III.K.9 REASONABLE PROGRESS GOALS

A. Overview

The Regional Haze Rule established a 60-year timeline to improve visibility in Class I areas from the baseline conditions to natural conditions in 2064. The first step in the process is for States to provide a demonstration of "reasonable progress" between the baseline and 2018, the first milestone year. As part of this demonstration, States must establish a Reasonable Progress Goal (RPG) for each Class I area that identifies the visibility improvement for the worst 20 percent of monitored (i.e., most-impaired) days while ensuring no degradation of visibility for the best 20 percent of monitored (i.e., least-impaired) days. States have the flexibility to establish different RPGs for each Class I area.

The first step in establishing the RPG is to calculate the Uniform Rate of Progress (URP) for each Class I area. The URP is a straight line from the baseline conditions to the natural conditions in 2064. This line, known as the "glide path", establishes the URP for 2018 which is the target year for the first planning period. The URP for each Class I area is shown in Section III.K.4.

States must consider the projected emissions in 2018 along with the benefits of all regional haze control measures as well as the URP when selecting RPGs. The 2018 URP does not mandate a reduction target. States have the option to select RPGs with greater, equivalent or lesser visibility improvements than established by the URP; however, in those cases where an RPG provides less improvement than URP, states must document why it is not possible to achieve the URP levels and why the selected value is "reasonable."

B. Steps in Demonstrating Reasonable Progress

Many of the steps followed in establishing RPG values in 2018 have been presented in earlier sections of this Plan. Presented below is a brief summary of each of the key steps followed for each Class I area.

1. <u>Establish Baseline and Natural Conditions</u> – The 2000–2004 baseline and natural conditions, which establish the target in 2064, were calculated by the WRAP for the best and worst days. A discussion of these calculations is presented in Section III.K.4.

2. <u>Calculate Uniform Rate of Progress (URP)</u> – The URP glide path was calculated from the baseline to 2064 for the worst days. The glide path established the 2018 planning target in units of deciviews. These calculations were presented in Section III.K.4.

3. <u>Identify Pollutants Impacting Visibility</u> – Section III.K.4 details the pollutant species contributing to visibility impairment on the 20 percent worst and best days during the baseline period.

4. <u>Characterize Emission Estimates for All State Sources Impacting Visibility</u> – Alaska devoted considerable resources to preparing the first statewide emission inventory of

criteria pollutants for use in assessing trends between the baseline and 2018. A discussion of the inventory is presented in Section III.K.5.

5. Evaluate the Source Contributions Impacting Visibility – The WEP analysis, presented in Section III.K.7, documents the distribution of sources impacting each Class I site. It also highlights the differences in pollutant specific contributions from anthropogenic and nonathropogenic sources between the baseline and 2018.

6. Document Emission Reductions From BART – A description of the modeling analysis and emission reductions achieved by BART for each impacted source is presented in Section III.K.6.

7. Conduct Four-Factor Analysis – A description of the process used to identify key pollutants and source categories impacting each Class I area is presented in Section III.K.9.C along with the results of the analysis.

8. Review of Additional Emission Reductions – A discussion of source-specific BART reductions and their impact on the pollutant-specific WEP reductions forecast for each site on the 20 percent worst days is presented below in Section III.K.9.D.

9. Establish RPGs – The process used to establish separate 2018 RPGs for each Class I area for the 20% worst and best days is presented below in Section III.K.9.E.

10. Contrast RPG and URP Targets in 2018 – A comparison between the RPG target established in Step 9 and the URP target established in Step 2 along with an affirmative demonstration that reasonable further progress is being made from anthropogenic sources within the limits of the uncertainty of the URP glide path is presented in Section III.K.9.F for each Class I area. Also presented is a review of how issues in Step 8 are expected to support that finding.

C. Summary of Four-Factor Analysis

Section 308(d)(1)(i)(A) of the Regional Haze Rule requires that states consider the following factors and demonstrate how they were taken into consideration in selecting the reasonable progress goals:

- Costs of compliance;
- Time necessary for compliance;
- Energy and non-air quality environmental impacts of compliance; and
- Remaining useful life of any potentially affected sources.

In conducting this four-factor analysis, EPA guidance indicates that states have "considerable flexibility" in how these factors are taken into consideration, in terms of what sources or source categories should be included in the analysis, and what additional control measures are reasonable.[*]

1. Rationale and Scope of the Four-Factor Analysis

ADEC looked at key pollutants and certain source categories and the magnitude of their emissions in applying the four factors. Based on the flexibility in how to apply the statutory factors, the rationale outlined below was used in defining the scope of this analysis.

- Focus on 20% worst days: The Regional Haze rule primarily focuses on demonstrating reasonable progress for the 20% worst days so ADEC's four-factor analysis addresses only the worst days. It is a reasonable assumption that emission reductions benefiting the worst days also benefit the best days.

- Focus on anthropogenic sources: The purpose of this analysis is to evaluate certain sources or source categories for potential controls; therefore, the analysis should be of sources that are controllable. While wildfire, natural windblown dust, and sea salt may be important contributors to regional haze, ADEC does not see the value in applying a four factor analysis to these natural source categories. Therefore, ADEC considered point, area, and mobile sources, and planned burning in the analysis.

  For mobile sources, there are major emissions reductions projected by 2018, based on numerous "on-the-books" federal and state regulations, as described in detail in the state's Long Term Strategy in Section III.K.8. These controls and emission reductions should result in significant visibility improvements by 2018. Based on the above findings, ADEC did not believe applying the four-factor analysis to mobile sources was warranted or productive in developing this plan

  For fire sources, planned forestry burning can be a large anthropogenic source. As detailed in the Long Term Strategy, these activities are controlled under Alaska's open burning regulations Enhanced Smoke Management Program (ESMP). Given the current level of control through the ESMP and regulations, Alaska has a relatively advanced level of smoke management in place. The on-going re-evaluation of these programs also provides for improvements over time. As a result, ADEC did not believe applying the four-factor analysis to forestry burning was needed.

  Given the considerations above, ADEC has focused the four-factor analysis on point and area sources only. Further refinement of this approach is provided below.

- Focus on fine particulate matter, sulfate, and nitrate pollutants: ADEC has determined that the four-factor analysis should focus on fine particulate matter ($PM_{2.5}$), sulfate, and

[*]"Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June 2007.

nitrate pollutants. Although there are six visibility-impairing pollutants of concern, sulfate and nitrate are typically associated with anthropogenic sources and tend to be more effective at degrading visibility than $PM_{2.5}$. $PM_{2.5}$ has been included, but is frequently associated with natural sources, such as wildfire and natural windblown dust; as a result the human-caused $PM_{2.5}$ emissions are often dwarfed by the natural sources.

2. Identification of Sources for Four-Factor Analysis

As EPA guidance indicates that states have "considerable flexibility" in terms of how the four factors are taken into consideration, what sources or source categories should be included in the analysis, and what additional control measures are reasonable, ADEC believes that focusing the application of the four-factor analysis to point and area sources, particularly of SO_2 and NOx, is consistent with the guidance and reasonable for the first planning period of the regional haze plan.

It is also useful to keep in perspective the sheer geographic scale of Alaska, the relative impacts of human-caused sources on regional haze impacts in Alaska's Class I areas and the anticipated reductions in pollutants from these sources. These impacts and trends were a consideration in determining which source categories to consider for this first analysis.

Natural wildfire emissions are by far the largest source of emissions within the state. Discussion of Alaska's emissions in Section III.K.5 indicates that human-caused SO_2 and NOx emissions represent 29.5% and 47.9%, respectively, of the total emissions for these pollutants in 2002. Statewide, however, both of these pollutant categories are estimated to have declining emissions between 2002 and 2018 based on existing control programs already in place. Two of the source categories showing increases in these pollutants are predominantly outside the state control: commercial marine vessels and aviation. Increases are expected across all pollutants in area source pollution due primarily to projected population growth between 2002 and 2018. Point sources are predicted to have declining NOx emissions, but increasing SO_2 emissions.

The Western Regional Air Partnership contracted with EC/R Incorporated for an analysis of the four regulatory factors for a number of source categories that are relevant to Alaska:

- Reciprocating Internal Combustion Engines and Turbines;
- Oil And Natural Gas Exploration and Productions Field Operations;
- Natural Gas Processing Plants;
- Industrial Boilers; and
- Petroleum Refineries.

ADEC's analysis described in this section relies on the report from this effort titled, "Supplementary Information for Four Factor Analyses by WRAP States," May 4, 2009, which is included in Appendix III.K.9. The Weighted Emission Potential (WEP) analysis for sources in Alaska provides information on these identified source categories, which can assist in determining whether these sources have the potential to significantly impact visibility in Class I areas and whether they are reasonable to control.

Section III.K.7 provided a detailed description of the development of WEP estimates for each source and pollutant for the three boroughs with the greatest potential impact at each of the Class I sites for 2002 and 2018. It also identified which source categories may be having a significant impact on those sites. The WEP values, however, provide no detail on the relative contribution of individual sources within each source category. Without this insight it is difficult to assess the potential benefits of control programs that are being implemented at the local, state or federal level. To provide this insight the percent distribution of emissions from individual sources was organized into common categories within the point and stationary area source categories (the two anthropogenic categories that may be significantly impacting the Class I sites). The percent distribution of their emissions within each source category, borough and year was applied to the corresponding WEP value for those boroughs shown as potentially having a significant impact at each site.

The following source categories were selected to represent the distribution of point sources:

- Industrial Boilers;
- Natural Gas Processing Plants;
- Oil & Natural Gas Exploration and Production Field Operations;
- Reciprocating IC Engines and Turbines; and
- Other.

Listed below are the source categories selected to represent the distribution of stationary area sources.

- Electric Utility – Distillate Oil
- Commercial – Distillate Oil
- Commercial – Natural Gas
- Residential – Distillate Oil
- Residential – Natural Gas
- Wood Burning
- Road Dust
- Other

The total change in WEP values for the pollutants with the greatest visibility impacts (i.e., NOx, SOx and $PM_{2.5}$) at each Class I area is presented in Table III.K.9-1. A similar presentation of area source WEP values potentially having a significant impact on Class I sites is presented in Table III.K.9-3. To be conservative, all boroughs/pollutants for these sources having a value above 5.0 are included in the tables. In some cases, however, these sources are shown to have a reduction. In other cases, as discussed in Section III.K.7, the overall increase in the WEP value shown is offset by reductions from other sources and boroughs impacting the site.

Table III.K.9-1
Total Change in WEP Values for NOx, SOx, and $PM_{2.5}$
at Each Class I Area Monitoring Site

Monitor Site	NOx	SOx	$PM_{2.5}$
Denali	-0.5	0.8	0.2
Trapper Creek	-5.1	0.9	6.0
Tuxedni	-17.1	-13.0	2.1
Simeonof	-2.8	-2.2	0.3

Table III.K.9-2
Distribution of WEP Values for Point Source Categories With the Potential to Significantly Impact Each Class I Area

Denali				
Source Categories	**Fairbanks - NOx**		**Fairbanks - SOx**	
	2002	**2018**	**2002**	**2018**
Industrial Boilers	4.9	4.5	11.0	9.2
Nat. Gas Process. Plants	0.0	0.0	0.0	0.0
Oil & Gas Field Operations	0.0	0.0	0.0	0.0
Petroleum Refineries	0.4	0.0	0.2	0.0
Recip. Engines & Turbines	5.5	8.4	12.4	25.7
Other	0.0	0.8	0.0	0.4
Total	10.8	13.7	23.7	35.3
Trapper Creek				
Source Categories	**Kenai - NOx**		**Fairbanks – SOx**	
	2002	**2018**	**2002**	**2018**
Industrial Boilers	0.7	0.5	2.9	2.3
Nat. Gas Process. Plants	0.0	0.0	0.0	0.0
Oil & Gas Field Operations	0.5	0.6	0.0	0.0
Petroleum Refineries	0.7	0.0	0.1	0.0
Recip. Engines & Turbines	7.5	5.7	3.3	6.4
Other	8.7	9.0	0.0	0.1
Total	18.0	15.7	6.3	8.8
Source Categories	**Mat-Su - NOx**			
	2002	**2018**		
Industrial Boilers	0.0	0.0		
Nat. Gas Process. Plants	0.0	0.0		
Oil & Gas Field Operations	0.0	0.0		
Petroleum Refineries	0.0	0.0		
Recip. Engines & Turbines	2.4	3.0		
Other	5.8	6.0		
Total	8.2	9.0		

Table III.K.9-2
Distribution of WEP Values for Point Source Categories With the Potential to Significantly Impact Each Class I Area

Tuxedni				
Source Categories	**Kenai - NOx**		**Kenai - SOx**	
	2002	**2018**	**2002**	**2018**
Industrial Boilers	2.3	1.6	0.3	0.2
Nat. Gas Process. Plants	0.0	0.0	0.0	0.0
Oil & Gas Field Operations	1.5	1.8	0.1	0.4
Petroleum Refineries	2.3	0.0	0.9	0.0
Recip. Engines & Turbines	25.4	17.5	2.6	2.9
Other	29.3	27.9	0.4	1.4
Total	60.9	48.7	4.3	5.0
Simeonof				
Source Categories	**North Slope - NOx**		**Kenai - NOx**	
	2002	**2018**	**2002**	**2018**
Industrial Boilers	0.0	0.0	0.2	0.2
Nat. Gas Process. Plants	0.0	0.0	0.0	0.0
Oil & Gas Field Operations	0.3	1.0	0.2	0.2
Petroleum Refineries	0.0	0.0	0.2	0.0
Recip. Engines & Turbines	9.2	6.3	2.6	1.9
Other	0.1	0.1	3.0	3.0
Total	9.6	7.4	6.2	5.3

Table III.K.9-3
Distribution of WEP Values for Area Source Categories With the Potential to Significantly Impact Each Class I Area

Trapper Creek				
Source Categories	**Mat-Su – PM2.5**		**Mat-Su – NOx**	
	2002	**2018**	**2002**	**2018**
Electric Utility - Dist. Oil	0.1	0.1	0.2	0.3
Commercial - Dist. Oil	0.0	0.0	0.2	0.3
Commercial - Nat. Gas	0.0	0.0	0.9	1.2
Residential - Dist. Oil	0.0	0.0	0.5	0.7
Residential - Nat. Gas	0.0	0.0	2.6	3.7
Wood Burning	5.3	7.9	0.1	0.1
Road Dust	4.1	6.2	0.0	0.0
Other	1.4	2.1	0.0	0.1
Total	10.9	16.4	4.5	6.4
Source Categories	**Mat-Su – SOx**			
	2002	**2018**		
Electric Utility - Dist. Oil	0.0	0.0		
Commercial - Dist. Oil	3.5	5.7		
Commercial - Nat. Gas	0.0	0.1		
Residential - Dist. Oil	10.4	17.0		
Residential - Nat. Gas	0.1	0.2		
Wood Burning	0.2	0.3		
Road Dust	0.0	0.0		
Other	0.3	0.4		
Total	14.5	23.7		
Tuxedni				
Source Categories	**Kenai – PM2.5**		**Kenai – SOx**	
	2002	**2018**	**2002**	**2018**
Electric Utility - Dist. Oil	0.0	0.0	0.0	0.0
Commercial - Dist. Oil	0.0	0.0	5.6	6.4
Commercial - Nat. Gas	0.0	0.0	0.1	0.1
Residential - Dist. Oil	0.0	0.0	16.9	19.1
Residential - Nat. Gas	0.1	0.1	0.3	0.3
Wood Burning	5.1	5.7	2.1	2.4
Road Dust	10.7	11.7	0.0	0.0
Other	0.3	0.3	0.7	0.7
Total	16.3	17.9	25.7	28.9

The WEP analysis (as shown in Table III.K.9-3) did not identify any of the Boroughs as having significant area source NOx, SOx or $PM_{2.5}$ impacts on either Denali or Simeonof. Increases in area source $PM_{2.5}$, NOx and SOx are, however, seen impacting Trapper Creek and Tuxedni. Table III.K.9-1 shows substantial reductions in aggregate NOx values at both Trapper Creek and Tuxedni, a large reduction in SOx at Tuxedni and a slight increase in SOx at Trapper Creek. Increases in area source $PM_{2.5}$ values however can be seen impacting both sites. A review of Table III.K.9-3 shows the principal sources of increasing $PM_{2.5}$ are wood burning and road dust. Since the statutory analysis factors established in section 169A(g) of the Clean Air Act are not readily applicable to these sources, they are not addressed in the four-factor analysis. Information presented in Table III.K.9-2, however suggests three categories of point sources that may be significant contributors to regional haze and warrant further analysis. These are industrial boilers, petroleum refineries and reciprocating engines and turbines.

3. Four-Factor Analysis

As noted above, three point source categories warrant further analysis based on the emission inventory trends and WEP results: Industrial Boilers, Petroleum Refineries, and Reciprocating Engines and Turbines. For this first Regional Haze Plan, ADEC believes that given the level of improvement needed to reach natural conditions and the level of technical tools available to demonstrate source specific impacts, it is reasonable to conduct the four-factor analysis on the general source categories rather than on individual sources. In future reviews and planning periods, ADEC can refine these analyses further, if needed, to address specific source impacts.

a. Industrial Boilers

The Industrial Boiler source category consists of point sources with industrial boilers that burn oil, natural gas, coal, and other fuels. These boilers are used in manufacturing, processing, mining, and refining, or any other industry to provide steam, hot water, and/or electricity. The WEP analysis indicates that Denali National Park monitoring sites have potential impacts for SOx and NOx from the industrial boilers in the Fairbanks North Star Borough and the Kenai Peninsula Borough. For the Tuxedni monitoring site, industrial boilers show potential impacts for VOC and NOx. The Simeonof monitoring site does not show significant impacts from industrial boilers.

Table III.K.9-4 shows the estimated statewide emissions for NOx, SO_2, PM_{10}, $PM_{2.5}$, and VOC from the WRAP emission inventory and four factor analyses for Alaska's industrial boilers.

The WRAP four-factor analysis identified control options for coal-fired, natural gas-fired, and oil-fired boilers as listed in Tables III.K.9-5- III.K.9-7. The age of a boiler impacts the amount of emission reduction that can be obtained through control. Older, pre-PSD boilers likely have more potential for emission reduction than newer boilers that have either been subject to PSD regulations or more recent BACT analyses.

Table III.K.9-4
Alaska Industrial Boiler Emissions

Emission Source	Pollutant Emissions, TPY				
	NOx	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**VOC**
Coal-fired Boilers	1823	1421	0	0	6
Natural gas-fired Boilers	260	7	11	10	11
Oil-fired Boilers	67	55	2	2	3
Total	2150	1483	13	12	21

Table III.K.9-5
Control Options for Coal-Fired Industrial Boilers

Pollutant Controlled	Control Technology[a]	Estimated Control Efficiency (%)
NOx	LNB	50
	LNB w/OFA	50-65
	SNCR	30-75
	SCR	40-90
SO_2	Physical coal cleaning	10-40
	Chemical coal cleaning	50-85
	Switch to lower sulfur fuel	20-90
	Dry sorbent injection	50-90
	Spray dryer absorber	90
	Wet FGD	90
$PM_{2.5}$, PM_{10}, Elemental Carbon	Fabric Filter	99.3
Organic Carbon	ESP	99.3

[a] Note: LNB=Low NOx Burner; OFA=Over Fire Air; SNCR=Selective NonCatalytic Reduction; SCR=Selective Catalytic Reduction; FGD=Flue Gas Desulfurization; ESP=Electrostatic Precipitator

Table III.K.9-6
Control Options for Natural Gas-Fired Industrial Boilers

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)
NOx	LNB	40
	LNB w/OFA	40-60
	LNB w/OFA and FGR	40-80
	SNCR	30-75
	SCR	70-90

Table III.K.9-7
Control Options for Oil-Fired Industrial Boilers

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)
NOx	LNB	40
	LNB w/OFA	30-50
	LNB w/OFA and FGR	30-50
	SNCR	30-75
	SCR	40-90
SO_2	Switch to lower sulfur fuel	20-90
	Spray dryer absorber	90
	Wet FGD	90
$PM_{2.5}$, PM_{10}, Elemental Carbon	Fabric Filter	95.8
Organic Carbon	ESP	95.8

Factor 1 – Cost of Compliance

The WRAP analyses provided a generalized range of cost estimates for the emission control options identified for each category of industrial boiler. These estimates are summarized in Table III.K.9-8 thru Table III.K.9-10.

Table III.K.9-8
Estimated Costs for Control of Coal-Fired Industrial Boilers

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($/MMBtu/hr)	Estimated Annual Cost ($M)	Cost Effectiveness ($/ton)
NOx	LNB	50	3,435-6,856	0.175-0.317	344-4,080
	LNB w/OFA	50-65	4,908-9,764	NA	412-4,611
	SNCR	30-75	3,550-7,083	0.333-0.419	1,728-6,685
	SCR	40-90	9,817-19,587	0.738-1.32	1,178-7,968
SO_2	Physical coal cleaning	10-40	NA	NA	70-563
	Chemical coal cleaning	50-85	NA	NA	1,699-2,561
	Switch to lower sulfur fuel	20-90	NA	NA	
	Dry sorbent injection	50-90	11,633-36,096	NA	851-5,761
	Spray dryer absorber	90	27,272-73,549	7.93-9.26	3,885-8,317
	Wet FGD	90	40,203-86,410	10.10-11.71	4,687-10,040
$PM_{2.5}$, PM_{10}, Elemental Carbon	Fabric Filter	99.3	20,065-30,287	0.82-1.39	406-592
Organic Carbon	ESP	99.3	17,037-24,293	0.66-1.17	342-485

Table III.K.9-9
Estimated Costs for Control of Natural Gas-Fired Industrial Boilers

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($/MMBtu/hr)	Estimated Annual Cost ($M)	Cost Effectiveness ($/ton)
NOx	LNB	40	1,205-2,405	0.190-0.346	412-7,075
	LNB w/OFA	40-60	1,722-3,435	NA	412-7,075
	LNB w/OFA and FGR	40-80	2,690-5,368	NA	439-6,689
	SNCR	30-75	2,840-5,666	0.206-0.355	1,997-9,952
	SCR	70-90	5,399-10,773	0.484-0.831	1,022-24,944

Table III.K.9-10
Estimated Costs for Control of Oil-Fired Industrial Boilers

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($/MMBtu/hr)	Estimated Annual Cost ($M)	Cost Effectiveness ($/ton)
NOx	LNB	40	1,205-2,405	0.190-0.346	412-7,075
	LNB w/OFA	30-50	1,722-3,435	NA	412-7,075
	LNB w/OFA and FGR	30-50	2,690-5,368	NA	439-6,689
	SNCR	30-75	2,840-5,666	0.206-0.355	1,997-9,952
	SCR	40-90	5,339-10,773	0.484-0.831	1,022-24,944
SO_2	Switch to lower sulfur fuel	20-90	NA	NA	5611
	Spray dryer absorber	90	119,731-270,514	7.72-8.80	4,947-10,887
	Wet FGD	90	36,930-73,660	9.85-11.29	6,008-13,156
$PM_{2.5}$, PM_{10}, Elemental Carbon	Fabric Filter	95.8	17,205-26,291	0.72-1.20	7,298-10,889
Organic Carbon	ESP	95.8	14,302-21,243	0.58-0.98	5,983-8,844

Factor 2 – Time Necessary for Compliance

If controls were implemented, the overall time for compliance is expected to be five to six years. Up to two years would be needed to develop and adopt rules necessary to require these controls. The WRAP analyses indicated that a source may require:

- Up to a year to procure the necessary capital to purchase control equipment;
- Approximately 18 months to design, fabricate, and install SCR or SNCR technology for NOx control;
- Approximately 30 months to design, build, and install SO_2 scrubbing technology; and
- additional time, up to 12 months, for staging the installation process if multiple boilers are to be controlled.

Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The WRAP four-factor analyses also evaluated the estimated energy and non-air pollution impacts of control measures for industrial boilers. These impacts are included in Tables III.K.9-11 through III.K.9-13. In general, the combustion modification technologies (LNB, OFA, FGR) do not require steam or generate solid waste, wastewater, or additional CO_2. They also do not require additional fuel to operate, and in some cases may decrease fuel usage because of the optimized combustion of the fuel.

Table III.K.9-11
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Coal-Fired Industrial Boilers

Control Technology	Pollutant	Energy and non-air pollution impacts (per ton of emission reduced)				
		Electricity Requirement	Steam Requirement	Solid Waste Produced	Wastewater Produced	Additional CO_2 Emitted
LNB	NOx					
LNB w/OFA	NOx					
SNCR	NOx	1-2 kW/1000 acfm	0.25			
SCR	NOx	0.89	0.25	0.021		
Physical coal cleaning	SO_2					
Chemical coal cleaning	SO_2					
Switch to lower sulfur fuel	SO_2					
Dry sorbent injection	SO_2	2-4 kW/1000 acfm	0.25	0.021		
Spray dryer absorber	SO_2	0.4		3.7	0.69	
Wet FGD	SO_2	4-8 kW/1000 acfm				
Fabric Filter	$PM_{2.5}$, PM_{10}	1-2 kW/1000 acfm				
ESP	$PM_{2.5}$, PM_{10}	0.5-1.5kW/1000 acfm				

Table III.K.9-12
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures For Natural Gas-Fired Industrial Boilers

Control Technology	Pollutant	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
		Electricity Requirement	Steam Requirement	Solid Waste Produced	Wastewater Produced	Additional CO_2 Emitted
LNB	NOx					
LNB w/OFA	NOx					
LNB w/OFA and FGR	NOx	6.4				
SNCR	NOx	1-2 kW/1000 acfm	0.25			
SCR	NOx	0.89	0.25	0.021		
Water Injection	NOx					

Table III.K.9-13
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures for Oil-Fired Industrial Boilers

Control Technology	Pollutant	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
		Electricity Requirement	Steam Requirement	Solid Waste Produced	Wastewater Produced	Additional CO_2 Emitted
LNB	NOx					
LNB w/OFA	NOx					
LNB w/OFA and FGR	NOx	6.4				
SNCR	NOx	1-2 kW/1000 acfm	0.25			
SCR	NOx	0.89	0.25	0.021		
Switch to lower sulfur fuel	SO_2					
Spray dryer absorber	SO_2	0.4		3.7	0.69	
Wet FGD	SO_2	4-8 kW/1000 acfm				
Fabric Filter	$PM_{2.5}$, PM_{10}	1-2 kW/1000 acfm				
ESP	$PM_{2.5}$, PM_{10}	0.5-1.5kW/1000 acfm				

Retrofitting with SNCR requires energy for compressor power and steam for mixing. This would produce a small increase in CO_2 emissions to generate electricity; the technology itself, however,does not produce additional CO_2 emissions.

Installation of SCR on an industrial boiler is not expected to increase fuel consumption. However additional energy is required to operate the SCR, which will produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.

For SO_2 control technologies, energy is required for material preparation (e.g., grinding), materials handling (e.g., pumps/blowers), flue gas pressure loss, and steam requirements. Power consumption is also affected by the reagent utilization of the control technology, which also affects the control efficiency of the control technology.

PM control technologies require energy to operate compressors, heaters, and ash handling. In addition, an additional fan may be required to reduce the flue gas pressure loss by the ESP or FF. The ESP also requires energy to operate the transformer-rectifier. These energy requirements will produce an increase in CO_2 emissions to generate the required electricity.

Factor 4 – Remaining Useful Life of Any Potentially Affected Sources

Industrial boilers do not have a set equipment life and it is difficult to estimate the remaining life of any potentially affected sources. Remaining useful life is specific to the facility for which controls are considered. The remaining life of an industrial boiler is not anticipated to affect the cost of control technologies for these sources.

b. Petroleum Refineries

The category of Petroleum Refineries consists of point sources at petroleum refineries, including process heaters, catalytic cracking units, coking units, and ancillary operations, flares, and incinerators. Reciprocating engines and turbines associated with refineries are handled within their separate categories. In Alaska, small petroleum refineries are found in the North Slope Borough (at the oil production facilities), in the Fairbanks North Star Borough (North Pole), in the Kenai Peninsula Borough (Nikiski), and in Valdez. The WEP analysis indicates that Denali National Park monitoring sites have small potential impacts for SOx and NOx from petroleum refineries in the Fairbanks North Star Borough and the Kenai Peninsula Borough. For the Tuxedni monitoring site, petroleum refineries show potential impacts for VOC and NOx. The Simeonof monitoring site does not show significant impacts from petroleum refineries.

Table III.K.9-14 and Table III.K.9-15 show the estimated statewide emissions for NOx, SO_2, PM_{10}, $PM_{2.5}$, and VOC from the WRAP 2002 emission inventory and four-factor analyses for Alaska's petroleum refineries.

Table III.K.9-14
Alaska Petroleum Refinery Emissions

Emission Source	Pollutant Emissions, TPY			
	NOx	SO_2	PM_{10}	$PM_{2.5}$
Process Heaters	573	62	30	2
Catalytic Cracking Units				
Flares	102	8	6	
Fluid Coking Units				
Coke Calcining				
Incinerators		41		
Other	122	41	7	0
Total	797	111	43	2

Table III.K.9-15
Alaska Petroleum Refinery Emissions

Emission Source	Pollutant Emissions, TPY VOC
Fugitive Emissions	
Wastewater Treatment	1018
Process Heaters	9
Flares	130
Other	11
Total	1167

The WRAP four-factor analysis identified control options for petroleum refineries as listed in Table III.K.9-16.

Table III.K.9-16
Control Options for Petroleum Refineries

Source Type	Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)
Process Heaters	NOx	LNB	40
	NOx	ULNB (Ultra Low NOx Burner)	75-85
	NOx	LNB and FGR	48
	NOx	SNCR	60
	NOx	SCR	70-90
	NOx	LNB and SCR	70-90
	SO_2	Fuel Treatment to remove sulfur	Up to 90
Fluid Catalytic Cracking Units	NOx	Catalyst additives for NOx reduction	46
	NOx	LoTOx™	85
	NOx	SNCR	40-80
	NOx	SCR	80-90
	SO_2	Catalyst additives for SO_2 absorbtion	20-60
	SO_2	Desulfurization of catalytic cracker feed	Up to 90
	SO_2	Wet scrubbing	70-99
	PM_{10}	ESP	95+
	$PM_{2.5}$	ESP	95+
	EC	ESP	95+
	OC	ESP	95+
Coking or coke calcining boilers	SO_2	Spray dry absorber	80-95
	SO_2	Wet FGD	90-99
Flares	SO_2	Improved process control and operator training	Varies
	SO_2	Expand sulfur recovery unit	Varies
	SO_2	Flare gas recovery system	Varies

Factor 1 – Cost of Compliance

The WRAP analyses provided a generalized range of cost estimates for the emission control options identified for petroleum refineries. These estimates are summarized in Table III.K.9-17.

Table III.K.9-17
Estimated Costs for Control of Petroleum Refineries

Source Type	Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($1000/unit)	Estimated Annual Cost ($/year/unit)	Units	Cost Effectiveness ($/ton)
Process Heaters	NOx	LNB	40	2.7-7.6	290-810	MM-Btu/hr	650-2,800
	NOx	ULNB	75-85	2.8-13	300-1,300	MM-Btu/hr	400-2,000
	NOx	LNB and FGR	48	5.8-16	640-1,700	MM-Btu/hr	1,000-2,600
	NOx	SNCR	60	5.2-22	570-2,400	MM-Btu/hr	890-5,200
	NOx	SCR	70-90	33-48	3,700-5,600	MM-Btu/hr	2,900-6,700
	NOx	LNB and SCR	70-90	37-55	4,000-6,300	MM-Btu/hr	2,900-6,300
	SO_2	Fuel Treatment to remove Sulfur	Up to 90	3.4-10	28,000-36,000	Refinery capacity, 1000 barrels/day	1,300-1,700
Fluid Catalytic Cracking Units	NOx	Catalyst additives for NOx reduction	46	N/A	N/A	N/A	N/A
	NOx	LoTOx™	85	N/A	N/A	N/A	1,700-2,000
	NOx	SNCR	40-80	N/A	N/A	N/A	2,500
	NOx	SCR	80-90	N/A	N/A	N/A	2,500
	SO_2	Catalyst additives for SO_2 absorbtion	20-60	N/A	N/A	N/A	N/A
	SO_2	Desulfurization of catalytic cracker feed	Up to 90	23-54	190,000-250,000	Refinery capacity, 1000 barrels/day	6,200-8,000
	SO_2	Wet scrubbing	70-99	N/A	N/A	N/A	1,500-1,800
	PM_{10}	ESP	95+	N/A	N/A	N/A	>10,000
	$PM_{2.5}$	ESP	95+	N/A	N/A	N/A	>10,000
	EC	ESP	95+	N/A	N/A	N/A	>10,000
	OC	ESP	95+	N/A	N/A	N/A	>10,000
Coking or coke calcining boilers	SO_2	Spray dry absorber	80-95	N/A	N/A	N/A	1,500-1,900
	SO_2	Wet FGD	90-99	N/A	N/A	N/A	1,500-1,800
Flares	SO_2	Improved process control and operator training	Varies	N/A	N/A	N/A	N/A
	SO_2	Expand sulfur recovery unit	Varies	N/A	N/A	N/A	N/A
	SO_2	Flare gas recovery system	Varies	N/A	N/A	N/A	N/A

Factor 2 – Time Necessary for Compliance

If controls were implemented, the overall time for compliance is expected to be 6.5 years. Up to two years would be needed to develop and adopt rules necessary to require these controls. The WRAP analyses indicated that a source may require the following lead time:

- Up to a year to procure the necessary capital to purchase control equipment;
- Approximately 13-18 months to design, fabricate, and install SCR or SNCR technology for NOx control;
- Approximately 30 months to design, build, and install SO_2 scrubbing technology for a single emission source; and
- Additional time, up to 12 months, for staging the installation process if multiple sources are to be controlled at a single facility.

Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

The WRAP four-factor analyses also evaluated the estimated energy and non-air pollution impacts of control measures for petroleum refineries. These impacts are included in Table III.K.9-18. Process modifications to desulfurize process gases burned in process heaters would generally require increases in catalytic hydrotreatment processing. These modifications may increase the generation of spent catalyst, which would need to be treated as a solid waste or a hazardous waste. Low NO_X burners for process heaters are expected to improve overall fuel efficiency. FGR would require additional electricity to recirculate the fuel gas into the heater. In SCR systems for process heaters or other sources, fans would be required to overcome the pressure drop through the catalyst bed. The fans would require electricity, with resultant increases in CO_2 to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.

Catalyst additives for reducing NOx and SO_2 emissions from fluid catalytic cracking units are likely to result in increased generation of spent catalyst, which would have to be disposed of as hazardous waste. These catalyst additives may also result in increases in fuel consumption, but information is not available to quantify these impacts. A LoTOx™ scrubbing system or wet scrubbing system applied to the fluidized catalytic cracking unit would require electricity to operate fans and other auxiliary equipment, and would produce a wastewater stream which would require treatment. In addition, sludge from the scrubber would require disposal as solid waste. SCR and SNCR systems would also require electricity for fans, and SCR systems would produce additional solid waste because of spent catalyst disposal. Dust captured by an ESP or fabric filter would also require disposal as a solid waste. The presence of catalyst fines in the dust may require treatment as a hazardous waste.

Sulfur recovery units require electricity and steam. Wet or dry scrubbers applied to incinerators and tail gas treatment units applied to sulfur recovery units would use electricity for the fan power needed to overcome the scrubber pressure drop. These systems would also produce solid waste, and wet scrubbers would produce wastewater which would require treatment.

Table III.K.9-18
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures For Petroleum Refineries

Source Type	Pollutant	Control Technology	Additional Fuel Requirement (%)	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
				Electricity Requirement (kW-hr)	Steam Requirement (tons steam)	Solid Waste Produced (tons waste)	Wastewater Produced (1000 gallons)	Additional CO_2 Emitted (tons)
Process Heaters	NOx	LNB	a	e				
	NOx	ULNB	a	e				
	NOx	LNB and FGR		3,300				3.3
	NOx	SNCR	0.16	460				3.2
	NOx	SCR		8,400		0.073		8.4
	NOx	LNB and SCR		8,400		0.073		8.4
	SO_2	Fuel Treatment to remove Sulfur	b					b
Fluid Catalytic Cracking Units	NOx	Catalyst additives for NOx reduction	d			d		
	NOx	LoTOx™		d		d	d	
	NOx	SNCR		460				3.2
	NOx	SCR		8,400		0.073		8.4
	SO_2	Catalyst additives for SO_2 absorption	d			d		
	SO_2	Desulfurization of catalytic cracker feed	d		d	d		d
	SO_2	Wet scrubbing		1,100	3.1		3.7	2.6
	PM_{10}	ESP		97		1		0.1
	$PM_{2.5}$	ESP		97		1		0.1
	EC	ESP		97		1		0.1
	OC	ESP		97		1		0.1
Coking or coke calcining boiler offgas	SO_2	Spray dry absorber		400				1.1
	SO_2	Wet FGD		1,100	3.1		3.7	2.6

Table III.K.9-18
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures For Petroleum Refineries

Source Type	Pollutant	Control Technology	Additional Fuel Requirement (%)	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
				Electricity Requirement (kW-hr)	Steam Requirement (tons steam)	Solid Waste Produced (tons waste)	Wastewater Produced (1000 gallons)	Additional CO_2 Emitted (tons)
Flares	SO_2	Improved process control and operator training						
	SO_2	Expand sulfur recovery unit	d	d	d			d
	SO_2	Flare gas recovery system	d	d	d			d

Notes: blank indicates no impact is expected.
[a] The measure is expected to improve fuel efficiency.
[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing diesel engines,
[c] EPA has estimated that control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible.
[d] Some impact is expected but insufficient information is available to evaluate the impact.
[e] Some designs of low-NOx burners and ultralow-NOx burners require the use of pressurized air supplies. This would require additional electricity to pressurize the combustion.

Factor 4 - Remaining Useful Life of Any Potentially Affected Sources

Industrial processes are often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most equipment is expected to be longer than the projected lifetime of pollution control technologies analyzed for this category. In the case of add-on technologies, the projected lifetime is 15 years. If the remaining life of an emission source is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

Where:

A_1 = the annual cost of control for the shorter equipment lifetime ($)
A_0 = the original annual cost estimate ($)
C = the capital cost of installing the control equipment ($)
r = the interest rate (0.07)
m = the expected remaining life of the emission source (years)
n = the projected lifetime of the pollution control equipment

c. Reciprocating Internal Combustion Engines and Turbines

The Reciprocating Internal Combustion Engine and Turbine source category consists of point sources with reciprocating engines and turbines typically located at industrial, commercial, and institutional facilities. Most of the turbines burn gaseous fuels including natural gas, liquefied petroleum gas, and industrial process gas. Reciprocating engines are divided between gaseous fuels and liquid fuels, like kerosene and diesel oil. The WEP analysis indicates that Denali National Park monitoring sites have potential impacts for SOx and NOx from the reciprocating engines and turbines in the Fairbanks North Star Borough and the Kenai Peninsula Borough. For the Tuxedni monitoring site, industrial boilers show potential impacts for VOC and NOx. The Simeonof monitoring site shows potential NOx impacts from North Slope Borough reciprocating engines and turbines.

Table III.K.9-19 shows the estimated statewide 2002 emissions for NOx, SO_2, PM_{10}, $PM_{2.5}$, and VOC from the WRAP emission inventory and four factor analyses for Alaska's reciprocating engines and turbines.

Table III.K.9-19
Alaska Industrial Boiler Emissions

Emission Source	Pollutant Emissions, TPY				
	NOx	SO_2	PM_{10}	$PM_{2.5}$	VOC
Turbines – gaseous fuel	44,293	705	167	66	665
Turbines – liquid fuel	4,446	2,539	140	127	2
Reciprocating Engines –gaseous fuel	50	0	0	0	1
Reciprocating Engines – liquid fuel	12,779	670	179	168	466
Total	61,569	3,915	486	361	1,133

The WRAP Four-Factor Analysis identified control options for reciprocating internal combustion engines and turbines as listed in Tables III.K.9-20-III.K.9-22.

Table III.K.9-20
Control Options for Turbines

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)
NOx	Water or steam injection	68-80
	Low-NOx burners	68-84
	SCR	90
	Water or steam injection with SCR	93-96

Table III.K.9-21
Control Options for Reciprocating Engines with Gaseous Fuels

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)
NOx	Air-Fuel ratio adjustment	10-40
	Ignition retarding technologies	15-30
	Low emission combustion (LEC) retrofit	80-90
	SCR	90
	NSCR	90-99
	Replacement with electric motors	100
VOC	NSCR	40-85
	Replacement with electric motors	100
SO_2	Replacement with electric motors	100
PM_{10}	Replacement with electric motors	100
$PM_{2.5}$	Replacement with electric motors	100
Elemental Carbon	Replacement with electric motors	100
Organic Carbon	Replacement with electric motors	100

Table III.K.9-22
Control Options for Reciprocating Engines with Diesel and Other Liquid Fuels

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)
NOx	Ignition timing retard	15-30
	EGR	40
	SCR	80-95
	Replacement of Tier 2 engines with Tier 4	87
PM_{10}	Replacement of Tier 2 engines with Tier 4	85
	Diesel Oxidation Catalyst	25
$PM_{2.5}$	Replacement of Tier 2 engines with Tier 4	85
	Diesel Oxidation Catalyst	25
Elemental Carbon	Replacement of Tier 2 engines with Tier 4	85
	Diesel Oxidation Catalyst	25
Organic Carbon	Replacement of Tier 2 engines with Tier 4	85
	Diesel Oxidation Catalyst	25
VOC	Replacement of Tier 2 engines with Tier 4	87
	Diesel Oxidation Catalyst	90

Factor 1 – Cost of Compliance

The WRAP analyses provided a generalized range of cost estimates for the emission control options identified for internal combustion reciprocating engines and turbines. These estimates are summarized in Tables III.K.9-23 through III.K.9-25.

Table III.K.9-23
Estimated Costs for Control of Turbines

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($/1000 Btu)	Estimated Annual Cost ($/yr/1000Btu)	Cost Effectiveness ($/ton)
NOx	Water or steam injection	68-80	4.4-16	2-5	560-3,100
	Low-NOx burners	68-84	8-22	2.7-8.5	5,200-16,200
	SCR	90	8-22	2.7-8.5	2,000-10,000
	Water or steam injection with SCR	93-96	13-34	5.1-13	1,000-6,700

Table III.K.9-24
Estimated Costs for Control of Reciprocating Engines with Gaseous Fuels

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($/hp/hr)	Estimated Annual Cost ($/yr/hp)	Cost Effectiveness ($/ton)
NOx	Air-fuel ratio adjustment	10-40	4.4-43	13-86	320-8,300
	Ignition retarding technologies	15-30	N/A	10-32	310-2,000
	LEC retrofit	80-90	120-820	30-210	320-2,500
	SCR	90	20-180	40-461	430-4,900
	NSCR	90-99	17-35	3-6	16-36
	Replacement with electric motors	100	120-140	38-44	100-4,700
VOC	NSCR	40-85			1,500-6,200
	Replacement with electric motors	100			1,000-60,000
SO_2	Replacement with electric motors	100			>13,000
PM_{10}	Replacement with electric motors	100			>13,000
$PM_{2.5}$	Replacement with electric motors	100			>13,000
EC	Replacement with electric motors	100			>33,000
OC	Replacement with electric motors	100			>50,000

Table III.K.9-25
Estimated Costs for Control of Reciprocating Engines with Diesel and Other Liquid Fuel

Pollutant Controlled	Control Technology	Estimated Control Efficiency (%)	Estimated Capital Cost ($/hp/hr)	Estimated Annual Cost ($/yr/hp)	Cost Effectiveness ($/ton)
NOx	Ignition timing retard	15-30	16-120	14-66	1,000-2,200
	EGR	40	100	26-67	780-2,000
	SCR	80-95	100-2,000	40-1,200	3,000-7,700
	Replacement of Tier 2 engines with Tier 4	87	125	20	900-2,400
PM_{10}	Replacement of Tier 2 engines with Tier 4	85			25,000-68,000
	Diesel Oxidation Catalyst	25			1,400
$PM_{2.5}$	Replacement of Tier 2 engines with Tier 4	85			25,000-68,000
	Diesel Oxidation Catalyst	25			1,400
EC	Replacement of Tier 2 engines with Tier 4	85			>50,000
	Diesel Oxidation Catalyst	25			3,300
OC	Replacement of Tier 2 engines with Tier 4	85			>50,000
	Diesel Oxidation Catalyst	25			4,200
VOC	Replacement of Tier 2 engines with Tier 4	87			22,000-59,000
	Diesel Oxidation Catalyst	90			350

Factor 2 – Time Necessary for Compliance

If controls were implemented, the overall time for compliance is expected to be 5.5 years. Up to 2 years would be needed to develop and adopt rules necessary to require these controls. The WRAP analyses indicated that a source may require the following lead-time:

- Up to a year to procure the necessary capital to purchase control equipment;
- Approximately 18 months to design, fabricate, and install SCR or SNCR technology for NOx control; and
- Additional time, up to 12 months, for staging the installation process if multiple boilers are to be controlled at a single facility.

Factor 3 – Energy and Non-Air Quality Environmental Impacts of Compliance

Tables III.K.9-26 through III.K.9-28 shows the estimated energy and non-air pollution impacts of control measures for reciprocating engines and turbines derived in the WRAP analyses. In general, air-to-fuel-ratio adjustments and ignition retarding technologies have been found to increase fuel consumption by up to 5%, with a typical value of about 2.5%. This increased fuel consumption would result in increased CO_2 emissions. LEC technology is not expected to increase fuel consumption and may provide some fuel economy.

Diesel oxidation catalyst and diesel filtration technologies would produce an increase in fuel consumption in order to overcome the pressure drop through the catalyst bed and the filter. This is assumed to be roughly the same as the increase in fuel consumption for SCR installations, about 0.5%. In the case of diesel oxidation catalysts, the catalyst would have to be changed periodically, producing an increase in solid waste disposal. If diesel reciprocating engines are replaced with electric motors, there would be an increase in electricity demand, but this would be offset by the fuel consumption that would be avoided by replacing the engine.

For turbines, water injection and steam injection would require electricity to operate pumps and ancillary equipment. Water injection would produce an increase in fuel consumption in order to evaporate the water, and steam injection would require energy to produce the steam. The increased electricity, steam, and fuel demands would produce additional CO_2 emissions.

Installation of SCR on any type of engine would cause a small increase in fuel consumption, about 0.5%, in order to force the exhaust gas through the catalyst bed. This would produce an increase in CO_2 emissions to generate the electricity. In addition, spent catalyst would have to be changed periodically, producing an increase in solid waste disposal.

Table III.K.9-26
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures For Turbines

Control Technology	Pollutant	Additional Fuel Requirement (%)	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
			Electricity Requirement (kW-hr)	Steam Requirement (tons steam)	Solid Waste Produced (tons waste)	Wastewater Produced (1000 gal)	Additional CO_2 Emitted (tons)
Water or steam injection	NOx	a		31			8.1
Low-NOx burners	NOx	a					
SCR	NOx	a					
Water or steam injection with SCR	NOx	0.45			0.026		1.7

Notes: blank indicates no impact is expected.
[a] The measure is expected to improve fuel efficiency.

Table III.K.9-27
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures For Reciprocating Engines with Gaseous Fuels

Control Technology	Pollutant	Additional Fuel Requirement (%)	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
			Electricity Requirement (kW-hr)	Steam Requirement (tons steam)	Solid Waste Produced (tons waste)	Wastewater Produced (1000 gal)	Additional CO_2 Emitted (tons)
Air-Fuel ratio controllers	NOx	a					
Ignition retarding technologies	NOx	a					
LEC retrofit	NOx	a					
SCR	NOx	0.5			0.008		0.43
NSCR	NOx	0.5			0.008		0.24
Replacement with electric motors	NOx	(100)	66,000				b
NSCR	VOC						
Replacement with electric motors	VOC						
Replacement with electric motors	SO_2						
Replacement with electric motors	PM_{10}						
Replacement with electric motors	$PM_{2.5}$						
Replacement with electric motors	EC						
Replacement with electric motors	OC						

Notes: blank indicates no impact is expected.
[a] The measure is expected to improve fuel efficiency
[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing diesel engine

Table III.K.9-28
Estimated Energy and Non-Air Environmental Impacts of Potential Control Measures For Reciprocating Engines with Diesel and Other Liquid Fuels

Control Technology	Pollutant	Additional Fuel Requirement (%)	Energy and Non-Air Pollution Impacts (per ton of emission reduced)				
			Electricity Requirement (kW-hr)	Steam Requirement (tons steam)	Solid Waste Produced (tons waste)	Wastewater Produced (1000 gal)	Additional CO_2 emitted (tons)
Ignition timing retard	NOx	a					
EGR	NOx	2.7					2.0
SCR	NOx	0.5			0.008		0.38
Replacement of Tier 2 engines with Tier 4	NOx	c					c
Replacement of Tier 2 engines with Tier 4	PM_{10}						
Diesel Oxidation Catalyst	PM_{10}	0.5			b		316
Replacement of Tier 2 engines with Tier 4	$PM_{2.5}$						
Diesel Oxidation Catalyst	$PM_{2.5}$						
Replacement of Tier 2 engines with Tier 4	EC						
Diesel Oxidation Catalyst	EC						
Replacement of Tier 2 engines with Tier 4	OC						
Diesel Oxidation Catalyst	OC						
Replacement of Tier 2 engines with Tier 4	VOC						
Diesel Oxidation Catalyst	VOC						2.5

Notes: blank indicates no impact is expected.
[a] The measure is expected to improve fuel efficiency
[b] CO_2 from the generation of electricity would be offset by avoided emissions due to replacing diesel engine
[c] EPA has estimated that control measures used to meet Tier 4 standards will be integrated into the engine design so that sacrifices in fuel economy will be negligible

Factor 4 – Remaining Useful Life of Any Potentially Affected Sources

Engines in industrial service are often refurbished to extend their lifetimes. Therefore, the remaining lifetime of most reciprocating engines and turbines is expected to be longer than the projected lifetime of pollution control technologies analyzed for this category. In the case of add-on technologies, such as SCR, the projected lifetime is 15 years.

If the remaining life of a reciprocating engine or turbine is less than the projected lifetime of a pollution control device, then the capital cost of the control device would have to be amortized over a shorter period of time, corresponding to the remaining lifetime of the emission source. This would cause an increase in the amortized capital cost of the pollution control option, and a corresponding increase in the total annual cost of control. This increased cost can be quantified as follows:

$$A_1 = A_0 + C \times \frac{1-(1+r)^{-m}}{1-(1+r)^{-n}}$$

Where:

- A_1 = the annual cost of control for the shorter equipment lifetime ($)
- A_0 = the original annual cost estimate ($)
- C = the capital cost of installing the control equipment ($)
- r = the interest rate (0.07)
- m = the expected remaining life of the emission source (years)
- n = the projected lifetime of the pollution control equipment

d. Conclusions from the Four-Factor Analysis

Based on the four-factor analyses above, ADEC concluded that it is not reasonable to require additional controls for these source categories at this time. The Alaskan Class I areas do not need large visibility improvements to reach natural conditions in 2064 and natural impacts are already significant in the current analysis. As a result, the uncertainty in visibility improvements that could be achieved through control, coupled with the costs and other factors, makes control at this time unreasonable.

This initial analysis provided a useful starting point for gathering information on possible controls and costs, which can provide a basis for analysis in future SIP revisions. ADEC will reassess the need for control of these sources and further evaluate control options during this first milestone period (through 2018) to determine whether additional emission reductions in these source categories would improve Class I area visibility in the next planning period.

D. Review of Additional Emission Reductions

While the conclusions of the four-factor analysis will not affect the WEP forecast of changes in pollutants impacting the Class I areas between the baseline and 2018, additional information needs to be considered when assessing those forecasts. A summary of the aggregate pollutant-specific reductions across all source categories, including anthropogenic and nonanthropogenic sources, is presented below in Table III.K.9-29. To provide a perspective on the split between anthropogenic and nonanthropogenic sources, the forecasted change is presented for the anthropogenic share of total emissions from all sources.

Table III.K.9-29
Change in Anthropogenic Share of WEP Forecast of Individual Pollutants for Each Class I Area Between Baseline and 2018 for 20% Worst Days
(% Share of All Anthropogenic and Nonanthropogenic Sources)

Class I Site	Year	$PM_{2.5}$	VOC	NOx	SOx	NH_3
Denali	Base	7.1	35.3	34.5	46.9	2.2
	2018	7.3	34.4	34.0	47.7	3.3
	Change	0.2	-0.9	-0.5	0.8	1.1
Simeonof	Base	5.2	27.6	42.3	20.7	4.4
	2018	5.5	30.4	39.5	18.5	2.4
	Change	0.3	2.8	-2.8	-2.2	2.0
Trapper Creek	Base	15.5	42.7	62.9	42.2	20.5
	2018	21.5	44.9	57.8	43.1	12.8
	Change	6.0	2.2	-5.1	0.9	7.7
Tuxedni	Base	22.8	61.1	85.1	57.8	44.6
	2018	24.9	62.1	68.0	44.8	79.8
	Change	2.1	1.0	-17.1	-13.0	35.2

Note: Sulfate and nitrate are highlighted because these are typically associated with anthropogenic sources and tend to be more effective at degrading visibility.

As noted in the four-factor analysis, while the focus was on fine particulate matter ($PM_{2.5}$), sulfate and nitrate pollutants, sulfate and nitrate are typically associated with anthropogenic sources and tend to be more effective at degrading visibility than fine particulate matter. For, this reason, the change in NOx and SOx values between the baseline and 2018 is highlighted. Presented below is a review of the forecasted changes in each Class I area along with a discussion of source-specific BART impacts that are not accounted for in the WEP analysis.

Denali – The WEP analysis shows the anthropogenic contribution of each of the pollutants impacting Denali varies considerably: $PM_{2.5}$ and NH_3 are at the low end, with values well below 10%; while VOC, NOx and SOx values range from roughly one third to one half of the total. It also shows that modest changes are projected for all of the pollutants impacting this site. For the key pollutants, NOx emissions are forecast to decline slightly while SOx emissions are forecast to increase slightly. The WEP analysis presented in Section III.K.7 showed the dominant boroughs impacting Denali included Yukon Koyukuk and Southeast Fairbanks (primarily natural fires impacting all of the pollutants) and Fairbanks North Star (point sources impacting SOx) and Denali (area sources impacting VOC). The BART analysis presented in Section III.K.6 showed GVEA's Healy Power Plant has a SO_2 limit in place so no increase in nearby SOx emissions can occur. It also showed that significant visibility improvements in Denali can be expected from additional NOx controls that will be implemented at that facility. These forecasts do not account for the emissions from the HCCP at the GVEA facility in Healy (i.e., unit # 2). That facility did not operate in 2002 and is not currently operating, but is permitted to operate. If brought on line, the point source NOx emitted within the Denali Borough would increase by a factor of 4.0 and the SOx would increase by a factor of 2.8 (based on permitted not actual emissions). This would substantially increase the WEP forecast of NOx and SOx emissions impacting the Denali monitors.

Simeonof – The WEP analysis shows the anthropogenic contribution of each of the pollutants varies considerably: $PM_{2.5}$ and NH_3 are also at the low end, with values well below 10%; while VOC, NOx, and SOx values range from roughly 20% to 40%. It also shows that with the exception of $PM_{2.5}$, more significant, but still limited, changes are forecast for the pollutants impacting this site. For the key pollutants, both NOx and SOx emissions are projected to decline from 2% to almost 3%. VOC and NH_3 levels are projected to have similar increases; however, as noted earlier, their impact on visibility is much less significant. The WEP analysis presented in Section III.K.7 showed natural fires in Yukon Koyukuk are the dominant source of each of the pollutants impacting Simeonof, with share values ranging from 54% to 91%. The BART analysis did not find any benefits of additional controls significantly impacting Simeonof.

Trapper Creek – The WEP analysis shows the anthropogenic share of pollutants impacting Trapper Creek were substantially higher than seen at either Denali or Simeonof. $PM_{2.5}$ and NH_3 are shown to have the lowest impact, but their values range from roughly 10% to 20%, while VOC, NOx, and SOx values range from 40% to 60%. For the key pollutants, NOx is projected to decline by 5% while SOx is projected to have a marginal increase of 0.9%. $PM_{2.5}$, VOC, and NH_3 are all projected to increase. The WEP analysis presented in Section III.K.7 found that natural fires in Yukon Koyukuk and Southeast Fairbanks were the dominant source of all pollutants impacting this site. Anthropogenic sources, located in the Mat Su Valley and the Kenai, were also shown to impact Trapper Creek. The BART analysis presented in Section III.K.6 found the Conoco Philips Kenai LNG Plant reduced the NOx impact below the 0.5 deciview threshold at Denali (and Tuxedni). Since the WEP analysis showed that point sources in the Kenai were a significant source of NOx emissions, the Conoco NOx reductions will be in addition to 5% reductions forecast by WEP analysis.

Tuxedni **–** The WEP analysis shows the anthropogenic share of pollutants impacting Tuxedni were the largest of the Class I sites. $PM_{2.5}$ levels were on the order of 20% and values for the remaining pollutants ranged from roughly 40% to 80%. Despite the magnitude of the anthropogenic contribution, both NOx and SOx values are projected to have significant reductions—17% and 13%, respectively. Counterbalancing those reductions, however, is a projected 35% increase in NH_3 emissions. A review of the WEP analysis presented in Section III.K.7 shows that essentially all of the increase is coming from the Kenai. Fortunately, the BART analysis shows the Agrium, Chem-Urea Plant in the Kenai has stopped operating and has a zero emission limit for its BART eligible units. Since this unit is responsible for 98% of NH_3 emissions in the Kenai, the 35% increase forecast for NH_3 is no longer valid. Moreover, no significant increase in NH_3 is likely to occur since any startup of that facility will trigger PSD permitting requirements.

E. Determination of Reasonable Progress Goals

The steps followed in preparing the reasonable progress demonstration were summarized earlier. While the URP for 2064 was calculated in Section III.K.4, no specific target was established for 2018. Table III.K.9-30 summarizes the calculations used to set the 2018 target. As can be seen,.

Table III.K.9-30
Calculation of Uniform Rate of Progress Target Reduction for 2018, 20% Worst Days (deciview)

Class I Site	Baseline	Natural Condition	Total Reduction	Reduction for 2018	% Reduction for 2018	2018 Target
Denali	9.9	7.3	2.6	0.6	6.0	9.3
Simeonof	18.6	15.6	3.0	0.7	3.7	17.9
Trapper Creek	11.6	8.4	3.2	0.7	6.5	10.9
Tuxedni	14.1	11.3	2.8	0.7	4.6	13.4

all of the reductions between the baseline and 2018 are less than 1 deciview, with percentage reductions ranging from roughly 4 to 6 percent of the baseline values

Since it was not possible to configure a photochemical model to represent conditions within Alaska, the State is unable to calculate deciview levels in 2018 resulting from forecasted inventory changes. Nevertheless, it is useful to contrast the percentage change in WEP values for each pollutant forecast between the baseline and 2018 versus the percentage reduction in the URP for the same period. The comparison between these values provides insight into
(a) whether the pollutants impacting each Class I area are increasing or decreasing, and
(b) whether the changes are roughly in proportion to the glide path established by the URP.
Table III.K.9-31 presents a comparison between pollutant and URP reductions for each Class I area forecast for 2018 for the 20% worst days.

Table III.K.9-31
Comparison Between % Change in WEP Forecast of Individual Pollutants and Glide Path Reduction Targets Between Baseline and 2018 for 20% Worst Days As Indicator of "Reasonable Progress" (all sources)

Class I Site	20% Worst Days, Baseline to 2018 Change in Emission Potential From All Boroughs Impacting Each Site					Glide Path Target (% deciview)
	$PM_{2.5}$	VOC	NOx	SOx	NH_3	
Denali	0.2	-0.9	-0.5	0.8	1.1	-6.0
Simeonof	0.3	2.8	-2.8	-2.2	2.0	-3.7
Trapper Creek	6.0	2.2	-5.1	0.9	7.7	-6.5
Tuxedni	2.1	1.0	-17.1	-13.0	35.2	-4.6

Note: Sulfate and nitrate are highlighted because these are typically associated with anthropogenic sources and tend to be more effective at degrading visibility.

As noted earlier, the pollutant reductions presented in Table III.K.9-31, which were computed in Section III.K.7 and displayed in Table III.K.9-29, do not account for BART-related improvements or changes resulting from facilities recently curtailing production. Ignoring those improvements for the moment, the comparison between pollutant and glide path reductions is instructive. The forecast for Denali is little change up or down for all pollutants and suggests a flat line forecast relative to the 6.0% reduction target established by the URP. The forecast for Simeonof is a modest downward slope with reductions in the key anthropogenic NOx and SOx values that are less than the 3.7% URP target. The forecast for Trapper Creek is more complex, with NOx values declining while the other pollutants register limited increases relative to a 6.5% reduction target. The Tuxedni forecast shows substantial reductions in NOx and SOx and modest increases in other pollutants. Thus, while no deciview estimate in 2018 is available for Tuxedni, the large reductions in NOx and SOx WEP values indicate that visibility levels there should improve at a rate exceeding the glide path target.

Another issue to consider when assessing forecasted pollutant reductions relative to the URP targets is the uncertainty associated with those targets. As shown in Section III.K.4, there is considerable variance in the available visibility measurements for each Class I area. That variance has been used to establish confidence bounds on the URP glide path. It is useful to contrast the URP deciview reductions expected for each site with an estimate of the deciview reductions produced by the forecasted WEP changes (approximated by averaging projected NOx and SOx changes) to determine if WEP-based changes fall within the range of uncertainty associated with each glide path.

A series of graphs, displayed in Figures III.K.9-1 through III.K.9-4, have been prepared to display historical and projected data for each site. In the figures, blue is used to show historical and projected visibility, while red is used to show URP glide path. The blue squares give historical visibility data for the period 2000 through 2006, which is the latest year reported. The projected trend in visibility to 2018 is shown by the solid blue line (WEP trend). The WEP trend is based on projected changes in WEP (referenced to the average baseline values starting in 2004) as explained below for each site. The 2000–2004 baseline value is shown by the solid red line, and the uniform rate of progress (URP) is given by the dotted red line that connects to the baseline. The dotted red lines above and below the URP line give +/- 95 percent confidence bounds[*] on the visibility (in a future year) that could be consistent with the URP due to the uncertainty in contributions from natural causes.

[*] The only site with complete data between 2000 and 2004 is Denali. Measurements for the remaining sites did not start until 2002. Because of the limited number of baseline measurements for these sites, all of the confidence intervals were based on available measurements through 2006 (i.e., seven values for Denali and five values for the other sites).

Figure III.K.9-1
Review of URP Glide path and WEP Trend, Baseline to 2018 for 20% Worst Days, Denali

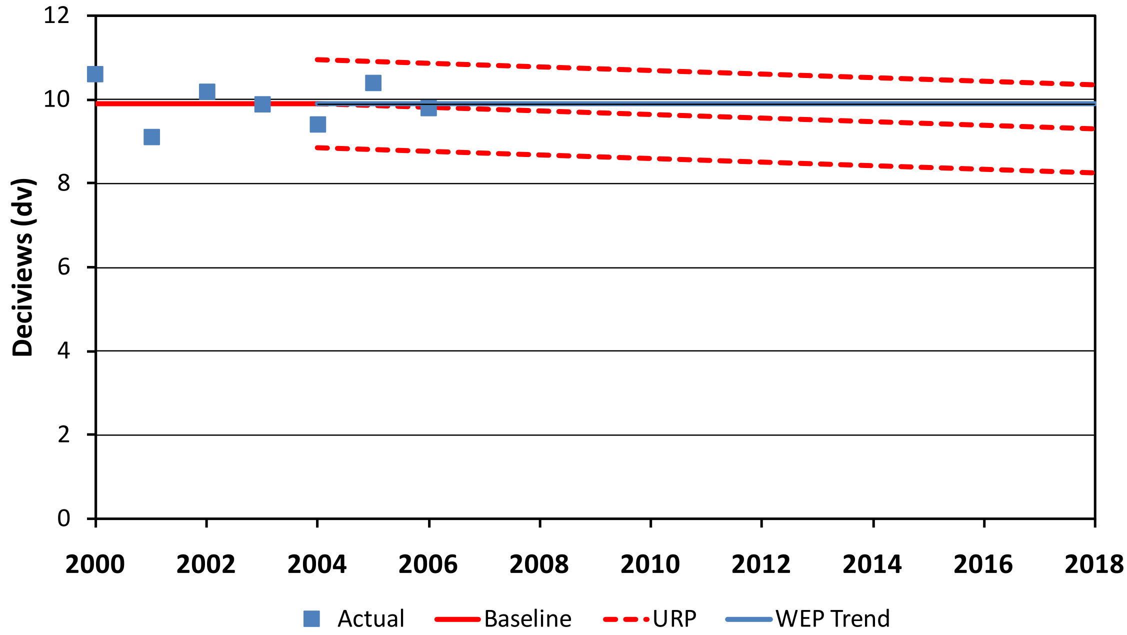


Figure III.K.9-2
Review of URP Glide path and WEP Trend, Baseline to 2018 for 20% Worst Days, Simeonof

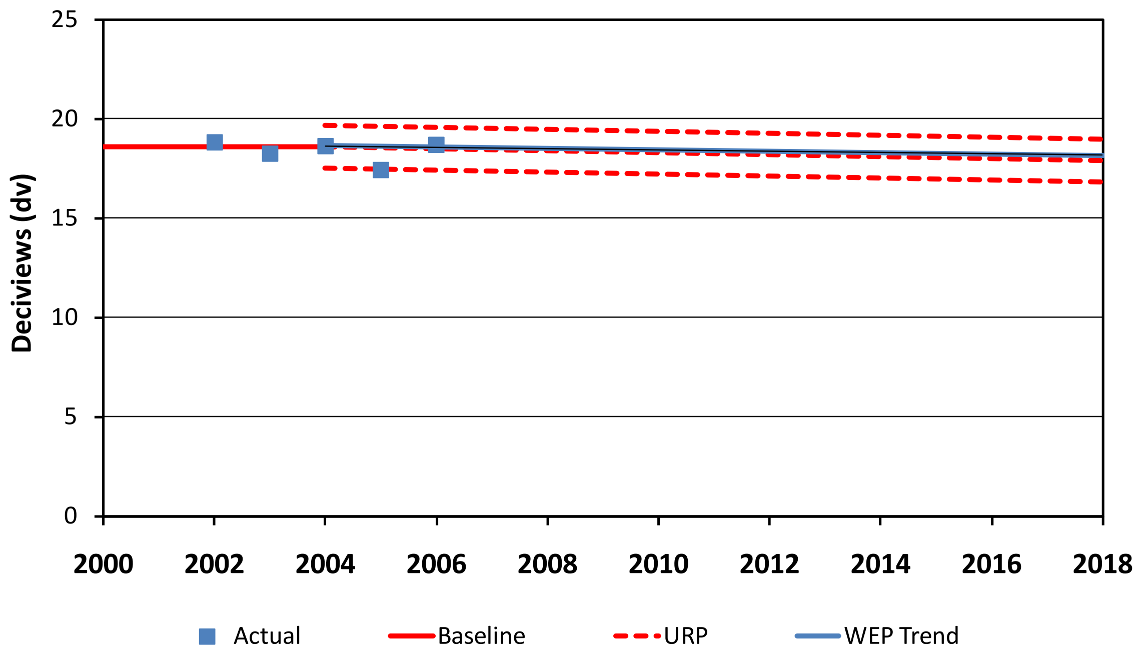


Figure III.K.9-3
Review of URP Glide path and WEP Trend, Baseline to 2018 for 20% Worst Days, Trapper Creek

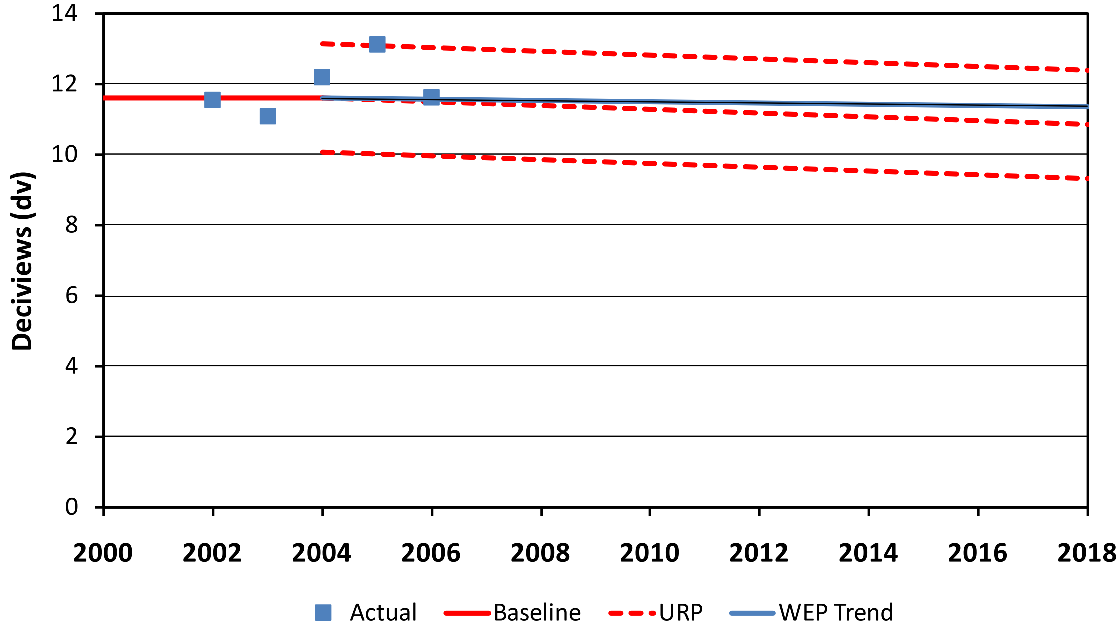
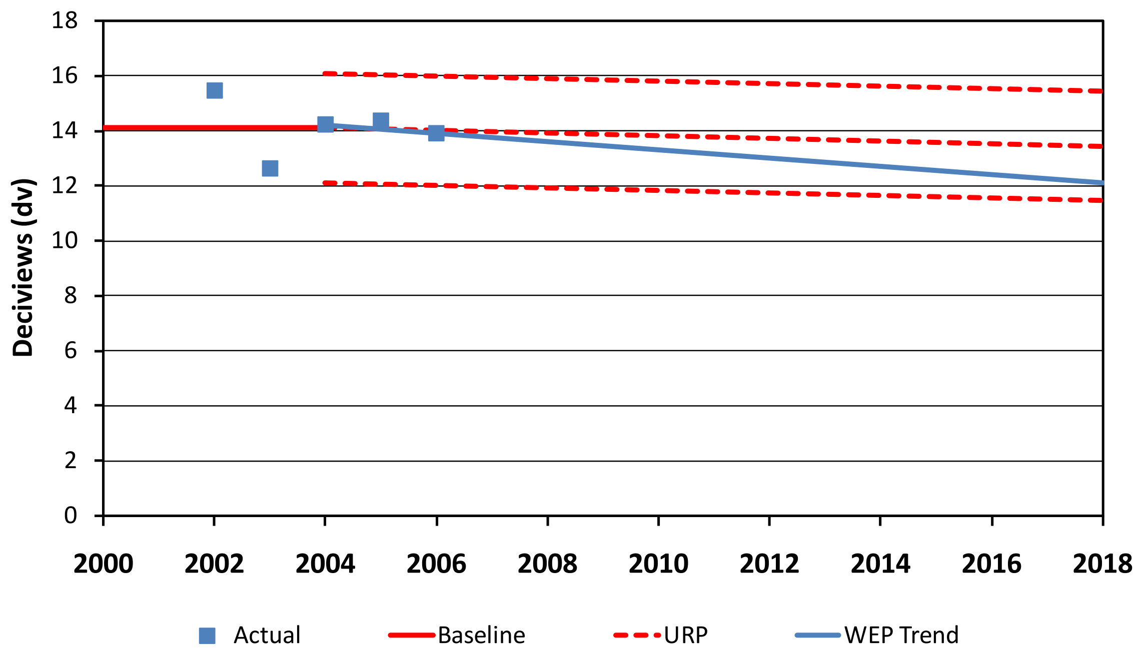


Figure III.K.9-4
Review of URP Glide path and WEP Trend, Baseline to 2018 for 20% Worst Days, Tuxedni



Forest fires and other natural events are larger causes of reduced visibility in Alaska than anthropogenic sources, and these events lead to substantial year-to-year variation in visibility as indicated by the fluctuation in the historical data. Even if a control program puts a site exactly on the URP line, on average, the actual visibilities measured historically and in the future can vary substantially from the URP trend on a year-to-year basis, making both program planning and the demonstration of progress more difficult. The extent of the deviations that can occur is indicated by the 95% confidence bounds, which were developed from the historical data. On a statistical basis, 19 of 20 years are expected to fall within these bounds. Given the extent of the year-to-year variability, the post-2000 historical data series are too limited (five or seven years) to permit estimating historical trends with any confidence. Instead, the standard deviation of the visibility values around the historical average was used to estimate the expected year-to-year fluctuation. The results presented for each site are discussed below.

<u>Denali</u> – Figure III.K.9-1 shows the URP glide path is quite modest relative to the baseline values (i.e., a 0.6 deciview reduction over a 14-year period). It also shows there is considerable variance in the 2000-2006 deciview measurements, which produce a standard deviation of 0.5 deciview. It is clear the WEP trend falls well within the resulting 95% confidence bounds surrounding the URP glide path. This indicates that there is no difference between the flat (i.e., no change) WEP forecast of pollutants impacting the site and the URP reduction target computed for 2018. . The WEP forecast does not account for emissions from GVEA's HCCP (i.e., Healy unit # 2). As previously noted, that facility did not operate in 2002, is not currently operating, but is permitted to operate. If it is brought on line, the permitted NOx and SOx emission levels would cause the WEP trend line to fall well above the 95% confidence bounds surrounding the URP glide path.

ADEC is well aware that changes in the operating status of major point sources have the potential to significantly impact visibility levels in one or more of the Class I areas. At this point the information available for assessing the potential effects of the HCCP facility on Denali visibility is mixed. While the WEP analysis shows the potential for negative impacts, the PSD modeling analysis for that facility demonstrated little potential for visibility impacts from plumes and haze derived that facility's operations. Another consideration is that HCCP is a clean coal demonstration project that integrates a slagging, multi-staged coal combustor system with an innovative sorbent injection / spray dryer absorber / baghouse exhaust gas scrubbing system. Since many of the coal fired boiler control options considered in the four-factor analysis have already been implemented at this facility, the modeling results provide conflicting views of the potential impacts and the facility has an active permit, as a result ADEC is not mandating additional controls prior to startup through this SIP.

<u>Simeonof</u> – Figure III.K.9-2 shows a similarly modest URP glide path (i.e., a 0.7 deciview reduction over a 14-year period). Since the average baseline value is almost twice that of Denali, the variance in the 2002–2006 measurements appears less pronounced. The standard deviation, however, is a slightly larger 0.6 deciview. There is little difference between the WEP trend and the URP glide path displayed. Clearly, the WEP trend falls within the 95% confidence bounds surrounding the URP glide path. Again, this indicates there is no difference between the WEP forecast of pollutants impacting the site and URP reduction target computed for 2018.

Trapper Creek – Figure III.K.9-3 also shows a modest URP glide path (i.e., a 0.7 deciview reduction over a 14-year period). Considerable variance in the 2002-2006 deciview measurements is evident, which produce a standard deviation of 0.8 deciview. The resulting 95% confidence bounds surrounding the URP glide path are wide enough to encompass the WEP trend, indicating there is no difference between the WEP forecast of pollutants impacting the site and the URP reduction targets computed for 2018.

Tuxedni – Consistent with the other sites, Figure III.K.9-4 shows a modest URP glide path (i.e., a 0.7 deciview reduction over a 14-year period). Considerable scatter, particularly for the 2002 and 2003, is evident in the 2002-2006 deciview measurements. This produces a standard deviation of 1.0 deciview, the largest observed across the Class I sites. The resulting 95% confidence bounds surrounding the URP glide path are wide enough to encompass the relatively large decline in the WEP trend, again indicating there is no difference between the WEP forecast of pollutants impacting the site and the URP reduction targets computed for 2018.

Based on the information presented in Figures III.K.9-1 through III.K.9-4, Alaska has determined that the RPG for each site on the 20% worst days should be the same as the 2018 URP target. The 2018 RPG values for the 20% worst days are as follows:

- Denali – 9.3 deciview
- Simeonof – 17.9 deciview
- Trapper Creek – 10.9 deciview
- Tuxedni – 13.4 deciview

Since none of the WEP trends on the 20% worst days indicate an increase in deciview levels and Alaska lacks the capability to model deciview levels for either best or worst days, the State has determined that RPGs for the 20% best days should be the same as the baseline deciview condition for each site, presented in Section III.K.4. As a result, the 2018 RPGs for the 20% best days are as follows:

- Denali – 2.4 deciview
- Simeonof – 7.6 deciview
- Trapper Creek – 3.5 deciview
- Tuxedni – 4.0 deciview

This decision is supported by (1) limited growth forecast for the State, (2) the results of the WEP analysis, (3) the additional BART reductions not reflected in the WEP analysis, and (4) reductions in $PM_{2.5}$ and related precursor emissions that will be produced by controls implemented under the $PM_{2.5}$ SIP that is being developed for Fairbanks.

To summarize, RPGs for 2018 were set by first comparing the percentage change in anthropogenic contributions between 2002 and 2018 from the WEP analyses to the target uniform rate of progress for 2018, and then in addition evaluating the uncertainty of the URP targets relative to the forecasted WEP reductions.

F. Affirmative Demonstration of RPGs for 20% Worst Days

As discussed earlier, EPA guidance indicates states may select an RPG that provides for lesser, equivalent, or greater visibility improvement than described by the URP glide path. The RPGs selected for 2018 on the 20% worst days show an improvement in visibility that is consistent with the URP targets in 2018. Outlined below are the factors that were considered when selecting the RPGs.

1. WEP Forecast – Since the WRAP was unable to perform photochemical modeling for Alaska, the WEP analysis provides the most insightful forecast of pollutant, source, and location impacting each Class I area. ADEC put considerable resources into the development of the statewide emissions inventory, the first prepared for the state. That inventory accounts for differences in emissions between each source category and community across the state in 2002 and 2018. When combined with the back trajectories of air parcels impacting each site on the 20% worst days, the WEP values provide substantial insight into which pollutant, source and borough have the greatest impacts at each site. They also provide a basis for assessing the benefits of additional controls that may be applied to sources impacting each site.

2. Four-Factor Analysis – The analysis was conducted as specified under Section 308 (d)(1)(i)(A). While that review determined that it was not reasonable to control additional source categories at this time, ADEC commits to reassess the need for control of these sources and further evaluate control options during this first milestone period (through 2018) to determine whether additional emission reductions in these source categories would improve Class I area visibility in the next planning period.

3. BART Analysis – Several key sources will be implementing additional controls that reduce pollutants impacting Denali, Trapper Creek, and Tuxedni. GVEA's Healy Power Plant has limits in place for SO_2, NOx, and PM_{10}. More importantly, additional NOx controls will be added to reduce the estimated visibility impacts at Denali below the 0.5 deciview significance threshold. This reduction is not reflected in the WEP analysis and indicates that deciview values at Denali will decline and not stay constant as indicated in the uncertainty analysis. The Conoco Philips Kenai LNG plant will also add new controls to reduce NOx levels below the 0.5 deciview significance threshold impacting Trapper Creek. These reductions are also not reflected in the WEP analysis and indicate that the deciview values at Trapper Creek are likely to decline more rapidly than indicated in the uncertainty analysis. Finally, the Agrium, Chem-Urea Plant in the Kenai has stopped operating and dramatically reduced NH_3 emissions impacting Tuxedni (by 98%). Significant reductions in NOx and $PM_{2.5}$ have also occurred (18% and 93%, respectively). These reductions in emissions from the Kenai ensure that the deciview values at Tuxedni should decline even more rapidly than indicated in the uncertainty analysis.

4. Additional Reductions – On December 13, 2009, Fairbanks was formally designated as a $PM_{2.5}$ nonattainment area. It has less than three years to prepare a SIP demonstrating

attainment with the ambient standard by the end of 2014. The control measures implemented to prepare an attainment demonstration will provide benefits to Denali as the WEP analysis demonstrated that sources in Fairbanks were significant contributors to NOx and SOx levels impacting Denali. These reductions are not reflected in the uncertainty analysis and further indicate that deciview values at Denali will decline and not stay constant as indicated in the uncertainty analysis. The WEP analysis also identified several older point sources located in areas impacting Class I areas that are not BART eligible. As these sources replace aging operating units, compliance with BART, PSD, and other EPA requirements ensures additional emission reductions will accrue and further enhance visibility at the impacted sites. ADEC plans to monitor modifications at these facilities and track the benefits for impacted Class I areas.

5. Evidence of Natural Source Significance – The speciation analysis presented in Section III.K.4 and the WEP analysis clearly demonstrate that natural fires are the dominant source of pollutants impacting the non-Simeonof Class I areas within Alaska on the 20% worst days. Since natural fires are larger causes of reduced visibility in Alaska than anthropogenic sources, these events lead to substantial year-to-year variation in visibility as indicated by the fluctuation in the historical data. Thus, even if a control program puts a site exactly on the URP line, on average, the actual visibilities measured historically and in the future can vary substantially from the URP trend on a year-to-year basis, making both program planning and the demonstration of progress difficult. For this reason, ADEC will track progress relative to the glide path and determine whether additional emission reductions are needed to ensure that (1) visibility is not degrading in any of the Class I areas and (2) reductions towards RPGs are achieved.

6. New Maritime Emission Regulations – The recent decision of the International Maritime Organization (IMO) to designate waters off of North American coasts as an emission control area (ECA) ensures large reductions in particulate and sulfur emissions from vessels operating in areas that impact ports and coastal areas. These reductions were not included in the WEP analysis and are expected to further improve visibility at Tuxedni, as it is located within the ECA; and to a lessor extent Simeonof, which is outside of the ECA, but, as shown in Section III.K.4 is significantly impacted by sea salt. Given its location, it is likely that reductions in maritime sulfur and particulate levels will enhance Simeonof visibility.