Appendix A-TSD
Methods Used to Incorporate State and Local Control Programs in WRAP Emissions Inventories

Overview:
The purpose of this appendix is to provide a list of state and local emission control programs and assumptions included in the emissions inventories prepared by WRAP contractors for §309. Documentation about the details and assumptions for each emissions inventory are contained in the individual contractors' reports, listed as references in Appendix C of this document. Federal control programs and actions are published in the Federal Register, and are incorporated into EPA emissions models in most cases, and are not listed in this appendix.

Area Sources:
This information is from Chapter IV "Existing Source State Regulation Analyses, Western Regional Air Partnership Emission Forecasts For 2018 - Final Report", E.H. Pechan & Associates, Inc., December 2002, Pechan Rpt. No. 02.12.003/9409.000.

This chapter describes analyses of State and Local regulations affecting criteria pollutant emissions between 1996 and 2018. Results of these analyses are organized by pollutant: PM_{10}, followed by NO_x regulations, followed by SO_2. These analyses were performed in order to update the IAS model control factors so that they would reflect the expected pollution reduction effects of State and local regulations.

PM_{10} :
Many PM_{10} nonattainment areas are located in the Western United States. Federal, State, and local air pollution regulations and other initiatives likely to affect point and area PM_{10} sources were analyzed. The focus was on PM_{10} sources in nonattainment areas and the control measures that areas are implementing to bring their areas into attainment. It is not expected that attainment areas would implement post-1996 control measures for PM_{10} and that any pre-1996 regulation effects would already be incorporated in their 1996 emission estimates.

Using EPA's web site *Classifications of PM-10 Nonattainment Areas*, a group of twelve nonattainment areas were selected for analyses (EPA, 2001b). The selected areas included all of the listed serious classification nonattainment areas – Clark County, NV; Coachella Valley, CA; Los Angeles/South Coast Air Basin, CA; Owens Valley, CA; Phoenix, AZ; and San Joaquin Valley, CA . The selected areas also included a sampling of moderate classification nonattainment areas in the WRAP States. For the moderate classification areas, selection was also based on availability of the needed information. The selected moderate classification nonattainment areas included Aspen, CO; Anthony, NM; Klamath Falls, OR; Salt Lake County, UT; Spokane County, WA; and Sheridan, WY.

Area-specific PM_{10} control plans and information were collected and compiled from EPA Regional Offices, and State and local agencies for each of the selected nonattainment areas. Often the information was available via the Internet and the agency was able to provide the web site address. Agency staff was also interviewed to gain insight into an area 's particular nonattainment situation and learn about novel or unique control measures. EPA's web site *Federal Register Notices Related to PM-10 Designations and Classifications* was used to identify recent actions related to the selected nonattainment areas (EPA, 2001c).

Pechan reviewed the gathered documents and prepared a series of tables to summarize the control measure information for each nonattainment area. This information is summarized in Tables IV-3 through IV-9. Each table presents adopted measures for a different source category. Source categories include construction, residential wood combustion, vacant land/unpaved lots, open burning, agricultural tilling, salting/sanding of paved roads, and miscellaneous sources. For use in this analysis, the information about PM_{10} control measures by PM_{10} nonattainment area was translated into a set of PM_{10} control efficiencies by area that were applied as PM_{10} control factors in the 2018 emissions forecast. Each table identifies the nonattainment area and names the types of measures that the area uses to control emissions of PM_{10}. The assumed degree of control of road dust emissions in each PM_{10} nonattainment area is described in the mobile sources emissions inventory report (ENVIRON, 2003). For road dust emissions, PM control measures were applied to fugitive dust emissions from paved and unpaved roads in all PM_{10} nonattainment areas, with the control factors reflecting a higher control level in serious PM_{10} nonattainment areas than was applied in moderate PM_{10} nonattainment areas.

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Table IV-3
SCC - 2311010000 / Construction

FIP	Nonattainment Area	County	State	PM_{10} Nonattainment Designation	Control Measures							Note
					1	2	3	4	5	6	7	
32003	Clark County		NV	Serious	x	x	x				x	
06065	Coachella Valley	Riverside Co	CA	Serious								
06059	Los Angeles South Coast Air Basin	Los Angeles Co, Orange Co, Riverside Co, San Bernardino Co	CA	Serious								
04013	Phoenix	Maricopa Co	AZ	Serious			x				x	
06077	San Joaquin Valley	Fresno Co, Kern Co, Kings Co, Madera Co, San Joaquin Co, Stanislaus Co, Tulare Co	CA	Serious	x	x	x	x	x	x	x	
35013	Anthony	Dona Ana Co	NM	Moderate	x	x		x	x	x	x	
41035	Klamath Falls	Klamath Co	OR	Moderate	x							
08097	Aspen	Pitkin Co	CO	Moderate								
49035	Salt Lake County		UT	Moderate		x		x	x	x	x	
53063	Spokane County		WA	Moderate				x		x	x	

NOTES: 1=Trackout device
2=Chemical stabilizers
3=Dust control plan
4=Water
5=Windbreaks
6=Cover piles/trucks
7=Stop/reduce/restrict activity/traffic

Table IV-4
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SCC - 2104008000 / Residential Wood Combustion

FIP	Nonattainment Area	County	State	PM_{10} Nonattainment Designation	Control Measures					Note
					1	2	3	4	5	
04013	Phoenix	Maricopa Co	AZ	Serious	x	x	x			
06077	San Joaquin Valley	Fresno Co, Kern Co, Kings Co, Madera Co, San Joaquin Co, Stanislaus Co, Tulare Co	CA	Serious	x	x	x	x	x	
41035	Klamath Falls	Klamath Co	OR	Moderate			x	x		Woodstove owners must register their stoves. Program to replace woodstoves in place.
08097	Aspen	Pitkin Co	CO	Moderate		x			x	
49035	Salt Lake County		UT	Moderate			x	x		Solid fuel burning devices must be registered. Ban resale of uncertified previously used solid fuel burning devices.
53063	Spokane County		WA	Moderate			x			

NOTES:
1=Ban the sale/installation of uncertified stoves
2=Switch to natural gas
3=No-burn periods
4=Citizen education
5=Limit number of woodburning devices

Table IV-5
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Vacant Land, Unpaved Lots

FIP	Nonattainment Area	County	State	PM_{10} Nonattainment Designation	Control Measures							Note
					1	2	3	4	5	6	7	
32003	Clark County		NV	Serious			x	x		x		
06027	Owens Valley	Inyo Co	CA	Serious	x	x					x	Source: Owens dry lake bed, control with shallow flooding
06077	San Joaquin Valley	Fresno Co, Kern Co, Kings Co, Madera Co, San Joaquin Co, Stanislaus Co, Tulare Co	CA	Serious	x	x		x	x	x	x	
35013	Anthony	Dona Ana Co	NM	Moderate	x	x		x	x	x		

NOTES:
1=Re-vegetate/mulch
2=Pave/gravel
3=Prohibit unpaved lots
4=Windbreaks
5=Chemical suppressants
6=Limit use and surface disruption
7=Water

Table IV-6
19
SCC - 261000000 / Open Burning

FIP	Nonattainment Area	County	State	PM_{10} Nonattainment Designation	Control Measures				Note
					1	2	3	4	
06077	San Joaquin Valley	Fresno Co, Kern Co, Kings Co, Madera Co, San Joaquin Co, Stanislaus Co, Tulare Co	CA	Serious	x	x	x	x	Additional controls - Edu. Program; reduce acres burned, fuel loading, and fuel consumption
41035	Klamath Falls	Klamath Co	OR	Moderate		x			Residential open burning- 2610030000
53063	Spokane County		WA	Moderate	x				

NOTES:
1=Alternatives to burning (use as fuel, removal, chipping, till into soil)
2=Burn ban on no-burn days
3=Require permits
4=Smoke management plan

Table IV-7 [20]
SCC - 2801000003 / Agricultural Tilling

FIP	Nonattainment Area	Area Description	State	PM_{10} Nonattainment Designation	Control Measures
04013	Phoenix	Maricopa Co	AZ	Serious	USDA Soil Conservation Plan
06077	San Joaquin Valley	Fresno Co, Kern Co, Kings Co, Madera Co, San Joaquin Co, Stanislaus Co, Tulare Co	CA	Serious	USDA Soil Conservation Plan
35013	Anthony	Dona Ana Co	NM	Moderate	USDA Soil Conservation Plan

Table IV-8
[21]SCC - 2294000002 / Salting/Sanding Paved Roads

FIP	Nonattainment Area	Area Description	State	PM_{10} Nonattainment Designation	Control Measures
08097	Aspen	Pitkin Co	CO	Moderate	Cleaner winter salting/sanding materials
49035	Salt Lake County		UT	Moderate	Cleaner winter salting/sanding materials
56033	City of Sheridan	Sheridan Co.	WY	Moderate	Cleaner winter sanding materials Regular maintenance and watering of sanded paved roads

Table IV-9 [22]
Miscellaneous Sources

FIP	Nonattainment Area	County	State	PM_{10} Nonattainment Designation	Source / SCC	Control
32003	Clark County		NV	Serious	"Industrial Sources"**	Tighten emission offset requirements
06077	San Joaquin Valley	Fresno Co, Kern Co, Kings Co, Madera Co, San Joaquin Co, Stanislaus Co, Tulare Co	CA	Serious	Cattle Feedlots / 2805001000	
08097	Aspen	Pitkin Co	CO	Moderate	Restaurant grills / 2810025000	Require control devices
41035	Klamath Falls	Klamath Co	OR	Moderate	Agricultural burning / 2801500000	Year-round ban on agricultural open burning
49035	Salt Lake County		UT	Moderate	Mining / 2325000000	Keep tailings pond wet
49035	Salt Lake County		UT	Moderate	Refineries	Apply sulfur removal unit Low-SO2 catalyst technology Restrict burning of liquid fuel oil

NOTE: **Not considered a significant source in Clark County.

Table IV-10 lists the control factors that were applied to the 2018 PM_{10} emissions in the listed PM_{10} nonattainment areas in the Western States. Some of the source categories that are included in the prior tables in this chapter are not included in the control factor file because their PM_{10} emissions are not accounted for in the point and area source inventories.

Table IV-10
Area Source Control File for PM

State ID	County ID	PM_{10} Nonattainment Area	SCC	Control Factors for 2018 PM_{10}	Control Factors for 2018 $PM_{2.5}$
Construction					
32	003	Clark	2311010000	75	37.5
06	059	LA	2311010000	75	37.5
04	013	Phoenix	2311010000	37.5	18.75
06	077	SJV	2311010000	75	37.5
35	013	Anthony	2311010000	75	37.5
41	035	Klamath	2311010000		
08	097	Aspen	2311010000		
49	035	Salt Lake	2311010000	75	37.5
53	063	Spokane	2311010000		
Agricultural Tilling					
04	013	Phoenix	2801000003	20	20
06	077	SJV	2801000003	20	20
53	063	Spokane	2801000003	20	20

The control efficiencies and rule penetration values shown below are based on control measure evaluations performed by Pechan for EPA's regulatory analysis of the PM National Ambient Air Quality Standard. Control factor development is described by source category below:

Construction Activity - the numerous measures adopted to reduce fugitive dust PM emissions from construction activity were condensed in to two primary measures: a dust control plan and chemical stabilization. A typical dust control plan includes water treatment of disturbed soil and vacuum street sweeping of nearby paved areas. Control efficiency and rule penetration values are as follows:

	PM_{10}		$PM_{2.5}$	
Measure	Control Efficiency	Rule Penetration	Control Efficiency	Rule Penetration
Dust control plan	50%	75%	25%	75%
Chemical stabilization	75%	75%	50%	75%

Agricultural Tilling - the typical measure in the PM_{10} nonattainment area plan s is soil conservation plans. A 20 percent control efficiency is applied to both PM_{10} and $PM_{2.5}$ emissions in areas that have these plans. This 20 percent control efficiency may be conservative for estimating emission reductions for areas like Maricopa County, Arizona where agricultural best management practices have been adopted.

Prescribed Forest/Range and Agricultural Fire Smoke Management Programs:
The following information is from “Integrated Assessment Update and 2018 Emissions Inventory for Prescribed Fire, Wildfire, and Agricultural Burning”, Air Sciences Inc., originally published August 27, 2002, revisions in press, Project # 178-2.

Table 6.4: Summary of $PM_{2.5}$ Emissions from Prescribed Burning by State and Smoke Management (SM) Scenario. The Relative Emissions are Based on the Total $PM_{2.5}$ Emissions in the Wildfire Emissions Inventory.

	No Smoke Management		Base Smoke Management		Optimal Smoke Management	
State	Absolute (tons x 10^3)	Relative (%)	Absolute (tons x 10^3)	Relative (%)	Absolute (tons x 10^3)	Relative (%)
Arizona	77.0	15	69.5	14	65.6	15
California	110.3	21	109.7	22	95.1	21
Colorado	25.0	5	24.8	5	21.6	5
Idaho	47.1	9	47.1	9	39.9	9
Montana	40.0	8	39.1	8	34.6	8
Nevada	5.9	1	5.8	1	5.1	1
New Mexico	74.5	14	74.4	15	63.6	14
North Dakota	1.8	0.3	1.8	0.4	1.6	0.4
Oregon	48.1	9	46.7	9	39.7	9
South Dakota	3.7	0.7	3.6	0.7	3.3	0.7
Utah	46.4	9	45.7	9	38.5	9
Washington	25.8	5	25.2	5	20.5	5
Wyoming	17.1	3	16.9	3	16.2	4
TOTAL	522.6		510.4		445.2	

Table 6.5: Summary of $PM_{2.5}$ Emissions from Agricultural Burning by State and Smoke Management (SM) Scenario. The Relative Emissions are Based on the Total $PM_{2.5}$ Emissions in the Wildfire Emissions Inventory.

	No Smoke Management		Base Smoke Management		Optimal Smoke Management	
State	Absolute (tons x 10^3)	Relative (%)	Absolute (tons x 10^3)	Relative (%)	Absolute (tons x 10^3)	Relative (%)
Arizona	0.21	0.8	0.21	0.9	0.07	1.0
California	8.05	30.0	7.00	26.0	2.20	33.3
Colorado	0.01	<0.1	0.01	0.1	0.01	0.1
Idaho	5.60	20.9	5.60	28.6	2.42	26.7
Montana	0.03	0.1	0.03	0.1	0.01	0.1
Nevada	0.00	0.0	0.00	0.0	0.00	0.0
New Mexico	0.04	0.1	0.04	0.1	0.01	0.2
North Dakota	2.23	8.3	2.23	6.6	0.56	10.6
Oregon	6.78	25.3	2.58	19.9	1.68	12.3
South Dakota	0.56	2.1	0.56	1.9	0.16	2.7
Utah	0.21	0.8	0.21	0.7	0.06	1.0
Washington	2.91	10.9	2.35	14.7	1.24	11.2
Wyoming	0.19	0.7	0.19	0.5	0.05	0.9
TOTAL	26.83		21.02		8.45	

On-Road Mobile Sources:
This information is from “Development Of WRAP Mobile Source Emission Inventories”, Pollack, 2003, in press.

1996 Control Programs:
MOBILE6/PART5 inputs related to several on-road control programs were also included in the modeling. These control programs are area-specific (i.e., not applied nationally or regionwide), generally based on an area’s ozone or CO nonattainment status. These programs include vehicle inspection and maintenance (I/M) programs, oxygenated fuel programs, and Stage II (at-the-pump) vehicle refueling controls. Note that reformulated gasoline is not included in this list because none of the WRAP states had implemented a reformulated gasoline program by 1996. The default control program parameters were those in the 1996 NET. These were updated by the state and local air agencies in some cases. As described in Section 2, federal control programs are included in MOBILE6 and no additional inputs are needed to model these programs.

Inspection and Maintenance (I/M) Programs:

I/M program inputs are specific to each state or area implementing such a program. The default I/M program inputs were those from the 1996 NET, converted to MOBILE6 input format, along with the county coverage of these programs in the 1996 NET. Updated information on these programs was provided by Arizona, Colorado, Nevada, Oregon, Utah, and Washington. Table 3-2 lists the counties modeled with an I/M program in place.

Table 3-2. Counties modeled with an inspection and maintenance program in 1996.

State	County
AZ	Maricopa
AZ	Pima
CO	Adams
CO	Arapahoe
CO	Boulder
CO	Douglas
CO	Jefferson
CO	Denver
CO	El Paso
CO	Larimer
CO	Weld
ID	Ada
NM	Bernalillo
NV	Clark
NV	Washoe
OR	Clackamas
OR	Jackson
OR	Multnomah
OR	Washington
UT	Davis
UT	Salt Lake
UT	Weber
UT	Utah
WA	Clark
WA	King
WA	Snohomish
WA	Spokane
WA	Pierce

Oxygenated Fuel:
For the WRAP modeling, the program in place in each of the mid-months of the seasons was used (i.e., the program in place in January for the November to February winter season). Table 3-3 lists the counties that were modeled with oxygenated fuels and the inputs used to model these programs. The information in this table includes updated information on these programs provided by the states.

Table 3-3. Oxygenated fuel inputs.

		January Oxygenated Fuel Inputs				October Oxygenated Fuel Inputs			
		Market Share (%)		Oxygen Content (%)		Market Share (%)		Oxygen Content (%)	
State	County	Ether Blend	Alcohol Blend	Ether Blend	Alcohol Blend	Ether Blend	Alcohol Blend	Ether Blend	Alcohol Blend
AZ	Maricopa	17	83	2.7	3.5	17	83	2.7	3.5
AZ	Pima	17	83	2.7	3.5	17	83	2.7	3.5
CO	Adams	25	75	2.7	3.3				
CO	Arapahoe	25	75	2.7	3.3				
CO	Boulder	25	75	2.7	3.3				
CO	Denver	25	75	2.7	3.3				
CO	Douglas	25	75	2.7	3.3				
CO	El Paso	0	100	2.7	2.7	0	100	2.7	2.7
CO	Jefferson	25	75	2.7	3.3				
CO	Larimer	0	100	2.7	2.7	0	100	2.7	2.7
CO	Weld	25	75	2.7	3.3				
MT	Missoula	0	100	2.7	3.5	0	100	2.7	3.5
NV	Clark	24	76	2.7	3.5	24	76	2.7	3.5
NV	Washoe	95	5	2.7	3.5	95	5	2.7	3.5
NM	Bernalillo	15	85	2.7	3.5	15	85	2.7	3.5
OR	Clackamas	0	100	0	3.5	0	100	0	3.5
OR	Jackson	0	100	0	3.5	0	100	0	3.5
OR	Josephine	0	100	0	3.5	0	100	0	3.5
OR	Klamath	0	100	0	3.5	0	100	0	3.5
OR	Multnomah	0	100	0	3.5	0	100	0	3.5
OR	Washington	0	100	0	3.5	0	100	0	3.5
OR	Yamhill	0	100	0	3.5	0	100	0	3.5
UT	Utah	0	100	0	3.5	0	100	0	3.5
WA	Clark	0	100	0	2.7				
WA	King	0	100	0	2.7				
WA	Pierce	0	100	0	2.7				
WA	Snohomish	0	100	0	2.7				
WA	Spokane	0	100	0	3.2	0	100	0	3.5

Stage II Refueling Controls:
Stage II controls were applied in the following counties: Maricopa County, AZ; Clark and Washoe Counties, NV; Multnomah County, OR; and Clark, King, and Pierce Counties, WA. The Oregon and Washington counties were modeled with a 95 percent Stage II control efficiency for light-duty gasoline vehicles and trucks and an 80 percent Stage II control

efficiency for heavy-duty gasoline vehicles. Maricopa County, Clark County (NV), and Washoe County were modeled with a 50 percent control efficiency, 95 percent control efficiency, and 85 percent control efficiency, respectively, applied to both light and heavy vehicles.

Processing of California Data:
California has different on-road mobile source control programs from the rest of the country. CARB has its own model that estimates the effects of these control programs. CARB provided 1996 on-road emissions estimates from EMFAC2000 model runs by vehicle class, county, and season, with all applicable controls incorporated.

Future Control Programs for 2003, 2008, 2013, and 2018:
The effects of Federal on-road control programs are included in the MOBILE6 and modified PART5 models. The Federal control programs that started in or after 1996 that are treated as defaults in the MOBILE6/PART5 modeling are: National Low Emission Vehicle (NLEV) emission standards starting with the 2001 model year; Tier 2 emission standards starting with the 2004 model year; two phases of new heavy duty vehicle emission standards—one starting in the 2004 model year and the other starting in the 2007 model year; onboard diagnostics; and the Supplemental Federal Test Procedure (SFTP) rule. As discussed above, the low sulfur gasoline fuel corresponding with the Tier 2 emission standards and the low sulfur diesel fuel corresponding with the heavy-duty vehicle 2007 emission standards were also modeled throughout the WRAP region. Also modeled as part of the default conditions in MOBILE6 are estimates of excess NO_x emissions resulting from the use of defeat devices in heavy-duty diesel vehicles as well as the provisions to offset these excess emissions through early pull-ahead of the 2004 heavy-duty diesel emission standards and through low emission rebuilds of existing engines. All of these control programs were modeled using the MOBILE6 defaults and the modified PART5 model defaults, with no additional user input.

In addition to the national on-road control programs, several area-specific control programs were included in the MOBILE6 modeling for the projection years. These include I/M and ATP programs, oxygenated fuel programs, and Stage II refueling control programs. These were modeled as follows:

- I/M and ATP Programs – County coverage of the I/M and ATP programs did not change from the 1996 base year modeling to the projection years. The counties with I/M and/or ATP programs are listed in Table 3-2 (above). The States of Colorado, Oregon, Utah, and Washington provided updates to the I/M or ATP program inputs for the projection years. For the remaining States with I/M or ATP programs modeled in the 1996 base year modeling (Arizona, Idaho, New Mexico, and Nevada), the same I/M and ATP program inputs were modeled in the projection years. It should be noted, however, that these programs did already include projection years in the inputs, with OBD testing starting with the 1996 model year. In both the base year modeling and the projection year modeling, the I/M programs in Washington were only applied to a fraction of the VMT in each of the five counties with an I/M program. These fractions that the I/M emission factors apply to were provided by Washington, and emission factors without I/M programs applied were modeled for the remainder of the VMT in each of these counties.

- Oxygenated Fuel Programs – Table 3-3 (above) lists the counties that were modeled with oxygenated fuel in the 1996 base year, as well as the corresponding inputs used to model the oxygenated fuel program in each county with MOBILE6. Several changes were made to these base year oxygenated fuel inputs for the projection years. For Utah County, Utah, the oxygen content of the oxygenated fuel was changed from 3.5 percent to 2.7 percent. For the counties with oxygenated fuel in Oregon, the oxygenated fuel program was eliminated from the 2008, 2013, and 2018 projection years. In Clark, King, Pierce, and Snohomish Counties, Washington, the oxygenated fuel program was discontinued after 1996, so no oxygenated fuel was modeled for these counties in any of the projection years.

- Stage II Refueling Controls – In the 1996 base year modeling, Stage II controls were applied in the following counties: Maricopa County, AZ; Clark and Washoe Counties, NV; Multnomah County, OR; and Clark, King, and Pierce Counties, WA. The only changes made for the projection year modeling were to add Stage II controls in Clackamas County and Washington Counties, in Oregon. The MOBILE6 inputs for modeling Stage II controls applied to these two counties were the same as those applied to Multnomah County in the 1996 base year modeling - a 95 percent Stage II control efficiency for light-duty gasoline vehicles and trucks and an 80 percent Stage II control efficiency for heavy-duty gasoline vehicles.

Processing of Future California Data:
For California, CARB provided on-road emissions estimates from EMFAC2000 model runs for all four future years by vehicle class, county, and season with all applicable control programs incorporated.

Non-Road Mobile Sources:
For non-road sources, 1996 emissions estimates are directly controlled by fuel input, as control technologies were not required for these sources. 1996 state-level off-road fuel sulfur averages are shown below; there are some differences by counties within states and the county-specific sulfur contents were used in developing the 1996 emissions estimates. The fuel sulfur inputs were adjusted to reflect federal rules for gasoline and highway diesel fuels that become effective between 1997 and 2018. No additional control technologies were assumed for 2018.

1996 State Averages

	Gasoline Sulfur (ppm)	Highway Diesel Sulfur (ppm)	Off-Highway Diesel Sulfur (ppm)
Arizona	213	338	2005
California	23	135	135
Colorado	195	335	4100
Idaho	285	380	3075
Montana	375	320	4100
Nevada	91	310	3400
New Mexico	303	310	4100
North Dakota	266	312	4175
Oregon	293	299	3400

South Dakota	238	320	4186
Utah	186	366	3955
Washington	281	301	3400
Wyoming	285	380	4100

California has somewhat different off-road mobile source control programs from the rest of the country, and CARB has its own internal model that estimates the effects of these control programs. CARB provided 1996 off-road emissions estimates from their OFFROAD model by equipment type, county, and season, with all applicable controls incorporated.

Stationary Sources - Existing Source State Regulation Analyses:
This information is from Chapter IV "Existing Source State Regulation Analyses, Western Regional Air Partnership Emission Forecasts For 2018 - Final Report", E.H. Pechan & Associates, Inc., December 2002, Pechan Rpt. No. 02.12.003/9409.000.

NO_x :
The analysis of NO_x emission regulations primarily examined ozone nonattainment areas. These are limited to California and Maricopa County (Phoenix), Arizona.

Arizona:
Portions of Maricopa County are (were) nonattainment for both ozone and PM_{10}. The primary ozone control measure adopted in Maricopa County was a 15 percent rate VOC emission reduction requirement of the CAA. This emission reduction has no direct impact on SO_2, NO_x and PM_{10} emissions. There are a limited number of NO_x control requirements.

California:
In California, the thirty-five (35) air pollution control districts have jurisdiction in imposing emission limits on point sources. The following sections present the district NO_x emission limits for turbines, boilers, internal combustion engines, and petroleum refineries. The fuel combustion sources (boilers, internal combustion engines, and turbines) are of particular interest in this study because they are the largest stationary source NO_x emitters in California.

The impact of these regulatory requirements was estimated as follows. Uncontrolled emission rates were estimated u sing EPA AP-42 uncontrolled emission factors, which are primarily listed in units of pounds per million British thermal units (lbs/MMBtu). EPA guidance was followed to convert these EPA emission factors into parts per million (ppm). This was done for comparison to the California district rules and Maricopa County rules that regulate emissions from these emission units in ppm. This method was used to estimate the likely level of control required by the California Air Pollution Control District (CAPCD) regulations and Maricopa County, Arizona rules. The CAPCD point source regulations also apply to existing units, except as noted. Several CAPCD regulations impose different NO_x limits for units larger than 10 megawatts (MW) depending on whether they have an SCR control device. Since it is not clear whether units in those districts with two sets of rules have installed SCR, to be conservative, the less restrictive emission limit is imposed (assuming no SCR).

Gas Turbines:
The first row of Table IV-11 lists the NO_x emission factors for uncontrolled turbine units. They are provided for comparison with emission limits permitted from gas turbines as found by CAPCD. In some cases, CAPCDs impose different NO_x emission limits on units with identical

Table IV-11
Turbine NO_x Emission Limits[1]

District	Compliance Date	NO_x (ppm)	Control Eff.	Units
-	EPA AP-42	108/297	1/1	Uncontrolled gas/oil
Bay Area	1997	42[2]	0.15-0.39	0.3-10 MW
		15	0.05-0.14	>10 MW w/o SCR
		9	0.03-0.09	> 10 MW w/ SCR
Kern	1997 SCR	10/40	0.10/0.14	> 10 MW co-gen; gas/oil
	1997 SCR	9/25	0.09/0.09	> 10 MW co-gen; gas/oil
	1997 Westinghouse	96/114	0.89/0.39	Constructed by 1983; gas/oil
	1997 Westinghouse	20/42	0.19/0.15	Constructed by 1983; gas/oil
MOJAQMD	1995	42	0.39	Gas-fired
nonattainment		65	0.22	Oil-fired
area		90/gas fuel	0.84	SoCal Model LM 1500
Monterey	-	225	1	All existing
		140 pounds/hr		New or expanded
PLAAPCD	1995	42/65	0.39/0.22	0.3-2.9 MW; gas/liquid
SACAQMD	1997	25/65	0.24/0.22	2.9-10 MW; gas/liquid
YSAQMD	1998	15/42	0.14/0.15	>10 MW no SCR; gas/liquid
VENAPCD	1997	9/25	0.09/0.09	>10 MW w/ SCR gas/liquid
SCAQMD	1989	25	0.09-0.24	0.3-2.9 MW
		15	0.05-0.14	2.9-10 MW no SCR & >60 MW combined cycle (cc)
		9	0.03-0.09	>2.9 MW; >60 MW cc no SCR
		12	0.04-0.12	>10 MW no SCR
SDAPCD	1999 – new units	42/65	0.39/0.22	0.3-2.9 MW; gas/liquid
	2001 - existing units	25/65	0.24/0.22	2.9-10 MW; gas/liquid
	2001 - existing units	15/42	0.14/0.15	>10 MW no SCR; gas/liquid
	2001 - existing units	9/25	0.09/0.09	>10 MW w/ SCR gas/liquid
SJVUAPCD	1998-2000	42/65	0.39/0.22	0.3-10 MW; gas/liquid
		15/42	0.14/0.15	>10 MW no SCR; gas/liquid
		9/25	0.09/0.09	>10 MW w/ SCR gas/liquid
TEHAPCD	No date provided	42/65	0.39/0.22	> 0.3 MW; gas/liquid

NOTES: [1]This represents the emission factor limits from turbines. There are exceptions to these limits, primarily for small sources and during natural gas curtailment or short testing periods. A reference condition of 15% oxygen is usually cited.
[2]Except 55 parts per million by volume (ppmv) allowed for refinery fuel gas firing.

power ratings that differ only in whether they are equipped with SCR control technology. In all of these cases, those units without SCR control technology are allowed a higher NO_x emission limit. Since it is not clear whether most gas turbines are equipped with SCR or not, to be conservative the less restrictive emission limit assuming no SCR control is being used applies. With this information, the control effectiveness of the NO_x emission limits imposed in each CAPCD is identified. The control effectiveness is obtained by dividing the CAPCD imposed NO_x emission limits by the corresponding and applicable EPA AP-42 uncontrolled emission factor. The CAPCD turbine regulations also apply to existing units, except as noted.

Industrial Boilers:
The IAS separately tracks emissions from industrial coal (incobo), natural gas (inngbo), oil (inoibo), and wood (inwobo) boilers. Table IV-12 lists the EPA NO_x uncontrolled emission factors used for these boilers. Also listed in Table IV-12 are the NO_x emission factor limits imposed on these boilers as found for some CAPCDs. These CAPCD regulations also apply to steam generators and process heaters, except as noted. The control effectiveness of these regulations is obtained by dividing the CAPCD imposed NO_x emission limits by the corresponding and applicable EPA AP-42 uncontrolled emission factor.

Internal Combustion Engines:
Table IV-13 lists the NO_x emission factors appearing in EPA AP-42 applicable to uncontrolled internal combustion units. Also listed in Table IV-13 are the emission limits imposed on these units within Maricopa County, Arizona and by CAPCD. With this information, one is able to identify the control effectiveness of the NO_x emission limits imposed within Maricopa County, Arizona and in each CAPCD. The control effectiveness is obtained by dividing the Maricopa County or CAPCD imposed NO_x emission limits by the corresponding and applicable EPA AP-42 uncontrolled emission factor. The CAPCD regulations also apply to existing units, except as noted.

As previously noted, the base case emission inventory for this study is 1996. Because some CAPCD regulations go into effect after 1996, it is expected that these post-1996 regulations will result in a corresponding emission reduction in those areas for these sources relative to 1996. This is captured by reporting the NO_x emission reduction expected in each region relative to 1996, where data are available to perform this task. We have also been able to identify the control effectiveness of the NO_x emission limits imposed in Maricopa County, Arizona and within each CAPCD. The control effectiveness is obtained by dividing the Maricopa County, Arizona and CAPCD imposed NO_x emission limits by the corresponding and applicable EPA AP-42 uncontrolled emission factor. The CAPCD regulations also apply to existing units, except as noted.

Table IV-12
Industrial Boiler, Steam Generator and Process Heater NO_x Emission Limits[1]

District	Compliance Date	NO_x (ppmv)	Reduc. to '96	Control Eff.	Units[4]
Uncontrolled	EPA AP-42	200/1156/140	1	1/1/1	gas/liquid/solid
AVAPCD	1990-1993	30 – 40	-	0.03-0.29	gas/liquid/solid
Bay Area	1996	30 40	-	0.15 0.04-0.29	> 10 MMBtu; gas > 10 MMBtu; non-gas
El Dorado	1999	30 40	-	0.15 0.04-0.29	> 5 MMBtu; gas > 5 MMBtu; non-gas
Great Basin Monterey VENAPCD	1992 - 1972	140 lb/hr	-		New or expanded
Kern	1998	70 115	-	0.35 0.10	> 5 MMBtu; gas > 5 MMBtu; liquid
Calaveras, El Dorado, Mariposa Placer No. Sierra Tuolumne	- - 1977 1991 -	140 lb/hr	-		New or expanded Steam Generator facilities
MOJAQCD nonattainment area	1996 gas other than gas 1996 gas other than gas	70 115 30 40	-	0.35 0.10-0.82 0.15 0.04-0.29	< 5 5t/d and < 250 t/y > 5 t/d or > 250 t/y
Monterey	-	225	-	0.20-1	> 1.5 MMBtu
PLAAPCD	1995 major sources 1997 minor sources	30 40	-	0.15 0.04-	Gas non-gas
SACAQMD[3]	No date provided	30 40 70	-	0.15 0.04-0.29 -	> 5 MMBtu; gas > 5 MMBtu; non-gas > 5 MMBtu; biomass
SBAPCD	1996	30 40	-	0.15 0.04-0.29	> 5 MMBtu; gas > 5 MMBtu; non-gas
SCAQMD	1988-1992 gas liquid 1996 No date provided No date provided 2002	0.14 lb/MMBtu 0.308 lb/MMBtu 0.03 lb/MMBtu 30 40 30/40	-	 0.15 0.04-0.29	Petroleum Ref.* Petroleum Ref.* Petroleum Ref.* > 40 MMBtu; gas* > 5 MMBtu; non-gas* > 5 MMBtu; gas/non-gas*
SDAPCD	1997 major sources 1998 minor sources	30 gas 40 liquid	-	0.15 0.04	> 50 MMBtu
SHAAQMD	1996	70 115	-	0.35 0.10-0.82	gas liquid/solid
SJUAPCD Not applied west of I5 in Fres, Kern, King Counties	1995 1995 1997-2001	0.20 lb/MMBtu 95 115 165 30/40 147/155	- 1 1 1 0.32/0.35	0.10-0.50 0.48 0.10 0.15 0.15 / 0.04-0.29 -	solid gas distillate oil residual/crude oil >30 MMBtu; gas/non-gas >30 MMBtu;gas/non-gas[2]

Table IV-12 (continued)

District	Compliance Date	NO_x (ppmv)	Reduc. to '96	Control Eff.	Units[4]
SLOAPCD	1993	140 lb/hr	-	-	All facility units
	1995-1997 (1995 new, 1997 existing)	30 or 0.036 lb/MMBtu		0.15	gas
		40 or 0.052 lb/MMBtu		0.04 / 0.29	liquid/solid
TEHAPCD	No date provided	70	-	0.35	gas
		115		0.10-0.82	liquid or solid
VCAPCD	1991-1992	40	-		> 5 MMBtu
	1994-1995	30			1-5 MMBtu
YSAQMD	1998	30	-	0.15	gas
		40		0.04-0.29	non-gas

NOTES: [1]This represents the emission factor limits from boilers. There are exceptions to these uses, primarily for small and/or emergency uses. A reference condition of 3% oxygen is usually cited.
[2]Box or cabin units.
[3]Boilers only.
[4]MMBtu = MMBtu/hr.
*The Petroleum Ref. applicable section is for boilers and process heaters, the corresponding items for this district do not apply to Petroleum Ref. boilers and process heaters > 40 MMBtu and sulfur plant reaction boilers.

Table IV-13
Internal Combustion Engine NO_x Emission Limits[1]

District	Calendar Year	NO_x (ppmv)	Reduction to '96	Control Eff.	Units
Uncontroled	-	500		1	Rich
		700		1	Lean
		1000		1	Diesel
Maricopa, AZ	New units	213 or 80% red.	-	0.31-0.43	Rich/Lean
		810 [3]		0.81	50 - 116 hp (CI)
		770 [3]		0.77	117 - 339 hp (CI)
		550 [3]		0.55	$\geq$ 400 hp (CI)
AVAPCD	1981-1991	48 or 90% red.	1	0.096	Rich
		96 or 80% red.	1	0.14	Lean
	1994/2004	36	0.375-0.75	0.036 - 0.072	> 500 hp
		45	0.47 -0.94	0.045 - 0.090	50-500 hp
Bay Area	1997	56 / 140	-	0.12 / 0.2	Rich/Lean NG only
		210 / 140		0.21 / 0.14	Rich/Lean other
El Dorado	1995	640	1	1	Rich
		740	1	1	
		700	1	0.70	Diesel
	1997		0.14	0.18	Rich
		150	0.21	0.22	Lean
		600	0.86	0.60	Diesel
Kern	No date provided	50 or 90% red.	-	0.10	Rich > 250 hp
		125 or 80% red.		0.18	Lean > 250 hp
		600 or 30% red.		0.60	Diesel > 250 hp
MOJAQMD	1995, except 1995-97 for SoCalGas 1996-98 PGE	50 or 90% red.		0.10	Rich
		140 or 80% red.		0.20	Lean
		700 or 30% red.		0.70	Diesel
Monterey	-	225 ppm	-	0.45/0.32/0.23	All
		140 lb/hr			New or expanded
SACAQMD	1995 if no retrofit needed	50 or 90% red.	1	0.10	Rich
		125 or 90% red.	1	0.18	Lean
		700 or 90% red.	1	0.70	Diesel (CI)
	1997 if controls needed	25	0.2-0.5	0.05	Rich/Lean (SI)
		80	0.12	0.08	Diesel(CI)
SCAQMD	1994	90 or 80% red.	1	0.10	Rich
		150 or 70% red.	1	0.22	Lean
	2004	36	0.24-0.40	0.036 - 0.072	> 500 hp
		45	0.30-0.50	0.045 - 0.090	50-500 hp
	2000; except if controls needed than 2010	80		-	Portable SI
		535-750		-	Portable CI
SHAAQMD TEHAPCD	1999	640	-	1	Rich (50-300 hp)
		740		1	Lean (50-300 hp)
		600		0.60	Diesel (50-300 hp)
		90		0.18	Rich (>300 hp)
		150		0.22	Lean (>300 hp)
		600		0.60	Diesel (>300 hp)

Table IV-13 (continued)

District	Calendar Year	NO_x (ppmv)	Reduction to '96	Control Eff.	Units
SJVUAPCD	1996	90 or 80% red.	1	0.10	Other Rich
		150 or 70% red.	1	0.22	Lean
		600 or 20% red.	1	0.60	Diesel
	1999/2001	50 or 90% red.[3]	0.56	0.10	Other Rich
		75 or 85% red.[3]	0.50	0.11	Lean
		80 or 90% red.[3]	0.14	0.08	Diesel
SLOAPCD	2000	50 or 90% red.	-	0.10	Rich
		125 or 80% red.		0.18	Lean
		600 or 30% red.		0.60	Diesel
VCAPCD	1994 or 2002	25 or 96% red.	-	0.05	Rich
		45 or 94% red.		0.07	Lean
		80 or 90% red.		0.08	Diesel
		50 or 96% red.		-	Rich-Waste Gas
		125 or 94% red.		-	Lean-Waste Gas
YSAQMD	1995	640 or 9.5 g/hphr	1	1	Rich
		740 or 10.1 g/hphr	1	1	Lean
		700 or 9.6 g/hrhr	1	0.70	Diesel
	1997	90/ 150/ 600	0.15/ 021/ 0.86	0.10/0.22/0.60	Rich/Lean/Diesel

NOTES: [1]Represents emission factor limits from internal combustion engines. Reductions (red.) are from uncontrolled levels. There are exceptions to these limits, primarily for small and/or emergency uses. A reference condition of 15% oxygen is usually cited.
[2]Not applicable to engines owned by public water districts.
[3]Alternatively, a unit with a turbocharger and aftercooler/intercooler or with 4-degree injection timing retard will satisfy Maricopa County, AZ regulations.

Industrial Reciprocating Engines, Including Natural Gas:

Table IV-14 lists the NO_x emission factors permitted from natural gas and other fuels used in reciprocating engines as reported by CAPCD. As shown below , only Santa Barbara County and San Diego County Air Pollution Control Districts apply specific NO_x emission factor limits from these types of units.

Table IV-14
Industrial Reciprocating Engine NO_x Emission Limits[1]

District	Compliance Date	NO_x (ppmv)	Control Eff.	Units
Uncontrolled	-	500	1	Rich NG
		625	1	Lean NG
		1000	1	Diesel
Monterey	-	225	0.45/0.36/0.23	All
		140 lb/hr		New or expanded
SBCAPCD	1994	50 or 90% red.	0.10	Rich
		125 or 80% red.	0.20	Lean
		797	0.80	Diesel
SDAPCD	No date provided	50 rich or 90% red.	0.10	Rich NG
		125 lean or 80% red.	0.20	Lean NG
		700 diesel	0.30	Diesel
	2003	25 or 96% red.	0.05	Rich NG
		65 or 90% red.	0.10	Lean NG
		535 or 90% red.	0.535	Diesel

NOTES: [1]This represents the emission factor limits from reciprocating engines. The reference condition used is 15% oxygen content.

Industrial Petroleum Refineries:
The California Bay Area District imposed regulations limiting NO_x emissions from boilers, steam generators, and process heaters in petroleum refineries. The limits imposed were 0.2 pounds per MMBtu in 1995 and 0.033 pounds per MM Btu in 1997. In other words, the Bay Area District decreased the allowable NO_x emission factor from petroleum refineries by 83.5 percent from 1995 to 1997 (see Table IV-15).

Table IV-15
Industrial Petroleum Refinery NO_x Emission Limits[1]

Calendar Year	Control Factor	NO_x (lbs/MMBtu)
1995	1.00	(0.2)
1997	0.165	(0.033)

NOTES: [1]This represents the control effectiveness of emissions from the refinery, it says nothing about the growth in refinery output. This excludes carbon monoxide (CO) boilers.

Oil and Gas Production Facilities:
None of the documents checked on-line included any information about regulated NO_x or PM emissions. The documents related to oil and gas production had to do with leak detection and repair, which affects VOC emissions.

Missouri:
Missouri is included in this analysis because its emissions are within the WRAP Region modeling domain. EPA's (1999b) Regional Transport NO_x State Implementation Plan (SIP) proposed to reduce NO_x emissions within many States east of the Rocky Mountains, including Missouri, in an effort to reduce trans ported ozone concentrations in eastern States. The primary focus for reducing NO_x emission s was from electric gene rating units (EGUs).

For EGU point sources, base year 1995/1996 NO_x emissions were used to develop an Integrated Planning Model (IPM) Year 2007 emission inventory. For Missouri, the IPM Year 2007 summer emission inventory for EGU point sources equaled 82,097 tons. The EPA 2007 NO_x control case was then developed by unit by applying IPM growth factors to the unit emission rate for the 1995/1996 base year. Emissions from EGUs greater than 25 MW equivalents were then limited to 0.15 lbs NOx/MMBtu. Units 25 MW equivalents or smaller were left at their 2007 base case NO_x emission rate. For Missouri, the resulting IPM NO_x control Year 2007 summer emission inventory for EGU point sources equaled 24,216 tons. Thus, the EPA analysis called for a 70 percent reduction in EGU 2007 NO_x emissions relative to the IPM base case Year 2007 Missouri inventory (see Table IV-16).

Table IV-16
NO_x Emission Reductions Required from EGUs in Eastern Missouri Counties

Description	NO_x Emissions
2007 IPM	82,097 tons
2007 IPM with controls	24,216 tons
% Emission Reduction	70% = 100% x (1 – 24,216/82,097)

Texas:
Texas is included in this analysis because its emissions are within the WRAP Region modeling domain. Recent revisions to the SIPs for the major ozone nonattainment areas in Texas have added many regulations that require stationary source NO_x emitters to reduce their future year emissions.

The Texas SIPs developed by the Texas Natural Resource Conservation Commission (TNRCC) to reduce ozone concentrations in ambient air are very source-specific. There are three ozone nonattainment areas of note in Texas: (1) Beaumont/Port Arthur; (2) Houston/Galveston; and (3) Dallas/Fort Worth. The SIPs developed for these areas require a reduction in NO_x emissions from specific point sources or uniformly across a source category as described below. In addition, TNRCC entered into orders requiring Alcoa and Eastman Chemical to reduce NO_x and VOC emissions for the purpose of revising its SIP for ozone. The effect of these orders in terms of NO_x emission reductions is also included in this analysis. There is also a TNRCC SIP requirement that utility and grandfathered non-utility sources in Eastern and Central counties of Texas reduce emissions. The recommended implementation of this requirement is presented below.

Beaumont/Port Arthur:
The Beaumont/Port Arthur ozone nonattainment area includes Hardin, Jefferson, and Orange counties. TNRCC (2000a) believes Tier 1 reductions in NO_x emissions from these three counties will be enough for Beaumont/Port Arthur to attain the 1-hour ozone standard.

The Tier 1 reductions amount to a 40.6 percent, 61.9 percent, and 36.5 percent reduction in NO_x emissions from point sources in Hardin, Jefferson, and Orange counties (see Table IV-17). TNRCC (2000) reports that these reductions are equivalent to requiring a 50 percent emission reduction from utility sources and a 20 percent emission reduction from four (4) refineries and fifteen (15) chemical plants. These NO_x reductions of 40.6 percent, 61.9 percent, and 36.5 percent from point sources in Hardin, Jefferson, and Orange counties were uniformly applied to all point sources in this ozone nonattainment area.

Table IV-17
NO_x Emission Reductions Required from Texas Sources

Ozone Nonattainment Area	County	NO_x Emission Reduction
Beaumont/Port Arthur	Hardin	40.6%
Beaumont/Port Arthur	Jefferson	61.9%
Beaumont/Port Arthur	Orange	36.5%
Dallas/Fort Worth	Collin, Dallas, Denton, Tarrant	Source specific
Houston/Galveston	Brazoria	90%
Houston/Galveston	Chambers	90%
Houston/Galveston	Fort Bend	90%
Houston/Galveston	Galveston	90%
Houston/Galveston	Harris	90%
Houston/Galveston	Liberty	90%
Houston/Galveston	Montgomery	90%
Houston/Galveston	Waller	90%
Alcoa boilers (3)	Milam	19.6%
Cement Kilns	Bexar, Comal, Ellis, Hays, McLennan	Incorporated in the Dallas/Fort Worth emission reduction requirement
Eastman Chemical	Harris	Incorporated in the Houston/Galveston emission reduction requirement.
Central & Eastern Industry and Utilities	Atascosa, Bastrop, Bexar, Brazos, Calhoun, Cherokee, Fannin, Fayette, Freestone, Goliad, Gregg, Grimes, Harrison, Henderson, Hood, Hunt, Lamar, Limestone, Marion, McLennan, Milam, Morris, Nueces, Parker, Red River, Robertson, Rusk, Titus, Travis, Victoria, Wharton	50% for utilities; 7.3% for remaining sources

Houston/Galveston:
The Houston/Galveston ozone nonattainment area includes Brazoria, Chambers, Fort Bend, Galveston, Harris, Liberty, Montgomery, and Waller counties. For point sources, TNRCC compiled a 2007 future year NO_x emission inventory equal to 564 and 641 tpy (TNRCC, 2000b) for Phase II and Phase III base cases. TNRCC also compiled a 2007 future year control case NO_x inventory. This control case inventory contained 64 and 67 tpy (TNRCC, 2000b) of point source NO_x emissions, respectively, for Phase II and Phase III scenarios. The difference in the 2007 base case and control case amounts to a 90 percent reduction in NO_x emissions from point sources within Houston/Galveston ozone nonattainment area counties (see Table IV-17). (The 90 percent reduction is calculated from the Phase III scenario as follows: 90 percent = 100 percent x (1 – 67 t/ 641 t).) This 90 percent reduction was applied uniformly to all point sources in the Houston/Galveston area counties shown in Table IV-17.

Dallas/Fort Worth:
Appendix F of the Dallas/Fort Worth ozone nonattainment demonstration (TNRCC, 1999a) identifies NO_x control factors proposed for specific industrial boilers and engines and EGUs in that area. These unit specific reductions were applied to estimate 2018 NO_x emissions.

Alcoa:
Alcoa operates a plant in Milam County, Texas. A TNRCC order with Alcoa limits future maximum NO_x emissions from Alcoa's 3 boilers to 13,622.4 tpy. This equals a 19.6 percent NO_x emission reduction relative to the emission inventory for these three boilers in the WRAP database for 1996. These reductions were applied in the forecast year.

Cement Kilns:
Appendix F of the Dallas/Fort Worth ozone nonattainment demonstration (TNRCC, 1999a) identifies 11 cement kilns modeled as part of the proposed Dallas/Fort Worth NO_x emission reduction strategy. The level of NO_x controls required by TNRCC ranged by unit from 6 to 66 percent. These controls were applied on a unit-by-unit basis as reported by TNRCC. However, one of the four Texas Industries (Ellis County) cement kilns identified by TNRCC as requiring control was not listed in the WRAP 1996 emission inventory. It is unclear whether the WRAP emission inventory missed counting emissions from a cement kiln, or whether there is a typo in the Dallas/Fort Worth ozone SIP strategy.

Eastman Chemical:
Eastman Chemical operates a chemical plant in Harris County, Texas. Harris County is part of the Houston/Galveston ozone nonattainment area. A TNRCC order requires this Eastman Chemical plant to reduce NO_x emission s from 14 units by 1,671.5 tpy. Thirteen of the 14 units are to be retired. Because the retirement of these units would also reduce emissions of other pollutants, these specific units in the WRAP database for Eastman Chemical were retired.

Because the unit specific codes in the WRAP database and the TNRCC unit identifiers for Eastman Chemical did not match, this required some judgment to determine which units in the WRAP database best matched those identified by TNRCC.

Industry and Utility Units in Central and Eastern Texas:
As part of the Houston/Galveston area SIP, TNRCC (1999b) added the following NO_x emission reduction requirements applicable outside the Houston/Galveston area nonattainment counties and within Central and Eastern Texas:

- 50 percent reduction of NO_x emissions from all utility stationary sources, and
- 30 percent reduction of NO_x emissions from remaining grandfathered sources.

The 50 percent reduction was applied uniformly to all utility stationary sources in Central and Eastern Texas. The 30 percent NO_x reduction requirement from grandfathered sources is difficult to simulate, because the identity of the grandfathered sources was not provided by TNRCC. An analysis was made to determine how this information could be adapted and applied uniformly. The analysis made use of a NO_x emissions data file for grandfathered and nongrandfathered sources. The Alcoa boilers (3) mentioned above are thought to represent a part of the non-utility grandfathered sources in Central and Eastern counties of Texas. When the Alcoa boilers emission reduction requirement is removed, the 30 percent reduction required by TNRCC from grandfathered non-utility sources equates to a 7.3 percent emission reduction requirement from all non-utility sources in Central and Eastern Texas. The 7.3 percent reduction was applied uniformly to all non-utility point sources, except for Alcoa.

SO_2 :
The analysis of existing source State regulations affecting SO_2 emissions in the WRAP States focused on identifying the regulations that were recent enough that existing sources would not have responded to them by 1996. It was also recognized that regulations affecting the largest point source SO_2 emitters would be most important to the forecast. This evaluation focuses on non-utility sources. Utility units are affected by the Federal Acid Rain Program, but as is explained in Chapter VII, future year utility SO_2 and NO_x emission estimates incorporate 2018 utility unit values that were prepared under a separate study. The tables in the following pages report the recent SO_2 emission regulations for the WRAP States that have SO_2 nonattainment areas, or regulations that affect the major sources in their States.

California:
Table IV-18 lists the SO_2 emission factor limits found on-line as reported by CAPCD. The emission limits found cover a range of unit operations or in some cases cover all unit operations possible.

Arizona:
Arizona air pollution control regulations restrict copper smelter SO_2 emissions by facility as shown below. Of the listed Arizona copper smelters, only ASARCO-Hayden and Phelps Dodge-Miami are currently operating.

SO_2 Emission Limits	
Copper Smelter	SO_2 Emissions (Pounds per hour)
Magma Copper Company, San Manuel Division	18,275
ASARCO, Inc., Hayden	9,521
ASARCO, Inc., Ray Mines Division	7,790
Cyprus Miami Mining Corporation, Miami	3,163
Phelps Dodge Corporation, New Cornelia Branch	8,900
Phelps Dodge Corporation, Morenci Branch	10,505

SOURCE: DEQ, 2001.

Table IV-18
Point Source SO_2 Emission Limits[1]
State of California

District	Unit Operation	SCC	Year	SO_2
Bay Area	Catalyst Manufacturing		1992	50 lb/hr
Bay Area	Coke calcining kiln		-	400 ppm & 250 lb/hr
AVAPCD			1983	80% red.
SCAQMD			-	
Bay Area	Fluid catalytic cracker		-	1,000 ppmv
SCAQMD			1987	132 lb/1000 barrels feed
Bay Area	Fresh fruit sulfuring		-	20-30 lb/ton of fruit
SDAPCD	Gas turbine		-	150 ppm @15% O_2
AVAPCD	Fuel Combustion	e.g.,	1976	0.56 lb/MMBtu solid
Calaveras		inxxboxx	-	200 lb/hr steam gener. facility
EDAPCD				
Mariposa				
No. Sierra				
Placer				
Tuolumne				
IMAPCD				500 ppm & 200 lb/hr
SDAPCD				0.8 lb/MMBtu liquid 1.2 lb/MMBtu solid
VENAPCD				300 ppm
Bay Area	Liquid fuel (except in the manufacture of sulfur compounds)		-	0.5% S
IMAPCD				0.5% S*
SCAQMD	Secondary Lead		1977	200 ppm & 2.1 kg/ton processed
Bay Area	Sulfur Recovery Plant/Units[2]	ptescxxx	-	250 ppm @ 0% O_2
SDAPCD				
AVAPCD MOJAQMD				500 ppm & 198 lb/hr
SCAQMD				
IMAPCD				
SLOAPCD				500 ppm & 200 lb/hr
	new or altered units			2000 ppm & 200 lb/hr
AVAPCD	Sulfuric Acid Plant	ptsapxxx	1981	500 ppm & 198 lb/hr
Bay Area			1992	300 ppm @ 15% O_2
IMAPCD			-	500 ppm & 198 lb/hr
MOJAQMD			1976	500 ppm & 198 lb/hr
SLOAPCD				2000 ppm & 200 lb/hr
Bay Area	All other operations not referenced herein	-		300 ppm
IMAPCD				2000 ppm
SLOAPCD				2000 ppm
VENAPCD				500 ppm
Butte	All Operations	-	-	2000 ppm
Colusa			-	
Feather River			1991	
Great Basin			1974	
Monterey			-	
SJUAPCD			1992	
Kern			1972	1000 ppm
Mendocino			-	
No. Sonoma			-	
No. Coast			-	

NOTES: [1]This represents the emission factor limits.
[2]Not in effect for plants which emit less than 100 lb per day of SO_2.
*There are other exceptions not noted.

Montana:

Lewis and Clark County (East Helena) (County Code: 30-049)
These SO_2 emission limits were part of the SIP submitted by the State of Montana, and have been included in the Federally (EPA) approved SIP (SMAQCIP, 1995).

SO_2 Emissions			
ASARCO Lead Smelter	**Year Adopted**	**Unit of Measure**	**SO_2 Emissions Limit**
Sulfuric Acid Plant Stack	1995	Daily Emissions-Tons per Calendar Day	<= 4.30
Sinter Plant Stack	1995	Daily Emissions-Tons per Calendar Day	<= 60.27
Blast Furnace Stack	1995	Daily Emissions-Tons per Calendar Day	<= 29.64
Concentrate Storage and Handling Building Stack	1995	Tons per Calendar Day	<= 0.552
Crushing Mill Baghouse Stack=1	1995	Tons per Calendar Day	<= 0.19
Crushing Mill Baghouse Stack=2	1995	Tons per Calendar Day	<= 0.37

SOURCE: SMAQCIP, 1995.

Yellowstone County (County Code: 30-111):
These SO_2 emission limits were part of SIPs submitted by the State of Montana but have not been approved by EPA. Therefore, these limits are State-enforceable only. In addition, the following emission limits will apply whenever the Yellowstone Energy Limited Partnership (YELP) facility receives Exxon Coker unit flue gas, or whenever the Exxon Coker unit is not in operation (SMAQCIP, 2000a).

SO_2 Emissions			
Exxon Petroleum Refinery-YELP Facility	**Year Submitted for Approval**	**Unit of Measure**	**SO_2 Emissions Limit**
Refinery Fuel Gas Combustion[1]	2000	Daily Emissions-Tons per Calendar Day	<= 0.37
F-2 Crude/Vacuum Heater Stack	2000	Daily Emissions-Tons per Calendar Day	<= 1.09
Fluid Catalytic Cracking (FCC) CO Boiler Stack[2]			
Daily Average FCC Fresh Feed Rate (kBD):			
Less than 12,999	2000	Daily Emissions-Tons per Calendar Day	<= 23.55
13,000 to 13,999	2000	Daily Emissions-Tons per Calendar Day	<= 24.21
14,000 to 14,999	2000	Daily Emissions-Tons per Calendar Day	<= 24.41
15,000 to 15,999	2000	Daily Emissions-Tons per Calendar Day	<= 24.52
16,000 to 16,999	2000	Daily Emissions-Tons per Calendar Day	<= 24.89
Greater then 17,000	2000	Daily Emissions-Tons per Calendar Day	<= 25.12

NOTES: [1]From the following units: Coker CO Boiler, FCC CO Boiler, F-2 Crude/Vacuum Heater, F-3 unit, F-3X unit, F-5 unit, F-700 unit, F-201 unit, F-202 unit, F-402 unit, F-551 unit, F-651 unit, and standby boiler house (B-8 boiler).
[2]The daily SO_2 emission limits from the FCC CO Boiler stack shall be determined by the Daily Average FCC Fresh Feed Rate, expressed in thousands of barrels per day (kBD), rounded to the nearest whole barrel.

SOURCE: SMAQCIP, 2000a.

SO$_2$ Emissions			
YELP	**Year Submitted for Approval**	**Unit of Measure**	**SO$_2$ Emissions Limit**
Boiler stack emissions-when either the Exxon Coker Unit is not operating or the Exxon Coker Unit is operating and YELP is receiving the Exxon Coker flue gas	2000	Daily Emissions-Tons per Calendar Day	8.16
YELP boiler stack emissions-when the Exxon Coker Unit is operating and YELP is not receiving the Exxon Coker flue gas	2000	Daily Emissions-Tons per Calendar Day	5.27

SOURCE: SMAQCIP, 2000a.

SO$_2$ Emissions			
Cenex Petroleum Refinery	**Year Submitted for Approval**	**Unit of Measure**	**SO$_2$ Emissions Limit**
FCC Regenerator/CO Boiler Stack	1998	Daily Emissions-Tons per Calendar Day	<= 8.57
Old SRU Tail Gas Oxidizer Stack	1998	Daily Emissions-Tons per Calendar Day	<= 11.66
HDS Complex SRU Stack	1998	Daily Emissions-Tons per Calendar Day	<= 0.17
Emissions from the Combustion Sources (#3, #4, and #5 Boiler Stacks, and Main Crude Heater Stack), Fuel Gas Fired Sources, and the Combustion of Sour Water Stripper Overhead Gases in the Main Crude Heater	1998	Combined Daily Emissions-Tons per Calendar Day	<= 12.06

SOURCE: SMAQCIP, 2000b.

SO$_2$ Emissions			
Conoco Petroleum Refinery	**Year Submitted for Approval**	**Unit of Measure**	**SO$_2$ Emissions Limit**
Main Boiler House Stack	1998	Daily Emissions-Tons per Calendar Day	<= 3.86
FCC Stack	1998	Daily Emissions-Tons per Calendar Day	<= 3.95
Jupiter Sulfur SRU Stack	1998	Daily Emissions-Tons per Calendar Day	<= 0.30
Process Heaters (#1, #2, #4, #5, #10, #11, #12, #13, #14, #15, #16, #17, #18, #19, #20, #21, #22, #23, #24), Coker Heater, Fractionator Feed Heater, and Recycle Hydrogen Heater	1998	Combined Daily Emissions-Tons per Calendar Day	<= 0.35

SOURCE: SMAQCIP, 2000b.

SO_2 Emissions			
Montana Sulfur and Chemical Company	Year Submitted for Approval	Unit of Measure	SO_2 Emissions Limit
SRU 100 Meter Stack[1]	1998	Daily Emissions-Tons per Calendar Day	<= 14.31
SRU 30 Meter Stack	1998	Daily Emissions-Tons per Calendar Day	<= 0.048

NOTE: [1]Whenever SO_2 emissions from either the Railroad Boiler, the H-1 Unit, the H 1-A Unit, the H1-1 Unit, or the H1-2 Unit are exhausting through the SRU 30 meter stack.

SOURCE: SMAQCIP, 2000b.

SO_2 Emissions			
Western Sugar	Year Submitted for Approval	Unit of Measure	SO_2 Emissions Limit
Boiler House Stack	1998	Daily Emissions-Tons per Calendar Day	<= 3.42
East Dryer Stack and West Dryer Stack	1998	Combined Daily Emissions-Tons per Calendar Day	<= 0.354

SOURCE: SMAQCIP, 2000b.

Nevada:

Nevada State SO_2 regulations were summarized as follows:

SO_2 Emissions			
Sources	Year Adopted	Unit of Measure	SO_2 Emissions Limit
Gabbs Plant of Basic Refractories, Air Quality Region 148, Basin 122, Gabbs Valley	1995	Pounds per MMBtu	<= 0.26
Nevada Power Company's Reid Gardner Power Station, Power Generating Units Number 1, 2, and 3, Air Quality Control Region 13, Basin 218, California Wash	1995	Pounds per MMBtu	<= .275
Nevada Power Company's Reid Gardner Power Station, Power Generating Unit Number 4, Air Quality Control Region 13, Basin 218, California Wash[1]	1995	Pounds per MMBtu	<= 0.145
Sierra Pacific Power Company's North Valmy Power Station, Power Generating Unit 2, Air Quality Control Region 147, Basin 64, Clovers Area[2]	1995	Pounds per MMBtu	<= 0.3

NOTES: [1]The efficiency of the capture of Sulfur must be maintained at a minimum of 85 percent, based on a 30-day rolling average.
[2]The efficiency of the capture of Sulfur must be maintained at a minimum of 70 percent, based on a 30-day rolling average.

New Mexico:

Coal Burning Equipment (After December 31, 1984, the owner or operator of a coal burning station that has two or more units o f existing coal burning equipment that have a rated heat capacity greater than 250 MMBtus per hour has an SO2 emission limit of 17,900 pounds per hour, which is averaged over any three-hour period and determined on a total station basis (NMED, 1995).)

SO_2 Emissions		
Year Adopted	Unit of Measure	SO_2 Emissions Limit
1985	Pounds per Hour	17,900

SOURCE: NMED, 1995.

Natural Gas Processing Plants

SO_2 Emissions				
Average SO_2 Released	Undiluted Off-Gas Stream	Year Adopted	Unit of Measure	SO_2 Emissions Limit
>= 10 tons per day (tpd)	> 20 mole percent H_2S	1995	Number of pounds for every 100 pounds	<= 10
>= 10 tpd	<= 20 mole percent H_2S	1995	Number of pounds for every 100 pounds	<= 12
7.5 <= 10 tpd	> 20 mole percent H_2S	1995	Number of pounds for every 100 pounds	<= 10
7.5 <= 10 tpd	<= 20 mole percent H_2S	1995	Number of pounds for every 100 pounds	<= 12

SOURCE: NMED, 1995.

Petroleum Refineries

SO_2 Emissions		
Year Adopted	Unit of Measure	SO_2 Emissions Limit
1995	Tons per 24 hours	<= 5

SOURCE: NMED, 1995.

Sulfur Recovery Plants (This limit applies to plants where fabrication, erection, or installation commenced before August 14, 1974.

SO_2 Emissions		
Year Adopted	Unit of Measure	SO_2 Emissions Limit
1995	Number of pounds for every 100 pounds	<= 12

SOURCE: NMED, 1995.

Sulfuric Acid Production Units

SO$_2$ Emissions			
Sulfuric Acid Production Units	**Year Adopted**	**Unit of Measure**	**SO$_2$ Emissions Limit**
Units located within the Pecos-Permian Basin Intrastate Air Quality Control Region[1]	1995	Pounds per hour	<= 575
Units located outside the Pecos-Permian Basin Intrastate Air Quality Control Region	1995	Pounds per hour	<= 680

NOTE: [1]With a minimum stack height of 40 meters.

SOURCE: NMED, 1995.

Nonferrous Smelters

SO$_2$ Emissions		
Year Adopted	**Unit of Measure**	**SO$_2$ Emissions Limit**
1995	Pounds per hour (Annual average Emissions)	<= 7000[1]

NOTE: [1]Except as provided for in Section 112 of Title 20, Chapter 2, Part 41 in the New Mexico Administrative Code (NMED, 1995).

SOURCE: NMED, 1995.

Utah:
The SIP for Utah was last approved by EPA on July 8, 1994, except for the Amoco Oil Company submission.

SO$_2$ Emissions			
Point Source	**Year Adopted**	**Unit of Measure**	**SO$_2$ Emissions Limit**
Amoco Oil Company	Pending	Tons per year	<= 1,964
Kennecott Utah Copper Smelter-Main Stack	1994	Tons per year (annual average)	<= 14,191
Crysen Refining, Inc.	1994	Tons per year	<= 183
Chevron U.S.A., Inc.	1994	Tons per year	<= 1,731

SO$_2$ Emissions			
Point Source	**Year Adopted**	**Unit of Measure**	**SO$_2$ Emissions Limit**
Phillips 66 Company	1994	Tons per year	<= 1,762
Flying J Inc.	1994	Tons per year	<= 824.8

SOURCE: USIP, 1994.

After gathering the above information about State regulations, the SO$_2$ emission limits were compared with the SO$_2$ emissions in the WRAP 1996 point source file for affected facilities. In all cases, it was found that emission points/facilities were in compliance with these SO$_2$ regulations. Therefore, no additional SO$_2$ controls were placed on point sources in the 2018 emission forecast.

Stationary Sources – Retirement Factors, Unit Lifetime Analysis:
This information is from Chapter V "Retirement Factors – Unit Lifetime Analysis, Western Regional Air Partnership Emission Forecasts For 2018 - Final Report", E.H. Pechan & Associates, Inc., December 2002, Pechan Rpt. No. 02.12.003/9409.000.

In the original IAS model, future year forecasts of electric utility emissions used estimates of the date of initial operation and expected unit lifetimes in years to determine when existing source emission rates were likely to be replaced with new source emission rates. So, for example, if an oil-fired utility boiler began operating in 1970, it would be expected to be replaced by a new boiler that emits at NSPS/BACT level emission rates in 2000 at the end of its 30-year lifetime. For non-utility units, the IAS model includes the effects of retirements using an annual rate. So, each unit in any source category has the same annual retirement rate applied. For example, the annual retirement rate for industrial boilers in the IAS model has been 0.6 percent per year. If this retirement rate were applied to the 1996 to 2018 forecast horizon that is being used for this project, then 12.4 percent of industrial boiler capacity would be retired during this 22-year period. One of the objectives of this project was to establish projection methods for the largest non-utility units that parallel those used for utilities. This requires gathering and using information about the year of initial operation for individual non-utility units and expressing non-utility unit lifetimes in years. The year of initial operation data gathering activity is described in Chapter II. This chapter describes the effort to establish appropriate lifetime estimates for the source categories (scc_ ids) in the IAS model.

Industrial Sources:
This section deals with estimating the lifetimes of the IAS industrial sources listed in Table V-1. The IAS annual retirement rates for each sector were converted into the lifetime years listed above by the following formula:

$$\frac{1}{\text{Retirement Rate}} = \text{Years}$$

We consulted several other data sources, such as Internal Revenue Service Publications, Bureau of Economic Analysis (BEA) depreciation schedules, other industry publications, and estimates provided by authorities in different sectors, to estimate the actual lifetimes of the different industrial sector units or plants. The following sub sections describe how the lifetimes of the different industrial sector units or plants were calculated or estimated.

Table V-1
Industrial IAS Source Group Retirement/Lifetime Years

Sector	Scc_id	Annual Retirement Rate	Equivalent Lifetime (Years)	Source
Industrial Boilers (Fuel combustion)	inngbo incobo inwobo inoibo inothr inngre	0.6 %	167	Industrial Combustion Emissions (ICE) Model
Copper Smelters	incopp	1.2%	83	NEMS Model (Other Primary Metals sector)
Oil and Gas Production (except Sweetening Plants), Solvents, Other N.E.C. Refineries Nitric Acid Plants	inoipr ingspr inngcm inngfl inpere inpepr	2.3%	43	NEMS Model (Misc. Manufacturing)
Gas Production-Sweetening Plants Organic Chemical Storage Gasoline Storage	inchem inngsw inorch inagpe	1.9%	53	NEMS Model (Bulk Chemicals sector)

Industrial Boilers:
The annual retirement rates used in the original IAS model for industrial fuel combustors or industrial boilers are taken from a U.S. energy model named the ICE model. The ICE model was developed and applied as part of the National Acid Precipitation Assessment Program (NAPAP) emission and control techniques evaluation process. The assumed IAS annual industrial boiler retirement rate of 0 .6 percent converts into a lifetime of 167 years. However, other data sources present boiler lifetimes that are much lower, and these estimates are presented next.

According to *Steam/its generation and use*, the degree of pressure and heat associated with a boiler, along with its design, function, and operation affect boiler lifetime. Industrial boilers operating at pressures above 1,200 psi (pounds per square inch, absolute or difference) and 900 F (482 C) final steam temperature undergo more complicated aging mechanisms than lower temperature boilers (Stultz, 1992). The high pressures and associated high furnace wall temperatures make these units more susceptible to water side corrosion. Table V-2 presents the component replacement sequence for a typical high pressure, high temperature boiler (Stultz, 1992).

Table V-2
Component Replacement Schedule for a Typical High Temperature, High Pressure Boiler

Typical Life (Years)	Component Replaced	Cause for Replacement
20	Miscellaneous tubing	Corrosion, erosion, over-heating
	Attemperator	Fatigue
25	Superheater (SH)	Creep
	SH outlet header	Creep fatigue
	Burners and throats	Overheating, corrosion
30	Reheater	Creep
35	Primary economizer	Corrosion
40	Lower furnace	Overheating, corrosion

In the case of a typical high temperature, high-pressure boiler, most boiler pressure part components have been replaced after 40 years of operation. However, the aging process and rate of component degradation differ from boiler to boiler. Moreover, the actual component life of a boiler is highly variable depending on the specific design, operation, maintenance, and fuel (Stultz, 1992). In another analysis, Teknekron Research Inc. assumed a 30-year boiler lifetime when calculating the retirement rate of a boiler in its report "Review of Modeling Activities
Related to New Source Performance Standards for Industrial Boilers" (Placet, 1980). However, it was also found that some boilers over 70 years old were still in use, with no plans to retire them. Therefore, Teknekron suggested an approximate boiler lifetime of 40 years as a reasonable estimate of the lifetime of an industrial boiler (Placet, 1980).

The Internal Revenue Service's "Publication 946: How to Depreciate Property" lists lifetimes of industrial boilers from a depreciation point of view. The IRS uses a system called Modified Accelerated Cost Recovery System (MACRS) to depreciate assets. According to this system, a class life of 28 years is estimated for the asset category "Central Steam Utility Production and Distribution." In addition, 20-year and 28-year recovery periods are estimated for the General Depreciation System (GDS) and Alternative Depreciation System (ADS), respectively (IRS, 2000). The lifetime years used in the depreciation schedules in this publication may not be directly representative of the actual lifetime of a boiler. Therefore, we presume that these lifetimes represent a minimum lifetime estimate for industrial boilers. This same issue arose in interpreting the BEA 's depreciation schedules. These schedules estimate a service life of 32 years for "Steam Engines and Turbines" (Fraumeni, 1997). Again, since this depreciation lifetime may not directly represent the actual lifetime of a boiler, these lifetimes might represent a minimum lifetime estimate for industrial boilers.

Discussions w ere held with Bob Bessette of the Council of Industrial Boiler Owners (CIBO), Randall Rawson of the American Boiler Manufacturers Association, Ian Lutes of Foster Wheeler Corporation, and Brian Moore of the Hartford Steam Boiler Company. The opinion among this group was that while industrial boiler lifetimes could range from 30 to 100 years, the majority of these boilers stay in service from 35 to 60 years. Industrial boilers generally have less focus on maintenance than utility boilers. Utility boilers, as a rule, are optimally maintained. In some cases, industrial boiler owners are reticent to perform maintenance on their units for fear of triggering new source review. Therefore, it would be expected that the average lifetime of an industrial boiler would be less than that of a comparable utility boiler. There are exceptions, of course, especially when industrial boilers are well maintained and operated at lower pressures. Field erected units tend to have higher lifetimes than package boilers for a variety of reasons.

Through discussions with staff at the U.S. Department of Energy, it was determined that the most comprehensive data source about expected unit lifetimes by source type was Energy and Environmental Analysis's Industrial Sector Technology Use Mod el (ISTUM). The estimated lifetimes by industrial sector technology from ISTUM (EEA, 2001) range from 20 years for refinery heaters and distillation units to 30 years for industrial boilers. However, there is evidence that the equipment turnover in these industries is not nearly as rapid as ISTUM predicts.

Pechan's recommendation based on the evidence provided by the boiler industry representatives is that a 45-year lifetime be used for all industrial boilers in the emission forecasts to 2018. This is 1.5 times the lifetime used by the ISTUM model. It is also recommended that the IAS model lifetimes for other industrial sector technologies be 1.5 times the ISTUM values. This makes the lifetimes for most refinery equipment 30 years, and makes the cement kiln lifetimes 37.5 y ears. Making these changes provides a more conservative estimate of future year WRAP State emissions. A summary of estimated unit lifetimes by industrial source category is provided in Table V-3.

Table V-3
Summary of Estimated Unit Lifetimes by Industrial Source Category

Source Category	Estimated Unit Lifetime (years)
Industrial boilers	45
Lime calcining	45
Cement making	37.5
Lime calcining (paper)	45
Refineries - distillation	30
Refineries - cracking	30
Refineries - alkylation	30
Refineries - hydrogen production	30
Refineries - hydrotreating	30
Refineries - reforming	30
Refineries - other petroleum products	30
Refineries - generic carriers	30

Example Calculations

The IAS model algorithms are applied to estimate 2018 emissions given the primary variables affecting emissions in that year, which are: 1996 emissions, unit date of initial operation, expected unit lifetime or retirement rate, new source control efficiency, and growth rates/factors. The base IAS algorithm for performing emission forecasts to 2018 at the unit level is shown in the equation below.

2018 Emissions = 1996 Emissions (1 - Fraction Retired) + 1996 Emissions (New Source Control Efficiency) (Growth Factor - (1 - Fraction Retired))

In the point source emission projections, there are three cases that all of the sources fall into. These three cases are listed below:

1. The initial date of operation is known, but the unit has not retired by 2018.
2. The initial date of operation is known and the unit's emissions have been fully replaced by new source emission rates.
3. No initial date of operation is available, so retirement rates are used to distinguish existing versus new source emission fractions.

Example calculations of 2018 emissions are provided below for each of these three cases:

Case 1 Example: 1996 NO_x emissions = 5,437 tpy
Expected Retirement Date = 2039
New Source Control Efficiency = 97 percent
2018 Emissions = 5,437 tpy (1 - 0) + 5,437 tpy (0.03) (1.673 - (1-0))
2018 Emissions = 5,437 tpy + 109 tpy
= 5,546 tpy

In this example, because the unit is expected to still be operating in 2018, the existing source portion of the SO_2 emissions (5,437 tpy) remains the same as in 1996. Any increase in activity at this facility is estimated to occur at new source emission rate levels, which are 3 percent of existing source rates.

Case 2 Example: 1996 NO_x emissions = 2,931 tpy
Expected Retirement Date = 2008
New Source Control Efficiency = 72 percent
2018 Emissions = 2,931 tpy (1 - 1) + 2,931 (0.28) (1.719 - (1 - 1))
= 0 + 1,406
= 1,406 tpy

Because this unit has an expected retirement date before 2018, all of the 2018 emissions are at new source rates, which are 28 percent of existing source rates. The growth factor that is applied to the new source emission rates incorporates 1996 activity, plus expected activity increases from 1996 to 2018.

Case 3 Example: No Specific Start Date/Retirement Date
New Source Control Efficiency = 60 percent
2018 Emissions = 2,743 tpy (1 - .7333) + 2,743 (0.4) (1.634 - (1 - .7333))
= 732 + 1,500 tpy
= 2,232 tpy

With no specific start date/retirement date available, the retirement rate is applied in a way to capture the percentage o f existing capacity in this industry that is expected to retire each year over the 22-year forecast horizon. In this example, 73 percent of the 1996 capacity is estimated to have been retired by 2018. While, in reality, units do not retire a fraction of their capacity each year, this calculation is expected to provide a reasonable simulation of existing source retirement, new source growth when spread over a broad geographic region, like the WRAP States.

Implications of Retirement Assumptions in IAS

The practical result of using the revised estimates of unit lifetimes by source category and technology is that future emissions are lower for source categories with significant differences between new and existing source emission rates. Figure V-1 presents an example 1996 to 2018 SO_2 emissions path using the previous industrial boiler IAS retirement rate of 0.6 percent per year compared with the new retirement rate of 2.2 percent per year. This is a source category where the new source SO_2 control efficiency is 90 percent, so the faster the existing units retire, the more rapid the decline in future SO_2 emissions. A 2.0 percent per year new source growth rate is used in this example. So, a 1,000 tpy SO_2 source in 1996 would be estimated to have 2018 emissions of 936 tpy if the prior IAS retirement rate was used. The emission forecasting methods applied in this study yield a 2018 emissions estimate of 619 tpy. This is a significant reduction in future emissions from this source category compared with prior methods.

Figure V-1
Industrial Boiler Lifetime Effects on Emission Forecasts