Developing the WRAP Point and Area Source Emissions Projections for the 2018 Reasonable Progress Milestone for Regional Haze Planning

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ABSTRACT

The Western Regional Air Partnership (WRAP) is assessing impacts and evaluating control strategies pertaining to regional haze within its geographic domain: States of Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, Wyoming, and the Native American reservations located within these states. To assist the WRAP with this assessment and to provide emission projection inputs into the visibility models used by the WRAP's Regional Modeling Center, the WRAP and its contractors developed a base case emissions inventory of point and area sources for the year 2018, and have now updated that 2018 inventory to a "Preliminary Reasonable Progress" (PRP) data set, to support haze plans due in December 2007. (Other inventories for other source types, such as mobile sources and fire, were addressed by other contractor teams and are not covered in this paper.)

This paper discusses the methods used to develop the WRAP 2018 Base Case version 1 and PRP18 inventories. These activities included data collection from each state, local and tribal (S/L/T) agency related to post-2002 "on-the-books" controls resulting from implementation or enforcement of consent decrees, new permit limits, new rules/regulations, and Early Action Compacts; determination of adjustments needed to reflect post-2002 conditions such as new facilities that had come on line, facilities that were retired or closed. Growth factors were developed using information from DOE/EIA and the U.S. EPA's EGAS (Version 5.0) model.

The results of the 2018 point and area source base case inventory were provided in several formats, including Excel pivot tables (i.e., for analysis of results at the state, county, facility, or SCC level), National Emissions Inventory Format (NIF) 3.0, and Sparse Matrix Operator Kernel emission (SMOKE)/Inventory Data Analyzer (IDA) format. The WRAP 2018 base case inventory for point and

area source was used by the WRAP RMC to model the planning target for the first regional haze planning milestone year.

As a follow-on project, the 2018 Base Case version 1 inventory was revised in early 2007 to correct omissions/errors in the original data set and to update some facility emissions projections, as well as growth and control factors. This resulted in the PRP18 inventory, revised Excel pivot tables, and NIF and SMOKE/IDA files for modeling. Details on the methods, data, assumptions, and results of the work to develop the PRP18 emissions inventory for point and area sources are also discussed in the paper.

INTRODUCTION

The Western Regional Air Partnership (WRAP) is assessing impacts and evaluating control strategies pertaining to regional haze within its geographic domain (States of Alaska, Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, Wyoming, and the Native American Reservations located within these states). The WRAP's Stationary Sources Joint Forum (SSJF) sponsored a project to provide WRAP work groups and forums with data, information, and assessments necessary for developing regional haze control strategies. This project was conducted by Eastern Research Group, Inc. (ERG) and its subcontractors, ENVIRON International Corporation and Alpine Geophysics, LLC, for the WRAP SSJF under Contracts No. 30204-101 and 30204-116 with the Western Governors' Association (WGA). This work was conducted as part of a multi-task effort for the WRAP SSJF, which included the following tasks:

- Phase 1:
  - Task 1A: WRAP 2002 point and area (non-oil and gas) sources emissions inventory quality assurance;
  - Task 1B: WRAP 2002 and 2018 oil and gas (area sources) emissions inventory;
  - Task 1C: WRAP 2018 base case point and area sources (non-oil and gas) emissions inventory;
  - Task 2: Control technology analysis;
  - Task 3: Tribal inventories for 2002 and 2018;
  - Task 4: California inventories for 2002 and 2018; and
  - Temporal profiles for WRAP electric generating units.
- Phase 2: Preliminary Reasonable Progress 2018 analysis (in progress)

The objective of this project was to develop 2018 base case emissions inventory projection data (Phase 1) and technical basis for making preliminary evaluations of reasonable progress toward individual Class I area visibility goals by the WRAP (Phase 2). This was done by updating the WRAP region 2018 point and area sources emission inventory projections from the 2018 Base Case version 1 project, completed by Eastern Research Group, Inc. (ERG) in January 2006.[1] The resulting emissions inventory is the WRAP region Preliminary Reasonable Progress emissions inventory for 2018 (PRP18).

This paper contains details pertaining to the data and methods used, and results achieved for the draft PRP18 analyses for point and area sources. However, in order to provide a comprehensive assessment of methods and results, many details pertaining to the other tasks are either discussed or incorporated by reference.

Inventory Characteristics

The year of 2018 is the first milestone in a 60-year path to restoring visibility in federal Class 1 areas to natural conditions; the goal of preventing visibility impairment, and remedying existing impairment is set forth in the federal Clean Air Act, as amended. This "reasonable progress" milestone year for visibility requires all states to submit haze control plans (SIPs), as defined in the federal Regional Haze Rule (RHR), and establishes the future year for the WRAP projected inventory for modeling purposes.

The geographic domain covered by this 2018 emissions inventory is shown in Figure 1 and includes the following:

- WRAP region states (AK, AZ, CA, CO, ID, MT, NV, NM, ND, OR, SD, UT, WA, and WY); and
- Native American Reservations (NARs) within the WRAP region; the following tribes provided emissions inventory data for 2018 projections (i.e., the Arapahoe and Shoshone Tribes of the Wind River Reservation, the Assiniboine and Sioux Tribes of the Fort Peck Indian Reservation, the Cabazon Band of Cahuilla Mission Indians of the Cabazon Reservation, the Coeur d'Alene Tribe of the Coeur d'Alene Reservation, Confederated Tribes and Bands of the Yakama Nation, Confederated Tribes of the Colville Reservation, Confederated Tribes of the Umatilla Reservation, Fort Mojave Indian Tribe of Arizona, Gila River Indian Community of the Gila River Indian Reservation, La Posta Band of Diegueno Mission Indians of the La Posta Indian Reservation, Navajo Nation, Pueblo of Laguna, Pueblo of Santa Ana, Salt River Pima-Maricopa Indian Community of the Salt River Reservation, Shoshone-Bannock Tribes of the Fort Hall Reservation, Tohono O'Odham Nation, Ute Mountain Ute Tribe of the Ute Mountain Ute Reservation).

The sources included in the PRP18 inventory are point sources and area (nonpoint) stationary sources. Certain area source categories that were not included in this project, but were dealt with in other WRAP projects and contracts include the following:

- Fugitive dust from paved and unpaved roads (SCCs 2294xxxxxx and 2296xxxxxx);
- Windblown dust (SCCs 27014xxxxx and 27301xxxxx);
- Wildfires, waste burning, agricultural burning (SCCs 28015xxxxx and 28100xxxxx); and
- Agricultural production livestock (SCCs 2805xxxxxx).

Also, nonroad mobile sources (e.g., commercial marine, locomotives, aircraft, etc.) were not included in this inventory of point and area sources.

The pollutants included in the PRP18 inventory are nitrogen oxides (NO_x), sulfur dioxide (SO_2), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter (PM) with an aerodynamic diameter of less than 10 micrometers (µm) (PM_{10}) and less than 2.5 µm ($PM_{2.5}$), and ammonia (NH_3).

The actual pollutants included in the PRP18 inventory for a given point or area source category are dependent upon those pollutants included in the 2002 WRAP inventory for that source. For example, if only PM_{10}-Filterable and $PM_{2.5}$-Filterable (and not PM_{10}-Primary and $PM_{2.5}$-Primary) are included in the 2002 inventory for a given source, then only those pollutants are included in the PRP18 inventory (i.e., no 2002 emissions or pollutants were augmented or gap filled).

METHODOLOGY

Figure 2 shows the steps followed to project the WRAP 2002 emissions inventory to the year 2018. The data and calculations for each of the layers in this roadmap were stored in an Excel spreadsheet for each state, and a single spreadsheet for the WRAP tribes. The types of information used in each step are described as follows:

Figure 1. WRAP 2018 inventory domain.

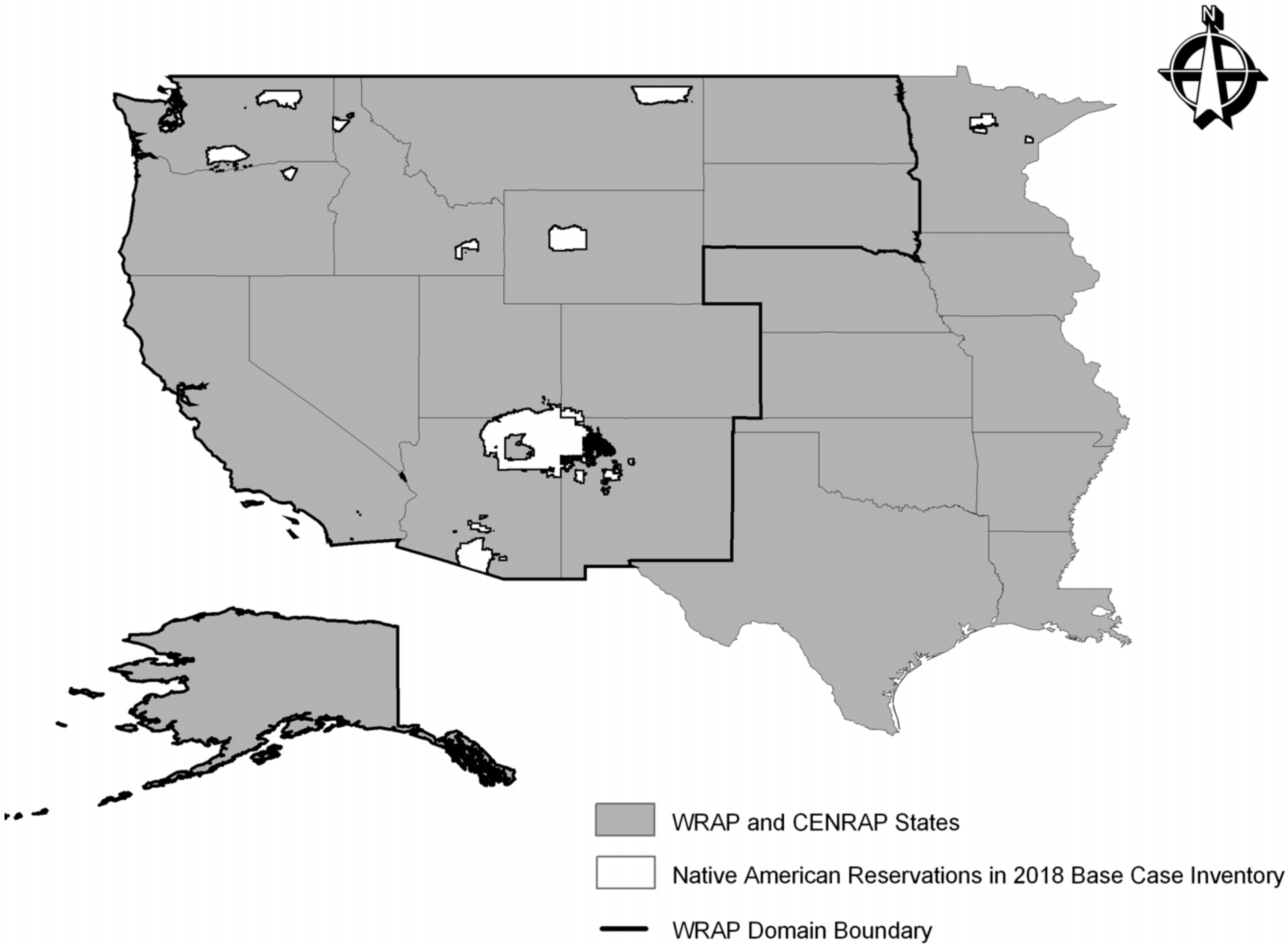
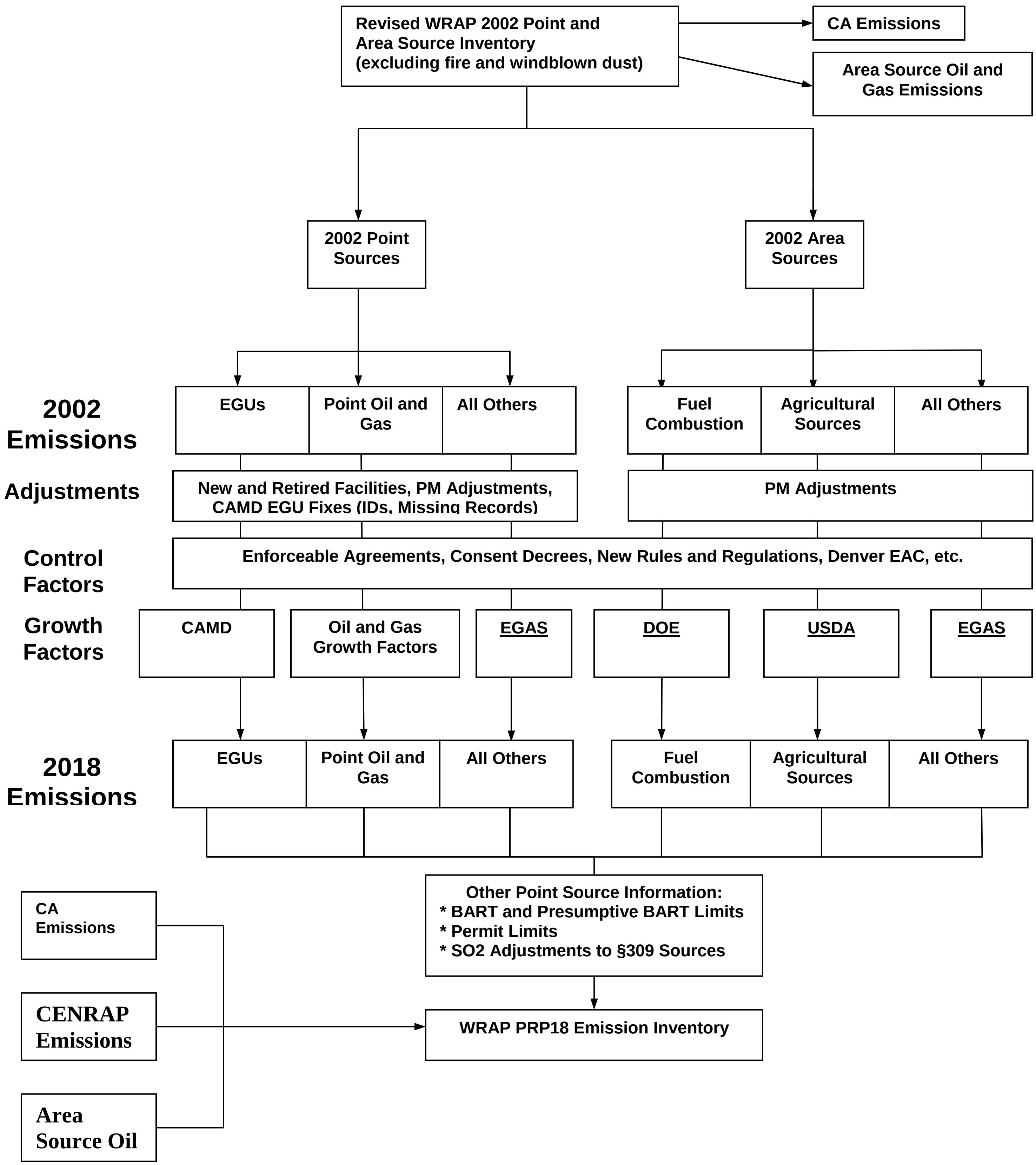


Figure 2. 2018 WRAP inventory projection methodology



- 2002 Emissions Inventory. This information was taken from the revised 2002 WRAP point and area source inventory updated in Phase 1 (which was based on the draft U.S. EPA National Emissions Inventory [NEI]), and included the following fields:
  - State and county FIPS
  - State facility identifier
  - Emission unit ID
  - Process ID
  - Pollutant code
  - Emission release point ID
  - Emission numeric value
  - Emission unit numerator
  - Tribal code
  - Primary SIC and NAICS
  - Facility name
  - City
  - SCC
  - BART flag (i.e., 1-Yes; 2-Likely; 3-Potential; 4-Do not know; 5-No)
- Adjustments:
  - Emissions for new facilities that have come on-line since 2002
  - Corrections for facilities that retired since 2002 and will not return to operation in the future
  - Corrections to facility IDs for electric generating unit (EGU) emissions taken from the U.S. EPA's Clean Air Markets Division (CAMD) database for 2002, and replacement of deleted records for non-CAMD units located at facilities with CAMD EGUs
  - Other (i.e., ratios to correct certain PM10 and PM2.5 emission factors/SCCs for combustion of natural gas)
- Control factors: Emission reductions due to known (i.e., on-the-books) controls, consent decree reductions, SIP control measures, and other relevant regulations that have gone into effect since 2002, or will go into effect before the end of 2018. These controls do not include impacts from any future control scenarios that have yet to be determined.
- Growth factors: SCC-specific growth factors developed from EGAS projection factor model; special analysis of EGU growth relative to unit capacity threshold.
- Retirement and replacement rates: Effects of retirement estimated using annual retirement rates based on expected equipment lifetimes. Retired equipment replaced by lower-emitting new equipment. Unit lifetimes examined for natural gas-fired EGUs; no retirements for coal-fired EGUs.
- Permit limits: Used in the cases where the projected emissions may have inadvertently exceeded an enforceable emission limit (i.e., emissions were adjusted downward to the permit limit, as applicable).
- Updates to SO_2 emissions for 2002 and/or 2018 as a result of a separate analysis conducted for §309 states to address significant (>100 tons) non-EGU sources.

An extensive data collection effort was conducted to identify the information needs for the adjustments, control factors, growth factors, retirement and replacement rates, and permit limits, etc. needed to develop the various factors and data needed for the projections. The actual data collected, adjustments made, factors calculated, and results are described in detail in the remaining sections of this paper.

Part of this WRAP 2018 projection process included numerous telephone conferences with the WRAP SSJF Projections Workgroup, who provided input and feedback on proposed methods for various source sectors, especially electric generating units. Both the draft 2018 base case inventory (Phase 1) and the draft PRP18 inventory (Phase 2) were generated and distributed to all affected states and tribal entities for review and comment. During the PRP18 process, calls were held with each agency to allow discussion of the inventory development to that point, and answer questions. Written comments then followed, and were compiled and responded to. All of this information was used to develop the draft PRP18 inventory. In some cases, comments received on the 2002 emissions were also addressed, and the 2002 inventory database was modified (although these changes were minimized and focused only on very significant comments).

Next, the results of PRP18 inventory were formatted using NIF 3.0 for input in to the WRAP Emissions Data Management System (EDMS), and SMOKE/IDA format to be used by the WRAP Regional Modeling Center (RMC) for modeling reasonable progress.

The remainder of this section explains the steps performed to develop the draft PRP18 emissions inventory. In some cases, the work was performed under Phase 1 and incorporated into Phase 2.

Post-2002 Adjustments

To provide the basis for an accurate projections inventory, adjustments were made to the WRAP 2002 point and area source inventory to reflect changes in sources and emissions that have occurred since the 2002 baseline inventory. These adjustments were associated with new facilities and emissions, or, in some cases, factors that were multiplied by the 2002 baseline inventory. This section discusses the various types of adjustments made to the 2002 WRAP emissions in order to achieve an up-to-date accounting of actual emissions.

<u>New, Retired, or Omitted Facilities</u>

Based on information received from the S/L/T agencies, facilities that had either come on-line or have been retired since 2002 were added or removed from the inventory. Also, changes were made for emissions at facilities (or specific units at facilities) that, for various reasons, needed to be corrected from their 2002 levels (e.g., emissions reported to the U.S. EPA CAMD database but not included in the 2002 WRAP inventory, uncharacteristically high or low emissions in 2002, duplicate facility record or SCC).

<u>PM Combustion Emission Corrections</u>

U.S. EPA has recently developed and distributed ratios to correct certain natural gas and liquefied petroleum gas combustion emission factors.[2] As currently understood, U.S. EPA will apply these ratios when finalizing the 2002 National Emissions Inventory (NEI), thus it was felt that the WRAP inventory should reflect this change as well, and that the most appropriate place to make this change was in the 2018 base case inventory (and not in the 2002 inventory, since this would create an inconsistency with most 2002 state emission inventories.) These ratios were applied at the SCC level to adjust the WRAP 2002 emissions prior to applying other factors in subsequent steps. Most of the ratios affect point sources (8-digit SCCs), although some area sources (10-digit SCCs) are affected as well. Most of the impacts are significant, ranging from a 92.3 to 95.4 percent decrease in PM_{10}-Primary and a 94.2 to 97.2 percent decrease in $PM_{2.5}$-Primary.

<u>Corrected CAMD EGU Facility IDs and Added Missing Records</u>

The basis of the WRAP 2002 emissions inventory, and thus the WRAP 2018 version 1 and PRP18 inventories, were the data submitted by S/L/T agencies for the U.S. EPA National Emissions Inventory (NEI). During the development of the NEI, NO_x and SO_2 emissions data for EGUs reporting to the CAMD database were used instead of the emissions submitted by the agencies. When these NO_x

and SO_2 emissions data were placed into the NEI, they were assigned a unique facility ID beginning with "EGU" in order to distinguish that record from the record submitted by the state. Generally, the NO_x and SO_2 emissions values from CAMD varied only slightly from those submitted by the S/L agency (i.e., ERG observed results showing about a 1-2% difference in emissions between CAMD and S/L agency emissions). However, the use of the CAMD "EGU" numbering scheme resulted in two different facility IDs for the same EGU in the resulting dataset. This eventually became recognized as a problem when these data were used in the WRAP 2002 and 2018 pivot tables and in the WRAP Emissions Data Management System (EDMS).

Also, another problem had occurred during the data replacement activities, that resulted in some NO_x and SO_2 emission records for non-CAMD units operating at facilities with CAMD units being deleted, causing non-CAMD EGU emissions to be underreported in the resulting dataset. For these reasons, ERG performed a task to (1) replace the CAMD "EGU" facility IDs with the S/L agency facility IDs as originally submitted to the NEI, and (2) to replace the dropped NO_x and SO_2 emission records in the 2002 inventory database and project these to 2018. These corrections are now reflected in the draft WRAP 2018 PRP emissions inventory.

Post-2002 Control Factors

Post-2002 control factors were calculated to reflect impacts from on-the-books controls (i.e., with implementation dates from 2003 to the end of 2018). These control factors are based on expected or actual post-2002 emission reductions from these general areas:

- Compliance with consent decrees (CDs) resulting from enforcement of various federal regulations, such as New Source Review (NSR), Prevention of Significant Deterioration (PSD), and Title V permits, by U.S. EPA;
- Air quality plan impacts from State Implementation Plan (SIP) implementation and other state programs to control air pollution, such as the Denver Early Action Compact (EAC) Ozone Plan, and implementation of Agricultural Best Management Practices (BMPs) in Maricopa County and Salt River SIP in Arizona; and
- Public/private stakeholder agreements for improving air quality, such as the Denver Metro Emissions Reduction Project.

In some cases, the effect of these post-2002 controls did not take the form of a factor, but rather an emission limit, equipment shutdown, or some other condition.

In addition to the control impacts that could be quantified, there was a significant amount of information gathered for other types of control impacts that could not be quantified due to various reasons (e.g., dust control requirements in SIPs with no specific emission reductions quantified, potential post-2002 control through voluntary reductions not enforceable through permit limits). Details on the two most significant initiatives and types of controls considered are described next.

<u>National Wood Products Initiative</u>

The wood products industry includes manufacturers of plywood, panelboard, medium density fiberboard (MDF), and oriented strand board. In 1988, the U.S. EPA began investigating the industry for a suspected nationwide pattern of noncompliance with the PSD regulations under the NSR provisions of the Clean Air Act and state rules.[3] Within the WRAP region, settlements were reached with Willamette Industries (2000) and Boise Cascade Corporation (2002).

The Willamette facilities affected within the WRAP states were located in Oregon. However, all of the operating Willamette facilities have achieved compliance with their respective settlement CDs as of 2002; thus, it is not necessary to reflect on-the-books controls.

The Boise Cascade facilities affected with the WRAP states were located in Idaho, Washington, and Oregon. In general, the settlements with both companies required significant VOC reductions (i.e., 90 to 95 percent), while minimizing NO_x and CO emissions. For the most part, VOC reductions were to be achieved through regenerative catalytic oxidation (RCO) or regenerative thermal oxidation (RTO) installed on the wood/veneer dryers.

National Petroleum Refinery Initiative

U.S. EPA's national petroleum refinery initiative is an enforcement and compliance strategy to address air emissions from the nation's petroleum refineries.[4] Since 2000, U.S. EPA has entered into 17 settlements with U.S. companies that refine over 75 percent of the nation's petroleum. The settlements focus on four main areas of the Clean Air Act (CAA):

- NSR/PSD (affecting fluidized catalytic cracking units and heaters and boilers);
- New Source Performance Standards (NSPS) (affecting flares, sulfur recovery units, and fuel gas combustion devices);
- Leak detection and repair requirements; and
- Benzene National Emissions Standards for Hazardous Air Pollutants (NESHAP).

Table 1 lists the refineries within the WRAP region with CDs that have been negotiated as part of the national petroleum refinery initiative. As part of the development of the 2018 base case inventory, each CD was reviewed to determine the types of controls, emission limits, applicable equipment, and deadline for achieving reductions. However, most of the CD requirements call for preliminary studies to determine the most feasible and effective types of controls, installation of equipment that meets NSPS requirements, and other types of programmatic approaches. As a result, the specific mass reductions expected (e.g., mainly NO_x, SO_2, and PM) are not provided in the CD, or have yet to be fully negotiated. Of the 14 refineries listed in Table 2, specific emission reductions estimates were only available for two: BP Amoco Mandan Refinery and (Navajo Refining) Artesia Refinery.

Table 1. Refineries in WRAP states subject to the national petroleum refinery initiative.

State	EPA Region	Refinery
CO	8	Conoco (Suncor Energy) Refinery (Denver)
CO	8	Valero (Colorado Refining) Refinery (Denver)
MT	8	Exxon Mobile (Billings)
MT	8	Montana Refining (Great Falls)
MT	8	Conoco Refinery (Billings)
MT	8	Centex Harvest States (Laurel)
ND	8	BP Amoco Mandan Refinery
NM	6	Artesia Refinery
NM	6	Lea Refinery
UT	8	Chevron Salt Lake Refinery
UT	8	BP Amoco Salt Lake City Refinery
WA	10	Equilon-Puget Sound Refining (Anacortes)
WA	10	ConocoPhillips (Ferndale)
WA	10	BP Cherry Point Refinery (Blaine)

EGU Growth Factor and Rate Analysis

In addition to post-2002 control factors, the 2018 projections also account for the effects of future growth from 2002 to 2018. A specialized methodology was developed for coal-fired EGUs in order to incorporate detailed information regarding EGU operation, while a generalized approach was used for the majority of the other sources. The growth factor and rate analysis methodologies are described in detail below.

Because EGUs are the largest source of NO_x and SO_2 in the WRAP inventory domain, considerable effort was spent to develop projections for them. In particular, projections were developed on an EGU-by-EGU basis, rather than for the sector as a whole. The starting point of this effort was the revised 2002 WRAP point sources inventory; all EGU sources were then extracted from the overall inventory. Under Task 1A of this project, NO_x and SO_2 emissions data had already been incorporated into the inventory for all EGUs that had continuous emissions monitors (CEMs) and reported to the Clean Air Markets Division (CAMD) database. The specialized methodology was applied only to CAMD EGUs; EGUs not contained in the CAMD database were treated like other non-EGU point sources. The methodology details specific to coal-fired CAMD EGUs are presented first, followed by the methodology details for all other CAMD EGUs.

Coal-Fired EGUs

After the coal-fired EGUs were extracted from the overall inventory, new coal-fired EGUs that commenced operation after 2002 were added to the inventory. Likewise, coal-fired EGUs that retired since 2002 were removed from the list of coal-fired EGU sources (i.e., Arapahoe Units #1 and #2). After the list of CAMD coal-fired EGUs was compiled, then the following data were downloaded from the CAMD website for each of the units:

- Nameplate unit capacity (megawatts [MW]);
- 2002 gross electricity generation (megawatt-hours [MWh]);
- 2002 heat input (million British thermal units [MMBtu]);
- 2002 NOx emissions (tpy);
- 2002 SO2 emissions (tpy);
- 2004 NOx emissions (tpy); and
- 2004 SO2 emissions (tpy).

For each CAMD unit, a 2002 capacity factor (CF) was calculated using the following equation:

Equation (1) CF = (gross generated electricity [MWh])/(nameplate unit capacity [MW] × 8760 hours)

After calculating the 2002 capacity factor, a capacity threshold (CT) was used to calculate the appropriate growth factor (GF) for each coal-fired EGU. The GF value represents how much growth is needed to project from the current level of operation up to the CT value. The equation used is as follows:

Equation (2) GF = CT/CF

The capacity threshold represents the theoretical level of generation at which the utilities will need to begin construction of a new EGU to meet additional demand requirements. For coal-fired EGUs, a CT value of 0.85 was assumed based on input from the Projections Work Group. The use of this CT value was based upon historical precedent; the value was previously used many years ago in the WRAP Integrated Assessment System (IAS) and has been carried forward to the present time.

For all pollutants except NO_x and SO_2, the 2002 emissions were then multiplied by the calculated GF value in order to determine the 2018 emissions using the following equation:

Equation (3) $\text{Emissions}_{2018} = \text{Emissions}_{2002} \times \text{GF}$

An expanded methodology was utilized for NO_x and SO_2. The calculated GF was multiplied by the 2002 heat input (HI) to obtain a projected 2018 HI:

Equation (4) $HI_{2018} = HI_{2002} \times GF$

The 2004 NO_x and SO_2 emission rates (ER) in pounds (lbs) per MMBtu were generated by dividing 2004 emissions by 2004 HI as follows:

Equation (5) $ER_{NOx} = Emissions_{NOx,2004}/HI_{2004}$
Equation (6) $ER_{SO2} = Emissions_{SO2,2004}/HI_{2004}$

Based on the guidance of WRAP SSJF, the CAMD 2004 NO_x and SO_2 emission rates, which are the most current full year emission rates for coal-fired EGUs, were used to represent coal-fired EGU operation in 2018. Emissions were calculated as follows:

Equation (7) $Emissions_{NOx,2018} = HI_{2018} \times ER_{NOx}$
Equation (8) $Emissions_{SO2,2018} = HI_{2018} \times ER_{SO2}$

As a final step, projected emissions were reduced by any relevant emission caps or permit limits.

<u>Other EGUs</u>

The methodology used to project other EGUs was similar to that used for the coal-fired EGUs. As with the coal-fired EGUs, the other EGUs were extracted from the overall inventory with adjustments made for post-2002 new EGUs and retired EGUs. After the list of CAMD EGUs was compiled, then the following data were downloaded from the CAMD website for each of the units:

- Nameplate unit capacity (MW);
- 2002 gross electricity generation (MWh);
- 2002 NO_x emissions (tpy); and
- 2002 SO_2 emissions (tpy).

The 2002 capacity factor (CF) was calculated using the following equation:

Equation (9) CF = (gross generated electricity [MWh])/(nameplate unit capacity [MW] × 8760 hours)

After calculating the 2002 capacity factor, a capacity threshold (CT) was used to calculate the appropriate growth factor (GF) for each other EGU. The GF value represents how much growth is needed to project from the current level of operation up to the CT value. The equation used is as follows:

Equation (10) $GF = CT/CF$

Different CT values were used for the other non-coal fired EGUs depending upon the fuel and technology present. These CT values used were 0.50 for oil-/diesel-fired EGUs, 0.25 for simple cycle natural gas-fired turbines, and 0.60 for natural gas-fired combined cycle EGUs.

For all pollutants, the 2002 emissions were then multiplied by the calculated GF value in order to determine the 2018 emissions using the following equation:

Equation (11) $Emissions_{2018} = Emissions_{2002} \times GF$

<u>Future EGUs</u>

Another unique aspect of the growth analysis for EGUs as compared to other point sources is the identification of future EGUs that will need to be built in order to meet projected electricity demand in 2018. The basis of the projected electricity demand is the Energy Information Administration's (EIA) annual energy projections. The original analysis for the 2018b inventory relied on EIA projections released in 2005 with estimates out to 2025; the most current projections were released in February 2007 and provide estimates out to 2030.[5,6] Historical statistics for 2002 and projections for 2018 were obtained from the EIA documentation for 4 of the 13 electricity market module regions:

- Northwest Power Pool (Idaho, Oregon, Utah, Washington, Wyoming; and parts of California, Montana, Nevada, and South Dakota);
- Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (Arizona and Colorado; and parts of Nevada, New Mexico, and Texas);
- Mid-Continent Area Power Pool (North Dakota, Nebraska; and parts of Montana, South Dakota, Minnesota, Iowa, and Wisconsin); and
- California (parts of California).

A comparison of the original and revised generation projections are shown in Tables 2 and 3.

Table 2. EIA electricity projections (billion kWh)

Electricity Market Module Region	2018 Required Coal-Fired Generation (2005 EIA)	2018 Required Coal-Fired Generation (2007 EIA)
California[a]	77.76	83.17
Northwest Power Pool[b]	88.37	106.05
Rocky Mountain Power Area[c]	162.18	167.05
Mid-Continent Area Power Pool (ND and SD portions only)	45.61	45.05
Total	**373.92**	**401.32**

[a] Portions of CA.
[b] ID, OR, UT, WA, and WY; portions of CA, MT, NV, and SD.
[c] AZ and CO; portions of NV and NM.

Table 3. Future electricity generation analysis (billion kWh)

Growth Parameter	Original 2018b Analysis (2005 EIA)	Revised PRP18 Analysis (2007 EIA)
2002 Electricity Generation	258.70	258.70
2018 Electricity Generation	373.92	401.32
Needed Generation	115.22	142.62
Unused Capacity at Existing 2002 Facilities	16.60	16.60
New Capacity at 2003-2004 Facilities	0.66	0.66
Capacity Currently Under Construction	9.61	9.83
Capacity Currently Being Permitted	21.82	74.33
Remaining Capacity to be Allocated	66.53	41.20

Future EGUs – Coal. The revised analysis of future electricity generation for coal is summarized in Table 3, which shows that the required 2018 generation in the revised analysis increased by 7.3% (i.e., 27.40 billion kWh) relative to the original analysis. This growth is offset by increased generation capacity (i.e., 52.51 billion kWh) that is currently being permitted. A list of facilities that are currently under construction or currently being permitted is provided in Table 4.

Table 4. Coal-fired EGUs under construction or being permitted (MW).

Facility Name	State	Original 2018b Analysis: Under Construction	Original 2018b Analysis: Being Permitted	Revised PRP18 Analysis: Under Construction	Revised PRP18 Analysis: Being Permitted
Rocky Mountain Power/Hardin Gen. Station	MT	160		160	
Bull Mountain Plant/Roundup Plant	MT	750		780	
Wygen Station #2/Black Hills Corp	WY	100		100	
Two Elk (#1)/Bechtel	WY	280		280	
Springerville (#3 and #4)	AZ		760		800
Comanche (#3)	CO			750	750
Northern Nevada Energy/Newmont	NV		200		200
NEVCO Energy Company	UT		270		270
Intermountain Power Plant (#3)	UT		950		950
Ft. Morgan/LS Power	CO				600
Akron/AES Power	CO				640
Highwood/Southern Montana Electric	MT				270
White Pine Energy Association/LS Power	NV				1,500
Gascoyne #1/Montana Dakota Utility	ND				175
Gascoyne #2/Montana Dakota Utility	ND				500
South Heart/Great Northern Power	ND				500
Great River Energy	ND				66
Wygen (#3)	WY				100
Two Elk (#2)	WY				740
Dry Fork/ Basin Electric	WY				422
Desert Rock/Sithe Global Power	Navajo (NM)				1,500
Total		**1,290**	**2,180**	**2,070**	**9,983**

After considering the facilities listed in Table 4, 41.20 billion kWh of coal-fired electricity generation still remained. Assuming that a typical future coal-fired EGU has a nameplate capacity of 500 MW and operates at the capacity threshold of 0.85 (assumptions that were based upon input from the Projections Work Group), then a total of 11 future coal-fired EGUs are required under the revised analysis compared to the 18 EGUs estimated with the original analysis. The state-level allocation of the future coal-fired EGUs in the original analysis was based upon current state-level capacity (i.e., sum of capacity at existing, under construction, and permitted facilities). This same state-level allocation was maintained for the revised analysis with three exceptions.

First, no additional future coal-fired EGUs were assigned to ND; the ND and SD generation analysis was conducted separately from the other Western states because ND and SD are in a different electricity market module region and lignite coal is preferentially used, instead of bituminous and sub-bituminous coal. Three future coal-fired EGUs (i.e., total of 1,500 MW) were allocated to ND and SD in the original analysis; the newly identified permitted facilities located in ND (i.e., Gascoyne #1 and #2, South Heart, and Great River Energy) have a total capacity of 1,241 MW. In addition, the ND and SD projected coal-fired electricity generation decreased slightly in the new EIA data. Therefore, no additional EGUs were assigned to ND.

The second exception is that the one future coal-fired EGU assigned to Idaho in the original analysis was removed. This is based upon a moratorium on the construction of coal-fired EGUs in Idaho. Although this moratorium is not necessarily permanent, WRAP staff indicated that the future coal-fired EGU assigned to Idaho should be removed from the revised analysis.

The third exception is the identification of the Desert Rock/Sithe Global Power EGU consisting of two 750 MW units that is being permitted for the Navajo Nation (San Juan County, New Mexico). Desert Rock will "replace" the two future coal-fired EGUs allocated to the Navajo Nation in the original ERG analysis, as well as one other EGU located elsewhere from the original ERG analysis. Because the highest number of allocated future coal-fired EGUs were located in Wyoming, in the previous analysis, the number of these EGUs was reduced from three to two in the PRP18 analysis.

The state-level allocations are presented in Table 5 (both original and revised). WRAP staff indicated that the county-level allocations used in the original analysis (based upon announcements of plans to build coal-fired EGUs and locations of existing coal-fired EGUs and associated infrastructure) should be maintained in the PRP18 analysis.

Table 5. State-level allocation of future placeholder coal-fired EGUs required to match total electricity demand forecasts (number of 500 MW Units)

State	Original 2018b Analysis	Revised PRP18 Analysis
Arizona	2	2
Colorado	2	2
Idaho	1	0
Montana	1	1
Nevada	1	1
New Mexico	1	1
North Dakota	3	0
Oregon	0	0
South Dakota	0	0
Utah	2	2
Washington	0	0
Wyoming	3	2
Tribes (Navajo)	2	0
Total	**18**	**11**

In addition to new generation projections and future plant allocations, the revised analysis for coal-fired EGUs included a review of permitted emission rates for new EGUs. The previous analysis used emission rates derived from a range of values from 12 Western facilities that were reported to U.S. EPA; the revised analysis uses permitted emission rates collected by WRAP staff. These emission rates are shown in Table 6; blank cells in the table indicated no reported permit limit. The permitted emission rates were used at each respective permitted EGU. Average emission rates were calculated from these collected emission rates and then applied to each of the future allocated EGUs. Three permitted emission rates (i.e., PM_{10} at Springerville #3 and #4 and SO_2 at Neil Simpson #2) were excluded from the calculation of the average emission rates because they were significant outliers. In addition, the VOC rate (0.0022 lb/MMBtu) used in the previous analysis was used instead of the average calculated VOC rate (0.0056 lb/MMBtu; based upon only about half of the permitted EGUs).

The emission rates applied to each of the future allocated EGUs are identified in the bottom row of Table 6.

The emission profile of the future allocated EGUs is presented in Table 7. This emission profile is based upon a 500 MW EGU operating year-round at 0.85 capacity with a conversion factor of 10 MMBtu/MWh.

Future EGUs – Natural Gas. A similar natural gas-fired electricity demand analysis was also developed. The original analysis indicated that a total of 148.77 billion kWh of natural gas-fired electricity generation is projected to be required by 2018. A total of 29.00 billion kWh of this generation can be obtained from unused capacity. An additional 158.01 billion kWh of natural-gas fired generation has been identified from facilities that came on-line in 2003 or 2004, are currently under construction, or are currently being permitted. All of these facilities were added to the 2018 inventory. Because the identified generation exceeded the projected 2018 needed generation, no additional future natural gas-fired EGUs were expected to be needed in the WRAP Region. An examination of the revised natural gas-fired electricity generation projections did not indicate any significant differences. Therefore, no new future natural gas-fired EGUs were added to the 2018 inventory beyond those that are currently under construction or are currently being permitted.

Other Point Source Growth Analysis

In general, for all other non-EGU point sources, growth factors were obtained from U.S. EPA's Economic Growth and Analysis System growth factor model (EGAS), Version 5.0. The EGAS model generates SCC-specific growth factors for a specified geographic area, base year (i.e., 2002), and future year (i.e., 2018) using various socio-economic data.[7,8] EGAS model runs were made for every state within the inventory with the exception of California (California growth factors are discussed below). Growth factors from the EGAS model runs were matched using SCCs to each inventory record. In the event that an inventory record SCC did not match any of the SCCs in the EGAS output, a growth factor of 1.0000 was assigned. In most cases, unmatched SCCs were caused by the input of incorrect SCCs in the inventory record.

Table 6. Permitted emissions rates for coal-fired EGUs (lb/MMBtu)

Facility Name	State	NO_x	SO_2	VOC	CO	PM_{10}
Springerville #3	AZ	0.090	0.090			0.055[a]
Springerville #4	AZ	0.054	0.077			0.055[a]
AES Power/Akron	CO	0.070	0.100			0.012
Comanche #3	CO	0.080	0.100	0.0035	0.130	0.013
LS Power/Ft. Morgan	CO	0.070	0.078			0.012
Roundup Power/Bull Mountain #1	MT	0.070	0.100	0.0030	0.15	0.012
Roundup Power/Bull Mountain #2	MT	0.070	0.100	0.0030	0.15	0.012
Southern Montana Electric/Highwood	MT	0.070	0.038	0.0030	0.10	0.012
Nevada Energy/Newmont	NV	0.067	0.090		0.150	0.012
LS Power/ White Pine Energy	NV	0.070	0.078			0.012
Great River Energy	ND	0.090	0.060			0.013
Montana Dakota Utility/Gascoyne #1	ND	0.090	0.038	0.0050	0.150	0.013
Montana Dakota Utility/Gascoyne #2	ND	0.090	0.060			0.012
Great Northern Power/South Heart	ND	0.090	0.039	0.0025	0.150	0.010
Otter Tail Power Company	SD			0.0036	0.150	0.030
Intermountain Power #3	UT	0.070	0.090	0.0027	0.15	0.012
Nevco/Sevier Power	UT	0.100	0.022		0.115	0.0154
Basin Electric/ Dry Fork	WY	0.050	0.080	0.0039	0.15	0.012
Black Hills Power/ Neil Simpson #2	WY	0.023	0.200[a]	0.0150	0.15	0.02
Two Elk #1	WY	0.090	0.132	0.0135	0.135	0.018
Two Elk #2	WY	0.070	0.084	0.0035	0.15	0.015
Black Hills Power/ Wygen #2	WY	0.070	0.100	0.0100	0.15	0.012
Black Hills Power/ Wygen #3	WY	0.050	0.090		0.15	0.012
Average New Unit Rates		0.072	0.078	0.0056	0.143	0.014
Previous Analysis New Unit Rates		0.090	0.090	0.0022	0.150	0.018
Current Analysis New Unit Rates		**0.072**	**0.078**	**0.0022**	**0.143**	**0.014**

Table 7. Emissions profile for 500 MW future allocated coal-fired EGU

Facility Name	NO_x	SO_2	VOC	CO	PM_{10}
Emission Factors from Table 5 (lb/MMBtu)	0.072	0.078	0.0022	0.143	0.014
Annual Emissions (tpy)	1,340.3	1,452.0	41.3	2,661.9	260.6

An exception to the use of EGAS growth factors was for the oil and gas point source emissions. County-specific growth factors for oil and gas production area sources were developed under Task 1B of this project. These growth factors were then applied to the point source inventory by mapping the oil and gas area source categories to the corresponding point source SCCs. If an SCC/county-specific growth factor did not exist for a particular oil and gas inventory record, then regional growth factors obtained from EIA forecasts were applied.

Area Source Growth Analysis

For area sources, growth factors were obtained from one of three sources: the EGAS growth factor model, energy projections from EIA, or agricultural crop projections from the U.S. Department of Agriculture (USDA). The EGAS area source projection factors were obtained in the same manner as described above for the EGAS point source projection factors.

As discussed above, the EIA has issued annual energy projections out to the year 2030. Historical statistics from 2002 combined with projected use quantities for 2018 were used to derive projection factors for use with area source fuel combustion sources. These EIA-based projection factors were used for the following source categories: Industrial fuel combustion (SCC 2102xxxxxx), commercial/institutional fuel combustion (SCC 2103xxxxxx), and residential fuel combustion (SCC 2104xxxxxx).

Growth factors for agricultural tilling (SCC 2801000003) were obtained from harvested acreage projections developed by USDA.[9] The USDA projections covered a 12-year period from 2003 to 2014 and included harvested acreage estimates for eight major field crops (i.e., wheat, barley, corn, rice, oats, soybeans, sorghum, and upland cotton). Extrapolation was used to extend the time series back to 2002 and forward to 2018. The 2002 harvested acreage was estimated to be 226.9 millions acres; while the 2018 harvested acreage was estimated to be 235.1 millions acres. This corresponds to a growth factor of 1.0361.

California Point and Area Sources

The California 2018 base case emissions were developed using an entirely different methodology than has been described in this report for the other WRAP states. The California Air Resources Board (ARB) used the California Emission Forecasting System (CEFS) to develop California's 2018 base case inventory and provided it directly to the WRAP. The California 2018 base case inventory was provided by ARB in CEFS output format. CEFS uses two separate forecast algorithms: TREND forecast module for aggregating emissions by air district, air basin, and county, and GIS forecast module for developing forecasts at the facility/device/process level for use in gridded inventory inputs for modeling. The TREND module was used to develop the 2018 base case inventory for the WRAP. The CEFS 2018 database files for point sources (i.e., 128,425 records; 20,914 facilities) and area sources (i.e., 16,340 records; 618 SCCs across all counties) were provided in units of tons per day. The pollutants were NO_x, SO_2, reactive organic gases (ROG), CO, PM_{10}, and $PM_{2.5}$. ROG was taken to be equivalent to VOC; no NH_3 emissions were provided.

The following steps were then performed to place the CEFS emissions into the proper format, eliminate inconsistencies with the remaining WRAP inventory, and fill data gaps for required NIF and IDA fields:

- Point Sources:
  - SCCs were checked for validity; invalid SCCs were removed.
  - Tons per day were converted to tons per year by multiplying by 365.
  - PM10 and PM2.5 records were adjusted according to the U.S. EPA correction factors for natural gas combustion.
  - Latitude/longitude coordinates were assigned to the 2018 records using information from California's 2002 inventory (compiled under Task 1A of this project). County centroids were assigned to 2018 sources that could not be matched to 2002 records.

- Area Sources:
  - Certain EICs were removed (i.e., sources not included in this inventory effort – wildfires, prescribed burning, forest fires, rangeland burning, agricultural burning, and windblown dust).
  - Remaining EICs were mapped to SCCs.
  - Tons per day were converted to tons per year by multiplying by 365.

After these steps were completed, then the California files were converted to NIF3.0 and IDA formats for use in subsequent steps of the 2018 base case inventory process.

In addition to controls and growth, the 2018 projected inventory also includes the effects of point source retirement and replacement. The assumptions used to apply the concepts of point source retirement and replacement were handled as follows:

- All point sources have a finite lifetime (of 'x' number of years);
- Upon reaching that finite lifetime, a point source will be retired;
- A retired point source will be replaced by a point source of similar size;
- The new replacement point source will have lower controlled emissions than the emissions from the retired point source; and
- Point source retirement/replacement is entirely separate from future growth.

Because future year emission rates could not be quantified for some source types, point source retirement/replacement was only applied to a limited number of source types (i.e., SCCs). The general methodology is outlined below, along with specific modifications that were made for the special case of EGUs.

Retirement and replacement was applied to a subset of the point sources contained in the 2002 WRAP inventory. A list of the point sources and SCCs is provided in Table 8 along with expected facility lifetime, annual retirement rate, and projection retirement rate. The annual retirement rate is the percentage of sources under a particular SCC that are expected to retire in a given year; the annual retirement rate is defined as (1/lifetime). For example, an SCC with an expected lifetime of 50 years has an annual retirement rate of 0.02 (i.e., 1/50 years). The projection retirement rate is the percentage of sources under a particular SCC that are expected to retire over the period of the projection (i.e., from 2002 to 2018, or 16 years). In the case of the SCC example above, the projection retirement rate is 0.32 (i.e., 0.02 × 16 years).

For each of the SCCs listed in Table 8, reduction factors were developed for NO_x, SO_2, and PM_{10}. These factors were based on the expected reduction as an uncontrolled source is retired and replaced by a new controlled source. Reduction factors were calculated using the following equation:

Equation (12) Reduction Factor = (Retired Rate – Replacement Rate)/(Retired Rate)

The effects of retirement and replacement were applied as a sector-wide adjustment to each record in that sector based on SCC. In addition, if a particular SCC had reduction factors applied to it, then the reduction factors were also applied to new growth as well. This is shown in the following equations where R is equal to the retirement rate, G is the growth rate, and C is the reduction rate for a particular pollutant:

Equations (13) Total 2018 Emissions = Unretired 2002 Emissions + Retired/Replaced 2002 Emissions + Grown 2018 Emissions

Equations (14) Total 2018 Emissions = (2002 Emissions × [1 – R]) + (2002 Emissions × R × [1 – C])

$$+ (2002\ \text{Emissions} \times [G - 1] \times [1 - C])$$

The retirement/replacement methodology described above was applied to all point sources that matched the SCCs in Table 8. The one key exception was for EGUs. Instead of applying annual retirement rates to EGUs, the age of the EGU based upon known start-up dates was compared to expected lifetimes as shown in Table 8. If the age of any EGU exceeded its expected lifetime in 2018, then that EGU was assumed to be replaced by a similarly-sized EGU grown up to capacity with the appropriate reduced emission rates. Further input from the WRAP SSJF Projections Work Group and other stakeholders indicated that the retirement/replacement methodology used for other point sources was not appropriate for coal-fired EGUs (i.e., no coal-fired EGUs in the WRAP region are expected to retire by 2018). Therefore, no retirement/replacement effects were applied to the coal-fired EGUs in the inventory.

Table 8. Retirement and replacement SCCs, lifetimes, and retirement rates

Category	Applicable SCCs	Lifetime (years)	Annual Retirement Rate	Projection Retirement Rate
Utility Oil Boiler	101004xx, 101005xx, 10102101, 10101302	60	0.0167	0.2667
Utility Natural Gas Boilers	101006xx	60	0.0167	0.2667
Utility Renewable Boilers	10101501, 10101502, 10101801	60	0.0167	0.2667
Utility Oil Turbine	20100101, 20100108, 20100109, 20101302	30	0.0333	0.5333
Utility Natural Gas Turbine	20100201, 20100208, 20100209	30	0.0333	0.5333
Utility Cogeneration	10200219, 10200229, 10200307, 10200405, 10200505, 10200604, 10200710	45	0.0222	0.3556
Industrial Coal Boilers	102001xx, 102002xx, 102003xx, 10500102	45	0.0222	0.3556
Industrial Oil Boilers	102004xx, 102005xx, 10201302, 10500105, 10500113, 10500114	45	0.0222	0.3556
Industrial Natural Gas Boilers	102006xx, 10500106	30	0.0333	0.5333
Industrial Wood Boilers	102009xx	45	0.0222	0.3556
Industrial Oil Turbines	20200101, 20200103, 20200108, 20200109	30	0.0333	0.5333
Industrial Natural Gas Turbines	20200201, 20200203, 20200208, 20200209	30	0.0333	0.5333
Industrial IC Engines	All other 202002xx	30	0.0333	0.5333
Oil and Gas Production	310002xx	30	0.0333	0.5333
Cement Kilns	305006xx	32.5	0.0308	0.4923
Petroleum Refining	30600105, 30600201, 30600202	30	0.0333	0.5333

Other Point Source Projection Information Used to Develop the 2018b and PRP18 Emission Inventories

In addition to the application of post-2002 controls and growth factors in the steps described above, several other types of information were incorporated into WRAP's 2018 inventory. This information is described next.

BART and Presumptive BART Limits

One of the key elements of the work conducted in Phase 2 was to modify the 2018b inventory to reflect the impacts from implementation of best available retrofit technology (BART).

With assistance from WRAP staff, ERG collected information on specific BART limits for all sources subject to BART in CO, ND, and UT, as well as the Boardman facility in OR. These were used in place of the 2018 projections in the WRAP 2018 PRP inventory. The information related to BART limits is summarized in Table 9.

In addition to these specific BART limits, the presumptive limit of 0.15 lb of SO_2/MMBtu was applied to all coal-fired EGUs that have been determined to be either subject to BART (but for which a specific limit had not yet been determined) or eligible for BART, according to the WRAP's latest WRAP BART Clearinghouse.[10] The methodology used to estimate the annual SO_2 emissions based on the presumptive BART rate was to multiply the rate times the 2018 heat input (MMBtu) from U.S. EPA's CAMD database.[11] A summary of changes made as a result of applying presumptive BART limits is shown in Table 10.

Table 9. Summary of known BART limits for subject electric generating units

Facility Name and Unit	2018b Base Case		BART Limits		Changes Due to BART	
	NO_x (tpy)	SO_2 (tpy)	NO_x (tpy)	SO_2 (tpy)	NO_x (tpy)	SO_2 (tpy)
Colorado						
Colorado Springs Utilities – Nixon Unit 1	2,416	4,774	2,331	4,073	-85	-701
Colorado Springs Utilities – Drake Unit 5	838	1,581	752	1,464	-86	-117
Colorado Springs Utilities – Drake Unit 6	1,493	2,999	1,344	566	-149	-2,433
Colorado Springs Utilities – Drake Unit 7	1,918	3,991	2,412	941	+494	-3,050
Public Service – Valmont Unit 5	2,190	709	2,279	879	+89	+170
Public Service – Cherokee Unit 4	3,834	1,457	4,317	1,750	+483	+293
Public Service – Comanche Unit 1	3,090	1,858	2,317	1,856	-773	-2
Public Service – Comanche Unit 2	3,053	1,828	2,587	1,830	-466	+2
Public Service – Hayden Unit 1	4,083	1,234	3,819	1,265	-264	+31
Public Service – Hayden Unit 2	4,018	1,530	3,488	1,633	-530	+103
Public Service – Pawnee Unit 1	4,900	13,700	3,942	2,225	-958	-11,475
Tri-State Generation – Craig Unit 1	4,685	657	5,426	1,066	+741	+409
Tri-State Generation – Craig Unit 2	5,866	1,891	5,548	1,051	-318	-840
Trigen – Colorado Energy Corp Unit 4	464	452	508	733	+44	+281
Trigen Colorado Energy Corp Unit 5	776	987	677	1,891	-99	+904
				Change in CO Due to BART	**-1,877**	**-16,425**
North Dakota						
Coal Creek – Unit 143	5,186	14,706	4,285	3,781	-901	-10,925
Coal Creek – Unit 144	5,941	12,638	4,104	3,621	-1,837	-9,017
Leland Olds – Unit 121	2,811	17,322	2,661	3,578	-150	-13,744
Leland Olds – Unit 122	10,550	33,531	5,904	3,205	-4,646	-30,326
M.R. Young – Unit 152	9,071	19,997	3,857	2,571	-5,214	-17,426
M.R. Young – Unit 152	14,332	10,160	6,392	5,661	-7,940	-4,499
R.M. Heskett – Unit 154	945	2,754	858	1,660	-87	-1,094
Stanton – Unit 141	2,101	6,296	1,720	1,179	-381	-5,117
				Change in ND Due to BART	**-21,156**	**-92,148**
Oregon						
PGE Boardman	9,418	14,917	4,960	3,235	-4,458	-11,682
				Change in OR Due to BART	**-4,458**	**-11,682**
Utah						
Hunter – Unit 1	6,564	2,610	4,851	2,239	-1,713	-371
Hunter – Unit 2	6,430	2,477	4,734	2,185	-1,696	-292
Hunter – Unit 3	6,255	950	5,717	1,682	-538	+732
Huntington – Unit 1	5,757	2,693	4,445	2,052	-1,312	-641
Huntington – Unit 2	5,294	13,519	3,776	1,743	-1,518	-11,776
				Change in UT Due to BART	**-6,777**	**-12,348**
Overall Total Change Due to BART[a]					**-34,268**	**-132,603**

[c] PGE Boardman post-presumptive BART emissions were calculated by Oregon DEQ based on firing capacity of 5,793 MMBtu/hour and a capacity factor of 85%. Email from Mark Fisher, ODEQ to Paula Fields, ERG, April 13, 2007.

Table 10. Summary of presumptive SO_2 BART limits for subject and eligible coal-fired electric generating units in the WRAP region.

Facility Name and Unit	2018b Base Case (tons SO_2)[a]	Presumptive BART - Rate (lb/MMBtu)	2018 Heat Input (MMBtu)	Presumptive BART- Annual (tons SO_2)
Alaska – GVEA Healy Power Plant – Unit 1	366	0.15		140
Change in AK Due to Presumptive BART	**-226 tons SO_2**			
Arizona				
AZ Electric Power Cooperative, Inc. – Apache 2	1,439	0.15	15,248,939	1,144
AZ Electric Power Cooperative, Inc. – Apache 3	1,225	0.15	14,487,789	1,087
Coronado Generating Station – Unit 1B	6,449	0.15	28,551,063	2,141
Coronado Generating Station – Unit 2B	7,030	0.15	31,029,812	2,327
Irvington Generating Station – Unit 4	5,374	0.15	13,393,547	1,005
Change in AZ Due to Presumptive BART	**-13,813 tons SO_2**			
Montana				
Colstrip Steam Electric Station – Unit 1[b]	5,517	0.15	29,843,850	2,238
Colstrip Steam Electric Station – Unit 2[b]	5,640	0.15	29,276,157	2,196
PPL Montana – JE Corette Plant – Unit 2	3,757	0.15	14,895,194	1,160
Change in MT Due to Presumptive BART	**-9,320 tons SO_2**			
New Mexico				
San Juan Generating Station – Unit 1	2,630	0.15	26,974,922	2,023
San Juan Generating Station – Unit 2	2,677	0.15	27,460,582	2,060
San Juan Generating Station – Unit 3	4,288	0.15	43,863,371	3,290
San Juan Generating Station – Unit 4	4,444	0.15	45,582,346	3,419
Change in NM Due to Presumptive BART	**-3,247 tons SO_2**			
South Dakota -- Otter Tail Power Company	12,220	0.15	37,111,681	2,783
Change in SD Due to Presumptive BART	**-9,437 tons SO_2**			
Wyoming				
Basin Electric – Laramie River Station – Unit 1	4,043	0.15	48,061,878	3,605
Basin Electric – Laramie River Station – Unit 2	4,096	0.15	48,607,657	3,646
Basin Electric – Laramie River Station – Unit 3	3,789	0.15	44,354,715	3,327
Pacificorp – Dave Johnston – Unit 4	8,555	0.22[c]	19,819,756	2,180
Pacificorp – Dave Johnston – Unit 2	4,250	0.15[c]	30,030,412	2,252
Pacificorp – Jim Bridger – Unit 1	7,069	0.15[c]	45,621,694	3,422
Pacificorp – Jim Bridger – Unit 2	6,906	0.15[c]	43,634,528	3,273
Pacificorp – Jim Bridger – Unit 3	6,537	0.15[c]	46,238,491	3,468
Pacificorp – Jim Bridger – Unit 4	4,107	0.15[c]	45,075,468	3,381
Pacificorp – Naughton Power Plant – Unit 1	6,518	0.41[c]	12,813,313	2,627
Pacificorp – Naughton Power Plant – Unit 2	8,694	0.41[c]	16,715,747	3,427
Pacificorp – Naughton Power Plant – Unit 3	5,980	0.21[c]	28,425,577	2,985
Pacificorp – Wyodak – Unit 1	8,281	0.32[c]	35,685,720	5,710
Change in WY Due to Presumptive BART	**-35,522 tons SO_2**			
EPA Sources on Navajo Tribal Land located in New Mexico				
Four Corners Power Plant – Unit 1	1,385	0.21[d]	14,846,431	1,559
Four Corners Power Plant – Unit 2	1,687	0.21[d]	16,632,804	1,746
Four Corners Power Plant – Unit 3	2,122	0.21[d]	19,873,582	2,087
Four Corners Power Plant – Unit 4	8,509	0.21[d]	57,929,739	6,083
Four Corners Power Plant – Unit 5	9,729	0.21[d]	56,778,871	5,962
Change on Navajo Tribal Land Due to SO_2 Control Levels Proposed by EPA	**-5,995 tons SO_2**			
Overall Total Change Due to Presumptive BART	**-77,560 tons SO_2[e]**			

[a] 2018-18b emissions are based on 2004 heat input data from CAMD.

[b] Colstrip Units 1 and 2 fire on both coal and petroleum coke. The BART limit was applied to the combined heat input for 2018 and will be applied across both SCCs based on a percentage of the 2018-18b emissions.

[c] Pacificorp unit emission rates are from BART control analysis performed by Pacificorp.

[d] Emission rate is based on current U.S. EPA proposal for APS Four Corners. http://www.epa.gov/fedrgstr/EPA-AIR/2006/September/Day-12/a15097.pdf

[e] Totals may not equal sum of columns due to rounding.

Several EGUs either have permit limits below the presumptive SO_2 BART limit, or they operated below the presumptive BART level in 2006. Therefore, no presumptive SO_2 BART reductions were applied for the 2018 PRP inventory for these BART subject or eligible sources:

- Cholla Power Plant (AZ) Units 1-4
- Navajo Generating Station (U.S. EPA source on Navajo Tribal land, located in northern AZ) Units 1-3
- Reid Gardner (NV) Units 1-3
- Mohave Power Plant (NV) Units 1-2
- TransAlta Centralia Units (WA) BW21 and BW22

Non-EGU SO_2 Changes in §309 states

A study was conducted for the WRAP SSJF in 2006 by Pechan to update the 2018 SO_2 emission projections (originally estimated by ERG and ENVIRON) for purposes of establishing SO_2 milestones for the 309 State Regional Haze State Implementation Plans.[11] The focus of that project was to update some of the projected 2018 version 1 emissions estimates for non-utility sources emitting more than 100 tons of SO_2 in the five milestone states (AZ, NM, UT, and WY). (Note that changes by Pechan to sources in OR were made as part of this project, although OR is no longer a §309 state.) The Pechan project resulted in revised 2018 SO_2 emissions from these industries: copper smelters, lime manufacturing, pulp and paper, oil and gas, chemical manufacturing, petroleum refining, and cement production.

For the WRAP PRP18 inventory, ERG summarized the changes from the Pechan report by state, distributed these to the applicable S/L/T agencies as part of the collection of comments process described above, and requested that each agency confirm these changes. Also, ERG obtained SCC level changes from Pechan, in order to make the detailed changes at the SCC level for this WRAP PRP18 inventory project.

RESULTS

The summary results of the PRP18 emissions inventory are presented in Table 11 (point sources) and Table 12 (area sources). The summary results of the 2018b base case emissions inventory are also shown in Table 11 and 12, along with changes from Phase 2 of this project. The resulting changes between the 2018 base case emissions inventory and the PRP18 emissions inventory are also graphically shown for NO_x, SO_2, and PM_{10} in Figures 3 and 4. From Figure 3, it is clear that the most significant point source changes are for SO_2 emissions. Likewise, from Figure 4, it is shown that the most significant area source changes are for NO_x emissions.

Table 11. Summary of draft 2018b base case emissions inventory, net changes made by state and resulting WRAP PRP18 emissions inventory – point sources (tons per year)

State	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	NH_3
WRAP 2018b Base Case Emissions Inventory (TPY):							
AK	67,959.43	7,781.59	6,637.31	25,881.08	2,884.91	357.32	1,103.95
AZ	77,738.22	94,407.68	9,466.23	33,242.90	9,893.22	1,644.24	729.29
CA	109,514.89	49,631.75	54,631.70	123,795.15	33,191.68	19,496.84	
CO	112,239.70	69,213.14	98,629.89	58,211.27	28,697.25	306.79	623.03
ID	14,048.16	25,467.31	3,060.02	38,019.05	1,741.19	643.01	1,649.87
MT	62,583.10	45,321.07	10,445.96	62,353.62	11,266.02	691.74	421.68
ND	92,097.99	162,704.76	2,493.21	22,589.46	4,369.38	3,051.53	522.95
NM	74,874.05	41,392.29	26,187.38	57,506.25	3,391.82	1,749.33	123.26
NV	69,016.45	24,040.65	4,112.87	20,745.67	6,200.35	1,534.57	1,172.78
OR	31,760.79	21,686.48	41,168.92	53,654.91	13,517.81	16,659.86	1,016.13
SD	24,725.86	15,268.20	3,522.79	6,858.87	1,044.86	256.93	101.60
UT	96,974.44	52,952.88	13,599.53	98,373.32	18,381.76	5,812.25	2,081.94
WA	49,396.97	51,355.44	28,013.12	187,705.34	12,096.19	4,676.22	5,495.06
WY	132,115.76	145,099.58	27,541.60	60,503.77	42,819.39	19,495.90	810.87
Tribal	92,580.06	32,894.77	2,864.32	12,987.96	7,748.84	3,206.27	125.44
Net Changes to 2018b Base Case Emissions Inventory (TPY):							
AK		-226.34			-1,118.54		
AZ	-4,666.91	-24,070.72	211.84	796.24	984.32	44.41	23.80
CA							
CO	1,120.93	-12,234.64	-21,100.97	5,782.57	-401.45	-211.29	-85.85
ID	-1,675.35	-15,522.06	-41.37	-2,792.25	-335.07	-87.42	-31.09
MT	-217.91	-8,840.88	55.17	1,000.74	-131.79	-246.52	
ND	-21,041.97	-95,626.23	1.79	-1,593.89	1,020.96	-262.26	-61.07
NM	-273.61	-9,011.88	-0.04	-130.31	-74.46	-87.43	-4.94
NV	-1,391.45	4,126.30	-247.12	6,968.94	-164.13	1,058.37	-308.31
OR	-6,813.49	-13,734.49	-530.41	-3,502.51	-433.54	-15,377.31	-184.31
SD	1.00	-9,433.88		0.00			
UT	-17,213.16	-15,014.36	-406.18	-1,920.34	-2,903.88	-1,311.37	-31.44
WA	59.34	-13,911.46	-1,801.03	-80,108.37	-2,370.47	-289.69	-29.27
WY	1,099.95	-49,955.64	728.59	4,278.61	19.80	-328.70	0.00
Tribal	7,922.92	-4,495.17	317.51	572.15	1,293.29	536.03	31.44
WRAP PRP18 Emissions Inventory (TPY):							
AK	67,959.43	7,555.25	6,637.31	25,881.08	1,766.37	357.32	1,103.95
AZ	73,071.31	70,336.96	9,678.07	34,039.14	10,877.54	1,688.65	753.09
CA	109,514.89	49,631.75	54,631.70	123,795.15	33,191.68	19,496.84	

Table 11. Continued

State	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	NH_3
CO	113,360.63	56,978.50	77,528.92	63,993.84	28,295.80	95.50	537.19
ID	12,372.81	9,945.25	3,018.65	35,226.80	1,406.12	555.59	1,618.78
MT	62,365.19	36,480.19	10,501.13	63,354.36	11,134.23	445.22	421.68
ND	71,056.02	67,078.53	2,495.01	20,995.57	5,390.34	2,789.28	461.88
NM	74,600.43	32,380.40	26,187.34	57,375.95	3,317.36	1,661.90	118.32
NV	67,625.00	28,166.95	3,865.76	27,714.61	6,036.22	2,592.94	864.46
OR	24,947.30	7,951.99	40,638.51	50,152.40	13,084.26	1,282.55	831.82
SD	24,726.86	5,834.32	3,522.79	6,858.87	1,044.86	256.93	101.60
UT	79,761.28	37,938.52	13,193.35	96,452.98	15,477.88	4,500.88	2,050.49
WA	49,456.32	37,443.99	26,212.09	107,596.98	9,725.72	4,386.52	5,465.79
WY	133,215.71	95,143.95	28,270.19	64,782.38	42,839.19	19,167.21	810.86
Tribal	100,502.99	28,399.61	3,181.83	13,560.10	9,042.14	3,742.30	156.88

Table 12. Summary of draft 2018b base case emissions inventory, net changes made by state and resulting WRAP PRP18 emissions inventory – area sources (tons per year)

State	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	NH_3
WRAP 2018b Base Case Emissions Inventory							
AK	9,293.35	6,043.71	16,539.14	29,055.82	21,531.05	6,877.71	639.23
AZ	12,558.62	3,410.26	171,414.85	70,097.25	137,883.20	39,332.92	9,457.14
CA	117,716.62	9,772.22	357,745.55	384,966.70	190,987.09	84,801.21	
CO	44,040.52	7,498.70	173,092.43	94,594.76	185,238.34	48,422.51	96.76
ID	42,067.89	2,720.52	194,210.06	40,971.48	62,880.57	7,702.74	2,288.40
MT	36,052.99	3,432.14	67,476.71	41,415.20	173,892.25	40,015.47	607.92
ND	21,128.65	5,856.27	82,650.71	21,606.83	311,272.53	64,978.37	462.99
NM	172,318.92	15,753.24	399,205.01	47,997.02	144,289.23	34,664.44	909.55
NV	7,487.60	14,194.42	47,609.85	17,479.33	97,755.67	23,312.88	1,645.65
OR	17,027.19	8,421.88	334,872.12	380,523.74	225,924.68	81,744.55	249.80
SD	7,206.93	11,667.18	50,072.09	25,112.44	226,750.11	48,648.35	502.02
UT	21,635.69	3,586.90	173,344.04	45,962.17	34,279.28	5,760.83	1,679.83
WA	22,745.95	8,667.27	253,709.83	252,446.63	348,329.35	113,984.70	7,021.73
WY	79,196.38	23,109.16	436,884.86	34,463.27	45,027.21	12,435.80	514.06
Tribal	6,639.04	2.08	18,240.28	563.99	2,062.46	412.22	0.07
Net Changes to 2018b Base Case Emissions Inventory							
AK	-566.98	-1.30	-91.90	-0.47			
AZ	224.89	-2.05	-505.80	7,865.47	-1,122.85	291.70	
CA							
CO	-27,617.20	-8.48	-36,938.50	-4,961.40			
ID		332.78					
MT	-30,491.27	-8.03	-7,517.34	-1,636.50			
ND	-8,620.46	-2.75	-13,003.22	-132.08			
NM	-138,346.67	-16.49	-327,913.29	-5,934.23	-2,689.07	-926.96	
NV	-72.09	-0.04	5,407.50	-1.44			
OR	-48.18		-19.37	-1.39			
SD	-2,759.18	-7,582.81	-394.53	-1,041.42	-2,673.97	-491.15	-6.23
UT	-13,153.59	-4.65	-95,061.48	-1,349.88			
WA							
WY	-59,439.61	-15.61	-403,798.30	-3,962.23			
Tribal							
WRAP PRP18 Emissions Inventory							
AK	8,726.37	6,042.41	16,447.24	29,055.35	21,531.05	6,877.71	639.23
AZ	12,783.50	3,408.20	170,909.05	77,962.72	136,760.35	39,624.62	9,457.14
CA	117,716.62	9,772.22	357,745.55	384,966.70	190,987.09	84,801.21	
CO	16,423.32	7,490.22	136,153.94	89,633.36	185,238.34	48,422.51	96.76

Table 12. Continued

State	NO_x	SO_2	VOC	CO	PM_{10}	$PM_{2.5}$	NH_3
ID	42,067.89	3,053.31	194,210.06	40,971.48	62,880.57	7,702.74	2,288.40
MT	5,561.72	3,424.11	59,959.38	39,778.71	173,892.25	40,015.47	607.92
ND	12,508.19	5,853.53	69,647.48	21,474.75	311,272.53	64,978.37	462.99
NM	33,972.25	15,736.76	71,291.71	42,062.80	141,600.16	33,737.48	909.55
NV	7,415.51	14,194.38	53,017.35	17,477.89	97,755.67	23,312.88	1,645.65
OR	16,979.01	8,421.88	334,852.75	380,522.35	225,924.68	81,744.55	249.80
SD	4,447.75	4,084.37	49,677.55	24,071.02	224,076.14	48,157.20	495.80
UT	8,482.11	3,582.25	78,282.56	44,612.29	34,279.28	5,760.83	1,679.83
WA	22,745.95	8,667.27	253,709.83	252,446.63	348,329.35	113,984.70	7,021.73
WY	19,756.77	23,093.55	33,086.56	30,501.05	45,027.21	12,435.80	514.06
Tribal	6,639.04	2.08	18,240.28	563.99	2,062.46	412.22	0.07

Figure 3. Emissions projection changes between 2018b inventory and PRP18 inventory - point sources

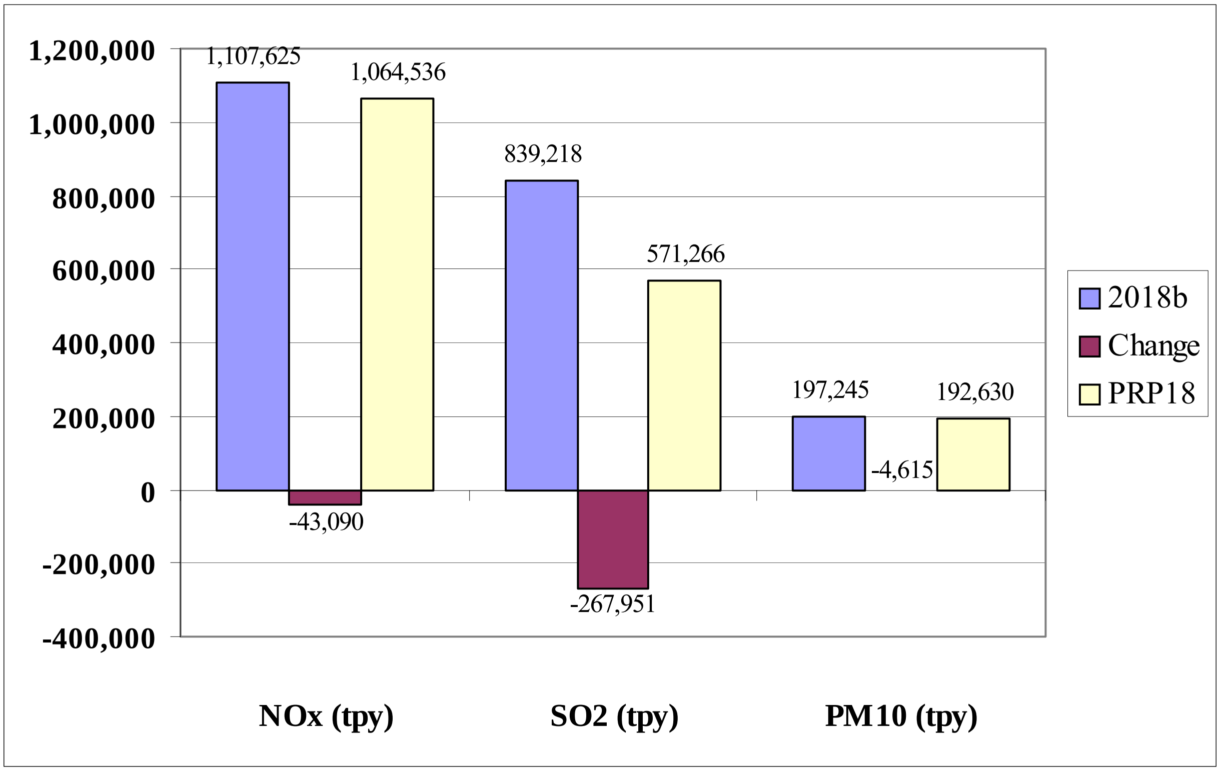


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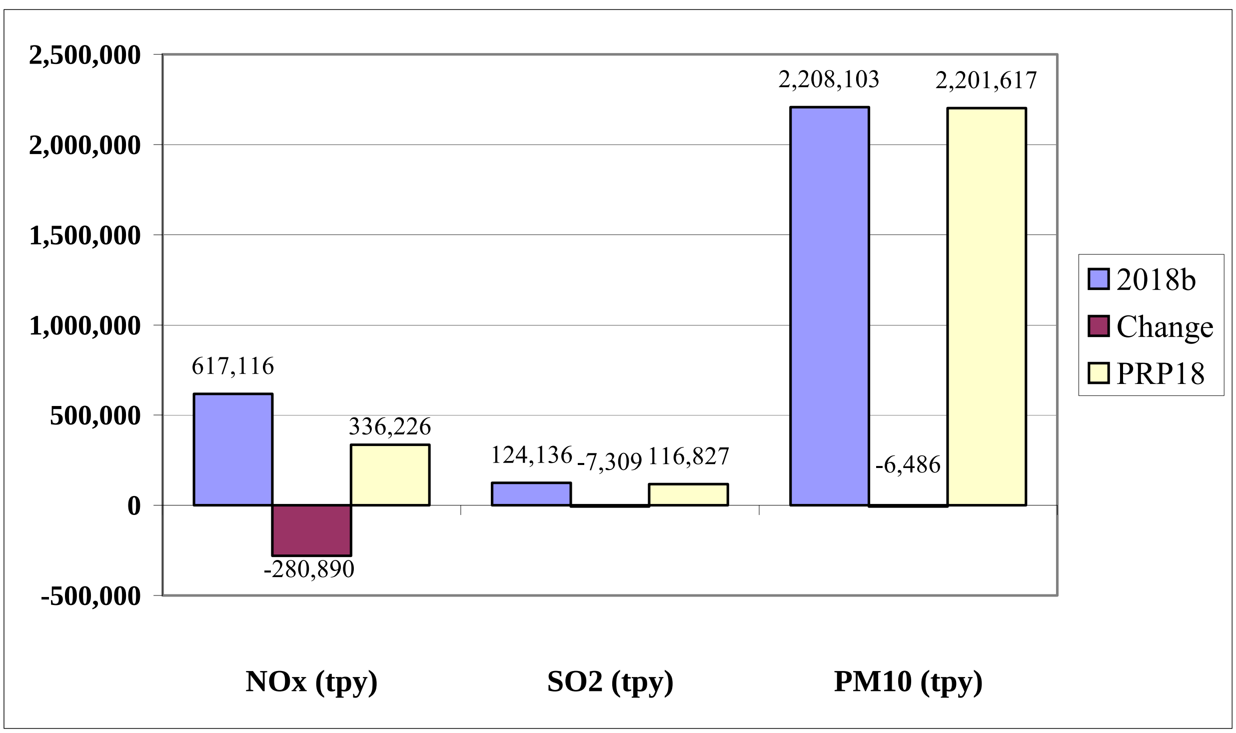
Figure 4. Emissions projection changes between 2018b inventory and PRP inventory - area sources



NEXT STEPS

The next steps in finalizing the PRP18 inventory include incorporating comments received from the S/L/T agencies on the draft PRP18, which is currently in process. Then, the final SMOKE/IDA files will be developed and submitted to the WRAP RMC. Next, new pivot tables in Microsoft Excel will be developed and posted on the WRAP Web site for access by the S/L/T agencies during their visibility SIP development process in the coming year.

Finally, NIF files will be developed for the PRP18 and for a revised 2002 inventory. The NIF files will be uploaded to the WRAP EDMS for easy on-line access.

The WRAP plans to complete two additional regional emissions and modeling analyses to support Western haze planning in late 2007 or early 2008. A final baseline period (2000-04) emissions and modeling analysis will be conducted in conjunction with a final Reasonable Progress (2018) emissions and modeling analysis. The final baseline period analyses will have a limited focus, on correcting inventory errors that affect the Reasonable Progress demonstration, as the inventory from that time period will have been supplanted by more recent and complete data. The associated final 2018 Reasonable Progress analysis will be completed when the 13 contiguous WRAP states and U.S. EPA are able to provide their permitted emission limits for sources subject to BART requirements. Other remaining 2018 inventory projection corrections will also be applied in those analyses. These final analyses for regional haze planning in the West will conducted simultaneously.

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KEY WORDS

Projections
WRAP
Modeling inventory
Point sources
Area sources