is made. Each such submission shall include the following certification statement by the Hg designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a Hg Budget source or a Hg Budget unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

#### **§ 60.4111 Alternate Hg designated representative.**

(a) A certificate of representation under §60.4113 may designate one and only one alternate Hg designated representative, who may act on behalf of the Hg designated representative. The agreement by which the alternate Hg designated representative is selected shall include a procedure for authorizing the alternate Hg designated representative to act in lieu of the Hg designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under §60.4113, any representation, action, inaction, or submission by the alternate Hg designated representative shall be deemed to be a representation, action, inaction, or submission by the Hg designated representative.

(c) Except in this section and §§60.4102, 60.4110(a) and (d), 60.4112, 60.4113, 60.4151, and 60.4174, whenever the term "Hg designated representative" is used in this subpart, the term shall be construed to include the Hg designated representative or any alternate Hg designated representative.

#### **§ 60.4112 Changing Hg designated representative and alternate Hg designated representative; changes in owners and operators.**

(a) Changing Hg designated representative. The Hg designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §60.4113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Hg designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new Hg designated representative and the owners and operators of the Hg Budget source and the Hg Budget units at the source.

(b) Changing alternate Hg designated representative. The alternate Hg designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under §60.4113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate Hg designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate Hg designated representative and the owners and operators of the Hg Budget source and the Hg Budget units at the source.

(c) *Changes in owners and operators.* (1) In the event a new owner or operator of a Hg Budget source or a Hg Budget unit is not included in the list of owners and operators in the certificate of representation under §60.4113, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the Hg designated representative and any alternate Hg designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a Hg Budget source or a Hg Budget unit, including the addition of a new owner or operator, the Hg designated representative or any alternate Hg designated representative shall submit a revision to the certificate of representation under §60.4113 amending the list of owners and operators to include the change.

#### **§ 60.4113 Certificate of representation.**

(a) A complete certificate of representation for a Hg designated representative or an alternate Hg designated representative shall include the following elements in a format prescribed by the Administrator:

(1) Identification of the Hg Budget source, and each Hg Budget unit at the source, for which the certificate of representation is submitted.

(2) The name, address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the Hg designated representative and any alternate Hg designated representative.

(3) A list of the owners and operators of the Hg Budget source and of each Hg Budget unit at the source.

(4) The following certification statements by the Hg designated representative and any alternate Hg designated representative:

(i) "I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Hg Budget unit at the source."

(ii) "I certify that I have all the necessary authority to carry out my duties and responsibilities under the Hg Budget Trading Program on behalf of the owners and operators of the source and of each Hg Budget unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions."

(iii) "I certify that the owners and operators of the source and of each Hg Budget unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit."

(iv) "Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a Hg Budget unit, or where a customer purchases power from a Hg Budget unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'Hg designated representative' or 'alternate Hg designated representative,' as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each Hg Budget unit at the source; and Hg allowances and proceeds of transactions involving Hg allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of Hg allowances by contract, Hg allowances and proceeds of transactions involving Hg allowances will be deemed to be held or distributed in accordance with the contract."

(5) The signature of the Hg designated representative and any alternate Hg designated representative and the dates signed.

(b) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

#### **§ 60.4114 Objections concerning Hg designated representative.**

(a) Once a complete certificate of representation under §60.4113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under §60.4113 is received by the Administrator.

(b) Except as provided in §60.4112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the Hg designated representative shall affect any representation, action, inaction, or submission of the Hg designated representative or the finality of any decision or order by the permitting authority or the Administrator under the Hg Budget Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any Hg designated representative, including private legal disputes concerning the proceeds of Hg allowance transfers.

### **Permits**

#### **§ 60.4120 General Hg budget trading program permit requirements.**

(a) For each Hg Budget source required to have a title V operating permit, such permit shall include a Hg Budget permit administered by the permitting authority for the title V operating permit. The Hg Budget portion of the title V permit shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter, except as provided otherwise by this section and §§60.4121 through 60.4124.

(b) Each Hg Budget permit shall contain, with regard to the Hg Budget source and the Hg Budget units at the source covered by the Hg Budget permit, all applicable Hg Budget Trading Program requirements and shall be a complete and separable portion of the title V operating permit.

**§ 60.4121 Submission of Hg budget permit applications.**

(a) *Duty to apply.* The Hg designated representative of any Hg Budget source required to have a title V operating permit shall submit to the permitting authority a complete Hg Budget permit application under §60.4122 for the source covering each Hg Budget unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the Hg Budget unit commences operation.

(b) *Duty to Reapply.* For a Hg Budget source required to have a title V operating permit, the Hg designated representative shall submit a complete Hg Budget permit application under §60.4122 for the source covering each Hg Budget unit at the source to renew the Hg Budget permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

**§ 60.4122 Information requirements for Hg budget permit applications.**

A complete Hg Budget permit application shall include the following elements concerning the Hg Budget source for which the application is submitted, in a format prescribed by the permitting authority:

- (a) Identification of the Hg Budget source;
- (b) Identification of each Hg Budget unit at the Hg Budget source; and
- (c) The standard requirements under §60.4106.

**§ 60.4123 Hg budget permit contents and term.**

- (a) Each Hg Budget permit will contain, in a format prescribed by the permitting authority, all elements required for a complete Hg Budget permit application under §60.4122.
- (b) Each Hg Budget permit is deemed to incorporate automatically the definitions of terms under §60.4102 and, upon recordation by the Administrator under §§60.4150 through 60.4162, every allocation, transfer, or deduction of a Hg allowance to or from the compliance account of the Hg Budget source covered by the permit.
- (c) The term of the Hg Budget permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the Hg Budget permit with issuance, revision, or renewal of the Hg Budget source's title V operating permit.

**§ 60.4124 Hg budget permit revisions.**

Except as provided in §60.4123(b), the permitting authority will revise the Hg Budget permit, as necessary, in accordance with the permitting authority's title V operating permits regulations addressing permit revisions.

**§ 60.4130 [Reserved]****Hg Allowance Allocations****§ 60.4140 State trading budgets.**

The State trading budgets for annual allocations of Hg allowances for the control periods in 2010 through 2017 and in 2018 and thereafter are respectively as follows:

State	Annual EGU Hg budget (tons)	
	2010-2017	2018 and thereafter
Alaska.....	0.010	0.004
Alabama.....	1.289	0.509
Arkansas.....	0.516	0.204
Arizona.....	0.454	0.179
California.....	0.041	0.016
Colorado.....	0.706	0.279
Connecticut.....	0.053	0.021
Delaware.....	0.072	0.028
Florida.....	1.232	0.487
Georgia.....	1.227	0.484
Hawaii.....	0.024	0.009
Iowa.....	0.727	0.287
Illinois.....	1.594	0.629
Indiana.....	2.097	0.828
Kansas.....	0.723	0.285
Kentucky.....	1.525	0.602
Louisiana.....	0.601	0.237
Massachusetts.....	0.172	0.068
Maryland.....	0.490	0.193
Maine.....	0.001	0.001
Michigan.....	1.303	0.514
Minnesota.....	0.695	0.274
Missouri.....	1.393	0.550
Mississippi.....	0.291	0.115
Montana.....	0.377	0.149
Navajo Nation.....	0.600	0.237
North Carolina.....	1.133	0.447
North Dakota.....	1.564	0.617
Nebraska.....	0.421	0.166
New Hampshire.....	0.063	0.025
New Jersey.....	0.153	0.060
New Mexico.....	0.299	0.118
Nevada.....	0.285	0.112
New York.....	0.393	0.155
Ohio.....	2.056	0.812
Oklahoma.....	0.721	0.285
Oregon.....	0.076	0.030
Pennsylvania.....	1.779	0.702
South Carolina.....	0.580	0.229
South Dakota.....	0.072	0.029
Tennessee.....	0.944	0.373
Texas.....	4.656	1.838
Utah.....	0.506	0.200
Ute Indian Tribe.....	0.060	0.024
Virginia.....	0.592	0.234
Washington.....	0.198	0.078
Wisconsin.....	0.890	0.351

West Virginia.....	1.394	0.550
Wyoming.....	0.952	0.376
	-----	
Total.....	38.000	15.000
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[71 FR 33401, June 9, 2006]

**§ 60.4141 Timing requirements for Hg allowance allocations.**

(a) By November 17, 2006, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with §60.4142(a) and (b), for the control periods in 2010, 2011, 2012, 2013, and 2014.

(b)(1) By October 31, 2008 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with §60.4142(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the Hg allowance allocations in accordance with paragraph (b)(1) of this section, the Administrator will assume that the allocations of Hg allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2018, the Administrator will assume that the allocations equal the allocations for the control period in 2017, multiplied by the amount of ounces (*i.e.*, tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 for 2018 and thereafter and divided by such amount of ounces of Hg emissions for 2010 through 2017.

(c)(1) By October 31, 2010 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with §60.4142(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the Hg allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of Hg allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2018, the Administrator will assume that the allocations equal the allocations for the control period in 2017, multiplied by the amount of ounces (*i.e.*, tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 for 2018 and thereafter and divided by such amount of ounces of Hg emissions for 2010 through 2017 and except that any Hg Budget unit that would otherwise be allocated Hg allowances under §60.4142(a) and (b), as well as under §60.4142(a), (c), and (d), for the applicable control period will be assumed to be allocated no Hg allowances under §60.4142(a), (c), and (d) for the applicable control period.

[70 FR 28657, May 18, 2005, as amended at 71 FR 33402, June 9, 2006]

**§ 60.4142 Hg allowance allocations.**

(a)(1) The baseline heat input (in MMBtu) used with respect to Hg allowance allocations under paragraph (b) of this section for each Hg Budget unit will be:

(i) For units commencing operation before January 1, 2001, the average of the three highest amounts of the unit's adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as the sum of the following:

(A) Any portion of the unit's control period heat input for the year that results from the unit's combustion of lignite, multiplied by 3.0;

(B) Any portion of the unit's control period heat input for the year that results from the unit's combustion of subbituminous coal, multiplied by 1.25; and

(C) Any portion of the unit's control period heat input for the year that is not covered by paragraph (a)(1)(i)(A) or (B) of this section, multiplied by 1.0.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit's total converted control period heat input over the first such 5 years.

(2)(i) A unit's control period heat input for a calendar year under paragraphs (a)(1)(i) of this section, and a unit's total ounces of Hg emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year. The unit's types and amounts of fuel combusted, under paragraph (a)(1)(i) of this section, will be based on the best available data reported to the permitting authority for the unit.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh and divided by 1,000,000 Btu/MMBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/MMBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,413 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/MMBtu.

(b)(1) For each control period in 2010 and thereafter, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 95 percent for a control period in 2010 through 2014, and 97 percent for a control period in 2015 and thereafter, of the amount of ounces (*i.e.*, tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget

under §60.4140 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate Hg allowances to each Hg Budget unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of Hg allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such Hg Budget unit to the total amount of baseline heat input of all such Hg Budget units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2010 and thereafter, the permitting authority will allocate Hg allowances to Hg Budget units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated Hg allowances equal to 5 percent for a control period in 2010 through 2014, and 3 percent for a control period in 2015 and thereafter, of the amount of ounces (*i.e.*, tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140.

(2) The Hg designated representative of such a Hg Budget unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated Hg allowances, starting with the later of the control period in 2010 or the first control period after the control period in which the Hg Budget unit commences commercial operation and until the first control period for which the unit is allocated Hg allowances under paragraph (b) of this section. The Hg allowance allocation request must be submitted on or before July 1 of the first control period for which the Hg allowances are requested and after the date on which the Hg Budget unit commences commercial operation.

(3) In a Hg allowance allocation request under paragraph (c)(2) of this section, the Hg designated representative may request for a control period Hg allowances in an amount not exceeding the Hg Budget unit's total ounces of Hg emissions during the control period immediately before such control period.

(4) The permitting authority will review each Hg allowance allocation request under paragraph (c)(2) of this section and will allocate Hg allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after July 1 of the control period, the permitting authority will determine the sum of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of Hg allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of Hg allowances in the new unit set-aside for the control period is less than the

sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of Hg allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each Hg designated representative that submitted an allowance allocation request of the amount of Hg allowances (if any) allocated for the control period to the Hg Budget unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated Hg allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each Hg Budget unit that was allocated Hg allowances under paragraph (b) of this section an amount of Hg allowances equal to the total amount of such remaining unallocated Hg allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for 2010 through 2014, and 97 percent for 2014 and thereafter, of the amount of ounces (*i.e.*, tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140, and rounded to the nearest whole allowance as appropriate.

### **Hg Allowance Tracking System**

#### **§ 60.4150 [Reserved]**

#### **§ 60.4151 Establishment of accounts.**

(a) *Compliance accounts.* Upon receipt of a complete certificate of representation under §60.4113, the Administrator will establish a compliance account for the Hg Budget source for which the certificate of representation was submitted unless the source already has a compliance account.

(b) *General accounts—(1) Application for general account.* (i) Any person may apply to open a general account for the purpose of holding and transferring Hg allowances. An application for a general account may designate one and only one Hg authorized account representative and one and only one alternate Hg authorized account representative who may act on behalf of the Hg authorized account representative. The agreement by which the alternate Hg authorized account representative is selected shall include a procedure for authorizing the alternate Hg authorized account representative to act in lieu of the Hg authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the Hg authorized account representative and any alternate Hg authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the Hg authorized account representative and any alternate Hg authorized account representative to represent their ownership interest with respect to the Hg allowances held in the general account;

(D) The following certification statement by the Hg authorized account representative and any alternate Hg authorized account representative: "I certify that I was selected as the Hg authorized account representative or the alternate Hg authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to Hg allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the Hg Budget Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account."

(E) The signature of the Hg authorized account representative and any alternate Hg authorized account representative and the dates signed.

(iii) Unless otherwise required by the permitting authority or the Administrator, documents of agreement referred to in the application for a general account shall not be submitted to the permitting authority or the Administrator. Neither the permitting authority nor the Administrator shall be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(2) *Authorization of Hg authorized account representative.* (i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The Hg authorized account representative and any alternate Hg authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to Hg allowances held in the general account in all matters pertaining to the Hg Budget Trading Program, notwithstanding any agreement between the Hg authorized account representative or any alternate Hg authorized account representative and such person. Any such person shall be bound by any order or decision issued to the Hg authorized account representative or any alternate Hg authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate Hg authorized account representative shall be deemed to be a representation, action, inaction, or submission by the Hg authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the Hg authorized account representative or any alternate Hg authorized account representative for the persons having an ownership interest with respect to Hg allowances held in the general account. Each such submission shall include the following certification statement by the Hg authorized account representative or any alternate Hg authorized account representative: "I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the Hg allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(iii) The Administrator will accept or act on a submission concerning the general account only if the

submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) Changing Hg authorized account representative and alternate Hg authorized account representative; changes in persons with ownership interest.

(i) The Hg authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Hg authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new Hg authorized account representative and the persons with an ownership interest with respect to the Hg allowances in the general account.

(ii) The alternate Hg authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate Hg authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate Hg authorized account representative and the persons with an ownership interest with respect to the Hg allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to Hg allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the Hg authorized account representative and any alternate Hg authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to Hg allowances in the general account, including the addition of persons, the Hg authorized account representative or any alternate Hg authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the Hg allowances in the general account to include the change.

(4) *Objections concerning Hg authorized account representative.* (i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative for a general account shall affect any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative or the finality of any decision or order by the Administrator under the Hg Budget Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the Hg authorized account representative or any alternative Hg authorized account representative for a general account, including private legal

disputes concerning the proceeds of Hg allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

**§ 60.4152 Responsibilities of Hg authorized account representative.**

Following the establishment of a Hg Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of Hg allowances in the account, shall be made only by the Hg authorized account representative for the account.

**§ 60.4153 Recordation of Hg allowance allocations.**

(a) By December 1, 2006, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at a source, as submitted by the permitting authority in accordance with §60.4141(a), for the control periods in 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2008, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or as determined by the Administrator in accordance with §60.4141(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a Hg Budget source's compliance account under §60.4154, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §60.4141(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By December 1, 2010 and December 1 of each year thereafter, the Administrator will record in the Hg Budget source's compliance account the Hg allowances allocated for the Hg Budget units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with §60.4141(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) *Serial numbers for allocated Hg allowances.* When recording the allocation of Hg allowances for a Hg Budget unit in a compliance account, the Administrator will assign each Hg allowance a unique identification number that will include digits identifying the year of the control period for which the Hg allowance is allocated.

**§ 60.4154 Compliance with Hg budget emissions limitation.**

(a) *Allowance transfer deadline.* The Hg allowances are available to be deducted for compliance with a source's Hg Budget emissions limitation for a control period in a given calendar year only if the Hg allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a Hg allowance transfer correctly submitted for

recordation under §§60.4160 through 60.4162 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) *Deductions for compliance.* Following the recordation, in accordance with §§60.4160 through 60.4162, of Hg allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account Hg allowances available under paragraph (a) of this section in order to determine whether the source meets the Hg Budget emissions limitation for the control period, as follows:

(1) Until the amount of Hg allowances deducted equals the number of ounces of total Hg emissions, determined in accordance with §§60.4170 through 60.4176, from all Hg Budget units at the source for the control period; or

(2) If there are insufficient Hg allowances to complete the deductions in paragraph (b)(1) of this section, until no more Hg allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of Hg allowances by serial number.* The Hg authorized account representative for a source's compliance account may request that specific Hg allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the Hg Budget source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct Hg allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of Hg allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any Hg allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any Hg allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to §§60.4160 through 60.4162, in the order of recordation.

(d) *Deductions for excess emissions.* (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the Hg Budget source has excess emissions, the Administrator will deduct from the source's compliance account an amount of Hg allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of ounces of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the Hg Budget source or the Hg Budget units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance

account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.* (1) The Administrator may review and conduct independent audits concerning any submission under the Hg Budget Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct Hg allowances from or transfer Hg allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

#### **§ 60.4155 Banking.**

(a) Hg allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any Hg allowance that is held in a compliance account or a general account will remain in such account unless and until the Hg allowance is deducted or transferred under §60.4154, §60.4156, or §§60.4160 through 60.4162.

#### **§ 60.4156 Account error.**

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Hg Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the Hg authorized account representative for the account.

#### **§ 60.4157 Closing of general accounts.**

(a) The Hg authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under §60.4160 through 60.4162 for any Hg allowances in the account to one or more other Hg Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any Hg allowances, the Administrator may notify the Hg authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of Hg allowances into the account under §60.4160 through 60.4162 or a statement submitted by the Hg authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

### **Hg Allowance Transfers**

#### **§ 60.4160 Submission of Hg allowance transfers.**

An Hg authorized account representative seeking recordation of a Hg allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the Hg allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each Hg allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the Hg authorized account representative of the transferor account and the date signed.

**§ 60.4161 EPA recordation.**

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a Hg allowance transfer, the Administrator will record a Hg allowance transfer by moving each Hg allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under §60.4160; and

(2) The transferor account includes each Hg allowance identified by serial number in the transfer.

(b) A Hg allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any Hg allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under §60.4154 for the control period immediately before such allowance transfer deadline.

(c) Where a Hg allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

**§ 60.4162 Notification.**

(a) *Notification of recordation.* Within 5 business days of recordation of a Hg allowance transfer under §60.4161, the Administrator will notify the Hg authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a Hg allowance transfer that fails to meet the requirements of §60.4161(a), the Administrator will notify the Hg authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a Hg allowance transfer for recordation following notification of non-recordation.

**Monitoring and Reporting**

**§ 60.4170 General requirements.**

The owners and operators, and to the extent applicable, the Hg designated representative, of a Hg Budget unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter. For purposes of complying with such requirements, the definitions in §60.4102 and in §72.2 of this

chapter shall apply, and the terms “affected unit,” “designated representative,” and “continuous emission monitoring system” (or “CEMS”) in part 75 of this chapter shall be deemed to refer to the terms “Hg Budget unit,” “Hg designated representative,” and “continuous emission monitoring system” (or “CEMS”) respectively, as defined in §60.4102. The owner or operator of a unit that is not a Hg Budget unit but that is monitored under §75.82(b)(2)(i) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a Hg Budget unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each Hg Budget unit shall:

(1) Install all monitoring systems required under this section and §§60.4171 through 60.4176 for monitoring Hg mass emissions and individual unit heat input (including all systems required to monitor Hg concentration, stack gas moisture content, stack gas flow rate, and CO<sub>2</sub> or O<sub>2</sub> concentration, as applicable, in accordance with §§75.81 and 75.82 of this chapter);

(2) Successfully complete all certification tests required under §60.4171 and meet all other requirements of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a Hg Budget unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a Hg Budget unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a Hg Budget unit for which construction of a new stack or flue or installation of add-on Hg emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system is completed after the applicable deadline under paragraph (b)(1) or (2) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue, add-on Hg emissions controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system.

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a Hg Budget unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for Hg concentration, stack gas flow rate, stack gas moisture content, and any other parameters required to determine Hg mass emissions and heat

input in accordance with §75.80(g) of this chapter.

(2) The owner or operator of a Hg Budget unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D of part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) *Prohibitions.* (1) No owner or operator of a Hg Budget unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this section and §§60.4171 through 60.4176 without having obtained prior written approval in accordance with §60.4175.

(2) No owner or operator of a Hg Budget unit shall operate the unit so as to discharge, or allow to be discharged, Hg emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter.

(3) No owner or operator of a Hg Budget unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording Hg mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter.

(4) No owner or operator of a Hg Budget unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under §60.4105 that is in effect;

(ii) The owner or operator is monitoring emissions from the unit with another certified monitoring system approved, in accordance with the applicable provisions of this section, §§60.4171 through 60.4176, and subpart I of part 75 of this chapter, by the permitting authority for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

(iii) The Hg designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with §60.4171(c)(3)(i).

#### **§ 60.4171 Initial certification and recertification procedures.**

(a) The owner or operator of a Hg Budget unit shall be exempt from the initial certification requirements of this section for a monitoring system under §60.4170(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of §75.21 of this chapter and appendix B to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under §60.4170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) Except as provided in paragraph (a) of this section, the owner or operator of a Hg Budget unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (e.g., a continuous emission monitoring system and an excepted monitoring system (sorbet trap monitoring system) under §75.15) under §60.4170(a)(1). The owner or operator of a unit that qualifies to use the Hg low mass emissions excepted monitoring methodology under §75.81(b) of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (d) or (e) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each monitoring system under §60.4170(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under §75.20 of this chapter by the applicable deadline in §60.4170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with §75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system, or an excepted monitoring system (sorbet trap monitoring system) under §75.15, under §60.4170(a)(1) that may significantly affect the ability of the system to accurately measure or record Hg mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of §75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with §75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system, and each excepted monitoring system (sorbet trap monitoring system) under §75.15, whose accuracy is potentially affected by the change, in accordance with §75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site.

(3) *Approval process for initial certification and recertification.* Paragraphs (c)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under §60.4170(a)(1). For recertifications, apply the word "recertification" instead of the words "certification" and "initial certification" and apply the word "recertified" instead of the word "certified," and follow the procedures in §75.20(b)(5) of this chapter in lieu of the procedures in paragraph (c)(3)(v) of this section.

(i) *Notification of certification.* The Hg designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with §60.4173.

(ii) *Certification application.* The Hg designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application

shall include the information specified in §75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with §75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the Hg Budget Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (c)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) *Certification application approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (c)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the Hg Budget Trading Program.

(A) *Approval notice.* If the certification application is complete and shows that each monitoring system meets the applicable performance requirements of part 75 of this chapter, then the permitting authority will issue a written notice of approval of the certification application within 120 days of receipt.

(B) *Incomplete application notice.* If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the Hg designated representative must submit the additional information required to complete the certification application. If the Hg designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (c)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (c)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under §75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (c)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority may issue a notice of disapproval of the certification status of a monitor in accordance with §60.4172(b).

(v) *Procedures for loss of certification.* If the permitting authority issues a notice of disapproval of a certification application under paragraph (c)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (c)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring

system, for each hour of unit operation during the period of invalid data specified under §75.20(a)(4)(iii), or §75.21(e) of this chapter and continuing until the applicable date and hour specified under §75.20(a)(5)(i) of this chapter:

(1) For a disapproved Hg pollutant concentration monitors and disapproved flow monitor, respectively, the maximum potential concentration of Hg and the maximum potential flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to part 75 of this chapter; and

(2) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO<sub>2</sub> concentration or the minimum potential O<sub>2</sub> concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(3) For a disapproved excepted monitoring system (sorbent trap monitoring system) under §75.15 and disapproved flow monitor, respectively, the maximum potential concentration of Hg and maximum potential flow rate, as defined in sections 2.1.7.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(B) The Hg designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (c)(3)(i) and (ii) of this section.

(C) The owner or operator shall repeat all certification tests or other requirements that were failed by the monitoring system, as indicated in the permitting authority's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(d) *Initial certification and recertification procedures for units using the Hg low mass emission excepted methodology under §75.81(b) of this chapter.* The owner or operator of a unit qualified to use the Hg low mass emissions (HgLME) excepted methodology under §75.81(b) of this chapter shall meet the applicable certification and recertification requirements in §75.81(c) through (f) of this chapter.

(e) *Certification/recertification procedures for alternative monitoring systems.* The Hg designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of §75.20(f) of this chapter.

#### **§ 60.4172 Out of control periods.**

(a) Whenever any monitoring system fails to meet the quality-assurance and quality-control requirements or data validation requirements of part 75 of this chapter, data shall be substituted using the applicable missing data procedures in subpart D of part 75 of this chapter.

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under §60.4171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority revokes prospectively the certification status of the

monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in §60.4171 for each disapproved monitoring system.

#### **§ 60.4173 Notifications.**

The Hg designated representative for a Hg Budget unit shall submit written notice to the permitting authority and the Administrator in accordance with §75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

#### **§ 60.4174 Recordkeeping and reporting.**

(a) *General provisions.* (1) The Hg designated representative shall comply with all recordkeeping and reporting requirements in this section and the requirements of §60.4110(e)(1).

(2) If a Hg Budget unit is subject to an Acid Rain emission limitation or the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, or CAIR NO<sub>x</sub> Ozone Season Trading Program, and the Hg designated representative who signed and certified any submission that is made under subpart F or G of part 75 of this chapter and that includes data and information required under this section, §§60.4170 through 60.4173, §60.4175, §60.4176, or subpart I of part 75 of this chapter is not the same person as the designated representative or alternative designated representative, or the CAIR designated representative or alternate CAIR designated representative, for the unit under part 72 of this chapter and the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, or CAIR NO<sub>x</sub> Ozone Season Trading Program, then the submission must also be signed by the designated representative or alternative designated representative, or the CAIR designated representative or alternate CAIR designated representative, as applicable.

(b) *Monitoring plans.* The owner or operator of a Hg Budget unit shall comply with requirements of §75.84(e) of this chapter.

(c) *Certification applications.* The Hg designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under §60.4171, including the information required under §75.63 of this chapter.

(d) *Quarterly reports.* The Hg designated representative shall submit quarterly reports, as follows:

(1) The Hg designated representative shall report the Hg mass emissions data and heat input data for the Hg Budget unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under §60.4170(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31,

2009.

(2) The Hg designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in §75.84(f) of this chapter.

(3) For Hg Budget units that are also subject to an Acid Rain emissions limitation or the CAIR NO<sub>x</sub> Annual Trading Program, CAIR SO<sub>2</sub> Trading Program, or CAIR NO<sub>x</sub> Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the Hg mass emission data, heat input data, and other information required by this section, §§60.4170 through 60.4173, §60.4175, and §60.4176.

(e) *Compliance certification.* The Hg designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this section, §§60.4170 through 60.4173, §60.4175, §60.4176, and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on Hg emission controls, a flue gas desulfurization system, a selective catalytic reduction system, or a compact hybrid particulate collector system and for all hours where Hg data are substituted in accordance with §75.34(a)(1) of this chapter, the Hg add-on emission controls, flue gas desulfurization system, selective catalytic reduction system, or compact hybrid particulate collector system were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter, or quality-assured SO<sub>2</sub> emission data recorded in accordance with part 75 of this chapter document that the flue gas desulfurization system, or quality-assured NO<sub>x</sub> emission data recorded in accordance with part 75 of this chapter document that the selective catalytic reduction system, was operating properly, as applicable, and the substitute data values do not systematically underestimate Hg emissions.

#### **§ 60.4175 Petitions.**

The Hg designated representative of a Hg unit may submit a petition under §75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of §§60.4170 through 60.4174 and §60.4176. Application of an alternative to any requirement of §§60.4170 through 60.4174 and §60.4176 is in accordance with this section and §§60.4170 through 60.4174 and §60.4176 only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

#### **§ 60.4176 Additional requirements to provide heat input data.**

The owner or operator of a Hg Budget unit that monitors and reports Hg mass emissions using a Hg concentration monitoring system and a flow monitoring system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

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Last updated: August 7, 2006

*DRAFT*

*August 17, 2006*

1 **R307. Environmental Quality, Air Quality.**  
2 **R307-210. Stationary Sources.**  
3 **R307-210-1. Standards of Performance for New Stationary Sources**  
4 **(NSPS).**

5 The provisions of 40 Code of Federal Regulations (CFR) Part  
6 60, effective on July 1, [~~2005~~]2006, except for Subparts Cb, Cc,  
7 Cd, Ce, BBBB, [~~and~~]DDDD,and HHHH, are incorporated by reference  
8 into these rules with the exception that references in 40 CFR to  
9 "Administrator" shall mean "executive secretary" unless by  
10 federal law the authority referenced is specific to the  
11 Administrator and cannot be delegated.

12  
13 **KEY: air pollution, stationary sources, new source review**  
14 **[~~June 15, 2006~~]2007**  
15 **Notice of Continuation: June 16, 2006**  
16 **19-2-104(3)(q)**  
17 **19-2-108**

18  
19

1 R307. Environmental Quality, Air Quality.  
 2 R307-220. Emission Standards: Plan for Designated Facilities.  
 3 R307-220. Incorporation by Reference.

4 ~~[(1)]~~Pursuant to 42 U.S.C. 7411(d), the Federal Clean Air  
 5 Act Section 111(d), the following sections hereby incorporate by  
 6 reference the Utah plan for designated facilities. Copies of the  
 7 plan are available at the Division of Air Quality and the  
 8 Division of Administrative Rules.]

9 ~~———— (2) Definitions. The definitions in The following  
 10 additional definitions apply to R307-220:~~

11 ~~———— "Designated Facility" means any existing source which emits  
 12 a designated pollutant and which would be subject to a standard  
 13 of performance for a new source if construction of the designated  
 14 facility had begun after the effective date of the standard of  
 15 performance issued under 40 CFR Part 60.~~

16 ~~———— "Designated Pollutant" means any air contaminant, the  
 17 emission of which:~~

18 ~~———— (a) is subject to a standard of performance for a new  
 19 source; and~~

20 ~~———— (b) is not subject to a National Ambient Air Quality  
 21 Standard; and~~

22 ~~———— c) is not a hazardous air pollutant as defined in R307-101-  
 23 2.]~~

24  
 25 R307-220-2. Section I, Municipal Solid Waste Landfills.

26 ...

27 R307-220-3. Section II, Hospital, Medical;, Infectious Waste  
 28 Incinerators.

29 ...

30 R307-220-4. Section III, Small Municipal Waste Combustion Units.

31 ...

32 R307-220-5. Section IV, Coal-Fired Electric Generating Units.

33 Section IV, Coal-Fired Electric Generating Units, as most  
 34 recently adopted by the Air Quality Board on February 7, 2007,  
 35 pursuant to Section 19-2-104, is hereby incorporated by reference  
 36 and made a part of these rules.

37  
 38 **KEY: air pollution, landfills, [~~environmental protection,~~**  
 39 **incinerators, electric generating units**

40 **Date of Enactment or Last Substantive Amendment: [~~October 3,~~**  
 41 **2002]2007**

42 **Notice of Continuation: March 26, 2002**

43 **Authorizing, Implemented, or Interpreted Law: 19-2-104(3)(g)**  
 44  
 45

1 R307. Environmental Quality, Air Quality.

2 R307-224. Mercury Emission Standards: Coal-Fired Electric  
3 Generating Units.

4 R307-224-1. Purpose and Applicability.

5 (1) Nationwide reductions of mercury (Hg) emissions from  
6 certain coal-fired electric generating units are required by 40  
7 CFR Part 60, subparts B and HHHH, in effect on June 9, 2006, and  
8 incorporated by reference in R307-210, and by the Designated  
9 Facilities Plan for coal-fired electric generating units,  
10 incorporated by reference at R307-220-5.

11 (2) R307-224 regulates mercury emissions from any coal-  
12 fired electric generating unit as defined in 40 CFR 60.24.

13  
14 R307-224-2. Emission Guidelines and Compliance Times for Coal-  
15 Fired Electric Generating Units.

16 (1) The following sections of 40 CFR Part 60, subpart HHHH  
17 effective on June 9, 2006, are adopted and incorporated by  
18 reference into these rules:

19 (a) Sections 60.4101 through 60.4124;

20 (b) Sections 60.4142 paragraph (c)(2) through paragraph  
21 (c)(4);

22 (c) Sections 60.4150 through 60.4176.

23  
24 KEY: air pollution, electric generating unit, mercury

25 Date of Enactment or Last Substantive Amendment: 2007

26 Authorizing, Implemented, or Interpreted Law: 19-2-104(3)(q); 40  
27 CFR Part 60, Subparts Da and HHHH

28  
29

1 R307. Environmental Quality, Air Quality.

2 R307-424. Permits: Mercury Requirements for Electric Generating  
3 Units.

4 R307-424-1. Purpose and Applicability.

5 The purpose of R307-424 is to regulate mercury emissions  
6 from any coal-fired electric generating unit (EGU). R307-424  
7 applies to any coal-fired electric generating unit as defined in  
8 40 CFR 60.24.

9  
10 R307-424-2. Part 70 Permit.

11 Sources meeting the applicability requirements of R307-424-  
12 1 above, and also meeting the applicability requirements of R307-  
13 415-4, are required to obtain a mercury (Hg) budget permit in  
14 accordance with R307-224-2(1)(a).

15  
16 R307-424-3. Offset Requirement: Mercury.

17 Sources meeting the applicability requirements of R307-424-  
18 1 above and making application for an approval order under R307-  
19 401 shall, in addition to any other requirement for obtaining  
20 such approval order, obtain an enforceable offset for any  
21 potential increase in mercury emissions in accordance with the  
22 following:

23 (1) The permitted increase in mercury emissions,  
24 considering the application of any control method or  
25 device, shall be offset by mercury emission credits at a  
26 ratio of 1 to 1.1 respectively.

27 (2) The averaging period for such determinations shall  
28 be a 12-month period.

29 (3) Mercury emission credits must be obtained from an  
30 EGU located within the State of Utah, including any EGU  
31 located on Indian lands within the State.

32 (4) To preserve reductions in mercury emissions as  
33 credits for use in offsetting potential increases, the  
34 executive secretary must identify such credits in an order  
35 issued pursuant to R307- 401 and shall provide a registry  
36 to identify the person, private entity or governmental  
37 authority that has the right to use or allocate the banked  
38 emission reduction credits, and to record any transfers of,  
39 or liens on, these rights.

40 (5) Any emission offsets shall be enforceable by the  
41 time a new or modified source commences construction, and,  
42 by the time a new or modified source commences operation,  
43 any emission offsets shall be in effect and enforceable.

44 (6) The quantity of mercury emission reductions to be  
45 used for credit will be determined in accordance with 40  
46 CFR part 75, or will be based on the best available data  
47 reported to the executive secretary. To the extent that  
48 the EGU has been subject to the requirements of part 75,

1 mercury emissions data shall be the average of the 3  
2 highest annual amounts over the most recent 5-year period.

3 (7) R307-424-3 shall not apply to any EGU for which a  
4 valid approval order was issued prior to November 17, 2006.

5  
6 **R307-424-4. Emission Rates.**

7 (1) By no later than December 31, 2012, the owner or  
8 operator of any EGU with an input heat capacity in excess of  
9 1,500 MMbtu per hour and having commenced operations prior to  
10 November 17, 2006, shall demonstrate compliance with at least one  
11 of the following:

12 (a) A maximum emission rate of  $6.50 \times 10^{-7}$  pounds mercury  
13 per million btu heat input; or

14 (b) A minimum of 90% control of total mercury emissions.

15 (2) Compliance with (1) above shall be based on an annual  
16 averaging period beginning January 1 and ending December 31.

17 (a) Beginning January 1, 2013, compliance shall be  
18 determined using the monitoring and recordkeeping requirements  
19 incorporated under R307-224-2. Upon completion of each year's  
20 fourth quarterly report, an assessment shall be made for the  
21 entire calendar year and reported to the executive secretary  
22 within 30 days.

23 (b) Where it is necessary to determine the mercury content  
24 of the coal or coals burned, the owner or operator shall use the  
25 appropriate ASTM method, and shall measure at least one  
26 representative sample each month. Records of such testing shall  
27 be kept for a period of at least five years, and shall be made  
28 available to the executive secretary upon request.

29 (3) Should an EGU be found in noncompliance with (1) above,  
30 despite properly operating the unit in conjunction with a  
31 baghouse as well as wet or dry flue gas de-sulfurization, the  
32 owner or operator may petition the executive secretary for a  
33 modification to the limits therein in accordance with R307-401.

34  
35 **KEY: air quality, mercury, offset, permitting authority**

36 **Date of Enactment or Last Substantive Amendment: 2007**

37 **Authorizing, Implemented, or Interpreted Law: 19-2-101, 19-2-**  
38 **104(3)(q), 40 CFR 60.24**

39  
40



State of Utah

Department of  
Environmental Quality

Dianne R. Nielson, Ph.D.  
*Executive Director*

DIVISION OF AIR QUALITY  
Richard W. Sprott  
*Director*

JON M. HUNTSMAN, JR.  
*Governor*

GARY HERBERT  
*Lieutenant Governor*

DAQ-069-06

**MEMORANDUM**

TO: Air Quality Board

THROUGH: Richard W. Sprott, Executive Secretary

FROM: Jan Miller, Environmental Planning Consultant

DATE: October 11, 2006

SUBJECT: Propose for Public Comment: New State Implementation Plan Section XXII, *Interstate Transport*, and R307-110-36.

---

When a new National Ambient Air Quality Standard (NAAQS) is promulgated, the Clean Air Act requires states to submit a State Implementation Plan (SIP) under section 110(a)(2)(D)(i) to address interstate transport of emissions that would affect nonattainment and maintenance areas in neighboring states.

The NAAQS for PM<sub>2.5</sub> and 8-hour ozone were promulgated in 1997, and EPA was sued for failure to require 110(a)(2)(D) SIPs to address those standards. EPA is now under a consent decree to issue a Federal Implementation Plan (FIP) for any state whose SIP is not submitted to EPA and approved by May 25, 2007.

EPA issued guidance to states on August 15, 2006, with supplemental information supplied on September 11. EPA asks that states submit their SIPs to EPA by November 25, 2006, in order that EPA has time to review and approve them before the deadline.

Note that this SIP is different from visibility and regional haze SIPs. This SIP is focused on demonstrating that Utah's regulation of air quality does not interfere with other states' regulation of their nonattainment and maintenance areas for 8-hour ozone or PM<sub>2.5</sub>, or with their implementation of the prevention of significant deterioration (PSD) or visibility programs. By contrast, SIPs for visibility and regional haze are required to protect visibility in federally-designated Class I areas in Utah and other states. EPA Region 8, including their Regional Counsel's office, has reviewed a draft of this SIP. Their recommendations are included in this draft.

Staff recommendation: Staff recommends that the attached drafts of R307-110-36 and SIP Section XXII, *Interstate Transport*, be proposed for public comment.

*DRAFT*

*October 13, 2006*

**UTAH STATE IMPLEMENTATION PLAN**

**SECTION XXII**

**INTERSTATE TRANSPORT**

**TO SATISFY THE REQUIREMENTS OF CLEAN AIR ACT  
110(a)(2)(D)(i)  
FOR THE 8-HOUR OZONE AND PM2.5 NAAQS  
PROMULGATED IN JULY 1997**

Adopted by the Utah Air Quality Board  
February 7, 2007

# UTAH STATE IMPLEMENTATION PLAN

## SECTION XXII

### A. Introduction

The Clean Air Act, §110(a)(2)(D)(i), requires that each state implementation plan (SIP) submitted to EPA must address emissions that affect other states through interstate transport. In addition, states must ensure that no SIP interferes with another state's program to prevent significant deterioration of its air quality, or interferes with visibility in another state. Until August 2006, there had been no EPA guidance as to the appropriate scope of such a SIP.

On April 25, 2005, in response to a lawsuit, EPA published (70 FR 21147) a finding that states had failed to submit SIPs meeting the requirements of 110(a)(2)(D)(i) within three years after EPA issued new National Ambient Air Quality Standards (NAAQS) for ozone and PM<sub>2.5</sub> in 1997. The finding requires that EPA issue a Federal Implementation Plan (FIP) for any state that does not submit a SIP and obtain EPA approval of it by May 25, 2007.

On August 15, 2006, EPA issued final guidance to states for preparation of SIPs that satisfy the 110(a)(2)(D)(i) requirements, and, on September 11, 2006, added a supplement to the guidance.

There are four components of 110(a)(2)(D)(i) that must be addressed. The first two, demonstrating adequate provisions to prevent emission from Utah from interfering with attainment or maintenance of the federal NAAQS in any other state, are discussed together in Part B below. The requirement that Utah show no interference with another state's program to prevent significant deterioration of its air quality is found in Part C below, and discussion of Utah's influence on visibility is found in Part D below.

### B. Nonattainment and Maintenance Area Impact

The "good neighbor" provisions of §110(a)(2)(D)(i) require that state SIPs prohibit

*any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will--*

*(1) contribute significantly to nonattainment in, or interference with maintenance by, any other state with respect to any such national primary or secondary ambient air quality standard...*

To demonstrate that emissions from Utah do not contribute to nonattainment or interfere with maintenance of the ozone or PM<sub>2.5</sub> standards issued in 1997, Utah relies on the modeling work conducted by EPA to determine which states should be included in the Clean Air Interstate Rule (CAIR). CAIR was proposed on January 30, 2004 at 69 FR 4566. In its CAIR proposal, EPA stated:

1        *In analyzing significant contribution to nonattainment, we determined it was reasonable*  
2        *to exclude the Western U.S., including the States of Washington, Idaho, Oregon,*  
3        *California, Nevada, Utah and Arizona from further analysis due to geography,*  
4        *meteorology, and topography. Based on these factors, we concluded that the PM 2.5 and*  
5        *8-hour ozone nonattainment problems are not likely to be affected significantly by*  
6        *pollution transported across these States' boundaries. Therefore, for the purpose of*  
7        *assessing State's contributions to nonattainment in other States, we have only analyzed*  
8        *the nonattainment counties located in the rest of the U.S.*<sup>1</sup>  
9

10       In addition, EPA addressed the modeling methodology and its determination that western states did not  
11       contribute to nonattainment or maintenance of the PM2.5 standard in other states:  
12

13       *Regarding modeling of all States, in the PM2.5 modeling for the NPRM, we modeled 41*  
14       *States, and found that the westernmost of these States made very small contributions to*  
15       *nonattainment in any other State.*<sup>2</sup> *For the revised modeling for the final rule, we*  
16       *reduced the set of States modeled [to 37 for PM] for reasons of efficiency.*<sup>3</sup> *The results*  
17       *again showed that the westernmost States modeled did not make contributions above the*  
18       *significance threshold, indicating that had other even more western States been modeled*  
19       *they also would not have done so.*<sup>4</sup>  
20

21       Based on the conclusions stated by the EPA in the above-cited guidance, the State of Utah agrees that  
22       emissions from Utah do not significantly affect nonattainment or maintenance areas in other states.  
23

## 24       **C.    Impact on PSD**

25       In § 110(a)(2)(D)(i)(II), the Clean Air Act requires that states prohibit emissions within the state from  
26       interfering "with measures required to be included in the applicable implementation plan for any other  
27       State under part C to prevent significant deterioration of air quality..."  
28

29       EPA guidance indicates that states with SIPs addressing Prevention of Significant Deterioration (PSD)  
30       and Nonattainment New Source Review (NNSR) have adequately demonstrated that they do not affect  
31       PSD implementation in other states:  
32

33       *For the 8-hour ozone standard, each State only needs to make a SIP submission that*  
34       *confirms that major sources in the State are currently subject to PSD and NNSR*  
35       *permitting programs that apply to the 8-hour ozone standard and that SIP-approved*  
36       *States are on track to meet the June 15, 2007 deadline for SIP submissions adopting the*  
37       *requirements of the Phase II ozone implementation rule.*

---

<sup>1</sup> *Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule Preamble,*  
69 FR at 4581, January 30, 2004, first full paragraph, middle column.

<sup>2</sup> The 9 westernmost states that were NOT modeled for the NPRM are Idaho, Washington, Oregon, Nevada, California, Utah, Nevada, Alaska, and Hawaii.

<sup>3</sup> The additional 4 states NOT modeled for the final rule are Montana, Wyoming, Colorado, and New Mexico.

<sup>4</sup> *Corrected Response To Significant Public Comments On the Proposed Clean Air Interstate Rule,* March 2005, Corrected April 2005, Document ID No. EPA-HQ-2003-0053-2172, pages 200-201.

1  
 2 *For the PM-2.5 standard, States need only provide a SIP submission that confirms that*  
 3 *major sources in the State are subject to PSD and NNSR permitting programs*  
 4 *implemented in accordance with EPA’s interim guidance calling for use of PM-10 as a*  
 5 *surrogate for PM-2.5 in the PSD and NNSR programs.*<sup>5</sup>  
 6

7 Utah has a fully-approved PSD and NNSR program, and has successfully implemented these programs  
 8 for many years. Utah's PSD SIP was revised effective June 16, 2006, to conform with the federal NSR  
 9 Reform rules. These changes have been submitted to EPA but are not yet approved. Until they are, the  
 10 previously-approved versions are federally enforceable. Utah will update the NNSR program when  
 11 EPA's PM<sub>2.5</sub> implementation guidance is finalized. Utah will implement the current rules in accordance  
 12 with EPA's interim guidance using PM<sub>10</sub> as a surrogate for PM<sub>2.5</sub> in the PSD and NNSR programs.  
 13

14 Based on the conclusions stated by the EPA in the above-cited guidance, the State of Utah concludes that  
 15 Utah's PSD SIP and NNSR rules ensure that Utah does not interfere with PSD implementation in other  
 16 states.  
 17

18 **D. Effects on Visibility**

19 The final requirement of § 110(a)(2)(D)(i)(II) is that states prohibit emissions within the state from  
 20 interfering with the programs of other states to protect visibility. In 1980, EPA issued regulations that  
 21 required states to address reasonably attributable visibility impairment (RAVI). EPA's guidance states  
 22 that:  
 23

24 *At this point in time, EPA has made no determination that emissions from any State*  
 25 *interfere with measures required to be included in a plan to address reasonably*  
 26 *attributable visibility impairment. Further, EPA is not aware of any certification of*  
 27 *existing reasonably attributable impairment of visibility by a Federal Land manager that*  
 28 *has not already been resolved. The EPA accordingly believes that States should be able*  
 29 *to make a relatively simple SIP submission verifying that no source within the State emits*  
 30 *pollutants that interfere with measures included in the visibility SIPs under the 1980*  
 31 *regulations.*<sup>6</sup>  
 32

33 Based on the conclusions stated by the EPA in the above-cited guidance, the State of Utah concludes that  
 34 there are no Utah sources of emissions that interfere with implementation of RAVI SIPs in other states.  
 35

36 Because states are not required to submit SIPs until December 2007, the transported pollution that affects  
 37 visibility in federally protected areas, EPA's guidance states that:  
 38

39 *EPA believes that it is currently premature to determine whether or not State SIPs for 8-*  
 40 *hour ozone or PM<sub>2.5</sub> contain adequate provisions to prohibit emissions that interfere*

---

<sup>5</sup> SIP Guidance on Section 110(a)(2)(D)(i) Findings of Failure to Submit, August 11, 2006, page 2.

<sup>6</sup> Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and PM<sub>2.5</sub> National Ambient Air Quality Standards, EPA, August 15, 2006, page 9.

1           with measures in other States' SIPs designed to address regional haze. Accordingly, EPA  
2           believes that States may make a simple SIP submission confirming that it is not possible  
3           at this time to assess whether there is any interference with measures in the applicable  
4           SIP for another State designed to "protect visibility" for the 8-hour ozone and PM2.5  
5           NAAQS until regional haze SIPs are submitted and approved.<sup>7</sup>  
6

7           Because Utah submitted its first Regional Haze SIP to EPA in December 2003 under 40 CFR 51.309,  
8           Utah has already demonstrated reasonable progress in reducing impacts on Class I areas on the Colorado  
9           Plateau. The 2007 SIP update will analyze any impacts from Utah that extend beyond the Colorado  
10          Plateau and determine appropriate long-term strategies for control measures.  
11

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<sup>7</sup> *Guidance for State Implementation plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and PM2.5 National Ambient Air Quality Standards*, August 15, 2006. Pages 9-10.

1 R307. Environmental Quality, Air Quality.  
2 R307-110. General Requirements: State Implementation Plan.  
3 R307-110-36. Section XXII, Interstate Transport.  
4 The Utah State Implementation Plan, Section XXII, Interstate  
5 Transport, as most recently adopted by the Utah Air Quality Board  
6 on February 7, 2007, pursuant to Section 19-2-104, is hereby  
7 incorporated by reference and made a part of these rules.  
8  
9 KEY: air pollution, PM10, PM2.5, ozone  
10 [~~December 6, 2006~~]2007 19-2-104(3)(e)  
11 Notice of Continuation September 8, 2005  
12  
13



State of Utah

Department of  
Environmental Quality

Dianne R. Nielson, Ph.D.  
*Executive Director*

DIVISION OF AIR QUALITY  
Richard W. Sprott  
*Director*

JON M. HUNTSMAN, JR.  
*Governor*

GARY HERBERT  
*Lieutenant Governor*

DAQ-071-06

### MEMORANDUM

**TO:** Air Quality Board

**THROUGH:** Richard Sprott, Executive Secretary

**FROM:** Eileen Brennan, MACT Coordinator

**DATE:** September 19, 2006

**SUBJECT:** Propose for Public Comment: R307-214-2, Incorporate by Reference Updates to Various Subparts of 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAPS), MACT Standards.

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The National Emission Standards for Hazardous Air Pollutants (NESHAPS) are federal rules that regulate hazardous air pollutants (HAPs) and implement Section 112 of the Clean Air Act (CAA). These standards are also commonly referred to as Maximum Achievable Control Technology (MACT) standards, and are located in 40 CFR Part 63.

The 1990 CAA amendments required the EPA to list source categories to be regulated by MACT standards and a schedule for promulgation of the standards. These source categories and schedules have been published, and 101 MACT standards have been promulgated. Under R307-214-2, the Division has adopted 94 of the MACTs in 40 CFR 63, and has chosen not to adopt seven of the MACTs

The Division committed to adopting, implementing, and enforcing all applicable MACT standards in the Operating Permit Program submittal to EPA in April 1994. The Division demonstrated the resources necessary to carry out this commitment, and EPA approved the Operating Permit Program in part based upon this demonstration. As EPA promulgates new standards, the Division proposes the adoption of those standards that are potentially applicable to Utah sources.

By updating our rule, the State will ensure the enforcement of the most current versions of the MACTs, and will maintain primacy over administration of these standards on Utah sources. This will be consistent with the historical approach taken by the Department of Environmental Quality, and will simplify procedures required of sources.

DAQ-071-06

Page 2

Staff recommendation: Staff recommends the MACT rule be proposed for public comment. The proposed text for the modification to R307-214-2 is attached for your review.

**R307. Environmental Quality, Air Quality.****R307-214. National Emission Standards for Hazardous Air Pollutants.****R307-214-2. Part 63 Sources.**

The provisions listed below of 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories, effective as of July 1, [2005]2006, or later for those whose subsequent publication citation is included below, are incorporated into these rules by reference. References in 40 CFR Part 63 to "the Administrator" shall refer to the executive secretary, unless by federal law the authority is specific to the Administrator and cannot be delegated.

(1) 40 CFR Part 63, Subpart A, General Provisions.

(2) 40 CFR Part 63, Subpart B, Requirements for Control Technology Determinations for Major Sources in Accordance with 42 U.S.C. 7412(g) and (j).

(3) 40 CFR Part 63, Subpart F, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry.

(4) 40 CFR Part 63, Subpart G, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater.

(5) 40 CFR Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks.

(6) 40 CFR Part 63, Subpart I, National Emission Standards for Organic Hazardous Air Pollutants for Certain Processes Subject to the Negotiated Regulation for Equipment Leaks.

(7) 40 CFR Part 63, Subpart J, National Emission Standards for Polyvinyl Chloride and Copolymers Production.

(8) 40 CFR Part 63, Subpart L, National Emission Standards for Coke Oven Batteries.

(9) 40 CFR Part 63, Subpart M, National Perchloroethylene Air Emission Standards for Dry Cleaning Facilities.

(10) 40 CFR Part 63, Subpart N, National Emission Standards for Chromium Emissions From Hard and Decorative Chromium Electroplating and Chromium Anodizing Tanks.

(11) 40 CFR Part 63, Subpart O, National Emission Standards for Hazardous Air Pollutants for Ethylene Oxide Commercial Sterilization and Fumigation Operations.

(12) 40 CFR Part 63, Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers.

(13) 40 CFR Part 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).

(14) 40 CFR Part 63, Subpart T, National Emission Standards for Halogenated Solvent Cleaning.

(15) 40 CFR Part 63, Subpart U, National Emission Standards for Hazardous Air Pollutant Emissions: Group I Polymers and Resins.

(16) 40 CFR Part 63, Subpart AA, National Emission Standards

1 for Hazardous Air Pollutants for Phosphoric Acid Manufacturing.  
2 (17) 40 CFR Part 63, Subpart BB, National Emission Standards  
3 for Hazardous Air Pollutants for Phosphate Fertilizer Production.  
4 (18) 40 CFR Part 63, Subpart CC, National Emission Standards  
5 for Hazardous Air Pollutants from Petroleum Refineries.  
6 (19) 40 CFR Part 63, Subpart DD, National Emission Standards  
7 for Hazardous Air Pollutants from Off-Site Waste and Recovery  
8 Operations.  
9 (20) 40 CFR Part 63, Subpart EE, National Emission Standards  
10 for Magnetic Tape Manufacturing Operations.  
11 (21) 40 CFR Part 63, Subpart GG, National Emission Standards  
12 for Aerospace Manufacturing and Rework Facilities.  
13 (22) 40 CFR Part 63, Subpart HH, National Emission Standards  
14 for Hazardous Air Pollutants for Oil and Natural Gas Production.  
15 (23) 40 CFR Part 63, Subpart JJ, National Emission Standards  
16 for Wood Furniture Manufacturing Operations.  
17 (24) 40 CFR Part 63, Subpart KK, National Emission Standards  
18 for the Printing and Publishing Industry.  
19 (25) 40 CFR Part 63, Subpart MM, National Emission Standards  
20 for Hazardous Air Pollutants for Chemical Recovery Combustion  
21 Sources at Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp  
22 Mills.  
23 (26) 40 CFR Part 63, Subpart OO, National Emission Standards  
24 for Tanks - Level 1.  
25 (27) 40 CFR Part 63, Subpart PP, National Emission Standards  
26 for Containers.  
27 (28) 40 CFR Part 63, Subpart QQ, National Emission Standards  
28 for Surface Impoundments.  
29 (29) 40 CFR Part 63, Subpart RR, National Emission Standards  
30 for Individual Drain Systems.  
31 (30) 40 CFR Part 63, Subpart SS, National Emission Standards  
32 for Closed Vent Systems, Control Devices, Recovery Devices and  
33 Routing to a Fuel Gas System or a Process (Generic MACT).  
34 (31) 40 CFR Part 63, Subpart TT, National Emission Standards  
35 for Equipment Leaks- Control Level 1 (Generic MACT).  
36 (32) 40 CFR Part 63, Subpart UU, National Emission Standards  
37 for Equipment Leaks-Control Level 2 Standards (Generic MACT).  
38 (33) 40 CFR Part 63, Subpart VV, National Emission Standards  
39 for Oil-Water Separators and Organic-Water Separators.  
40 (34) 40 CFR Part 63, Subpart WW, National Emission Standards  
41 for Storage Vessels (Tanks)-Control Level 2 (Generic MACT).  
42 (35) 40 CFR Part 63, Subpart XX, National Emission Standards  
43 for Ethylene Manufacturing Process Units: Heat Exchange Systems  
44 and Waste Operations.  
45 (36) 40 CFR Part 63, Subpart YY, National Emission Standards  
46 for Hazardous Air Pollutants for Source Categories: Generic MACT.  
47 (37) 40 CFR Part 63, Subpart CCC, National Emission  
48 Standards for Hazardous Air Pollutants for Steel Pickling-HCl  
49 Process Facilities and Hydrochloric Acid Regeneration Plants.  
50 (38) 40 CFR Part 63, Subpart DDD, National Emission  
51 Standards for Hazardous Air Pollutants for Mineral Wool  
52 Production.  
53 (39) 40 CFR Part 63, Subpart EEE, National Emission

1 Standards for Hazardous Air Pollutants from Hazardous Waste  
2 Combustors.

3 (40) 40 CFR Part 63, Subpart GGG, National Emission Standards  
4 for Hazardous Air Pollutants for Pharmaceuticals Production.

5 (41) 40 CFR Part 63, Subpart HHH, National Emission  
6 Standards for Hazardous Air Pollutants for Natural Gas  
7 Transmission and Storage.

8 (42) 40 CFR Part 63, Subpart III, National Emission  
9 Standards for Hazardous Air Pollutants for Flexible Polyurethane  
10 Foam Production.

11 (43) 40 CFR Part 63, Subpart JJJ, National Emission  
12 Standards for Hazardous Air Pollutants for Group IV Polymers and  
13 Resins.

14 (44) 40 CFR Part 63, Subpart LLL, National Emission  
15 Standards for Hazardous Air Pollutants for Portland Cement  
16 Manufacturing Industry.

17 (45) 40 CFR Part 63, Subpart MMM, National Emission  
18 Standards for Hazardous Air Pollutants for Pesticide Active  
19 Ingredient Production.

20 (46) 40 CFR Part 63, Subpart NNN, National Emission  
21 Standards for Hazardous Air Pollutants for Wool Fiberglass  
22 Manufacturing.

23 (47) 40 CFR Part 63, Subpart OOO, National Emission  
24 Standards for Hazardous Air Pollutants for Amino/Phenolic Resins  
25 Production (Resin III).

26 (48) 40 CFR Part 63, Subpart PPP, National Emission  
27 Standards for Hazardous Air Pollutants for Polyether Polyols  
28 Production.

29 (49) 40 CFR Part 63, Subpart QQQ, National Emission  
30 Standards for Hazardous Air Pollutants for Primary Copper  
31 Smelters.

32 (50) 40 CFR Part 63, Subpart RRR, National Emission  
33 Standards for Hazardous Air Pollutants for Secondary Aluminum  
34 Production.

35 (51) 40 CFR Part 63, Subpart TTT, National Emission  
36 Standards for Hazardous Air Pollutants for Primary Lead Smelting.

37 (52) 40 CFR Part 63, Subpart UUU, National Emission  
38 Standards for Hazardous Air Pollutants for Petroleum Refineries:  
39 Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur  
40 Recovery Units.

41 (53) 40 CFR Part 63, Subpart VVV, National Emission  
42 Standards for Hazardous Air Pollutants: Publicly Owned Treatment  
43 Works.

44 (54) 40 CFR Part 63, Subpart AAAA, National Emission  
45 Standards for Hazardous Air Pollutants for Municipal Solid Waste  
46 Landfills.

47 (55) 40 CFR Part 63, Subpart CCC, National Emission  
48 Standards for Manufacturing of Nutritional Yeast.

49 (56) 40 CFR Part 63, Subpart DDDD, National Emission  
50 Standards for Hazardous Air Pollutants for Plywood and Composite  
51 Wood Products [~~published on July 30, 2004 at 69 FR 45943~~].

52 (57) 40 CFR Part 63, Subpart EEEE, National Emission  
53 Standards for Hazardous Air Pollutants for Organic Liquids

1 Distribution (non-gasoline).  
2 (58) 40 CFR Part 63, Subpart FFFF, National Emission  
3 Standards for Hazardous Air Pollutants for Miscellaneous Organic  
4 Chemical Manufacturing.  
5 (59) 40 CFR Part 63, Subpart GGGG, National Emission  
6 Standards for Vegetable Oil Production; Solvent Extraction.  
7 (60) 40 CFR Part 63, Subpart HHHH - National Emission  
8 Standards for Wet-Formed Fiberglass Mat Production.  
9 (61) 40 CFR Part 63, Subpart IIII, National Emission  
10 Standards for Hazardous Air Pollutants for Surface Coating of  
11 Automobiles and Light-Duty Trucks.  
12 (62) 40 CFR Part 63, Subpart JJJJ, National Emission  
13 Standards for Hazardous Air Pollutants for Paper and Other Web  
14 Surface Coating Operations.  
15 (63) 40 CFR Part 63, Subpart KKKK, National Emission  
16 Standards for Hazardous Air Pollutants for Surface Coating of  
17 Metal Cans.  
18 (64) 40 CFR Part 63, Subpart MMMM, National Emission  
19 Standards for Hazardous Air Pollutants for Surface Coating of  
20 Miscellaneous Metal Parts and Products.  
21 (65) 40 CFR Part 63, Subpart NNNN - National Emission  
22 Standards for Large Appliances Surface Coating Operations.  
23 (66) 40 CFR Part 63, Subpart OOOO, National Emission  
24 Standards for Hazardous Air Pollutants for Fabric Printing,  
25 Coating and Dyeing Surface Coating Operations.  
26 (67) 40 CFR Part 63, Subpart PPPP, National Emissions  
27 Standards for Hazardous Air Pollutants for Surface Coating of  
28 Plastic Parts and Products.  
29 (68) 40 CFR Part 63, Subpart QQQQ, National Emission  
30 Standards for Hazardous Air Pollutants for Surface Coating of Wood  
31 Building Products.  
32 (69) 40 CFR Part 63, Subpart RRRR, National Emission  
33 Standards for Hazardous Air Pollutants for Metal Furniture Surface  
34 Coating Operations.  
35 (70) 40 CFR Part 63, Subpart SSSS - National Emission  
36 Standards for Metal Coil Surface Coating Operations.  
37 (71) 40 CFR Part 63, Subpart TTTT - National Emission  
38 Standards for Leather Tanning and Finishing Operations.  
39 (72) 40 CFR Part 63, Subpart UUUU - National Emission  
40 Standards for Cellulose Product Manufacturing.  
41 (73) 40 CFR Part 63, Subpart VVVV - National Emission  
42 Standards for Boat Manufacturing.  
43 (74) 40 CFR Part 63, Subpart WWWW, National Emissions  
44 Standards for Hazardous Air Pollutants for Reinforced Plastic  
45 Composites Production.  
46 (75) 40 CFR Part 63, Subpart XXXX - National Emission  
47 Standards for Tire Manufacturing.  
48 (76) 40 CFR Part 63, Subpart YYY Y, National Emission  
49 Standards for Hazardous Air Pollutants for Stationary Combustion  
50 Turbines.  
51 (77) 40 CFR Part 63, Subpart ZZZZ, National Emission  
52 Standards for Hazardous Air Pollutants for Stationary  
53 Reciprocating Internal Combustion Engines.

1 (78) 40 CFR Part 63, Subpart AAAAA, National Emission  
2 Standards for Hazardous Air Pollutants for Lime Manufacturing  
3 Plants.  
4 (79) 40 CFR Part 63, Subpart BBBBB, National Emission  
5 Standards for Hazardous Air Pollutants for Semiconductor  
6 Manufacturing.  
7 (80) 40 CFR Part 63, Subpart CCCCC, National Emission  
8 Standards for Hazardous Air Pollutants for Coke Ovens: Pushing,  
9 Quenching, and Battery Stacks.  
10 (81) 40 CFR Part 63, Subpart DDDDD, National Emission  
11 Standards for Hazardous Air Pollutants for Industrial, Commercial,  
12 and Institutional Boilers and Process Heaters [~~published on~~  
13 ~~September 13, 2004 at 69 FR 55217~~].  
14 (82) 40 CFR Part 63, Subpart EEEEE, National Emission  
15 Standards for Hazardous Air Pollutants for Iron and Steel  
16 Foundries.  
17 (83) 40 CFR Part 63, Subpart FFFFF, National Emission  
18 Standards for Hazardous Air Pollutants for Integrated Iron and  
19 Steel Manufacturing.  
20 (84) 40 CFR Part 63, Subpart GGGGG, National Emission  
21 Standards for Hazardous Air Pollutants for Site Remediation.  
22 (85) 40 CFR Part 63, Subpart HHHHH, National Emission  
23 Standards for Hazardous Air Pollutants for Miscellaneous Coating  
24 Manufacturing.  
25 (86) 40 CFR Part 63, Subpart IIIII, National Emission  
26 Standards for Hazardous Air Pollutants for Mercury Emissions from  
27 Mercury Cell Chlor-Alkali Plants.  
28 (87) 40 CFR Part 63, Subpart JJJJJ, National Emission  
29 Standards for Hazardous Air Pollutants for Brick and Structural  
30 Clay Products Manufacturing.  
31 (88) 40 CFR Part 63, Subpart KKKKK, National Emission  
32 Standards for Hazardous Air Pollutants for Clay Ceramics  
33 Manufacturing.  
34 (89) 40 CFR Part 63, Subpart LLLLL, National Emission  
35 Standards for Hazardous Air Pollutants for Asphalt Processing and  
36 Asphalt Roofing Manufacturing.  
37 (90) 40 CFR Part 63, Subpart MMMMM, National Emission  
38 Standards for Hazardous Air Pollutants for Flexible Polyurethane  
39 Foam Fabrication Operations.  
40 (91) 40 CFR Part 63, Subpart NNNNN, National Emission  
41 Standards for Hazardous Air Pollutants for Hydrochloric Acid  
42 Production.  
43 (92) 40 CFR Part 63, Subpart PPPPP, National Emission  
44 Standards for Hazardous Air Pollutants for Engine Test  
45 Cells/Stands.  
46 (93) 40 CFR Part 63, Subpart QQQQQ - National Emission  
47 Standards for Hazardous Air Pollutants for Friction Materials  
48 Manufacturing Facilities.  
49 (94) 40 CFR Part 63, Subpart RRRRR, National Emission  
50 Standards for Hazardous Air Pollutants for Taconite Iron Ore  
51 Processing.  
52 (95) 40 CFR Part 63, Subpart SSSSS, National Emission  
53 Standards for Hazardous Air Pollutants for Refractory Products

1 Manufacturing.

2 (96) 40 CFR Part 63, Subpart TTTT, National Emission  
3 Standards for Hazardous Air Pollutants for Primary Magnesium  
4 Refining.

5

6 **KEY: air pollution, hazardous air pollutant, MACT**

7 **Date of Enactment or Last Substantive Amendment: [~~November 3,~~**  
8 **~~2005]~~2007**

9 **Notice of Continuation: February 9, 2004**

10 **Authorizing, and Implemented or Interpreted Law: 19-2-104(1)(a)**

11

12



State of Utah

Department of  
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DIVISION OF AIR QUALITY  
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DAQ-073-06

### MEMORANDUM

**TO:** Air Quality Board

**THROUGH:** Richard W. Sprott, Executive Secretary

**FROM:** Bill Reiss, Environmental Engineer  
Mat Carlile, Environmental Planning Consultant

**DATE:** October 18, 2006

**SUBJECT:** PM Standards Update

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#### **Background**

The Clean Air Act (42 U.S.C. 7409 (b)(2)(d)(1)) requires the EPA to complete a thorough review of the National Ambient Air Quality Standards (NAAQS) at least every five years. Particulate Matter (PM) standards were last reviewed in 1997. The EPA was under court order to complete its review of the PM NAAQS by December 20, 2005 and have a final rule by September 27, 2006. EPA issued its final rule on September 21, 2006.

The final standards address two categories of particle pollution: *fine particles* (PM<sub>2.5</sub>) that are 2.5 micrometers in diameter and smaller; and *inhalable coarse particles* (PM<sub>10</sub>) that are smaller than 10 micrometers. EPA is strengthening the 24-hour fine particle standard from the 1997 level of 65 micrograms per cubic meter ( $\mu\text{g}/\text{m}^3$ ) to 35  $\mu\text{g}/\text{m}^3$ , and retaining the current annual fine particle standard at 15  $\mu\text{g}/\text{m}^3$ . The EPA is also retaining the existing national 24-hour PM<sub>10</sub> standard of 150  $\mu\text{g}/\text{m}^3$ ; however, it is revoking the annual PM<sub>10</sub> standard.

The following table summarizes the changes of the PM NAAQS:

	<b>24-hour</b>	<b>Annual</b>
Previous PM <sub>2.5</sub> NAAQS	65 µg/m <sup>3</sup> (three-year average of 98 <sup>th</sup> percentile 24-hour average values)	15 µg/m <sup>3</sup> (three-year weighted annual averages)
<i>New Rule</i>	35 µg/m <sup>3</sup> (three-year average of 98 <sup>th</sup> percentile 24-hour average values)	15 µg/m <sup>3</sup> (three-year weighted annual averages)
Previous PM <sub>10</sub> NAAQS	150 µg/m <sup>3</sup> (one exceedance of the standard per year averaged over a three year period.)	50 µg/m <sup>3</sup>
<i>New Rule</i>	150 µg/m <sup>3</sup> (one exceedance of the standard per year averaged over a three year period.)	Revoked

**Implication of New PM<sub>2.5</sub> Standards**

We have reviewed the monitoring data from our existing PM<sub>2.5</sub> monitoring network to determine the impact of the new PM standard, looking specifically at our data from 2003 through 2005. We determined that 12 out of the 17 monitors in Utah would have violated the new PM<sub>2.5</sub> 24-hour NAAQS during that period.

The following table summarizes how these modifications to the NAAQS could impact Utah’s PM<sub>2.5</sub> attainment status at our current monitors, based on data from 2003 through 2005. Bolded numbers indicate that there would have been a violation of the new 24-hour NAAQS had it been in place.

<b>Monitor</b>	<b>New 24-Hour Standards (35 µg/m<sup>3</sup>)<sup>1</sup></b>
<b>Bountiful</b> <sup>2</sup>	<b>40</b>
Brigham City	35
<b>Cottonwood</b>	<b>47</b>
<b>Logan</b>	<b>65</b>
<b>Lindon</b>	<b>43</b>
Harrisville	35
<b>Hawthorne</b>	<b>47</b>
Highland	35
Herriman	34
<b>Magna</b> <sup>2</sup>	<b>46</b>
<b>N. Provo</b>	<b>39</b>
<b>N. Salt Lake</b>	<b>49</b>

<sup>1</sup> PM<sub>2.5</sub> values based on 2003-2005 24-hour average, calculated from 98<sup>th</sup> percentile values obtained from EPA/AQS Quicklook reports. The 24-hour PM<sub>2.5</sub> NAAQS is met when the 24-hour value at each monitoring site is less than or equal to 35 µg/m<sup>3</sup>. Values are subject to rounding conventions of 40 CFR Part 50 Appendix N section 4.3(b).

<sup>2</sup> We did not have a full three years of data to determine averages for these sites. Bountiful and Magna data are based on 2 years of sampling, and Tooele #3 started monitoring on July 6, 2005. However, based on preliminary values, it appears that these sites potentially will violate the new 24-hour standard.

<b>Ogden #2</b>	<b>40</b>
<b>Spanish Fork</b>	<b>36</b>
<b>Tooele #3<sup>2</sup></b>	<b>46</b>
Washington Terrace	34
<b>West Valley</b>	<b>48</b>

We have put together a map (see attachment 1) that shows the potential nonattainment areas of the revised PM<sub>2.5</sub> standard based on EPA’s default designation boundaries of Metropolitan Statistical Areas (MSAs). As with the initial PM<sub>2.5</sub> designations, it is our intent to propose any nonattainment boundaries be based on scientific data and not solely on geopolitical boundaries.

**Implementation Schedule**

We have compiled an implementation schedule for the revised PM<sub>2.5</sub> standard (Attachment 2).

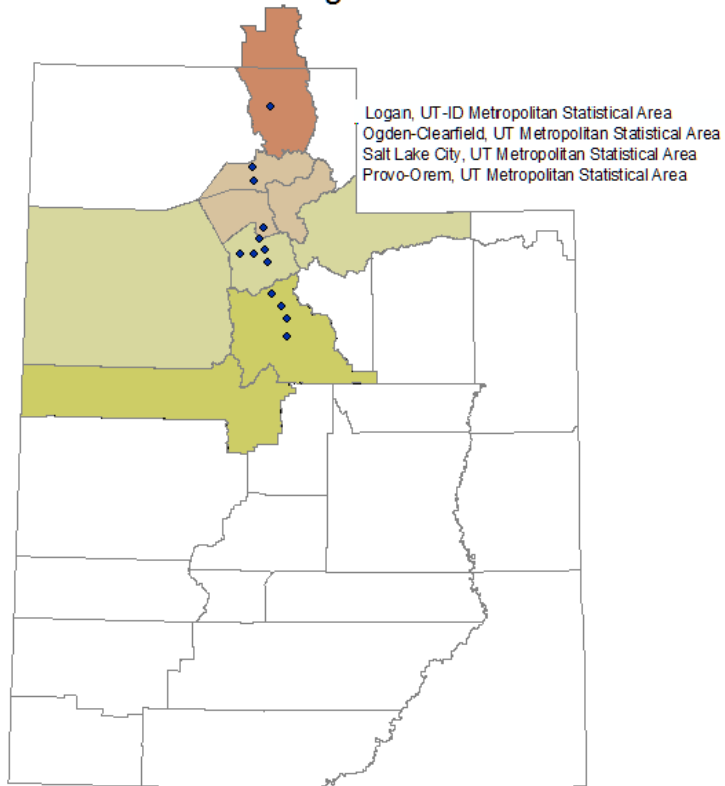
**Attachments:**

Attachment 1: Metropolitan Statistical Areas Likely to Violate a 35 µg/m<sup>3</sup> PM<sub>2.5</sub> NAAQS

Attachment 2: Implementation Schedule for the Revised PM<sub>2.5</sub> NAAQS

# Attachment 1:

Metropolitan Statistical Areas likely to violate a 35 ug/m<sup>3</sup> PM<sub>2.5</sub> NAAQS



Utah Division of Air Quality September, 2006

## Attachment 2

### Implementation Schedule for the Revised PM<sub>2.5</sub> NAAQS

The following is the implementation schedule for the revised PM<sub>2.5</sub> standard. All federal actions are, by statute, based on the most current three years of monitoring data.

<b>Expected Timeline for Revised PM<sub>2.5</sub> NAAQS</b>	
<b>Promulgation of Standard</b>	September 2006
<b>State Recommendations of Nonattainment Designations due to EPA</b>	December 2007 (based on 2004-2006 monitoring data)
<b>Final Designations Signature</b>	December 2009 (based on 2006-2008 monitoring data)
<b>Effective Date of Designations</b>	April 2010
<b>State Implementation Plan Due</b>	April 2013 (based on 2010-2012 monitoring data)
<b>Attainment Date</b>	April 2015
<b>Attainment Date with Extension</b>	April 2020



State of Utah

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DAQC-1248-2006

**MEMORANDUM**

**TO:** Air Quality Board  
**FROM:** Richard W. Sprott, Executive Secretary  
**DATE:** September 11, 2006  
**SUBJECT:** Compliance Activities –August 2006

---

Annual Inspections Conducted:

A ..... 20  
SM ..... 13  
B..... 20

Initial Compliance Inspections Conducted:

A ..... 0  
SM ..... 3  
B..... 2

On-Site stack test audits conducted: ..... 0

Stack test report reviews: ..... 0

On-site CEM audits conducted: ..... 8

Emission reports reviewed: ..... 36

<sup>1</sup>Miscellaneous inspections conducted ..... 63

Complaints received: ..... 34

VOC inspections:

Tanker trucks ..... 0  
Degreasers ..... 7  
Paint Booths ..... 11

Source Compliance Action Notice issued.....	0
Notices of Violation issued.....	0
Compliance Advisories issued.....	8
Settlement Agreements resolved.....	5
Penalties Collected.....	\$53,400.60

Notices of Violations issued:

None

Compliance Advisories issued:

Coughlin Company  
Clyde Companies Inc.  
Nuset Industries  
Western Rock Products  
Western Rock Products  
Granite Construction  
Harborlite Corporation  
D.G. Johnson Trucking

Settlement Agreements Reached:

Pentalon Construction .....	\$1,255.20
Western Pipe Coaters.....	\$4,780.80
Nephi Sandstone .....	\$37,100.00
Payson City Power Corp.....	\$4,749.60
Frehner Construction Co. Inc.....	\$3,760.00

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<sup>1</sup>Miscellaneous inspections include, e.g., surveillance, level I inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.



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DAQC-1413-2006

**MEMORANDUM**

**TO:** Air Quality Board  
**FROM:** Richard W. Sprott, Executive Secretary  
**DATE:** October 11, 2006  
**SUBJECT:** Compliance Activities – September 2006

---

Annual Inspections Conducted:

A ..... 19  
SM ..... 3  
B..... 18

Initial Compliance Inspections Conducted:

A ..... 1  
SM ..... 0  
B..... 5

On-Site stack test audits conducted: ..... 13

Stack test report reviews: ..... 2

On-site CEM audits conducted: ..... 24

Emission reports reviewed: ..... 8

<sup>1</sup>Miscellaneous inspections conducted ..... 61

Complaints received: ..... 22

VOC inspections:

Tanker trucks ..... 4  
Degreasers ..... 15  
Paint Booths ..... 7

Source Compliance Action Notice issued.....	4
Notices of Violation issued.....	0
Compliance Advisories issued.....	6
Settlement Agreements resolved.....	6
Penalties Collected.....	\$29,541.20

Notices of Violations issued:

None

Compliance Advisories issued:

Harborlite  
Geneva Rock (2)  
Salt Lake Department of Airports  
Sunroc  
Newman Construction

Settlement Agreements Reached:

Circle C Construction .....	\$5,600.00
Granite Construction.....	\$9,520.00
Holcim .....	\$2,631.20
Asphalt Materials.....	\$8,030.00
Flying J .....	\$1,760.00
Flying J .....	\$2,000.00

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<sup>1</sup>Miscellaneous inspections include, e.g., surveillance, level I inspections, complaints, on-site training, dust patrol, smoke patrol, open burning, etc.



State of Utah

Department of  
Environmental Quality

Dianne R. Nielson, Ph.D.  
*Executive Director*

DIVISION OF AIR QUALITY  
Richard W. Sprott  
*Director*

JON M. HUNTSMAN, JR.  
*Governor*

GARY HERBERT  
*Lieutenant Governor*

**MEMORANDUM**

DAQH-0631-06

TO: Utah Air Quality Board

FROM: Richard W. Sprott, Executive Secretary

DATE: August 24, 2006

SUBJECT: Hazardous Air Pollutant Section Compliance Activities – July 2006

Asbestos Demolition/Renovation Inspections	0
Asbestos in School Inspections	6
MACT Compliance Inspections	12
Other NESHAP Inspections	3
State Rules (Only) Inspections	0
Asbestos Notifications Accepted	104
Asbestos Phone Calls Answered	331
Asbestos Individuals Certifications: Approved/Disapproved	60/0
Company Certifications/Re-certifications	1/2
Alternate Asbestos Work Practices: Approved/Disapproved	4/0
Lead Based Paint (LBP) Inspections	4
LBP Notifications Approved	4
LBP Phone Calls Answered	98

LBP Letters prepared and mailed	27
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	1
LBP Certifications Approved/Disapproved	10/0
LBP Company Certifications	0
Small Business Phone Calls Answered	9
Notices of Violation Issued	0
Notices of Noncompliance (NON)	0
Compliance Advisories Issued	3
Fred Schafer – Dugway Proving Ground	
Donna Kirkham	
Fresh Air/Granite School District	
SCANS or Warning Letters Issued	13
Settlement Agreements Finalized	0
Penalties Agree to	0



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*Governor*

GARY HERBERT  
*Lieutenant Governor*

## MEMORANDUM

DAQH-0634-06

TO: Utah Air Quality Board

FROM: Richard W. Sprott, Executive Secretary

DATE: September 12, 2006

SUBJECT: Hazardous Air Pollutant Section Compliance Activities – August 2006

Asbestos Demolition/Renovation Inspections	5
Asbestos in School Inspections	5
MACT Compliance Inspections	16
Other NESHAP Inspections	0
State Rules (Only) Inspections	0
Asbestos Notifications Accepted	124
Asbestos Phone Calls Answered	435
Asbestos Individuals Certifications: Approved/Disapproved	35/0
Company Certifications/Re-certifications	2/0
Alternate Asbestos Work Practices: Approved/Disapproved	2/0
Lead Based Paint (LBP) Inspections	7
LBP Notifications Approved	2
LBP Phone Calls Answered	61

LBP Letters prepared and mailed	39
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	4
LBP Certifications Approved/Disapproved	21/0
LBP Company Certifications	0
Small Business Phone Calls Answered	8
Notices of Violation Issued	0
Notices of Noncompliance (NON)	0
Compliance Advisories Issued	10
Seagull Environmental	
Environmental Training Fund	
Fresh Air Environmental	
Country Cleaners	
Leone Drycleaners	
Mr. Drycleaner	
MKP Enterprises	
Applied Geoscience	
Forsey Laundry	
Summit Realty	
SCANS or Warning Letters Issued	6
Settlement Agreements Finalized	1
Penalties Agree to	\$11,050
Union Pacific Railroad	\$11,050



State of Utah

Department of  
Environmental Quality

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DIVISION OF AIR QUALITY  
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*Director*

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*Governor*

GARY HERBERT  
*Lieutenant Governor*

## MEMORANDUM

DAQH-0741-06

TO: Utah Air Quality Board

FROM: Richard W. Sprott, Executive Secretary

DATE: October 13, 2006

SUBJECT: Hazardous Air Pollutant Section Compliance Activities – September 2006

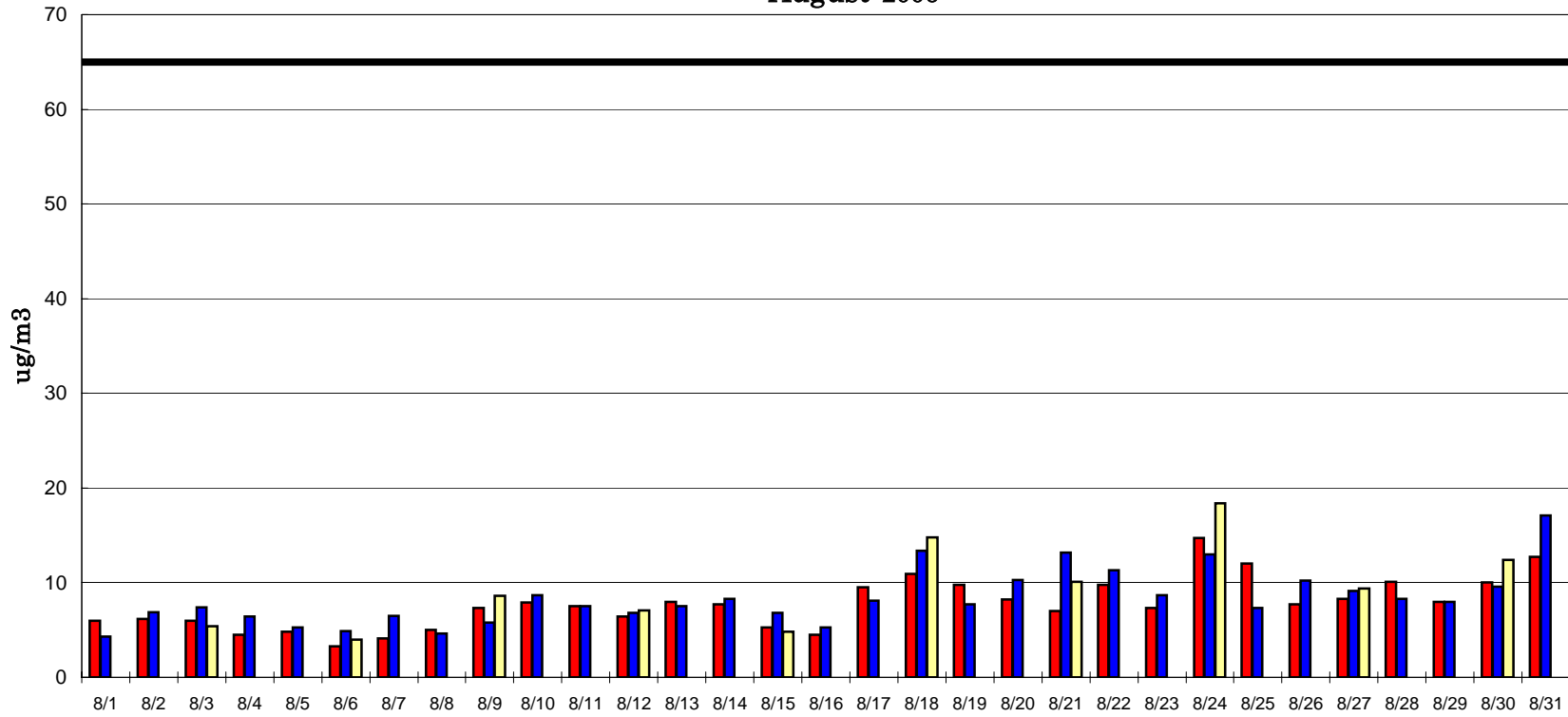
Asbestos Demolition/Renovation Inspections	10
Asbestos in School Inspections	4
MACT Compliance Inspections	3
Other NESHAP Inspections	4
State Rules (Only) Inspections	1
Asbestos Notifications Accepted	123
Asbestos Phone Calls Answered	366
Asbestos Individuals Certifications: Approved/Disapproved	59/0
Company Certifications/Re-certifications	2/0
Alternate Asbestos Work Practices: Approved/Disapproved	3/0
Lead Based Paint (LBP) Inspections	1
LBP Notifications Approved	1
LBP Phone Calls Answered	84

LBP Letters prepared and mailed	54
LBP Courses Reviewed/Approved	0/0
LBP Course Audits	0
LBP Certifications Approved/Disapproved	11/0
LBP Company Certifications	0
Small Business Phone Calls Answered	5
Notices of Violation Issued	0
Notices of Noncompliance (NON)	0
Compliance Advisories Issued	4
A2Z Construction	
Hill AFB	
Okland Construction	
Ted Diamant	
SCANS or Warning Letters Issued	8
Settlement Agreements Finalized	0
Penalties Agree to	

### 8 Hour Ozone Highest Daily Maximum Values August-September 2006

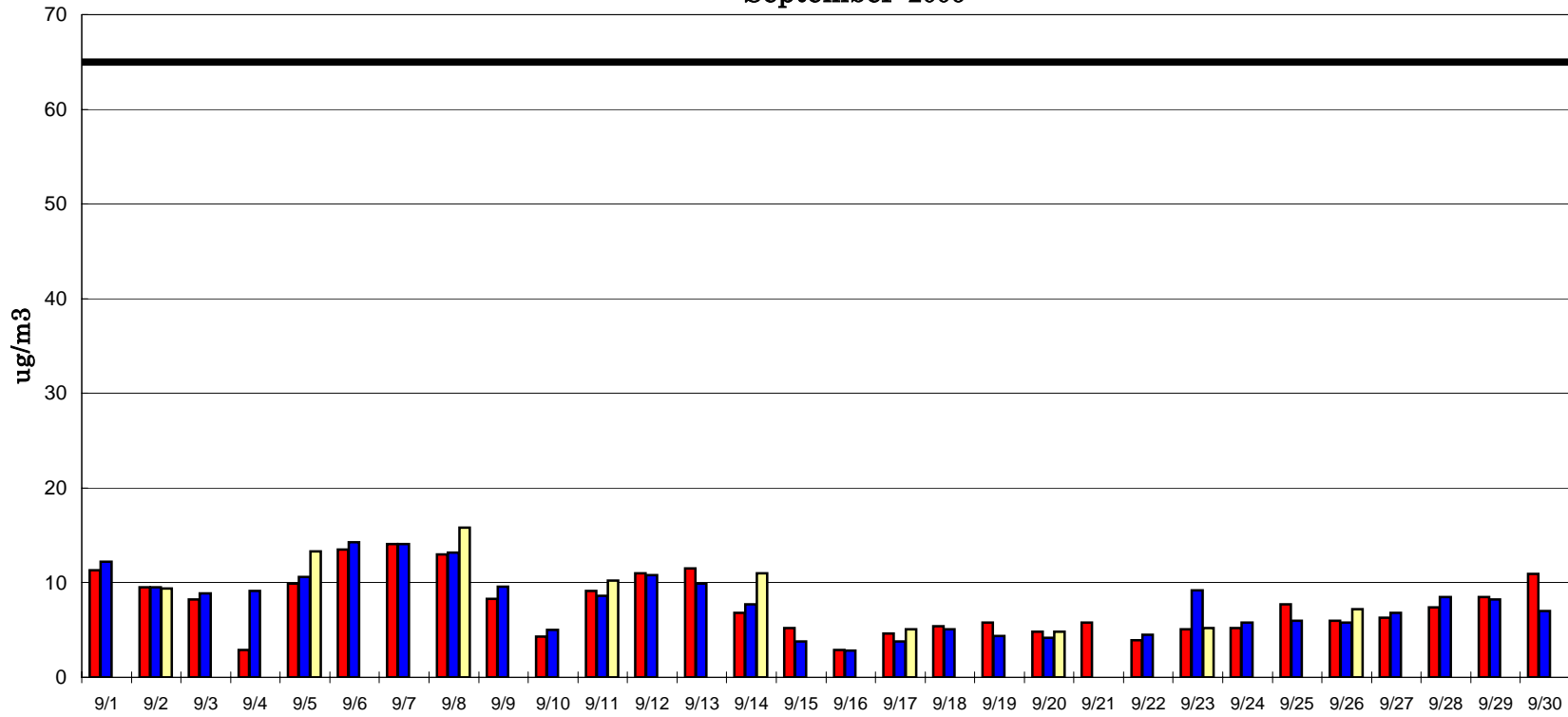


### Daily PM<sub>2.5</sub> Filter at Hawthorne, Lindon, & Ogden August 2006



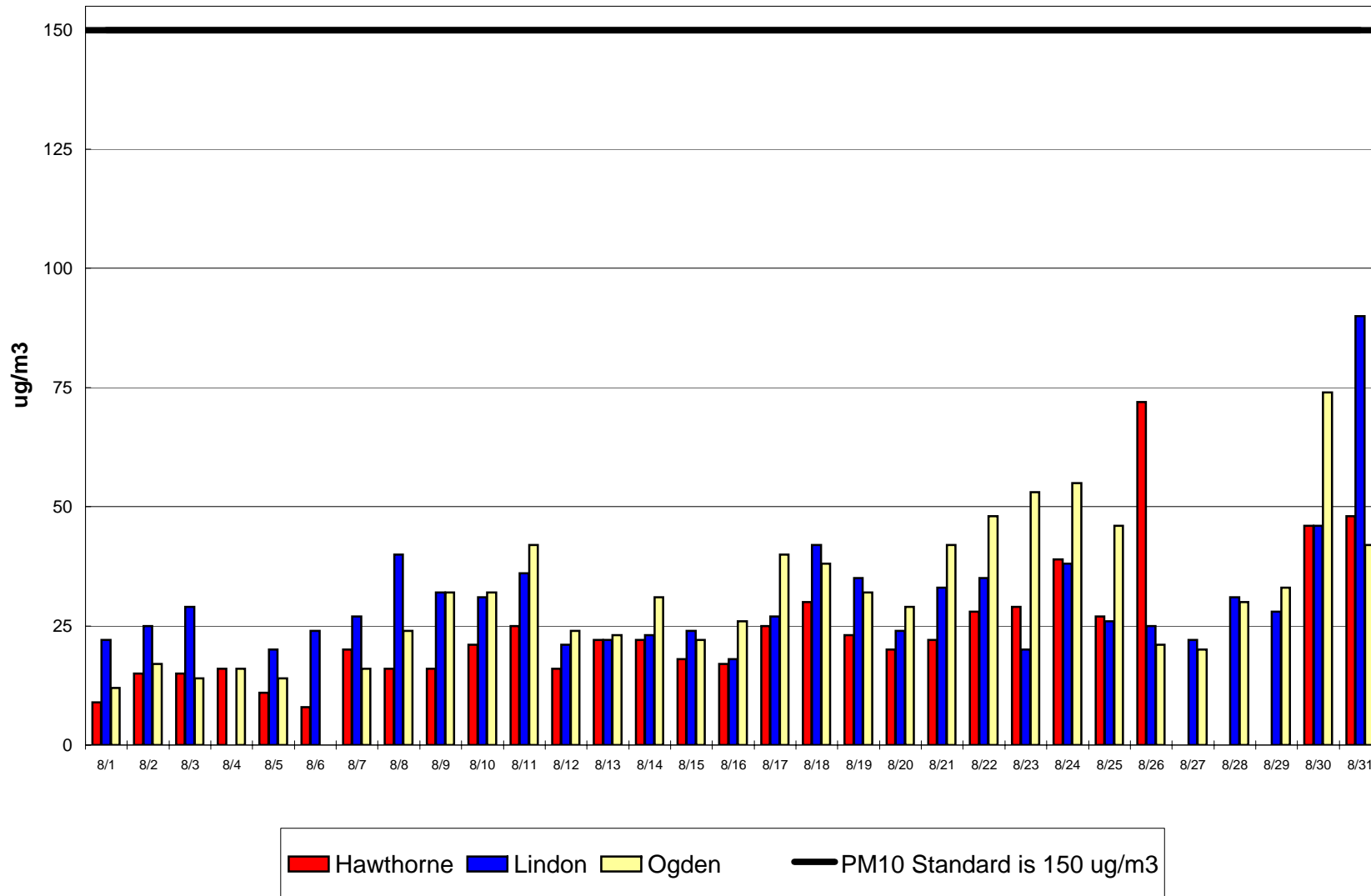
Legend: Hawthorne (red), Lindon (blue), Ogden (yellow), PM<sub>2.5</sub> Standard is 65 ug/m<sup>3</sup> (black line)

### Daily PM<sub>2.5</sub> Filter at Hawthorne, Lindon, & Ogden September 2006

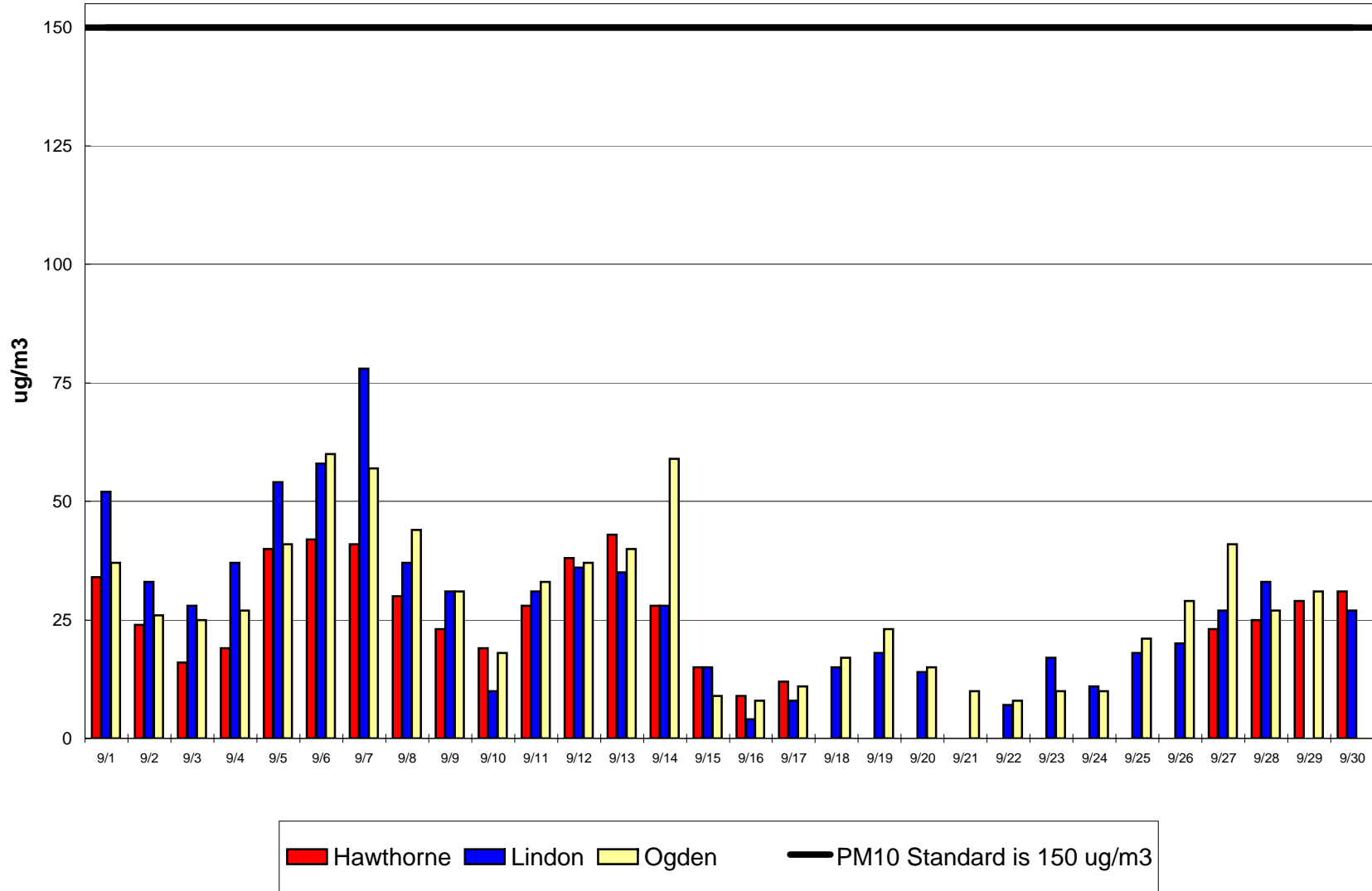


Legend: Hawthorne (red), Lindon (blue), Ogden (yellow), PM<sub>2.5</sub> Standard is 65 ug/m<sup>3</sup> (black line)

### Daily PM<sub>10</sub> Filter at Hawthorne, Lindon, & Ogden August 2006

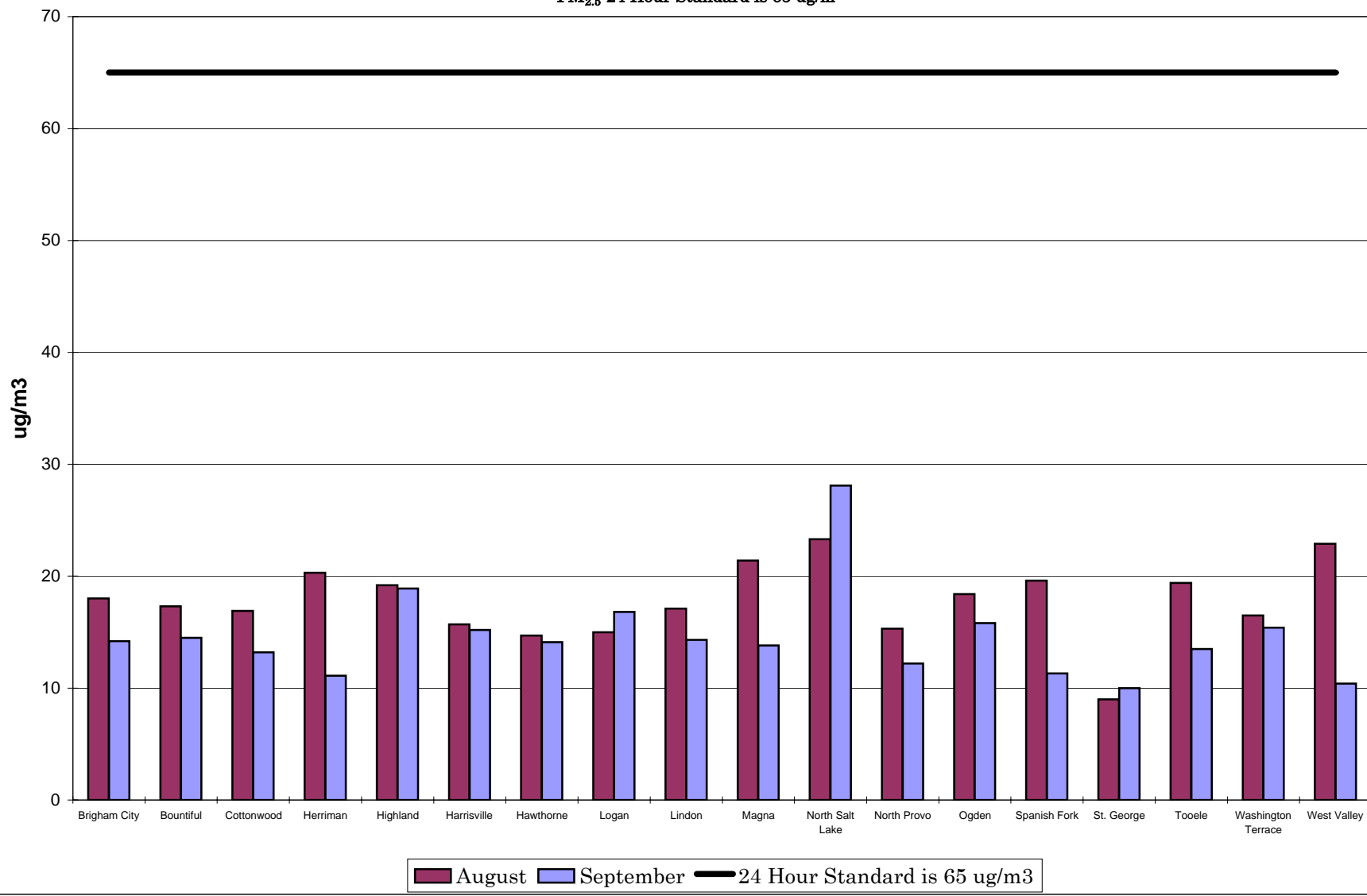


## Daily PM<sub>10</sub> Filter at Hawthorne, Lindon, & Ogden September 2006



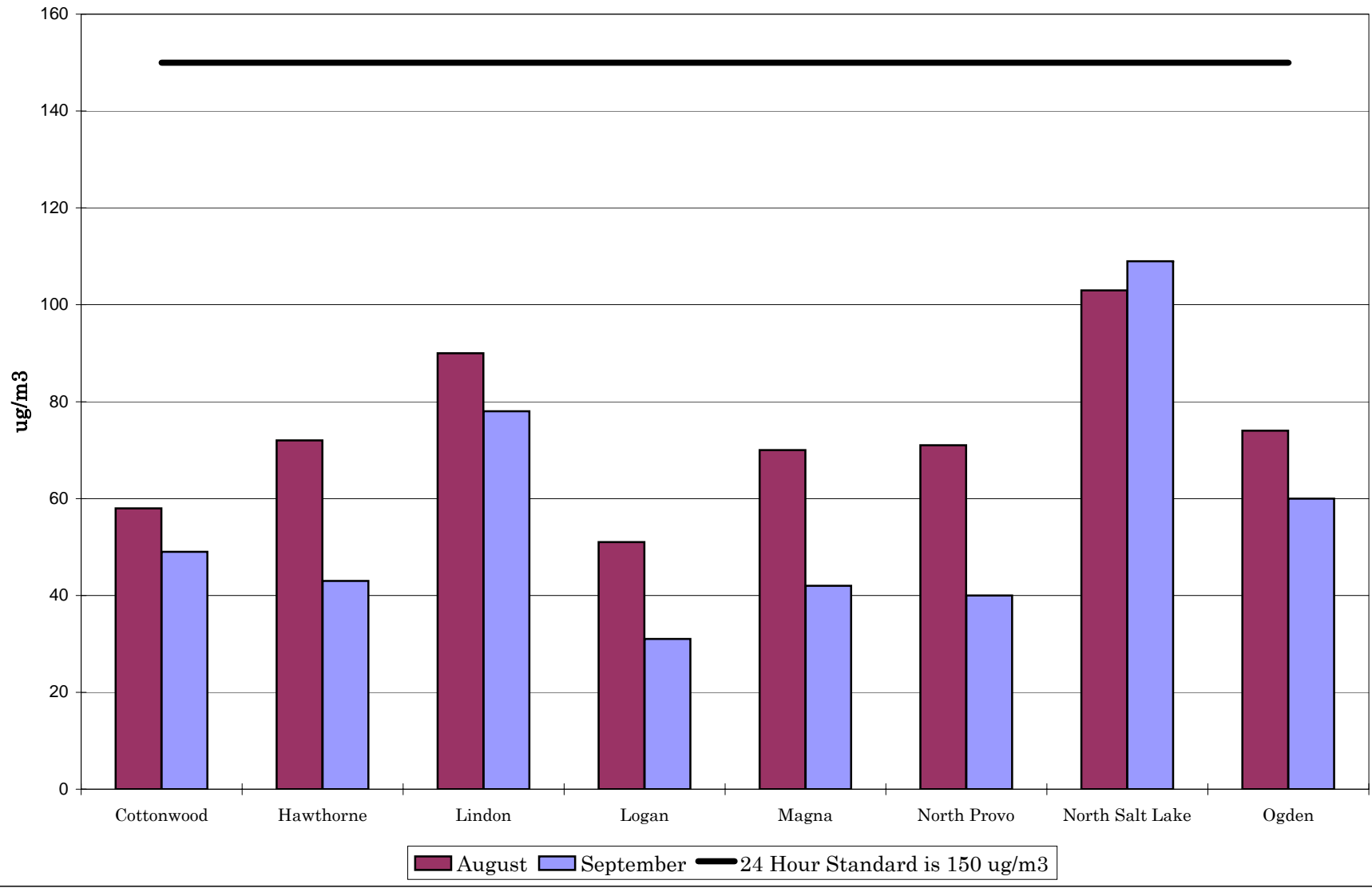
### Highest PM<sub>2.5</sub> Concentration for August-September 2006

PM<sub>2.5</sub> 24 Hour Standard is 65 ug/m<sup>3</sup>



# Highest PM<sub>10</sub> Concentration for August-September 2006

PM<sub>10</sub> 24 Hour Standard is 150 ug/m<sup>3</sup>



# UTAH STATE DIVISION OF AIR QUALITY

PM2.5 Actual Concentration (24-hr average) in Micrograms per Cubic Meter  
2006 August

Date	AG	BR	BV	CW	HE	HG	HV	HW	HY	L4	X4	LN	LX	MG	N2	NP	O2	SF	SW	T3	WT	WX	VV	VX	
08/01								6.0		13.6		4.3			11.0				6.5						
08/02								6.2				6.9			13.9										
08/03		5.3	6.3	7.7	9.6	6.4	4.2	6.0		5.6	5.7	7.4	7.1	7.8	12.5		5.4		4.7	5.9	5.3	5.9	16.7	9.2	
08/04								4.5		4.9	4.8	6.4			14.5										
08/05								4.8		5.3	5.5	5.3			13.5										
08/06		3.1	5.1	5.8	10.0	2.9	3.4	3.3		2.9	2.9	4.9		4.5	6.0	3.0	4.0	4.3			3.3			12.5	
08/07								4.1		4.5	5.0	6.5			7.9						2.7				
08/08								5.0		4.9	5.4	4.6			7.7										
08/09		6.7	6.3	7.2	9.7	6.4		7.3		6.6	7.7	5.8	6.5	6.3	11.4	6.9	8.6	8.6	5.2	5.7				13.2	8.9
08/10								7.9			7.4	8.7			12.1										
08/11								7.5		6.4	9.1	7.5			9.8										
08/12		10.1	7.7	6.4	7.6	19.2	5.8	6.4		7.2	8.2	6.8		6.7	9.7	6.2	7.1		5.5	5.5	6.5			11.3	
08/13								8.0		6.7	7.4	7.5			9.7										
08/14								7.7		7.2	8.1	8.3			13.0										
08/15		7.4	6.4		5.3	9.2	2.2	5.3			7.4	6.8	5.7	5.0	10.7	5.9	4.8	6.7	5.5	4.6	4.9	5.0	8.2	4.7	
08/16								4.5			8.8	5.3			9.0										
08/17								9.5		9.7	9.5	8.1			15.4										
08/18		8.3	12.7	11.3	10.2	12.9	9.8	10.9		8.1	9.5	13.4		8.7	13.8	13.7	14.8	12.7	5.8	7.1	9.7			10.9	
08/19								9.8		11.0	10.9	7.7			14.4										
08/20								8.2		9.9	9.9	10.3			10.8										
08/21		9.6	4.3	7.9	6.3	9.4	6.8	7.0		5.6	5.3	13.2	8.6	6.2	13.4		10.1	4.5			2.6	4.8	7.3		9.0
08/22								9.8		5.6	7.0	11.3			15.4	15.3			8.2						
08/23								7.3		7.6	7.9	8.7			12.1										
08/24		18.0	17.3	16.9	20.3		15.7	14.7		15.0	16.2	13.0		21.4	23.3	10.8	18.4	19.6	8.3	19.4	16.5			22.9	
08/25								12.0		10.5	10.8	7.3			21.7										
08/26								7.7		4.9	7.6	10.2			10.2										
08/27		8.7	7.7	8.6	7.9	8.7	8.5	8.3		7.2	11.7	9.1	11.1	8.3	11.3	8.5	9.4	8.0	9.0	6.2	7.6	8.6	9.2		9.8
08/28								10.1		8.4	11.7	8.3			17.4										
08/29								8.0		8.5	12.0	8.0			12.1										
08/30		11.3	10.7	5.9	10.0	10.0	11.6	10.0		10.6	18.0	9.6		9.8	21.5		12.4	8.9	7.6	8.3				9.1	
08/31								12.7		7.0	10.0	17.1			18.3										

Arith Mean		8.9	8.5	8.6	9.7	9.5	7.5	7.8		7.6	8.7	8.3	7.8	8.5	13.0	8.8	9.5	9.2	6.6	6.8	7.3	6.7	12.7	8.3
Max 24-hr Avg		18.0	17.3	16.9	20.3	19.2	15.7	14.7		15.0	18.0	17.1	11.1	21.4	23.3	15.3	18.4	19.6	9.0	19.4	16.5	8.6	22.9	9.8
Std.Dev		4.0	4.0	3.5	4.1	4.6	4.3	2.7		2.8	3.3	2.9	2.1	4.8	4.1	4.2	4.6	4.8	4.2	1.5	4.2	1.5	4.6	2.1
Days Data		10	10	9	10	9	9	31		27	29	31	5	10	31	8	10	8	10.0	10	8	4	9	5
Yearly Mean	9.3	8.0	9.6	11.3	7.8	8.6	8.7	11.6	8.0	9.9	9.8	10.3	9.8	8.9	14.1	9.5	10.4	7.8	8.9	7.9	8.4	7.9	12.0	10.8

# UTAH STATE DIVISION OF AIR QUALITY

PM2.5 Actual Concentration (24-hr average) in Micrograms per Cubic Meter  
**2006**      September

Date	AG	BR	BV	CW	HE	HG	HV	HW	HY	L4	X4	LN	LX	MG	N2	NP	O2	SF	SW	T3	WT	WX	VV	VX	
09/01								11.3		9.2	9.8	12.2			17.9										
09/02		7.9	9.4	9.6	8.0	8.4	8.6	9.5		8.2	8.1	9.5	7.8	7.0	9.5	11.5	9.4	9.6	6.5	6.7	8.8	8.2	10.4	10.8	
09/03								8.2		7.4	6.8	8.9			13.3										
09/04								2.9		7.1	7.3	9.1			6.4										
09/05		11.0		9.8	10.2	9.6	10.0	9.9		11.8	10.0	10.6			12.2	14.6	8.8	13.3	9.2		7.0			9.7	
09/06								13.5		14.1	13.4	14.3			18.8										
09/07								14.1		16.8	17.3	14.1			21.8				6.6						
09/08		14.2	14.5	13.2	11.1	18.9	15.2	13.0		16.4	16.2	13.2	13.1	13.8	16.0	12.2	15.8	11.3		13.5	15.4	14.8		12.5	
09/09								8.3		9.2	9.7	9.6							5.8						
09/10								4.3		6.4	6.5	5.0			10.3										
09/11			9.3	9.2	8.8	8.1	9.8	9.1		9.6	9.1	8.6			10.1	17.1	10.0	10.2	7.3		8.4	7.0		10.2	
09/12								11.0		10.6	10.5	10.8			28.1				10.0						
09/13								11.5		10.0	9.9	9.9			23.9										
09/14		7.8	7.5	7.2	7.3	7.4	8.7	6.8		8.1	8.7	7.7	8.5	6.7	12.8	11.7	11.0	3.8	7.3	5.8	8.6	8.8	7.1	6.9	
09/15								5.2		4.3	4.3	3.8			7.2										
09/16								2.9		3.4	3.3	2.8			3.9										
09/17		4.3	4.1	5.4	3.6	4.1	2.9	4.6		2.1	1.0	3.8			4.4	5.2	0.9	5.1	3.9	6.0	3.6	6.5			
09/18								5.4		6.1	5.8	5.1			7.3									4.9	
09/19								5.8		6.9	4.3	4.4													
09/20		3.8	4.2	4.7	4.0		2.5	4.8		3.3	2.5	4.2	4.3			5.0	4.8	3.3	6.5	3.5	5.0	3.8	7.6	6.1	
09/21								5.8		3.6	4.1														
09/22								3.9		2.5	1.3	4.5													
09/23		2.7	3.7	7.3	5.1		2.9	5.1		3.2	1.4	9.2				6.6	5.2	6.0	3.3	3.2	2.6		8.8		
09/24								5.2		3.2		5.8													
09/25								7.7		5.6	5.0	6.0			10.7										
09/26		5.0	5.6	7.5		5.1		6.0		6.1	6.7	5.8			6.7	13.1	6.1	7.2	4.3	8.5	4.5	6.5	4.7	8.1	8.4
09/27								6.3		6.7	6.8	6.6													
09/28								7.4		8.4	10.3	8.5													
09/29		9.5		10.4		6.6	8.3	8.5		11.2	11.5	8.2			7.5				7.3	7.7	7.2	10.6		9.7	
09/30								10.9		12.1	13.0	7.0				8.0									

Arith Mean	7.3	7.3	8.4	7.2	8.5	7.7	7.6			7.8	7.7	7.8	8.4	8.5	13.6	8.1	9.1	6.6	6.8	6.3	7.9	8.0	8.5	8.9
Max 24-hr Avg	14.2	14.5	13.2	11.1	18.9	15.2	14.1			16.8	17.3	14.3	13.1	13.8	28.1	12.2	15.8	11.3	10.0	13.5	15.4	14.8	10.4	12.5
Std.Dev	3.8	3.7	2.5	2.8	4.5	4.2	3.2			3.9	4.2	3.2	3.6	3.2	6.6	3.5	3.9	3.1	3.6	1.8	3.6	4.3	1.8	2.7
Days Data	9	8	10	8	8	9	30			30	29	30	4	8	19	10	9	10	10.0	10	9	5	9	5
Yearly Mean	9.3	8.0	9.4	11.0	7.8	8.6	8.6	11.1	8.0	9.7	9.6	10.1	9.7	8.9	14.1	9.4	10.3	7.7	8.7	7.7	8.3	8.0	11.7	10.6

# UTAH STATE DIVISION OF AIR QUALITY

PM2.5 Actual Concentration (24-hr average) in Micrograms per Cubic Meter  
**2006**      October

Date	AG	BR	BV	CW	HE	HG	HV	HW	HY	L4	X4	LN	LX	MG	N2	NP	O2	SF	SW	T3	WT	WX	WV	VX
10/01								5.7		7.7	8.0	6.0			11.0									
10/02		3.8	4.2	4.8	5.5	3.9	5.5	4.7	4.3	5.3	5.0	5.7	4.5	3.8	11.5	5.0	4.1	5.2					5.1	5.1
10/03								7.6		7.9	7.4	5.0			12.4									
10/04								4.3		4.1	14.6	3.5			9.1									
10/05		4.1	5.2		3.5	4.2	1.3	5.1		4.4	8.4	5.3		5.2	9.2	3.9	5.4	4.3		3.3			4.8	
10/06								4.1		1.9	7.8	4.3			6.0									
10/07								5.2		2.9	3.6	3.6			5.8									
10/08		3.8	5.6		9.0	5.0	4.3	7.2		4.7	5.4	6.8	7.8	5.7	9.6	6.9	6.7	6.1			6.4	6.3	9.0	9.1
10/09								8.5		5.1	10.3	11.2			13.0									
10/10								5.3				9.1												
10/11						11.5						13.0				10.7		9.1					15.5	
10/12												11.6												
10/13								7.0				6.2												
10/14								7.4				5.2	4.0			7.2		6.5					9.8	9.6
10/15								6.5				4.0												
10/16																								
10/17																								
10/18																								
10/19																								
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10/31																								
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Arith Mean		3.9	5.0	4.8	6.0	6.2	3.7	6.0	4.3	4.9	7.8	6.7	5.4	4.9	9.7	6.7	5.4	6.3		3.3	6.4	6.3	8.9	7.9
Max 24-hr Avg		4.1	5.6	4.8	9.0	11.5	5.5	8.5	4.3	7.9	14.6	13.0	7.8	5.7	13.0	10.7	6.7	9.1		3.3	6.4	6.3	15.5	9.6
Std.Dev		0.2	0.7		2.8	3.6	2.2	1.4		2.0	3.2	3.1	2.1	1.0	2.6	2.6	1.3					4.3	2.4	
Days Data		3	3	1	3	4	3	13	1	9	9	15	3	3	9	5	3	5		1	1	1	5	3
Yearly Mean	9.9	7.7	8.0	9.4	7.6	8.3	7.8	9.3	8.9	8.8	9.3	9.1	8.3	7.4	12.4	8.3	9.7	7.0	8.0	6.4	8.0	7.2	9.7	8.5

## UTAH STATE DIVISION OF AIR QUALITY

47mm Partisol: PM10 Concentration Adjusted to Sea Level (24-hr average) in Micrograms per Cubic Meter

2006 August

Date	Cottonwood	Hawthorn	Lindon	Logan 4	Magna(W)	StGeorge2	NProvo	NProvo-X	NSL	NSL-X	Ogden2
08/01		9	22			25			28		12
08/02		15	25						54		17
08/03	32	15	29	14	23		22	23	103	107	14
08/04		16				20			39		16
08/05		11	20						31		14
08/06	25	8	24	6	14		16		33		
08/07		20	27						48		16
08/08		16	40						33		24
08/09	36	16	32	22	20	24	25	20			32
08/10		21	31			16			67		32
08/11		25	36						49		42
08/12	30	16	21	26	24		21		50		24
08/13		22	22						42		23
08/14		22	23						73		31
08/15	26	18	24	16	25	29	29	29	59	60	22
08/16		17	18						45		26
08/17		25	27						51		40
08/18	43	30	42	25	30	29	42		44		38
08/19		23	35						50		32
08/20		20	24						47		29
08/21	30	22	33	29	35				67	69	42
08/22		28	35			47	39	39	53		48
08/23		29	20						65		53
08/24	53	39	38	43	55	40	32		99		55
08/25		27	26						73		46
08/26		72	25						23		21
08/27	25		22	14	15	25	16	20	24	26	20
08/28			31						58		30
08/29			28						43		33
08/30	58	46	46	51	70	36	71		82		74
08/31		48	90						59		42

Arith Mean	36	24	30	25	31	29	31	26	53	66	32
Max 24-hr Avg	58	72	90	51	70	47	71	39	103	107	74
Std. Dev	12	14	13	14	18	9	16	8	20	34	14
Days of Data	10	28	30	10	10	10	10	5	30	4	30
Days >150											
Yearly Avg	26	24	25	20	20	34	22	21	42	43	24

## UTAH STATE DIVISION OF AIR QUALITY

47mm Partisol: PM10 Concentration Adjusted to Sea Level (24-hr average) in Micrograms per Cubic Meter  
2006 September

Date	Cottonwood	Hawthorn	Lindon	Logan 4	Magna(W)	StGeorge2	NProvo	NProvo-X	NSL	NSL-X	Ogden2
09/01		34	52						65		37
09/02	33	24	33	25	21	23	34	33	47	47	26
09/03		16	28						35		25
09/04		19	37						32		27
09/05	49	40	54		42		40		82		41
09/06		42	58								60
09/07		41	78			27			71		57
09/08	33	30	37	30	32			28	45	47	44
09/09		23	31			15			39		31
09/10		19	10				13		25		18
09/11	35	28	31	24	26						33
09/12		38	36			35	29		109		37
09/13		43	35						72		40
09/14	28	28	28	31	17	45	31	30	74	73	59
09/15		15	15						16		9
09/16		9	4						6		8
09/17	14	12	8		6	16	10		13		11
09/18			15						28		17
09/19			18						34		23
09/20	18		14	8		37	12	11	29	30	15
09/21									20		10
09/22			7						3		8
09/23	16		17	7		15	13		25		10
09/24			11						24		10
09/25			18						39		21
09/26	24		20		18	42	22	22	54	56	29
09/27		23	27								41
09/28		25	33								27
09/29	33	29			17						31
09/30		31	27				21				

Arith Mean	28	27	28	21	22	28	22	25	41	51	28
Max 24-hr Avg	49	43	78	31	42	45	40	33	109	73	60
Std. Dev	11	10	17	11	11	12	10	9	26	15	15
Days of Data	10	21	28	6	8	9	10	5	24	5	29
Days >150											
Yearly Avg	26	24	25	20	20	34	22	21	42	43	24

# UTAH STATE DIVISION OF AIR QUALITY

47mm Partisol: PM10 Concentration Adjusted to Sea Level (24-hr average) in Micrograms per Cubic Meter

2006 October

Date	Cottonwood	Hawthorn	Lindon	Logan 4	Magna(W)	StGeorge2	NProvo	NProvo-X	NSL	NSL-X	Ogden2
10/01											
10/02	25	21	22	13	15		22	20	46	47	
10/03		25	16						41		
10/04		16	10						28		13
10/05	18	15	15	9	7		9		30		8
10/06		13	8						32		
10/07		12	8						15		
10/08	15	15	9	8	11		11	10	21	19	
10/09		16	21						43		
10/10		17	21						26		
10/11	27		26				21		36		
10/12			18						32		
10/13			23						48		
10/14			20				17	17	32	35	
10/15			13						31		
10/16											
10/17											
10/18											
10/19											
10/20											
10/21											
10/22											
10/23											
10/24											
10/25											
10/26											
10/27											
10/28											
10/29											
10/30											
10/31											
Arith Mean	21	17	16	10	11		16	16	33	33	11
Max 24-hr Avg	27	25	26	13	15		22	20	48	47	13
Std. Dev	5	4	6	3	4		6	5	9	14	3
Days of Data	4	9	14	3	3		5	3	14	3	2
Days >150											
Yearly Avg	25	22	25	21	20	34	23	20	42	43	25