The United States' Sulfur Dioxide Emissions Allowance Program: An Overview with Emphasis of Monitoring Requirements and Procedures and a summary report on U.S. experience with Environmental Trading Systems

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The United States' Sulfur Dioxide Emissions Allowance Program: An Overview with Emphasis of Monitoring Requirements and Procedures

1. Introduction

This paper provides a succinct overview of the SO2 trading program with particular emphasis on the emissions monitoring program. Accurate monitoring is the essential foundation of the SO2 trading program. It is also the most complex and costly component of the trading program. Assigning and trading allowances is elementary, but it is no simple task to monitor the several thousand effected utility units. Trading places an economic value on emissions and emission reduction, increasing the need for accurate monitoring. The consequence monetary value is a requirement for continuous emissions monitoring, with redundant capacity.

This summary reviews the SO2 program with specific emphasis on the monitoring procedures required to accomplish SO2 trading. Many details are omitted, however, as the procedures for monitoring are exceedingly complex, particularly in the application of the general rules to complex configurations. The only definitive reference is Section 40 of the US Code of Federal Regulations, Part 75 (p. 3701-3766), and the body of documents issued by the EPA Acid Rain Division (part of the Office of Air and Radiation) to expand and clarify the rules.

2. Overview of the Program

The SO2 trading program in the US is the most successful market based environmental program to date. The concept is simple. A total annual emissions budget (measured in tons of SO2) was established by Congress for the year 1995 and every year following. The emissions level declines in a number of steps from 1995 through 2020, then remains flat subsequent to 2020. Emissions allowances (in the form of one ton certificates) are issued to generating units on the basis of their emissions in 1985, for each year from either 1995 onward for 200+ units or 2000 onward for 2000+ units. The number of allowances quickly falls short of the emissions that would occur without measures to reduce emissions. Emissions are monitored continuously. At the end of the each year, the emissions for each unit are totaled. The owner of the unit must then surrender an allowance for each ton of SO2 emitted. The allowance may be a current year allowance (one issued for the year in which the emissions occurred) or a prior year allowance that was banked (not used in a prior year). Substantial, but not punitive fees are incurred if sufficient allowances can be produced. The key to the program is that allowances can be traded between units. In this way, units that have cost efficient control options can reduce their emissions below the allowance level, and sell their excess allowances to units that can not find economical ways to meet the requirements. In this way, investments can be made where they can do the most good, more capital is available for sensible environmental projects, and there is no need to retire aging facilities soley because of prohibitive environmental costs. Trading promotes efficient use of capital.

This, of course, is a very simple overview of the acid rain program. Every stack and duct of every large coal and oil fired unit in the US has at least one monitor each for SO2, NOX, flow rate, and either O2 or CO2. Every monitoring plan was reviewed and approved before acceptance by the EPA and before the equipment was installed. Once installed, each system went through a lengthy series of certification tests. Every monitor is calibrated daily. All calibration data and all monitoring data are recorded electronically along with a vast amount of other operations data that can be used to check the monitoring results. All of the monitoring data (30 gigabytes annually) are submitted to EPA electronically every quarter, upon which, every record is checked within a day of its arrival at EPA. More than 200 checks are performed looking for simple formatting problems, uncorrected calibration errors, errors in calculating emissions, or failure in applying the complex missing data substitution algorithm. The EPA engages in an active dialog with the operators of all of the effected units to work out problems in data collection and submission to obtain the most accurate data possible. At the end of year, each unit's operator identifies allowances to offset the final tally of emissions from his facility.

3. Effected Units and the Allocation of Allowances

Allowances are allocated for each year beginning in 1995. The SO2 allowance program is directed at generating "units". A unit in this case combustor or set of combustors driving a generator. In Phase I, EPA allocates allowances to each unit at an emission rate of 2. 5 pounds of SO2/mmBtu (million British thermal units) of heat input, multiplied by the unit's baseline mmBtu (the average fossil fuel consumed from 1985 through 1987). Alternative or additional allowance allocations are made for various units, including affected units in Illinois, Indiana, and Ohio, which were allocated a pro rata share of 200,000 additional allowances each year from 1995 to 1999.

In Phase II, which begins in the year 2000, the limits imposed on Phase I plants are tightened, and emissions limits are also imposed on smaller, cleaner units. Allowance allocation calculations are made for various types of units, such as coal and gas-fired units with low and high emissions rates or low fuel consumption. EPA allocates allowances to each unit at an emission rate of 1. 2 pounds of SO2/mmBtu of heat input, multiplied by the unit's baseline. During Phase II, the Act places a cap at 8. 95 million on the number of allowances issued to units each year. This effectively caps emissions at 8. 95 million tons annually and ensures that the mandated emissions reductions are maintained over time.

In addition to annual allocations, allowances are also available upon application to three EPA reserves. In Phase I, units can apply for and receive additional allowances by installing qualifying Phase I technology (a technology that can be demonstrated to remove at least 90 percent of the unit's SO2 emissions) or by reassigning their reduction requirements among other units employing such technology. A second reserve provides allowances as incentives for units achieving SO2 emissions reductions through customer-oriented conservation measures or renewable energy generation. The third reserve contains allowances set aside for auctions, which are sponsored yearly by EPA. In addition, allowances are given as incentives for utilities that replace boilers with new, cleaner and more efficient technologies. The incentives also apply to small diesel fuel refiners that have exceeded the Clean Air Act requirements to remove sulfur from fuels. Units that began operating in 1996 or later will not be allocated allowances. Instead, they will have to purchase allowances from the market or from the EPA auctions and direct sales to cover their SO2 emissions.

4. Startup of Monitoring

Monitoring requirements were phased in over a number of years. Covered units were divided into two groups. About 200 units were designated Phase I units. These were required to begin monitoring on November 15, 1993. Official tracking of emissions did not begin until January 1, 1994, allowing six weeks to utilities and the EPA to test their respective parts of the monitoring system together. The emissions offset program did not start until January 1, 1995 so the emissions data collected in 1994, while officially collected and recorded by the EPA, did not require allowances, so there was effectively no penalty for error. The Phase I units were large units owned by large utility companies. They were presumed to be better able to design and integrate the monitoring and data acquisition and handling systems. The Phase I period provided an opportunity for the more capable companies and for the equipment, computer, and information system providers to test and improve the individual components and integrated systems. It also provided the EPA with an opportunity to test and refine its systems to received, store, and validate the emissions data. The experience on both sides was absolutely essential to the startup of the program. Fully one third of the files received in the first round of submissions contained errors, and EPA processing was slow and difficult. Problems on both sides were largely resolved in time for the 1995 startup of the emissions program.

The monitoring program was extended to over 2000 Phase II units on January 1, 1995, but emissions allowances are not needed until 2000. Despite the 10-fold expansion of the program, the expansion went relatively smoothly, in large measure due to the equipment vendors', the utilities', and the EPA's experience in Phase I.

5. Basic Monitoring Requirements

The general monitoring requirements under the acid rain program are for sulfur dioxide (SO2), oxides of nitrogen (NOX), carbon dioxide (CO2) and opacity. All monitoring systems must have a cycle time of 15 minutes or less. The specific requirements are as follows:

5.1 Sulfur Dioxide

The owner of an affected unit must install and operate an SO2 continuous emissions monitoring system consisting of:

- an SO2 concentration monitor,
- a flow monitor, and
- a data acquisition and handling system (DAHS) to
  - record SO2 concentration in parts per million (ppm)
  - record flow in cubic feet per hour (scfh),

- calculate SO_2 mass emissions in pound per hour (lb/hr), and
- report the above data in the format specified in the next session of this report.

When SO_2 concentration is measured on a dry basis, the operator must either monitor and report the moisture content of the flue gas or correct the volumetric flow for moisture content on a continuous basis.

Hourly, quarterly, and annual emissions are calculated according to the following formula:

Eh = K * Chp * Qhr (100-%H2O) / 100

Where Eh = Hourly emissions (lb/hr)
K = 1.660E-7 (lb/scf)/ppm
Chp = Hourly average SO_2 concentration, dry (ppm)
Qhr = Hourly average volumetric flow rate, wet (scfh)
%H2O = Hourly average stack moisture content (percent by volume)

Emissions for the quarter and the year are the sum of emissions in each respective period.

5.2 Oxides of Nitrogen

The owner of an affected unit must and operate a continuous NOX emissions monitoring system consisting of:

- A NOX concentration monitor,
- An O_2 or CO_2 diluent gas monitor,
- A data acquisition and handling system (DAHS) to
  - record NOX concentration monitor in parts per million (ppm),
  - calculate NOX emissions rates in pounds per million Btu (lb/mmBtu).

The NOX emissions rates is calculated from the NOX concentration and diluent monitor as follows

Case 1: O2 is the diluent

E = K*Ck*F*(20.9/(20.9-PCTO2) there

Where E = Emissions of NOX in lb/MMBtu
K = 1.19E-7 (lb/dscf)/ppm NOX
Ck = average hourly pollutant concentration in ppm
PCTO2 = percent concentration of O2
F is fuel specific, defined in the table below

Fuel	F Factor (dscf/MMBtu)
Anthracite Coal	10,100
Bituminous Coal	9,780
Subbituminous Coal	9,780
Lignite	9,860
Oil	9,190
Natural Gas	8,710
Propane	8,710
Butane	8,710
Wood Bark	9,600
Wood residue	9,240

F represents the ratio of the volume of the dry flue gas generated to the caloric heat content of the fuel combusted. Note that all measurements must be on a dry basis or converted to a dry basis.

Case 2: CO2 is the diluent

$E = K*Ck*Fc * (100/PCTCO2)$

Where:

PCTCO2 = percent concentration of CO_2
Fc is fuel specific, defined below. It represents a ratio of the volume of CO_2 generated to the caloric content of the fuel combusted.

Fuel	Fc Factor (scf CO_2 /MMBtu)
Anthracite Coal	1,970
Bituminous Coal	1,800
Subbituminous Coal	1,800
Lignite	1,910
Oil	1,420
Natural Gas	1,040
Propane	1,190
Butane	1,250
Wood Bark	1,920
Wood residue	1,830

Units have the option of using an Fc factor calculated according to the formula below, if the table factor does not accurately represent their specific fuel.

$Fc = 3.21E5 * PctC / GCV$

where PctC = percent carbon content of the fuel
GCV = gross calorific content of the fuel (Btu/lb) calculated according to ASTM[1] standards specific to the fuel.

Mixed Fuels

If the unit burns a mixed fuel, the calculation is the same as described above for CO_2 and O_2 diluents, but the F and Fc factors are weighted average values, where the weighting factors are each fuel's fraction of GCV. If a unit burns different fuels (or mixes of fuels) at different times during the year, the emissions rate for the year is the weighted sum of the emissions rates for each fuel or mixture. The weighting factor is the fraction of the year each fuel or mixture of fuels is used.

5.3 Carbon Dioxide

Each unit must have a system for monitoring or estimating CO_2 emissions consistent using one of the following options:

- A CO_2 continuous emissions monitoring system consisting of:
  - A CO_2 concentration monitor,
  - A flow monitor, and a
  - DAHS that records CO_2 in ppm, records flow in scfh, and calculates CO_2 mass emissions in tons/hour.
- Calculation of CO_2 emissions based on the measured carbon content of the fuel (in tons per day) based on procedures describe later, or
- An O_2 concentration monitor from which CO_2 emissions are estimated by a procedure that will be described later.

Case 1: when CO_2 is measured on a wet basis

Hourly emissions are calculated according to the following equation

[1] American Society for Testing and Materials

Eh = K*Ch*Qh

Where :

Eh	=	Hourly CO_2 mass emissions (tons/hr)
K	=	5.7E-7 for Co2 ((tons/scf)/%CO2)
Ch	=	Hourly average CO_2 concentration, wet basis (%CO2)
Qh	=	Hourly average volumetric flow rate, wet basis (scfh)

Emissions for the quarter and year are the sum of the hourly emissions for the appropriate period.

Case 2: When O2 is monitored using and O2 diluent monitor

Hourly concentration is calculated according to the formula:

CO2H = 100*(Fc/F)*((20.9-O2H)/20.9)

Where:

CO2H	=	Hourly percent CO_2 concentration on a wet basis (% by volume)
Fc & F	=	Values as listed for oxides of nitrogen above (dscf/MMBtu)
O2H	=	Average hourly O_2 concentration on a dry basis (% by volume)
20.9		

5.4 Opacity

Each unit must have a system to monitor the opacity of the flue gas and a DAHS to calculate and report percent capacity.

5.5 Heat Input

The heat input from all fuels must be recorded for each hour or part of an hour that the unit is operating. For units with a flow monitor, different methods are used to calculate heat input depending on whether CO_2 or O_2 are measured and whether the measurements are on a wet basis of dry basis. The methods are listed below. Oil and gas units are not required to have flow monitors. When there is no flow monitor, heat content can be calculated from analysis of the fuels.

Case 1: CO2 measurements on a wet basis

Heat input is calculated as follows:

HI = QW * (1/Fc) * (%CO2/100)

Where

HI	=	Heat input (mmBtu/hr)
Qw	=	Average hourly flow rate, wet basis (scfh)
Fc	=	Factor listed previously, specific to the fuel type
%CO2w	=	Percent CO_2 concentration on a wet basis

Case 2: CO2 measurements on a dry basis

HI = Qh*((100-$H2O)/(100&Fc)*(%CO2D/100)

Where:

HI	=	Heat input (mmBtu/hr)
Qh	=	Average hourly flow rate, dry basis (scfh)
Fc	=	Factor listed previously, specific to the fuel type
%CO2d	=	Percent CO_2 concentration on a dry basis

Case 3: O2 measurements on a wet basis

HI = Qw*(1/F)*(0.209*(100-%H20)-%O2w)/20.9

Where

HI	=	Hourly heat input (mmBtu/hr)
Qw	=	Hourly average flow rate, wet basis, (scfh)
F	=	Dry basis F factor, listed previously, specific to the fuel type
%O2w	=	Hourly concentration of O2 on a wet basis
%H2O	=	Hourly percent moisture content by volume

Case 4: O2 measurements on a dry basis

HI = Qw* ((100-%H2O)/(100*F)) * ((20.9-%O2D)/20.9)

Where

HI	=	Hourly heat input (mmBtu/hr)
Qw	=	Hourly average flow rate, wet basis, (scfh)
F	=	Dry basis F factor, listed previously, specific to the fuel type
%O2d	=	Hourly concentration of O2 on a dry basis
%H2O	=	Hourly percent moisture content by volume

6. Quality Assurance

Extensive requirements are established to insure they demonstrate the accuracy of the monitoring systems. The staring point is a quality control program. This must include a detailed, step-by-step procedure for:

1. Calibration error tests
2. Linearity check procedures
3. Adjustment of calibration
4. Adjustment of linearity
5. Preventive maintenance
6. Audit
7. Recordkeeping and procedures, and
8. Frequency of testing.

6.1 Mechanical Provisions for Testing

Each Pollutant, CO2, and O2 monitor must be designed with a calibration gas injection port that allows for the entire measurement system to be checked when calibration as is introduced. For extraction and dilution type monitors, the test system must allow the evaluation of all components, including lines, scrubbers, filers, etc) that are exposed to the sample gas. For SO2, NOX, CO2, and O2, the test system must allow for testing over the entire range of the monitors.

For flow monitors, the test system must allow for daily testing over 0% to 20% of span and 50% to 70% of span. Testing must be for all components form the probe tip to the data acquisition and handling system. The flow meter must have provisions to ensure that the entire range of moisture possible at the monitoring point will not interfere with the monitoring system. The system must be designed to allow detection pluggage of all lines and sensing ports, and possible malfunction of each resistance temperature detector.

Differential pressure flow monitors must provide for an automatic period back purging of both lines or an equivalent measure of sufficient force to keep the lines sufficiently free of obstruction to obtain accurate measurements. The cleaning must be done on a daily basis. Thermal flow and ultrasonic monitors must include provisions to keep the problems sufficiently clean to maintain their accuracy.

6.2 Performance requirements

Specific daily tests are set for each type of monitor. Each test must be passed once or more each day. A monitor which fails any test is deemed to be "out of control" and all data collected with it are not deemed to be quality assured until the monitor passes all tests. A monitor that passes all tests is deemed to be calibrated for the hour of the test and 23 successive hours. Operators may test more frequently than once a day.

6.2.1 Daily Calibration Test

The maximum daily calibration error for SO2 and NOX monitors is 2.5% or 5ppm, whichever is greater. The maximum error for CO2 and O2 monitors is The maximum error for flow is 3.0%. Calibration error is calculated as follows:

CE = 100 * Abs(R-A) / S

Where
CE = calibration error
R = reference value of zero of high-level calibration gas
A = actual measurement in response to calibration gas
S = span of the instrument

6.2.2 Daily Linearity Check

The linearity check measures the linear response of the monitors over the span range. Linearity error is defined as follows:

LE = 100 * Abs(R-A) / R

Where all variables are defined as for the calibration error. For SO2 and NOX, the maximum linearity error is the max of 5.0% for tests done with low, medium, and high concentration calibration gases. For monitors with a ranges of 200ppm for less, the monitor is deemed to have a passed the linearity test if Abs(R-A) is less than or equal to 5ppm. For CO2 and O2 monitors the linearity error must be less than 5% for all three calibration gases or the average of the three errors must be less than 0.5%.

6.2.3 Relative Accuracy Test Audit (RATA)

The relative accuracy test specifies that the measurements of the continuous emissions monitoring system be consistent reference test methods. The standards by monitoring system are as follows:

SO2	10.0% variance, except where the test value is less than or equal to 250ppm or, for SO2 diluent monitors, 0.5lb/mmBtu, in which case, the standard is +/1 15.0 ppm or +/- 0.03lb/mmBtu for diluent monitors
NOX	10% variance or 0.02 lb/mmBtu, which ever is larger.
CO2	10% variance
Flow	15% until January 1, 2000, 10% thereafter except for flows of 10fps or less, in which case the allowable error is 2fps.
O2	No comparable reference method test

The relative accuracy is calculated as follows:

1. For a series of tests versus reference methods, calculate the arithmetic average of the differences between the measured and reference methods (d)
2. Calculate the standard deviation of the difference (Sd)
3. Calculate the 97.5% confidence level for the error using a T table, as follows:

CC = T * Sd / Sqrt(N)

Where

T = t value for 0.025 from table below

Sd = standard deviation of the error
N = number of tests

T values for the 97.5% confidence level

n-1	T	n-1	T	n-1	T
1	12.706	12	2.179	23	2.069
2	4.303	13	2.160	24	2.064
3	3.182	14	2.145	25	2.060
4	2.776	15	2.131	26	2.056
5	2.571	16	2.120	27	2.052
6	2.447	17	2.110	28	2.048
7	2.365	18	2.101	29	2.045
8	2.306	19	2.093	30	2.042
9	2.262	20	2.086	40	2.021
10	2.228	21	2.080	60	2.000
11	2.201	22	2.074	>60	1.960

Relative accuracy is defined as follows:

RA = 100 * (Abs(d) + Abs(cc)) / RM

Where RM is the mean of the values of the reference method.

6.2.4 Bias Test

The bias test insures that the readings from a continuous emissions monitoring system are not consistently biased relative to the reference methods. This test builds off of the relative accuracy test. If the mean difference (from step 1, above) is greater than the absolute value of the confidence coefficient (from step 3 above), then the monitor has failed the bias test. If the monitor passes the bias test, then no adjustment is necessary. If it fails the bias test, then a bias adjustment factor is applied. Each value reported by the monitor until a complete set of tests, is multiplied by the BAF, effectively increasing the reported emissions value. The bias adjustment factor is calculated as follows:

BAF = 1 + abs(d) / CEM

Where
Abs(d) = the absolute value of the mean difference, calculated in step 1
CEM = mean of the values provided by the monitor during the failed bias test

If the bias test is failed in a three-level accuracy test audit (with low-, medium-, and high concentration tests), the BAF is calculated for all three, and the highest is used in calculating the reported value.

7. Certification and Recertification

Before any data are considered valid, the monitoring system must be certified. A system must be recertified whenever there is a substantive change in its configuration. The starting point for a certification is a monitoring plan that specifies the configuration of the combustors, stacks, and ducts, the placement of the monitors, the specific type (make and model) of components used throughout the system, and the operating procedures. This must be reviewed and approved by the regional office of the EPA. Given an acceptable plan, a series of tests are necessary to certify the accuracy of the model essentially the same procedures described for the daily calibration are used in certification. The specific tests required are as follows:

- Seven day calibration test
- Relative accuracy test audit
- Bias test

- Cycle time/response test (15 minutes or less).

8. Missing Data Procedures

The EPA rules for the monitoring under the acid rain program require continuous emissions monitoring. They recognize, however, that the monitoring system may, for some for periods, fail to operate or fail to meet the calibration standard described previously. All of the data collected from all of the monitors must be recorded by the data acquisition and handling systems (DAHS). Results from the monitor calibration tests are used to determine whether the monitoring system for each pollutant is "is control." That is, it is operating normally and within EPA established standards for accuracy. If the primary monitor for a pollutant is not available, data from the backup monitor can be substituted. If no data from a backup or portable monitor is available, the missing data algorithms must be applied. Different algorithms are applied for each pollutant. The substitute value calculation is a function of the historical reliability of the monitoring system for the pollutant, and the duration of the period for which data are missing. In general, the higher the historical reliability of the monitoring system and the shorter the duration of the missing data period, the lower the substitute values. For longer gaps and for less reliable monitoring systems, the substitution algorithm produces higher values.

Special substitution algorithms are applied during a startup period for each unit, before adequate operating data have been obtained.

8.1 Initial Missing Data Procedures for SO2

Initial missing data procedures apply for SO2 for any gap occurring before the unit has logged 720 hours of operation with a calibrated monitor. During this period, the substituted value is the average of the value measured before the gap and the value measured immediately after the gap. If the gap occurs before there are any monitored data from a calibrated monitor, the maximum potential concentration is substituted. The maximum potential SO2 concentration is defined as follows:

$$MPC = 1.132E5 * (\%S/GCV) * ((20.9-\%O2w)/20.9) \quad \text{or}$$
$$MPC = 6.693E5 * (\%S/GCV) * (\%CO2w/100)$$

Where

MPC	=	Maximum potential concentration, wet basis (ppm)
%S	=	Maximum sulfur content of the fuel
GCV	=	Gross calorific value (Btu/lb)
%O2w	=	Percent oxygen concentration, wet basis, normal operation
%CO2w	=	Percent CO2 concentration, wet basis, normal operation.

8.2 Initial Missing Data Procedures for NOX and Flow

The initial missing data procedures apply for NOX and Flow for any gap occurring before the unit has logged 2160 hours of operation with a calibrated monitor. During this period, the substituted value is the average of the values collected to date from calibrated monitors. Average values for flow are calculated for a series of 10 load ranges based on percent of the maximum gross load of the unit. The ranges are as follows:

Operating Load Range	Percent of Maximum Gross Load
1	0-10
2	>10-20
3	>20-30
4	>30-40
5	>40-50
6	>50-60
7	>60-70
8	>70-80
9	>80-90
10	>90-100

If no NOX data are available for operating hour with a calibrated monitor, the maximum potential concentration is substituted. The MPC for NOX is set at 800ppm for coal units, and 400ppm for oil and gas units, unless the owner had reason to believe that concentration can exceed this value. In this case, tne MPC is set to 1600 ppm for coal units, and 480 ppm for oil and gas units.

If no flow data are available for a particular load range, the value from the next higher range should be substituted. If there are no data for any higher range, the maximum possible velocity should be substituted, calculated according to the equations, below:

$$MPV = (F*Hf/A) * (20.9/(200.9*\%O2d) * (100/(100-\%H2O)$$
$$MPV = ((Fc * Hf)/A) * (100/\%CO2d) * (100/(100-\%H2O)$$

Where:

MPV = maximum potential velocity (fpm)
F = factor previously defined
Hf = maximum heat input (mmBtu/minute)
A = inside cross-sectional area of the flue at the point of the flow monitor
%O2d = percent oxygen concentration on a dry basis
%CO2d = percent CO2 concentration on a dry basis
%H2O = percent moisture content of the flue gas

8.3 Standard Missing Data Procedures for SO2

The standard missing data procedures for SO2 pertain after 720 quality assured hours of data have been collected for a unit. Two factors are needed to calculate the substitute value: the percent monitor availability (PMA) and the duration of the gap. The PMA is defined as percent of hours since the unit was certified for which quality assured monitoring data are available. If the unit has logged more than 8,760 hours (a 365-day year), only the last 8760 hours are considered in calculating PMA. For SO2, the missing data procedures are as follows:

Percent Monitor Availability	Duration of Gap	Substitute Value
95% or more	Less than or equal to 24 hours	Average of the hour before and the hour after
	More than 24 hours	Maximum of (1) the average of the hour before and the hour after and (2) the 90th percentile of the value logged in the last 720 quality assured hours.
90% or more, but less than 95%	Less than or equal to 8 hours	Average of the hour before and the hour after

	More than 8 hours	Maximum of (1) the average of the hour before and the hour after the gap and (2) the 95th percentile of the values logged in the last 720 quality assured hours.
Less than 90%	Any	The maximum value logged in the last 720 hours.

8.4 Standard Missing Data Procedures for NOX and Flow

The standard missing data procedures for NOX and Flow pertain after 2160 quality assured hours of data have been collected for a unit. Two factors are needed to calculate the substitute value: the percent monitor availability (PMA) and the duration of the gap. PMA is calculated as for SO2. The NOX and flow procedures are as follows:

Percent Monitor Availability	Duration of Gap	Substitute Value
95% or more	Less than or equal to 24 hours	Average of the last 2160 hours. For flow, the average is the average for the load range, defined previously. If no data are available for a load range, use the next higher range, up to MPV.
	More than 24 hours	Maximum of (1) the average of the hour before and the hour after, regardless of load range and (2) the 90th percentile of the value logged in the last 2160 quality assured hours. For flow, the 90th percentile is the 90th percentile for the load range.
90% or more, but less than 95%	Less than or equal to 8 hours	Average of the hour before and the hour after, regarding of load range.
	More than 8 hours	Maximum of (1) the average of the hour before and the hour after the gap, regardless of load range and (2) the 95th percentile of the values logged in the last 2160 quality assured hours. . For flow, the 95th percentile is the 95th percentile for the load range.
Less than 90%	Any	The maximum value logged in the last 2160 hours. For flow the maximum is the maximum in the load range.

For flow, where load range is considered, it is possible that there will be not data the desired load range. In this case, a value from the next higher range for which data are available can be used.

9. Submitting Data

Once all of the data have been collected for a quarter, and the missing data algorithms applied, the data are organized according to a lengthy and very detailed format. All of the data for a unit are included in a single file. If more than one unit feeds and single stack, the stack may be monitored, and the data for all of the related units reported in a single file. Data from the stack are proportioned to the units based on heat input. Files can be very complicated when multiple units are connected to multiple stacks through complex headers.

The reporting is the "Electronic Data Reporting Format". The current version is EDR 1.3. The data acquisition and handling systems must format the according to the EDR. Because of the complexity of the format and the 2000+ DAHS, changes to the EDR are made rarely, and only after lengthy deliberation and comment.

After the quarterly file is prepared, it is sent to the U.S. EPA either on 3.5" diskette or electronically. Initially, most of the data was sent of diskette, but electronic submission now predominates. Electronic submission can be done through the file transfer protocol (FTP) or using custom dialup software provided free of charge by the EPA.

The EPA provides all units with PC-based software to review the quarterly file. ETS-PC performs more than 300 checks of range and format, and provides very detailed diagnostics. The checks performed on the PC are essentially the same as those performed by the EPA once the data are received. The utilities are not allowed to make corrections to the file directly, but can fix problems with the DAHS so that the data are reported correctly, or integrate data form backup or portable monitors if they are available.

The quarterly file is a flat ASCII file. For a single unit operating for an entire quarter it consists of about 15,000 records. A typical file is about one megabyte. It includes the mass emissions and emissions rate data, calculated as described previously, as well as operating and calibration data necessary to validate the emissions numbers. The data are ranged in a series of different record types identified by a three number record type at the beginning of each record. Not all record types are necessary for all units in all quarters. The complete EDR 1.3 is included in Appendix A. The record types are shown in the table that begins on the following page. The basic record type categories are as follows:

1xx Identify the files, provide information on file structure to facilitate electronic processing.
2xx Monitoring data - calibration data and direct monitor readings
3xx Unit operating data and calculated emissions
4xx Control equipment data
5xx Monitoring plan information
6xx Certification data

Categories 4xx and 5xx describe the configuration of the control and monitoring equipment. Certification data are included in categories 6xx when certification occurs during the quarter.

RECORD TYPES			
GROUP	**SUB-GROUP**	**RECORD TYPE**	**RECORD NUMBER**
Facility Data (100)	Facility	Facility ID Data	100
	Configuration	Record Types Submitted	101
Monitoring Data (200)	Pollutant Gas Concentrations	SO_2 Concentration Data	200
		NO_x Concentration Data	201
		CO_2 Concentration Data	202
	Diluent Gas Concentrations	CO_2 Concentration Data	210
		O_2 Concentration Data	211
	Moisture Data	Moisture Data	212
	Volumetric Flow	Volumetric Flow Data	220
	Daily Calibration and Interference Check Data and Results	Daily Calibration Test Data	230
		Daily Interference Check Results	231
	Reference Method Backup Quality Assurance Data	Hourly Pollutant and Diluent Concentration from RM Backup Analyzers	260
		Quality Assurance Run Data for Reference Method Analyzers or Systems Used as Backup CEMS	261
		Reference Method 2 -- Use of Backup Flow Rate Monitor	262
Unit Data (300)	Unit Operating Data	Unit Operating Data	300
		Quarterly Cumulative Emissions Data	301
		Oil Fuel Flow Rate	302
		Gas Fuel Flow Rate	303
	SO_2 Mass Emissions	SO_2 Mass Emissions Data	310
		SO_2 Mass Emissions Alternative Estimation Parameters for Oil	311
		SO_2 Mass Emissions Alternative Estimation Parameters for Natural Gas	312
		SO_2 Mass Emissions Alternative Estimation Parameters for Oil (Revised RT 311)	313
		SO_2 Mass Emissions Alternative Estimation Parameters for Natural Gas (Revised RT 312)	314

RECORD TYPES			
GROUP	**SUB-GROUP**	**RECORD TYPE**	**RECORD NUMBER**
	NO_x Emissions Rate	NO_x Emissions Rate Data	320
		NO_x Emissions Rate Alternative Estimation Parameters for Oil	321
		NO_x Emissions Rate Alternative Estimation Parameters for Natural Gas	322
		NO_x Emissions Rate Alternative Estimation Parameters for Natural Gas (Revised RT 322)	323
	CO_2 Mass Emissions	CO_2 Mass Emissions	330
		CO_2 Estimated Mass Emissions	331
Control Equipment Data (400)	SO_2 Control Equipment Operating Parameters	SO_2 Control Equipment Operating Data	400
		SO_2 Control Equipment Scrubber Module Operating Data	401
	NO_x Control Equipment Operating Parameters	NO_x Control Equipment Operating Data	410
	Qualifying Phase I SO_2 Removal Equipment Parameters	SO_2 Post-Combustion Treatment and Control - Inlet Data	420
		SO_2 Post-Combustion Treatment and Control - Outlet Data	421
		SO_2 Pre-combustion Treatment and Control Data	422
		Combustion Emission Controls	423
Monitoring Plan Information (500)	Units and Unit Pools	Unit Definition Table	500
		Stack Definition Table	501
		Unit Definition Table (Revised RT 500)	502
		Stack Definition Table (Revised RT 501)	503
	Systems/Components	Monitoring Systems/Analytical Component Definition Table	510
	Emissions Formulas	Emission Formula Table	520
	Span and Calibration Gas	Span and Calibration Gas Table	530
	Fuel Flowmeter Information	Fuel Flowmeter Table	540

RECORD TYPES			
GROUP	**SUB-GROUP**	**RECORD TYPE**	**RECORD NUMBER**
	Reasons for Missing Data Periods	Missing Data Period Reasons	550
	Recertification Events	Monitoring System Recertification Event	555
Certification Test Data and Results (600)	Calibration Error Tests	7-Day Calibration Error Test Data and Results	600
		Quarterly Linearity Test Data	601
		Quarterly Linearity Test Results	602
		Quarterly Leak Check Results	603
	RATA/Bias Tests	RATA/Bias Test Data	610
		RATA/Bias Test Results	611
		Reference Method Supporting Data for Gas RATAs	612
		Reference Method 2 Supporting Data for Flow RATAs	613
	Cycle/Response Time	Cycle Time/Response Time Test Data and Results	620
		Cycle Time/Response Time Test Data and Results (Revised RT 620)	621

Appendix

FACILITY INFORMATION							
RECORD TYPE	**TYPE CODE**	**START COL**	**DATA ELEMENT DESCRIPTION**	**UNITS**	**RANGE**	**LENGTH**	**FORMAT (FTN)**
Facility Identification	100	1	Record Type Code			3	I3
		4	ORISPL Number			6	I6
		10	Calendar quarter data contained in report (5=more than 1 quarter)		1-5	1	I1
		11	Calendar year data contained in report	YYYY	≥1993	4	I4
					Total Record Length	14	
Records Types Submitted	101	1	Record Type Code			3	I3
		4	Unit ID			6	A6
		10	Stack/Pipe ID			6	A6
		16	Parameter reported		[2]	7	A7
		23	Record type used			3	I3
		26	# of records		1-9999	4	I4
					Total Record Length	29	

[2] Available codes are: SO2CONC, SO2MASS, FLOWRTE, NOXCONC, DILUENT, NOXRATE, CO2CONC, CO2MASS, OPERATN, OILRATE, GASRATE, SO2RTIN, SO2RTOT

MONITORING DATA

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
POLLUTANT GAS CONCENTRATIONS							
SO_2 Concentration Data §75.54 (c)(1)	200	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Percent monitor data availability for SO_2 data	%	0.0-100.0	5	F5.1
		29	Average SO_2 concentration for the hour	ppm		6	F6.1
		35	Average SO_2 concentration for the hour adjusted for bias	ppm		6	F6.1
		41	Method of determination code		01-12	2	I2
				Total Record Length		42	
NO_x Concentration Data §75.54(d)(1) - (3),(8)	201	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Average NO_x concentration for the hour	ppm		6	F6.1
		30	Method of determination code		01-04	2	I2
				Total Record Length		31	
CO_2 Concentration Data §75.54(e)(i)-(vii)	202	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID				
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Average CO_2 concentration for the hour	%		6	F6.1
		30	Method of determination code		01-06, 14	2	I2
				Total Record Length		31	
DILUENT GAS CONCENTRATIONS							
CO_2 Concentration Data §75.54(e)(1)(i) - (iii) §75.54(d)(4)	210	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Average CO_2 concentration for the hour	%	0.0-100.0	5	F5.1
				Total Record Length		28	
O_2 Concentration Data §75.54(e)(1)(i)-(iii) §75.54(d)(4)	211	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Average O_2 concentration for the hour	%	0.0-100.0	5	F5.1
				Total Record Length		28	

MOISTURE DATA							
Moisture Data §75.54(e)(1)(i) - (iii) §75.54(d)(4)	212	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Average moisture content of flue gases for the hour	%	0.0-100.0	5	F5.1
		29	Formula ID			3	A3
				Total Record Length		31	
VOLUMETRIC FLOW							
Volumetric Flow Data §75.54(c)(2) §75.54(e)(1)(iv)	220	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Percent monitor data availability for volumetric flow	%	0.0-100.0	5	F5.1
		29	Average volumetric flow rate for the hour	scfh		10	I10
		39	Average volumetric flow rate for the hour adjusted for bias	scfh		10	I10
		49	Average moisture content of flue gases for the hour	%	0.0-100.0	5	F5.1
		54	Operating load range corresponding to gross load		01-20	2	I2
		56	Method of determination code		01-12	2	I2
				Total Record Length		57	
DAILY CALIBRATION AND INTERFERENCE CHECK DATA AND RESULTS							
Daily Calibration Test Data and Results §75.56(a)(1)	230	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Instrument span			13	F13.3
		37	Reference value			13	F13.3
		50	Measured value			13	F13.3
		63	Results (CE or |R-A|)	%,ppm	0.0-100.0	5	F5.1
		68	Alternative Performance Specification Flag[3]	0,1		1	I1
		69	Reserved			2	
		71	Calibration Gas Level (Z=zero, H=high)	Z,H		1	A1
				Total Record Length		71	
Flow Daily Interference Check Results §75.56(a)(2)	231	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Status (P-Pass, F-Fail)	P,F		1	A1
		25	Reserved			2	
				Total Record Length		26	

[3] If the alternative performance specification for low emitters (|R-A|) is used, a 1 is recorded; a zero is entered otherwise.

REFERENCE METHOD BACKUP QA DATA							
Hourly Pollutant and Diluent Concentration Data from RM Backup Analyzers §§ 75.24(c)(2) and 75.20(d)	260	1	Record Type			3	I3
		4	Unit/Stack ID			6	A6
		10	Reference Method Component ID			3	A3
		13	Reference Method Monitoring System ID			3	A3
		16	Parameter monitored (SO_2, NO_x, CO_2, O_2)			4	A4
		20	Run number			2	I2
		22	Date	YYMMDD		6	I6
		28	Hour	HH	00-23	2	I2
		30	Unadjusted (raw) average pollutant or diluent concentration for the hour			7	F7.2
		37	Adjusted average pollutant or diluent concentration for the hour			7	F7.2
				Total Record Length		43	
Quality Assurance Run Data for Reference Method Analyzers or Systems Used as Backup CEMS §§ 75.24(c)(2) and 75.20(d)	261	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Reference Method Component ID			3	A3
		13	Reference Method Monitoring System ID			3	A3
		16	Run number			2	I2
		18	RM run start date	YYMMDD		6	I6
		24	RM run start hour	HH	00-23	2	I2
		26	RM run end date	YYMMDD		6	I6
		32	Rm run end hour	HH	00-23	2	I2
		34	Type of analyzer/system	EXT, DIL		3	A3
		37	Moisture basis of RM analysis	WET, DRY		3	A3
		40	Instrument span (as defined in App A, Part 60)			5	I5
		45	Dilution factor			5	I5
		50	Reference zero gas concentration			7	F7.2
		57	Initial (pre-test) calibration response--zero gas			7	F7.2
		64	Pre-test calibration error--zero gas (% of span)	%		5	F5.1
		69	Reference mid-level gas concentration			7	F7.2
		76	Initial (pre-test) calibration response--mid gas			7	F7.2
		83	Pre-test calibration error--mid gas (% of span)	%		5	F5.1
		88	Reference high-level gas concentration			7	F7.2
		95	Initial (pre-test) calibration response--high gas			7	F7.2
		102	Pre-test calibration error--high gas (% of span)	%		5	F5.1
		107	Upscale gas used during run (mid, high)	M,H		1	A1
		108	Pre-run system response--zero gas			7	F7.2
		115	Pre-run system bias (non-dilution) or calibration error (dilution)--zero gas (% of span)	%		5	F5.1
		120	Post-run system response--zero gas			7	F7.2
		127	Post-run system bias (non-dilution) or calibration error (dilution)--zero gas (% of span)	%		5	F5.1
		132	Pre-run system response--upscale gas			7	F7.2
		139	Pre-run system bias (non-dilution) or calibration error (dilution)--upscale gas (% of span)	%		5	F5.1
		144	Post-run system response--upscale gas			7	F7.2
		151	Post-run system bias (non-dilution) or calibration error (dilution)--upscale gas (% of span)	%		5	F5.1
		156	Zero drift (% of span)	%		5	F5.1
		161	Calibration drift (% of span)	%		5	F5.1
		166	Stack gas density adjustment factor			5	F5.3
				Total Record Length		170	

Reference Method 2 -- Use of as Backup Flow Rate Monitor (Run Summary) §§ 75.24(c)(2) and 75.20(d)	262	1	Record Type			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Reference Method Component ID			3	A3
		13	Reference Method Monitoring System ID			3	A3
		16	Run date	YYMMDD		6	I6
		22	Run hour	HH	00-23	2	I2
		24	Number of traverse points			2	I2
		26	(Square root of _P)$_{avg.}$	in. H_2O		5	F5.2
		31	T_s, stack temperature	°R		4	I4
		35	P_{bar}, barometric pressure, in. Hg	in. Hg		5	F5.2
		40	P_g, stack static pressure, in. H_2O	in. H_2O		5	F5.2
		45	% CO_2 in stack gas, dry basis	%		5	F5.2
		50	% O_2 in stack gas, dry basis	%		5	F5.2
		55	% moisture in stack gas	% H_2O		5	F5.2
		60	M_d, stack gas molecular weight, dry basis	lbs/lbs-mole		5	F5.2
		65	M_s, stack gas molecular weight, wet basis	lbs/lbs-mole		5	F5.2
		70	C_p, pitot tube coefficient			5	F5.3
		75	Date of latest pitot tube calibration	YYMMDD		6	I6
		81	A_s, stack or duct cross-sectional area at test port	ft^2		6	F6.1
		87	Total volumetric flowrate	scfh		10	I10
				Total Record Length		96	

UNIT DATA

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
UNIT OPERATING DATA							
Unit Operating Parameters §75.50(b)(1) - (6)	300	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Unit operating time		0.00-1.00	4	F4.2
		22	Gross unit load for the hour	MWe-hr		6	I6
		28	Steam load[4]	1000 lb/hr		6	I6
		34	Operating load range corresponding to gross load for the hour		01-20	2	I2
		36	Total hourly heat input rate	mmBtu/hr		7	F7.1
				Total Record Length		42	
Quarterly Cumulative Emissions Data §75.64(a)	301	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Date of report generation	YYMMDD		6	I6
		16	Quarterly SO_2 tons emitted	ton		10	F10.1
		26	Cumulative annual SO_2 tons emitted	ton		10	F10.1
		36	Quarterly average NO_x emission rate	lb/mmBtu		13	F13.3
		49	Cumulative annual average NO_x emission rate	lb/mmBtu		13	F13.3
		62	Quarterly CO_2 tons emitted	ton		10	F10.1
		72	Cumulative annual CO_2 tons emitted	ton		10	F10.1
		82	Quarterly total heat input	mmBtu		10	I10
		92	Cumulative annual total heat input	mmBtu		10	I10
		102	Reserved			6	
		108	Reserved			6	
				Total Record Length		113	
Oil Fuel Flow for Appendix D, E & G §75.55(c) (Required January 1, 1996)	302	1	Record Type Code			3	I3
		4	Unit ID/Pipe ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Mass flow rate of oil for the hour	lb/hr		10	F10.1
		31	Missing data/source of data code for mass oil flow rate[5]	0-9		1	I1
		32	Operating load range corresponding to gross load		01-20	2	I2
		34	Gross calorific value (GCV) of oil	Btu/lb		10	F10.1
		44	Missing data flag for GCV of oil[4]	0,1		1	I1
		45	Heat input rate from oil for the hour	mmBtu/hr		7	F7.1
		52	Fuel usage time		0.00-1.00	4	F4.2
		56	Type of oil (OIL - residual oil, DSL - diesel)	OIL,DSL		3	A3
		59	Volumetric flow rate of oil for the hour			10	F10.1
		69	Units of measure for oil flow rate	[5]		5	A5
		74	Missing data/source of data code for oil flow rate[6]	0-9		1	I1
		75	Density of oil			8	F8.5
		83	Units of measure for density of oil	[5]		5	A5
		88	Missing data flag for density of oil[5]	0,1		1	I1
		89	Flag to indicate multiple or single fuel types combusted (M = multiple fuels combusted, S = this fuel only combusted)	M,S		1	A1
				Total Record Length		89	

[4] Steam load may be reported in lieu of total integrated unit load if appropriate.

[5] If this record represents substitute data, a 1 is recorded; a zero is entered otherwise. Other codes for "source of data code" are reserved for future designation.

[6] Limited to a Table of Codes: SCFH (scf/hr); GALHR (gal/hr); BBLHR (barrels/hr), M3HR (M^3/hr) for volumetric flow of oil
LBSCF (lb/scf); LBGAL (lb/gal); LBBBL (lb/barrel), LBM3 (lb/m^3) for density of oil

Gas Fuel Flow for Appendix D, E & G §75.55(c) (Required January 1, 1996)	303	1	Record Type Code			3	I3
		4	Unit ID/Pipe ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Flow rate of gas for the hour	100 scfh		10	F10.1
		31	Missing data flag for gas flow rate[7]	0,1		1	I1
		32	Operating load range corresponding to gross load		01-20	2	I2
		34	Gross calorific value (GCV) of gas	Btu/100 scf		10	F10.1
		44	Missing data flag for GCV[6]	0,1		1	I1
		45	Heat input rate from gas for the hour	mmBtu/hr		7	F7.1
		52	Fuel usage time		0.00-1.00	4	F4.2
		56	Type of gas (PNG - Pipeline Natural Gas, OTH - Other)	PNG,OTH		3	A3
		59	Flag to indicate multiple or single fuel types combusted (M = multiple fuels combusted, S = this fuel only combusted)	M,S		1	A1
				Total Record Length		59	
			SO_2 MASS EMISSIONS				
SO_2 Mass Emissions Data §75.50(c)(3)	310	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	SO_2 mass emissions rate for the hour	lb/hr		7	F7.1
		25	SO_2 mass emissions rate for the hour adjusted for bias	lb/hr		7	F7.1
		32	Formula ID from monitoring plan for hourly SO_2 emissions			3	A3
				Total Record Length		34	
SO_2 Mass Emissions Alternative Estimation Parameters for Oil §75.51(c)(1) and (2) (Effective Through December 31, 1995)	311	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Average flow rate of oil for the hour			10	F10.1
		28	Sulfur content of oil sample	%	0.0- 7.0	5	F5.1
		33	Code for method of oil sampling from monitoring plan (ADC, ADD, ADR)	ADC,ADD, ADR		3	A3
		36	Mass rate of oil combusted for the hour	lb/hr		10	F10.1
		46	Average SO_2 mass emissions for the hour	lb/hr		7	F7.1
		53	Highest sulfur content recorded from last 30 daily oil samples	%	0.0- 7.0	5	F5.1
		58	Missing data flag[6]	0,1		1	I1
				Total Record Length		58	
SO_2 Mass Emissions Alternative Estimation Parameters for Natural Gas §75.51(c)(3) (Effective Through December 31, 1995)	312	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Heat input from natural gas	mmBtu		10	F10.1
		26	Sulfur content of daily gas sample	grains/scf		8	F8.1
		34	Volume of gas combusted per day	kscf		8	F8.1
		42	SO_2 emission rate from NADB or NADB default for pipeline natural gas	lb/mmBtu		13	F13.5
		55	Missing data flag[6]	0,1		1	I1
				Total Record Length		55	

[7] If this record represents substitute data, a 1 is recorded; a zero is entered otherwise.

SO_2 Mass Emissions Alternative Estimation Parameters for Oil (Hourly) § 75.51(c)(1) and (2) (Revised Record Type 311) Required January 1, 1996	313	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Sulfur content of oil sample	%	.01-5.0	5	F5.2
		26	Code for method of oil sampling (ADC, ADD, ADR)	ADC, ADD, ADR		3	A3
		29	Missing data flag for sulfur content[7]	0,1		1	I1
		30	SO_2 mass emission rate from oil for the hour	lb/hr		7	F7.1
				Total Record Length		36	
SO2 Mass Emissions Alternative Estimation Parameters for Natural Gas (Hourly) § 75.51(c)(3) (Revised Record Type 312) Required January 1, 1996	314	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Sulfur content of gas sample	grains/100 scf		8	F8.1
		29	Missing data flag for sulfur content[8]	0,1		1	I3
		30	SO_2 emission rate from NADB or default SO_2 emission rate of 0.0006	lb/mmBtu		7	F7.5
		37	SO_2 mass emission rate from gas for the hour	lb/hr		8	F8.5
				Total Record Length		44	

[8] If this record represents substitute data, a 1 is recorded; a zero is entered otherwise.

UNIT DATA

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
			NO_x EMISSION RATE				
NO_x Emission Rate Data §75.54(d)(2),(5) - (9)	320	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Percent monitor data availability for NO_x emission rate calculations	%	0.0-100.0	5	F5.1
		26	F factor converting NO_x concentrations to emission rates			10	F10.1
		36	Average NO_x emission rate for the hour	lb/mmBtu/hr		6	F6.3
		42	Average NO_x emission rate for the hour adjusted for bias	lb/mmBtu/hr		6	F6.3
		48	Operating load range corresponding to gross load for the hour		01-10	2	I2
		50	Formula ID from monitoring plan for hourly NO_x emission rate			3	A3
		53	Method of determination code		01-15	2	I2
				Total Record Length		54	
NO_x Emission Rate Alternative Estimation Parameters for Oil §75.55(d)(1) (Effective through December 31, 1995)	321	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Fuel flowrate of oil for the hour	gal/hr		10	F10.1
		28	NO_x emission rate F factor for oil			10	F10.1
		38	Average NO_x emission rate for the hour	lb/mmBtu/hr		6	F6.3
		44	Missing data flag[9]	0,1		1	I1
				Total Record Length		44	
NO_x Emission Rate Alternative Estimation Parameters for Natural Gas §75.55(d)(2) (Effective through December 31, 1995)	322	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Fuel flowrate of natural gas for the hour	Mscf/hr		10	F10.1
		28	NO_x emission rate F factor for natural gas			10	F10.1
		38	Average NO_x emission rate for the hour	lb/mmBtu/hr		6	F6.3
		44	Missing data flag[8]	0,1		1	I1
				Total Record Length		44	
NO_x Emission Rate Alternative Estimation Parameters for Oil and Gas (Revised RT 322 for Appendix E) §75.55(d)(1) and (d)(2) Required January 1, 1996	323	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH		2	I2
		21	Parameters flag (Y = in spec, N = out of spec)	Y,N		1	A1
		22	Average NO_x emission rate for the hour (combined fuels)	lb/mmBtu/hr		6	F6.3
		28	Average NO_x emission rate for the hour for oil	lb/mmBtu/hr		6	F6.3
		34	Average NO_x emission rate for the hour for gas	lb/mmBtu/hr		6	F6.3

[9] If this record represents substitute data, a 1 is recorded; a zero is entered otherwise.

UNIT DATA							
RECORD TYPE	**TYPE CODE**	**START COL**	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
				Total Record Length		39	

UNIT DATA							
RECORD TYPE	**TYPE CODE**	**START COL**	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
			CO_2 MASS EMISSIONS				
CO_2 Mass Emissions Data §75.54(e)(1)(ii),(v), (vii) & (viii)	330	1	Record Type Code			3	I3
		4	Unit ID/Stack Pipe ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	CO_2 mass emissions rate for the hour	ton/hr		10	F10.1
		28	Formula ID from monitoring plan for hourly CO_2 mass emissions			3	A3
		31	Method of Determination Code - 13 = App. G Missing Data		13	2	I2
				Total Record Length		32	
CO_2 Mass Emissions Estimation Parameters §75.54(e)(2)	331	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Daily combustion related CO_2 mass emission rate adjusted for CO_2 retained in flyash	ton/day		10	F10.1
		26	Daily sorbent-related CO_2 mass emission rate	ton/day		10	F10.1
		36	Total daily CO_2 mass emission rate	ton/day		10	F10.1
				Total Record Length		45	

CONTROL EQUIPMENT DATA

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
SO_2 CONTROL EQUIPMENT OPERATING PARAMETERS							
SO_2 Control Equipment Operation Parameters §75.51(b)(1)	400	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Number of scrubber modules operating		≥1	2	I2
				Total Record Length		19	
SO_2 Control Equipment Scrubber Module Parameters §75.51(b)(1)	401	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Scrubber module number		1-n[10]	2	I2
		12	Date	YYMMDD		6	I6
		18	Hour	HH	00-23	2	I2
		20	Average percent solids in slurry for operating scrubber module	%	0.0-100.0	5	F5.1
		25	Average feedrate of makeup slurry to operating scrubber module	gal/hr		10	F10.2
		35	Average pressure differential across operating scrubber module			10	F10.2
		45	Average inline absorber pH		0.0-14.0	4	F4.1
		49	Number of spray levels in service		≥1	2	I2
		51	Average scrubber module inlet temperature	°F		3	I3
		54	Average scrubber module outlet temperature	°F		3	I3
				Total Record Length		56	
NO_x CONTROL EQUIPMENT PARAMETERS							
NO_x Control Equipment Operation Parameters §75.51(b)(2)	410	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Inlet air flow rate			6	I6
		24	Excess O_2 concentration of flue gas at stack outlet	%	0.0-100.0	5	F5.1
		29	CO concentration of flue gas at stack outlet	ppm		5	F5.1
		34	Flue gas temperature at furnace exit outlet duct	°F		3	I3
				Total Record Length		36	
QUALIFYING PHASE I SO_2 CONTROL EQUIPMENT PARAMETERS							
SO_2 Phase I Technology Post-Combustion Control Parameters Inlet Monitors §75.55(a)(1)	420	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Inlet SO_2 emission rate for the hour	lb/mmBtu		13	F13.3
		34	Reserved				
		47	Formula ID from monitoring plan for hourly inlet SO_2 emission rates			3	A3
		50	Method of determination code		01-04	2	I2
				Total Record Length		51	

[10] Upper limit equals the number of scrubber modules identified for the corresponding piece of control equipment.

SO_2 Phase I Technology Post-Combustion Control Parameters Outlet Monitors §75.55(a)(1)	421	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Outlet SO_2 emission rate for the hour	lb/mmBtu		13	F13.3
		34	Reserved				
		47	Formula ID from monitoring plan identifying formula deriving average hourly outlet SO_2 emission rates from monitor data			3	A3
		50	Method of determination code		01-04	2	I2
				Total Record Length		51	
SO_2 Phase I Technology Pre-Combustion Control Parameters §75.55(a)(2)(v)	422	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Date	YYMMDD		6	I6
		16	Hour	HH	00-23	2	I2
		18	Pre-treatment fuel weight	ton		10	F10.1
		28	Pre-treatment fuel sulfur content	%	0.0-100.0	5	F5.1
		33	Pre-treatment fuel gross calorific value	Btu/lb		10	F10.1
		43	Post-treatment fuel weight	ton		10	F10.1
		53	Post-treatment fuel sulfur content	%	0.0-100.0	5	F5.1
		58	Post-treatment fuel gross calorific value	Btu/lb		10	F10.1
				Total Record Length		67	
SO_2 Phase I Technology Combustion Emission Controls §75.55(a)(2)(i)-(iv)	423	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Hour	HH	00-23	2	I2
		21	Outlet SO_2 emission rate for the hour	lb/mmBtu		13	F13.3
		34	Daily inlet SO_2 emission rate (determined by coal sampling and analysis)	lb/mmBtu		13	F13.3
				Total Record Length		46	

MONITORING PLAN INFORMATION

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
Unit Definition Table §75.53(c)(2) Effective through December 31, 1995	500	1	Record Type Code			3	I3
		4	Plant Name			20	A20
		24	Unit Short Name			20	A20
		44	Unit ID (i.e., NADB Boiler ID)			6	A6
		50	Unit classification			2	A2
		52	Boiler type			3	A3
		55	Primary fuel			3	A3
		58	SO_2 controls			3	A3
		61	NO_x controls			8	A8
		69	Particulate controls			6	A6
		75	SO_2 monitoring method			3	A3
		78	NO_x monitoring method			8	A8
		86	CO_2 monitoring method			6	A6
		92	Opacity monitoring method			3	A3
				Total Record Length		94	
Stack/Pipe Header Definition Table Effective Through December 31, 1995	501	1	Record Type Code			3	I3
		4	Stack/Pipe Header ID			6	A6
		10	Stack/Pipe Header Description or Name			20	A20
		30	Unit ID			6	A6
		36	Submission status - Add (A), Delete (D), Correct (C), Unchanged (U)	A,C,D,U		1	A1
				Total Record Length		36	
Unit Definition Table §75.53(c)(2) (Revised RT 500) Required January 1, 1996	502	1	Record Type Code			3	I3
		4	Plant Name			20	A20
		24	Unit Short Name			20	A20
		44	Unit ID (i.e., NADB Boiler ID)			6	A6
		50	Unit classification			2	A2
		52	Boiler type			3	A3
		55	Primary fuel			3	A3
		58	SO_2 controls			3	A3
		61	NO_x controls			8	A8
		69	Particulate controls			6	A6
		75	SO_2 monitoring method			3	A3
		78	NO_x monitoring method			8	A8
		86	CO_2 monitoring method			6	A6
		92	Opacity monitoring method			3	A3
		95	Secondary fuels			13	A13
		108	Maximum hourly gross load in megawatts (used for load range calculations)	MWe-hr		6	I6
		114	Maximum hourly gross steam load (used for load range calculations)	1000 lbs/hr		6	I6
		120	Unit definition change date	YYMMDD		6	I6
				Total Record Length		125	
Stack/Pipe Header Definition Table (Revised RT 501) Required January 1, 1996	503	1	Record Type Code			3	I3
		4	Stack/Pipe Header ID			6	A6
		10	Stack/Pipe Header description or name			20	A20
		30	Unit ID (i.e., NADB Boiler ID)			6	A6
		36	Submission status - Add (A), Delete (D), Correct (C), Unchanged (U)	A,C,D,U		1	A1
		37	Maximum hourly gross load in megawatts (used for load range calculations)	MWe-hr		6	I6
		43	Maximum hourly gross steam load (used for load range calculations)	1000 lbs/hr		6	I6
		49	Activation date	YYMMDD		6	I6
		55	Retirement date	YYMMDD		6	I6
				Total Record Length		60	

Monitoring Systems/Analytical Components Table §75.53(c)(4)	510	1	Record Type Code			3	I3
		4	Unit ID/Stack or Pipe Header ID			6	A6
		10	Component ID/Software ID			3	A3
		13	Monitoring System ID			3	A3
		16	Status (Add (A), Correct (C), Delete (D), Unchanged (U)	A,C,D,U		1	A1
		17	System parameter monitored			4	A4
		21	Primary/backup designation	P,B,RB,RM, DB		2	A2
		23	Component type code			4	A4
		27	Sample acquisition method			3	A3
		30	Manufacturer			25	A25
		55	Model/version			15	A15
		70	Serial number			20	A20
		90	Provisional certification date	YYMMDD		6	I6
		96	Provisional certification time	HHMM	0000-2359	4	I4
				Total Record Length		99	
Formula Table §75.53(c)(6)	520	1	Record Type Code			3	I3
		4	Unit ID/Stack or Pipe Header ID			6	A6
		10	Submission Status - Add (A), Delete (D), Correct (C), Unchanged (U)	A,D,C,U		1	A1
		11	Formula ID			3	A3
		14	Parameter monitored			4	A4
		18	Formula code			5	A5
		23	Formula text			200	A200
				Total Record Length		222	
Span Table Required January 1, 1996 §75.53(c)(10)	530	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Parameter Monitored			4	A4
		14	Scale - High (H) or Low (L)	H,L		1	A1
		15	Method for calculating MPC/MEC/MPF	F,HD,TR, TB,OL		2	A2
		17	MPC/MEC/MPF	[11]		13	F13.3
		30	Maximum NO_x emission rate	lbs/mmBtu		6	F6.3
		36	Span value			13	F13.3
		49	Full scale range			13	F13.3
		62	MPC/MEC/MPF, span and full scale range units of measure	[12]		5	A5
		67	Submission status - Add (A), Delete (D), Correct (C) or Unchanged (U)	A,D,C,U		1	A1
		68	Span effective date	YYMMDD		6	I6
				Total Record Length		73	

[11] Provide SO_2 and NO_x MPC/MEC in ppm. Provide flow maximum potential flowrate (MPF) in scfh.

[12] For SO_2 and NO_x use PPM. For CO_2 use %. For flow use units corresponding to calibration as follows: SFPM, KSFPM, SCFM, KSCFM, SCFH, KSCFH, ACFM, KACFM, ACFH, KACFH, INH20, MSCFH, MACFH, AFPM, KAFPM

Fuel Flowmeter Data Required January 1, 1996	540	1	Record Type Code			3	I3
		4	Unit/Pipe Header ID			6	I6
		10	Monitoring System ID			3	A3
		13	Parameter monitored			4	A4
		17	Type of oil or gas (OIL - Residual Oil, DSL - Diesel, PNG - Pipeline Natural Gas, OTH - Other)	OIL,DSL, PNG,OTH		3	A3
		20	Maximum fuel flow rate			10	F10.1
		30	Units of measure for maximum fuel flow rate	[13]		5	A5
		35	Source of maximum rate (URV = Upper Range Value, UMX = Unit Max)	URV,UMX		3	A3
		38	Initial calibration method			11	A11
		49	Ongoing calibration method			11	A11
		60	Submission status - Add (A), Delete (D), Correct (C) or Unchanged (U)	A,D,C,U		1	A1
				Total Record Length		60	
Reasons for Missing Data Periods Required January 1, 1996	550	1	Record Type Code			3	I3
		4	Unit/Stack ID			6	A6
		10	Parameter (SO2, CO2, NOX, FLOW, OILM, OILV, GAS, GCVG, GCVO, %SG, %SO, DENS)			4	A4
		14	Monitoring System ID			3	A3
		17	Begin date	YYMMDD		6	I6
		23	Begin hour	HH	00-23	2	I2
		25	End date	YYMMDD		6	I6
		31	End hour	HH	00-23	2	I2
		33	Missing data reason code		[14]	2	I2
		35	Missing data description		[15]	75	A75
		110	Corrective action description			75	A75
				Total Record Length		184	
Monitoring System Recertification Events Required January 1, 1996	555	1	Record Type Code			3	I3
		4	Unit/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Begin date of recertification event	YYMMDD		6	I6
		19	Begin hour of recertification event	HH	00-23	2	I2
		21	Recertification event code		[16]	2	I2
		23	Recertification event description		[14]	50	A50
		73	Recertification event response/action taken			50	A50
		123	System permanently inactivated/retired	RET		3	A3
		126	7-day calibration test required	7CE		3	A3
		129	Linearity check required	LIN		3	A3
		132	Cycle time test required	CTT		3	A3
		135	RATA/bias test required	RAT		3	A3
		138	DAHS verification required	VER		3	A3
		141	Daily calibration	DLC		3	A3
		144	Interference Check	INT		3	A3
		147	Leak Check	LCK		3	A3
		150	Completion date of required recertification tests	YYMMDD		6	I6
		156	Completion hour of required recertification tests hour	HH	00-23	2	I2
				Total Record Length		157	

[13] For volumetric flow meters for oil use SCFH (scf/hr); GALHR (gal/hr); BBLHR (barrels/hr); M3HR (M^3/hr). For mass of oil flow meters use LBHR. For gas flow meters use HSCF (for 100 scfh).

[14] For missing data reason codes see instructions.

[15] Optional field. Provide information if code does not adequately explain reason or event.

[16] For recertification event codes see instructions.

CERTIFICATION TEST DATA AND RESULTS

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
			CALIBRATION/ERROR TESTS				
7-Day Calibration Error Test Data and Results §75.56(a)(1)	600	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Instrument span			13	F13.3
		37	Reference value			13	F13.3
		50	Measured value			13	F13.3
		63	Results (CE or |R-A|)	%, ppm	0.0-100.0	5	F5.1
		68	Alternative performance specification flag[17]	0,1		1	I1
		69	Calibration gas level (Z=zero, H=high)	Z,H		1	A1
				Total Record Length		69	
			LINEARITY CHECKS				
Quarterly Linearity Test Data §75.56(a)(3)	601	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Time	HHMM	0000-2359	4	I4
		26	Instrument span			13	F13.3
		39	Reference value			13	F13.3
		52	Measured value			13	F13.3
		65	Calibration gas level (L=low, M=mid, H=high)	L,M,H		1	A1
				Total Record Length		65	
Quarterly Linearity Check Results §75.56(a)(3)	602	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Instrument Span			13	F13.3
		35	Mean of reference values			13	F13.3
		48	Mean of measured values			13	F13.3
		61	Results (LE or |R-A|)	%, ppm	0.0-100.0	5	F5.1
		66	Alternative performance specification flag[16]	0,1		1	I1
		67	Reserved				
		71	Calibration gas level (L=low, M=mid, H=high)	L,M,H		1	A1
				Total Record Length		71	
			LEAK CHECKS				
Flow Quarterly Leak Check Results §75.56(a)(4)(i)	603	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Hour	HH	00-23	2	I2
		24	Status (P-Pass, F-Fail)	P,F		1	A1
		25	Reserved			4	
				Total Record Length		28	

[17] If the alternative performance specification for low emitters (|R-A|) is used, a 1 is recorded; a zero is entered otherwise.

RATA/BIAS TESTS

RATA and Bias Test Data §75.20(c)(1)(iii) and (iv) §75.20(c)(2)(ii) and (iii) §75.20(c)(5)(iii)	610	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Run start date	YYMMDD		6	I6
		19	Run start time	HHMM	0000-2359	4	I4
		23	Run end date	YYMMDD		6	I6
		29	Run end time	HHMM	0000-2359	4	I4
		33	Units of measure (1=ppm, 2=lb/mmBtu, 3=scfh, 4=%)	1,2,3,4		1	I1
		34	Value from CEM system being tested			13	F13.3
		47	Value from reference method, adjusted as necessary for moisture and/or calibration bias			13	F13.3
		60	Run number			2	I2
		62	RATA run status flag	0,1,9		1	I1
			0 = RATA used, run not used				
			1 = Run data used in calculating relative accuracy and bias				
			9 = RATA not used, run not used				
		63	Operating level - low, mid, high or normal (L,M,H,N)	L,M,H,N		1	A1
		64	Gross unit load	MWe		6	I6
				Total Record Length		69	
RATA and Bias Test Results §75.20(c)(1)(iii) and (iv) §75.20(c)(2)(ii) and (iii) §75.20(c)(5)(iii)	611	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Date	YYMMDD		6	I6
		19	Time	HHMM	0000-2359	4	I4
		23	Reference method used			11	A11
		34	Units of measure (1=ppm, 2=lb/mmBtu, 3=scfh, 4=%)	1,2,3,4		1	I1
		35	Arithmetic mean of CEMS values			13	F13.3
		48	Arithmetic mean of reference method values			13	F13.3
		61	Arithmetic mean of the difference data			13	F13.3
		74	Standard deviation of difference data			13	F13.3
		87	Confidence coefficient			13	F13.3
		100	Relative accuracy			5	F5.2
		105	Tabulated t- value (bias test)			6	F6.3
		111	Bias adjustment factor			5	F5.3
		116	Operating level - low, mid, high or normal (L,M,H,N)	L,M,H,N		1	A1
		117	Gross unit load	MWe		6	I6
		123	Reserved			4	
				Total Record Length		126	

Reference Method Supporting Data for Gas RATAs § 75.52(a)(5)(iii)(F) § 75.52(a)(7) § 75.64(a)(1) (Required January 1, 1998)	612	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Run number			2	I2
		18	RM run start date	YYMMDD		6	I6
		24	RM run start time	HHMM	0000-2359	4	I4
		28	RM run end date	YYMMDD		6	I6
		34	RM run end time	HHMM	0000-2359	4	I4
		38	Type of RM analyzer/system	EXT, DIL		3	A3
		41	Moisture basis of RM analysis	WET, DRY		3	A3
		44	RM instrument span (as defined in App A, Part 60)			5	I5
		49	RM dilution factor			5	I5
		54	Reference zero gas concentration			7	F7.2
		61	Initial (pre-test) calibration response--zero gas			7	F7.2
		68	Pre-test calibration error--zero gas (% of span)	%		5	F5.1
		73	Reference mid-level gas concentration			7	F7.2
		80	Initial (pre-test) calibration response--mid gas			7	F7.2
		87	Pre-test calibration error--mid gas (% of span)	%		5	F5.1
		92	Reference high-level gas concentration			7	F7.2
		99	Initial (pre-test) calibration response--high gas			7	F7.2
		106	Pre-test calibration error--high gas (% of span)	%		5	F5.1
		111	Upscale gas used during run (mid, high)	M,H		1	A1
		112	Pre-run system response--zero gas			7	F7.2
		119	Pre-run system bias (non-dilution) or calibration error (dilution)--zero gas (% of span)	%		5	F5.1
		124	Post-run system response--zero gas			7	F7.2
		131	Post-run system bias (non-dilution) or calibration error (dilution)--zero gas (% of span)	%		5	F5.1
		136	Pre-run system response--upscale gas			7	F7.2
		143	Pre-run system bias (non-dilution) or calibration error (dilution)--upscale gas (% of span)	%		5	F5.1
		148	Post-run system response--upscale gas			7	F7.2
		155	Post-run system bias (non-dilution) or calibration error (dilution)--upscale gas (% of span)	%		5	F5.1
		160	Zero drift (% of span)	%		5	F5.1
		165	Calibration drift (% of span)	%		5	F5.1
		170	Unadjusted (raw) average concentration for run			7	F7.1
		177	% Moisture in stack gas	% H_2O		5	F5.2
		182	Stack gas density adjustment factor			5	F5.1
		187	Adjusted average concentration for run (corrected for calibration bias/error and, if applicable, moisture and stack, gas density)			7	F7.1
		194	F-factor used for conversion to lb/mmBtu			6	I6
		200	Formula code for formula used to convert to lb/mmBtu			5	A5
				Total Record Length		204	

Reference Method 2 Supporting Data for Flow RATA Tests § 75.52(a)(5)(iii)(F) § 75.52(a)(7) § 75.64(a)(1) (Required January 1, 1998)	613	1	Record Type			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Monitoring System ID			3	A3
		13	Run start date	YYMMDD		6	I6
		19	Run start time	HHMM	0000-2359	4	I4
		23	Run end date	YYMMDD		6	I6
		29	Run end time	HHMM	0000-2359	4	I4
		33	Run number			2	I2
		35	Operating level	L,M,H,N		1	A1
		36	Number of traverse points			2	I2
		38	(Square root of _P)$_{avg.}$	in. H_2O		5	F5.2
		43	T_s, stack temperature	°R		4	I4
		47	P_{bar}, barometric pressure, in. Hg	in. Hg		5	F5.2
		52	P_g, stack static pressure, in. H_2O	in. H_2O		5	F5.2
		57	% CO_2 in stack gas, dry basis	%		5	F5.2
		62	% O_2 in stack gas, dry basis	%		5	F5.2
		67	% moisture in stack gas	% H_2O		5	F5.2
		72	M_d, stack gas molecular weight, dry basis	lbs/lbs-mole		5	F5.2
		77	M_s, stack gas molecular weight, wet basis	lbs/lbs-mole		5	F5.2
		82	C_p, pitot tube coefficient			5	F5.3
		87	Date of latest pitot tube calibration	YYMMDD		6	I6
		93	A_s, stack or duct cross-sectional area at test port	ft^2		6	F6.1
				Total Record Length		98	

CYCLE/RESPONSE TIME

Cycle Time/Response Time Test Data and Results §75.20(c)(1)(v) §75.20(c)(2)(iv) §75.20(c)(5)(iv) (Effective through December 31, 1995)	620	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Start time	HHMM	0000-2359	4	I4
		26	End time	HHMM	0000-2359	4	I4
		30	Response/cycle time	Min		2	I2
		32	Start monitor value			13	F13.3
		45	Reference value			13	F13.3
		58	Monitor value at which 95% of the reference value change has occurred			13	F13.3
				Total Record Length		70	

TEST INFORMATION

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
Cycle Time/Response Time Test Data and Results -- §75.20(c)(1)(v) §75.20(c)(2)(iv) §75.20(c)(5)(iv) (Required January 1, 1996)	621	1	Record Type Code			3	I3
		4	Unit ID/Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Start time	HHMM	0000-2359	4	I4
		26	End time	HHMM	0000-2359	4	I4
		30	Component cycle time	Min		2	I2
		32	Stable starting monitor value			13	F13.3
		45	Stable ending monitor value			13	F13.3
		58	Calibration gas value			13	F13.3
		71	Calibration gas level (Z=zero, H=high)	Z,H		1	A1
		72	Total or system cycle time[18]	Min		2	I2
				Total Record Length		73	
FUEL FLOW CALIBRATION							
Fuel Flowmeter Calibration Data §75.56(b)(1)	625	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Test number			2	I2
		24	Reference flow measurement value			10	F10.1
		34	Measured flow value			10	F10.1
		44	Units of measure for URV and flow rate	[19]		5	A5
		49	Fuel flow rate level (L=low, M=mid, H=high)	L,M,H		1	A1
				Total Record Length		49	
Fuel Flowmeter Calibration Results §75.56(b)(1)	626	1	Record Type Code			3	I3
		4	Unit ID/Pipe Header ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Date	YYMMDD		6	I6
		22	Test number			2	I2
		24	Component Upper range value			10	F10.1
		34	Mean of reference flow values			10	F10.1
		44	Mean of measured flow values			10	F10.1
		54	Units of measure for URV and flow rate	[18]		5	A5
		59	Accuracy results (% of URV)	%	0.0-100.0	5	F5.1
		64	Fuel flow rate level (L=low, M=mid, H=high)	L,M,H		1	A1
				Total Record Length		64	

[18] For time-shared systems, use the sum of the longest runs. For NO_x systems, report the longer cycle time of the two component analyzers as the system cycle time.

[19] Limited to a Table of Codes: SCFH (scf/hr); GALHR (gal/hr); BBLHR (barrels/hr); M3HR (m^3/hr) for volumetric flow of oil; LBHR (lbs/hr) for mass of oil; and HSCF (100 scfh) for gas flow.

ALTERNATIVE MONITORING PETITION DATA

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
Alternative Monitoring System Approval Petition Data §75.41(a)	630	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	AMS ID			6	A6
		22	Date	YYMMDD		6	I6
		28	Hour	HH	00-23	2	I2
		30	Hourly test data for alternative monitoring system			13	F13.3
		43	Hourly lognormalized test data for alternative monitoring system			13	F13.3
		56	Hourly test data for reference CEMS			13	F13.3
		69	Fuel type code			2	I2
		71	Operating Level - Low, Normal, High (L,N,H)	L,N,H		1	A1
		72	Gross unit load	MWge		6	I6
				Total Record Length		77	
Alternative Monitoring System Approval Petition Results and Statistics §75.41(a) - (c)	631	1	Record Type Code			3	I3
		4	Unit ID/ Stack ID			6	A6
		10	Component ID			3	A3
		13	Monitoring System ID			3	A3
		16	Unit of Measure (1=ppm, 2=lb/mmBtu, 3=scfh, 4=%)	1,2,3,4		1	A1
		17	Arithmetic mean of AMS values			13	F13.3
		30	Arithmetic mean of CEM values			13	F13.3
		43	Arithmetic mean of differences of paired AMS and CEM values			13	F13.3
		56	Variance of differences			13	F13.3
		69	Variance of measured values of AMS			13	F13.3
		82	Variance of measured values for CEM			13	F13.3
		95	F-statistic			13	F13.3
		108	Critical value of F at 95% confidence level for sample size			13	F13.3
		121	Coefficient of correlation (Pearson's r) of CEM and AMS data			13	F13.3
		134	Shapiro-Wilk test statistic (W) for AMS data			13	F13.3
		147	Shapiro-Wilk test statistic (W) for CEMS data			13	F13.3
		160	Lognormally adjusted data used in final analysis (1 = yes, 0 = no)	0,1		1	I1
		161	Autocorrelation coefficient (ρ) for AMS data			13	F13.3
		174	Autocorrelation coefficient (ρ) for CEM data			13	F13.3
		187	Autocorrelation coefficient (ρ) for differences of paired AMS and CEM data			13	F13.3
		200	Adjustment for autocorrelation used in final analysis (1 = yes, 0 = no)	0,1		1	I1
		201	Covariance of alternative monitoring data and associated lag(1) values			13	F13.3
		214	Covariance of continuous emission monitoring data and associated lag(1) values			13	F13.3
		227	Covariance of differences of paired AMS and CEM data			13	F13.3
		240	Standard deviation of AMS data			13	F13.3
		253	Standard deviation of CEM data			13	F13.3
		266	Standard deviation of differences of paired AMS and CEM data			13	F13.3
		279	Standard deviation of lag(1) AMS data			13	F13.3
		292	Standard deviation of lag(1) CEM data			13	F13.3
		305	Standard deviation of lag(1) differences of paired AMS and CEM data			13	F13.3
		318	Variance inflation factor for AMS data			13	F13.3
		331	Variance inflation factor for CEM data			13	F13.3
		344	Variance inflation factor for difference of paired AMS and CEM data			13	F13.3
				Total Record Length		356	

APPENDIX E TEST RECORDS

RECORD TYPE	TYPE CODE	START COL	DATA ELEMENT DESCRIPTION	UNITS	RANGE	LENGTH	FORMAT (FTN)
NO_x Heat Input Correlation Test Data Appendix E to Part 75	650	1	Record Type Code			3	I3
		4	Unit ID			6	A6
		10	Monitoring System ID for Appendix E System			3	A3
		13	Reference method run start date	YYMMDD		6	I6
		19	Reference method run start time	HHMM	0000-2359	4	I4
		23	Reference method run end date	YYMMDD		6	I6
		29	Reference method run end time	HHMM	0000-2359	4	I4
		33	Reference method response time	sec	0-800	3	I3
		36	Value from reference method during run			8	F8.3
		44	Run number			2	I2
		46	Operating level - 1 = lowest	1-99		2	I2
		48	Type of fuel combusted (O=residual oil, D=diesel fuel, G=gaseous fuel, M=mixture)	O,D,G,M		1	A1
		49	Total heat input or load during the run	mmBtu		7	F7.1
		56	Elapsed time	hrs	0.1-8.0	3	F3.1
		59	Hourly heat input for run	mmBtu/hr		7	F7.1
				Total Record Length		65	
NO_x/Heat Input Correlation Results Appendix E to Part 75	651	1	Record Type Code			3	I3
		4	Unit ID			6	A6
		10	Monitoring System ID for Appendix E System			3	A3
		13	Completion date of last test	YYMMDD		6	I6
		19	Completion time of last test	HHMM	0000-2359	4	I4
		23	Arithmetic mean of reference method values at this level	lb/mmBtu		8	F8.3
		31	F Factor converting NO_x concentrations to emission rates			10	F10.1
		41	Average heat input rate or load at this level	mmBtu/hr		7	F7.1
		48	Operating level - 1=lowest	1-99		2	I2
		50	Type of fuel combusted (O=residual oil, D=diesel fuel, G=gaseous fuel, M=mixture)	O,D,G,M		1	A1
				Total Record Length		50	
Oil Fuel Flow During Test Appendix E to Part 75	652	1	Record Type Code			3	13
		4	Unit ID			6	A6
		10	Monitoring System ID for Oil Fuel Flow System			3	A3
		13	Run start date	YYMMDD		6	I6
		19	Run start time	HHMM	0000-2359	4	I4
		23	Run end date	YYMMDD		6	I6
		29	Run end time	HHMM		4	I4
		33	Run number			2	I2
		35	Mass flow of oil during run	lb		10	F10.1
		45	Gross calorific value (GCV) of oil	Btu/lb		10	F10.1
		55	Heat input during run	mmBtu		7	F7.1
		62	Volumetric flow of oil during run			10	F10.1
		72	Units of measure for oil flow	[20]		5	A5
		77	Density of oil			8	F8.6
		85	Units of measure for density of oil	[19]		5	A5
				Total Record Length		89	

[20] Limited to a Table of Codes: SCFH (scf/hr); GALHR (gal/hr); BBLHR (barrels/hr), M3HR (m^3/hr) for volumetric flow of oil
LBSCF (lb/scf); LBGAL (lb/gal); LBBBL (lb/barrel), LBM3 (lb/m^3) for density of oil

APPENDIX E TEST RECORDS							
RECORD TYPE	**TYPE CODE**	**START COL**	**DATA ELEMENT DESCRIPTION**	**UNITS**	**RANGE**	**LENGTH**	**FORMAT (FTN)**
Gas Fuel Flow During Test Appendix E to Part 75	653	1	Record Type Code			3	I3
		4	Unit ID			6	A6
		10	Monitoring System ID for gas fuel flow system			3	A3
		13	Run start date	YYMMDD		6	I6
		19	Run start time	HHMM	0000-2359	4	I4
		23	Run end date	YYMMDD		6	I6
		29	Run end time	HHMM	0000-2359	4	I4
		33	Flow of gas for the run	100 scf		10	F10.1
		43	Gross calorific value (GCV) of gas	Btu/100 scf		10	F10.1
		53	Heat input from gas during the run	mmBtu		7	F7.1
				Total Record Length		59	

Emissions Trading Experience in the United States

The use of emissions trading systems began in the United States in the mid-1970's as a means of allowing new sources to locate in nonattainment areas without worsening air quality. From this important beginning, the use of pollution trading systems has expanded into a wide variety of forms encompassing a growing number of sources that impact all media (air, water, and land).
This report finds that there are approximately fifty emissions trading programs currently operating in the United States. While the majority of these are related to air quality programs, trading programs are also operating in water quality and land use programs as well.

The general principle of pollutant trading systems is that sources may satisfy their emissions obligations by one of two means: 1) limiting their releases of pollution to no more than the permitted amount, or 2) releasing more (or less) than the permitted amount and exchanging allowances representing any deficiency, or surplus, in the quantity of emissions controlled with other sources. Sources with marginal costs of pollution control are likely to meet their obligations without trading. Those with relatively high marginal control costs are likely buyers of pollution reduction allowances and sources with low marginal costs of control are likely sellers of excess allowances.

Today pollution trading systems have evolved to include far more than the exchange of pollution reduction allowances. For example, the acid rain trading program is based on allowances for future emissions. Certain Colorado communities have created programs to trade the right own and operate a wood burning stove or fireplace. For a number of years there was an active program in which refiners could trade lead for use as an additive in gasoline. Heavy-duty truck manufacturers can meet engine emission standards by averaging together the emissions performance of all engines they produce. Programs to trade water effluents are operating in selected locations. Developers whose activities would cause the loss of wetlands can satisfy mitigation requirements in some areas by purchasing credits from a wetland mitigation bank. These and other trading systems for air, water, and land are described in more detail in the following sections.

Air Pollution Trading Programs

The USEPA's air emissions trading program had its beginnings in the mid-1970's as a solution to the problem of locating new sources of air pollution in nonattainment areas. To accommodate new sources and expansion of existing sources, the USEPA proposed an "offset" policy that permitted growth within a nonattainment region provided that new sources install pollution control equipment meeting Lowest Achievable Emission Rate (LAER) standards and offset any excess by acquiring greater emission reductions from other sources in the area. Through this process, growth could still be accommodated while maintaining progress toward the attainment of the national ambient air quality standards.

The offset policy spawned three related programs: bubbles, banking and netting. The common element in which is the Emission Reduction Credit or ERC. An ERC is generated when a source reduces its emissions below the lower of the actual or allowable emissions and apply to the state for the certification of the reduction. Once certified an ERC is tradable with other facilities in the region pursuant to the regulations established by the state. The bubble program allowed a source to meet its emission limits by treating multiple emission points within one facility as if they had a single aggregate emission limit. Banking allowed facilities to bank emissions reductions achieved beyond control limits for use at a future date. Netting allowed sources undergoing modification to avoid New Source Review (NSR) regulations if they could demonstrate that plant-wide emissions did not increase significantly.

Nationwide Air pollution Trading Programs

Acid Rain Allowance Trading: *Cap-and-Trade/Budget Program* – Nationwide

The SO2 Allowance Trading Program is a cap-and-trade or budget-type program. The program is aimed at electric utilities, which produce the majority of SO2 emissions in the U.S. (66% in 1980, for example). Under the program, utilities receive annual allocations of SO2 allowances from EPA based on baseline emissions from 1985 to 1987. The first allocation year was 1995. Each allowance permits a utility to emit one ton of SO2 . Utilities may use the allowances for compliance purposes, bank them for future use, or sell them to other utilities or other buyers such as brokers, fuel companies, and environmental groups. Allowances have already been allotted for the years 1995 to 2030 (though they cannot be used for compliance until their designated year). The total number of allowances allotted has been phased down over time in accordance with aggregate emission reduction goals. The program will reach its full effect in 2010, when annual emissions from the electric utilities that are required to participate in the program - "major" utilities, namely those with more than 25 MW capacity - will be capped at 8.95 million tons, down from 17.0 million tons in 1980 and 15.6 million tons in 1990.

Title IV of the 1990 Clean Air Act Amendments (CAAA) - Acid Deposition Control - set out the requirements for the Federal Acid Rain Program. This program calls for reductions in nationwide emissions of SO2 and nitrogen oxides (NOx) beginning in 1995. One component of the Acid Rain Program is the SO2 Allowance Trading Program, the first nationwide emission allowance program. The first set of "core" rules to implement the SO2 Allowance Trading Program were finalized in January 1993. Phase I of the program, which applies to roughly 440 generating units at 180 electric utility plants (representing about 50 utility companies) in 21 eastern states, including, as designated in the CAAA, 263 units at 110 of the nation's highest-emitting electric utility plants, began on January 1, 1995. During Phase II, which begins January 1, 2000, another 1,500 or so generating units at approximately 470 electric utility plants across the country will be brought into the program. Active trading in SO2 allowances began prior to the start of Phase I. In fact, the first annual auction of SO2 allowances at the Chicago Board of Trade (CBOT) was conducted on March 29, 1993. The Allowance Tracking System, which electronically tracks the allocation, holdings, and trading of all allowances, went into operation on March 14, 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

CFC Production Allowance Trading: *Cap-and-Trade/Budget Program* – Nationwide

The Montreal Protocol on Substances that Deplete the Ozone Layer established a limit on the consumption of chlorofluorocarbons and halon substances. The Protocol limited consumption to 1986 levels and scheduled reductions for 1993 and 1998. In 1990, at a second meeting of the parties, a full phase out of these substances was agreed to by the year 2000. To accomplish the phase out by the most efficient means possible, the United States decided on a program that coupled a marketable allowance trading system with excise taxes on CFC production, (the excise taxes were designed to capture the windfall profits associated with the diminishing supply CFCs, whereas the allowance trading system was designed to assure that control of the production and import of these substances was accomplished efficiently). This system was then implemented by the USEPA.

The Protocol defined consumption as production plus imports, minus exports. Consequently to establish the Allowance Trading system the USEPA allocated allowances to companies that produced or imported CFCs and halons. EPA distributed allowances to 5 CFC producers, 3 halon producers, 14 CFC importers, and 6 halon importers, based on their 1986 market share.
Producers and importers could then trade allowances of specific CFC types and/or between CFC types (example CFC-11 could be traded for and equal amount of CFC-12, CFC-13, CFC-14 or CFC-15). The USEPA rules also specify that each time a production allowance is traded, on percent of the allocation is "retired" to assure environmental improvement.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Regional Air Emissions Trading Programs

NESCAUM/MARAMA: ***Cap-and-Trade/Budget Program – Northeastern and Midatlantic States***

NESCAUM/MARAMA initiated a demonstration project in June of 1993 to help resolve the issues surrounding emission trading in the states from North Carolina to Maine. The first phase developed principles for creating discrete emission reductions (DERs). The second phase, completed in 1995, developed protocols to promote an environmentally sound trading system by reviewing actual and proposed trades. The third phase assisted the USEPA in developing the Open Market Trading Rule enacted on July 26,1995. This group has gone on to help design and implement a program to reduce NOx emissions on a region-wide basis. The third phase has now become a large part of what makes up the Ozone Transport Committee (OTC).

Sources: 1) USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.
2)NESCAUM/MARAMA NOx Budget Model Rule

OTC/OTAG Regional NOx Reduction Program: ***Cap-and-Trade/Budget Program*** **– Northeastern U.S.**

Title I of the Clean Air Act Amendments establish a northeast transport region consisting of 12 states and the District of Columbia, which run from Northern Virginia to New England. This region is treated as a Moderate ozone nonattainment area requiring RACT controls. Title I also called upon the EPA to establish the Ozone Transport Commission (OTC) as a consensus building organization with representation from each affected jurisdiction to recommend control measures.

A task force of representatives from the OTC, including NESCAUM and MARAMA, were charged with developing a program to implement region-wide NOx emissions reduction beginning in 1999. The Northeast States for Coordinated Air Use Management (NESCAUM) and the Mid-Atlantic Regional Air Management association (MARAMA) worked together with the OTC and OTAG process to develop a program that includes a cap on NOx emissions and subsquent trading of emissions allowances. Analysis of the problem demonstrated that substantial economic benefits could be achieved by implementing a significant NOx reduction with a “cap and trade” program compared to a traditional emissions limit program (command and control). The initial reductions will occur in 1999, with further reductions to be implemented in 2003.

To implement the program, the OTC MOU emissions reductions are applied to a 1990 baseline for NOx Emission sin the Ozone transprort region to create a “cap” or emissions budget for each of the two target years: 1999 and 2003. The 1990 baseline was established through extensive work of the OTC Stationary and Area Source Committee, the USEPA, and industry, to refine and quality assure the information available on actual NOx emissions for 1990. The 1990 baseline emissions and budget has been disaggregated to a state level and the states will allocate allowances to the facilities affected, called budget sources. Beginning in 1999, the sum of NOx emissions from budget sources can not exceed the equivalent number of allowances allocated in the region. An allowance is equal to one ton of NOx emissions. Budget sources must hold allowances for all NOx emitted during the ozone season months of May through September and budget sources are allowed to buy, sell, or trade allowances as needed.

Once the Ozone Season has ended, budget sources have a window of opprotunity to evaluate their reported emissions and obtain any additional allowances they may need to balance the emissions during the ozone season. This is called the end of season reconcilliation period. Allowances that are not used automatically roll-over into the following year and are banked. The allowance banking provisions of the NOx Budget Model Rule provide for unlimited banking of allowances with pirce-based progressive flow control on the use of banked allowances. This establishes incentives for companies to build up banks of unused allowances.

Sources: 1) USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.
2)NESCAUM/MARAMA NOx Budget Model Rule

Open Market Trading: ***Command and Market*** **– Regionally Around the U.S.**

The USEPA Open Market Trading Rule was proposed in August of 1995. It was termed “Open Market” to distinguish it from other trading systems with a budget cap or “closed market” systems. The goal was to create a model program that states could use as a basis for their own program implemented as part of their State Implementation Plan (SIP). The proposed rule would allow sources to legally substitute discrete emission reductions (DERs) for strict compliance using pollution control equipment. DERs could be offered by sources that control more than required, much like the earlier offset program. Numerous comments on the Open Market trading Rule have been received by the USEPA. Some favorable some not. Many of the state programs that are detailed later in this document have been developed to be at least compatible with the USEPAs open market trading initiative. The open market trading rule remains under consideration as of this time and whether and/or in what form the USEPA decides promulgate the rule is still unknown.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Lead Credit Trading: *Command and Market* – Regionally Around the U.S.

In the 1970’s virtually all gasoline contained an average of 2.4 grams per gallon of Lead to the increase octane of the fuel. In 1975 the USEPA acted to curtail the amount of Lead added to gasoline because of the associated health risks and the fact that lead fouled catalytic converters. Vehicles produced after the model 1975 were required to us unleaded fuel for theses reasons.

During the late 1970’s demand for leaded fuel was reduced steadily as more cars that ran on unleaded fuel were produced. By the early 1980’s the market for leaded fuel was so reduced that the USEPA average lead content limits had little impact on the amount of lead in gasoline. In 1982 the USEPA acted to sharply curtail the remaining use of lead in gasoline by setting standards that would eliminated almost all of it by January 1986. To facilitate the phase out of the remaining lead in gasoline the USEPA allowed trading in two forms: 1) inter-refinery averaging and banking for future use or sale.

Lead credits were created by refiners, importers and ethanol blenders, that were then tradable to refiners still producing leaded fuel. The lead trading program was quite successful judging by market activity. By the end of the program 60 percent of refiners participated in the program and 90 percent of those participated in banking of credits. Ultimately, lead trading allowed the USEPA to phase out the use of lead in gasoline much more rapidly than otherwise feasible.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Trading of Gasoline Constituents: *Command and Market* – Regionally Around the U.S.

Mobile source emissions standards in the United States were significantly enhanced by the Clean Air Act Amendments (CAAA) of 1990. Title II of the 1990 CAAA allows states to establish trading systems for three constituents of reformulated fuels: oxygen, aromatics, and benzene. Under this trading system, refiners can meet reformulated content requirements by producing gasoline that met the new specifications or by trading credits in these constituents with other refiners so that collectively the standards were satisfied.

Participation in this program is optional for states. In areas where trading has been permitted, credits in oxygenates can be exchanged between parties that the state has designated as responsible for satisfying the fuel requirements. While trading theoretically offers a cost effective means of meeting the reformulation requirements, in fact there have been almost no trading programs implemented. Only the state of Pennsylvania has adopted trading rules and no trades have been reported to date in the state.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Heavy Duty Truck Engine Emissions Trading: ***Command and Market*** **– Regionally Around the U.S.**

Title II of the CAAA of 1990 also sets standards for NOx and particulate emissions from heavy duty truck engines. The goal is to reduce these pollutants to the maximum degree achievable and hopefully to reach a 75 percent average reduction across the fleet. To accomplish the reductions the USEPA has allowed manufacturers to average together the emission performance of all heavy duty truck engines they produce. Averaging emissions facilitates compliance, since not every engine has to meet the 75% reductions, but if and how much money companies have saved because of this is unknown at this time.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Hazardous Air Pollutants (HAPs) Trading – Early Reduction: ***Command and Market*** **– Regionally Around the U.S.**

This rule issued by the USEPA in December of 1992, allows qualifying facilities to intertemporally exchange their early emissions reductions for their later emissions reductions. Basically if a facility qualifies by reducing its emissions of hazardous air pollutants by 90 percent before the USEPA issues Maximum Achievable Control Technology (MACT) regulations for the source category, the facility may defer compliance with the new MACT standards for up to six years. Obviously, there must be a direct cost savings for facilities to participate but by mid-1993 over 60 chemical plants in the US had asked to participate.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Hazardous Air Pollutants Trading (HAPs) – Petroleum Industry NESHAPS: ***Command and Market*** **– Regionally Around the U.S.**

Two Petroleum industry related NESHAPS rules were promulgated in the summer of 1995 establishing MACT requirements for process vents, storage vessels, wastewater streams, equipment leak tanks, and marine vessel tank loading operations. Both rules permit the use of emissions averaging among marine tank vessel loading operations, bulk gasoline terminal or pipeline breakout station storage vessels, and bulk gasoline loading racks, and petroleum refineries. Emissions averaging gives the owner the opportunity to find the most cost-effective control strategies for their operation.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Hazardous Air Pollutants Trading (HAPs) – HON NESHAPS: ***Command and Market*** **– Regionally Around the U.S.**

The Hazardous Organic Chemical (HON) NESHAP requires sources to limit emissions of organic HAPs to apply "reference control" or equivalent technology at MACT. Because of the high cost of MACT controls for this industry the USEPA included a provision allowing for emissions averaging for facilities that over control in one area to earn credits that can be applied in other areas.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

State Air Pollution Trading Programs

Regional Clean Air Incentives Market (RECLAIM): *Cap-and-Trade/Budget Program* – California

RECLAIM is a mandatory cap-and-trade, or allocation, program for stationary sources in the South Coast Air Basin that emit four tons or more of NOx or SOx per year. Two separate allocation and trading systems/markets are maintained - one for NOx and one for SOx. Based on system-wide NOx and SOx emission caps for the year, participating NOx facilities receive an annual allocation of NOx RECLAIM Trading Credits (RTCs) and participating SOx facilities receive an annual allocation of SOx RTCs. Each NOx and SOx RTC permits the holder to emit one pound of NOx and SOx, respectively, in the year designated (with certain restrictions - RTCs are not property rights). RTC allocations are diminished over time in accordance with emission reduction requirements in the South Coast Air Quality Management Plan (AQMP). RTCs can be bought, sold, or transferred, allowing facilities to select the most cost-effective strategy for meeting their annual emission targets. Trading allows facilities to achieve RECLAIM compliance with maximum flexibility and at minimum cost. Based on their unique operational needs, facilities can meet their declining annual emission targets by reducing actual emissions or can increase their emission limits by securing RTCs through trades.

In general, facilities are subject to RECLAIM if they had NOx or SOx emissions of four tons or greater in 1989 or any subsequent year. However, certain facilities are categorically excluded from RECLAIM, including restaurants, police and fire-fighting facilities, potable water delivery operations, and all facilities located in the Riverside County and Los Angeles County portions of the Southeast Desert Air Basin. Additionally, certain other categories of facilities are not automatically subject to RECLAIM, but individual facilities in these categories have the option to enter the program at their discretion ("opt-in"). These categories include ski resorts, prisons, hospitals, and publicly owned waste-to-energy facilities.

At the end of the second compliance year (June 30, 1996), the RECLAIM "universe" consisted of 330 facilities. All 330 were participating in the NOx market, and 37 were participating in the SOx market as well. The total of 330 represented a reduction of 14 from 344 at the end of the first compliance year. During the second compliance year, 10 facilities shut down, 6 were excluded from RECLAIM, one was included (two others were included in the SOx market but they were already participating in the NOx market), and one facility, the City of Burbank (with a power plant), opted in. The RECLAIM universe is expected to remain fairly stable in the future, with any increases or decreases resulting primarily from changes in the level of economic activity.

Although participation in RECLAIM is by stationary sources, the RECLAIM rules allow for the conversion of tradeable emission reduction credits (ERCs), including mobile source ERCs and area source credits (ASCs), into RTCs as a way to supply additional credits to the program.

RECLAIM was adopted by the SCAQMD Governing Board on October 15, 1993. The first compliance year was January 1, 1994 through December 31, 1994 for Cycle 1 facilities, and July 1, 1994 through June 30, 1995 for Cycle 2 facilities. The second compliance year was January 1, 1995 to December 31, 1995 for "Cycle 1" facilities and July 1, 1995 to June 30, 1996 for "Cycle 2" facilities. Trading in RECLAIM Trading Credits (RTCs) commenced on March 22, 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

Alternative Control Plan (ACP) Regulation: *Command-and-Market Program* – California

The ACP supplements existing State regulations for VOC emissions from the use of consumer products by allowing emissions averaging/bubbling. Limits can be placed on aggregate emissions from a group of products rather than on emissions from individual products. Manufacturers (or other "responsible ACP parties") can sell products that exceed VOC standards in the existing regulations provided that the emissions from these high-VOC products will be offset by the emissions from other products reformulated to "overcomply" with the standards. Participation in the ACP is voluntary (though the existing VOC regulations are mandatory). For the benefit of businesses without sufficient resources or product diversity to significantly average emissions under an ACP bubble, the ACP allows limited trading of "surplus reduction credits." Only small businesses -- manufacturers/marketers with no more than 250 employees and retail outlets with gross annual receipts of no more than $2 million -- and businesses that market only one product or product line subject to the existing VOC regulations can purchase surplus reduction credits. An exception is made under certain conditions when a business needs credits to reconcile an exceedance of the ACP bubble limit. Businesses of any size can sell surplus reduction credits.

The ACP became State law on September 9, 1995.

Source: USEPA Directory of Air quality Economic Incentive Programs

Interchangeable Air Pollution Reduction Credits: *Command-and-Market Program* – California

The regulation sets out general requirements that local air pollution control districts and air quality management districts ("districts") must meet when developing rules governing the generation and use of interchangeable credits. An interchangeable credit is "an emission reduction credit generated from a stationary, mobile, or area source that can be used, traded, or banked among programs and/or source categories" (as specified in the regulation and in accordance with state and Federal law). The regulation is applicable only to districts that choose to adopt, implement, or amend a rule or regulation that authorizes the interchangeable use of emission reduction credits other than as offsets for new source review (NSR). In order to standardize and facilitate credit trading, the proposed regulation establishes a uniform credit currency, expressed in pounds of pollutant in the year generated.

On May 22, 1997, the California ARB adopted a statewide regulation in Interchangeable Air Pollution Emission Reduction Credits. The regulation is pursuant to California Assembly Bill 1777, which became law in October 1995 and is now codified as Health and Safety Code (HSC) sections 39607.5 and 39617. Section 39607.5 requires ARB to develop and adopt a methodology for use by local air pollution districts to calculate the value of "interchangeable" emission reduction credits generated from stationary, mobile, and area sources.

Source: USEPA Directory of Air quality Economic Incentive Programs

New Source Review (NSR): *Command-and-Market Program* - California

As part of its NSR process, the San Diego APCD requires an emission offset for any increase in the potential to emit of a nonattainment pollutant, or its precursor, from a new major stationary source or an existing major stationary source undergoing a major modification. There are emission reduction credit (ERC) banking and trading provisions to accommodate this requirement. Unless the actual emission reductions being proposed to offset the emission increases occur concurrently at the new or modified stationary source, emission reductions must be banked (as ERCs) to qualify as an emission offset. San Diego is the only air district in California (out of 34) that, based on air modeling, has minimum interpollutant offset ratios written into its NSR rules. Ratios are specified for combinations of NOx, VOCs, SOx, and PM10. CO is not included due to air modeling considerations. The ratio is 2 to 1 for offsetting an NOx emission increase with a VOC emission decrease, and 1 to 1 for offsetting a VOC emission increase with an NOx emission decrease. The San Diego APCD is willing to reassess the ratios if air quality conditions change or if they don't have the predicted results.

The San Diego APCD's General Provisions for NSR, along with emission reduction credit (ERC) banking provisions, have been in effect since July 5, 1979.

Source: USEPA Directory of Air quality Economic Incentive Programs

Project SEED (Solutions for the Environment and Economic Development: *Command-and-Market Program* – California

Project SEED is a pilot program under which emission reduction credits (*ERCs*) are leased by the SMAQMD (the "district") to stationary sources at an equivalent of the cost of the credits on the open market. The sources of the credits are emission reductions from the cessation of B52 flights at Mather Air Force Base (AFB). These credits now represent the single largest source of ERCs in the district. Lease revenues will be used to fund innovative, market-based projects that achieve emissions reductions beyond those already promised in the SIP.

This will create new ERCs to replace ERCs that have been leased out. The funding is likely to be directed primarily at mobile sources, which account for about 70 percent of the emissions inventory in the district and therefore present the greatest opportunities for achieving emissions reductions.

Approved by the SMAQMD Board of Directors on August 1, 1996. Began operation on September 4, 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Credits for the Voluntary Repair of On-Road Motor Vehicles Identified through Remote Sensing Devices: *Command-and-Market Program* - California

Rule 1605 is one of five rules under SCAQMD Regulation XVI, Mobile Source Offset Programs, that provide a mechanism to generate mobile source emission reduction credits (MSERCs) by reducing emissions in excess of the requirements of local, State, and Federal regulations. Under the rule, MSERCs are generated by voluntarily repairing high-emitting motor vehicles to reduce their emissions. High-emitting vehicles must be identified through the use of remote sensing devices (RSDs). MSERCs can be used by, or traded to, stationary sources for alternative compliance with certain SCAQMD regulations.

Adopted and became effective on October 11, 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Old Vehicle Scrapping: *Command-and-Market Program* – California

Rule 1610 is one of five rules under SCAQMD Regulation XVI, Mobile Source Offset Programs, that provide a mechanism to generate mobile source emission reduction credits (MSERCs) by reducing emissions in excess of the requirements of local, State, and Federal regulations. Under the rule, MSERCs are generated by scrapping "old" (pre-1982) motor vehicles. Vehicle owners voluntarily give up their vehicles to an SCAQMD "licensed scrapper" - an entity certified by the SCAQMD to generate MSERCs by scrapping vehicles - typically in return for an incentive payment. MSERCs can be used by, or traded to, stationary sources for alternative compliance with certain SCAQMD regulations.

Rule 1610 was adopted on January 8, 1993 and amended six times since (most recently on May 9, 1997).

Source: USEPA Directory of Air quality Economic Incentive Programs

Credits for Clean On-Road Vehicles: *Command-and-Market Program* – California

Rule 1612 is one of five rules under SCAQMD Regulation XVI, Mobile Source Offset Programs, that provide a mechanism to generate mobile source emission reduction credits (MSERCs) by reducing emissions in excess of the requirements of local, State, and Federal regulations. Under the rule, MSERCs are generated by voluntarily operating low- or zero-emission on-road vehicles. MSERCs can be used by, or traded to, stationary sources for alternative compliance with certain SCAQMD regulations.

Rule 1612 was adopted on September 8, 1995. Became effective on January 1, 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Credits for Clean Off-Road Vehicles: *Command-and-Market Program* – California

Rule 1620 is one of five rules under SCAQMD Regulation XVI, Mobile Source Offset Programs, that provide a mechanism to generate mobile source emission reduction credits (MSERCs) by reducing emissions in excess of the requirements of local, State, and Federal regulations. Under the rule, MSERCs are generated by voluntarily operating low- or zero-emission off-road equipment. MSERCs can be used by, or traded to, stationary sources for alternative compliance with certain SCAQMD regulations.

Rule 1620 was adopted on September 8, 1995. Became effective on January 1, 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Credits for Clean Lawn and Garden Equipment: *Command-and-Market Program* – California

Rule 1623 is one of five rules under SCAQMD Regulation XVI, Mobile Source Offset Programs, that provide a mechanism to generate mobile source emission reduction credits (*MSERCs*) by reducing emissions in excess of the requirements of local, State, and Federal regulations. Under the rule, MSERCs are generated by voluntarily *scrapping and replacing* existing lawn and garden equipment with new equipment that meets lower emission standards or by voluntarily purchasing new low- or zero-emission lawn and garden equipment. MSERCs can be used by, or traded to, stationary sources for alternative compliance with certain SCAQMD regulations.

Adopted and became effective on May 10, 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Banking of Mobile Source Emission Reduction Credits (MERCs): *Command-and-Market Program* – California

Rule 27 governs the creation, ownership, use, and transfer of mobile source emission reduction credits (MERCs). Five alternative MERC-generating programs are set forth: 1) accelerated vehicle retirement; 2) purchasing and operating new low-emission urban buses; 3) purchasing zero-emission vehicles; 4) retrofitting passenger cars, light-duty trucks, and medium-duty vehicles to reduce emissions; and 5) retrofitting on-road heavy-duty vehicles and engines to low-emission configurations. Other mobile source emission reduction strategies are eligible to generate MERCs subject to the approval of the San Diego APCD's Air Pollution Control Officer and concurrence from the California Air Resources Board (ARB). MERCs can be used by stationary sources as emission offsets for new source review (NSR).

Rule 27 was adopted and became effective on November 29, 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

SCRAP South Coast Recycled Auto Program: *Command-and-Market Program* – California

SCRAP was a buyback and scrappage program conducted by UNOCAL for old vehicles registered in the South Coast Air Quality Management District (SCAQMD) of California (encompassing all of Los Angeles, Orange, and Riverside Counties, and the non-desert portion of San Bernardino County). Owners were offered payment to turn in their old vehicles for scrapping/recycling: $700 for pre-1971 model year vehicles (which have little or no emission controls) in SCRAP I, $700 for 1971-1979 model year vehicles in SCRAP II, $700 for pre-1972 model year vehicles in SCRAP III, and $700 for pre-1972 and $600 for 1972-1974 model year vehicles in SCRAP IV. Altogether, 8,376 vehicles were scrapped in SCRAP I, 502 in SCRAP II, 335 in SCRAP III, and 1,167 in SCRAP IV. Mobile source emission reduction credits (MSERCS) were generated from the SCRAP III and SCRAP IV projects - pursuant to the SCAQMD's Rule 1610, Old-Vehicle Scrapping - to defer the installation of vapor recovery equipment at UNOCAL's marine terminal in Los Angeles Harbor.

Four projects, SCRAP I through SCRAP IV, were conducted from June 1990 to February 1995.

Source: USEPA Directory of Air quality Economic Incentive Programs

Generic Emissions Trading and Banking: *Command-and-Market Program* – Colorado

The program involves the banking and trading of emission reduction credits (ERCs). The program is applicable statewide, including in attainment, nonattainment, and maintenance areas. There are two basic types of ERCs: permanent and temporary. Permanent ERCs reflect emission reductions that are permanent, temporary ERCs reflect emission reductions that are of limited duration. (As a result, permanent ERCs are measured in tons/year, temporary ERCs in tons.) The program also accommodates mobile source emission reduction credits (MERCs), which are considered temporary ERCs. The Air Pollution Control Division (the "Division") operates an electronic bulletin board listing available ERCs and related information necessary to support the trading system.

Adopted by the Colorado Air Quality Control Commission on October 24, 1996. Will not become effective until approved by EPA as a SIP revision.

Source: USEPA Directory of Air quality Economic Incentive Programs

Wood Stove Permit Trading: *Command and Market* – Colorado, Regionally

During the 1970's and 1980's a number of communites in Colorado experienced high levels of particulate pollution during the winter because of the use of wood-burning stoves and fireplaces. In 1987 the city of Telluride Colorado adopted a control program that allowed for air pollution offsets to combat the growing problem. Existing wood stoves and fireplaces were grandfathered with operating permits but they were required to meet stringent emissions standards within three years. For new construction, the owner must produce permits to operate two fireplaces or stoves for each one they plan to install. The only place to acquire these permits is from existing owners. Since the installation of this program the area has had no violations of the ambient air quality standards for Particulate Matter.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

NOx Emissions Reduction Credit Trading Program: *Command-and-Market Program* – Connecticut

The program involves the voluntary trading and banking of NOx emission reduction credits (ERCs). Two types of ERCs are defined: mass-based, reflecting discrete emission reductions; and rate-based, reflecting continuous emission reductions. The discrete ERCs are measured in tons and the continuous ERCs in tons per year. Credit generators have been showing a preference for discrete ERCs because of the permanent commitment associated with continuous ERCs. All ERC generation and use requires the Commissioner's approval.

The ERC program has been active since mid-1995.

Source: USEPA Directory of Air quality Economic Incentive Programs

Emission Banking and Trading Program: *Command-and-Market Program* - Delaware

Delaware's proposed regulation establishes a voluntary statewide emission banking and trading program. Reductions from stationary, area, or mobile sources that are greater than one ton per year are eligible for credit if they are determined to be real, surplus, permanent, quantifiable, and enforceable. All reductions must be certified by the State prior to banking or use. Certified reductions are termed emission reduction credits (ERCs) and are incorporated into permit terms.

The draft regulation was released in December 1995, and presented at two public workshops. The draft was formally proposed in January 1996, with final adoption anticipated by December 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Clean Fueled Fleets Program: *Command-and-Market Program* – Georgia

The Clean Fueled Fleets Program is a requirement of the 1990 Clean Air Act Amendments (CAAA). Fleets of ten or more covered vehicles - both light- and heavy-duty - in ozone nonattainment areas are required to participate. A vehicle is covered if it weighs less than 26,000 pounds and is centrally fueled (fueled at a site owned, operated, or otherwise controlled by the fleet operator, or under contract with the fleet operator) or capable of being centrally fueled 100 percent of the time. Exempted vehicle fleets include rental cars, vehicles used primarily outside the ozone nonattainment area, non-road vehicles, and emergency vehicles (e.g., police, ambulance). The program in Georgia applies to the ozone nonattainment area comprising 13 counties around Atlanta. The program starts in 1998 with 1999-model-year purchases. For participating light-duty vehicle fleets, 30 percent of 1999-model-year purchases must be EPA-certified (by the manufacturer) as "clean-fueled." This increases to 50 percent for the 2000 model year and 70 percent for 2001 and on. For heavy-duty vehicle fleets, the requirement is 50 percent for every model year starting with 1999.

Vehicle fleets can earn credits by purchasing clean-fueled vehicles earlier than required, by purchasing extra or exempted clean-fueled vehicles, or by purchasing clean-fueled vehicles that meet stricter emission standards than required. The credits can, in turn, be used to meet current or future clean-fueled-vehicle purchase requirements. They cannot be used outside the Clean Fueled Fleet Program in the Atlanta ozone nonattainment area. (For example, they cannot be used by stationary sources.) They must be registered with the Georgia EPD but do not have to be pre-approved by the agency.

Rules and regulations are in place; participating vehicle fleets have been determined and the program is set to start up in March 1998.

Source: USEPA Directory of Air quality Economic Incentive Programs

Chicago Emissions Reduction Credit Banking and Trading Program: *Command-and-Market Program* - Illinois

An emission reduction credit (ERC) bank was founded in 1994 after a 300-ton donation by the 3M Company. Donations are the only source of ERCs for the bank. The ERCs - equal to 1/10 tons of VOC emissions per year - are available as new source review (NSR) offsets to stationary sources in the Chicago ozone nonattainment area.

Although the program was set up to facilitate trades between stationary sources, it could be possible for mobile and area sources to also generate ERCs, pending the State of Illinois VOM (volatile organic materials) Emissions Trading System, currently under development.

The primary purpose of the ERC bank is economic development. The supply of ERCs is available to new sources as an inducement to locate in or near Chicago. In fact, even if they had a market value, it is not expected that the ERCs would be sold to new sources. Rather, they would be included in overall inducement packages. The program also seeks environmental benefits by retiring three percent of the credits per year. Retired credits can be credited against SIP requirements.

After the initial donation by 3M, there has been no activity in the bank: there have been no further donations, and no credits have been distributed to new sources. Hence the balance is still 300 tons. The city has been looking for potential users as part of their economic development efforts, but so far none have been found due to slack demand. This could change when the State of Illinois VOM Emissions Trading System - which should stimulate the trading market - is implemented.

Due to the lack of activity, the three percent per year retirement clause has not been invoked. The ERCs have a 5-year life. Allowed credit-generating activities will be dictated by the State of Illinois VOM Emissions Trading System, currently under development. The ERCs must be "PERQS": permanent, enforceable, real, quantifiable, and surplus. Presently there is no use for the ERCs in the bank other than as NSR offsets. They specifically cannot be used for RACT compliance.

The ERC Bank became effective November 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

Illinois Accelerated Vehicle Scrappage Program: *Cap-and-Trade/Budget Program* - Illinois

The program permits "allotment trading units" (ATUs) - each representing 200 pounds of VOM (volatile organic materials) emissions during the ozone season defined as May 1 - September 30 - to be earned by scrapping vehicles in the Northeastern Illinois ozone non-attainment area (Chicago and vicinity). These ATUs can be applied against emissions from stationary point sources participating in Illinois' VOM Emissions Trading System, an allowance or "cap and trade" program. There are currently no other applications for these scrappage ATUs.

The program was developed after positive results (e.g., significant emissions impacts) from a pilot program involving about 200 vehicles in 1992.

Companies or organizations wishing to receive credit (ATUs) for scrapping vehicles must first submit a plan to Illinois EPA for approval. The plan must document how the emissions impacts will be determined (e.g., testing protocols). The plan must also describe the method that will be used to notify parts recyclers and car collector groups of any vehicles that are on a predetermined list of vehicles of interest to them. The parts recyclers and car collectors would then have the opportunity to offer to purchase these vehicles, though, because the vehicles would then not be scrapped, this would not be for credit.

The life of a scrappage ATU is variable, to be decided by Illinois EPA depending on the plan submitted. A three-year life will be granted for programs that follow the Federal Guidelines on Accelerated Vehicle Scrappage Programs.

The final rules have been written and will soon be submitted to the Illinois Pollution Control Board for review and promulgation.

Source: USEPA Directory of Air quality Economic Incentive Programs

VOM Emissions Trading System: *Cap-and-Trade/Budget Program* – Illinois

The VOM Emissions Trading System is an allowance ("cap and trade") system applying to all stationary point sources in the Northeastern Illinois ozone non-attainment area (Chicago and vicinity) emitting 10 tons or more of VOMs (volatile organic materials) during the ozone season defined as May 1 - September 30. However, sources that agree to limit their seasonal emissions to 15 tons or less may opt out of the program. The allowances (which will be allotted annually to program participants) are termed "allotment trading units (ATUs)," and represent 200 pounds of VOM emissions during the ozone season.

Although the program applies to stationary sources with ozone-season VOM emissions of 10 tons and above, ATUs can also be earned by mobile sources that meet the requirements of the Illinois Accelerated Vehicle Scrappage Program. These ATUs can in turn be sold to stationary sources in the VOM program. Point sources smaller than 10 tons per season can also generate ATUs for the program under certain conditions.

The program targets VOMs as a means of ozone attainment. Originally an NOx trading program was considered but was discontinued in favor of a VOM program when air quality modeling showed that the impact of NOx reductions on ozone in the Northeastern Illinois ozone non-attainment area would be insignificant.

Program rules have been developed and submitted to the Illinois Pollution Control Board.

Source: USEPA Directory of Air quality Economic Incentive Programs

Regulations on Control of Emissions through the use of Emission Reduction Credit Banking: *Command-and-Market Program* – Louisiana

The regulations govern the use of emission reduction credits (ERCs) and mobile emission reduction credits (MERCs), both equal to one ton of emission reductions per year, as new source review (NSR) offsets and in netting. The regulations are mandatory in the seven parishes not in attainment for ozone (six "serious," around Baton Rouge; and one "marginal," though about to be redesignated attainment) and voluntary in ten parishes that are in attainment but were previously classified "transitional" or "incomplete data." (There are a total of 64 parishes in Louisiana.) For the seven nonattainment parishes, ERCs must be banked (by submitting a "bank balance sheet" to the DEQ) in order to be used, while banking is optional in the ten other parishes. MERCs - which are intended as an alternative method of compliance for stationary sources - are generated by scrapping vehicles. Fair market value, and a minimum of $450, must be paid to motorists who offer up their vehicles for scrappage.

Enacted (became a state regulation) August 20, 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

Innovative Market Program for Air Credit Trading (IMPACT): *Command-and-Market Program* – Massachusetts

IMPACT is a voluntary, statewide emission banking and trading program. Reductions that are determined to be real, quantifiable, surplus, enforceable, and permanent are eligible for certification as ERCs. DEP must certify all ERCs prior to use, banking or trading, and conditions for generation or use are incorporated into permit terms. Most of the applications that have been disapproved by DEP to date were determined to not meet one of the five criteria, most frequently the requirement that reductions be real. Others, specifically those involving the shutdown of unpermitted equipment, did not meet the definition of surplus. Under the existing rule, ERCs are quantified in terms of the average hourly or daily emission rate, expressed in pounds. DEP is currently proposing the creation of two banks based on how the ERC is quantified: a Mass ERC Bank for credits calculated in tons and a Rate ERC Bank for credits calculated in tons per year. Credit life is equal to the expected life of the reduction - either a discrete timeframe or forever - with the exception of those credits in the Rate Bank, which are only available for use as offsets and expire after 10 years. DEP is also considering instituting a de minimis cutoff level for ERC applications, e.g., 1 or 5 tons.

The regulation establishing IMPACT was adopted by Massachusetts in 1993. The program officially started in January 1994 and the first program audit was conducted in 1995. In October 1996, IMPACT became the first EPA-approved EIP, thereby eliminating the need for EPA approval of each credit generated and used. Based upon the audit results, DEP recently proposed several revisions to the regulation. Public comment on the proposed revisions closed in December 1996.

Since the inception of the program, DEP has received a total of 51 applications for emission reduction credit (ERC) generation, of which 7 were fully approved, 10 are draft approvals undergoing public comment or pending final DEP action, 2 are on hold pending regulatory changes, 12 were disapproved, 3 were terminated, 2 were withdrawn, 13 are in the review backlog, and 2 are undergoing review subject to new review timelines established by fees promulgated in 1995. DEP has also received one application to use ERCs to delay compliance with NOx control requirements. Additionally, seven other sources plan to use ERCs as a result of DEP enforcement actions.

Source: USEPA Directory of Air quality Economic Incentive Programs

Offset Trading Program: *Command-and-Market Program* – Maine

This program establishes an Offset credit trading system for New Source Review (NSR) applications in the State of Maine. The offset credits represent one ton of emissions per year. Credits can be generated by any type of activity, including shutdowns, as long as it can be demonstrated that the emission reductions are permanent. The credits have an unlimited life, i.e., they can be banked and used at any time in the future. If credits are obtained from another New England state, an additional 15% must be obtained. This means, for example, that if a source needs to offset 100 tons of new emissions, it must generate or purchase 115 credits. If credits are obtained from a state outside New England, but within the Ozone Transport Region, they must be obtained at a 2:1 ratio.

The current proposal allows NOx credits to offset VOC emissions, and vice versa, except Northern Maine where NOx credits are not required. This is because Maine is generally NOx-limited, owing to the large emissions contribution of biogenic VOC sources (e.g., trees). The department is proposing interpollutant trades at a 1:1 ratio. There are seasonal trading restrictions: credits from emission reductions in the winter cannot be used to offset emission increases in the summer, when the ozone problem is worse. Interstate trading is permitted, within New England, as long as it is directionally correct (trades must be downwind). Trades cannot be to an ozone nonattainment area with a "higher classification," e.g., from a marginal to a moderate ozone nonattainment area. Liability for improper trading can rest with either the seller (generator) or buyer (user), depending on who is determined to be the responsible party, i.e., who breaches the contract.

A draft proposal has been written. Waiting for opinion of State Attorney General's office. Two public hearings on the offset trading rule have been held and comments are currently being reviewed and responses are being drafted. Rule is expected to be finalized this Spring.

Source: USEPA Directory of Air quality Economic Incentive Programs

Emission Trading Program: *Command-and-Market Program* – Michigan

The Michigan Emission Trading Program is a voluntary, open-market program with statewide applicability. The unit of currency is the Emission Reduction Credit (ERC), equal to one ton of emissions reductions.

The program is intended to facilitate the attainment and maintenance of National Ambient Air Quality Standards (NAAQS) and create market-based incentives for emissions reductions. An emissions impact is assured by the stipulation of a ten percent net air quality benefit contribution (i.e., discount) before ERCs can be used. (For ERCs generated before the effective date of the program, from January 1, 1991 to March 16, 1996, the discount rate is 50%.) Moreover, for ozone-related ERCs (i.e., VOCs, NOx), there is an additional 10 percent discount for every ozone season (April 1 - September 30) that their use is deferred. The program is also intended to increase operating flexibility and encourage technological innovations for reducing and quantifying emissions.

Over 80 submittals have been received under the program to date. Submittals to generate ERCs have documented the following emission reductions: over 750 tons of VOC reduced, over 37,000 tons of NOx reduced, over 225 tons of CO reduced, and over 3 tons of PM10 reduced. ERC Uses and Transfers (the trading of ERCs) have increased dramatically during the first quarter of 1998, likely the result of increased market confidence due to the pending EPA approval and increased broker activity in Michigan. See website for on-line registry database to obtain more information on the generation, use, and trading of ERCs in Michigan.

Became effective at the state level on March 16, 1996. Has been submitted to the U.S. EPA for approval as a revision to Michigan's SIP. On September 18, 1997 the EPA published a Notice of Proposed Rulemaking (NPR) proposing approval of the Michigan program once certain deficiencies were addressed through revisions to the rules and procedures. MDEQ reconveined the stakeholder workgroup, including representatives from EPA Region 5, to address EPA's concerns as stated in the NPR. MDEQ, EPA and the stakeholders have arrived at acceptable compromises regarding the issues and MDEQ will resubmit the revised rules and operational procedures to EPA following the completion of the state rulemaking process (Fall, '98). Final federal approval of the submittal is anticipated.

Source: USEPA Directory of Air quality Economic Incentive Programs

Discrete Emissions Reductions Trading Program: *Command-and-Market Program* – New Hampshire

The Discrete Emissions Reductions Trading Program is an open market system of trading for discrete emissions reductions (DERs). The DERs are mass-based units (1 DER = 1 ton) representing discrete, retrospective emission reductions.

DERs can be generated by stationary, mobile, or area (e.g., off-road equipment, consumer products) sources. NOx and VOCs are included because New Hampshire is in the Ozone Transport Region.

The Discrete Emissions Reductions Trading Program is intended to give RACT sources and sources subject to New Source Review (NSR) compliance flexibility and the opportunity to reduce compliance costs. Although it is not an attainment strategy, the program benefits the environment by requiring that 10 percent of all credits are retired (discounted) before they are used.

DERs can be banked for future use, and they do not require the DES's approval before use. However, the buyer may be liable if the DES finds any shortfalls. NOx for VOC trading is permitted, but not vice versa. This is intended to encourage NOx reductions, which contribute more than VOC reductions to ozone improvement in New Hampshire, which, as a rural state, is NOx-limited. Inter-pollutant trading ratios have not yet been worked out.

The DER Trading Program was proposed on October 10, 1996 and adopted on January 20, 1997.

Source: USEPA Directory of Air quality Economic Incentive Programs

Open Market Emissions Trading: *Command-and-Market Program* – New Jersey

New Jersey's open market trading program authorizes the creation, use, and trading of discrete emission reductions (DERs). A DER represents 1/20th of 1 ton of emission reductions from stationary or mobile sources. Generators and users must supply notice and certification to the State registry, and all DERs must be verified by an independent third party prior to use.

DERs can be generated by stationary or mobile sources. The generation and use periods for any "batch" of DERs cannot exceed 1 year; however, additional batches can be generated/used over consecutive periods. DERs cannot be generated by shutdowns or curtailments, and DERs generated outside of the ozone season cannot be used during the ozone season. Interstate trading is subject to certain restrictions, depending on the pollutant, locations of the generator and user, and reciprocal state provisions. The regulation establishes requirements for emission quantification protocols for DER generators and users.

The three overall goals of New Jersey's program are to encourage voluntary reductions, provide companies with flexibility in meeting air quality standards, and lower costs of compliance. As a result of a 10 percent discount assessed at the time of use (as well as decreasing/increasing the amount of DERs created/needed when notification is delayed), the program also benefits the environment. Retired DERs, however, are not applied towards RFP.

The regulation establishing New Jersey's Open Market Trading Program was promulgated on July 1, 1996 and became operative on August 2, 1996. Several trades have been approved or are underway, and agreements for interstate trading with Connecticut and Massachusetts are in place.

Source: USEPA Directory of Air quality Economic Incentive Programs

NSR Emission Offset Program: *Command-and-Market Program* – New York

The NSR Emission Offset Program authorizes the creation, use, and trading of emission reduction credits (ERCs). The ERCs are rate-based units (1 ERC = 1 ton/year) representing continuous, permanent emission reductions. ERCs can be used by stationary sources for new source review (NSR) netting and as NSR offsets only. ERCs must be certified by and registered with the NYSDEC before they can be used or traded. Emission reductions that are quantifiable, enforceable, permanent, and surplus are eligible for certification as ERCs. Once certified and registered, ERCs are not discounted and have unlimited life.

All types of emission reductions from stationary sources are allowable, including overcontrol, process changes, energy conservation, and production curtailments or shutdowns. Stationary sources can also implement demand-side management measures - energy-saving process or equipment changes that generate NOx credits for electric utilities. (The implementing source doesn't get the credits, but does get a lower electric bill.) The NYSDEC is considering adding provisions for generating credits from mobile sources, pending the release of mobile source quantification protocols in EPA's Open Market Trading Guidance.

The main objective of the program is attainment of NAAQS. SIP credit towards attainment is taken for the offset ratios that apply: 1.3 to 1.0 (i.e., for every 1 ton of emissions that must be offset, 1.3 tons of ERCs must be applied) in the severe ozone nonattainment areas, including New York City and surrounding counties (including all of Long Island); and 1.15 to 1.0 in the rest of the state which is designated moderate ozone nonattainment by virtue of the entire state being in the Ozone Transport Region (OTR). By increasing the availability of offsets, the program also promotes new source growth and therefore economic development.

So far in the program, two ERC trades have been approved, both for NOx, and both inter-firm. Another NOx trade is expected to be approved soon. This pending trade will include - under a Memo of Understanding with Pennsylvania - the transfer of 100 tons of NOx ERCs from Pennsylvania.

Currently in the State registry (bank) there are 5,067 tons of NOx ERCs, 1,756 tons of VOC ERCs, 1,151 tons of CO ERCs, and 26 tons of PM-10 ERCs.

The ERC Program has been State regulation since October 15, 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

Nitrogen Oxides Allowance Requirements: *Cap-and-Trade/Budget* – Pennsylvania

The NOx Allowance Requirements Program will be a mandatory cap-and-trade program for certain sources (defined in the regulation as fossil fuel-fired indirect heat exchange combustion units with a maximum capacity of 250 MMBTU/hour or more and fossil fuel-fired electric-generating facilities rated at 15 megawatts or greater). Beginning in 1999, the program will operate every ozone season, May 1 - September 30. Under the DEP's regulation, each source required to participate in the program is allocated a certain number of allowances per season based on 1990 operations (each allowance is equal to 1 ton of NOx). Every source in the program will have to demonstrate that it holds allowances in an amount equal to or greater than the total NOx emitted by that source during the ozone season. (The number of allowances allocated to a source will remain unchanged each season, unless the DEP revises the allocations through a regulatory amendment.) Allowances may be traded during designated intervals each year if proper documentation is provided to the NOx Allowance Tracking System Administrator.

Final regulations were published in the Pennsylvania Bulletin (DEP's version of the Federal Register) on November 1, 1997. The regulations can be found at 25 PA Code Chapters 121 (definitions) and 123. A copy of the final regulation is available on our Web site at www.dep.state.pa.us/dep/subject/Rec_Final_regulations.htm Sources have submitted Authorized Account Representative forms and monitoring plans. Monitoring is to begin July 1, 1998.

Source: USEPA Directory of Air quality Economic Incentive Programs

Accelerated Vehicle Retirement Program: *Command-and-Market Program* – Texas

The Texas Accelerated Vehicle Retirement Program is a vehicle scrappage program currently in effect in the state's four ozone nonattainment areas: Houston/Galveston, Beaumont/Port Arthur, Dallas/Fort Worth, and El Paso. Mobile source emission reduction credits (MERCs) generated by scrapping automobiles and light-duty trucks can be used by stationary sources as offsets for new source review (NSR). While the program is intended for companies that want to generate MERCs for their own use (as offsets), technically the MERCs can be traded to other sources. The program rewards motorists who turn in their vehicles typically with a cash payment and with avoided repair costs to pass the state I/M emissions test.

Although the MERCs are generated by mobile sources (automobiles and light-duty trucks), they can only be used by stationary sources for NSR.

The MERCs can be banked for three years and also can be used (as offsets) for only three years, the estimated average remaining life of a vehicle that is scrapped. Unlike ERCs (which in Texas can be banked for 10 years and used indefinitely), MERCs do not represent permanent emissions reductions. MERCs can only be traded within a nonattainment area.

The Accelerated Vehicle Retirement Program Rule was adopted in October 1994.

Source: USEPA Directory of Air quality Economic Incentive Programs

Area Emission Reduction Credit Organizations (AERCOs): *Command-and-Market Program* – Texas

AERCOs are voluntary organizations set up by local governments - under a Texas statute - to assist sources subject to new source review (NSR) in ozone nonattainment areas to locate emission reduction credits (ERCs) needed as offsets. One way in which AERCOs can make ERCs available is by acquiring ERCs and maintaining an account in the state's ERC bank.

The major purpose of AERCOs is economic development. AERCOs try to make it easier for new sources and expanding sources to find offsets needed for NSR. For AERCOs funded by "supplemental environmental projects" undertaken by companies penalized for noncompliance (up to 50% of such projects can be contributions to AERCOs), there is a requirement to retire five to ten percent of banked ERCs per year, meant to benefit the environment (though no SIP credit is taken). There are no retirement requirements for other sources of ERCs.

AERCOs can receive ERCs (equal to one ton of emissions per year) as donations or can acquire ERCs, or receive money to purchase ERCs, from supplemental environmental projects. So far there have been no donations of ERCs but three projects have contributed about $¼ million to the Houston/Galveston AERCO. This money will eventually have to be used to purchase ERCs. At this point neither the Houston/Galveston nor Beaumont/Port Arthur AERCOs have acquired any ERCs.

Instituted in the Beaumont/Port Arthur and Houston/Galveston ozone nonattainment areas in March 1994. Dallas/Fort Worth is currently in the proposal phase.

Source: USEPA Directory of Air quality Economic Incentive Programs

Emissions Banking Program: *Command-and-Market Program* – Texas

The Texas Emissions Banking Program is an emission reduction credit (ERC) banking and trading program currently in place in the state's four ozone nonattainment areas: Beaumont/Port Arthur, Houston/Galveston, Dallas/Fort Worth, and El Paso. The ERCs are used as offsets for new source review (NSR).

Although the ERCs can only be used by stationary sources (for NSR), they can be generated by mobile and area sources as well as stationary sources.

The ERCs, equal to one ton of emissions per year, can be used for NSR but not for any other purpose such as

RACT compliance. The ERCs can be used as offsets only in the nonattainment area in which they were generated (i.e., they can't be traded between nonattainment areas). The ERCs must be certified by TNRCC before they are sold and therefore there is no risk (e.g., liability) to the buyer. Allowed credit-generating activities include shutdowns. The baseline for calculating credits is average emissions in the two years preceding the emissions reduction.

In the three years since the program was established there has been only one transaction (125 tons of NOx ERCs in Houston). Activity has been low because little NSR permitting has been going on, and new sources that have applied for permits have generally not required offsets (e.g., they have been netting out of NSR). Due to the low level of participation an original three percent per year banking discount was rescinded and the life of ERCs was extended from five to ten years.

TNRCC is currently in the early stages of developing a new emissions banking and trading program based in part on the Open Market Trading Guidance. The new program is expected to incorporate the use of both ERCs and discrete emission reductions (DERs). Other expected changes from the current program: it will be possible to use ERCs and DERs for RACT, and it will not be possible for mobile and area sources to generate ERCs (though it will be possible to generate DERs).

Rule adopted in March 1993.

Source: USEPA Directory of Air quality Economic Incentive Programs

Texas Clean Fleet Program: *Command-and-Market Program* – Texas

The Texas Clean Fleet Program is an opt-out or alternative to the Federal Clean Fuel Fleet Program. Starting September 1, 1998, affected fleets must ensure that certain percentages of their new vehicle purchases and total fleet are "clean-fuel vehicles," meaning that they have a vehicle/fuel combination certified by the U.S. EPA to meet or exceed the Federal low emission vehicle (LEV) standards. Two types of bankable and tradable credits - mobile emission reduction credits (MERCs) and program compliance credits (PCCs) - can be earned by 1) acquiring LEVs earlier than required, 2) acquiring more LEVs than required, or 3) acquiring vehicles certified to meet an emission standard more stringent than LEV, such as the ultra-low emission vehicle (ULEV), the inherently low emission vehicle (ILEV), and the zero emission vehicle (ZEV).

While the objective of the entire Clean Fleet Program is to lower emissions, the economic incentives aspect of the program - credit banking and trading - is intended only to increase operating flexibility and allow for cost-effective compliance.

Affected fleets include local government fleets with more than 15 vehicles (excluding law enforcement and emergency vehicles) and private fleets with more than 25 vehicles (excluding emergency vehicles), located within or operating primarily in the Houston/Galveston and El Paso ozone nonattainment areas, and eventually (a proposal is scheduled for spring 1997) the Dallas/Fort Worth and Beaumont/Port Arthur ozone nonattainment areas; and certain mass transit fleets operating in these four ozone nonattainment areas.

Participating fleets can choose between MERCs and PCCs when claiming credit. One MERC is equal to one LEV-equivalent, or the emission reductions from a standard light-duty vehicle certified as an LEV. The number of MERCs associated with being certified as an LEV will depend on the type and size of vehicle. PCCs, established by the Texas Legislature, do not vary by type and size of vehicle. Simply, one PCC is granted for LEV, two for ULEV, and three for ILEV or beyond. For most credit-generating activities, more MERCs can be earned than PCCs, though there are exceptions.

PCCs have application only in the Texas Clean Fleet Program. In contrast, MERCs, subject to conversion formulas, can be used as offsets for new source review (NSR) by stationary sources, as well as for RACT compliance. MERCs and PCCs can be converted into each other unless they have been traded. For example, a fleet that created and still holds PCCs can convert them into MERCs (if, for example, NSR applications are desired). Once traded, however, MERCs and PCCs must be used "as is." MERCs and PCCs can be used for as long as the life of the vehicles from which they were created, normally about five years. There is no discounting for use in future years.

Became effective August 1996.

Source: USEPA Directory of Air quality Economic Incentive Programs

Grass Burning Permit Trading: *Command and Market* – Washington

The city of Spokane Washington, is a major growing region for grass seed, between 15,000 and 30,000 acres are planted for seed production each year. After the harvest each year the fields are burned to control pests and weeds and to stimulate the grass to produce seed. The city also is geographically situated such that temperature inversions that trap air pollution are common. The area exceeds the federal PM10 standard several times every year.

In 1990 Spokane County air pollution authorities implemented an innovative program to reduce grass burning as a source of PM10. The program imposes a cap on the number of acres that can be burned each year (35,000 arces). Growers are allocated permits to burn based on the number of acres they had permitted during the base years of 1985-1989. The program allows transfers of permits in three situations: permanent land transfers, temporary land transfers by lease, and transfer through auction. In an auction, 10 percent of the burnable acreage is deducted from the buyers account there by resulting in a decrease in burnable acres over time. The auction system was patterned after the Acid Rain Programs system.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.

Emissions Trading Program: *Command-and-Market Program* – Wisconsin

The Wisconsin Air Bureau developed a trading program for VOC and NOx emissions based on the New Source Review provision of the 1990 Clean Air Act. This program establishes the structure for the trading of Offsets for new sources locating in nonattainment areas. The state has proposed a “banking fee” of $35 per ton in the first year the credit is certified, to discourage the long-term banking of emissions credits. This fee would double every year until the credit is sold. This fee has been controversial and the WAB is awaiting approval from the USEPA before fully implementing the program.

Source: USEPA Document - The United States Experience with Economic Incentives in Environmental Pollution Control Policy.