Regulatory Impact Analysis for the Proposed Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone National Ambient Air Quality Standards (NAAQS)

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Regulatory Impact Analysis for the Proposed Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone National Ambient Air Quality Standards (NAAQS)

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GLOSSARY OF TERMS AND ABBREVIATIONS

The following are abbreviations of terms used in this Regulatory Impact Analysis.

CAA or Act	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMx	Comprehensive Air Quality Model with Extensions
CBI	Confidential Business Information
CEM	Continuous Emissions Monitoring
CSAPR	Cross-State Air Pollution Rule
EGU	Electric Generating Unit
FIP	Federal Implementation Plan
FR	Federal Register
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse Gas
GW	Gigawatts
ICR	Information Collection Request
IPM	Integrated Planning Model
km	Kilometer
lb/mmBtu	Pounds per Million British Thermal Unit
LNB	Low-NO_x Burners
NAAQS	National Ambient Air Quality Standard
NBP	NO_X Budget Trading Program
NEI	National Emission Inventory
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standard
OFA	Overfire Air
$PM_{2.5}$	Fine Particulate Matter
ppb	Parts Per Billion
RIA	Regulatory Impact Analysis
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan

SMOKE	Sparse Matrix Operator Kernel Emissions
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
TIP	Tribal Implementation Plan
TPY	Tons Per Year
TSD	Technical Support Document

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EXECUTIVE SUMMARY

Overview

The primary purpose of the proposed rule is to address interstate air quality impacts with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS). The EPA promulgated the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011,[1] to address interstate transport of ozone pollution under the 1997 ozone NAAQS.[2] The proposed rule would update CSAPR to address interstate emissions transport of nitrogen oxides (NO_X) that contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states. The proposed rule also responds to the D.C. Circuit's July 28, 2015 remand of certain CSAPR ozone season NO_X emissions budgets to the EPA for reconsideration. This Regulatory Impact Analysis (RIA) presents the health and welfare benefits and climate co-benefits of the proposal to update CSAPR, and compares the benefits to the estimated costs of implementing the proposed rule for the 2017 analysis year. This RIA also reports certain impacts of the proposed rule such as its effect on employment and energy prices. This executive summary both explains the analytic approach taken in the RIA and summarizes the RIA results.

ES.1 Identifying Required Emissions Reductions

As described in the preamble for the proposal, CSAPR provides a 4-step process to address the requirements of CAA section 110(a)(2)(D)(i)(I) (sometimes called the "good neighbor provision") for ozone or fine particulate matter ($PM_{2.5}$) standards: (1) identifying downwind receptors that are expected to have problems attaining or maintaining clean air standards (i.e., NAAQS); (2) determining which upwind states contribute to these identified problems in amounts sufficient to "link" them to the downwind air quality problems; (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of a standard by

[1] *See* 76 FR 48208 (July 6, 2011)

[2] CSAPR also addressed interstate transport of fine particulate matter ($PM_{2.5}$) under the 1997 and 2006 $PM_{2.5}$ NAAQS.

quantifying available upwind emission reductions and apportioning upwind responsibility among linked states; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, reducing the identified upwind emissions via regional emissions allowance trading programs. This action proposes to apply this 4-step process to update CSAPR with respect to the 2008 ozone NAAQS. The reductions required by the proposed rule would be achieved through a federal implementation plan (FIP) for any state that does not have an approved state implementation plan (SIP) addressing its contribution by the date this rule is finalized. Furthermore, under the FIPs, affected EGUs would participate in the CSAPR NO_X ozone-season allowance trading program. More details on the methods and results of applying this process can be found in the preamble for this proposal, and in Chapter 4 of this RIA.

Application of the first two steps of this process with respect to the 2008 ozone NAAQS provides the analytic basis for proposing that ozone season emissions in 23 eastern states[3] affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS. Figure ES-1 shows the affected states.

[3] Alabama, Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

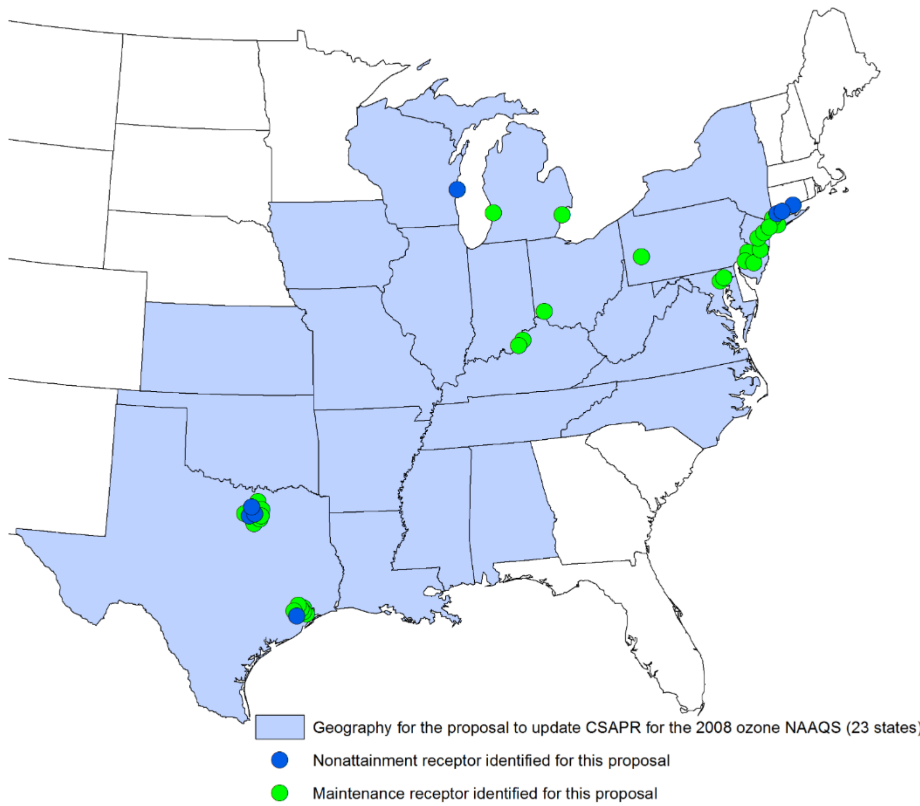

Figure ES-1. Nonattainment and Maintenance Receptors Identified for this Proposal and Upwind States Linked to these Downwind Air Quality Problems with Respect to the 2008 Ozone NAAQS

Applying Step 3 of this process, this action proposes to quantify electric generating unit (EGU) NO_X reductions in these 23 eastern states and to update CSAPR ozone season NO_X emissions budgets. A state's updated CSAPR ozone season NO_X emissions budget is the quantity of EGU NO_X emissions that would remain after reducing significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS in an average year.[4] These updated CSAPR NO_X budgets were developed considering EGU NO_X reductions that are achievable for the 2017 ozone season.[5] The EPA applied a multi-factor test in step 3 to evaluate EGU NO_X reduction potential for 2017 and is proposing to quantify EGU NO_X ozone-

[4] For example, assuming no abnormal variation in electricity supply due to events such as abnormal meteorology.

[5] Non-EGU NOx emission control measures and reductions are not included in this proposal. More information on non-EGU NOx control measures and the potential for emission reductions can be found in the Non-EGU TSD on Emissions and Potential Reductions in 2017, which can be found in the docket for this proposal: EPA-HQ-OAR-2015-0500.

season emissions budgets reflecting EGU NO_X reduction strategies that are widely available at a uniform annualized cost of $1,300 per ton (2011$). This assessment revealed that there is significant EGU NO_X reduction potential that can be achieved by 2017, which would make meaningful and timely improvements in ozone air quality. Applying Step 4 of this process, the EPA is proposing to implement these EGU NO_X emissions budgets through the CSAPR NO_X ozone-season allowance trading program.

For the RIA, in order to implement the OMB Circular A-4 requirement to assess one less stringent and one more stringent alternative to the proposal, the EPA is also analyzing EGU NO_X ozone season emissions budgets reflecting NO_X reduction strategies that are widely available at a uniform cost of $500 per ton (2011$) and strategies that are widely available at a uniform cost of $3,400 per ton (2011$). The EPA applies these alternative uniform costs for quantifying EGU NO_X ozone-season emissions budgets in Step 3 of the 4-step process.

ES.2 Baseline and Analysis Year

The proposal sets forth the requirements for states to reduce their significant contribution to downwind nonattainment or interference with maintenance of the 2008 ozone NAAQS. To evaluate the benefits and costs of this regulation, it is important to first establish a baseline projection of both emissions and air quality in the analysis year of 2017, taking into account currently on-the-books Federal regulations, substantial Federal regulatory proposals, enforcement actions, state regulations, population, and where possible, economic growth. Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by the proposal.

Below is a list of some of the national rules reflected in the baseline. For a more complete list of the rules reflected in the air quality modeling, please see the Technical Support Document: Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform (U.S. EPA, 2015).[6] For a list of those regulations reflected in the compliance and cost modeling

[6] U.S. Environmental Protection Agency, 2015. Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform, Research Triangle Park, NC, (http://www.epa.gov/ttn/chief/emch/2011v6/2011v6_2_2017_2025_EmisMod_TSD_aug2015.pdf).

of the electricity sector, please see "EPA Base Case v.5.15 Using IPM Incremental Documentation" August, 2015.[7]

- Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Final Rule) (U.S. EPA, 2015)
- Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units (Final Rule) (U.S. EPA, 2015a)
- Tier 3 Motor Vehicle Emission and Fuel Standards (U.S. EPA, 2014)
- 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards (U.S. EPA, 2012)
- Cross State Air Pollution Rule (CSAPR) (U.S. EPA, 2011)[8]
- Mercury and Air Toxics Standards (MATS) (U.S. EPA, 2011a)[9]
- Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (U.S. EPA, 2011b)[10]
- C3 Oceangoing Vessels (U.S. EPA, 2010)
- Reciprocating Internal Combustion Engines (RICE) NESHAPs (U.S. EPA, 2010a)
- Regulation of Fuels and Fuel Additives: Modifications to Renewable Fuel Standard Program (RFS2) (U.S. EPA, 2010b)
- Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule for Model-Year 2012-2016 (U.S. EPA, 2010c)

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[7] http://www.epa.gov/powersectormodeling/

[8] On July 28, 2015, the D.C. Circuit issued its opinion regarding CSAPR on remand from the Supreme Court, *EME Homer City Generation, L.P., v. EPA*, No. 795 F.3d 118, 129-30, 138 (*EME Homer City II*). The court largely upheld CSAPR, but remanded to EPA without vacatur certain states' phase 2 emissions budgets for reconsideration. Compliance with these remanded emissions budgets was included in the baseline modeling for this proposal, which was already underway when this opinion was issued.

[9] On June 29, 2015, the United States Supreme Court reversed the D.C. Circuit opinion affirming the MATS. The EPA is reviewing the decision and will determine any appropriate next steps once the review is complete. MATS is included in the baseline for this analysis, and the EPA does not believe including MATS substantially alters the results of this analysis, because MATS was remanded, not vacated.

[10] This rule is Phase 1 of the Heavy Duty Greenhouse Gas Standards for New Vehicles and Engines (76 FR 57106, September 15, 2011). Phase 2 of the Heavy Duty Greenhouse Gas Standards for New Vehicles and Engines (80 FR 40138, July 13, 2015) is not included because the rulemaking was not finalized in time to include in this analysis.

- Hospital/Medical/Infectious Waste Incinerators: New Source Performance Standards and Emission Guidelines: Final Rule Amendments (U.S. EPA, 2009)
- Emissions Standards for Locomotives and Marine Compression-Ignition Engines (U.S. EPA, 2008a)
- Control of Emissions for Nonroad Spark Ignition Engines and Equipment (U.S. EPA, 2008b)
- NO_x Emission Standard for New Commercial Aircraft Engines (U.S. EPA, 2005)
- Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations (U.S. EPA, 2005a)

ES.3 Control Strategies and Emissions Reductions

The proposal requires EGUs in 23 eastern states to reduce interstate transport of NO_X emissions that significantly contribute to nonattainment or interfere with maintenance of the 2008 ozone NAAQS. The proposal sets EGU ozone season NO_X emissions budgets (allowable emission levels) for 2017 and future years. The proposal would implement these reductions through FIPs in any state that does not have an approved good neighbor SIP by the date this rule is finalized. Furthermore, under the FIPs, affected EGUs would participate in the CSAPR NO_X ozone-season allowance trading program. The allowance trading program is the remedy in the FIP that achieves the ozone season NO_X emissions reductions required by the proposed rule. The allowance trading program essentially converts the EGU NO_X emissions budget for each of the 23 states subject to the FIP into a limited number of NO_X ozone-season allowances that, on a tonnage basis, equal the state's ozone season emissions budget.

The EGU ozone season NO_X budgets for each state reflect EGU NO_X reduction strategies that are widely available at a uniform cost of $1,300 per ton of NO_X for affected EGUs. Specifically, this uniform cost reflects turning on idled selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR) and upgrading combustion controls. Furthermore, this RIA analyzes regulatory control alternatives based on more and less stringent state emissions budgets based on uniform NO_X control costs of $3,400 per ton and $500 per ton, respectively.

Table ES-1 show the emission reductions expected from the proposal and the more and less stringent alternatives analyzed. Included in the table are annual and seasonal NO_X, sulfur dioxide (SO_2), and carbon dioxide (CO_2) reductions over the contiguous U.S.

Table ES-1. Projected 2017* EGU Emissions Reductions of NO_X, SO_2, and CO_2 with the Proposed NO_X Emissions Budgets and More and Less Stringent Alternatives (Tons)**

	Proposal	More Stringent Alternative	Less Stringent Alternative
NO_X (annual)	90,000	93,000	24,000
NO_X (ozone season)	85,000	87,000	24,000
SO_2 (annual)	1,200	1,200	1,100
CO_2 (annual)	660,000	710,000	770,000

* The forecast of annual reductions of co-pollutants in 2017 is based on 2018 IPM direct model outputs.
** NO_x and SO_2 emissions are reported in English (short) tons; CO_2 is reported in metric tons. All estimates rounded to two significant figures.

ES.4 Costs

The EPA analyzed ozone-season NO_X emissions reductions, as well as the associated compliance costs of the power sector of implementing the EGU NO_X ozone-season emissions budgets in each of the 23 states, using the Integrated Planning Model (IPM) and its underlying data and inputs. All EGU emissions reduction estimates are taken directly from IPM modeling results. We use the compliance cost estimate from IPM as a proxy for social costs. As currently configured, IPM directly estimates the costs for two of the NO_X reduction strategies: turning on idled existing SCRs and SNCRs, and shifting generation to lower-NO_X emitting EGUs. The costs of other mitigation measures, which are optimizing existing operating SCR or SNCR and installing or upgrading NO_X combustion controls, are estimated outside of IPM but are calculated using IPM inputs.

One additional aspect of the analysis conducted using IPM is that the existing but idle SCRs or SNCRs in the model baseline are required to be turned on and fully utilized in the model for compliance with the emissions budgets. For the proposal, the EPA estimates that, given the characteristics of these units and the average cost per ton of NO_X reduced to comply with the proposed emissions budgets, turning on the existing but idle SCRs is a reasonable and cost-effective compliance method to evaluate for this RIA.

The estimate of the cost of this proposal, therefore, is the combination of NO_x costs estimated by IPM and additional costs estimated outside of IPM. The cost estimates for the proposal and more and less stringent alternatives are presented in Table ES-2.[11] All costs are in 2011 dollars.

Table ES-2. Cost Estimates (2011$) for Proposal and More and Less Stringent Alternatives

Policy	Annualized*
Proposal	$93,000,000
More Stringent Alternative	$96,000,000
Less Stringent Alternative	$4,700,000

*Costs are annualized over the period 2016 through 2040 using the 4.77 percent discount rate used in IPM's objective function for minimizing the net present value of the stream of total costs of electricity generation.

ES.5 Benefits to Human Health and Welfare

Implementing this proposal to update CSAPR is expected to reduce emissions of ozone season NO_X. In the presence of sunlight, NO_X and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions also reduces human exposure to ozone and the incidence of ozone-related health effects, though this also depends partly on local levels of volatile organic compounds (VOCs). In addition, implementing the proposal would reduce emissions of NO_X throughout the year. Because NO_X is also a precursor to formation of ambient $PM_{2.5}$, reducing these emissions would also reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-related health effects. Finally, these emissions reductions would lower ozone and $PM_{2.5}$ concentrations in regions beyond those subject to this proposal, and the RIA accounts for those additional benefits.

Based on the IPM modeling results, the EPA does not expect this proposal to significantly change annual power sector emissions of SO_2, which is also a $PM_{2.5}$ precursor. Accordingly, this RIA does not quantify SO_2-related $PM_{2.5}$ co-benefits. Additionally, although we do not have sufficient data to quantify these impacts in this analysis, reducing emissions of NO_X would also reduce ambient exposure to nitrogen dioxide (NO_2) and its associated health effects.

[11] It should be noted that the costs associated with implementation of monitoring, recordkeeping, and reports requirements are not included within the estimates in this table. Such costs, which are estimated separately from the approaches listed above and are found in Chapter 7, are actually negative on net but are very small compared to the magnitude of the costs in Table ES-2.

In this section, we provide an overview of the monetized ozone benefits and $PM_{2.5}$-related co-benefits estimated from NO_X reductions for compliance with the proposed CSAPR EGU NO_X ozone season emissions budgets and for the more and less stringent alternatives. A full description of the underlying data, studies, and assumptions is provided in the PM NAAQS RIA (U.S. EPA, 2012a) and Ozone NAAQS RIA (U.S. EPA, 2015).

ES.5.1 Human Health Benefits and Climate Co-benefits

We follow a "damage-function" approach in calculating benefits, which estimates changes in individual health endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the values for those individual endpoints. Because the EPA rarely has the time or resources to perform new research to measure directly either health outcomes or their values for regulatory analyses, our estimates are based on the best available methods of benefits transfer, which is the science and art of adapting primary research from similar contexts to estimate benefits for the environmental quality change under analysis. In addition to transferring information from other contexts to the context of this regulation, we also use a "benefit-per-ton" approach to estimate the ozone and $PM_{2.5}$ benefits in this RIA. Benefit-per-ton approaches apply an average benefit-per-ton derived from modeling of benefits of specific air quality scenarios to estimates of emissions reductions for scenarios where no air quality modeling is available. More information on these approaches is available in Chapter 6 of the RIA. Thus, to develop estimates of benefits for this RIA, we are transferring both the underlying health and economic information from previous studies and information on air quality responses to emissions reductions from other air quality modeling.

The benefit-per-ton approach we use in this RIA relies on estimates of human health responses to exposure to ozone and PM obtained from the peer-reviewed scientific literature. These estimates are used in conjunction with population data, baseline health information, air quality data and economic valuation information to conduct health impact and economic benefits assessments. These assessments form the key inputs to calculating benefit-per-ton estimates.

The Health Impact Assessment (HIA) for ozone and $PM_{2.5}$, discussed further in Chapter 6 of this RIA, quantifies the changes in the incidence of adverse health impacts resulting from changes in human exposure to ozone and $PM_{2.5}$. We use the environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE) (version 1.1) to systematize health impact analyses by applying a database of key input parameters, including population projections, health impact functions, and valuation functions (Abt Associates, 2012). For this assessment, the HIA is limited to those health effects that are directly linked to ambient ozone and $PM_{2.5}$ concentrations. Table ES-3 provides national summaries of the reductions in estimated health incidences associated with the proposed CSAPR EGU NO_x ozone-season emissions budgets and for more and less stringent alternatives for 2017.

Table ES-3. Summary of Avoided Health Incidences from Ozone-Related and $PM_{2.5}$-Related Benefits from NO_X reductions for the Proposal for 2017*

Ozone-related Health Effects	Proposal	More Stringent Alternative	Less Stringent Alternative
Avoided Premature Mortality			
Smith *et al.* (2009) (all ages)	48	50	14
Zanobetti and Schwartz (2008) (all ages)	81	83	23
Avoided Morbidity			
Hospital admissions—respiratory causes (ages > 65)	79	81	22
Emergency room visits for asthma (all ages)	320	330	90
Asthma exacerbation (ages 6-18)	93,000	95,000	26,000
Minor restricted-activity days (ages 18-65)	240,000	240,000	67,000
School loss days (ages 5-17)	77,000	79,000	22,000
$PM_{2.5}$-related Health Effects			
Avoided Premature Mortality			
Krewski *et al.* (2009) (adult)	21	22	5.6
Lepeule *et al.* (2012) (adult)	48	50	13
Woodruff *et al.* (1997) (infant)	<1	<1	<1
Avoided Morbidity			
Emergency department visits for asthma (all ages)	12	12	3.1
Acute bronchitis (age 8–12)	31	32	8.1
Lower respiratory symptoms (age 7–14)	390	400	100
Upper respiratory symptoms (asthmatics age 9–11)	560	580	150
Minor restricted-activity days (age 18–65)	16,000	16,000	4,200
Lost work days (age 18–65)	2,700	2,700	700
Asthma exacerbation (age 6–18)	580	600	150
Hospital admissions—respiratory (all ages)	6	7	2
Hospital admissions—cardiovascular (age > 18)	8	8	2
Non-Fatal Heart Attacks (age >18)			
Peters *et al.* (2001)	26	25	7
Pooled estimate of 4 studies	3	3	1

* All estimates are rounded to whole numbers with two significant figures. Co-benefits for $PM_{2.5}$ are based on ozone season NO_X emissions. Confidence intervals are unavailable for this analysis because of the incidence-per-ton methodology. In general, the 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski *et al.* (2009) and ±46 percent based on Lepeule *et al.* (2012).

There may be other indirect health impacts associated with reducing emissions, such as occupational health exposures. Epidemiological studies generally provide estimates of the relative risks of a particular health effect for a given increment of air pollution (often per 10 ppb for ozone or $\mu g/m^3$ for $PM_{2.5}$). These relative risks can be used to develop risk coefficients that relate a unit reduction in ozone to changes in the incidence of a health effect. We refer the reader to Chapter 6 of this RIA, as well as to the Ozone NAAQS RIA (U.S. EPA, 2015) and PM NAAQS RIA (U.S. EPA, 2012a) for more information regarding the epidemiology studies and risk coefficients applied in this analysis.

Co-benefits of the proposed rule come from reducing emissions of CO_2. Chapter 6 of this RIA provides a brief overview of the 2009 Endangerment Finding and climate science assessments released since then. Chapter 6 also provides information regarding the economic valuation of CO_2 using the social cost of carbon (SC-CO_2), a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year.

ES.5.2 Combined Health Benefits and Climate Co-Benefits Estimates

In this analysis, we were able to monetize the estimated benefits associated with the reduced exposure to ozone and $PM_{2.5}$ and co-benefits of decreased emissions of CO_2. Specifically, we estimated combinations of health benefits at discount rates of 3 percent and 7 percent (as recommended by the EPA's *Guidelines for Preparing Economic Analyses* [U.S. EPA, 2014] and OMB's *Circular A-4* [OMB, 2003]) and climate co-benefits using four SC-CO_2 estimates (the average SC-CO_2 at each of three discount rates—5 percent, 3 percent, 2.5 percent—and the 95th percentile SC-CO_2 at 3 percent as recommended in the current SC-CO_2 TSD[12]; see Chapter 6 of this RIA for more details). In this analysis we were unable to monetize the co-benefits associated with reducing exposure to SO_2, and NO_2, as well as ecosystem effects

[12] Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Domestic Policy Council, Environmental Protection Agency National Economic Council, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: https://www.whitehouse.gov/omb/oira/social-cost-of-carbon.

and visibility impairment. In addition, there are expected to be unquantified health and welfare impacts associated with changes in hydrogen chloride.

Table ES-4 provides the combined health and climate benefits for the proposal and for more and less stringent alternatives for the 2017 analysis year. In the table, ranges within the total benefits rows reflect multiple studies upon which the estimates of premature mortality were derived.

Table ES-4. Combined Health Benefits and Climate Co-Benefits for the Proposed CSAPR EGU NO_X Ozone Season Emissions Budgets and for More and Less Stringent Alternatives for 2017 (millions of 2011$)*

$SC\text{-}CO_2$ Discount Rate**	Health and Climate Benefits (Discount Rate Applied to Health Co-Benefits) 3%	7%	Climate Co-Benefits Only
Less Stringent Alternative			
5%	$190 to $340	$190 to $330	$7.6
3%	$210 to $360	$210 to $350	$27
2.5%	$230 to $380	$220 to $370	$41
3% (95th percentile)	$260 to $410	$260 to $400	$78
Proposal			
5%	$680 to $1200	$660 to $1200	$6.5
3%	$700 to $1200	$680 to $1200	$23
2.5%	$710 to $1300	$690 to $1200	$35
3% (95th percentile)	$740 to $1300	$720 to $1200	$66
More Stringent Alternative			
5%	$700 to $1300	$680 to $1200	$6.5
3%	$720 to $1300	$700 to $1200	$23
2.5%	$730 to $1300	$710 to $1200	$35
3% (95th percentile)	$760 to $1300	$740 to $1300	$66

*All estimates are rounded to two significant figures. Co-benefits are based on benefit-per-ton estimates. Benefits for ozone and $PM_{2.5}$ co-benefits are based on ozone season NO_X emissions. Ozone benefits and $PM_{2.5}$ co-benefits occur in the analysis year, so they are the same for all discount rates. The health benefits range is based on adult mortality functions (e.g., from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Zanobetti and Schwartz (2008)). Climate co-benefits are based on reductions in CO_2 emissions. The monetized health co-benefits do not include changes in health effects from direct exposure to NO_2, SO_2, ecosystem effects; or visibility impairment.
**The $SC\text{-}CO_2$ estimates are calculated with four different values of a one ton reduction. See RIA Chapter 6 for a complete discussion.

ES.5.3 Unquantified Co-Benefits

The monetized co-benefits estimated in this RIA reflect a subset of co-benefits attributable to the health effect reductions associated with ambient ozone and fine particles. Data, time, and resource limitations prevented the EPA from quantifying the impacts to, or monetizing the co-benefits from several important benefit categories, including co-benefits associated with reduced exposure to SO_2 and NO_2, as well as ecosystem effects, and visibility impairment from reduced NO_X due to the absence of air quality modeling data for these pollutants in this analysis. This does not imply that there are no co-benefits associated with changes in exposures to SO_2 and NO_2. These co-benefits are listed in Table ES-5 below, and discussed more fully in Chapter 6 of this RIA.

Table ES-5. Unquantified Health and Welfare Co-benefits Categories

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[1]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[2,3]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[1]
	Asthma emergency department visits (all ages)	—	—	SO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[1]
	Premature mortality	—	—	SO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[1,2]
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Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[1]
	Tree mortality and decline	—	—	NO_x SO_x ISA[2]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[2]
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Coastal eutrophication	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[2]

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[2]
		—	—	
		—	—	

[1] We assess these co-benefits qualitatively due to data and resource limitations for this RIA.

[2] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.

[3] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

ES.5 Results of Benefit-Cost Analysis

Below in Table ES-6, we present the primary costs and benefits estimates for 2017. The net benefits of the proposal and more and less stringent alternatives reflect the benefits of implementing EGU NO_X emissions reductions for the affected 23 states via the proposed FIPs minus the costs of those emissions reductions.

The guidelines of OMB Circular A-4 require providing comparisons of social costs and social benefits at discount rates of 3 and 7 percent. Ideally, streams of social costs and social benefits over time would be estimated and the net present values of each would be compared to determine net benefits of the illustrative control strategy. The three different uses of discounting in the RIA – (i) construction of annualized costs, (ii) adjusting the value of mortality risk for lags in mortality risk decreases, and (iii) adjusting the cost of illness for non-fatal heart attacks to adjust for lags in follow up costs – are all appropriate. We explain our discounting of benefits in Chapter 6 of the RIA, specifically the application of 3 and 7 percent to air quality benefits and 2.5, 3, and 5 percent to climate co-benefits; we explain our discounting of costs, in which we use a single discount rate of 4.77 percent, in Chapter 5. Our estimates of net benefits are the approximations of the net value (in 2017) of benefits attributable to emissions reductions needed to implement the NO_X emissions budgets for each state.

Table ES-6. Total Costs, Total Monetized Benefits, and Net Benefits of the Proposal in 2017 for U.S. (millions of 2011$)[a,b,c]

	Proposal	More Stringent AAA	Less Stringent
Climate Co-Benefits	$23	$23	$27
Air Quality Health Benefits	$670 to $1200	$690 to $1300	$190 to $340
Total Benefits	$700 to $1200	$720 to $1300	$210 to $360
Annualized Compliance	$93	$96	$4.7
Net Benefits	$600 to $1100	$620 to $1200	$210 to $360
Non-Monetized Benefits[d]	Non-quantified climate benefits		
	Reductions in exposure to ambient NO_2 and SO_2		
	Ecosystem benefits assoc. with reductions in emissions of NOx, SO_2, and PM		
	Visibility impairment		

[a] Estimating multiple years of costs and benefits is limited for this RIA by data and resource limitations. As a result, we provide compliance costs and social benefits in 2017, using the best available information to approximate compliance costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Benefits ranges represent discounting of health benefits and climate co-benefits at a discount rate of 3 percent. See Chapter 6 for additional detail and explanation. The costs presented in this table reflect compliance costs annualized at a 4.77 percent discount rate and include monitoring, recordkeeping, and reporting costs. See Chapter 5 for additional detail and explanation.
[c] All costs and benefits are rounded to two significant figures; columns may not appear to add correctly.
[d] Non-monetized benefits descriptions are for all three alternatives and are qualitative.

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CHAPTER 1: INTRODUCTION AND BACKGROUND

Introduction

The EPA is proposing to update the Cross-State Air Pollution Rule (CSAPR) to reduce interstate transport of emissions of nitrogen oxides (NO_X) that contribute significantly to nonattainment or interfere with maintenance of the 2008 Ozone National Ambient Air Quality Standard (NAAQS) in downwind states. The primary purpose of the proposal (hereafter referred to as the "proposal to update CSAPR", or simply "the proposal"), is to address interstate air quality problems with respect to the 2008 ozone NAAQS. The proposal also responds to the D.C. Circuit's July 28, 2015 remand of certain CSAPR ozone-season NO_X emission budgets to the EPA for reconsideration. This Regulatory Impact Analysis (RIA) presents the health and welfare benefits of the proposal to update CSAPR, and compares the benefits of the rule to the estimated costs of implementing the rule in 2017. This chapter contains background information relative to the rule and an outline of the chapters of this RIA.

1.1 Background

Clean Air Act (CAA or the Act) section 110(a)(2)(D)(i)(I), sometimes called the "good neighbor provision," requires states to prohibit emissions that will contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to any primary or secondary NAAQS.[13] The EPA promulgated CSAPR on July 6, 2011[14] to address interstate transport for the 1997 ozone NAAQS and the 1997 and 2006 fine particulate matter ($PM_{2.5}$) NAAQS.[15] (See section IV of the preamble to the proposal to update CSAPR for a discussion of CSAPR litigation and implementation.)

As described in the preamble for the proposal, CSAPR provides a 4-step process to address the requirements of the good neighbor provision for ozone or $PM_{2.5}$ standards: (1)

[13] The EPA uses the term "states" to include the District of Columbia in this RIA.

[14] *See* 76 FR 48208 (July 6, 2011)

[15] CSAPR did not evaluate transport obligations for the 2008 ozone standard because the 2008 ozone NAAQS was under reconsideration during the analytic work for CSAPR.

identifying downwind receptors that are expected to have problems attaining or maintaining clean air standards (i.e., NAAQS); (2) determining which upwind states contribute to these problems in amounts sufficient to "link" them to the downwind air quality problems; (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to nonattainment or interfere with maintenance by quantifying upwind NO_X reductions and apportioning upwind responsibility (this step establishes emissions budgets, which are remaining allowable emissions after reducing significant contribution to nonattainment and interference with maintenance); and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS downwind, reducing the identified upwind NO_X emissions. In this action, the EPA proposes to apply this 4-step process to update CSAPR with respect to the 2008 ozone NAAQS. The reductions required by the proposed rule would be achieved through a FIP in any state that does not have an approved SIP addressing its contribution by the date this rule is finalized. Furthermore, under the FIPs, affected EGUs would participate in the CSAPR NO_X ozone-season allowance trading program. More details on the methods and results of applying this process can be found in the preamble for this proposal and in Chapter 4 of this RIA. The 2008 ozone NAAQS is an 8-hour standard that was set at 75 parts per billion (ppb). *See* 73 FR 16436 (March 27, 2008).

1.2.1 Role of Executive Orders in the Regulatory Impact Analysis

Several statutes and executive orders apply to any public document. The analyses required by these statutes and executive orders are presented in detail in Chapter 7, and below we briefly discuss the requirements of Executive Orders 12866 and 13563 and the guidelines of the Office Of Management and Budget (OMB) Circular A-4 (U.S. OMB, 2003).

In accordance with Executive Orders 12866 and 13563 and the guidelines of OMB Circular A-4, the RIA analyzes the benefits and costs associated with emissions reductions for compliance with the proposal to update CSAPR. OMB Circular A-4 requires analysis of one potential alternative standard level more stringent than the proposal and one less stringent than the proposal. This RIA evaluates the benefits, costs, and certain impacts of a more and a less stringent alternative to the proposal.

1.2.2 *Illustrative Nature of this Analysis*

The EPA proposes to implement the proposed EGU NO_X emissions budgets via updating the CSAPR regional NO_X ozone-season allowance trading program. This implementation approach provides utilities with the flexibility to determine their own compliance path. This RIA develops and analyzes one possible scenario for compliance with the NOx budgets proposed by this action and possible scenarios for EGU compliance with more and less stringent alternatives.

1.2.3 *The Need for Air Quality or Emissions Standards*

OMB Circular A-4 indicates that one of the reasons a regulation may be issued is to address a market failure. The major types of market failure include: externalities, market power, and inadequate or asymmetric information. Correcting market failures is one reason for regulation; it is not the only reason. Other possible justifications include improving the function of government, correcting distributional unfairness, or securing privacy or personal freedom.

Environmental problems are classic examples of externalities – uncompensated benefits or costs imposed on another party as a result of one's actions. For example, the smoke from a factory may adversely affect the health of local residents and soil the property in nearby neighborhoods. Pollution emitted in one state may be transported across state lines and affect air quality in a neighboring state. If bargaining were costless and all property rights were well defined, people would eliminate externalities through bargaining without the need for government regulation.

From an economics perspective, setting an emissions standard (i.e., EGU NO_X ozone-season emissions budgets in this proposal) is a straightforward remedy to address an externality in which firms emit pollutants, resulting in health and environmental problems without compensation for those incurring the problems. Setting the emissions standard attempts to incentivize those who emit the pollutants to reduce their emissions, which lessens the impact on those who suffer the health and environmental problems from higher levels of pollution.

1.2 Overview and Design of the RIA

1.2.1 Methodology for Identifying Required Reductions

Application of the first two steps of the CSAPR process (described above) with respect to the 2008 ozone NAAQS provides the analytic basis for proposing that ozone season emissions in 23 eastern states affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS. Figure 1-1 shows the affected states.

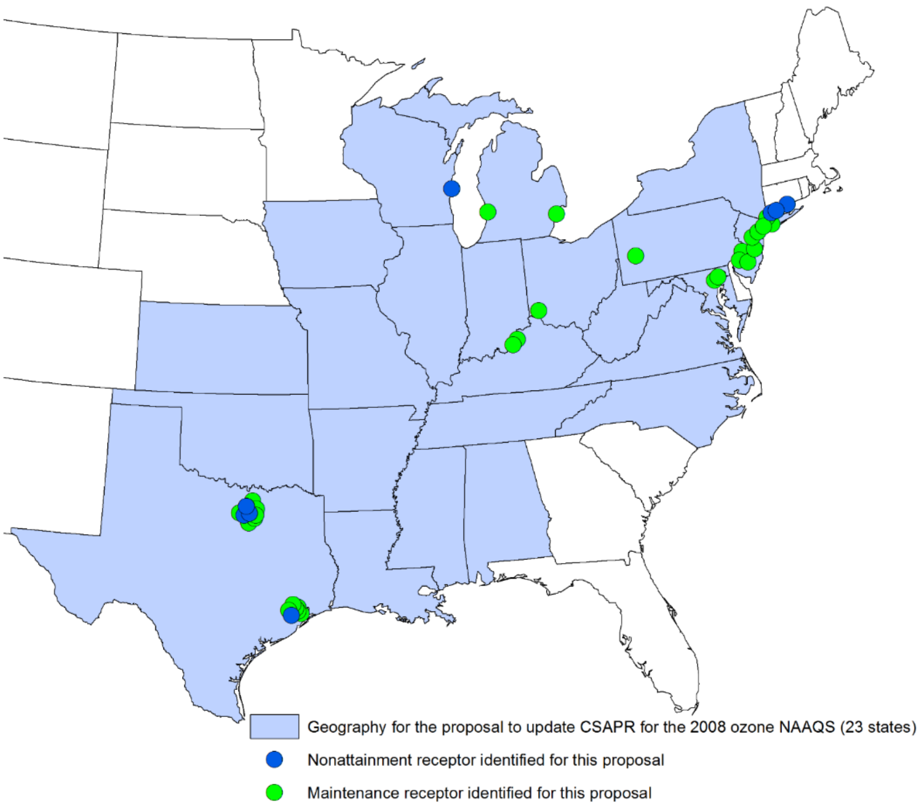

Figure 1-1. Nonattainment and Maintenance Receptors Identified for this Proposal and Upwind States Linked to these Downwind Air Quality Problems with Respect to the 2008 Ozone NAAQS

Applying Step 3 of this process, this action proposes to quantify electric generating unit (EGU) NO_X reductions in these 23 eastern states and to update CSAPR ozone season NO_X emissions budgets. A state's CSAPR ozone season NO_X emissions budget is the quantity of EGU NO_X emissions that would remain after reducing significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS in an average year.[16] These NO_X budgets were developed considering EGU NO_X reductions that are achievable for the 2017 ozone season.[17] The EPA applied a multi-factor test to evaluate EGU NO_X reduction potential for 2017 and proposes to quantify EGU NO_X ozone-season emissions budgets reflecting EGU NO_X reduction strategies that are widely available at a uniform cost of $1,300 per ton (2011$). This assessment revealed that there is significant EGU NO_X reduction potential that can be achieved by 2017, which would make meaningful and timely improvements in ozone air quality. Applying Step 4 of this process, the EPA is proposing to implement these EGU NO_X emissions budgets through the CSAPR NO_X ozone-season allowance trading program.

For the RIA, in order to implement the OMB Circular A-4 requirement to assess one less stringent and one more stringent alternative to the proposal, the EPA is also analyzing EGU NO_X ozone season emissions budgets reflecting NO_X reduction strategies that are widely available at a uniform cost of $500 per ton (2011$) and strategies that are widely available at a uniform cost of $3,400 per ton (2011$).

1.2.2 States Covered by the Proposed Rule

For each state that would be affected by one of the proposed federal implementation plans (FIPs)[18] (as shown in Figure ES-1), and that is already included in the CSAPR NO_X ozone-season trading program to address interstate ozone transport for the 1997 NAAQS, the proposed rule would lower EGU NO_X ozone-season emissions budgets to reduce ozone transport for the 2008 ozone NAAQS. One state, Kansas, would have a new CSAPR ozone-season requirement

[16] For example, assuming no abnormal variation in electricity supply due to events such as abnormal meteorology.

[17] Non-EGU NOx emission control measures and reductions are not included in this proposal. More information on non-EGU control measures and the potential for emission reductions can be found in the TSD on the Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance in 2017, which can be found in the docket for this proposal.

[18] Alabama, Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

under this proposal. The remaining 22 states were included in the original CSAPR ozone-season program as to the 1997 ozone NAAQS.

1.2.3 Regulated Entities

The proposed rule affects fossil fuel-fired EGUs in these 23 eastern states which are classified as code 221112 by the North American Industry Classification System (NAICS) and have a nameplate capacity of greater than 25 megawatts (MWe).

1.2.4 Baseline and Analysis Year

As described in the preamble, the EPA proposes to align implementation of this rule with relevant attainment dates for the 2008 ozone NAAQS, as required by the D.C. Circuit's decision *North Carolina v. EPA.*[19] The EPA's final 2008 Ozone NAAQS SIP Requirements Rule revised the attainment deadline for ozone nonattainment areas currently designated as moderate from December 2018 to July 2018 in accordance with the D.C. Circuit's decision in *NRDC v. EPA.*[20] Because July 2018 falls during the 2018 ozone season, the 2017 ozone season will be the last full season from which data can be used to determine attainment of the NAAQS by the July 2018 attainment date. We believe that *North Carolina* compels the EPA to identify upwind reductions and implementation programs to achieve these reductions, to the extent possible, for the 2017 ozone season.

The proposal to update CSAPR sets forth the requirements for states to reduce their significant contribution to downwind nonattainment and interference with maintenance of the 2008 ozone NAAQS. To develop and evaluate control strategies for addressing these obligations, it is important to first establish a baseline projection of air quality in the analysis year of 2017, taking into account currently on-the-books Federal regulations, substantial Federal regulatory proposals, enforcement actions, state regulations, population, and where possible, economic growth. Establishing this baseline for the analysis then allows us to estimate the incremental costs and benefits of the additional emissions reductions that will be achieved by the transport

[19] 531 F.3d 896, 911-12 (D.C. Cir. 2008) (holding that EPA must coordinate interstate transport compliance deadlines with downwind attainment deadlines).

[20] 777 F.3d 456, 469 (D.C. Cir. 2014).

rule. Furthermore, the analysis in this RIA focuses on benefits, costs and certain impacts in 2017. Certain impacts in 2020, such as forecast emissions changes from the electricity sector, are also reported in this RIA. The results from the analysis in support of this proposal that are reported in this RIA are limited to these two analysis years because important regulatory actions, including the Clean Power Plan (CPP) and potentially the 2015 ozone NAAQS, are expected to have an important and uncertain influence on the electricity sector in later years, as explained below. For this reason, the EPA expects that most of the proposed CSAPR update's influence on emissions reductions will occur between 2017 and 2020.

The first year that EGUs must comply with the CPP is 2022 and investments in renewable generation and energy efficiency in 2020 and 2021 are expected to influence generation patters in the electricity sector in those years, The CPP is not anticipated to have significant interactions with the CPP and the near-term (i.e., starting in 2017) ozone-season EGU NO_X emission reduction requirements under this proposal. States must submit a state plan, or an initial submittal with an extension request, by September 6, 2016 describing how they will implement the emissions guidelines of the final CPP. See section VII.E of the preamble for further discussion.

As discussed in the RIA for the final 2015 ozone NAAQS, it is assumed that potential nonattainment areas everywhere in the U.S., excluding California, will be designated such that they are required to attain the revised standard by 2025. Furthermore, as discussed in the memo to EPA Regional Administrators, *Implementing the 2015 Ozone National Ambient Air Quality Standards*, implementation of the 2015 ozone NAAQS may use the framework of the CSAPR. Doing so may influence compliance with the budgets that are the subject of this proposal.

In addition to other on-the-books Federal regulations, the baseline for the analysis of the benefits, costs and certain impacts of this proposal includes CSAPR phase II NOx ozone-season emissions budgets. As discussed in section III.C of the preamble, in *EME Homer City II*[21], the D.C. Circuit declared invalid the CSAPR phase 2 ozone-season NOx emissions budgets of 11 states. Because the proposed rule modeling was performed prior to the D.C. Circuit's issuance of

[21] *EME Homer City Generation, L.P., v. EPA*, No. 795 F.3d 118, 129-30, 138 (*EME Homer City II*).

EME Homer City II, the modeling assumes that the baseline for all states includes the emission reductions associated with the CSAPR phase 2 ozone-season budgets. Furthermore, as these budgets were remanded, it is reasonable to treat them, for the purposes of the analysis in this RIA, as on-the-books Federal regulations.[22] As discussed in the preamble, this proposal incorporates revised emissions budgets that would supplant and replace the budgets promulgated in the original CSAPR rule including the remanded budgets. Furthermore, these proposed budgets would be effective for the 2017 ozone season, the same period in which the phase 2 budgets that were invalidated by the court are currently scheduled to become effective. Of the 11 states for which the CSAPR phase 2 ozone-season NOx emissions budgets were remanded, 9 are among the 23 states for which budgets are established in this proposal. They are: Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Texas, Virginia, and West Virginia. The baseline and analysis year are discussed in more detail in Chapters 3 and 5 of this RIA.

In addition, on June 29, 2015, the United States Supreme Court reversed the D.C. Circuit opinion affirming the MATS. The EPA is reviewing the decision and will determine any appropriate next steps once the review is complete. MATS is included in the baseline for this analysis, and the EPA does not believe including MATS substantially alters the results of this analysis, because MATS was remanded, not vacated.

1.2.5 Emissions Controls and Cost Analysis Approach

The EPA estimated the control strategies and compliance costs of the proposed rule using the Integrated Planning Model (IPM) as well as certain costs that are estimated outside the model, but use IPM inputs for their estimation. These cost estimates reflect costs incurred by the power sector, and include (but are not limited to) the costs of purchasing, installing, and operating NO_X control technology, changes in fuel costs, and changes in the generation mix. A description of the methodologies used to estimate the costs and economic impacts to the power sector is contained in chapter 5 of this RIA.

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1.2.6 Benefits Analysis Approach

The EPA estimated human health benefits (i.e., mortality and morbidity effects) considering an array of health impacts attributable to changes in exposure to ozone and fine particulate matter ($PM_{2.5}$). We estimated these benefits using benefit-per-ton estimates derived from the BenMAP tool. The EPA also estimated the climate co-benefits of the proposal. A description of the methodologies used to estimate the human health and climate benefits is contained in chapter 6 of this RIA. In addition, chapter 6 contains a discussion of welfare co-benefits, such as ecosystem benefits from reduced nitrogen deposition.

1.3 Organization of the Regulatory Impact Analysis

This RIA is organized into the following remaining chapters:

- *Chapter 2: Electric Power Sector Profile.* This chapter describes the electric power sector in detail.
- *Chapter 3*: *Emissions and Air Quality Modeling Impacts*. The data, tools, and methodology used for the air quality modeling are described in this chapter, as well as the post-processing techniques used to produce a number of air quality metrics for input into the analysis of benefits and costs.
- *Chapter 4: Regulatory Control Scenarios.* The chapter summarizes the rationale for the three regulatory control alternatives analyzed and how the requirements of these alternatives are represented in IPM.
- *Chapter 5: Cost, Economic, Employment, and Energy Impacts.* The chapter summarizes the data sources and methodology used to estimate the costs and other impacts incurred by the power sector.
- *Chapter 6: Benefits Analysis Results*. The chapter quantifies the health-related benefits of the ozone-related air quality improvements associated with the three regulatory control alternatives analyzed.
- *Chapter 7*: *Statutory and Executive Order Impact Analyses*. The chapter summarizes the Statutory and Executive Order impact analyses.
- *Chapter 8: Comparison of Benefits and Costs*. The chapter compares estimates of the total benefits with total costs and summarizes the net benefits of the three alternative regulatory control scenarios analyzed.

CHAPTER 2: ELECTRIC POWER SECTOR PROFILE

Overview

This chapter discusses important aspects of the power sector that relate to today's proposal to update CSAPR with respect to the interstate transport of emissions of nitrogen oxides (NO_X) that contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states. This chapter describes types of existing power-sector sources affected by the proposed regulation, and provides background on the power sector and electricity generating units (EGUs). In addition, this chapter provides some historical background on trends in the past decade in the power sector, as well as about existing EPA regulation of the power sector.

2.1 Background

In the past decade there have been significant structural changes in both the mix of generating capacity and in the share of electricity generation supplied by different types of generation. These changes are the result of multiple factors in the power sector, including normal replacements of older generating units with new units, changes in the electricity intensity of the U.S. economy, growth and regional changes in the U.S. population, technological improvements in electricity generation from both existing and new units, changes in the prices and availability of different fuels, and substantial growth in electricity generation by renewable and unconventional methods. Many of these trends will continue to contribute to the evolution of the power sector. The evolving economics of the power sector, in particular the increased natural gas supply and subsequent relatively low natural gas prices, have resulted in more gas being utilized as base load energy in addition to supplying electricity during peak load. This chapter presents data on the evolution of the power sector from 2000 through 2013. Projections of future power sector behavior and the impact of this rule are discussed in more detail in chapters 3 and 5 of this RIA.

2.2 Power Sector Overview

The production and delivery of electricity to customers consists of three distinct segments: generation, transmission, and distribution.

2.2.1 Generation

Electricity generation is the first process in the delivery of electricity to consumers. There are two important aspects of electricity generation; capacity and net generation. *Generating Capacity* refers to the maximum amount of production an EGU is capable of producing in a typical hour, typically measured in megawatts (MW) for individual units, or gigawatts (1 GW = 1000 MW) for multiple EGUs. *Electricity Generation* refers to the amount of electricity actually produced by an EGU over some period of time, measured in kilowatt-hours (kWh) or gigawatt-hours (GWh = 1 million kWh). Net Generation is the amount of electricity that is available to the grid from the EGU (i.e., excluding the amount of electricity generated but used within the generating station for operations). Electricity generation is most often reported as the total annual generation (or some other period, such as seasonal). In addition to producing electricity for sale to the grid, EGUs perform other services important to reliable electricity supply, such as providing backup generating capacity in the event of unexpected changes in demand or unexpected changes in the availability of other generators. Other important services provided by generators include facilitating the regulation of the voltage of supplied generation.

Individual EGUs are not used to generate electricity 100 percent of the time. Individual EGUs are periodically not needed to meet the regular daily and seasonal fluctuations of electricity demand. Furthermore, EGUs relying on renewable resources such as wind, sunlight and surface water to generate electricity are routinely constrained by the availability of adequate wind, sunlight or water at different times of the day and season. Units are also unavailable during routine and unanticipated outages for maintenance. These factors result in the mix of generating capacity types available (e.g., the share of capacity of each type of EGU) being substantially different than the mix of the share of total electricity produced by each type of EGU in a given season or year.

Most of the existing capacity generates electricity by creating heat to create high pressure steam that is released to rotate turbines which, in turn, create electricity. Natural gas combined cycle (NGCC) units have two generating components operating from a single source of heat. The first cycle is a gas-fired turbine, which generates electricity directly from the heat of burning natural gas. The second cycle reuses the waste heat from the first cycle to generate steam, which is then used to generate electricity from a steam turbine. Other EGUs generate electricity by using water or wind to rotate turbines, and a variety of other methods including direct photovoltaic generation also make up a small, but growing, share of the overall electricity supply. The generating capacity includes fossil-fuel-fired units, nuclear units, and hydroelectric and other renewable sources (see Table 2-1). Table 2-1 also shows the comparison between the generating capacity in 2000 and 2013.

In 2013 the power sector consisted of over 19,000 generating units with a total capacity[23] of 1,168 GW, an increase of 301 GW (or 35 percent) from the capacity in 2000 (867 GW). The 301 GW increase consisted primarily of natural gas fired EGUs (246 GW) and wind generators (58 GW), with substantially smaller net increases and decreases in other types of generating units.

Table 2-1. Existing National Electricity Generating Capacity by Energy Source, 2000 and 2013

	2000		2013		Change Between '00 and '13		
Energy Source	**Generator Nameplate Capacity (MW)**	**% Total Capacity**	**Generator Nameplate Capacity (MW)**	**% Total Capacity**	**% Increase**	**Nameplate Capacity Change (MW)**	**% of Total Capacity Increase**
Coal	336,247	39%	329,815	29%	-2%	-6,433	-2%
Natural Gas	242,602	28%	488,169	42%	101%	245,567	82%
Nuclear	104,734	12%	104,424	9%	0%	-311	0%
Hydro	95,879	11%	100,182	8%	4%	4,303	1%

[23] As with all data presented in this section, this includes generating capacity not only at EGUs primarily operated to supply electricity to the grid, but also generating capacity at commercial and industrial facilities that produce both electricity used onsite as well as dispatched to the grid. Unless otherwise indicated, capacity data presented in this RIA is installed nameplate capacity (also known as nominal capacity), defined by EIA as “The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer.” Nameplate capacity is consistently reported to regulatory authorities with a common definition, where alternate measures of capacity (e.g., net summer capacity and net winter capacity) can use a variety of definitions and specified conditions. Natural Gas information in this chapter (unless otherwise stated) reflects data for all generating units using natural gas as the primary fossil heat source. This includes Combined Cycle Combustion Turbine, Gas Turbine, and miscellaneous (< 1 percent)

Petroleum	68,080	8%	49,794	5%	-27%	-18,287	-6%
Wind	2,394	0.3%	60,712	5.1%	2436%	58,318	19%
Other Renewable	14,047	1.6%	25,748	1.8%	83.3%	11,701	3.9%
Misc	3,079	0.4%	5,180	0.4%	68.2%	2,101	0.7%
Total	867,062	100%	1,167,995	100%	35%	300,933	100%

Note: This table presents generation capacity. Actual net generation is presented in Table 2-2.

Source: U.S. EIA. Downloaded from EIA Electricity Data Browser, Electric Power Plants Generating Capacity By energy source, by producer, by state back to 2000 (annual data from EIA Form 860). Available online at: <http://www.eia.gov/electricity/data.cfm#gencapacity.> Accessed 8/7/15.

The 35 percent increase in generating capacity is the net impact of newly built generating units, retirements of generating units, and a variety of increases and decreases to the nameplate capacity of individual existing units due to changes in operating equipment, changes in emission controls, etc. During the period 2000 to 2013, a total of 408,022 MW of new generating capacity was built and brought online, and 83,240 MW existing units were retired. The net effect of the re-rating of existing units reduced the total capacity by 23,848 MW. The overall net change in capacity was 300,933 MW, as shown in Table 2-1.

The newly built generating capacity was primarily natural gas (307,764 MW), which was partially offset by gas retirements (36,876 MW). Wind capacity was the second largest type of new builds (58,477 MW), augmented by solar (6,273 MW).[24] The overall mix of newly built and retired capacity, along with the net effect, is shown on Figure 2-1.

[24] Partially offset by 86 MW retired older wind or solar capacity.

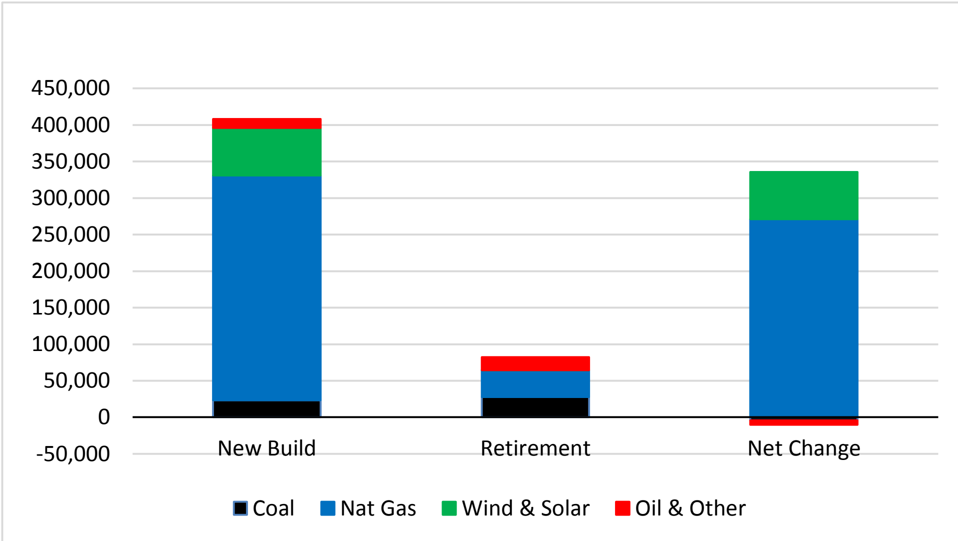


Figure 2-1 National New Build and Retired Capacity (MW) by Fuel Type, 2000-2013[25]

The information in Table 2-1 and Figure 2-1 present information about the generating capacity in the entire U.S. The proposal to update CSAPR, however, directly affects EGUs in 23 eastern states (i.e., the CSAPR 2008 Ozone Region), as discussed in Chapter 1. The share of generating capacity from each major type of generation differs between the CSAPR 2008 Ozone Region and the rest of the U.S. (non-region). Figure 2-2 shows the mix of generating capacity for each region. The overall capacity and generation in the CSAPR 2008 Ozone Region is 60% of the national total, reflecting the larger total population in the region. The mix of capacity and generation are noticeably different in the two regions. In the CSAPR 2008 Ozone Region, coal makes up a significantly larger share of total capacity (34 percent) than it does in the rest of the country (19%). The shares of natural gas, however, are quite similar (41% in the region, and 43% in the rest of country). The difference in the share of coal's capacity is balanced by relatively more hydro, wind, solar and other capacity in the rest of country compared to the CSAPR 2008 Ozone Region.

[25] Source: EIA Form 860. Not visible: wind and solar retirements = 87 MW, net change in coal capacity = -4,186 MW

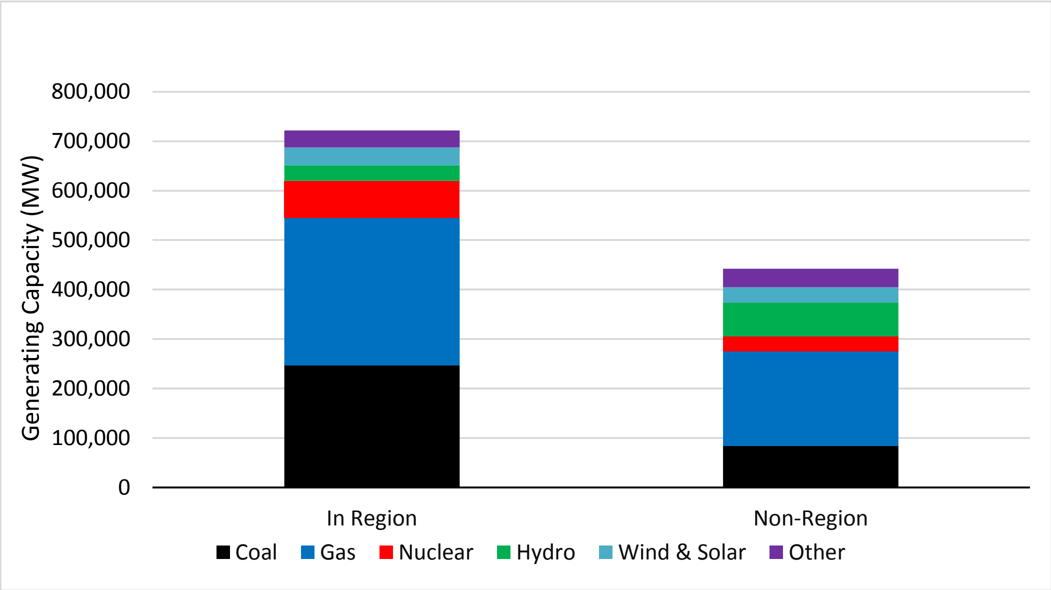


Figure 2-2 Regional Differences in Generating Capacity (MW), 2013.

Source: EIA Form 860 Note: "Other" includes petroleum, geothermal, other renewable, waste materials and misc.

In 2013, electric generating sources produced a net 4,058 trillion kWh to meet national electricity demand, a 7 percent increase from 2000. As presented in Table 2-2, almost 70 percent of electricity in 2013 was produced through the combustion of fossil fuels, primarily coal and natural gas, with coal accounting for the largest single share. Although the share of the total generation from fossil fuels in 2013 (67 percent) was only modestly smaller than the total fossil share in 2000 (71 percent), the mix of fossil fuel generation changed substantially during that period. Coal generation declined by 18 percent and petroleum generation by 76 percent, while natural gas generation increased by 83 percent. This reflects both the increase in natural gas capacity during that period as well as an increase in the utilization of new and existing gas EGUs during that period. Wind generation also grew from a very small portion of the overall total in 2000 to 4.1 percent of the 2013 total.

Table 2-2. Net Generation in 2000 and 2013 (Trillion kWh = TWh)

	2000		2013		Change Between '00 and '13	
	Net Generation (TWh)	Fuel Source Share	Net Generation (TWh)	Fuel Source Share	Net Generation Change (TWh)	% Change in Net Generation
Coal	1,966.3	52%	1,586.0	39%	-380.3	-19.3%
Natural Gas	615.0	16%	1,125.9	28%	510.9	83.1%

Nuclear	753.9	20%	789.0	19%	35.1	4.7%
Hydro	270.0	7%	264.7	7%	-5.3	-2.0%
Petroleum	111.2	2.9%	26.9	0.7%	-84.4	-75.8%
Wind	5.6	0.1%	167.7	4.1%	162.1	-
Other Renewable	75.3	2.0%	85.7	2.1%	10.4	13.7%
Misc	4.8	0.1%	12.4	0.3%	7.6	157.7%
Total	**3,802**	**100%**	**4,058**	**100%**	**256**	**7%**

Source: U.S. EIA Monthly Energy Review, December 2014. Table 7.2a Electricity Net Generation: Total (All Sectors). Available online at: <http://www.eia.gov/totalenergy/data/monthly/>. Accessed 12/19/2014

Coal-fired and nuclear generating units have historically supplied "base load" electricity, the portion of electricity loads which are continually present, and typically operate throughout all hours of the year. The coal units meet the part of demand that is relatively constant. Although much of the coal fleet operates as base load, there can be notable differences across various facilities (see Table 2-3). For example, coal-fired units less than 100 megawatts (MW) in size compose 37 percent of the total number of coal-fired units, but only 6 percent of total coal-fired capacity. Gas-fired generation is better able to vary output and is the primary option used to meet the variable portion of the electricity load and has historically supplied "peak" and "intermediate" power, when there is increased demand for electricity (for example, when businesses operate throughout the day or when people return home from work and run appliances and heating/air-conditioning), versus late at night or very early in the morning, when demand for electricity is reduced.

Table 2-3 also shows comparable data for the capacity and age distribution of natural gas units. Compared with the fleet of coal EGUs, the natural gas fleet of EGUs is generally smaller and newer. While 55 percent of the coal EGU fleet is over 500 MW per unit, 77 percent of the gas fleet is between 50 and 500 MW per unit. Many of the largest gas units are gas-fired steam-generating EGUs.

Table 2-3. Coal and Natural Gas Generating Units, by Size, Age, Capacity, and Thermal Efficiency in 2013 (Heat Rate)

Unit Size Grouping (MW)	No. Units	% of All Units	Avg. Age	Avg. Net Summer Capacity (MW)	Total Net Summer Capacity (MW)	% Total Capacity	Avg. Heat Rate (Btu/kWh)
COAL							

0 – 24	223	18%	40.7	11.4	2,538	1%	11,733
25 – 49	108	9%	44.2	36.7	3,963	1%	11,990
50 – 99	157	12%	49.0	74.1	11,627	4%	11,883
100 - 149	128	10%	50.6	122.7	15,710	5%	10,971
150 - 249	181	14%	48.7	190.4	34,454	11%	10,620
250 - 499	205	16%	38.4	356.2	73,030	23%	10,502
500 - 749	187	15%	35.4	604.6	113,056	36%	10,231
750 - 999	57	5%	31.4	823.9	46,963	15%	9,942
1000 - 1500	11	1%	35.7	1259.1	13,850	4%	9,732
Total Coal	1257	100%	42.6	250.7	315,191	100%	11,013
NATURAL GAS							
0 – 24	1992	37%	37.6	7.0	13,863	3%	13,531
25 – 49	410	8%	21.8	125.0	51,247	12%	9,690
50 – 99	962	18%	15.6	174.2	167,536	39%	8,489
100 - 149	802	15%	23.4	39.9	31,982	8%	11,765
150 - 249	167	3%	28.7	342.4	57,179	13%	9,311
250 - 499	982	18%	24.6	71.1	69,788	16%	12,083
500 - 749	37	1%	40.0	588.8	21,785	5%	11,569
750 - 1000	14	0.3%	35.9	820.9	11,492	3%	10,478
Total Gas	5366	100%	27.7	79.2	424,872	100%	11,652

Source: National Electric Energy Data System (NEEDS) v.5.14

Note: The average heat rate reported is the mean of the heat rate of the units in each size category (as opposed to a generation-weighted or capacity-weighted average heat rate.) A lower heat rate indicates a higher level of fuel efficiency. Table is limited to coal-steam units in operation in 2013 or earlier, and excludes those units in NEEDS with planned retirements in 2014 or 2015.

In terms of the age of the generating units, 50 percent of the total coal generating capacity has been in service for more than 38 years, while 50 percent of the natural gas capacity has been in service less than 15 years. Figure 2-2 presents the cumulative age distributions of the coal and gas fleets, highlighting the pronounced differences in the ages of the fleets of these two types of fossil-fuel generating capacity. Figure 2-3 also includes the distribution of generation, which is similar to the distribution of capacity.

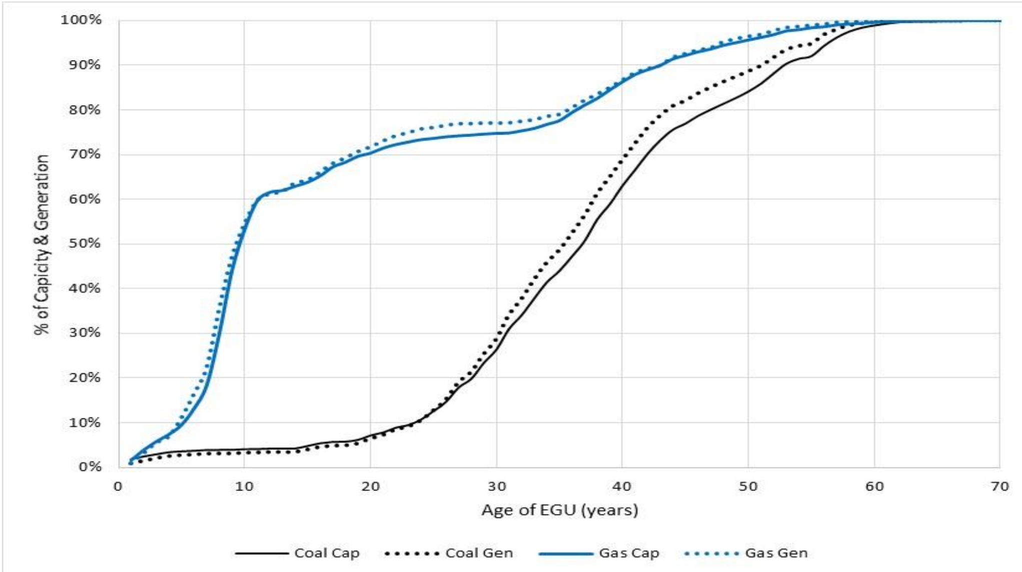


Figure 2-3. Cumulative Distribution in 2013 of Coal and Natural Gas Electricity Capacity and Generation, by Age

Source: National Electric Energy Data System (NEEDS) v.5.15
Not displayed: coal units (376 MW total, 1 percent of total) and gas units (62 MW, < .01 percent of total)) over 70 years old for clarity. Figure is limited to coal-steam units in NEEDS v5.13 in operation in 2013 or earlier (excludes ~2,100 MW of coal-fired IGCC and fossil waste capacity), and excludes those units in NEEDS with planned retirements in 2014 or 2015.

The locations of existing fossil units in EPA's National Electric Energy Data System (NEEDS) v.5.15 are shown in Figure 2-4.

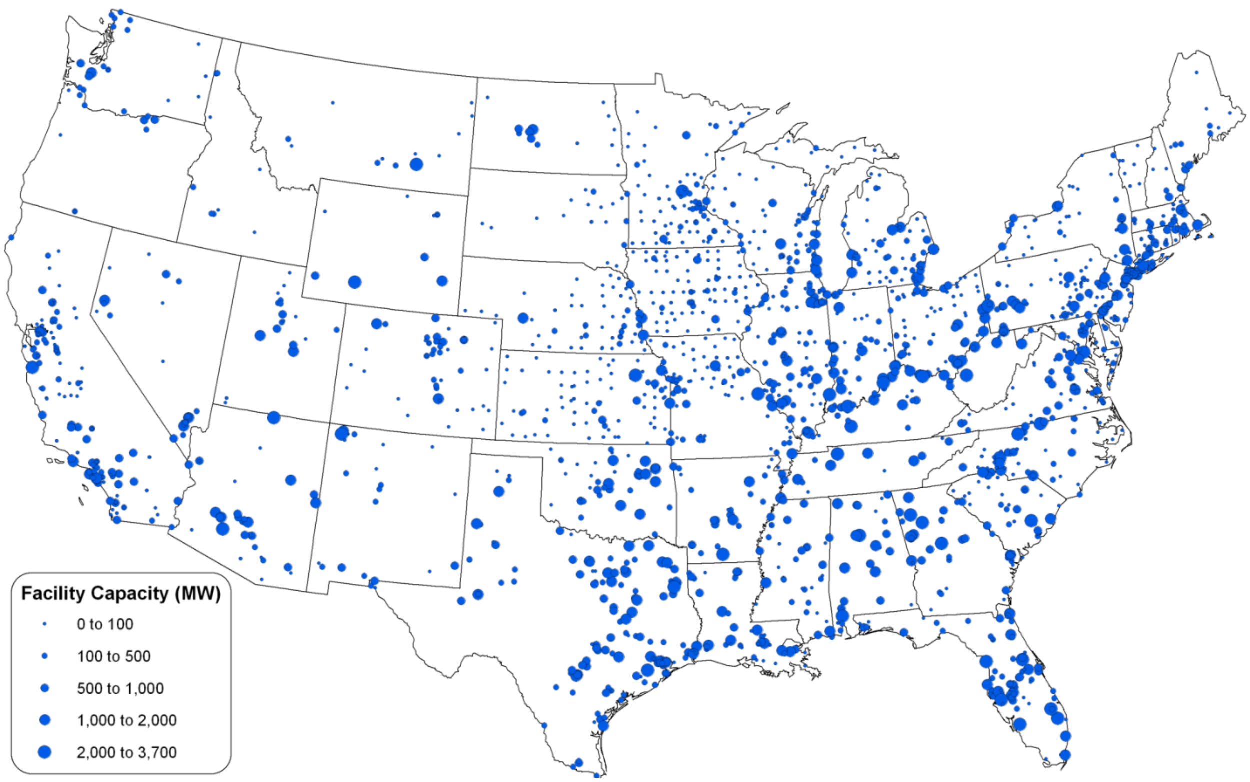


Figure 2-4. Fossil Fuel-Fired Electricity Generating Facilities, by Size

Source: National Electric Energy Data System (NEEDS) v.5.15
Note: This map displays fossil capacity at facilities in the NEEDS v.5.15 IPM frame. NEEDS v.5.15 reflects generating capacity expected to be on-line at the end of 2016. This includes planned new builds already under construction and planned retirements. In areas with a dense concentration of facilities, some facilities may be obscured.

2.2.2 Transmission

Transmission is the term used to describe the bulk transfer of electricity over a network of high voltage lines, from electric generators to substations where power is stepped down for local distribution. In the U.S. and Canada, there are three separate interconnected networks of high voltage transmission lines,[26] each operating synchronously. Within each of these transmission networks, there are multiple areas where the operation of power plants is monitored and controlled by regional organizations to ensure that electricity generation and load are kept in

[26] These three network interconnections are the Western Interconnection, comprising the western parts of both the US and Canada (approximately the area to the west of the Rocky Mountains), the Eastern Interconnection, comprising the eastern parts of both the US and Canada (except those part of eastern Canada that are in the Quebec Interconnection), and the Texas Interconnection (which encompasses the portion of the Texas electricity system commonly known as the Electric Reliability Council of Texas (ERCOT)). See map of all NERC interconnections at http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg

balance. In some areas, the operation of the transmission system is under the control of a single regional operator;[27] in others, individual utilities[28] coordinate the operations of their generation, transmission, and distribution systems to balance the system across their respective service territories.

2.2.3 Distribution

Distribution of electricity involves networks of lower voltage lines and substations that take the higher voltage power from the transmission system and step it down to lower voltage levels to match the needs of customers. The transmission and distribution system is the classic example of a natural monopoly, in part because it is not practical to have more than one set of lines running from the electricity generating sources to substations or from substations to residences and businesses.

Over the last few decades, several jurisdictions in the United States began restructuring the power industry to separate transmission and distribution from generation, ownership, and operation. Historically, vertically integrated utilities established much of the existing transmission infrastructure. However, as parts of the country have restructured the industry, transmission infrastructure has also been developed by transmission utilities, electric cooperatives, and merchant transmission companies, among others. Distribution, also historically developed by vertically integrated utilities, is now often managed by a number of utilities that purchase and sell electricity, but do not generate it. As discussed below, electricity restructuring has focused primarily on efforts to reorganize the industry to encourage competition in the generation segment of the industry, including ensuring open access of generation to the transmission and distribution services needed to deliver power to consumers. In many states, such efforts have also included separating generation assets from transmission and distribution assets to form distinct economic entities. Transmission and distribution remain price-regulated throughout the country based on the cost of service.

[27] E.g., PMJ Interconnection, LLC, Western Area Power Administration (which comprises 4 sub-regions).

[28] E.g., Los Angeles Department of Power and Water, Florida Power and Light.

2.3 Sales, Expenses, and Prices

These electric generating sources provide electricity for ultimate commercial, industrial and residential customers. Each of the three major ultimate categories consume roughly a quarter to a third of the total electricity produced[29] (see Table 2-4). Some of these uses are highly variable, such as heating and air conditioning in residential and commercial buildings, while others are relatively constant, such as industrial processes that operate 24 hours a day. The distribution between the end use categories changed very little between 2000 and 2013.

Table 2-4. Total U.S. Electric Power Industry Retail Sales, 2000 and 2013 (billion kWh)

		2000		2013	
		Sales/Direct Use (Billion kWh)	**Share of Total End Use**	**Sales/Direct Use (Billion kWh)**	**Share of Total End Use**
Sales	Residential	1,192	33%	1,395	36%
	Commercial	1,055	29%	1,344	35%
	Industrial	1,064	30%	978	25%
	Transportation	NA		8	0.2%
	Other	109	3%	NA	
Total		3,421	95%	3,725	96%
Direct Use		171	5%	143	4%
Total End Use		**3,592**	**100%**	3,869	100%

Source: Table 2.2, EIA Electric Power Annual, 2013 and 2010

Notes: Retail sales are not equal to net generation (Table 2-2) because net generation includes net exported electricity and loss of electricity that occurs through transmission and distribution.

Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electricity sales or transfers to adjacent or co-located facilities for which revenue information is not available.

2.3.1 Electricity Prices

Electricity prices vary substantially across the United States, differing both between the ultimate customer categories and also by state and region of the country. Electricity prices are typically highest for residential and commercial customers because of the relatively high costs of

[29] Transportation (primarily urban and regional electrical trains) is a fourth ultimate customer category which accounts less than one percent of electricity consumption.

distributing electricity to individual homes and commercial establishments. The higher prices for residential and commercial customers are the result both of the necessary extensive distribution network reaching to virtually every part of the country and every building, and also the fact that generating stations are increasingly located relatively far from population centers (which increases transmission costs). Industrial customers generally pay the lowest average prices, reflecting both their proximity to generating stations and the fact that industrial customers receive electricity at higher voltages (which makes transmission more efficient and less expensive). Industrial customers frequently pay variable prices for electricity, varying by the season and time of day, while residential and commercial prices historically have been less variable. Overall industrial customer prices are usually considerably closer to the wholesale marginal cost of generating electricity than residential and commercial prices.

On a state-by-state basis, all retail electricity prices vary considerably. In 2013, the national average retail electricity price (all sectors) was 10.12 cents/KWh, with a range from 7.09 cents (Washington) to 33.26 (Hawaii).

Average national retail electricity prices increased between 2000 and 2013 by 7.1 percent in real terms (2011$). The amount of increase differed for the three major end use categories (residential, commercial and industrial). National average residential prices increased the most (8.7 percent), and commercial prices increased the least (2.3 percent). The real year prices for 2000 through 2013 are shown in Figure 2-5.

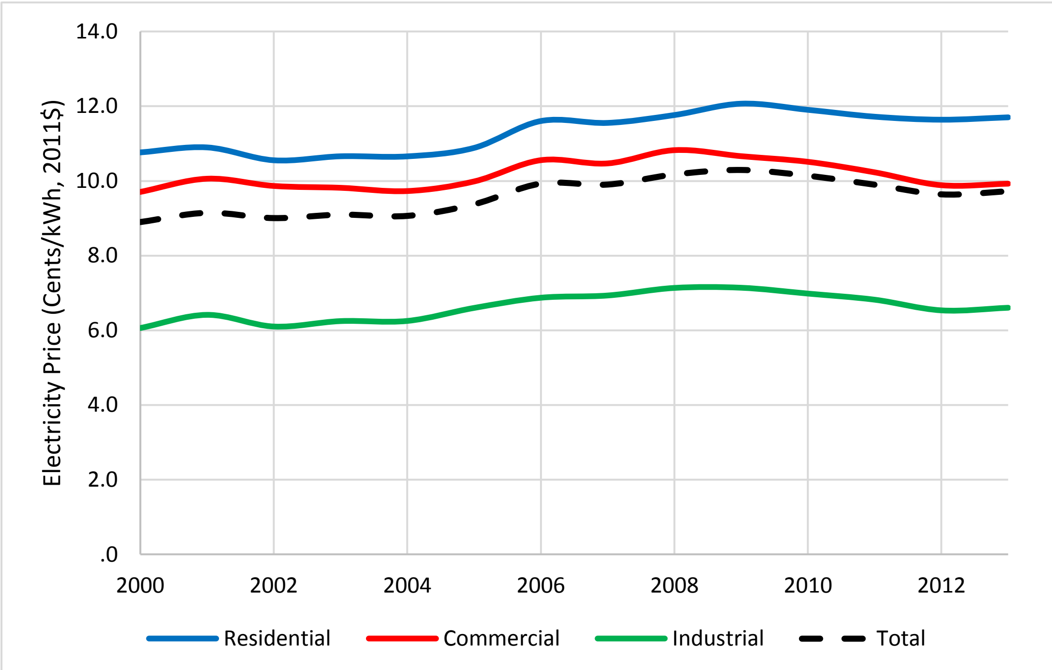


Figure 2-5. Real National Average Electricity Prices for Three Major End-Use Categories

Source: EIA AEO 2013, Table 2.4

Most of these electricity price increases occurred between 2002 and 2008; since 2008 nominal electricity prices have been relatively stable while overall inflation continued to increase. The increase in nominal electricity prices for the major end use categories, as well as increases in the GDP price and CPI-U indices for comparison, are shown in Figure 2-6.

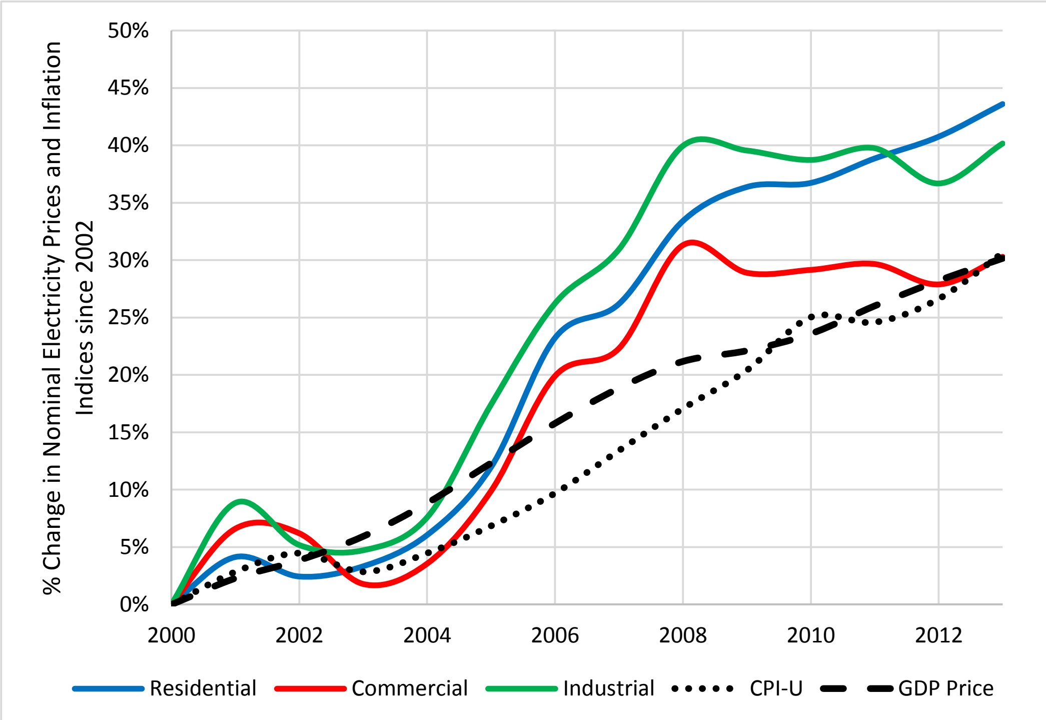


Figure 2-6. Relative Increases in Nominal National Average Electricity Prices for Major End-Use Categories, With Inflation Indices

For a longer term perspective, Figure 2-7 shows real[30] (2011$) electricity prices for the three major customer categories since 1960, and Figure 2-8 shows the relative change in real electricity prices relative to the prices since 1960. As can be seen in the figures, the price for industrial customers has always been lower than for either residential or commercial customers, but the industrial price has been more volatile. While the industrial real price of electricity in 2014 was relatively unchanged from 1960, residential and commercial real prices are 23 percent and 28 percent lower respectively than in 1960.

[30] All prices in this section are estimated as real 2011 prices adjusted using the GDP implicit price deflator unless otherwise indicated.

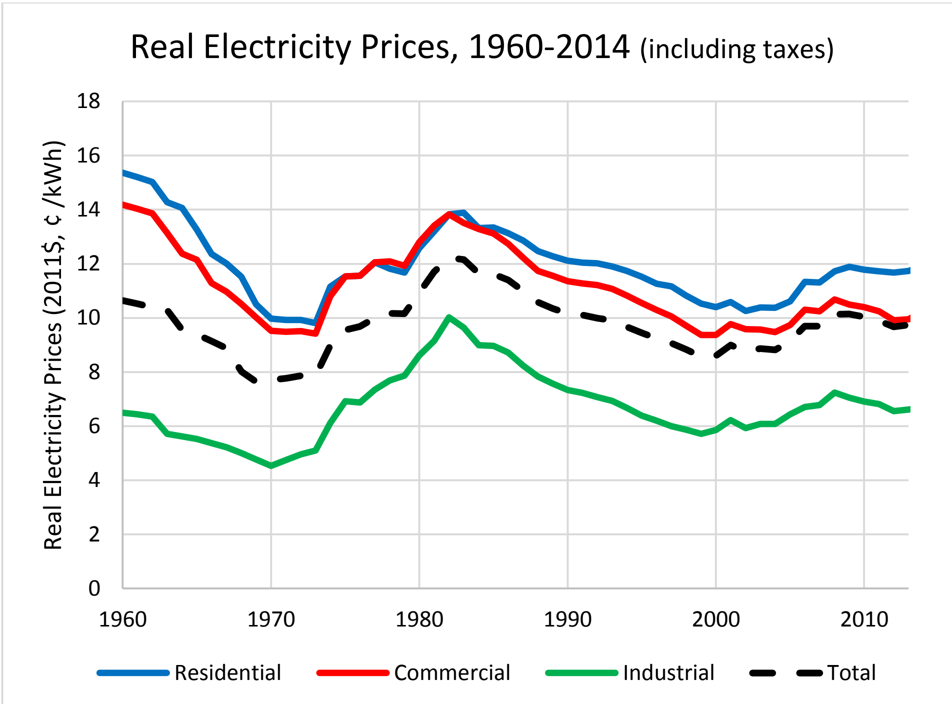


Figure 2-7. Real National Average Electricity Prices (2011$) for Three Major End-Use Categories

Source: EIA Monthly Energy Review, April 2015, Table 9.8

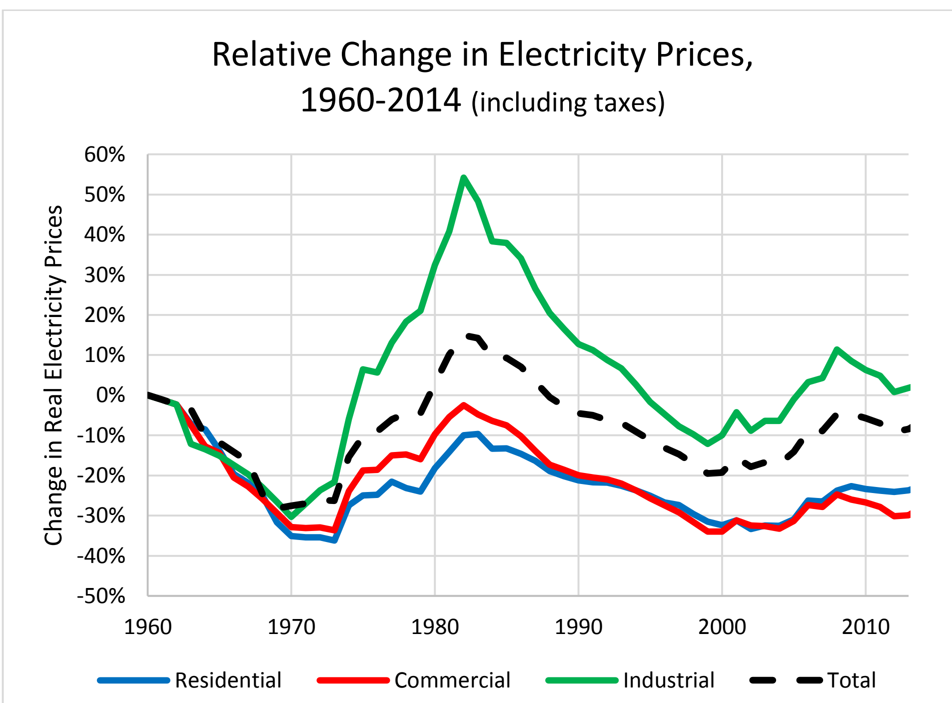


Figure 2-8. Relative Change in Real National Average Electricity Prices (2011$) for Three Major End-Use Categories

Source: EIA Monthly Energy Review, April 2015, Table 9.8

2.3.2 Prices of Fossil Fuels Used for Generating Electricity

Another important factor in the changes in electricity prices are the changes in fuel prices[31] for the three major fossil fuels used in electricity generation; coal, natural gas and oil. Relative to real prices in 2000, the national average real price (in 2011$) of coal delivered to EGUs in 2013 had increased by 50.5 percent, while the real price of natural gas decreased by 22.6 percent. The real price of oil increased by 112 percent, but with oil declining as an EGU fuel (in 2013 oil generated only 1 percent of electricity) the doubling of oil prices had little overall impact in the electricity market. The combined real delivered price of all fossil fuels in 2013 increased by 36.9 percent over 2000 prices. Figure 2-9 shows the relative changes in real price of all 3 fossil fuels between 2000 and 2013.

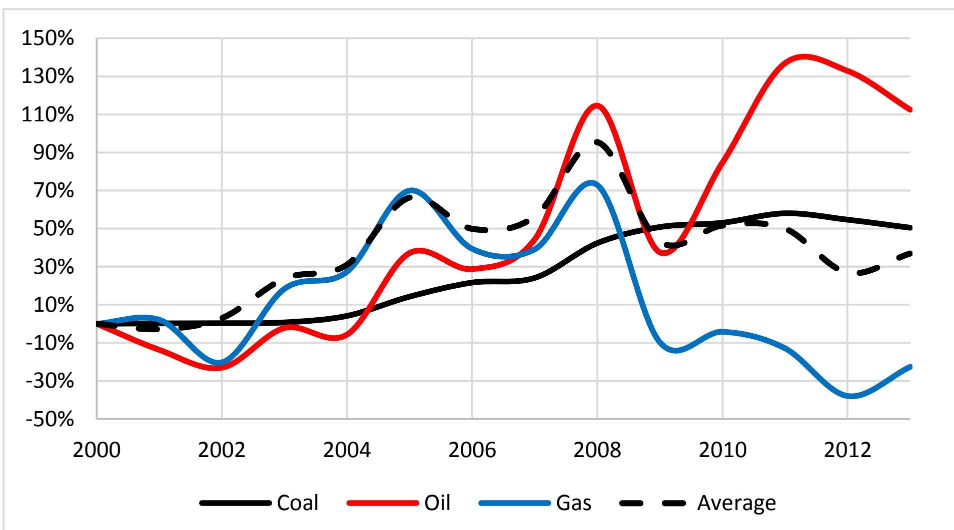


Figure 2-9. Relative Real Prices of Fossil Fuels for Electricity Generation; Change in National Average Real Price per MBtu Delivered to EGU

Source: EIA AEO 2015, Table 9.9

[31] Fuel prices in this section are all presented in terms of price per Btu to make the prices comparable.

2.3.3 Changes in Electricity Intensity of the U.S. Economy from 2000 to 2013

An important aspect of the changes in electricity generation (i.e., electricity demand) between 2000 and 2013 is that while total net generation increased by 6.7 percent over that period, the demand growth for generation was lower than both the population growth (12.2 percent) and real GDP growth (25.4 percent). Figure 2-10 shows the growth of electricity generation, population and real GDP during this period.

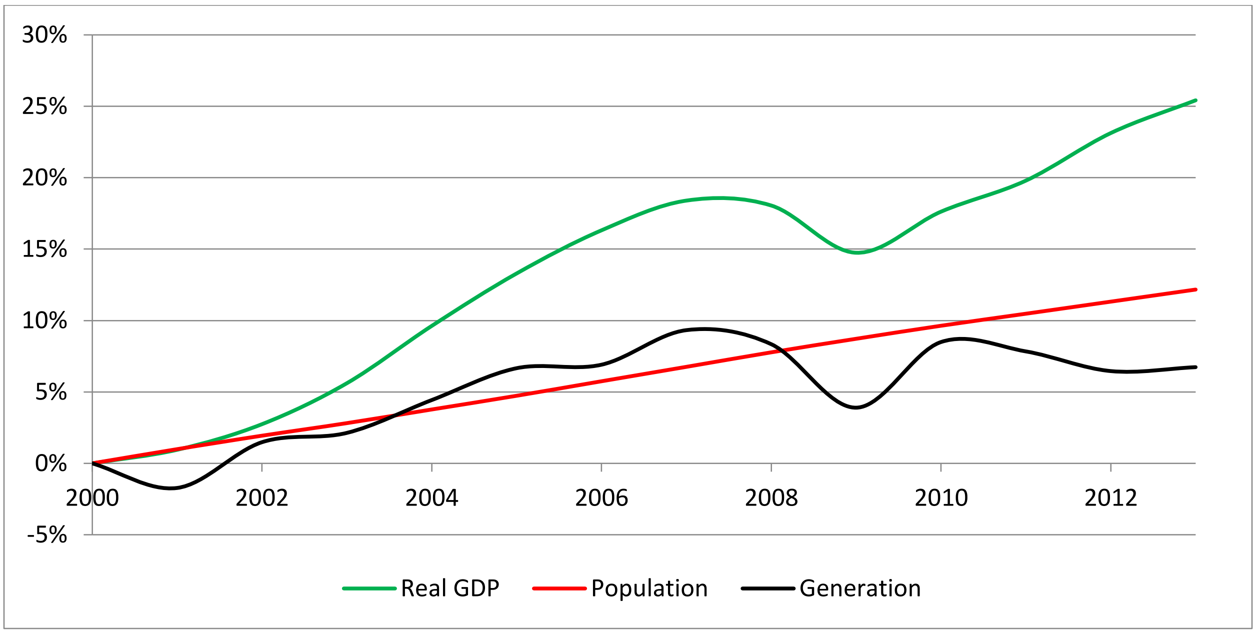


Figure 2-10. Relative Growth of Electricity Generation, Population and Real GDP Since 2000

Sources: U.S. EIA Monthly Energy Review, December 2014. Table 7.2a Electricity Net Generation: Total (All Sectors). U.S. Census.

Because demand for electricity generation grew more slowly than both the population and GDP, the relative electric intensity of the U.S. economy improved (i.e., less electricity used per person and per real dollar of output) during 2000 to 2013. On a per capita basis, real GDP per capita grew by 11.8 percent, increasing from $44,500 (in 2011$) per person in 2000 to $49,800/person in 2013. At the same time electricity generation per capita decreased by 4.8 percent, declining from 13.4 MWh/person in 2000 to 12.8 MWh/person in 2013. The combined effect of these two changes improved the overall electricity efficiency of the U.S. market economy. Electricity generation per dollar of real GDP decreased 14.9 percent, declining from 303 MWh per $1 million of GDP to 258 MWh/$1 million GDP. These relative changes are shown in Figure 2-11. Figures 2-10 and 2-11 clearly show the effects of the 2007 – 2009 recession on both GDP and electricity generation, as well as the effects of the subsequent economic recovery.

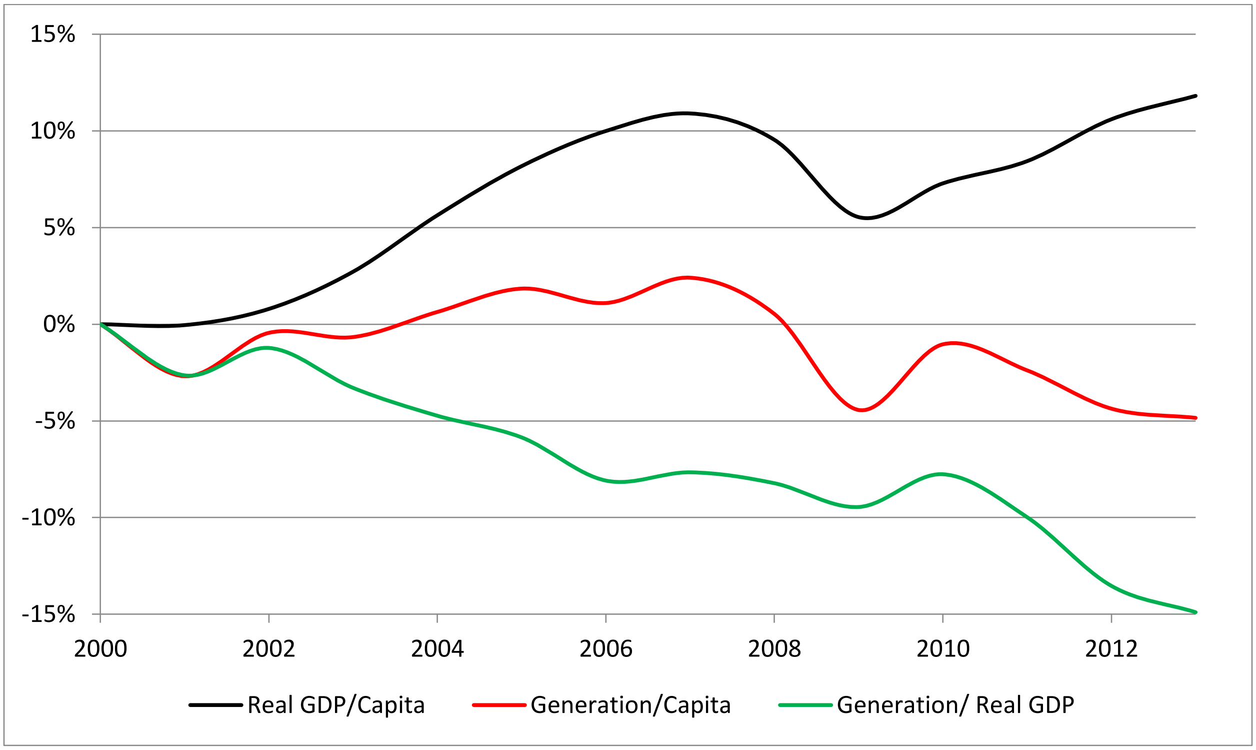


Figure 2-11. Relative Change of Real GDP, Population and Electricity Generation Intensity Since 2000

Sources: U.S. EIA Monthly Energy Review, December 2014. Table 7.2a Electricity Net Generation: Total (All Sectors). U.S. Census.

2.4 Deregulation and Restructuring

The process of restructuring and deregulation of wholesale and retail electricity markets has changed the structure of the electric power industry. In addition to reorganizing asset management between companies, restructuring sought a functional unbundling of the generation, transmission, distribution, and ancillary services the power sector has historically provided, with the aim of enhancing competition in the generation segment of the industry.

Beginning in the 1970s, government policy shifted against traditional regulatory approaches and in favor of deregulation for many important industries, including transportation (notably commercial airlines), communications, and energy, which were all thought to be natural monopolies (prior to 1970) that warranted governmental control of pricing. However, deregulation efforts in the power sector were most active during the 1990s. Some of the primary drivers for deregulation of electric power included the desire for more efficient investment choices, the economic incentive to provide least-cost electric rates through market competition, reduced costs of combustion turbine technology that opened the door for more companies to sell power with smaller investments, and complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes. Deregulation and market restructuring in the power sector involved the divestiture of generation from utilities, the formation of organized wholesale spot energy markets with economic mechanisms for the rationing of scarce transmission resources during periods of peak demand, the introduction of retail choice programs, and the establishment of new forms of market oversight and coordination.

The pace of restructuring in the electric power industry slowed significantly in response to market volatility in California and financial turmoil associated with bankruptcy filings of key energy companies. By the end of 2001, restructuring had either been delayed or suspended in eight states that previously enacted legislation or issued regulatory orders for its implementation (shown as "Suspended" in Figure 2-12). Eighteen other states that had seriously explored the possibility of deregulation in 2000 reported no legislative or regulatory activity in 2001 (EIA, 2003) ("Not Active" in Figure 2-13). Currently, there are 15 states plus the District of Columbia where price deregulation of generation (restructuring) has occurred ("Active" in Figure 2-13). Power sector restructuring is more or less at a standstill; by 2010 there were no active proposals under review by the Federal Energy Regulatory Commission (FERC) for actions aimed at wider restructuring, and no additional states have begun retail deregulation activity since that time.

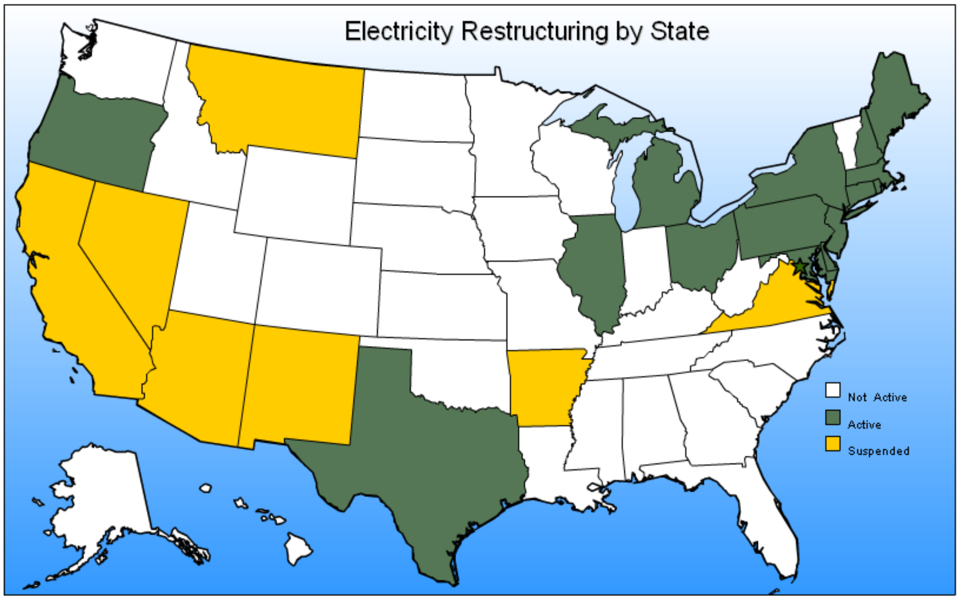


Figure 2-12. Status of State Electricity Industry Restructuring Activities

Source: EIA 2010. "Status of Electricity Restructuring by State." Available online at: <http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html>.

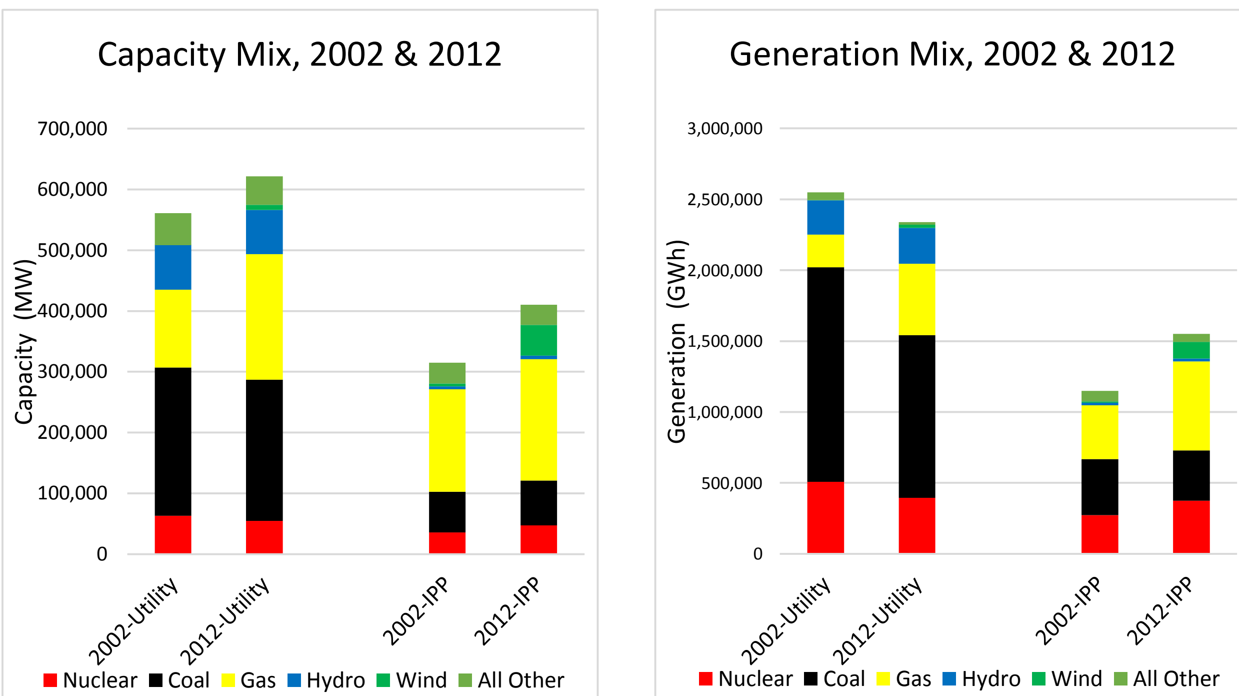
One major effect of the restructuring and deregulation of the power sector was a significant change in type of ownership of electricity generating units in the states that deregulated prices. Throughout most of the 20th century electricity was supplied by vertically integrated regulated utilities. The traditional integrated utilities provided generation, transmission and distribution in their designated areas, and prices were set by cost of service regulations set by state government agencies (e.g., Public Utility Commissions). Deregulation and restructuring resulted in unbundling of the vertical integration structure. Transmission and distribution continued to operate as monopolies with cost of service regulation, while generation shifted to a mix of ownership affiliates of traditional utility ownership and some generation owned and operated by competitive companies known as Independent Power Producers (IPPs). The resulting generating sector differed by state or region, as the power sector adapted to the restructuring and deregulation requirements in each state.

By the year 2000, the major impacts of adapting to changes brought about by deregulation and restructuring during the 1990s were nearing completion. In 2000, traditional utilities owned 79 percent of U.S. generating capacity (MW) while IPPs[32] and commercial and industrial producers owned 18 percent and 3 percent of U.S. generating capacity, respectively. The mix of electricity generated (MWh) was more heavily weighted towards the utilities, with a distribution in 2000 of 81 percent, 15 percent and 4 percent for utilities, IPPs and commercial/industrial, respectively.

Since 2000, IPPs have expanded faster than traditional utilities, substantially increasing their share by 2013 of both capacity (59 percent utility, 38 percent IPPs, and 3 percent commercial/industrial) and generation (58 percent, 38 percent and 4 percent).

The mix of capacity and generation for each of the ownership types is shown in Figures 2-13 (capacity) and 2-14 (generation). The capacity and generation data for commercial and industrial owners are not shown on these figures due to the small magnitude of those ownership

Figures 2-13 & 2-14. Capacity and Generation Mix by Ownership Type, 2002 & 2012



[32] IPP data presented in this section include both combined and non-combined heat and power plants.

types. A portion of the shift of capacity and generation is due to sales and transfers of generation assets from traditional utilities to IPPs, rather than strictly the result of newly built units.

CHAPTER 3: EMISSIONS AND AIR QUALITY MODELING IMPACTS

Overview

This Chapter describes the methods for estimating emissions and air quality for the 2017 baseline and 2017 illustrative control case. In Section 3.1, we describe the air quality modeling platform, in Section 3.2 we describe the development of emissions inventories used in the air quality modeling, and in Section 3.3 we describe the methods for processing the air quality modeling outputs to create inputs for estimating benefits. The 2017 baseline and illustrative control case air quality model predictions were used to calculate "benefit per ton" factors of reduced NO_X on both ozone and fine particulate matter ($PM_{2.5}$) concentrations.[33,34] These factors were then used to estimate the benefits of the regulatory control alternatives, as described in Chapter 6. Details on the air quality modeling are provided in the Air Quality Modeling Technical Support Document, which can be found in the docket for this proposed rule.

3.1 Air Quality Modeling Platform

We use the emissions inputs described in Section 3.2 for national scale applications of the Comprehensive Air Quality Model with Extensions (CAMx) modeling system to estimate ozone and $PM_{2.5}$ air quality in the contiguous U.S. CAMx is a three-dimensional grid-based Eulerian photochemical model designed to estimate ozone and $PM_{2.5}$ concentrations over seasonal and annual time periods. Because it accounts for spatial and temporal variations as well as differences in the reactivity of emissions, CAMx is useful for evaluating the impacts of the rule on ozone and $PM_{2.5}$ concentrations.

For this analysis we used CAMx to simulate air quality for every hour of every day of the year. These model applications require a variety of input files that contain information pertaining to the modeling domain and simulation period. In addition to the CAMx model, our

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[33] The 2017 baseline air quality model predictions were also used to inform the EPA's ozone transport policy analysis by identifying which states significantly contribute to nonattainment or interfere with maintenance of downwind receptors. See *Ozone Transport Policy Analysis Proposed Rule* Technical Support Document, which can be found in the docket for this proposed rule.

[34] Note that the baseline underlying the air quality modeling does not reflect the updated IPM emissions baseline used to develop costs and benefits in Chapters 5 and 6. See the discussion in section 3.2.2 of this chapter.

modeling system includes (1) emissions for a 2011 base year and emissions for the 2017 baseline and illustrative control case, (2) meteorological data inputs for the year 2011, and (3) estimates of intercontinental transport (i.e., boundary concentrations) from a global photochemical model. Using these data, CAMx generates hourly predictions of ozone and $PM_{2.5}$ component species concentrations.[35] The model predictions for the 2011 base year, the 2017 baseline, and the 2017 illustrative control case were combined with ambient air quality observations to calculate seasonal mean ozone air quality metrics and annual mean $PM_{2.5}$ for the 2017 baseline and 2017 illustrative control case, which were then used as input for the benefits analysis.

3.1.1 Simulation Periods

For use in this benefits analysis, the simulation period modeled by CAMx included separate full-year application for each of the three emissions scenarios (i.e., 2011 base year, 2017 baseline and 2017 illustrative control case).

3.1.2 Air Quality Modeling Domain

Figure 3-1 shows the geographic extent of the modeling domain that was used for air quality modeling in this analysis. The domain covers the 48 contiguous states, along with the southern portions of Canada and the northern portions of Mexico. This modeling domain contains 25 vertical layers with a top at about 17,550 meters, or 50 millibars (mb), and horizontal grid resolution of 12 km x 12 km. The model simulations produce hourly air quality concentrations for each 12 km^2 grid cell across the modeling domain.

[35] The CAMx output data files are titled *Air Quality Modeling Data Drives for the 2008 NAAQS CSAPR Proposal* and have been placed in the rulemaking docket EPA-HQ-OAR-2015-0500.

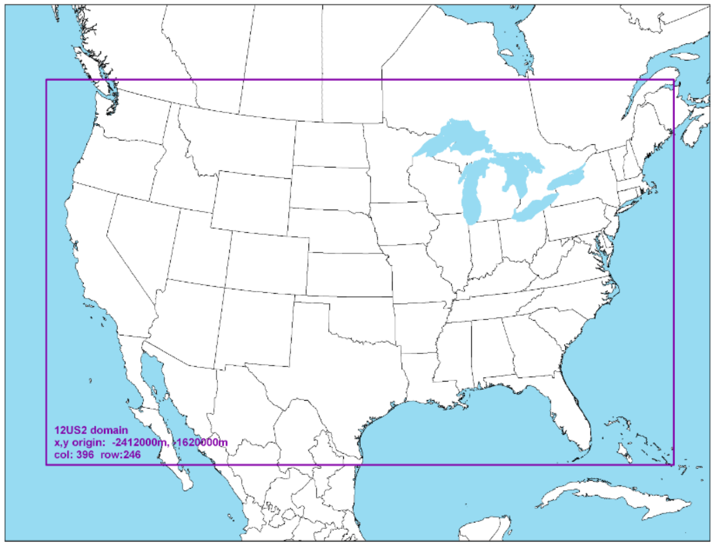

Figure 3-1. National air quality modeling domain.

3.1.3 Air Quality Model Inputs

CAMx requires a variety of input files that contain information pertaining to the modeling domain and simulation period. These include gridded, hourly emissions estimates and meteorological data, and initial and boundary conditions. Separate emissions inventories were prepared for the 2011 base year, the 2017 baseline, and 2017 illustrative control case. All other inputs were specified for the 2011 base year model application and remained unchanged for each future-year modeling scenario.

CAMx requires detailed emissions inventories containing temporally allocated emissions for each grid-cell in the modeling domain for each species being simulated, as described in Section 3.2. The meteorological data model inputs for the 2011 base year were derived from running Version 3.4 of the Weather Research Forecasting Model (WRF). The meteorological outputs from WRF include hourly-varying horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each grid cell in each vertical layer. The CAMx lateral boundary and initial species concentrations are provided by a three-dimensional global atmospheric chemistry and transport model (GEOS-Chem). The lateral boundary species concentrations varied with height and time (every 3 hours).

3.2 Development of Emissions Inventories

3.2.1 2011 Base Year Emissions

The 2011 emissions inventories are primarily based on the National Emissions Inventory, version 2 (2011NEIv2) for point sources, nonpoint sources, commercial marine vessels (CMV), nonroad mobile sources and fires, although the inventories used for modeling often have temporal resolution additional to what is available in the NEI. The onroad mobile source emissions are similar to those in the 2011NEIv2, but were generated using the official release 2014 version of the Motor Vehicle Emissions Simulator (MOVES2014) (http://www3.epa.gov/otaq/models/moves/), while the 2011NEIv2 emissions were generated using a slightly earlier version of MOVES2014. Biogenic emissions and emissions inventories for Canada and Mexico are also included in the air quality modeling. The meteorological data used to develop and temporally allocate emissions were consistent with the 2011 data used for the air quality modeling.

The emissions inventories and modeling thereof incorporate comments received on the Federal Register notices issued for the 2011 and 2018 emissions modeling platforms: the Notice of Availability of the Environmental Protection Agency's 2011 Emissions Modeling Platform issued November 27, 2013 (78 FR 70935) and the Notice of Availability of the Environmental Protection Agency's 2018 Emissions Modeling Platform issued January 14, 2014 (79 FR 2437), respectively. The Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system (Houyoux et al., 2000) version 3.6.5 was used to prepare the emissions inventories for CAMx. Details regarding the development of the emission inventories and emissions modeling for the 2011 base year and the 2017 baseline are documented in the Technical Support Document Preparation of Emissions Inventories for the Version 6.2, 2011 Emissions Modeling Platform (EPA, 2015) and can be found in the docket for this proposed rule.

3.2.2 2017 Baseline Emissions

The emission inventories for the 2017 future baseline have been developed using projection methods that are specific to emission source type. Future emissions are projected from the 2011 base year either by running models to estimate future year emissions from specific types of emission sources (e.g., EGUs, and onroad and nonroad mobile sources), or for other types of sources by adjusting the base year emissions according to the best estimate of changes expected to occur in the intervening years (e.g., non-EGU point and nonpoint sources). The biogenic, fire, offshore oil platforms, and Canadian emissions use the same emissions in the base and future years.[36] For the remaining sectors, rules and specific legal obligations that go into effect in the intervening years, along with changes in activity for the sector, are considered when possible. The modeled 2017 baseline emission inventories represent predicted emissions that account for Federal and State measures promulgated or under reconsideration by December, 2014. With the exception of speciation profiles for mobile sources and temporal profiles for EGUs, the same ancillary data files are used to prepare the future year emissions inventories for air quality modeling as were used to prepare the 2011 base year inventories.

The 2017 baseline inventory for EGUs represents demand growth, fuel resource availability, generating technology cost and performance, and other economic factors affecting power sector behavior. The EGU emissions for the air quality modeling were developed using the IPM version 5.14 base case.[37] The IPM base case reflects the expected emissions accounting for the effects of environmental rules and regulations, consent decrees and settlements, plant closures, units built, control devices installed, and forecast unit construction through the calendar year 2017. The 2017 baseline EGU emissions include impacts from the Final Mercury and Air Toxics Standards announced on December 21, 2011[38] and the CSAPR issued on July 6, 2011.[39] The EPA notes that because the modeling for the proposal was performed prior to the D.C. Circuit's issuance of *EME Homer City II*,[40] that modeling assumed in its baseline for all states

[36] The biogenic and fire emissions are normally held constant between base and future years. The offshore and Canadian emissions were held constant due to the lack of detailed information available to adequately project those emissions to future years.

[37] IPM is a multiregional, dynamic, deterministic linear programming model of the U.S. electric power sector. This model is described in more detail in Chapter 5 of this RIA. The documentation for version 5.14 can be found on EPA"s power sector modeling website: http://www.epa.gov/airmarkets/powersectormodeling.html

[38] In *Michigan v. EPA*, the Supreme Court reversed on narrow grounds a portion of the D.C. Circuit decision upholding the Mercury and Air Toxics Standards, finding that EPA erred by not considering cost when determining that regulation of EGUs was "appropriate" pursuant to CAA section 112(n)(1). 135 S.Ct. 192 (2015). The case was remanded to the D.C. Circuit for further proceedings, and the Mercury and Air Toxics Standards currently remain in place.

[39] We note that the NO_x emissions changes that result from the Mercury and Air Toxics Standards and in the baseline do not substantially alter the results of the analysis. The NO_x reductions based on EPA emissions modeling are only 7 percent of the nationwide total for EGUs in 2016, as found by subtraction of emissions in Table 5A-11 from Table 5A-9 of the Mercury and Air Toxics Standards RIA.

[40] *EME Homer City Generation, L.P., v. EPA*, No. 795 F.3d 118, 129-30, 138 (*EME Homer City II*)

the emission reductions associated with the CSAPR NO_X ozone-season phase 2 emissions budgets.

The Clean Power Plan (CPP) is not included in the modeled IPM 5.14 2017 baseline. The EPA notes that after the 2011 base year, the 2017 baseline, and 2017 illustrative control case air quality modeling for this proposal were underway, the EPA released an updated IPM base case, version 5.15, and the final CPP. In order to reflect all on-the-books policies as well as the most current power sector modeling data, the EPA performed an assessment of benefits, costs, and impacts of this proposal using the IPM 5.15 base case and including the final CPP, as described further in Chapter 5 of this RIA.

The 2018 emissions output from IPM were adjusted to reflect 2017 emissions levels as described in "Calculating 2017 NOx Emissions" (see http://www2.epa.gov/airmarkets/calculating-2017-nox-emissions). Temporal allocation was used to process the seasonal emissions outputs from IPM to hourly emissions. To the extent possible, this temporal allocation process preserved the emissions patterns from the base year (2011), while keeping the maximum emissions below those that occurred in the period 2011-2014.

Projections for most stationary emissions sources other than EGUs (i.e., non-EGUs) were developed by using the EPA Control Strategy Tool (CoST) to create post-controls future year inventories. CoST is described at http://www3.epa.gov/ttnecas1/cost.htm. The 2017 baseline non-EGU stationary source emissions inventory includes all enforceable national rules and programs, including the Reciprocating Internal Combustion Engines (RICE) and cement manufacturing National Emissions Standards for Hazardous Air Pollutants (NESHAPs) and Boiler Maximum Achievable Control Technology (MACT) reconsideration reductions. Projection factors and percent reductions for non-EGU point sources reflect comments received by EPA in response to 79 FR 2437, along with emissions reductions due to national and local rules, control programs, plant closures, consent decrees and settlements. Ancillary reductions to criteria air pollutant (CAP) emissions from stationary engines as a result of the Reciprocating Internal Combustion Engines (RICE) National Emission Standard for Hazardous Air Pollutants (NESHAP) are included. Reductions due to the New Source Performance Standards (NSPS) volatile organic compound (VOC) controls for oil and gas sources, and the NSPS for process heaters, internal combustion engines, and natural gas turbines are also included.

Regional projection factors for point and nonpoint oil and gas emissions were developed using Annual Energy Outlook (AEO) 2014 (U.S. EIA, 2014) projections from year 2011 to year 2018.Projected emissions for corn ethanol, cellulosic ethanol and biodiesel plants, refineries and upstream impacts represent the Energy Independence and Security Act (EISA) renewable fuel standards mandate in the Renewable Fuel Standards Program (RFS2). Airport-specific terminal area forecast (TAF) data were used for aircraft to account for projected changes in landing/takeoff activity.

Projection factors for livestock are based on expected changes in animal population from 2005 Department of Agriculture data, updated according to EPA experts in July 2012; fertilizer application ammonia (NH_3) emissions projections include upstream impacts representing EISA. Area fugitive dust projection factors for categories related to livestock estimates are based on expected changes in animal population and upstream impacts from EISA. Fugitive dust for paved and unpaved roads take growth in VMT and population into account. Residential Wood Combustion (RWC) projection factors reflect assumed growth of wood burning appliances based on sales data, equipment replacement rates and change outs. These changes include growth in lower-emitting stoves and a reduction in higher emitting stoves. Impacts from the NSPS for wood burning devices are also included.

Projection factors for the remaining nonpoint sources such as stationary source fuel combustion, industrial processes, solvent utilization, and waste disposal, reflect comments received on the projection of these sources as a result of rulemakings and outreach to states on emission inventories, and they also include emission reductions due to control programs. Future year portable fuel container (PFC) inventories reflect the impact of the final Mobile Source Air Toxics (MSAT2) rule along with state comments received in response to 79 FR 2437.

The MOVES2014-based 2017 onroad emissions[41] account for changes in activity data and the impact of on-the-books national rules including: the Tier 3 Vehicle Emission and Fuel Standards Program, the Light-Duty Vehicle Tier 2 Rule, the Heavy Duty Diesel Rule, the Mobile Source Air Toxics Rule, the Renewable Fuel Standard (RFS2), the Light Duty Green House Gas/Corporate Average Fuel Efficiency (CAFE) standards for 2012-2016, the Heavy-Duty Vehicle Greenhouse Gas Rule, the 2017 and the Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule (LD GHG). The 2017 onroad emissions also include state rules related to the adoption of low emission vehicle (LEV) standards, inspection and maintenance programs, Stage II refueling controls, and local fuel restrictions. For California, the baseline emissions included most of this state's on-the-books regulations, such as those for idling of heavy-duty vehicles, chip reflash, public fleets, track trucks, drayage trucks, and heavy duty trucks and buses. The California emissions do not reflect the impacts of the GHG/Smartway regulation, nor do they reflect state GHG regulations for the projection of other emissions sectors because that information was not included in the provided inventories.

The nonroad mobile source emissions for 2017, including those for railroads and commercial marine vessel emissions, also include all national control programs. These control programs include the Clean Air Nonroad Diesel Rule – Tier 4, the Nonroad Spark Ignition rules, and the Locomotive-Marine Engine rule. For ocean-going vessels (Class 3 marine), the emissions data reflect the 2005 voluntary Vessel Speed Reduction (VSR) within 20 nautical miles, the 2007 and 2008 auxiliary engine rules, the 40 nautical mile VSR program, the 2009 Low Sulfur Fuel regulation, the 2009-2018 cold ironing regulation, the use of 1% sulfur fuel in the Emissions Control Area (ECA) zone, the 2012-2015 Tier 2 NO_x controls, the 2016 0.1% sulfur fuel regulation in ECA zone, and the 2016 International Marine Organization (IMO) Tier 3 NO_x controls. Non-U.S. and U.S. category 3 commercial marine emissions were projected to 2017 using consistent methods that incorporated controls based on ECA and IMO global NO_x and SO_2 controls. For California, the 2017 emissions for these categories reflect the state's Off-Road Construction Rule for "In-Use Diesel", cargo handling equipment rules in place as of 2011

[41] The 2017 onroad mobile emissions were derived from a 2018 MOVES model run that was adjusted to account for 2017. See the emissions modeling TSD (US EPA, 2015)for more details.

(see http://www.arb.ca.gov/ports/cargo/cargo.htm), and state rules through 2011 related to Transportation Refrigeration Units, the Spark-Ignition Marine Engine and Boat Regulations adopted on July 24, 2008 for pleasure craft, and the 2007 and 2010 regulations to reduce emissions from commercial harbor craft.

All modeled 2011 and 2017 emissions cases use 2010 Canada emissions data, which is the latest year for which Environment Canada had provided data at the time the modeling was performed. No accompanying future-year projected baseline inventories were provided in a form suitable for this analysis. For Mexico, emissions compiled from the Inventario Nacional de Emisiones de Mexico, 2008 were used for 2011, as that was the latest complete inventory available. For the 2017 baseline, projected emissions for the year 2018 based on the 2008 inventory were used (ERG, 2014). Table 3-1 shows the modeled 2011 and 2017 NO_X and VOC emissions by sector. Additional details on the emissions by state are given in the emissions modeling TSD (US EPA, 2015)[42].

Table 3-1 2011 Base Year and 2017 Baseline NOx and VOC Emissions by Sector (thousand tons)

Sector	2011 NO_x	2017 NO_x	2011 VOC	2017 VOC
EGU-point	2,000	1,500	36	40
NonEGU-point	1,200	1,200	800	810
Point oil and gas	500	410	160	170
Wildfires and Prescribed Fires	330	330	4,700	4,700
Nonpoint oil and gas	650	690	2,600	3,200
Residential wood combustion	34	35	440	440
Other nonpoint	760	730	3,700	3,500
Nonroad	1,600	1,100	2,000	1,400
Onroad	5,700	3,200	2,700	1,500
C3 Commercial marine vessel (CMV)	130	130	5	6
Locomotive and C1/C2 CMV	1,100	910	48	35
Biogenics	1,000	1,000	41,000	41,000
TOTAL	**15,000**	**11,200**	**58,000**	**57,000**

3.2.3 2017 Illustrative Control Case Emissions

The EPA’s approach to developing IPM v5.14-based emissions for the illustrative control case is methodologically consistent with the EPA’s approach to establishing the proposed EGU

[42] Available in the rulemaking docket: EPA-HQ-OAR-2015-0500.

NO_X ozone-season emissions budgets to reduce interstate ozone transport for the 2008 ozone NAAQS. Specifically, the EPA performed IPM modeling that applied a uniform cost of $1,300 per ton on EGU NO_X emissions. Next, the EPA established illustrative EGU NO_X ozone-season emissions budgets for the 23 eastern states included in this proposal by multiplying the resulting state-specific emissions rate for affected EGUs by the corresponding (i.e., affected EGU) 2014 heat input. These illustrative EGU NO_X ozone-season emissions budgets and their associated assurance levels, along with corresponding emission changes for other pollutants as predicted by IPM, were modeled in IPM v5.14 to create the illustrative control case.

The emissions for the illustrative control case were processed for air quality modeling in the same way as the 2017 baseline. The only difference in the emissions inventories were the EGU emissions. The hourly temporal allocation for the illustrative control case inventories preserved the patterns from the 2017 baseline. This was accomplished by generating ratios of 2017 base hourly emissions to the total seasonal emissions by unit and then applying these ratios to the total seasonal emissions from the 2017 illustrative control case. Thus, the same hourly temporal patterns in the baseline are reflected in this control case, including any adjustments made to constrain the hourly 2017 emissions below the maximum levels during the 2011-2014 period.

3.3 Post-Processing of Air Quality Modeling for Benefits Calculations

3.3.1 Converting CAMx Ozone Outputs to Benefits Inputs

The CAMx model generates predictions of hourly ozone concentrations for every grid cell. Future-year estimates of ozone for each of three health benefits metrics for ozone were calculated using model predictions. The modeled change in ozone between the 2011 base year and the 2017 future baseline and illustrative control case were used to create relative reduction factors (RRFs) which were then applied to 2011 ambient ozone concentrations, as described below. The health benefits metrics for ozone are May through September seasonal average 8-hour daily maximum ozone concentrations. The procedures for determining the ozone RRFs for these metrics are similar to those described in EPA guidance for modeling attainment of the ozone standard (EPA, 2014). This guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in ozone concentrations for a future year emissions case. The RRFs and future year ozone concentrations were calculated using EPA's software Modeled Attainment Test Software (MATS) (Abt, 2014). EPA used MATS to estimate the ozone impacts of the emissions reductions in the 2017 illustrative control case.

For the purposes of projecting future ozone concentrations for input to the benefits calculations, we applied MATS using the base year 2011 modeling results and the results from the 2017 baseline and 2017 illustrative control case scenarios. In our application of MATS for ozone we used the ozone monitoring data centered about 2011 (2010-2012 ozone data) from the Aerometric Information Retrieval System (AIRS) as the set of base-year measured concentrations. The ambient ozone data and modeled ozone outputs were combined using the MATS "eVNA" spatial fusion technique to generate gridded sets of spatial fields (interpolated ozone metrics for each modeled 12km grid cell in the modeling domain) for each of the three ozone metrics for the 2011 base year period. The ratio of the seasonal average model-predicted future case ozone concentrations to the corresponding seasonal average model-predicted 2011 concentrations in each grid cell (RRF's) was calculated and then multiplied by the gridded interpolated ozone concentrations for each metric to produce gridded ozone concentrations for the 2017 baseline and 2017 illustrative control case. The resulting gridded files for the 2017 baseline and illustrative control cases were then input to the Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE) (version 1.1)[43] to calculate benefit per ton factors for each metric. Information on the calculation of the benefit per ton factors is provided in Chapter 6.

3.3.2 Converting CAMx $PM_{2.5}$ Outputs to Benefits Inputs

The CAMx model[44] generates predictions of hourly $PM_{2.5}$ species concentrations for every grid. The species include a primary fraction and several secondary $PM_{2.5}$ species (e.g., sulfates, nitrates, and organics). $PM_{2.5}$ is calculated as the sum of the primary and the secondary formed

[43] Abt Associates, Inc. 2012. "BenMAP User's Manual Appendices," prepared for U.S. Research Triangle Park, NC: U. S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Available at: <http://www.epa.gov/air/benmap/models/BenMAPAppendicesOct2012.pdf>. Accessed June 6, 2015

[44] ENVIRON, 2014. User's Guide Comprehensive Air Quality Model with Extensions version 6.11, www.camx.com. ENVIRON International Corporation, Novato, CA.

particles. Future-year estimates of $PM_{2.5}$ were calculated using RRFs applied to 2010-2012 ambient $PM_{2.5}$ and $PM_{2.5}$ species concentrations, as described below.

The procedures for determining the RRFs are similar to those in EPA guidance for modeling the $PM_{2.5}$ NAAQS (EPA, 2014). This guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each $PM_{2.5}$ species. The modeled attainment test procedure for calculating future year $PM_{2.5}$ values is described in the modeling guidance and is codified in EPA's MATS. EPA used this procedure to estimate the ambient impacts of the emissions reductions in the 2017 illustrative control case. For the purposes of projecting future $PM_{2.5}$ concentrations for input to the benefits calculations, we applied the modeled attainment test procedure using the base year 2011 modeling results and the results from the 2017 baseline and 2017 illustrative control case. In our application of MATS for $PM_{2.5}$ we used the $PM_{2.5}$ monitoring data and speciated monitoring data centered about 2011 (2010-2012) from the state $PM_{2.5}$ Federal Reference Method (FRM) network, the Chemical Speciation Network (CSN) and Interagency Monitoring of Protected Visual Environments (IMPROVE) network as the set of base-year measured concentrations. The ambient $PM_{2.5}$ and species data and modeled $PM_{2.5}$ and species outputs were combined using the MATS "eVNA" spatial fusion technique to generate gridded sets of spatial fields (interpolated annual average $PM_{2.5}$ and species concentrations for each modeled 12km grid cell in the modeling domain) for the 2011 base year period. The ratio of the quarterly average model-predicted future case $PM_{2.5}$ species concentrations to the corresponding quarterly average model-predicted 2011 species concentrations in each grid cell (RRF's) were calculated and then multiplied by the gridded interpolated $PM_{2.5}$ species concentrations to produce gridded $PM_{2.5}$ species concentrations for the 2017 baseline and 2017 illustrative control case. Output files from this process include both quarterly and annual mean $PM_{2.5}$ mass concentrations and $PM_{2.5}$ species concentrations which are then processed to produce BenMAP input files containing annual mean $PM_{2.5}$ mass concentrations for the 2017 baseline and for the 2017 illustrative control case. These data files were then input to BenMAP to calculate $PM_{2.5}$ benefit per ton factors. Information on the calculation of the benefit per ton factors is provided in Chapter 6.

3.4 References

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CHAPTER 4: REGULATORY CONTROL ALTERNATIVES

Introduction

The primary purpose of this proposal is to address interstate air quality impacts with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS). The EPA promulgated the Cross-State Air Pollution Rule (CSAPR) on July 6, 2011,[45] to address interstate transport of ozone pollution under the 1997 ozone NAAQS.[46] This action proposes to update CSAPR to reduce interstate transport of electricity generating unit (EGU) ozone-season (May 1 through September 30) emissions of nitrogen oxides (NO_X) that contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone NAAQS in downwind states. The EPA proposes to implement the proposed EGU NO_X reductions by setting emissions budgets (limits on allowable emissions) that are implemented through the CSAPR NO_X ozone-season allowance trading program. As described in the preamble, the EPA is proposing transport Federal Implementation Plans (FIPs) in this action. The EPA is proposing transport FIPs for 23 eastern states. The EPA would finalize a FIP for any state that does not have an approved State Implementation Plan (SIP) addressing its good neighbor obligation by the date the rule is finalized.

This Regulatory Impact Analysis (RIA) evaluates the benefits, costs and certain impacts of three different illustrative regulatory control alternatives. The alternatives differ in the level of the NO_X emissions budget. One of the alternatives represents the proposed budgets which are based on a uniform NO_X control cost of $1,300 per ton (2011$), whereas the other two more and less stringent alternatives represent budgets based on uniform NO_X control costs of $3,400 per ton and $500 per ton (2011$), respectively. The regulatory control alternatives also differ in the size of the assurance limit, which equals 21 percent of the NO_X ozone-season emissions budget, for 2017 and following years for each state. The assurance provision limits the total ozone season

[45] *See* 76 FR 48208 (July 6, 2011)

[46] CSAPR also addressed interstate transport of fine particulate matter ($PM_{2.5}$) under the 1997 and 2006 $PM_{2.5}$ NAAQS.

NO_X emissions from affected EGUs for each state as described below. Other key regulatory features of the proposed allowance trading program, such as the ability to bank allowances for future use, are the same across all three alternatives. This chapter describes the three alternatives analyzed in the RIA.

4.1 Background

As described in detail in the preamble as well as in Chapter 1, the proposed rule requires 23 states in the eastern U.S. to reduce interstate emission transport that significantly contributes to nonattainment, or interferes with maintenance, of the 2008 ozone NAAQS by reducing their ozone season EGU NO_X emissions in 2017 and future years. The rule proposes emissions budgets, which are allowable emissions after reducing significant contribution to nonattainment and interference with maintenance of the 2008 ozone NAAQS for the emissions of affected EGUs in the 23 states. The reductions required by the proposed rule would be achieved through a FIP in any state that does not have an approved SIP addressing its contribution by the date this rule is finalized. Furthermore, under the FIPs, affected EGUs would participate in the CSAPR NO_X ozone-season allowance trading program. The allowance trading program is the remedy in the FIP that achieves the ozone season NO_X emission reductions required by the proposed rule. The allowance trading program essentially converts the EGU NO_X emissions budget for each of the 23 states subject to the FIP into a limited number of NO_X allowances that, on a tonnage basis, equal the state's ozone season emissions budget. EGUs covered by the seasonal NO_X allowance trading program in the proposed FIPs are able to trade NO_X ozone-season emission allowances among EGUs within their state and across state boundaries, with emissions and the use of allowances subject to certain limits. This RIA analyzes the benefits, costs, and certain impacts of implementing the regulatory control alternative through the allowance trading program assuming that all 23 states are subject to the proposed FIPs.

In accordance with Executive Orders 12866 and 13563, and the guidelines of OMB Circular A-4, this RIA analyzes the benefits and costs associated with emissions controls to comply with the proposal to update CSAPR. OMB Circular A-4 requires analysis of one potential alternative standard level more stringent the proposed standard and one less stringent than the revised standard. In response to this requirement, this RIA analyzes the proposed remedy under the FIP as well as a more and a less stringent option (i.e., alternative) to the proposal under the FIP. The more and less stringent options differ from the proposed remedy in that they set different EGU NO_X ozone-season emissions budgets for the affected EGUs.

4.2 Regulatory Control Alternatives Considered

This RIA analyzes the benefits, costs and certain impacts of the proposed rule. In the proposed rule, the EGU ozone-season NO_X emissions budgets for each state are based on applying a uniform cost of $1,300 per ton (2011$) to affected EGUs. This uniform cost of reducing a ton of NO_X emissions reflects the cost of NO_X reduction technologies that are both widely available and can be implemented in the near-term (i.e., by 2017). The budget setting process is described in the preamble and in detail in the proposal's Ozone Transport Policy Analysis Technical Support Document (TSD)[47]. Furthermore, this RIA analyzes regulatory control alternatives with higher and with lower EGU emissions budgets. The EGU emissions budgets in these more and less stringent regulatory control alternatives are based on uniform NO_X costs of $3,400 and $500 per ton (2011$), respectively. The rationale for choosing these regulatory control alternatives for analysis in the RIA is described in Section 4.3.

As described in Chapter 5 of this RIA, the benefits, costs, and impacts of the proposed rule are estimated, in part, by an economic model estimating how affected EGUs may comply with the proposed rule. In addition to the limitation on ozone-season NO_X emissions required by the proposed EGU emissions budgets for the 23 states, there are four important features of the allowance trading program that are represented in the model that may influence the level and location of NO_X emissions from affected EGUs. They are: the ability of affected EGUs to buy and sell ozone-season NO_X emissions allowances from one another for compliance purposes; the ability of affected EGUs to bank ozone-season NO_X allowances for future use; the effect of limits on the total ozone-season NO_X emissions from affected EGUs in each state required by the assurance provisions; and the treatment of banked 2015 and 2016 vintage ozone-season NO_X allowances issued under CSAPR to address interstate ozone transport for the 1997 ozone NAAQS. Each of these features of the ozone-season allowance trading program is described below.

[47] Available in the rulemaking docket: EPA-HQ-OAR-2015-0500.

Affected EGUs are expected to choose the least-cost method of complying with the requirements of the allowance trading program. As described in Chapter 5, in the modeling of EGU compliance, the distribution of ozone season NO_X emissions across affected EGUs is generally governed by this cost-minimizing behavior. In the analysis, the total ozone season NO_X emissions from affected EGUs are limited to the amount allowed by the sum of the NO_X budgets across the 23 states. Furthermore, as allowances may be banked for future use, if it is less costly to abate ozone season NO_X emissions in a current ozone season than to abate emissions in a later ozone season, affected EGUs are expected to bank NO_X ozone-season allowances in the current ozone season for use in the later ozone season. Again, the ability of EGUs to bank allowances is represented in the compliance modeling discussed in Chapter 5, and the number of banked allowances is based on an outcome that minimizes the cost of complying with the NO_X ozone-season emissions budgets over time.

While there are no explicit limits on the exchange of allowances between affected EGUs and on the banking of 2017 and future vintage NO_X ozone-season allowances in the proposal, the assurance provisions limit the amount of seasonal NO_X emissions by affected EGUs in each of the 23 states. The assurance level limits affected EGU emissions over an ozone season to the state's NO_X ozone-season emissions budget plus an increment equal to 21 percent of each state's emissions budget. The increment is called the variability limit. See section VII.B.4 of the preamble for a discussion of the purpose of the assurance provision and further detail about how the variability and assurance limits are determined. If a state exceeds its assurance level in a given year it is assessed a 2-to-1 allowance surrender on the excess tons. Section VII.B.4 of the preamble also explains how EPA then determines which EGUs are subject to this surrender requirement. In the analysis in this RIA the assurance provisions are represented by a limit on the total amount of ozone season NO_X emissions that can be emitted by affected EGUs in each state. That is, in the analysis, affected EGUs do not have the option of surrendering additional allowances at the 2-to-1 rate in the compliance modeling.

As described in section VII.B.5 of the preamble the rule proposes to allow 2015 and 2016 vintage NO_X ozone-season allowances that were issued under CSAPR to address interstate ozone transport for the 1997 ozone NAAQS to be used for compliance with this rule that reduces interstate ozone transport for the 2008 ozone NAAQS. Specifically, 2015 and 2016 vintage

CSAPR NO_X ozone-season allowances may be used for compliance with this rule from 2017 forward.[48] If an EGU in one of the 23 states affected by this proposed rule chooses to do so, it must use four pre-2017 vintage allowances to cover one ton of NO_X emitted. Based on EPA's expectation of the size of the NO_X allowance bank after the 2016 ozone season, the treatment of these banked allowances is represented in the modeling as an additional 71,982 tons of NO_X allowances that may be used by affected EGUs during the 2017 ozone season or in later ozone seasons.

Table 4.1 reports the seasonal budget for each of the 23 affected states. It also shows the sum of all of the emissions budgets across all 23 states. As described above, in both the proposed rule and the analysis in this RIA, emissions from affected EGUs in the entire region cannot exceed this sum but for the ability to use banked allowances from previous years. Furthermore, as described above, emissions from affected EGUs in a particular state may not exceed the state's budget plus the assurance provision during the ozone season in any year (in 2017 and later).

Table 4-1 Ozone-Season NO_X Emissions Budgets (Tons) for Proposed, More Stringent and Less Stringent Regulatory Control Alternatives in 2017 and Later

	Proposed Emissions Budgets Alternative	More Stringent Control Alternative	Less Stringent Control Alternative
Alabama	9,979	9,931	11,886
Arkansas	6,949	6,101	7,038
Illinois	12,078	11,992	12,144
Indiana	28,284	27,585	33,483
Iowa	8,351	8,118	8,614
Kansas	9,272	9,259	9,278
Kentucky	21,519	20,945	32,783
Louisiana	15,807	15,378	15,861
Maryland	4,026	4,026	4,026
Michigan	19,115	18,624	22,022
Mississippi	5,910	5,487	6,083
Missouri	15,323	15,240	15,380
New Jersey	2,015	2,011	2,016
New York	4,450	4,391	4,607
North Carolina	12,275	10,705	12,278
Ohio	16,660	16,637	20,194
Oklahoma	16,215	16,215	16,215

48 Allowances were only issued under CSAPR for the 2015 and 2016 ozone seasons.

	Proposed Emissions Budgets Alternative	More Stringent Control Alternative	Less Stringent Control Alternative
Pennsylvania	14,387	14,358	38,270
Tennessee	5,481	5,449	5,520
Texas	58,002	55,864	58,492
Virginia	6,818	5,834	6,955
West Virginia	13,390	12,367	22,932
Wisconsin	5,561	5,511	5,588
TOTAL	**311,867**	**302,028**	**371,665**

These regulatory control alternatives are illustrative. For example, the EGUs have flexibility in determining how they will comply with the allowance trading program. The way that they comply may differ from the methods forecast in the modeling for this RIA.

4.3 Rationale for Regulatory Control Alternatives Chosen

As described in the preamble, the $1,300 per ton uniform cost used to set the proposed EGU NO_X ozone-season emissions budgets for the affected states is based on control technologies that are both widely available and can be implemented in the near-term (i.e., by 2017). The uniform cost of $500 per ton was used to establish NO_X ozone-season emissions budgets for CSAPR and in this current rulemaking is the cost of fully optimizing post-combustion controls that are already running. The uniform cost of $3,400/ton was used to establish NO_X ozone-season emissions budgets for the NO_X SIP Call and reflects the cost of turning on idled existing SNCRs. The proposal takes comment on budgets based on these two uniform cost thresholds. Therefore evaluating the benefits and costs of complying with these higher and lower budgets both responds to the requirement of Circular A-4 to evaluate a less and a more stringent option (i.e., alternatives) and is informative to evaluating alternative control stringencies on which the EPA is seeking comment. Achievable emission reductions from higher uniform NO_X cost levels were also evaluated for this proposal. Budgets are not being proposed for this rule based on these higher uniform cost levels as they are based on the application of NO_X controls that could not be installed in the near term (i.e., by 2017). See section VI of the preamble and the Ozone Transport Policy Analysis TSD for further explanation.

CHAPTER 5: COST, ECONOMIC, ENERGY, AND EMPLOYMENT IMPACTS

Overview

This chapter reports the compliance cost, emissions, economic, energy and employment impact analyses performed for the proposal to update CSAPR. The EPA used the Integrated Planning Model (IPM), developed by ICF International, to conduct most of the analysis discussed in this chapter. The EPA conducted additional analysis using the IPM estimates of changes in the power and fuels sector as a basis for examining the potential direct labor impacts in those sectors.

IPM is a dynamic linear programming model of the power sector that can be used to examine air pollution control policies affecting NO_X, CO_2, SO_2, mercury (Hg), hydrochloric acid (HCl), and other air pollutants throughout the contiguous United States for the entire power system. Future-year electricity demand levels are based on projections from the Energy Information Administration (EIA).

This chapter of the RIA presents analyses of the proposed rule that include assumptions about the possible actions that EGUs may pursue as they reduce their NO_X emissions to comply with the proposed EGU NO_X ozone-season emissions budgets in the 23-state region. Over the past two decades, the EPA has used IPM and other analytical methods described in this chapter to conduct extensive analyses of proposed and final federal environmental regulatory actions affecting the power sector. These previous analytical efforts support the Agency's understanding of key variables that influence the effects of a policy and provide the framework for how the Agency estimates the costs and benefits associated with its actions.

5.1 Power Sector Modeling Framework

IPM is a state-of-the-art, peer-reviewed, dynamic linear programming model that can be used to project power sector behavior under future business-as-usual conditions, and to examine prospective air pollution control policies throughout the contiguous United States for the entire electric power system. EPA used IPM to project likely future electricity market conditions with and without the proposed updates to CSAPR.

IPM is a multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides estimates of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[49]

The model incorporates a detailed representation of the fossil-fuel supply system that is used to estimate equilibrium fuel prices. The model includes an endogenous representation of the North American natural gas supply system through a natural gas module that reflects a partial supply/demand equilibrium of the North American gas market, accounting for varying levels of potential power sector and non-power sector gas demand and corresponding gas production and price levels.[50] This module consists of 118 supply, demand, and storage nodes and 15 liquefied natural gas re-gasification facility locations that are tied together by a series of linkages (i.e., pipelines) that represent the North American natural gas transmission and distribution network.

IPM also endogenously models the partial equilibrium of coal supply and EGU coal demand levels throughout the contiguous U.S., taking into account assumed non-power sector demand and imports/exports. IPM reflects 36 coal supply regions, 14 coal grades, and the coal transport network, which consists of over four thousand linkages representing rail, barge, and truck and conveyer linkages. The coal supply curves in IPM were developed during a thorough

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[49] The documentation of EPA's Base Case using IPM (v5.15) contains detailed information, including all the underlying assumptions, data sources, and architecture parameters. The documentation for EPA's Base Case v.5.15 using IPM consists of a comprehensive document for IPM v. 5.13, and an incremental update document for both v.5.14 and v.5.15. All are available at available at:

http://www.epa.gov/airmarkets/powersectormodeling.html

[50] See Chapter 10 of EPA's Base Case using IPM (v5.15) documentation, available at: http://www.epa.gov/airmarkets/powersectormodeling.html

bottom-up, mine-by-mine approach that depicts the coal choices and associated supply costs that power plants would face if selecting that coal over the modeling time horizon. The IPM documentation outlines the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 36 coal regions' supply curves.[51]

To estimate the annualized costs of additional capital investments in the power sector, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. The CRF is derived from estimates of the power sector's cost of capital (i.e., private discount rate), the amount of insurance coverage required, local property taxes, and the life of capital.[52] It is important to note that there is no single CRF factor applied in the model; rather, the CRF varies across technologies, book life of the capital investments, and regions in the model in order to better simulate power sector decision-making.

The EPA has used IPM extensively over the past two decades to analyze options for reducing power sector emissions. Previously, the model has been used to estimate the costs, emission changes, and power sector impacts for the Clean Air Interstate Rule (U.S. EPA, 2005), the 2011 Cross-State Air Pollution Rule (CSAPR) (U.S. EPA, 2005), the Mercury and Air Toxics Standards (MATS) (U.S. EPA, 2011a), the Clean Power Plan (CPP) for Existing Power Plants (U.S. EPA, 2015), and the Carbon Pollution Standards for New Power Plants (U.S. EPA, 2015a). EPA has also used IPM to estimate the air pollution reductions and power sector impacts of water and waste regulations affecting EGUs, including Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014), Disposal of Coal Combustion Residuals from Electric Utilities (CCR) (U.S. EPA, 2015b) and Steam Electric Effluent Limitation Guidelines (ELG) (U.S. EPA, 2015c).

The model and EPA's input assumptions undergo periodic formal peer review. The rulemaking process also provides opportunity for expert review and comment by a variety of stakeholders, including owners and operators of capacity in the electricity sector that is

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[51] See Chapter 9 of EPA's Base Case using IPM (v.5.15) documentation, available at: http://www.epa.gov/airmarkets/powersectormodeling.html

[52] See Chapter 8 of EPA's Base Case using IPM (v5.15) documentation, available at: http://www.epa.gov/airmarkets/powersectormodeling.html

represented by the model, public interest groups, and other developers of U.S. electricity sector models. The feedback that the Agency receives provides a highly-detailed review of key input assumptions, model representation, and modeling results. IPM has received extensive review by energy and environmental modeling experts in a variety of contexts. For example, in the late 1990s, the Science Advisory Board reviewed IPM as part of the CAA Amendments Section 812 prospective studies[53] that are periodically conducted. The model has also undergone considerable interagency scrutiny when it was used to conduct over a dozen legislative analyses (performed at Congressional request) over the past decade. The Agency has also used the model in a number of comparative modeling exercises sponsored by Stanford University's Energy Modeling Forum over the past 15 years. IPM has also been employed by states (e.g., for RGGI, the Western Regional Air Partnership, Ozone Transport Assessment Group), other Federal and state agencies, environmental groups, and industry.

5.2 EPA's Power Sector Modeling Base Case for the Proposal to Update CSAPR

The IPM "base case" for any regulatory impact analysis is a business-as-usual scenario that would be expected under market and regulatory conditions in the absence of the rule. As such, an IPM base case represents an element of the baseline for this RIA.[54] The EPA frequently updates the IPM base case to reflect the latest available electricity demand forecasts from the U.S. Energy Information Agency (EIA) as well as expected costs and availability of new and existing generating resources, fuels, emission control technologies, and regulatory requirements.

Our analysis of the proposal to update CSAPR involved two different IPM base cases. The EPA used IPM version 5.14 (IPM v.5.14) to provide power sector emissions data for air quality modeling. Specifically, IPM v.5.14 was used for the air quality modeling of a 2017 baseline and 2017 illustrative control case. This air quality modeling and IPM v.5.14 are detailed in Chapter

[53] http://www2.epa.gov/clean-air-act-overview/benefits-and-costs-clean-air-act

[54] As described in Chapter 5 of EPA's *Guidelines for Preparing Economic Analyses*, the baseline "should incorporate assumptions about exogenous changes in the economy that may affect relevant benefits and costs (e.g., changes in demographics, economic activity, consumer preferences, and technology), industry compliance rates, other regulations promulgated by EPA or other government entities, and behavioral responses to the proposed rule by firms and the public." (USEPA, 2010).

3.[55] IPM v.5.14 was also used for the air quality modeling to quantify upwind state contributions, described in Section V of the preamble for this proposal.

After these air quality modeling scenarios were underway, the EPA released an updated IPM base case, version 5.15 (IPM v.5.15), and the final Clean Power Plan (CPP). The EPA used IPM v.5.15 for developing the proposed state NO_X emissions budgets discussed in Chapter 4 of this RIA, and for analyzing the proposed rule's cost, benefits and impacts. The EPA relied on IPM v.5.15 for these analyses so that the baseline for this RIA would reflect all on-the-books policies, including the CPP, as well as the most current power sector modeling data. Using IPM v.5.15 for these analyses provides EPA with the best information available to develop the proposed rule and to provide the public with the most current information possible.

5.2.1 EPA's IPM Base Case v.5.15

When the EPA began using the current version of IPM (version 5), the EPA developed a comprehensive updated base case (v.5.13), as well as a companion updated database of EGU units (the National Electricity Energy Data System, or NEEDS v.5.13) that is used in EPA's modeling applications of IPM. The EPA base case is updated periodically to reflect the annual electricity demand forecasts from the EIA, among other data updates. EPA's IPM modeling platform used to analyze this proposed rule (v.5.15) incorporates the version of the model used to analyze the potential impacts of the CPP, which was finalized in August, 2015. As discussed below in Section 5.2.2, the base case for the proposal to update CSAPR also includes certain revisions to the v.5.15 base case used in the CPP analysis.

The updates to the base case between v.5.14 and v.5.15 include an update to the natural gas supply as well as routine calibrations with the EIA's Annual Energy Outlook (AEO), such as updating the electric demand forecast consistent with the AEO 2015.[56] Additional updates, based on the most up-to-date information and/or public comments received by the EPA, include unit-

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[55] As described in Chapter 3, the baseline used for the air quality modeling used to generate the benefit-per-ton estimates used in Chapter 6, differs from the baseline used to estimate the benefits, costs and impacts of the proposed rule and more and less stringent alternatives.

[56] The naming conventions used for EPA's IPM modeling (such as v.5.15) reflect both the major overall version of IPM (v.5) and which iteration of the AEO (currently AEO 2015) that supplies the electricity demand forecast used in IPM.

level specifications (e.g., pollution control configurations), planned power plant construction and closures, and updated cost and performance for onshore wind and utility-scale solar technologies. The IPM v.5.15 modeling platform incorporates federal and most state laws and regulations whose provisions were either in effect or enacted and clearly delineated by March 2015. This update also includes two non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule (U.S. EPA, 2014)..Combustion Residuals from Electric Utilities (CCR) (U.S. EPA, 2015b).. Additionally, all new capacity projected by the model is compliant with Clean Air Act 111(b) standards, including the final standards of performance for GHG emissions from new sources[57]. For a detailed account of all updates made to the v.5.15 modeling platform, see the Incremental Documentation for EPA Base Case v.5.15 Using IPM.[58]

EPA also updated the National Electric Energy Data System (NEEDS)[59]. This database contains the unit-level data that is used to construct the "model" plants that represent existing and committed units in EPA modeling applications of IPM. NEEDS includes detailed information on each individual EGU, including geographic, operating, air emissions, and other data on every generating unit in the contiguous U.S.

5.2.2 The IPM Base Case Used to Analyze the Proposal to Update CSAPR

As discussed above, IPM Base Case v.5.15 was used as the base case in EPA's analysis of the final CPP, which was finalized in August, 2015. We are using a different IPM base case for this analysis of the proposal to update CSAPR to reflect the fact that the Clean Power Plan is now a finalized and promulgated federal regulation. The CPP is now a part of the business-as-usual scenario that would be expected under market and existing regulatory conditions in the absence of this proposal.

The base case used to analyze the proposal to update CSAPR is the IPM configuration EPA used to analyze one of the final CPP illustrative policy options. Specifically, the base case used in the current analysis is the IPM configuration for the CPP's "rate-based" illustrative plan

[57] http://www2.epa.gov/cleanpowerplan/carbon-pollution-standards-new-modified-and-reconstructed-power-plants

[58] Available at: http://www.epa.gov/airmarkets/powersectormodeling.html/

[59] http://www2.epa.gov/airmarkets/power-sector-modeling-platform-v515

approach. Using the CPP rate-based IPM configuration for the proposed CSAPR analysis assures that the IPM results are the incremental impacts on the power sector of the proposal to update CSAPR alone, and avoids "double counting" the impacts of the CPP as well as all other federal and state regulations included the v.5.15 base case. Extensive information on the IPM configuration and detailed results of the CPP rate-based analysis is available in the Clean Power Plan Final Rule – Regulatory Impact Analysis[60] for the CPP as well as at EPA's Power Sector Modeling website. [61]

The 2017 baseline EGU emissions include impacts from the Final MATS announced on December 21, 2011[62] and CSAPR issued on July 6, 2011. The EPA notes that because the modeling for the proposal was performed prior to the D.C. Circuit's issuance of EME Homer City II,[63] that modeling assumed in its baseline for all states the emission reductions associated with the CSAPR NO_X ozone-season phase 2 emissions budgets.

5.3 Evaluating the Regulatory Control Alternatives

To estimate the costs, benefits, and economic and energy market impacts of the proposal to update CSAPR, the EPA conducted quantitative analysis of three regulatory control alternatives: the proposed EGU NO_X ozone-season emissions budgets that reflect EGU NO_X control strategies represented by a uniform NO_X cost of $1,300 per ton (2011$); and more and less stringent alternative EGU NO_X ozone-season emissions budgets that reflect EGU NO_X control strategies represented by uniform NO_X costs of $3,400 per ton and $500 per ton (2011$), respectively. Details about these regulatory control alternatives, including state-specific EGU NO_X ozone-season emissions budgets for each alternative, are provided in Chapter 4 of this RIA.

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[60] Available at: http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-regulatory-impact-analysis

[61] Available at: http://www.epa.gov/airmarkets/powersectormodeling.html/

[62] In Michigan v. EPA, the Supreme Court reversed on narrow grounds a portion of the D.C. Circuit decision upholding MATS, finding that EPA erred by not considering cost when determining that regulation of EGUs was "appropriate" pursuant to CAA section 112(n)(1). 135 S.Ct. 192 (2015). The case was remanded to the D.C. Circuit for further proceedings, and because MATS was remanded but not vacated, MATS currently remain in place.

[63] *EME Homer City Generation, L.P., v. EPA*, No. 795 F.3d 118, 129-30, 138 (*EME Homer City II*)

Before undertaking power sector analysis to evaluate compliance with the regulatory control alternatives, the EPA first considered available EGU NO_X mitigation strategies that could be implemented for the first compliance period (i.e., the 2017 ozone season) assuming that this rule is finalized in the summer of 2016. The EPA considered all widely used EGU NO_X control strategies: fully operating existing selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) – including optimizing NO_X removal by existing, operational SCRs and SNCRs as well as turning on and optimizing existing idled SCRs and SNCRs; installation of (or upgrading to) state-of-the-art NO_X combustion controls; shifting generation to units with lower NO_X emission rates within the same state; and installing new SCRs and SNCRs. EPA determined that the power sector could implement all of these NO_X mitigation strategies, except installation of new SCRs or SNCRs, for the 2017 ozone-season, assuming this proposed rule is finalized in the summer of 2016. The installation of new SCRs or SNCRs (the amount of time from contract award through commissioning for retrofit) exceeds 18 and 12 months, respectively. It would therefore not be feasible to retrofit new SCR or SNCR to achieve EGU NO_X reductions in the 2017 ozone season. For more details on these assessments, including the assessment of EGU NO_X mitigation costs and feasibility, please refer to the EGU NO_X Mitigation Strategies TSD, in the docket for this rule[64].

The EPA notes that, due to limitations on model size, IPM v.5.15 does not have the capacity to determine, within the model, whether or not to operate existing EGU post-combustion NO_X controls (i.e., SCR or SNCR) that are idle in the base case.[65] In order to evaluate compliance with the regulatory control alternatives (including the proposal and more and less stringent alternatives), the EPA determined, outside the model, whether or not it would be reasonably expected for these controls to operate in order to comply with each of the evaluated regulatory control alternatives. After imposing the requirement to operate these control systems, IPM then estimated the associated NO_X reductions and costs.

[64] Available at: EPA-HQ-OAR-2015-0500.

[65] The EPA notes that EGUs with idled SCR or SNCR in the base represent a small percentage (less than 10 percent) of the EGU fleet that is equipped with NO_X post-combustion controls.

The EGU NO_X mitigation strategies that are assumed to operate or be available to reduce NO_X in order to comply with each of the regulatory control alternatives are shown in Table 5-1; more information about the estimated costs of these controls can be found in the EGU NO_X Mitigation Strategies TSD.

Table 5-1. NO_X Mitigation Strategies Implemented for Compliance with the Regulatory Control Alternatives

Regulatory Control Alternative	NO_X Controls Implemented
Less Stringent Alternative	(1) Fully operating existing SCRs to achieve 0.075 lb/MMBtu NO_X emission rate (outside IPM) (2) Shift generation to minimize costs (within IPM)
Proposal	(All controls above) (3) Turn on idled SCRs (within IPM) (4) Install or upgrade combustion controls (outside IPM)
More Stringent Alternative	(All controls above) (5) Turn on idled SNCRs (outside IPM)

5.3.1 Emission Reduction Assessment

As discussed in Chapter 3 the EPA determined that NO_X emissions in 23 eastern states affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS. For these 23 eastern states, the EPA is proposing to issue Federal Implementation Plans (FIPs) that generally update the existing CSAPR NO_X ozone-season emission budgets for EGUs and implement these budgets via the CSAPR NO_X ozone-season allowance trading program.

The EPA analyzed ozone-season NO_X emission reductions from implementing each of the three regulatory control alternatives. Specifically, the EPA conducted IPM modeling of each of the regulatory control alternatives to evaluate the corresponding power sector emissions reductions from complying with the EGU NO_X ozone-season emissions budgets that are provided in Chapter 4 of this RIA.

The NO_X emissions reductions are presented for two time periods – 2017 (the principal year of interest for the proposal to update CSAPR) and 2020. However, this version of IPM was not structured to simulate 2017 directly. To evaluate the 2017 ozone season EGU NO_X reductions from compliance with the regulatory control alternatives, EPA developed estimates of emissions for 2017 by adjusting IPM's direct estimates for 2018 to account for a number of known differences. For example, these adjustments account for emissions from EGUs that are expected to operate in 2017, but that have announced plans to retire by 2018 (and whose future-year emissions are thus not otherwise represented in IPM's direct 2018 estimates). The EPA has only made such adjustments for ozone season NO_X emissions given the air quality objective of the proposal to address transported ozone pollution by the 2017 ozone season.[66] For co-pollutant EGU emissions (i.e., annual NO_X, SO_2, and CO_2), the EPA assumes that the 2018 IPM results are representative of 2017 with no further adjustment. The EPA believes that this is reasonable given that the overall magnitude of the adjustments to ozone season NO_X emissions for 2017 is relatively small and that the adjustments generally affect both the base case and the regulatory control scenarios and therefore have an even smaller influence on the emissions difference between the base case and the regulatory control scenarios.

Table 5-2 presents the reduction in EGU NO_X emissions resulting from compliance with the regulatory control alternatives (i.e., emissions budgets) in the 23-state region, as well as the impact on states not in the region. The emission reductions follow an expected pattern: the less stringent alternative produces substantially smaller emission reductions than EPA's proposed emissions budgets, and the more stringent alternative results in modestly more NO_X reductions.

Table 5-2. EGU Ozone Season NO_X Emission Reductions (tons) for the Proposal and More and Less Stringent Alternatives

Ozone Season NO_X		Proposal	More Stringent Alternative	Less Stringent Alternative
2017	23-State Region	85,000	88,000	24,000
	Non-Region	-400	-500	-300
	Total	85,000	87,000	24,000
2020	23-State Region	83,000	84,000	24,000
	Non-Region	-300	-460	-260
	Total	83,000	84,000	24,000

In addition to the ozone season NO_X reductions, there will also be reductions of other air emissions emitted by EGUs burning fossil fuels (i.e., co-pollutants). These other emissions include the annual total changes in emissions of NOx, SO_2 and CO_2. The co-pollutant emission reductions are presented in Table 5-3.

[66] The 2018 emissions output from IPM were adjusted to reflect 2017 emissions levels as described in http://www.epa.gov/airmarkets/documents/ipm/Adjusted2017.pdf

Table 5-3. EGU Annual Emission Reductions (tons) for SO_2 and CO_2 for the Proposal and More and Less Stringent Alternatives

Annual NOx		Proposal	More Stringent Alternative	Less Stringent Alternative
2017	23-State Region	91,000	93,000	24,000
	Non-Region	-560	-700	-500
	Total	90,000	93,000	24,000
2020	23-State Region	92,000	94,000	24,000
	Non-Region	-1,000	-1,700	-700
	Total	91,000	92,000	24,000
Annual SO_2				
2017	23-State Region	2,000	2,160	1,800
	Non-Region	-820	-920	-710
	Total	1,200	1,200	1,100
2020	23-State Region	1,700	1,600	1,300
	Non-Region	-1,100	-1,500	-910
	Total	610	100	360
Annual CO_2				
2017	23-State Region	1,300,000	1,600,000	1,300,000
	Non-Region	-670,000	-920,000	-520,000
	Total	660,000	710,000	770,000
2020	23-State Region	1,700,000	2,200,000	1,400,000
	Non-Region	-1,400,000	-2,400,000	-1,100,000
	Total	270,000	-250,000	360,000,000

5.3.2 Compliance Cost Assessment

This section describes EPA's approach to quantify the costs for compliance with the regulatory control alternatives. IPM directly estimated the costs for three of the NO_X mitigation strategies: turning on idled SCRs, turning on idled SNCRs, and shifting generation to lower-NO_X emitting EGUs. However, the costs of increasing the use and optimizing the performance of existing and operating SCRs and SNCRs, and for installing or upgrading NO_X combustion controls, were estimated using an incremental analysis step that EPA developed to quantify the additional costs of these controls. These methods and analysis relies on data and methods used within IPM, including NO_X control cost equations used in IPM. Therefore, this analysis is consistent with IPM and provides the best available quantification of the costs of these NO_X mitigation strategies.

The following steps illustrate this analytical method and demonstrate the application of this method to the EPA's cost estimate of compliance with the proposal:

Analytical Method	Application to Estimate the Costs of Compliance with the Proposal
• Identify the IPM modeled EGU NO_X reductions that are attributable to NO_X mitigation strategies with costs that are not included in the model.	• Maximizing the use of existing SCRs accounts for approximately 33,000 tons of ozone season EGU NO_X reductions. • Installing or upgrading NO_X combustion controls accounts for approximately 7,800 tons of ozone season EGU NO_X reductions.
• Estimate the costs associated with these EGU NO_X mitigation strategies.	• Maximizing the use of existing SCRs costs approximately $500 per ton. • Installing or upgrading NO_X combustion controls costs approximately $1,200 per ton.
• Calculate the cost of each EGU NO_X mitigation strategies as applied to reduce emissions within the model.	• The cost of maximizing the use of existing SCRs is approximately $17,000,000 annually for 2017. • The cost of installing or upgrading NO_X combustion controls is approximately $9,400,000 annually for 2017.

The total costs of compliance with the regulatory control alternatives are estimated as the sum of the costs that are modeled within IPM and the costs that are calculated outside the model.

The results of EPA's IPM analysis show that, with respect to compliance with the proposed EGU NO_X emissions budgets, turning on idle existing SCRs provides the largest amount of ozone season NO_X emission reductions (51 percent), and maximizing the use of existing SCRs produces an additional 39 percent of the total ozone season NO_X reductions. Combustion controls (9 percent) and generation shifting (1 percent) make up the remainder of the ozone season NO_X reductions. In the more stringent alternative, compliance by turning on idle existing SNCRs makes up 3 percent of the total reductions, while the shares attributed to the other four mitigation measures are similar to the shares for compliance with the proposed EGU NO_X emissions budgets.

The estimates of the changes in the cost of supplying electricity for the regulatory control alternatives are presented in Table 5-4. The costs associated with compliance with monitoring, recordkeeping, and reports requirements are not included within the estimates in this table and can be found in Chapter 7.

Table 5-4. Cost Estimates (millions of 2011$) for Proposal and More and Less Stringent Alternatives

	Proposal	More Stringent Alternative	Less Stringent Alternative
Annualized*	$92.9	$95.7	$4.7
Annual 2017	$71.6	$63.4	-$47.6
Annual 2020	$48.6	$20.3	-$27.6

*Levelized annual costs over the period 2016 through 2040, discounted using the 4.77 discount rate used in IPM's objective function of minimizing the net present value (NPV) of the stream of total costs of electricity generation.

There are several notable aspects of the results presented on Table 5-4. The most notable result in Table 5-4 is that the estimated annual compliance costs for the less stringent alternative are negative (i.e., a cost reduction) in 2017 and 2020, although this regulatory control alternative reduces NO_X emissions by over 25,000 tons as shown in Table 5-3. The estimate of the cost of controls determined outside the model are positive. Therefore, the finding of net negative annual compliance costs derives from the portion of the annual compliance cost estimate that comes from IPM. While seemingly counter-intuitive, such an estimated cost reduction is quite possible given the dynamic, perfect foresight linear programing structure of IPM. IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period. For example, IPM's perfect foresight structure makes it possible that the least cost way of complying may be to delay a new investment otherwise expected to occur in the base case. Such a delay could result in a lowering of annual cost in an early time period and increases in later time periods.

A better understanding of the cause of the negative costs for the less stringent alternative can come from considering the entire time path of costs, rather than focusing on the 2017 and 2020 estimates in isolation. Because IPM only reports estimates for certain years, it is necessary to estimate the cost values for the years between the years directly simulated. A simple but straightforward method is to use a linear interpolation between the annual cost estimates for directly simulated years to estimate a potential annual compliance cost time series across all years in a given period. Figure 5-1 shows the annual cost estimates, which are the sum of the annual compliance cost estimated by IPM and the annual compliance costs estimated outside the model, for each directly simulated year from 2016 through 2040. It also shows the linearly interpolated annual cost between those years for all three of the regulatory control alternatives.[67]

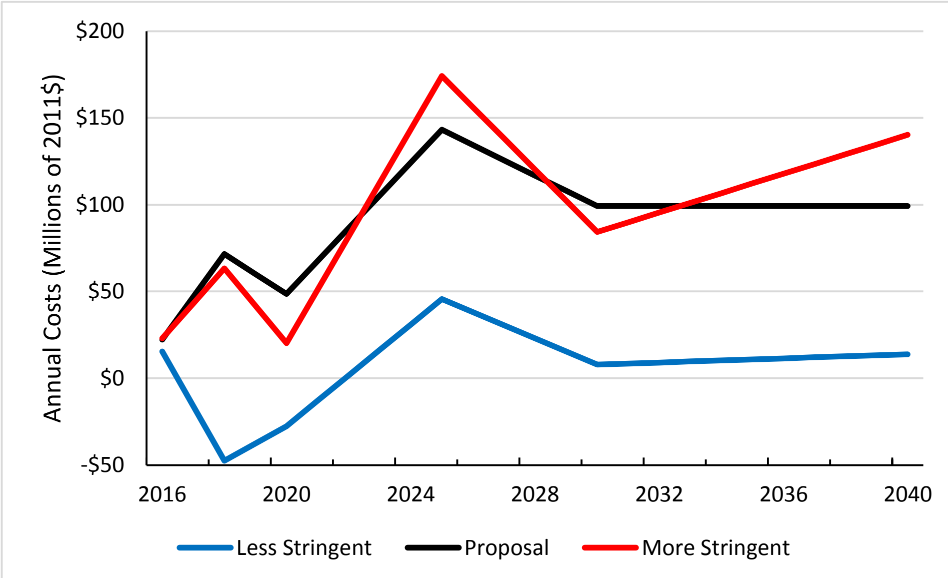

Figure 5-1. Time Series of Annual Costs for the Proposal and More and Less Stringent Alternatives

Figure 5-1 shows that while two of the IPM year cost estimates (2017 and 2020) in the less stringent alternative are negative, the rest of the annual costs are positive, resulting in the majority of the years between 2016 and 2040 having positive costs. All years have positive costs under compliance with the proposed EGU NO_X ozone-season emissions budgets and the more stringent alternative.

Using the estimated annual cost time series, it is possible to use a standard NPV calculation to estimate an annualized cost (i.e., levelized annual cost) of the annual cost stream associated with compliance with each regulatory control alternative.[68] For this analysis we first

[67] EPA estimated year-specific outside-the-model cost adjustments only for 2017 and 2020. For this analysis of the time series of costs, the outside-the-model compliance cost adjustments estimated for 2020 are added to all years between 2021 and 2040. While this approach is a relatively rougher estimate of the likely cost of the exogenously-imposed NOx controls for those years, it is consistent with an assumption that once the CSAPR update is implemented it will continue to have similar costs and emission reductions throughout the rest of the model's forecast horizon.

[68] The XNPV() function in Microsoft Excel 2013 was used to calculate the NPV of the variable stream of costs.

calculated the NPV of the stream of costs from 2016 through 2040. We calculate the NPV in 2016 of each cost stream using a 4.77 percent discount rate.[69] EPA typically uses a 3 and a 7 percent discount rate to discount future year social benefits and social costs in regulatory impact analyses (USEPA, 2010). In this cost annualization approach we use a 4.77 percent rate to be consistent with the optimization approach used within IPM. IPM's cost minimization objective function estimates the lowest possible NPV, and uses a 4.77 percent discount rate to calculate the NPV. IPM v.5.15 uses a 4.77 percent discount rate as an estimate of the real opportunity cost of capital in the power sector.[70]

After calculating the NPV of the cost streams, the same 4.77 percent discount rate and 2016-2040 time period is used to calculate the levelized annual (i.e., annualized) cost estimates shown in Table 5-3.[71]

Figure 5-2 depicts the annualized cost estimates on top of the time stream of annual costs previously presented on Figure 5-1.

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[69] While IPM also reports the costs for 2050, we do not include the 2050 estimates in this analysis. In this situation, extending the present value calculations to include 2050 does not materially change the results.

[70] The IPM Base Case documentation (Section 8.2.1 Introduction to Discount Rate Calculations) states "The real discount rate for expenditures (e.g., capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Base Case v.5.13 is 4.77%. This serves as the default discount rate for all expenditures." Section 8.2 in that documentation describes the rationale for using a real opportunity cost of capital specific to the power sector, and describes the data used to derive the 4.77 percent rate.

[71] The PMT() function in Microsoft Excel 2013 is used to calculate the level annualized cost from the estimated NPV.

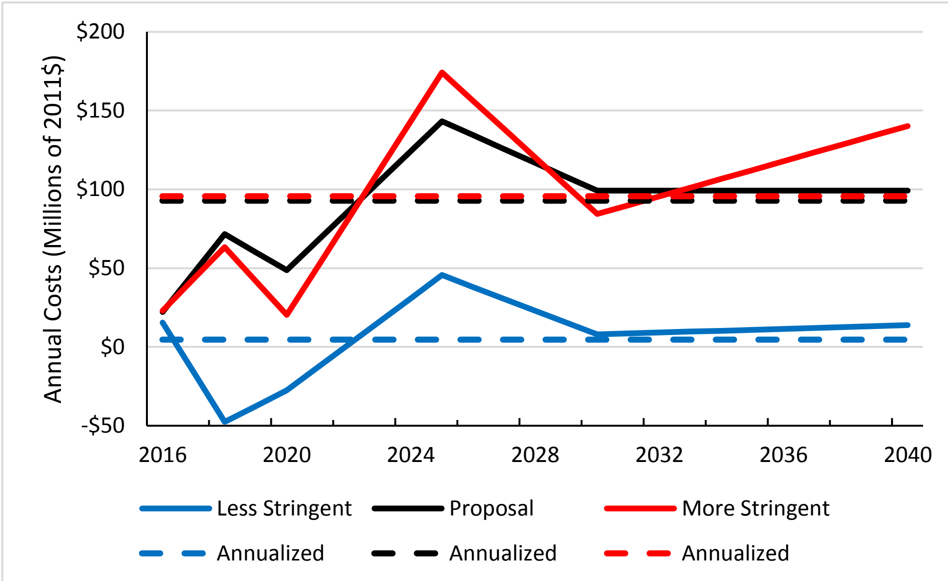

Figure 5-2. Time Series of Annual Costs and Annualized Costs for the Proposal and More and Less Stringent Alternatives

As can be seen in Table 5-3 and Figure 5-2, the annualized costs are positive for compliance with each of the three regulatory control alternatives. Furthermore, the annualized costs have the expected relationship; the annualized costs are lowest for the less stringent alternatives, and highest for the more stringent alternative.

5.3.3 Impacts on Fuel Use, Prices and Generation Mix

The proposal to update CSAPR is estimated to have a variety of different impacts to the power sector. While all the impacts are relatively small in percentage terms, considering the potential impacts in addition to the cost and emissions estimates presented previously is an important component of assessing the overall impact of the proposal. In this section of the RIA we discuss the estimated changes in fuel use, prices of fuel and retail electricity, generation by fuel type, and capacity by fuel type.

Table 5-5 presents the percentage changes in national coal and natural gas usage by EGUs in 2017. Percent changes in fuel prices are also shown. As will be seen for the other measures of impacts on the power sector, the fuel use estimates in Table 5-5 estimates reflect a modest shift to natural gas from coal.

Table 5-5. Percent Changes* in Coal and Natural Gas Usage by EGUs for the Proposal and More and Less Stringent Alternatives for 2017

	Proposal	More Stringent Alternative	Less Stringent Alternative
Change in Fuel Quantity (TBtu)			
Coal	-0.077%	-0.072%	-0.091%
Natural Gas	0.105%	0.090%	0.134%
Change in Fuel Prices			
Coal**	-0.211%	-0.279%	-0.321%
Natural Gas***	0.002%	-0.004%	0.004%

*Fuel use changes measured in TBtu
**Coal price changes are minemouth prices per MMBtu
***Natural gas price changes are delivered gas prices per MMBtu

Table 5-6 presents the projected percentage changes in the amount of electricity generation nationally in 2017 by 3 major types of electricity generation: coal, gas, and conventional hydro. The amount generated by nuclear energy is unchanged in all three alternatives.Table 5-6. Percent Changes* in Generation by Major Fuel Type for the Proposal and More and Less Stringent Alternatives for 2017

	Proposal	More Stringent Alternative	Less Stringent Alternative
Coal	-0.087%	-0.079%	-0.103%
Natural Gas	0.094%	0.101%	0.127%
Total Generation**	**0.009%**	**0.008%**	**0.009%**
Detail by Region for Proposal			
	In-Region	Non-Region	Total
Coal	-0.185%	0.174%	-0.087%
Natural Gas	0.167%	-0.009%	0.094%
Total Generation	**-0.009%**	**0.040%**	**0.009%**

*Changes in GWh generated in 2017.
**Changes in total generation is from all types of generation nationally, including fossil, non-fossil and renewable EGUs dispatching electricity to the grid.

Table 5-7 presents the projected percentage changes in the amount of generating capacity in 2017 for coal, natural gas and total capacity.

Table 5-7. Changes* in Generating Capacity by Major Fuel Type for the Proposal and More and Less Stringent Alternatives in 2017

	Proposal	More Stringent Alternative	Less Stringent Alternative
Percent Change			
Coal	-0.144%	-0.136%	-0.162%
Natural Gas	-0.006%	-0.006%	-0.006%
Total Capacity	-0.006%	-0.004%	-0.015%
Capacity Change (MW)			
Coal	-282	-318	-266
Natural Gas	-24	-95	-22

	Proposal	More Stringent Alternative	Less Stringent Alternative
Total Capacity	-60	-146	-36

*Changes in generating capacity available in 2017.

The EPA estimated the change in the retail price of electricity (2011$) using the Retail Price Model (RPM).[72] The RPM was developed by ICF International for the EPA, and uses the IPM estimates of changes in the cost of generating electricity to estimate the changes in average retail prices. The prices are average prices over consumer classes (i.e., consumer, commercial and industrial) and regions, weighted by the amount of electricity used by each class and in each region. The RPM combines the IPM annual cost estimates in each of the 64 IPM regions with EIA electricity market data for each of the 22 electricity supply regions in the electricity market module of the National Energy Modeling System (NEMS).[73]

Table 5-8 presents the projected percentage changes in the retail price of electricity for the proposal and more and less stringent alternatives. Estimates are presented for both 2017 and 2020. While all of the estimated changes in prices are quite small, Table 5-8 includes both positive and negative retail electricity price changes. This is consistent with the pattern of positive and negative annual cost estimates discussed above in Section 5.3.3, and also reflects some influence from aggregating results for the 22 NEMS regions into separate estimates for the 23 -state region affected by the proposal to update CSAPR, and the rest of the country.

[72] See documentation available at: http://www.epa.gov/powersectormodeling/

[73] See documentation available at:
http://www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068(2014).pdf

Table 5-8. Retail Electricity Price for the Proposal and More and Less Stringent Alternatives for 2017 & 2020

	Base Case	Percent Change in Retail Electricity Price		
	Price (cents/kWh)	**Proposal**	**More Stringent Alternative**	**Less Stringent Alternative**
2017				
National Price	9.93	-0.069%	-0.099%	-0.025%
23 State Region	9.69	-0.161%	-0.371%	-0.047%
Non-Region	10.75	-0.154%	-0.371%	-0.027%
2020				
National Price	10.33	0.031%	0.034%	0.009%
23 State Region	10.26	0.027%	0.028%	0.022%
Non-Region	11.11	0.018%	0.022%	-0.001%

5.3.4 Effect of Emission Reductions on Downwind Receptors

As described in Sections V and VI of the preamble, and in the *Ozone Transport Policy Analysis Proposed Rule* TSD, and summarized here, EPA evaluated the effect of the proposed rule on nonattainment and maintenance receptors with respect to interstate transport for the 2008 ozone NAAQS. The 2008 ozone standard is 0.075 parts per million (ppm), annual fourth-highest daily maximum 8 hour concentration, averaged over 3 years. As described in Section V of the preamble, the nonattainment and maintenance receptors with respect to interstate transport for the 2008 ozone NAAQS in 2017 were identified using the Comprehensive Air Quality Model with Extensions (CAMx) modeling system. From this CAMx analysis there are 37 receptors in 10 states evaluated for this proposed update to CSAPR.[74] All 37 have a maximum design value of 0.076 ppm or higher in 2017. Fourteen of these receptors have an average design value of 0.076 ppm or higher in 2017.[75] Furthermore, as described in the Ozone Transport Policy

[74] The CAMx air quality modeling scenario used to identify these receptors was also used as the baseline in Chapter 3 to estimate benefit-per-ton values for NO_X reductions.

[75] As described in the preamble, section V.C, the approach for projecting future ozone design values involved the projection of an average of up to 3 design value periods, which include the years 2009-2013 (design values for 2009-2011, 2010-2012, and 2011-2013). The average of the 3 design values creates a "5-year weighted average" value. The 5-year weighted average values and the individual design values for 2009-2011, 2010-2012, and 2011-2013 were projected to 2017. The highest of the three individual values is the "maximum" design value. We are proposing to identify nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current measured air quality and also have projected average design values of 76 parts per billion (ppb) or greater. Maintenance-only receptors, i.e., those that are at risk of not maintaining the NAAQS, therefore include both (1) those sites with projected average design values above the NAAQS that are currently measuring clean data and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 76 ppb or greater. In addition to the maintenance-only receptors, the 2017 ozone

Analysis Proposed Rule TSD, the forecast ambient concentration at these receptors was adjusted to reflect a new IPM base case (IPM v.5.15 with CPP), different from the one that was represented in the emissions inventory for the CAMx modeling of the ambient concentrations (IPM v.5.14). The results described in this subsection, and in the rest of this RIA except where otherwise noted, are from a baseline that includes IPM version 5.15 with CPP. After this adjustment to reflect the updated IPM base case, 33 of the 37 receptors have a maximum design values of 0.076 ppm or higher in 2017, while 12 have average design values of 0.076 ppm or higher in 2017.

To evaluate the effect of the proposed rule on ambient ozone concentrations at the receptors in 2017 relative to the baseline, the EPA first evaluated the response of the electricity sector to the proposed rule using IPM. The IPM analysis used to estimate the compliance cost, benefits, and impacts of the proposed rule is the same analysis used to identify the effect of the proposed rule on the level and spatial pattern of ozone seasonal NO_X emissions from EGUs.

The emissions outputs from IPM are then used to estimate the change in ambient ozone concentrations at the 37 receptors. The ozone Air Quality Assessment Tool (AQAT) is used to estimate the impact of the upwind states' EGU NO_X reductions on downwind ozone pollution concentrations. AQAT is used to forecast both the average and maximum design values at all monitors, including the 37 receptors. The ozone AQAT was developed specifically for use in the proposed rule's significant contribution analysis AQAT uses CAMx outputs to calibrate its predicted change in ozone concentrations to changes in NOx emissions. See the *Ozone Transport Policy Analysis Proposed Rule* TSD for the air quality estimates and for details on the construction of ozone AQAT.

In summary, the proposed rule is expected to reduce the average design values at the 37 receptors by 0.61 parts per billion (ppb) on average, and to reduce the maximum design values at these receptors by 0.63 ppb on average. At the 12 receptors with an average design values of 0.076 ppm or greater in the baseline, the proposed rule reduces the difference between the baseline average ambient concentration and 0.076 ppm by 14% on average (an average reduction

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nonattainment receptors are also maintenance receptors because the maximum design values for each of these sites is always greater than or equal to the average design value.

of 0.24 ppb). The proposed rule reduces the maximum design values below 0.076 ppm for 7 of the 33 receptors. Of the remaining 26 receptors with maximum design values of 0.076 ppm or greater, the proposed rule reduces the difference between the baseline maximum design value and 0.076 ppm by 21% on average (an average of reduction of 0.37 ppb). The proposed rule is therefore expected to provide notable improvements in ambient air quality at these monitors by 2017. Results for each of the 37 receptors, as well as for the more and less stringent alternatives, are described in the *Ozone Transport Policy Analysis Proposed Rule* TSD.

5.4 Employment Impacts

Executive Order 13563 directs federal agencies to consider regulatory impacts on job creation and employment. According to the Executive Order, “our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science” (Executive Order 13563, 2011). Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts,[76] we typically conduct employment analyses for economically significant rules. This section discusses and projects potential employment impacts related to today’s proposal.[77]

Section 5.5.1 describes the theoretical framework used to analyze regulation-induced employment impacts, discussing how economic theory alone cannot predict whether such impacts are positive or negative. Section 5.5.2 presents an overview of the peer-reviewed literature relevant to evaluating the effect of environmental regulation on employment. Section 5.5.3 provides background regarding recent employment trends in the electricity generation, coal and natural gas extraction sectors. Section 5.5.4 discusses the potential direct employment impacts in these sectors.

[76] Labor expenses do, however, contribute toward total costs in the EPA’s standard benefit-cost analyses.

[77] The employment analysis in this RIA is part of EPA’s ongoing effort to “conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]” pursuant to CAA section 321(a).

5.4.1 Economic Theory and Employment

Regulatory employment impacts are difficult to disentangle from other economic changes affecting employment decisions over time and across regions and industries. Labor market responses to regulation are complex. They depend on labor demand and supply elasticities and possible labor market imperfections (e.g., wage stickiness, long-term unemployment, etc.). The unit of measurement (e.g., number of jobs, types of jobs, hours worked, and earnings) may affect observability of that response. Net employment impacts are composed of a mix of potential declines and gains in different areas of the economy (e.g., the directly regulated sector, the environmental protection sector, upstream and downstream sectors, etc.) over time. In light of these difficulties, economic theory provides a constructive framework for analysis.

Microeconomic theory describes how firms adjust their use of inputs in response to changes in economic conditions.[78] Labor is one of many inputs to production, along with capital, energy, and materials. In competitive markets, firms choose inputs and outputs to maximize profit as a function of market prices and technological constraints.[79,80] Berman and Bui (2001) adapt this model to analyze how environmental regulations affect labor demand.[81] They model environmental regulation as effectively requiring certain factors of production, such as pollution abatement capital, at levels that firms would not otherwise choose. Berman and Bui (2001) model two components that drive changes in firm-level labor demand: output effects and substitution effects.[82] Regulation affects the profit-maximizing quantity of output by changing the marginal cost of production. If a regulation causes marginal production cost to increase, it will place upward pressure on output prices, leading to a decrease in demand, and resulting in a decrease in production. The output effect describes how, holding labor intensity constant, a

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[78] See Layard and Walters (1978), a standard microeconomic theory textbook, for a discussion, in Chapter 9.

[79] See Hamermesh (1993), Ch. 2, for a derivation of the firm's labor demand function from cost-minimization.

[80] In this framework, labor demand is a function of quantity of output and prices (of both outputs and inputs).

[81] Morgenstern, Pizer, and Shih (2002) develop a similar model.

[82] The authors also discuss a third component, the impact of regulation on factor prices, but conclude that this effect is unlikely to be important for large competitive factor markets, such as labor and capital. Morgenstern, Pizer and Shih (2002) use a very similar model, but they break the employment effect into three parts: 1) a demand effect; 2) a cost effect; and 3) a factor-shift effect.

decrease in production causes a decrease in labor demand. As noted by Berman and Bui, although many assume that regulations must increase marginal cost, in some cases they may decrease it. A regulation could induce a firm to upgrade to less polluting and more efficient equipment that lowers the marginal cost of production. In such a case, output could increase after firms comply with the regulation. An unregulated profit-maximizing firm may not have chosen to install such an efficiency-improving technology if the return on investment were too low, but once the technology is in place it lowers marginal production costs.

The substitution effect describes how, holding output constant, regulation affects the labor-intensity of production. Although increased environmental regulation may increase use of pollution control equipment and energy to operate that equipment, the impact on labor demand is ambiguous. For example, equipment inspection requirements, specialized waste handling, completing required paperwork, or pollution technologies that alter the production process may affect the number of workers necessary to produce a unit of output. Berman and Bui (2001) model the substitution effect as the effect of regulation on pollution control equipment and expenditures required by the regulation and the corresponding change in the labor-intensity of production.

In summary, as output and substitution effects may be positive or negative, economic theory alone cannot predict the direction of the net effect of regulation on labor demand. In addition, the empirical literature illustrates difficulties with estimation of net employment impacts. The most commonly used empirical methods, for example, Greenstone (2002), likely overstate employment impacts because they rely on relative comparisons between more regulated and less regulated counties, which can lead to "double counting" of impacts when production and employment shift from more regulated towards less regulated areas. Thus these empirical methods cannot be used to estimate net employment effects.[83]

The conceptual framework described thus far focused on regulatory effects on plant-level decisions within a regulated industry, but employment impacts at an individual plant do not necessarily represent impacts for the sector as a whole. At the industry-level, labor demand is

[83] See Greenstone (2002) p. 1212.

more responsive if: (1) the price elasticity of demand for the product is high, (2) other factors of production can be easily substituted for labor, (3) the supply of other factors is highly elastic, or (4) labor costs are a large share of total production costs.[84] For example, if all firms in an industry are faced with the same regulatory compliance costs and product demand is inelastic, then industry output may not change much, and output of individual firms may change slightly.[85]

In addition to changes to labor demand in the regulated industry, net employment impacts encompass changes in other related sectors, for example, the environmental protection sector. This proposal may increase demand for the nitrogenous reagent (typically ammonia or urea) used in SCRs and SNCRs to reduce NOx, which may increase revenue and employment in the firms providing these chemicals.

If the U.S. economy is at full employment, even a large-scale environmental regulation is unlikely to have a noticeable impact on aggregate net employment.[86] Instead, labor in affected sectors would primarily be reallocated from one productive use to another (e.g., from producing electricity to manufacturing, installing, or operating and maintaining pollution-abatement equipment), and net national employment effects from environmental regulation would be small and transitory (e.g., as workers move from one job to another).[87] Some workers may retrain or relocate in anticipation of new requirements or require time to search for new jobs, while shortages in some sectors or regions could bid up wages to attract workers. These adjustment costs can lead to local labor disruptions.

If, on the other hand, the economy is operating at less than full employment, economic theory does not clearly indicate the direction or magnitude of the net impact of environmental regulation on employment; it could cause either a short-run net increase or short-run net decrease (Schmalansee and Stavins, 2011). For example, the Congressional Budget Office considered

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[84] See Ehrenberg & Smith, p. 108.

[85] This discussion draws from Berman and Bui (2001), pp. 293.

[86] Full employment is a conceptual target for the economy where everyone who wants to work and is available to do so at prevailing wages is actively employed. The unemployment rate at full employment is not zero.

[87] Arrow *et al.* 1996; see discussion on bottom of p. 8. In practice, distributional impacts on individual workers can be important, as discussed in later paragraphs of this section.

EPA's Mercury Air Toxics Standards and regulations for industrial boilers and process heaters as potentially leading to short-run net increases in economic growth and employment, driven by capital investments for compliance with the regulations (Congressional Budget Office, 2011). Environmental regulation may also affect labor supply and productivity. In particular, reducing pollution and other environmental risks may improve labor productivity or employees' ability to work.[88] While the theoretical framework for analyzing labor supply effects is analogous to that for labor demand, it is more difficult to study empirically. There is a small emerging literature that uses detailed labor and environmental data to assess these impacts.

To summarize, economic theory provides a framework for analyzing the impacts of environmental regulation on employment. The net employment effect incorporates expected employment changes (both positive and negative) in the regulated sector and other related sectors including the environmental protection sector. Labor demand impacts for regulated firms, and also for the regulated industry, can be decomposed into output and substitution effects which may be either negative or positive. Estimation of net employment effects for regulated sectors is possible when data of sufficient detail and quality are available. Finally, economic theory suggests that labor supply effects are also possible. In the next section, we discuss the empirical literature.

5.4.1.2 Current State of Knowledge Based on the Peer-Reviewed Literature

The peer-reviewed empirical literature specifically estimating employment effects of environmental regulations is limited but growing. We summarize it briefly in this section.

5.4.1.3 Regulated Sector

Several empirical studies, including Berman and Bui (2001) and Ferris, Shadbegian, and Wolverton (2014), suggest that regulation-induced net employment impacts may be zero or slightly positive, but small in the regulated sector. Gray et al (2014) find that pulp mills that had to comply with both the air and water regulations in EPA's 1998 "Cluster Rule" experienced relatively small, and not always statistically significant, decreases in employment. Other research on regulated sectors suggests that employment growth may be lower in more regulated areas

[88] E.g. Graff Zivin and Neidell (2012).

(Greenstone 2002, Walker 2011, 2013). However, since these latter studies compare more regulated to less regulated counties, this methodological approach likely overstates employment impacts to the extent that regulation causes plants to locate in one area of the country rather than another, which would lead to "double counting" of the employment impacts. List *et al.* (2003) find some evidence that this type of geographic relocation may be occurring.

5.4.1.4 Economy-Wide

Given the difficulty noted above with estimating national impacts of regulations, EPA has not generally estimated economy-wide employment impacts of its regulations in its benefit-cost analyses. However, in its continuing effort to advance the evaluation of costs, benefits, and economic impacts associated with environmental regulation, EPA has formed a panel of experts as part of EPA's Science Advisory Board (SAB) to advise EPA on the technical merits and challenges of using economy-wide economic models to evaluate the impacts of its regulations, including the impact on net national employment.[89] Once EPA receives guidance from this panel, it will carefully consider this input and then decide if and how to proceed on economy-wide modeling of employment impacts of its regulations.

5.4.1.5 Labor Supply Impacts

The empirical literature on environmental regulatory employment impacts focuses primarily on labor demand. However, there is a nascent literature focusing on regulation-induced effects on labor supply.[90] Although this literature is limited by empirical challenges, researchers have found that air quality improvements lead to reductions in lost work days (e.g., Ostro, 1987). Limited evidence suggests worker productivity may also improve when pollution is reduced. Graff Zivin and Neidell (2012) used detailed worker-level productivity data from 2009 and 2010, paired with local ozone air quality monitoring data for one large California farm growing multiple crops, with a piece-rate payment structure. Their quasi-experimental structure identifies an effect of daily variation in monitored ozone levels on productivity. They find "ozone levels well below federal air quality standards have a significant impact on productivity: a 10 parts per

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[89] For further information see: http://yosemite.epa.gov/sab/sabproduct.nsf/0/07E67CF77B54734285257BB0004F87ED?OpenDocument

[90] For a recent review see Graff-Zivin and Neidell (2013).

billion (ppb) decreases in ozone concentrations increases worker productivity by 5.5 percent." (Graff Zivin and Neidell, 2012, p. 3654).[91]

5.4.1.6 Conclusion

This section has outlined the challenges associated with estimating regulatory effects on both labor demand and supply for specific sectors. These challenges make it difficult to estimate net national employment estimates that would appropriately capture the way in which costs, compliance spending, and environmental improvements propagate through the macro-economy.

5.4.2 Recent Employment Trends

The U.S. electricity system includes employees that support electric power generation, transmission and distribution; the extraction of fossil fuels; renewable energy generation; and supply-side and demand-side energy efficiency. This section describes recent employment trends in the electricity system.

5.4.2.1 Electric Power Generation

In 2014, the electric power generation, transmission and distribution sector (NAICS 2211) employed about 390,000 workers (U.S. BLS, 2015) in the U.S. Installation, maintenance, and repair occupations (U.S. BLS, 2014) accounted for the largest share of workers (25 percent). These categories include inspection, testing, repairing and maintaining of electrical equipment and/or installation and repair of cables used in electrical power and distribution systems. Other major occupation categories include office and administrative support (18 percent), production occupations (16 percent), architecture and engineering (10 percent), business and financial operations (7 percent) and management (7 percent). As shown in Figure 5-3, employment in the electric power industry averaged about 420,000 workers 2000 to 2005, declining to an average of about 400,000 workers for the rest of the decade, and then declining to about 390,000 workers in 2014.

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[91] The EPA is not quantifying productivity impacts of reduced pollution in this rulemaking using this study. In light of this recent research, however, the EPA is considering how best to incorporate possible productivity effects in the future.

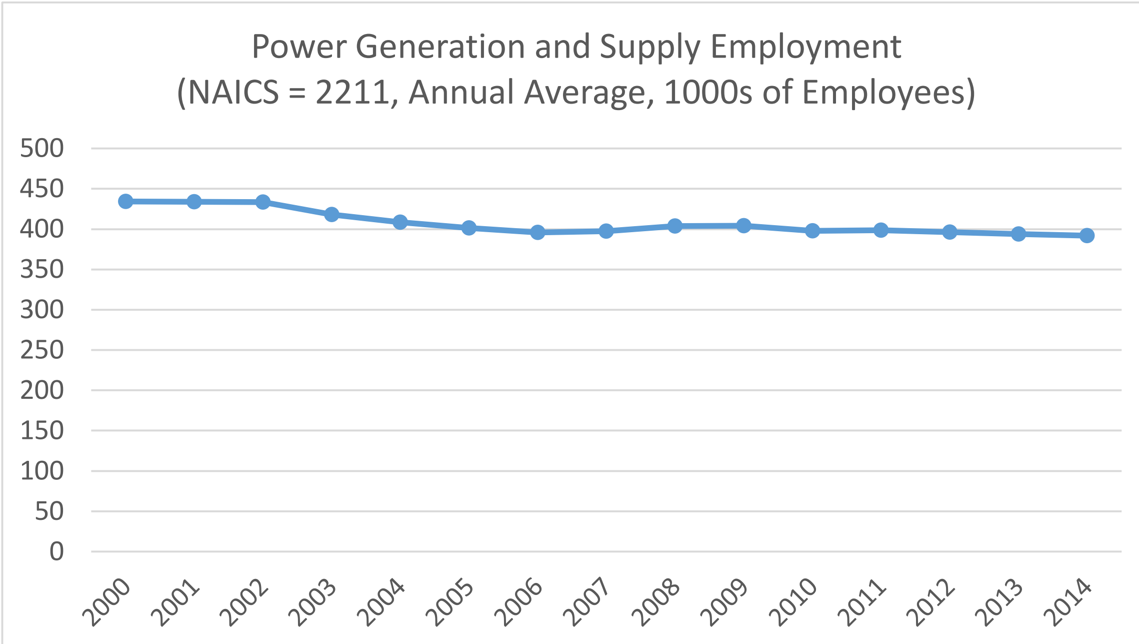

Figure 5-3. Electric Power Industry Employment

5.4.2.2 Fossil Fuel Extraction

Coal Mining. The coal mining sector (NAICS 2121) is primarily engaged in coal mining and coal mine site development, excluding metal ore mining and nonmetallic mineral mining and quarrying. In 2014, BLS reported about 74,000 coal mining employees (Figure 5-4). During the 2000 to 2014 period, coal mining employment peaked in 2011 at about 87,000 employees.

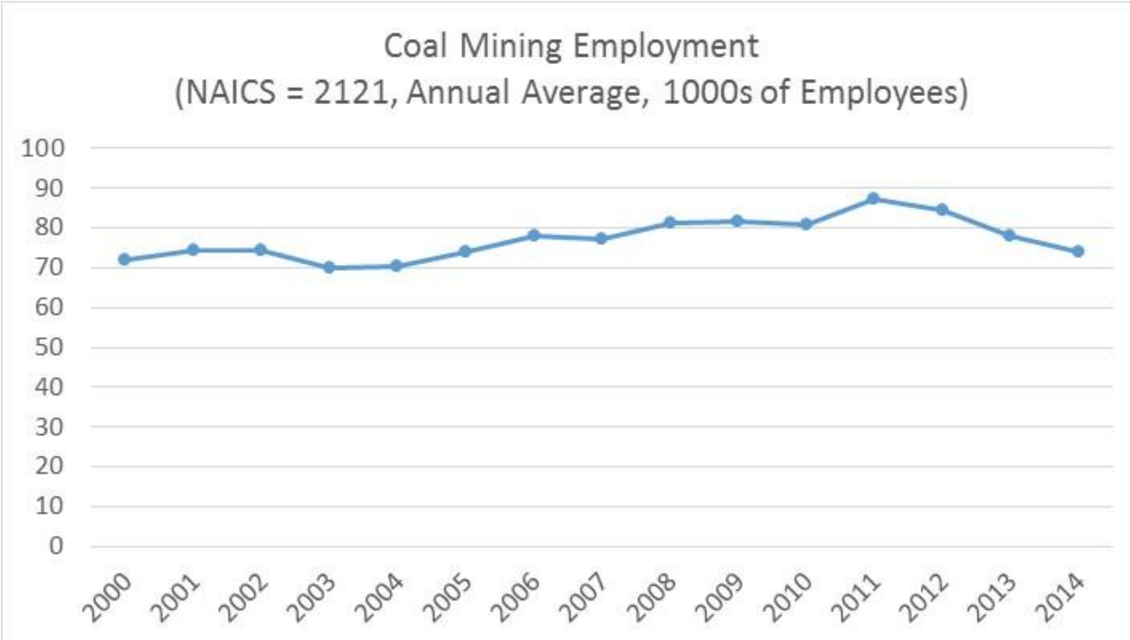

Figure 5-4. Coal Production Employment
Source: BLS (2014a)

Oil and Gas Extraction. In 2014, there were close to 200,000 employees in the oil and gas extraction sector (NAICS 211). This sector includes production of crude petroleum, oil from oil shale and oil sands, production of natural gas, sulfur recovery from natural gas, and recovery of hydrocarbon liquids. Activities include the development of gas and oil fields, exploration activities for crude petroleum and natural gas, drilling, completing, and equipping wells, and other production activities. In contrast with coal, Figure 5-5 shows there has been a sharp increase in employment in this sector over the past decade.

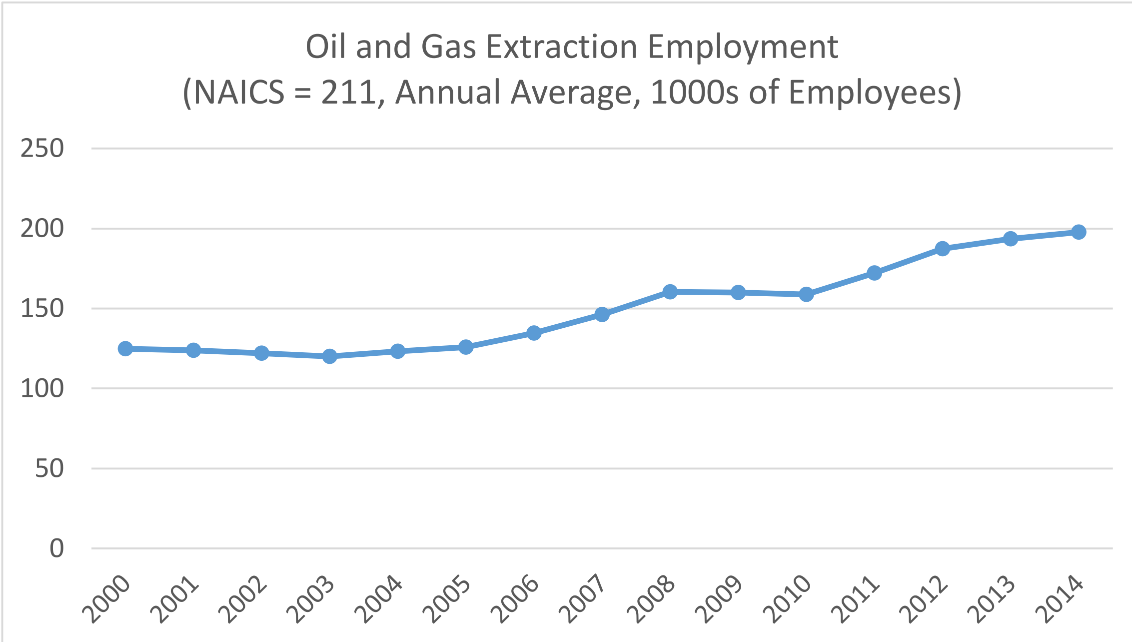

Figure 5-5 Oil and Gas Extraction Employment
Source: BLS (2014b)

5.4.3 Power and Fuels Sector Direct Employment Impacts

As described above, affected EGUs may respond to the CSAPR update by upgrading or improving performance of existing combustion controls, or by upgrading, improving, or utilizing post-combustion NO_X systems already in place. In addition, some net generation may shift from higher NO_X-emitting EGUs to units with lower NO_X emission rates. All of these changes will likely involve some amount of change in various types of amount of labor needed in different parts of the fuels and utility power sectors. There also may be other labor impacts in sectors that provide products and materials used in reducing NO_X emissions at EGUs, such as catalysts used in SCR control systems. These direct labor impacts will likely include both increased demand for certain types of labor in some portions of the affected sectors, and reduced demand for labor in other portions of the affected sectors.

Installing and operating new equipment could change labor demand in the electricity generating sector itself, as well as associated equipment and services sectors. Specifically, the direct employment effects in the power sector that could occur because of actions taken by the 2017 ozone season include:

- Optimizing NO_X removal from existing and operational SCR and SNCR systems;
- Turning on and optimizing idled SCR and SNCR systems;
- Installing, optimizing or upgrading combustion-side improvements resulting in reduced NO_X emissions;
- Shifting generation from units with higher NO_X emission rates to units with lower emission rates.

In addition, there could be directly induced employment impacts (both positive and negative) in the labor demand in the fossil fuels industry supplying fuels to the power sector. Once implemented, both the potential increases in operating efficiency and NO_X reductions, as well as and shifting generation to lower NO_X emitting assets, could impact the utility power sector's demand for fossil fuels, and hence the demand for labor needed in the coal mining and gas extraction sectors.

The direct net employment impacts of this proposed rule, in terms of the power sector and fuels sector, however, are anticipated to be relatively small. This is consistent with the relatively small estimated changes in the power sector's overall cost of generation, as well as relatively small changes in generation, fuel use, capacity, and the percent of total generation produced by each type of fuel.

For example, for the proposal in 2017, the estimated impacts relevant to changes in labor demand include:

- The overall total national cost of generation in 2017 increases by 0.046 percent (the levelized annualized total cost of generation increases by 0.01 percent);
- Total net generation increases by 0.009 percent (coal generation decreases by .084 percent, and natural gas generation increases by 0.11 percent);
- The power sector's total tons of coal used for electricity generation decreases by 0.04 percent (or 0.09 percent increase in BTUs);
- Total natural gas increases by 0.11 percent.

The results of the power sector modeling suggest that because of the very small changes in the power and fuels sector, the direction and magnitude of the potential labor impacts are very small in all three regulatory alternatives analyzed. To illustrate this point, the direct labor impacts have been quantified for the proposed regulation for 2017 and 2020. The labor impacts for the more and less stringent alternatives have not been quantified.

Affected EGUs may respond the proposed requirement for EGUs in 23 eastern states to reduce NO_X emissions during the ozone season by improving and optimizing existing NO_X emission control systems or to shift generation to generating sources with lower NO_X emission rates. Meeting the new EGU ozone season NOx budget limits will involve changes in the amount of labor needed in different parts of the utility power sector. Installing and operating new equipment, optimizing combustion control operations to reduce NOx emissions, and shifting generation to other sources could affect labor demand in the electricity generating sector itself, as well as associated equipment and services sectors. Specifically, the direct employment effects of initiatives at existing fossil EGUs would include increases in labor demand during the implementation phase for manufacturing, installing, and operating the NOx emissions controls at existing fossil units. Once implemented, increases in operating efficiency and shifting generation to existing generation resources will impact the utility power sector's demand for fossil fuels and potentially plans for EGU retirement.

The generation-side employment analysis uses the cost projections from the engineering-based IPM to project labor demand impacts of the final emission guidelines on affected EGUs in the electricity power sector and the fuel production sector (coal and natural gas). These projections include effects attributable to improving the NOx control performance of combustion control systems, optimizing the operation of post-combustion NOx control systems, generation shifts, and changes in fuel use.

The following section presents the EPA's quantitative projections of potential employment impacts in the electricity generation sector, as well as the impacts in the coal and natural gas fuel sectors. These projections are based in part on the IPM estimates of the impact of the proposed regulation previously discussed in this RIA.

5.4.3.1 Methods Used to Estimate Changes in Employment in Electricity Generation and Fuel Supply

The analytical approach used in this analysis is a bottom-up engineering method combining the EPA's cost analysis of the NOx emission limits with data on labor productivity, engineering estimates of the amount and types of labor needed to manufacture, construct, and operate different types of NOx control systems, and prevailing wage rates for skilled and general labor categories. This approach is different from the economy-wide types of economic analyses discussed in section 5.4.1. Lacking robust peer-reviewed methods to estimate economy-wide impacts, the engineering-based analysis focuses on the supply-side direct impact on labor demand in industries closely involved with electricity generation. The engineering approach projects labor changes measured as the change in each analysis year in job-years employed in the utility power sector and directly related sectors (e.g., equipment manufacturing and fuel supply). Some of the quantified employment impacts in this analysis are one-time impacts, such as changes associated with upgrading the combustion controls. Other labor impacts will continue, such as changes associated with operating and maintaining generating units that will be retired, shifting generation to lower emitting generating units, and changes in the demand for labor providing the fuels supplied to the affected fossil-fired EGUs.

The methods the EPA uses to estimate the labor impacts are based on the analytical methods used in many previous EPA regulatory analyses. The most relevant prior analysis was the RIAs for CPP (2015), and the CSAPR (2011). The methods used in this analysis to estimate the labor impacts (e.g., labor associated with changes in operating and maintaining generating units, as well as labor needed to mine coal and natural gas) are the same as we used in the CPP and CSAPR RIAs (with updated data where available).

The bottom-up engineering-based labor analysis in the CPP RIA was primarily concerned with the labor needs of improving CO_2 emissions from operating of existing EGUs nationwide, and changes in the expected retirements of existing coal-fired EGUs and avoiding the need for new gas-fired EGUs. A central feature of the labor analysis for this RIA, however, involves the labor needs of upgrading and optimizing NOx control systems on existing EGUs in the affected 23-state region. In addition to the changes at EGUs within the 23-state region, there are also estimated changes in the utilization of existing generating units in other states, as well as changes in the gas and coal supply sectors.

The methods and data used to estimate the labor associated with upgrading combustion control systems are assumed to be the same as those used to estimate heat rate improvements (HRI, another type of combustion control system upgrade) in the CPP RIA. There are two components of this assumption.

- The mix of labor categories needed to implement the combustion control upgrades in this NOx analysis (i.e., the share of the labor cost of the upgrades apportioned general construction, boilermaker, engineering and management labor) is the same as the HRI-related combustion control upgrades needed in the CPP CO_2 analysis.

- The fully loaded labor cost of each labor category is the same for NOx control upgrades as for the HRI CO_2 upgrades

5.4.3.2 Estimates of the Changes in Employment in Electricity Generation and Fuel Supply

The estimated labor impacts of the proposed revisions to the NOx budgets from EGUs in the 23-state region are presented in Table 5-9. Given the methods the EPA uses to estimate labor impacts, it is not possible to directly separate the labor impacts that occur within the 23-state region from the labor impacts in the states not in the region. However, all the labor changes associated with combustion control upgrades, and optimization of existing post-combustion NOx control systems, will occur within the 23-state region. The fuel supply labor impacts, however, will occur both within the 23-state region as well as in other states. This occurs for two reasons. First, coal and natural gas used at EGUs throughout the United States are both extracted within the 23-state region and in other states. Second, the shifts in fossil-fired generation will also occur both with within the 23-state region and in other states.

Table 5-9. Annual Net Employment Impacts for Power and Fuels Sectors of the Proposed Option in 2017 & 2020

	2017	2020
Upgrades and Optimization		
SCR	70	66
SNCR*	0	
Combustion Control	67	66
Sub-Total	**137**	**132**
Plant Retirement		
Coal	-160	-95
Fuel Use Change		
Coal	-87	-42
Natural Gas	50	19
Subtotal	-36	-22
Net Employment Impact	**-60**	**15**

*SNCR optimization is only required in the more stringent alternative. Job-year estimates are derived from IPM investment and upgrade estimates, as well as IPM fuel use estimates (tons coals or MMBtu gas). All job-year estimates are full-time equivalent (FTE) jobs.

5.5 Social Costs

As discussed in the EPA Guidelines for Preparing Economic Analyses, social costs are the total economic burden of a regulatory action (USEPA, 2010). This burden is the sum of all opportunity costs incurred due to the regulatory action, where an opportunity cost is the value lost to society of any goods and services that will not be produced and consumed as a result of reallocating some resources towards pollution mitigation. Estimates of social costs may be compared to the social benefits expected as a result of a regulation to assess its net impact on society. The social costs of a regulatory action will not necessarily be equivalent to the expenditures associated with compliance. Nonetheless, here we use compliance costs as a proxy for social costs.

The cost estimates for the proposed and more or less stringent alternatives presented in this chapter are the change in expenditures required by the power sector for compliance under each alternative. The change in the expenditures required by the power sector to maintain compliance reflect the changes in electricity production costs resulting from application of NO_X control strategies described above necessary to comply with the emissions budgets that are described in Chapter 4. The changes in electricity production costs estimated by IPM as described earlier in Chapter 5, and the change in expenditures required by the power sector to maintain compliance are also described earlier in Chapter 5.

5.6 Secondary Economic Impacts

The energy sector impacts presented earlier in Chapter 5 of this RIA include potential changes in the prices for electricity, natural gas, and coal potentially resulting from the proposal. This chapter addresses the impact of these potential changes on other markets outside of the power sector and discusses some of the determinants of the magnitude of these impacts. We refer to these changes as secondary market impacts.

The analysis of costs for this proposal includes strategies for affected states to reduce NO_X emissions from EGUs to comply with the proposed EGU NO_X ozone-season emissions budgets in 2017. Ultimately, given the flexibilities afforded EGUs and states in complying with the proposed rule, the benefits, cost and economic impacts reported in this RIA may differ given the compliance approaches affected EGUs adopt. The abatement strategies adopted by affected EGUs, will ultimately drive the magnitude and timing of secondary impacts from changes in the price of electricity, and the demand for inputs by the electricity sector, on other markets that use and produce these inputs.

To estimate the costs, benefits, and impacts of implementing the proposal, the EPA modeled a compliance approach for the proposal and more and less stringent alternatives. Chapter 4 provides a description of the proposal and the more and less stringent alternatives considered. This chapter provides a quantitative assessment of the energy price impacts for these approaches and a qualitative assessment of the factors that will in part determine the timing and magnitude of effects in other markets.

5.6.1 Methods

One potential quantitative approach to evaluating the secondary market impacts is to use a computable general equilibrium (CGE) model. CGE models are able to provide aggregated representations of the whole economy in equilibrium in the baseline and potentially with regulation in place. As such, a CGE model may be able to capture interactions between economic sectors and provide information on changes outside of the directly regulated sector. In support of previous rulemakings, such as the 2008 Final Ozone NAAQS (U.S. EPA, 2008) and the 2010 Transport Rule proposal (U.S. EPA, 2010a), the EPA used the Economic Model for

Policy Analysis (EMPAX) CGE model to estimate the secondary market effects based on the cost impacts projected by IPM for the directly regulated sector.

When considering the secondary market impacts of a regulation, the effects of the costs, the benefits of improved air quality, and their interaction may be relevant. Therefore, in the Second Prospective Analysis under Section 812 of the Clean Air Act Amendments, the EPA incorporated a set of health benefits arising from air quality improvement into the EMPAX CGE model when studying the economy-wide impacts of the Clean Air Act (U.S. EPA 2011). While the external Council on Clean Air Compliance Analysis (COUNCIL) review of this study stated that inclusion of benefits in an economy-wide model "represent[ed] a significant step forward in benefit-cost analysis" (Hammitt 2010), the EPA recognizes that serious technical challenges remain when attempting to evaluate the benefits and costs of potential regulatory actions using economy-wide models.

In light of these challenges, the EPA has established a Science Advisory Board (SAB) panel on economy-wide modeling to consider the technical merits and challenges of using this analytical tool to evaluate costs, benefits, and economic impacts in regulatory development. In addition, EPA is asking the panel to identify potential paths forward for improvements that could address the challenges posed when using economy-wide models to evaluate the effects of regulations. The final panel membership was announced in March 2015 and the first of multiple face-to-face meetings of the SAB panel was held October 22 and 23, 2015. The EPA will use the recommendations and advice of this panel as an input into its process for improving benefit-cost and economic impact analyses used to inform decision-making at the agency.

The advice from the SAB panel formed specifically to address the subject of economy-wide modeling was not available in time for this proposed action. Given the ongoing SAB panel on economy-wide modeling, and the ongoing challenges of accurately representing costs, benefits, energy efficiency improvements in economy-wide modeling, this chapter considers the energy impacts associated with the proposed alternatives analyzed and a qualitative assessment of the factors that will, in part, determine the timing and magnitude of effects in other markets.

5.6.2 *Summary of Secondary Market Impacts of Energy Price Changes*

Electricity, natural gas, and coal are important inputs to the production of other goods and services. Therefore, changes in the price of these commodities will shift the production costs for sectors that use electricity, natural gas, and coal in the production of other goods and services. Changes in the types and levels of inputs used by producers in response to electricity and fuel price changes may mitigate the production cost changes in these sectors. Such changes in production costs may lead to changes in the quantities and/or prices of the goods or services produced and changes in imports and exports.

The EPA used IPM to estimate electricity, natural gas, and coal price changes based on compliance with the regulatory control alternatives for this rule. The RPM uses estimated changes in wholesale prices to estimate changes in average retail prices. The prices are average prices over consumer classes and regions weighted by the amount used. Table 5-10 shows these estimated price changes for the proposal in 2017 and, for illustrative purposes only, 2020. For other results generated by IPM and the RPM, please refer to earlier sections in Chapter 5.

There are many factors influencing the projected natural gas prices. IPM (and its integrated gas resource and supply module) models natural gas natural gas supplies based on a multitude of factors. Since the model simulates perfect foresight, it anticipates future demand for natural gas and responds accordingly. In addition, IPM (and the natural gas module) are viewing a very long time horizon (through 2050), such that the impacts in certain years may be responsive to other modeling assumptions or drivers. The modeling framework is simultaneously solving for all of these key market and policy parameters (both electric and natural gas), resulting in the impacts discussed in previous sections and shown in Table 5-9.

Table 5-10. Estimated Percentage Changes in Average Energy Prices by Energy Type for the Proposed Alternative*

Proposed Rule	2017	2020
Electricity Price Change	-0.1%	-0.2%
Delivered Natural Gas Price Change	0.01%	-0.1%
Delivered Coal Price Change	-0.3%	-0.4%

*A minus sign in front of the number denotes a negative change, or a price decrease.

For years when the price of electricity, natural gas, or coal increased, one would expect decreases in production and increases in market prices in sectors for which these commodities are inputs, ceteris paribus. Conversely, for years when prices of these inputs decreased, one would expect increases in production and decreases in market prices within these sectors. Smaller changes in input price changes would lead to smaller impacts within secondary markets. For compliance with the proposal and more and less stringent alternatives these price changes are quite small, or even negative, in 2017. Thus, one could readily surmise that the impacts of this proposed rule upon secondary markets should be minimal. As seen in Table 5-9, most of the price changes are negative, thus showing an estimated decrease in energy prices, albeit very small. The variation for these prices at the regional level is not substantially different from the national-level price changes, and the variation of energy prices related to the proposal and the regional level can be found among the IPM outputs in the public docket for this rulemaking. However, a number of factors, in addition to the magnitude and sign of the energy price changes, influence the magnitude of the impact on production and market prices for sectors using electricity, natural gas, or coal as inputs to production. These factors are discussed below.

5.6.3 Share of Total Production Costs

The impact of energy price changes in a particular sector depends, in part, on the share of total production costs attributable to those commodities. For sectors in which the directly affected inputs are only a small portion of production costs, the impact will be smaller than for sectors in which these inputs make up a greater portion of total production costs. Therefore, more energy-intensive sectors would potentially experience greater cost increases when electricity, natural gas, or coal prices increase, but would also experience greater reduced costs when these input prices decrease.

5.6.4 Ability to Substitute between Inputs to the Production Process

The ease with which producers are able to substitute other inputs for electricity, natural gas, or coal, or even amongst those commodities, influences the impact of price changes for these inputs. Those sectors with a greater ability to substitute across energy inputs or to other inputs will be able to, at least partially, offset the increased cost of these inputs resulting in smaller market impacts. Similarly, when prices for electricity, natural gas, or coal decrease, some sectors may choose to use more of these inputs in place of other more costly substitutes.

5.6.5 Availability of Substitute Goods and Services

The ability of producers in sectors experiencing changes in their input prices to pass along the increased costs to their customers in the form of higher prices for their products depends, in part, on the availability of substitutes for the sectors' products. Substitutes may be either other domestic products or foreign imports. If close substitutes exist, the demand for the product will in general be more elastic and the producers will be less able to pass on the added cost through a price increase.

Such substitution can also take place between foreign and domestic goods within the same sector. Changes in the price of electricity, natural gas, and coal can influence the quantities of goods imported or exported from sectors using these inputs. When the cost of domestic production increases due to more expensive inputs, imports may increase as consumers substitute towards relatively less costly foreign-produced goods, and vice versa.

5.6.6 Effect of Changes in Input Demand from Electricity Sector

Section 5.7.2 focuses on the effects of changes in energy prices, and possible responses to those price changes, on sectors outside of the electricity sector. A change in demand for inputs in the electricity sector, as well as changes in demand for energy efficiency services and products, will also influence economic activity in other sectors of the economy. For example, EPA estimates EGUs will increase use of ammonia and urea to reduce NOx emissions, which could result in a price driven reduction in demand in other sectors (e.g., fertilizer manufacturing and agriculture) using these industrial chemicals.

5.6.7 Conclusions

Changes in the price of electricity, natural gas, and coal can affect markets for goods and services produced by sectors that use these energy inputs in the production process. The direction and magnitude of these impacts are influenced by a number of factors. For example, the more producers in these sectors are able to substitute away from the use of these energy inputs, the smaller the effect of energy prices changes will be on their production cost. Changes in cost of production may lead to changes in price, quantity produced, and profitability of firms within secondary markets. Furthermore, the demand inputs in the electricity sector will also affect secondary markets. If regulation results in changes in domestic markets that lead to an increase in imports, then domestic producers may experience less demand from their consumers, and vice versa.

Modeling choices in IPM influence the estimated changes in electricity, natural gas, and coal prices in this RIA. Actual market conditions will ultimately influence the price changes of these energy inputs and consequent effects on secondary markets, as will the plan approaches that states adopt.

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CHAPTER 6: ESTIMATED HUMAN HEALTH BENEFITS AND CLIMATE CO-BENEFITS

6.1 Introduction

As discussed in Chapter 4, this action proposes to update CSAPR to reduce interstate transport of EGU ozone season NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2008 ozone NAAQS. The EPA proposes to implement the proposed EGU NO_X reductions by setting emissions budgets that are implemented through the CSAPR NO_X ozone-season allowance trading program. Implementing this proposal to update CSAPR is expected to reduce emissions of NO_X during the summer ozone season and provide ancillary annual NO_X and carbon dioxide (CO_2) benefits (i.e., co-benefits). This chapter describes the methods used to estimate the monetized ozone-related air quality health benefits, fine particulate matter ($PM_{2.5}$)-related air quality health co-benefits from reductions in NO_X emissions and climate co-benefits from reductions of CO_2 emissions. These health benefits are associated with reducing exposure to ambient ozone and $PM_{2.5}$ by reducing emissions of precursor pollutants (i.e., NO_X). Data, resource, and methodological limitations prevent the EPA from monetizing several important co-benefits from reducing emissions of several pollutants, including those from reducing direct exposure to NO_2, ecosystem effects and visibility impairment. We qualitatively discuss these unquantified benefits in this chapter.

This chapter provides estimates of the monetized air quality health benefits and climate co-benefits associated with emission reductions for the regulatory control alternatives across several discount rates. The estimated benefits associated with these emission reductions are beyond those achieved by previous EPA rulemakings, including the 2011 CSAPR[92] and the finalized Clean Power Plan (CPP).

[92] As discussed in Chapters 1, 3 and 5, the 2017 baseline EGU emissions for this proposal include impacts from CSAPR issued on July 6, 2011. As discussed and elaborated on in Chapter 1, because the modeling for the proposal was performed prior to the D.C. Circuit's issuance of *EME Homer City II*, 11 that modeling assumed in its baseline for all states the emission reductions associated with the CSAPR NO_X ozone-season phase 2 emissions budgets.

6.2 Estimated Human Health Benefits

The proposal to update CSAPR is expected to reduce emissions of ozone season NO_X. In the presence of sunlight, NO_X and VOCs can undergo a chemical reaction in the atmosphere to form ozone. Reducing NO_X emissions also reduces human exposure to ozone and the incidence of ozone-related health effects, though this depends partly on local levels of volatile organic compounds (VOCs). The proposal would also reduce emissions of NO_X throughout the year. Because NO_X is also a precursor to formation of ambient $PM_{2.5}$, reducing these emissions would also reduce human exposure to ambient $PM_{2.5}$ throughout the year and would reduce the incidence of $PM_{2.5}$-related health effects.[93] This RIA does not quantify $PM_{2.5}$-related benefits associated with SO_2 emission reductions. As discussed in Chapter 3, the EPA does not estimate significant SO_2 emission reductions as a result of this proposal. Furthermore, these reductions would reduce ozone and $PM_{2.5}$ concentrations in regions other than those with nonattainment monitors that are the subject of this proposal, and the benefits of reducing these pollutants in those regions are assessed in this Chapter. Reducing emissions of NO_X would also reduce ambient exposure to NO_2 and its associated health effects, though we do not quantify these effects because we have not developed a reduced-form technique for estimating NO_2 impacts. In this section, we provide an overview of the monetized ozone-related benefits and $PM_{2.5}$-related co-benefits estimated for the proposed updated CSAPR EGU NO_X ozone season emissions budgets and for the more and less stringent alternatives. A full description of the epidemiological studies we use, the methods we apply and the tools we employ to quantify the incidence of these effects may be found in the PM NAAQS RIA (U.S. EPA, 2012a) and Ozone NAAQS RIA (U.S. EPA, 2015). The estimated benefits associated with these emissions reductions are additional to those achieved by previous EPA rulemakings, including the finalized CPP.

Implementing these updated CSAPR EGU NO_X emissions budgets for the ozone season in 23 eastern states may reduce ambient ozone and $PM_{2.5}$ concentrations below the National Ambient Air Quality Standards (NAAQS) in some areas and assist other areas with attaining the ozone and $PM_{2.5}$ NAAQS. The NAAQS RIAs (U.S. EPA, 2008, 2012a, 2015) also calculated the benefits of attaining alternate ozone and PM NAAQS, and so differences in the design and

[93] Additionally, this RIA does not estimate changes in emissions of directly emitted particles.

analytical objectives of each RIA are worth noting here. The NAAQS RIAs illustrate the potential costs and benefits of attaining a revised air quality standard nationwide based on an array of emission reduction strategies for different sources reflecting the application of identified and unidentified controls, incremental to implementation of existing regulations and controls needed to attain the NAAQS that currently is in effect. In short, NAAQS RIAs hypothesize, but do not predict, the strategies that States may choose to enact when implementing a revised NAAQS. Setting a NAAQS does not directly result in costs or benefits, and as such, the EPA's NAAQS RIAs are illustrative. The estimated costs and benefits from NAAQS RIAs are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and prescribe specific emission reductions. For example, some of the emissions reductions estimated to result from implementing the proposal to update CSAPR may achieve some of the air quality improvements that resulted from the hypothesized attainment strategies presented in the NAAQS RIAs. The emissions reductions from implementing the proposal to update CSAPR will decrease the remaining amount of emissions reductions needed in nonattainment areas to, and reduce the costs to those areas to, meet the 2008 ozone NAAQS. Specifically, the anticipated reductions in ozone concentrations from this rule would help areas attain and maintain the 2008 ozone NAAQS and achieve some of the air quality improvements from the hypothesized attainment strategy from the 2008 ozone NAAQS RIA. These ozone improvements would similarly achieve some of the air quality improvements assumed in the baseline (i.e., 2008 ozone NAAQS attainment projection) for the 2015 ozone NAAQS RIA.

As discussed in Chapter 4, the IPM modeling showing compliance with the regulatory control alternatives for which emission reductions are estimated in this RIA is also illustrative in nature. However, unlike the illustrative control strategies analyzed in NAAQS RIAs described above, all of the emission reductions for the illustrative compliance modeling for this proposal would occur in one well-characterized sector (i.e., the EGU sector). The EPA is more confident in the magnitude and location of the emission reductions for this proposal because it imposes a specific requirement that limits emissions from a specific sector. Emission reductions achieved under this rule, if finalized, will ultimately be reflected in the baseline of future NAAQS analyses and would lower the emissions reductions needed to attain revised future NAAQS. For more information on the relationship between illustrative analyses, such as for the NAAQS and its associated implementation rules, please see the Ozone NAAQS RIA (U.S. EPA, 2015).

6.2.1 Health Impact Assessment for Ozone and $PM_{2.5}$

The *Integrated Science Assessment for Ozone and Related Photochemical Oxidants* (Ozone ISA) (U.S. EPA, 2013b) identified the human health effects associated with ambient ozone exposure, which also include premature mortality and a variety of morbidity effects associated with acute and chronic exposures. Similarly, the *Integrated Science Assessment for Particulate Matter* (PM ISA) (U.S. EPA, 2009b) identified the human health effects associated with ambient $PM_{2.5}$ exposure, which include premature mortality and a variety of morbidity effects associated with acute and chronic exposures. Table 6-1 identifies the quantified and unquantified benefit and co-benefit categories captured in the EPA's health benefits estimates for reduced exposure to ambient ozone and $PM_{2.5}$. Although the table below does not list unquantified health effects or welfare effects, such as acidification and nutrient enrichment, these effects are described in detail in Chapters 5 and 6 of the PM NAAQS RIA (U.S. EPA, 2012a) and summarized later in this chapter. It is important to emphasize that the list of unquantified benefits categories is not exhaustive, nor is quantification of each effect complete.

Table 6-1. Human Health Effects of Ambient Ozone and $PM_{2.5}$

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Human Health				
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	✓	✓	Ozone ISA
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA[1]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	✓	✓	Ozone ISA
	Hospital admissions—respiratory causes (age <2)	✓	✓	Ozone ISA
	Emergency department visits for asthma (all ages)	✓	✓	Ozone ISA
	Minor restricted-activity days (age 18–65)	✓	✓	Ozone ISA
	School absence days (age 5–17)	✓	✓	Ozone ISA
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[1]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2,3]
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	✓	✓	PM ISA
	Infant mortality (age <1)	✓	✓	PM ISA
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	✓	✓	PM ISA
	Hospital admissions—respiratory (all ages)	✓	✓	PM ISA
	Hospital admissions—cardiovascular (age >20)	✓	✓	PM ISA
	Emergency room visits for asthma (all ages)	✓	✓	PM ISA
	Acute bronchitis (age 8-12)	✓	✓	PM ISA
	Lower respiratory symptoms (age 7-14)	✓	✓	PM ISA
	Upper respiratory symptoms (asthmatics age 9-11)	✓	✓	PM ISA
	Asthma exacerbation (asthmatics age 6-18)	✓	✓	PM ISA
	Lost work days (age 18-65)	✓	✓	PM ISA
	Minor restricted-activity days (age 18-65)	✓	✓	PM ISA
	Chronic Bronchitis (age >26)	—	—	PM ISA[1]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[1]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[1]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[2,3]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2,3]

[1] We assess these co-benefits qualitatively due to data and resource limitations for this analysis, but we have quantified them in sensitivity analyses for other analyses.
[2] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.
[3] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

We follow a “damage-function” approach in calculating benefits, which estimates changes in individual health endpoints (specific effects that can be associated with changes in air quality) and assigns values to those changes assuming independence of the values for those individual endpoints. Because the EPA rarely has the time or resources to perform new research to measure directly either health outcomes or their values for regulatory analyses, our estimates are based on the best available methods of benefits transfer, which is the science and art of adapting primary research from similar contexts to estimate benefits for the environmental quality change under analysis. In addition to transferring information from other contexts to the context of this regulation, we also use a "benefit-per-ton" approach to estimate the ozone and $PM_{2.5}$ benefits in this RIA. Benefit-per-ton approaches apply an average benefit per ton derived from modeling of benefits of specific air quality scenarios to estimates of emissions reductions for scenarios where no air quality modeling is available. Thus, to develop estimates of benefits for this RIA, we are transferring both the underlying health and economic information from previous studies and information on air quality responses to emissions reductions from other air quality modeling. This section describes the underlying basis for the health and economic valuation estimates that inform the benefit-per-ton estimates, and the subsequent section provides an overview of the benefit-per-ton estimates, which are described in detail in the appendix to this chapter.

The benefit-per-ton approach we use in this RIA relies on estimates of human health responses to exposure to ozone and PM obtained from the peer-reviewed scientific literature. These estimates are used in conjunction with population data, baseline health information, air quality data and economic valuation information to conduct health impact and economic benefits assessments. These assessments form the key inputs to calculating benefit-per-ton estimates. The next sections provide an overview of the health impact assessment (HIA) methodology and additional details on several key elements.

The HIA quantifies the changes in the incidence of adverse health impacts resulting from changes in human exposure to ozone and $PM_{2.5}$. We use the environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE) (version 1.1) to systematize health impact analyses by applying a database of key input parameters, including population projections, health impact functions, and valuation functions (Abt Associates, 2012). For this assessment, the HIA is limited to those health effects that are directly linked to ambient ozone and $PM_{2.5}$ concentrations. There may be other indirect health impacts associated with reducing emissions, such as occupational health exposures. Epidemiological studies generally provide estimates of the relative risks of a particular health effect for a given increment of air pollution (often per 10 ppb for ozone or $\mu g/m^3$ for $PM_{2.5}$). These relative risks can be used to develop risk coefficients that relate a unit reduction in pollution (e.g., ozone) to changes in the incidence of a health effect. We refer the reader to the Ozone NAAQS RIA (U.S. EPA, 2015) and PM NAAQS RIA (U.S. EPA, 2012a) for more information regarding the epidemiology studies and risk coefficients applied in this analysis, and we briefly elaborate on adult premature mortality below. The size of the mortality effect estimates from epidemiological studies, the serious nature of the effect itself, and the high monetary value ascribed to reducing risks of premature death make mortality risk reduction the most significant health endpoint quantified in this analysis.

6.2.1.1 Mortality Effect Coefficients for Short-term Ozone Exposure

The overall body of evidence indicates that there is likely to be a causal relationship between short-term ozone exposure and premature death. The 2013 ozone ISA concludes that the evidence suggests that ozone effects are independent of the relationship between PM and mortality. (U.S. EPA, 2013a). However, the ISA notes that the interpretation of the potential confounding effects of PM on ozone-mortality risk estimates requires caution due to the PM sampling schedule (in most cities) which limits the overall sample size available for evaluating potential confounding of the ozone effect by PM (U.S. EPA 2013a).

In 2006, the EPA requested an NAS study to answer the following four key questions regarding ozone-related mortality: (1) How did the epidemiological literature to that point improve our understanding of the size of the ozone-related mortality effect?; (2) How best can EPA quantify the level of ozone-related mortality impacts from short-term exposure?; (3) How might EPA estimate the change in life expectancy?; and (4) What methods should EPA use to estimate the monetary value of changes in ozone-related mortality risk and life expectancy?

In 2008, the NAS (NRC, 2008) issued a series of recommendations to the EPA regarding the quantification and valuation of ozone-related short-term mortality. Chief among these was that "…short-term exposure to ambient ozone is likely to contribute to premature deaths" and the committee recommended that "ozone-related mortality be included in future estimates of the health benefits of reducing ozone exposures…" The NAS also recommended that "…the greatest emphasis be placed on the multi-city and NMMAPS studies without exclusion of the meta-analyses" (NRC, 2008). In addition, NAS recommended that EPA "should give little or no weight to the assumption that there is no causal association between estimated reductions in premature mortality and reduced ozone exposure" (NRC, 2008). In 2010, the Health Effects Subcommittee of the Advisory Council on Clean Air Compliance Analysis, while reviewing EPA's *The Benefits and Costs of the Clean Air Act 1990 to 2020* (U.S. EPA, 2011a), also confirmed the NAS recommendation to include ozone mortality benefits (U.S. EPA-SAB, 2010a).

In view of the findings of the ozone ISA, the NAS panel, the SAB-HES panel, and the CASAC panel, we estimate ozone-related premature mortality for short-term exposure in the core health effects analysis using effect coefficients from the Smith et al. (2009) NMMAPS analysis and the Zanobetti and Schwartz (2008) multi-city study with several additional studies as sensitivity analyses. This emphasis on newer multi-city studies is consistent with recommendations provided by the NAS in their ozone mortality report (NRC, 2008). CASAC supported using the Smith et al. (2009) and Zanobetti and Schwartz (2008) studies for the ozone HREA (U.S. EPA-SAB, 2012, 2014), and these are multi-city studies published more recently (as compared with other multi-city studies or meta-analyses included in the sensitivity analyses – see discussion below).

Smith et al. (2009) reanalyzed the NMMAPS dataset, evaluating the relationship between short-term ozone exposure and mortality. While this study reproduces the core national-scale estimates presented in Bell et al. (2004), it also explored the sensitivity of the mortality effect to different model specifications including (a) regional versus national Bayes-based adjustment,[94] (b) co-pollutant models considering PM_{10}, (c) all-year versus ozone-season based estimates, and (d) consideration of a range of ozone metrics, including the daily 8-hour max. In addition, the Smith et al. (2009) study did not use the trimmed mean approach employed in the Bell et al.

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[94] In Bayesian modeling, effect estimates are "updated" from an assumed prior value using observational data. In the Smith et al. (2009) approach, the prior values are either a regional or national mean of the individual effect estimates obtained for each individual city. The Bayesian adjusted city-specific effect estimates are then calculated by updating the selected prior value based on the relative precision of each city-specific estimate and the variation observed across all city-specific individual effect estimates. City-specific estimates are pulled towards the prior value if they have low precision and/or if there is low overall variation across estimates. City-specific estimates are given less adjustment if they are precisely estimated and/or there is greater overall variation across estimates.

(2004) study in preparing ozone monitor data.[95] In selecting effect estimates from Smith et al. (2009), we focused on an ozone-only estimate for non-accidental mortality using the 8-hour max metric for the warmer ozone season. For the sensitivity analysis, we included a co-pollutant model (ozone and PM_{10}) from Smith et al. (2009) for all-cause mortality, using the 8-hour max ozone metric for the ozone season. Using a single pollutant model for the core analysis and the co-pollutant model in the sensitivity analysis reflects our concern that the reduced sampling frequency for days with co-pollutant measurements (1/3 and 1/6) could affect the ability of the study to characterize the ozone effect. This choice is consistent with the ozone ISA, which concludes that ozone effects are likely to be independent of the relationship between PM and mortality (U.S. EPA, 2013a).

The Zanobetti and Smith (2008) study evaluated the relationship between ozone exposure (using an 8-hour mean metric for the warm season June-August) and all-cause mortality in 48 U.S. cities using data collected between 1989 and 2000. The study presented single pollutant C-R functions based on shorter (0-3 day) and longer (0-20 day) lag structures, with the comparison of effects based on these different lag structures being a central focus of the study. We used the shorter day lag based C-R function since this had the strongest effect and tighter confidence interval. We converted the effect estimate from an 8-hour mean metric to an equivalent effect estimate based on an 8-hour max to account for the period of the day in which most individuals are exposed to ozone. To do this, we used the ozone metric approach wherein the original effect estimate (and standard error) is multiplied by the appropriate ozone metric adjustment ratio.

6.2.1.2 $PM_{2.5}$ Mortality Effect Coefficients for Adults and Infants

A substantial body of published scientific literature documents the association between elevated $PM_{2.5}$ concentrations and increased premature mortality (U.S. EPA, 2009b). This body of literature reflects thousands of epidemiology, toxicology, and clinical studies. The PM ISA completed as part of the most recent review of the PM NAAQS, which was twice reviewed by the SAB-CASAC (U.S. EPA-SAB, 2009a, 2009b), concluded that there is a causal relationship between mortality and both long-term and short-term exposure to $PM_{2.5}$ based on the entire body

[95] There are a number of concerns regarding the trimmed mean approach including (1) the potential loss of temporal variation in the data when the approach is used (this could impact the size of the effect estimate), and (2) a lack of complete documentation for the approach, which prevents a full reviewing or replication of the technique.

of scientific evidence (U.S. EPA, 2009b). The size of the mortality effect estimates from epidemiological studies, the serious nature of the effect itself, and the high monetary value ascribed to prolonging life make mortality risk reduction the most significant health endpoint quantified in this analysis.

Researchers have found statistically significant associations between $PM_{2.5}$ and premature mortality using different types of study designs. Time-series methods have been used to relate short-term (often day-to-day) changes in $PM_{2.5}$ concentrations and changes in daily mortality rates up to several days after a period of exposure to elevated $PM_{2.5}$ concentrations. Cohort methods have been used to examine the potential relationship between community-level $PM_{2.5}$ exposures over multiple years (i.e., long-term exposures) and community-level annual mortality rates that have been adjusted for individual level risk factors. When choosing between using short-term studies or cohort studies for estimating mortality benefits, cohort analyses are thought to capture more of the public health impact of exposure to air pollution over time because they account for the effects of long-term exposures, as well as some fraction of short-term exposures (Kunzli et al., 2001; NRC, 2002). The National Research Council (NRC) stated that "it is essential to use the cohort studies in benefits analysis to capture all important effects from air pollution exposure" (NRC, 2002, p. 108). The NRC further noted that "the overall effect estimates may be a combination of effects from long-term exposure plus some fraction from short-term exposure. The amount of overlap is unknown" (NRC, 2002, p. 108-9). To avoid double counting, we focus on applying the risk coefficients from the long-term cohort studies in estimating the mortality impacts of reductions in $PM_{2.5}$.

Over the last two decades, several studies using "prospective cohort" designs have been published that are consistent with the earlier body of literature. Two prospective cohort studies, often referred to as the Harvard "Six Cities Study" (Dockery et al., 1993; Laden et al., 2006; Lepeule et al., 2012) and the "American Cancer Society" or "ACS study" (Pope et al., 1995; Pope et al., 2002; Pope et al., 2004; Krewski et al., 2009), provide the most extensive analyses of ambient $PM_{2.5}$ concentrations and mortality. These studies have found consistent relationships between fine particle indicators and premature mortality across multiple locations in the United States. The credibility of these two studies is further enhanced by the fact that the initial published studies (Pope et al., 1995; Dockery et al., 1993) were subject to extensive reexamination and reanalysis by an independent team of scientific experts commissioned by the Health Effects Institute (HEI) and by a Special Panel of the HEI Health Review Committee (Krewski et al., 2000). Publication of studies confirming and extending the findings of the 1993 Six Cities Study and the 1995 ACS study using more recent air quality data and a longer follow-up period for the ACS cohort provides additional validation of the findings of these original studies (Pope et al., 2002, 2004; Laden et al., 2006; Krewski et al., 2009; Lepeule et al., 2012). The SAB-HES also supported using these two cohorts for analyses of the benefits of PM reductions, and concluded, "the selection of these cohort studies as the underlying basis for PM mortality benefit estimates [is] a good choice. These are widely cited, well studied and extensively reviewed data sets" (U.S. EPA-SAB, 2010a). As both the ACS and Six Cities studies have inherent strengths and weaknesses, we present benefits estimates using relative risk estimates from the most recent extended reanalysis of these cohorts (Krewski et al., 2009; Lepeule et al., 2012). Presenting results using both ACS and Six Cities is consistent with other recent RIAs (e.g., U.S. EPA, 2010c, 2011a, 2011c). The PM ISA concludes that the ACS and Six Cities cohorts provide the strongest evidence of the association between long-term $PM_{2.5}$ exposure and premature mortality with support from a number of additional cohort studies (described below).

The extended analyses of the ACS cohort data (Krewski et al., 2009) refined the earlier ACS studies by (a) extending the follow-up period by 2 years to the year 2000, for a total of 18 years; (b) incorporating almost double the number of urban areas; (c) addressing confounding by spatial autocorrelation by incorporating ecological, or community-level, co-variates; and (d) performing an extensive spatial analysis using land use regression modeling in two large urban areas. These enhancements make this analysis well-suited for the assessment of mortality risk from long-term $PM_{2.5}$ exposures for the EPA's benefits analyses.

In 2009, the SAB-HES again reviewed the choice of mortality risk coefficients for benefits analysis, concluding that "[t]he Krewski et al. (2009) findings, while informative, have not yet undergone the same degree of peer review as have the aforementioned studies. Thus, the SAB-HES recommends that EPA not use the Krewski et al. (2009) findings for generating the Primary Estimate" (U.S. EPA-SAB, 2010a). Since this time, the Krewski et al. (2009) has undergone additional peer review, which we believe strengthens the support for including this study in this RIA. For example, the PM ISA (U.S. EPA, 2009b) included this study among the key mortality studies. In addition, the risk assessment supporting the PM NAAQS (U.S. EPA, 2010b) used risk coefficients drawn from the Krewski et al. (2009) study, the most recent reanalysis of the ACS cohort data. The PM risk assessment cited a number of advantages that informed the selection of the Krewski et al. (2009) study as the source of the core effect estimates, including the extended period of observation, the rigorous examination of model forms and effect estimates, the coverage for ecological variables, and the large dataset with over 1.2 million individuals and 156 MSAs (U.S. EPA, 2010b). The CASAC also provided extensive peer review of the PM risk assessment and supported the use of effect estimates from this study (U.S. EPA-SAB, 2009a, b, 2010b).

Consistent with the PM risk assessment (U.S. EPA, 2010b), which was reviewed by the CASAC (U.S. EPA-SAB, 2009a, b), we use the all-cause mortality risk estimate based on the random-effects Cox proportional hazard model that incorporates 44 individual and 7 ecological covariates (RR=1.06, 95% confidence intervals 1.04–1.08 per 10 μg/m^3 increase in $PM_{2.5}$). The relative risk estimate (1.06 per 10 μg/m^3 increase in $PM_{2.5}$) is identical to the risk estimate drawn from the earlier Pope et al. (2002) study, though the confidence interval around the Krewski et al. (2009) risk estimate is tighter.

In the most recent Six Cities study, which was published after the last SAB-HES review, Lepeule et al. (2012) evaluated the sensitivity of previous Six Cities results to model specifications, lower exposures, and averaging time using eleven additional years of cohort follow-up that incorporated recent lower exposures. The authors found significant associations between $PM_{2.5}$ exposure and increased risk of all-cause, cardiovascular and lung cancer mortality. The authors also concluded that the C-R relationship was linear down to $PM_{2.5}$ concentrations of 8 μg/m^3 and that mortality rate ratios for $PM_{2.5}$ fluctuated over time, but without clear trends, despite a substantial drop in the sulfate fraction. We use the all-cause mortality risk estimate based on a Cox proportional hazard model that incorporates 3 individual covariates. (RR=1.14, 95% confidence intervals 1.07–1.22 per 10 μg/m^3 increase in $PM_{2.5}$). The relative risk estimate is slightly smaller than the risk estimate drawn from Laden et al. (2006), with relatively smaller confidence intervals.

Given that monetized benefits associated with $PM_{2.5}$ are driven largely by reductions in premature mortality, it is important to characterize the uncertainty in this endpoint. In order to do so, we utilize the results of an expert elicitation sponsored by the EPA and completed in 2006 (Roman et al., 2008; IEc, 2006). The results of that expert elicitation can be used as a characterization of uncertainty in the C-R functions.

In addition to the adult mortality studies described above, several studies show an association between PM exposure and premature mortality in children under 5 years of age.[96] The PM ISA states that less evidence is available regarding the potential impact of $PM_{2.5}$ exposure on infant mortality than on adult mortality and the results of studies in several countries include a range of findings with some finding significant associations. Specifically, the PM ISA concluded that evidence exists for a stronger effect at the post-neonatal period and for respiratory-related mortality, although this trend is not consistent across all studies. In addition, compared to avoided premature deaths estimated for adult mortality, avoided premature deaths for infants are significantly smaller because the number of infants in the population is much smaller than the number of adults and the epidemiology studies on infant mortality provide smaller risk coefficients associated with exposure to $PM_{2.5}$.

In 2004, the SAB-HES noted the release of the WHO Global Burden of Disease Study focusing on ambient air, which cites several recently published time-series studies relating daily PM exposure to mortality in children (U.S. EPA-SAB, 2004). With regard to the cohort study conducted by Woodruff et al. (1997), the SAB-HES noted several strengths of the study, including the use of a larger cohort drawn from a large number of metropolitan areas and efforts to control for a variety of individual risk factors in infants (e.g., maternal educational level, maternal ethnicity, parental marital status, and maternal smoking status). Based on these findings, the SAB-HES recommended that the EPA incorporate infant mortality into the primary benefits estimate and that infant mortality be evaluated using an impact function developed from the Woodruff et al. (1997) study (U.S. EPA-SAB, 2004).

In 2010, the SAB-HES again noted the increasing body of literature relating infant mortality and PM exposure and supported the inclusion of infant mortality in the monetized

[96] For the purposes of this analysis, we only calculate benefits for infants age 0–1, not all children under 5 years old.

benefits (U.S. EPA-SAB, 2010a). The SAB-HES generally supported the approach of estimating infant mortality based on Woodruff et al. (1997) but also noted that a more recent study by Woodruff et al. (2006) continued to find associations between $PM_{2.5}$ and infant mortality in California. The SAB-HES also noted, "when PM_{10} results are scaled to estimate $PM_{2.5}$ impacts, the results yield similar risk estimates." Consistent with *The Benefits and Costs of the Clean Air Act 1990 to 2020* (U.S. EPA, 2011a), we continue to rely on the earlier 1997 study in part due to the national–scale of the earlier study.

6.2.2 Economic Valuation for Health Benefits

After quantifying the change in adverse health impacts, we estimate the economic value of these avoided impacts. Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects by a small amount for a large population. Therefore, the appropriate economic measure is willingness to pay (WTP) for changes in risk of a health effect. For some health effects, such as hospital admissions, WTP estimates are generally not available, so we use the cost of treating or mitigating the effect. These cost-of-illness (COI) estimates generally (although not necessarily in every case) understate the true value of reductions in risk of a health effect. They tend to reflect the direct expenditures related to treatment but not the value of avoided pain and suffering from the health effect. The unit values applied in this analysis are provided in Table 5-9 of the PM NAAQS RIA for each health endpoint (U.S. EPA, 2012a).

For this proposed rule avoided premature deaths account for over 90 percent of monetized ozone-related benefits and 98 percent of monetized PM-related co-benefits. The economics literature concerning the appropriate method for valuing reductions in premature mortality risk is still developing. The adoption of a value for the projected reduction in the risk of premature mortality is the subject of continuing discussion within the economics and public policy analysis community. Following the advice of the SAB's Environmental Economics Advisory Committee (SAB-EEAC), the EPA currently uses the value of statistical life (VSL) approach in calculating estimates of mortality benefits, because we believe this calculation provides the most reasonable single estimate of an individual's willingness to trade off money for reductions in mortality risk (U.S. EPA-SAB, 2000). The VSL approach is a summary measure for the value of small changes in mortality risk experienced by a large number of people.

The EPA continues work to update its guidance on valuing mortality risk reductions, and the Agency consulted several times with the SAB-EEAC on this issue. Until updated guidance is available, the Agency determined that a single, peer-reviewed estimate applied consistently, best reflects the SAB-EEAC advice it has received. Therefore, the EPA has decided to apply the VSL that was vetted and endorsed by the SAB in the *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2014)[97] while the Agency continues its efforts to update its guidance on this issue. This approach calculates a mean value across VSL estimates derived from 26 labor market and contingent valuation studies published between 1974 and 1991. The mean VSL across these studies is $6.3 million (2000$).[98] We then adjust this VSL to account for the currency year and to account for income growth from 1990 to the analysis year. Specifically, the VSL applied in this analysis in 2011$ after adjusting for income growth is $9.9 million for 2017.

The Agency is committed to using scientifically sound, appropriately reviewed evidence in valuing mortality risk reductions and has made significant progress in responding to the SAB-EEAC's specific recommendations. In the process, the Agency has identified a number of important issues to be considered in updating its mortality risk valuation estimates. These are detailed in a white paper, "Valuing Mortality Risk Reductions in Environmental Policy" (U.S. EPA, 2010c), which recently underwent review by the SAB-EEAC. A meeting with the SAB on this paper was held on March 14, 2011 and formal recommendations were transmitted on July 29, 2011 (U.S. EPA-SAB, 2011). The EPA is taking SAB's recommendations under advisement.

In valuing $PM_{2.5}$-related premature mortality, we discount the value of premature mortality occurring in future years using rates of 3 percent and 7 percent (OMB, 2003). We assume that there is a "cessation" lag between changes in PM exposures and the total realization of changes in health effects. Although the structure of the lag is uncertain, the EPA follows the advice of the SAB-HES to assume a segmented lag structure characterized by 30 percent of mortality reductions in the first year, 50 percent over years 2 to 5, and 20 percent over the years 6 to 20 after the reduction in $PM_{2.5}$ (U.S. EPA-SAB, 2004c). Changes in the cessation lag assumptions

[97] In the updated *Guidelines for Preparing Economic Analyses* (U.S. EPA, 2010e), the EPA retained the VSL endorsed by the SAB with the understanding that further updates to the mortality risk valuation guidance would be forthcoming.
[98] In 1990$, this base VSL is $4.8 million.

do not change the total number of estimated deaths but rather the timing of those deaths. Because short-term ozone-related premature mortality occurs within the analysis year, the estimated ozone-related co-benefits are identical for all discount rates.

6.2.3 Benefit-per-ton Estimates for Ozone

We used a "benefit-per-ton" approach to estimate the ozone benefits in this RIA. The EPA has applied this approach in several previous RIAs (e.g., U.S. EPA, 2011b, 2011c, 2012b, 2014a; 2015). These benefit-per-ton estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of NO_X (an ozone precursor). We generated benefit-per-ton estimates for ozone based on air quality modeling for the illustrative control case described in Chapter 3 of this RIA. The estimates correspond to NO_X emissions from U.S. EGUs during the ozone-season (May to September). Because we estimate ozone health impacts from May to September only, this approach underestimates ozone benefits in areas with a longer ozone season such as Texas. These estimates assume that EGU-attributable ozone formation at the regional-level is due to NO_X alone. Because EGUs emit little VOC relative to NO_X emissions, it is unlikely that VOCs emitted by EGUs would contribute substantially to regional ozone formation. We provide more detailed information regarding the generation of these estimates in the appendix to this chapter.

As noted below in the characterization of uncertainty, all benefit-per-ton estimates have inherent limitations. Specifically, the benefit-per-ton estimates reflect the geographic distribution of the modeled illustrative control case, which may not match the geographic distribution of emission reductions anticipated for compliance with the regulatory control alternatives, and they may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors for any specific location.

6.2.4 Benefit-per-ton Estimates for $PM_{2.5}$

We used a "benefit-per-ton" approach to estimate the $PM_{2.5}$ co-benefits in this RIA, which represent the total monetized human health co-benefits (the sum of premature mortality and premature morbidity), of reducing one ton of $PM_{2.5}$ (or $PM_{2.5}$ precursor such as NO_X) from a specified source. Specifically, in this analysis, we multiplied the benefit-per-ton estimates by the corresponding emission reductions that were generated from air quality modeling of the illustrative control case. The appendix to this chapter provides additional detail regarding these calculations. All benefit-per-ton estimates have inherent limitations and should be interpreted with caution. Even though we assume that all fine particles have equivalent health effects, the benefit-per-ton estimates vary between precursors depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure.

6.2.5 Estimated Health Benefits Results

Table 6-2 provides the benefit-per-ton estimates for the analysis year 2017; because the modeled change in SO_2 levels was very small, we did not quantify the SO_2-related $PM_{2.5}$ benefits. Table 6-3 provides the emission reductions estimated to occur in the analysis year. Table 6-4 summarizes the national monetized ozone-related and PM-related health benefits estimated to occur for regulatory control alternatives for the 2017 analysis year, by precursor pollutant using discount rates of 3 percent and 7 percent. Table 6-5 provides national summaries of the reductions in estimated health incidences associated with the proposal and more and less stringent alternatives for the 2017 analysis year.[99] Figure 6-1 provides a visual representation of the range of estimated ozone and $PM_{2.5}$-related benefits using benefit-per-ton estimates based on concentration-response functions from different studies and expert opinion for the proposal evaluated for 2017.

[99] Incidence estimates were generated using the same "per ton" approach as used to generate the dollar benefit per ton values. See Appendix 6-A for details.

Table 6-2. Summary of Ozone and $PM_{2.5}$ Benefit-per-Ton Estimates Based on Air Quality Modeling from the Illustrative Control Case in 2017 (2011$)*

Pollutant	Discount Rate	National
NO_X (as Ozone)	N/A	$5,700 to $9,400
NO_X (as $PM_{2.5}$)	3%	$2,100 to $4,700
	7%	$1,900 to $4,300

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for ozone and $PM_{2.5}$. All estimates are rounded to two significant figures. The monetized co-benefits do not include reduced health effects from direct exposure to NO_2, SO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ concentrations, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Benefit-per-ton estimates for ozone are based on ozone season NO_X emissions. Ozone co-benefits occur in the analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski *et al.* (2009) and Lepeule *et al.* (2012).

Table 6-3. Emission Reductions of Criteria Pollutants for the Proposal and More and Less Stringent Alternatives in 2017 (thousands of short tons)*

	Proposal	More Stringent Alternative	Less Stringent Alternative
Ozone Season NO_X	85,000	87,000	24,000
All Year NO_X	90,000	93,000	24,000
All Year SO_2	380	430	300

*All emissions shown in the table are rounded, so regional emission reductions may appear to not sum to national total.

Table 6-4. Summary of Estimated Monetized Health Benefits for the Proposal and More and Less Stringent Alternatives Regulatory Control Alternatives for 2017 (millions of 2011$) *

Pollutant		Proposal	More Stringent Alternative	Less Stringent Alternative
NOx (as Ozone)		$490 to $790	$500 to $820	$140 to $220
NOx (as $PM_{2.5}$)	3% Discount Rate	$190 to $430	$190 to $440	$49 to $110
	7% Discount Rate	$170 to $380	$170 to $390	$45 to $100
Total	3% Discount Rate	$670 to $1,200	$690 to $1,300	$190 to $340
	7% Discount Rate	$650 to $1,200	$670 to $1,200	$180 to $330

* All estimates are rounded to two significant figures so numbers may not sum down columns. The health benefits range is based on adult mortality functions (e.g., from Krewski et al. (2009) with Smith et al. (2009) to Lepeule et al. (2012) with Zanobetti and Schwartz (2008)). The estimated monetized co-benefits do not include climate benefits or reduced health effects from direct exposure to NO_2, ecosystem effects, or visibility impairment. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized co-benefits incorporate the conversion from precursor emissions to ambient fine particles and ozone. Co-benefits for ozone are based on ozone season NO_X emissions. Ozone co-benefits occur in analysis year, so they are the same for all discount rates. Confidence intervals are unavailable for this analysis because of the benefit-per-ton methodology. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski *et al.* (2009) and Lepeule *et al.* (2012). The confidence intervals

around the ozone mortality estimates are on the order of +/- 60 percent depending on the concentration-response function used.

Table 6-5. Summary of Avoided Health Incidences from Ozone-Related and $PM_{2.5}$-Related Benefits for the Proposal and More and Less Stringent Alternatives for 2017*

Ozone-related Health Effects	Proposal	More Stringent Alternative	Less Stringent Alternative
Avoided Premature Mortality			
Smith *et al.* (2009) (all ages)	48	50	14
Zanobetti and Schwartz (2008) (all ages)	81	83	23
Avoided Morbidity			
Hospital admissions—respiratory causes (ages > 65)	79	81	22
Emergency room visits for asthma (all ages)	320	330	90
Asthma exacerbation (ages 6-18)	93,000	95,000	26,000
Minor restricted-activity days (ages 18-65)	240,000	240,000	67,000
School loss days (ages 5-17)	77,000	79,000	22,000
$PM_{2.5}$-related Health Effects			
Avoided Premature Mortality			
Krewski *et al.* (2009) (adult)	21	22	5.6
Lepeule *et al.* (2012) (adult)	48	50	13
Woodruff *et al.* (1997) (infant)	<1	<1	<1
Avoided Morbidity			
Emergency department visits for asthma (all ages)	12	12	3.1
Acute bronchitis (age 8–12)	31	32	8.1
Lower respiratory symptoms (age 7–14)	390	400	100
Upper respiratory symptoms (asthmatics age 9–11)	560	580	150
Minor restricted-activity days (age 18–65)	16,000	16,000	4,200
Lost work days (age 18–65)	2,700	2,700	700
Asthma exacerbation (age 6–18)	580	600	150
Hospital admissions—respiratory (all ages)	6	7	2
Hospital admissions—cardiovascular (age > 18)	8	8	2
Non-Fatal Heart Attacks (age >18)			
Peters *et al.* (2001)	26	25	7
Pooled estimate of 4 studies	3	3	1

* All estimates are rounded to whole numbers with two significant figures.. Co-benefits for ozone are based on ozone season NOx emissions. Confidence intervals are unavailable for this analysis because of the incidence-per-ton methodology. In general, the 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski *et al.* (2009) and ±46 percent based on Lepeule *et al.* (2012). The confidence intervals around the ozone mortality estimates are on the order of +/- 60 percent depending on the concentration-response function used.

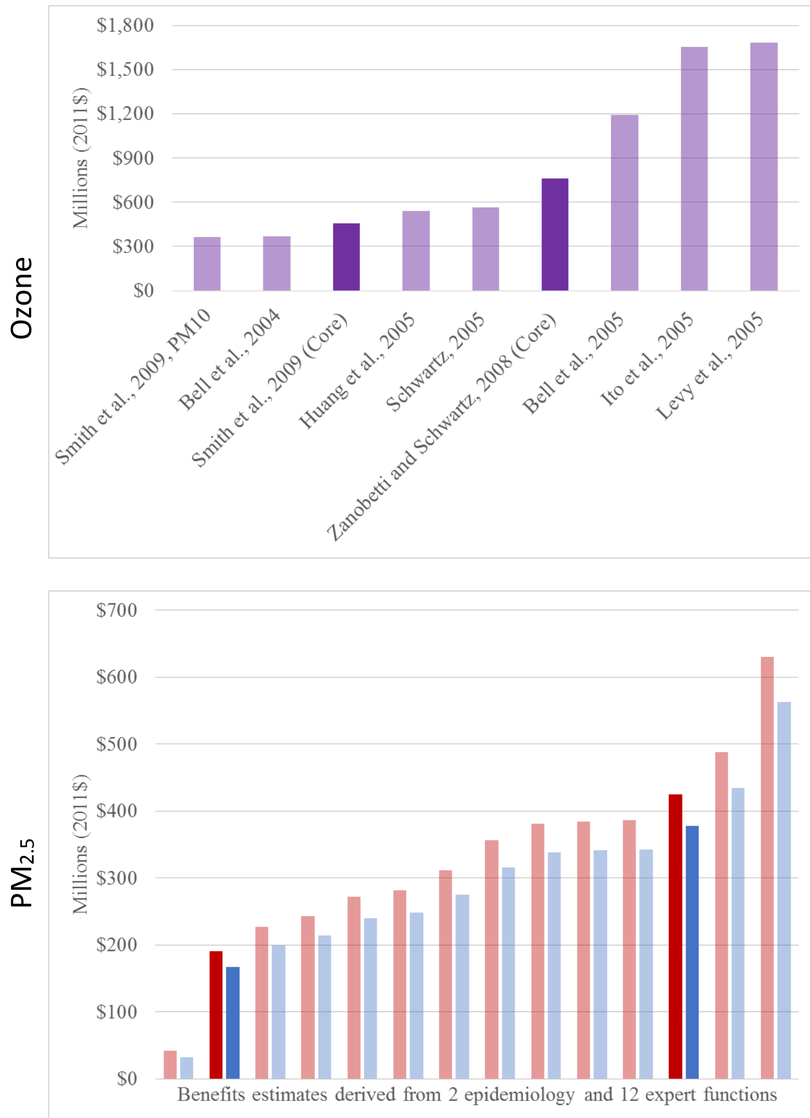


Figure 6-1. Monetized Health Benefits of Proposal for 2017 *

*The $PM_{2.5}$ graphs show the estimated $PM_{2.5}$ co-benefits at discount rates of 3% and 7% using effect coefficients derived from the Krewski *et al.* (2009) study and the Lepeule *et al.* (2012) study, as well as 12 effect coefficients derived from EPA's expert elicitation on PM mortality (Roman *et al.*, 2008). The results shown are not the direct results from the studies or expert elicitation; rather, the estimates are based in part on the concentration-response functions provided in those studies. Ozone benefits occur in the analysis year, so they are the same for all discount rates. These estimates do not include benefits from reductions in CO_2. The monetized co-benefits do not include climate benefits from changes in NO_2 or reduced health effects from direct exposure to NO_2, ecosystem effects, or visibility impairment.

6.2.6 Characterization of Uncertainty in the Estimated Health Benefits

In any complex analysis using estimated parameters and inputs from numerous models, there are likely to be many sources of uncertainty. This analysis is no exception. This analysis includes many data sources as inputs, including emission inventories, air quality data from models (with their associated parameters and inputs), population data, population estimates, health effect estimates from epidemiology studies, economic data for monetizing benefits, and assumptions regarding the future state of the world (i.e., regulations, technology, and human behavior). Each of these inputs may be uncertain and would affect the estimate of benefits. When the uncertainties from each stage of the analysis are compounded, even small uncertainties can have large effects on the total quantified benefits. In addition, the use of the benefit-per-ton approach adds additional uncertainties beyond those for analyses based directly on air quality modeling. Therefore, the estimates of benefits should be viewed as representative of the general magnitude of benefits of the regulatory control alternatives for the 2017 analysis year, rather than the actual benefits anticipated from implement the proposal.

This RIA does not include the type of detailed uncertainty assessment found in the Ozone NAAQS RIA (U.S. EPA, 2015) or the PM NAAQS RIA (U.S. EPA, 2012a) because we lack the necessary air quality modeling input and/or monitoring data to run the benefits model. However, the results of the quantitative and qualitative uncertainty analyses presented in the Ozone NAAQS RIA and PM NAAQS RIA can provide some information regarding the uncertainty inherent in the estimated benefits results presented in this analysis. For example, sensitivity analyses conducted for the PM NAAQS RIA indicate that alternate cessation lag assumptions could change the estimated $PM_{2.5}$-related mortality co-benefits discounted at 3 percent by between 10 percent and –27 percent and that alternative income growth adjustments could change the $PM_{2.5}$-related mortality benefits by between 33 percent and −14 percent. Although we generally do not calculate confidence intervals for benefit-per-ton estimates as they can provide an incomplete picture about the overall uncertainty in the benefits estimates, the PM NAAQS RIA provides an indication of the random sampling error in the health impact and economic valuation functions using Monte Carlo methods. In general, the 95th percentile confidence interval for monetized $PM_{2.5}$ benefits ranges from approximately -90 percent to +180 percent of the central estimates based on Krewski *et al.* (2009) and Lepeule *et al.* (2012). The 95th percentile confidence interval for the health impact function alone ranges from approximately ±30 percent for mortality incidence based on Krewski *et al.* (2009) and ±46 percent based on Lepeule *et al.* (2012).

We applied benefit-per-ton estimates, which reflect specific geographic patterns of emissions reductions and specific air quality and benefits modeling assumptions. For example, these estimates may not reflect local variability in population density, meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual co-benefits of controlling PM and ozone precursors. As such, it is not feasible to estimate the proportion of co-benefits occurring in different locations. Use of these benefit-per-ton values to estimate benefits may lead to higher or lower benefit estimates than if benefits were calculated based on direct air quality modeling. Great care should be taken in applying these estimates to emission reductions occurring in any specific location, as these are all based on a broad emission reduction scenario and therefore represent average benefits-per-ton over the entire region. The benefit-per-ton for emission reductions in specific locations may be very different than the estimates presented here. To the extent that the geographic distribution of the emissions reductions achieved by implementing the proposal is different than the emissions in the air quality modeling of the illustrative control case, the benefits may be underestimated or overestimated.

Our estimate of the total monetized benefits is based on the EPA's interpretation of the best available scientific literature and methods and supported by the SAB-HES and the National Academies of Science (NRC, 2002). Below are key assumptions underlying the estimates for $PM_{2.5}$-related premature mortality, which accounts for 98 percent of the monetized $PM_{2.5}$ health co-benefits.

1. We assume that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because $PM_{2.5}$ varies considerably in composition across sources, but the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type. The PM ISA concluded that "many constituents of $PM_{2.5}$ can be linked with multiple health effects, and the evidence is not yet sufficient to allow differentiation of those constituents or sources that are more closely related to specific outcomes" (U.S. EPA, 2009b).

2. We assume that the health impact function for fine particles is log-linear without a threshold. Thus, the estimates include health co-benefits from reducing fine particles in areas with varied concentrations of $PM_{2.5}$, including both areas that do not meet the fine particle standard and those areas that are in attainment, down to the lowest modeled concentrations.

3. We assume that there is a "cessation" lag between the change in PM exposures and the total realization of changes in mortality effects. Specifically, we assume that some of the incidences of premature mortality related to $PM_{2.5}$ exposures occur in a distributed fashion over the 20 years following exposure based on the advice of the SAB-HES (U.S. EPA-SAB, 2004c), which affects the valuation of mortality co-benefits at different discount rates.

In general, we are more confident in the magnitude of the risks we estimate from simulated $PM_{2.5}$ concentrations that coincide with the bulk of the observed PM concentrations in the epidemiological studies that are used to estimate the benefits. Likewise, we are less confident in the risk we estimate from simulated $PM_{2.5}$ concentrations that fall below the bulk of the observed data in these studies. Concentration benchmark analyses (e.g., lowest measured level [LML], one standard deviation below the mean of the air quality data in the study, etc.) allow readers to determine the portion of population exposed to annual mean $PM_{2.5}$ levels at or above different concentrations, which provides some insight into the level of uncertainty in the estimated $PM_{2.5}$ mortality benefits. In this analysis, we apply two concentration benchmark approaches (LML and one standard deviation below the mean) that have been incorporated into recent RIAs and the EPA's *Policy Assessment for Particulate Matter* (U.S. EPA, 2011d). There are uncertainties inherent in identifying any particular point at which our confidence in reported associations becomes appreciably less, and the scientific evidence provides no clear dividing line. However, the EPA does not view these concentration benchmarks as a concentration threshold below which we would not quantify health benefits of air quality improvements.[100] Rather, the co-benefits estimates reported in this RIA are the best estimates because they reflect the full range of air quality concentrations associated with the regulatory control alternatives. The PM ISA concluded that the scientific evidence collectively is sufficient to conclude that the relationship between long-term $PM_{2.5}$ exposures and mortality is causal and that, overall, the studies support the use of a no-threshold log-linear model to estimate PM-related long-term mortality (U.S. EPA, 2009b).

We report also the key assumptions associated with our analysis of ozone-related effects:

[100] For a summary of the scientific review statements regarding the lack of a threshold in the $PM_{2.5}$-mortality relationship, see the TSD entitled *Summary of Expert Opinions on the Existence of a Threshold in the Concentration-Response Function for $PM_{2.5}$-related Mortality* (U.S. EPA, 2010b).

- **Key assumption and uncertainties related to modeling of ozone-related premature mortality**: Ozone-related short-term mortality represents a substantial proportion of total monetized benefits (over 94% of the ozone-related-benefits), and these estimates have the following key assumptions and uncertainties. We utilize a log-linear impact function without a threshold in modeling short-term ozone-related mortality. However, we acknowledge reduced confidence in specifying the nature of the C-R function in the range of ≤20ppb and below (ozone ISA, section 2.5.4.4). Thus, ozone-related premature deaths estimated at or below this level are subject to greater uncertainty, but we cannot judge whether (and in what direction) these impacts are biased.

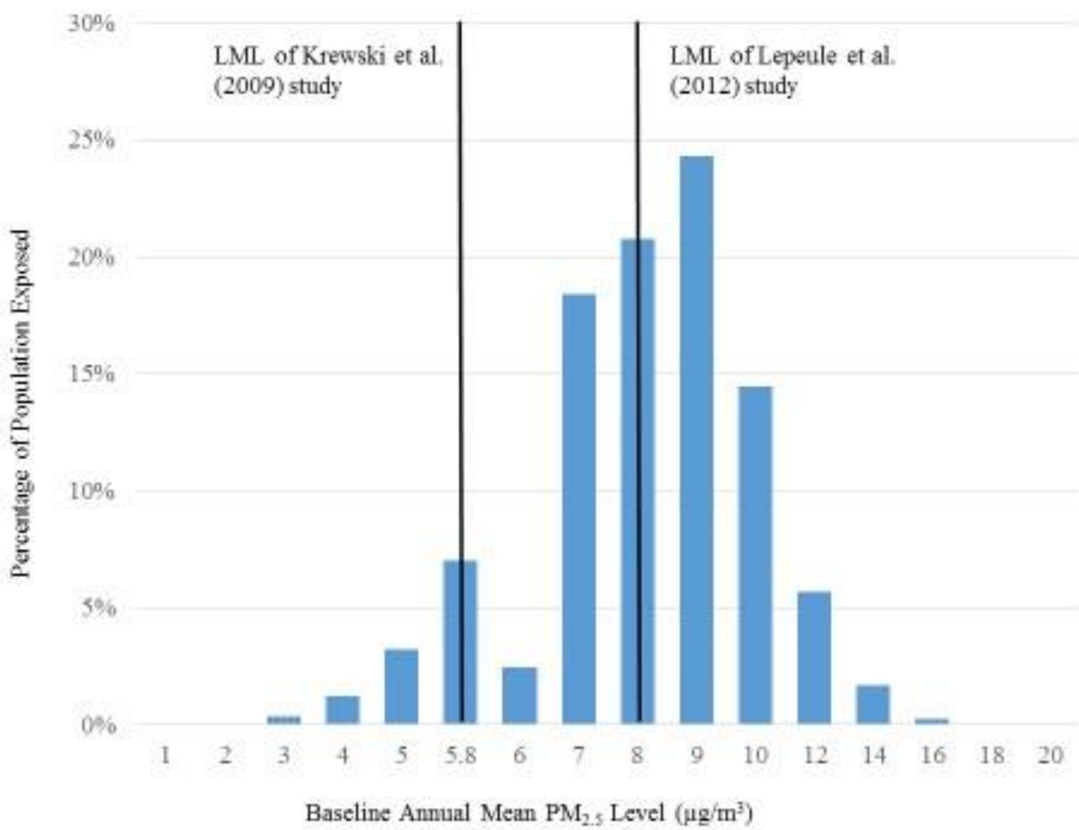
- **Avoided premature mortality according to baseline pollutant concentrations**: We recognize that, in estimating short-term ozone-related mortality, we are less confident in specifying the shape of the C-R function at lower ambient ozone concentrations (at and below 20 ppb, ozone ISA, section 2.5.4.4). Quantitative uncertainty analyses completed for the Ozone NAAQS RIA (U.S. EPA, 2015) found almost 100% of mortality reductions occurred above 20 ppb, where we are more confident in specifying the nature of the ozone-mortality effect (ozone ISA, section 2.5.4.4). However, as discussed in section 6B.7 of that RIA, care must be taken in interpreting these results since the ambient air metric used in modeling this endpoint is the mean 8-hour max value in each grid cell (and not the full distribution of 8-hour daily max values). Had the latter been used, then the distribution would have likely been wider.

For this analysis, policy-specific air quality data is not available, and the control scenarios are illustrative of what states may choose to do. However, we believe that it is still important to characterize the distribution of exposure to baseline concentrations. As a surrogate measure of mortality impacts, we provide the percentage of the population exposed at each $PM_{2.5}$ concentration in the baseline of the air quality modeling used to calculate the benefit-per-ton estimates for this RIA using 12 km grid cells across the contiguous U.S.[101] It is important to note

[101] As described in Chapter 3, the baseline for the air quality modeling used to calculate the benefit-per-ton values differs from the baseline used to estimate the benefits, costs, and impacts of this rulemaking. See Chapter 3 for more details about the differences between the two baselines.

that baseline exposure is only one parameter in the health impact function, along with baseline incidence rates population and change in air quality. In other words, the percentage of the population exposed to air pollution below the LML is not the same as the percentage of the population experiencing health impacts as a result of a specific emission reduction policy. The most important aspect, which we are unable to quantify without rule-specific air quality modeling, is the shift in exposure anticipated by implementing the proposal. Therefore, caution is warranted when interpreting the LML assessment in this RIA because these results are not consistent with results from RIAs that had air quality modeling.

Figure 6-3 shows a bar chart of the percentage of the population exposed to various air quality levels, including the LML concentration benchmarks in the illustrative control case modeling, and Figure 6-4 shows a cumulative distribution function of the same data. Both figures identify the LML for each of the major cohort studies.

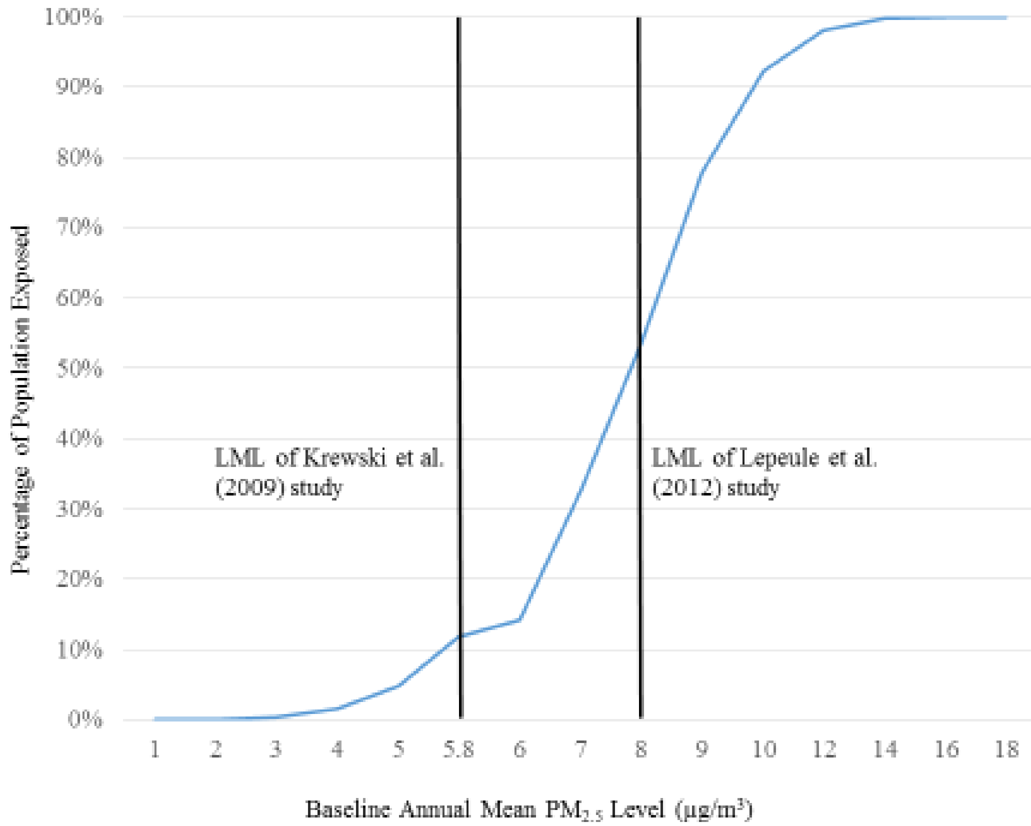


Among the populations exposed to $PM_{2.5}$ in the baseline:

88% are exposed to $PM_{2.5}$ levels at or above the LML of the Krewski *et al.* (2009) study

47% are exposed to $PM_{2.5}$ levels at or above the LML of the Lepeule *et al.* (2012) study

Figure 6-2. Percentage of Adult Population (age 30+) by Annual Mean $PM_{2.5}$ Exposure in the Baseline used for the Air Quality Analysis in Chapter 3



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47% are exposed to $PM_{2.5}$ levels at or above the LML of the Lepeule *et al.* (2012) study

Figure 6-3. Cumulative Distribution of Adult Population (age 30+) by Annual Mean $PM_{2.5}$ Exposure in the Baseline used for the Air Quality Analysis in Chapter 3

6.3 Estimated Climate Co-Benefits from CO_2

A co-benefit of this proposal is reducing emissions of CO_2. In this section, we provide a brief overview of the 2009 Endangerment Finding and climate science assessments released since then. We also provide information regarding the economic valuation of CO_2 using the Social Cost of Carbon (SC-CO_2), a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Table 6-6 summarizes the quantified and unquantified climate benefits in this analysis.

Table 6-6. Climate Effects

Benefits Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Global climate impacts from CO_2	—[1]	✓	SCC TSD
	Climate impacts from ozone and black carbon (directly emitted PM)	—	—	Ozone ISA, PM ISA[2]
	Other climate impacts (e.g., other GHGs such as methane, aerosols, other impacts)	—	—	IPCC[2]

[1] The global climate and related impacts of CO_2 emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the SC-CO_2. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the welfare effects of quantified changes in CO_2 emissions.
[2] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.

There are several important considerations in assessing the climate-related benefits for an ozone air quality-focused rulemaking. First, the estimated health benefits do not account for any climate-related air quality changes (e.g., increased ambient ozone associated with higher temperatures). Excluding climate-related air quality changes may underestimate ozone-related health benefits. It is unclear how $PM_{2.5}$-related health benefits would be affected by excluding climate-related air quality changes since the science is unclear as to how climate change may affect $PM_{2.5}$ exposure. Second, the estimated health benefits also do not consider temperature modification of $PM_{2.5}$ and ozone risks (Roberts 2004; Ren 2006a, 2006b, 2008a, 2008b). Third, the estimated climate co-benefits reported in this RIA reflect global benefits, while the estimated health benefits are calculated for the contiguous U.S. only. Excluding temperature modification of air pollution risks and international air quality-related health benefits likely leads to underestimation of quantified health benefits (Anenberg et al, 2009, Jhun et al, 2014). Fourth, as noted earlier, we do not estimate the climate co-benefits associated with reductions in PM and ozone precursors.

6.3.1 *Climate Change Impacts*

Through the implementation of CAA regulations, the EPA addresses the negative externalities caused by air pollution. In 2009, the EPA Administrator found that elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated both to endanger public health and to endanger public welfare. For health, these include the increased likelihood of heat waves, negative impacts on air quality, more intense hurricanes, more frequent and intense storms and heavy precipitation, and impacts on infectious and waterborne diseases. For welfare, these include reduced water supplies in some regions, increased water pollution, increased occurrences of floods and droughts, rising sea levels and damage to coastal infrastructure, increased peak electricity demand, changes in ecosystems, and impacts on indigenous communities.

The preamble also summarizes new scientific assessments and recent climatic observations. Major scientific assessments released since the 2009 Endangerment Finding have improved scientific understanding of the climate, and provide even more evidence that GHG emissions endanger public health and welfare for current and future generations. The National Climate Assessment (NCA), in particular, assessed the impacts of climate change on human health in the United States, finding that Americans will be affected by "increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks." These assessments also detail the risks to vulnerable groups such as children, the elderly and low income households. Furthermore, the assessments present an improved understanding of the impacts of climate change on public welfare, higher projections of future sea level rise than had been previously estimated, a better understanding of how the warmth in the next century may reach levels that would be unprecedented relative to the preceding millions of years of history, and new assessments of the impacts of climate change on permafrost and ocean acidification. The impacts of GHG emissions will be realized worldwide, independent of their location of origin, and impacts outside of the United States will produce consequences relevant to the United States.

6.3.2 *Social Cost of Carbon*

We estimate the global social benefits of CO_2 emission reductions expected from the final emission guidelines using the SC-CO_2 estimates presented in the *Technical Support Document:*

Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, Revised July 2015) ("current TSD").[102] We refer to these estimates, which were developed by the U.S. government, as "SC-CO_2 estimates." The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CO_2 emissions).

The SC-CO_2 estimates used in this analysis were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. As discussed further below, the IWG published two minor corrections to the SC-CO_2 estimates in July 2015.

The SC-CO_2 estimates were developed using an ensemble of the three most widely cited integrated assessment models in the economics literature with the ability to estimate the SC-CO_2. A key objective of the IWG was to draw from the insights of the three models while respecting the different approaches to linking GHG emissions and monetized damages taken by modelers in the published literature. After conducting an extensive literature review, the interagency group selected three sets of input parameters (climate sensitivity, socioeconomic and emissions trajectories, and discount rates) to use consistently in each model. All other model features were

[102] Docket ID EPA-HQ-OAR-2013-0495, Technical Support Document: *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (May 2013, Revised July 2015). Available at: <https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf> Accessed 7/11/2015.

left unchanged, relying on the model developers' best estimates and judgments, as informed by the literature. Specifically, a common probability distribution for the equilibrium climate sensitivity parameter, which informs the strength of climate's response to atmospheric GHG concentrations, was used across all three models. In addition, a common range of scenarios for the socioeconomic parameters and emissions forecasts were used in all three models. Finally, the marginal damage estimates from the three models were estimated using a consistent range of discount rates, 2.5, 3.0, and 5.0 percent. See the 2010 TSD for a complete discussion of the methods used to develop the estimates and the key uncertainties, and the current TSD for the latest estimates.[103]

The SC-CO_2 estimates represent global measures because of the distinctive nature of climate change, which is highly unusual in at least three respects. First, emissions of most GHGs contribute to damages around the world independent of the country in which they are emitted. The SC-CO_2 must therefore incorporate the full (global) damages caused by GHG emissions to address the global nature of the problem. Second, the U.S. operates in a global and highly interconnected economy, such that impacts on the other side of the world can affect our economy. This means that the true costs of climate change to the U.S. are larger than the direct impacts that simply occur within the U.S. Third, climate change represents a classic public goods problem because each country's reductions benefit everyone else and no country can be excluded from enjoying the benefits of other countries' reductions, even if it provides no reductions itself. In this situation, the only way to achieve an economically efficient level of emissions reductions is for countries to cooperate in providing mutually beneficial reductions beyond the level that would be justified only by their own domestic benefits. In reference to the public good nature of mitigation and its role in foreign relations, thirteen prominent academics noted that these "are compelling reasons to focus on a global SCC" in a recent article on the SCC (Pizer et al., 2014). In addition, as noted in OMB's Response to Comments on the SCC, there is no bright line between domestic and global damages. Adverse impacts on other countries can have spillover

[103] See https://www.whitehouse.gov/omb/oira/social-cost-of-carbon for both TSDs.

effects on the United States, particularly in the areas of national security, international trade, public health and humanitarian concerns.[104]

The 2010 TSD noted a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently integrated assessment models do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research.[105] The limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult. These individual limitations do not all work in the same direction in terms of their influence on the SC-CO_2 estimates, though taken together they suggest that the SC-CO_2 estimates are likely conservative. In particular, the IPCC Fourth Assessment Report (2007), which was the most current IPCC assessment available at the time of the IWG's 2009-2010 review, concluded that "It is very likely that [SC-CO_2 estimates] underestimate the damage costs because they cannot include many non-quantifiable impacts." Since then, the peer-reviewed literature has continued to support this conclusion. For example, the IPCC Fifth Assessment report observed that SC-CO_2 estimates continue to omit various impacts that would likely increase damages. The 95th percentile estimate was included in the recommended range for regulatory impact analysis to address these concerns.

The EPA and other agencies have continued to consider feedback on the SC-CO_2 estimates from stakeholders through a range of channels, including public comments on rulemakings that use the SC-CO_2 in supporting analyses and through regular interactions with stakeholders and

[104] See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 66,496, 66,535 (Dec. 15, 2009) and National Research Council 2013a.

[105] Climate change impacts and SCC modeling is an area of active research. For example, see: (1) Howard, Peter, "Omitted Damages: What's Missing from the Social Cost of Carbon." March 13, 2014, http://costofcarbon.org/files/Omitted_Damages_Whats_Missing_From_the_Social_Cost_of_Carbon.pdf; and (2) Electric Power Research Institute, "Understanding the Social Cost of carbon: A Technical Assessment," October 2014, www.epri.com.

research analysts implementing the SC-CO_2 methodology used by the interagency working group. In addition, OMB's Office of Information and Regulatory Affairs issued a separate request for public comment on the approach used to develop the estimates.[106] After careful evaluation of the full range of comments submitted to OMB's Office of Information and Regulatory Affairs, the IWG continues to recommend the use of these SC-CO_2 estimates in regulatory impact analysis. With the release of the response to comments[107], the IWG announced plans to obtain expert independent advice from the National Academies of Sciences, Engineering, and Medicine (Academies) to ensure that the SC-CO_2 estimates continue to reflect the best available scientific and economic information on climate change.[108] The Academies' process will be informed by the public comments received and focuses on the technical merits and challenges of potential approaches to improving the SC-CO_2 estimates in future updates.[109]

Concurrent with OMB's publication of the response to comments on SC-CO_2 and announcement of the Academies process, OMB posted a revised TSD that includes two minor technical corrections to the current estimates. One technical correction addressed an inadvertent omission of climate change damages in the last year of analysis (2300) in one model and the second addressed a minor indexing error in another model. On average the revised SC-CO_2 estimates are one dollar less than the mean SC-CO_2 estimates reported in the November 2013 revision to the May 2013 TSD. The change in the estimates associated with the 95th percentile estimates when using a 3% discount rate is slightly larger, as those estimates are heavily influenced by the results from the model that was affected by the indexing error.

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106 See https://www.federalregister.gov/articles/2013/11/26/2013-28242/technical-support-document-technical-update-of-the-social-cost-of-carbon-for-regulatory-impact

107 See https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-response-to-comments-final-july-2015.pdf

108 See https://www.whitehouse.gov/blog/2015/07/02/estimating-benefits-carbon-dioxide-emissions-reductions.

109 See http://sites.nationalacademies.org/DBASSE/BECS/CurrentProjects/DBASSE_167526?utm_source=All%20DBASSE%20Newsletters&utm_campaign=e84c13e8c4-New_Project_the_Social_Cost_of_Carbon&utm_medium=email&utm_term=0_e16023964e-e84c13e8c4-267347161 for more information about the National Academies process and the status of the project.

The four SC-CO_2 estimates are as follows: \$12, \$41, \$63, and \$120 per metric ton of CO_2 emissions in the year 2017 (2011\$).[110] The first three values are based on the average SC-CO_2 from the three IAMs, at discount rates of 5, 3, and 2.5 percent, respectively. SC-CO_2 estimates for several discount rates are included because the literature shows that the SC-CO_2 is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context (where costs and benefits are incurred by different generations). The fourth value is the 95th percentile of the SC-CO_2 from all three models at a 3 percent discount rate. It is included to represent higher-than-expected impacts from temperature change further out in the tails of the SC-CO_2 distribution (representing less likely, but potentially catastrophic, outcomes).

Table 6-7 presents the global SC-CO_2 estimates in metric tons for the years 2015 to 2050. In order to calculate the dollar value for emission reductions, the SC-CO_2 estimate for each emissions year would be applied to changes in CO_2 emissions for that year, and then discounted back to the analysis year using the same discount rate used to estimate the SC-CO_2.[111, 112] The SC-CO_2 increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change. Note that the interagency group estimated the growth rate of the SC-CO_2 directly using the three integrated assessment models rather than assuming a constant annual growth rate. This helps to ensure that the estimates are internally consistent with other modeling assumptions. Table 6-8 reports the incremental climate co-benefits from CO_2 emission impacts estimated for the proposal and more and less stringent alternatives for the 2017 analysis year.

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[110] The current version of the TSD is available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf. The 2010 and 2013 TSDs present SC-CO_2 in 2007\$ per metric ton. The unrounded estimates from the current TSD were adjusted to 2011\$ using GDP Implicit Price Deflator (1.061374), http://www.bea.gov/iTable/index_nipa.cfm. The estimates presented here have been rounded to two significant digits.

[111] Emission impacts for this rulemaking are shown for the year 2017 and are calculated in short tons. Therefore, the conversion factor 0.90718474 metric tons in a short ton was applied to the calculate the benefits in the year 2017.

[112] This analysis considered the climate impacts of only CO_2 emission change. As discussed below, the climate impacts of other pollutants were not calculated for the proposed guidelines. While CO_2 is the dominant GHG emitted by the sector, we recognize the representative facilities within these comparisons may also have different emission rates for other climate forcers that will serve a minor role in determining the overall social cost of generation.

Table 6-7. Social Cost of CO_2, 2015-2050 (in 2011$ per metric ton)*

Year	5% Average	3% Average	2.5% Average	3% (95th percentile)
	Discount Rate and Statistic			
2015	$12	$38	$59	$110
2017	$12	$41	$63	$120
2020	$13	$45	$66	$130
2025	$15	$49	$72	$150
2030	$17	$53	$77	$160
2035	$19	$58	$83	$180
2040	$22	$64	$89	$190
2045	$24	$68	$94	$210
2050	$28	$73	$100	$230

* These SC-CO_2 values are stated in $/metric ton and rounded to two significant figures. The estimates vary depending on the year of CO_2 emissions and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

Table 6-8. Estimated Global Climate Co-benefits of CO_2 Reductions for the Proposal and More and Less Stringent Alternatives for 2017 (millions of 2011$)*

Discount rate and statistic	**Proposal**	**More Stringent Alternative**	**Less Stringent Alternative**
Thousands of short tons of CO_2 reduced**	610	610	720
5% (average)	$6.5	$6.5	$7.6
3% (average)	$23	$23	$27
2.5% (average)	$35	$35	$41
3% (95^{th} percentile)	$66	$66	$78

* The SC-CO_2 values are dollar-year and emissions-year specific. SC-CO_2 values represent only a partial accounting of climate impacts.

**Emission impacts for this rulemaking are shown for the year 2017 and are calculated in short tons. The conversion factor 0.90718474 metric tons in a short ton was applied to the calculate the benefits in the year 2017.

It is important to note that the climate co-benefits presented above are associated with changes in CO_2 emissions only. Implementing this proposal, however, will have an impact on the emissions of other pollutants that would affect the climate. Both predicting reductions in emissions and estimating the climate impacts of these other pollutants, however, is complex. The climate impacts of these other pollutants have not been calculated for this proposal.[113]

[113] The SC-CO_2 estimates used in this analysis are designed to assess the climate benefits associated with changes in CO_2 emissions only.

The other emissions potentially reduced as a result of the proposal to update CSAPR include other greenhouse gases (such as methane), aerosols and aerosol precursors such as black carbon, organic carbon, sulfur dioxide and nitrogen oxides, and ozone precursors such as nitrogen oxides and volatile organic carbon compounds. Changes in emissions of these pollutants (both increases and decreases) could directly result from changes in electricity generation, upstream fossil fuel extraction and transport, and/or downstream secondary market impacts. Reductions in black carbon or ozone precursors are projected to lead to further cooling, but reductions in the other aerosol species and precursors are projected to lead to warming. Therefore, changes in non-CO_2 pollutants could potentially augment or offset the climate co-benefits calculated here. These pollutants can act in different ways and on different timescales than carbon dioxide. For example, aerosols reflect (and in the case of black carbon, absorb) incoming radiation, whereas greenhouse gases absorb outgoing infrared radiation. In addition, these aerosols are thought to affect climate indirectly by altering properties of clouds. Black carbon can also deposit on snow and ice, darkening these surfaces and accelerating melting. In terms of lifetime, while carbon dioxide emissions can increase concentrations in the atmosphere for hundreds or thousands of years, many of these other pollutants are short lived and remain in the atmosphere for short periods of time ranging from days to weeks and can therefore exhibit large spatial and temporal variability.

6.4 Combined Health Benefits and Climate Co-Benefits Estimates

In this analysis, we were able to monetize the estimated benefits associated with the reduced exposure to ozone and $PM_{2.5}$ and co-benefits of decreased emissions of CO_2, but we were unable to monetize the co-benefits associated with reducing exposure to mercury, carbon monoxide, and NO_2, as well as ecosystem effects and visibility impairment. In addition, there are expected to be unquantified health and welfare impacts associated with changes in hydrogen chloride. Specifically, we estimated combinations of health benefits at discount rates of 3 percent and 7 percent (as recommended by the EPA's *Guidelines for Preparing Economic Analyses* [U.S. EPA, 2014] and OMB's *Circular A-4* [OMB, 2003]) and climate co-benefits at estimates of the SC-CO_2 (average SC-CO_2 at each of three discount rates—5 percent, 3 percent, 2.5 percent—and the 95th percentile SC-CO_2 at 3 percent) (as recommended by the IWG).

Different discount rates are applied to SC-CO_2 than to the health benefit estimates because CO_2 emissions are long-lived and subsequent damages occur over many years. Moreover, several rates are applied to SC-CO_2 because the literature shows that it is sensitive to assumptions about discount rate and because no consensus exists on the appropriate rate to use in an intergenerational context. The SC-CO_2 interagency group centered its attention on the 3 percent discount rate but emphasized the importance of considering all four SC-CO_2 estimates.[114] The EPA has evaluated the range of potential impacts by combining all SC-CO_2 values with health benefits values at the 3 percent and 7 percent discount rates. Combining the 3 percent SC-CO_2 values with the 3 percent health benefit values assumes that there is no difference in discount rates

Table 6-9 provides the combined health and climate benefits for the proposal and more and less stringent alternatives for the 2017 analysis year.

[114] See the 2010 SCC TSD. Docket ID EPA-HQ-OAR-2009-0472-114577 or http://www.whitehouse.gov/sites/default/files/omb/inforeg/for-agencies/Social-Cost-of-Carbon-for-RIA.pdf for details.

Table 6-9. Combined Health Benefits and Climate Co-Benefits for the Proposal and More and Less Stringent Alternatives for 2017 (millions of 2011$)*

SC-CO_2 Discount Rate**	Health and Climate Benefits (Discount Rate Applied to Health Co-Benefits) 3%	7%	Climate Co-Benefits Only
Proposal			
5%	$680 to $1200	$660 to $1200	$6.5
3%	$700 to $1200	$680 to $1200	$23
2.5%	$710 to $1300	$690 to $1200	$35
3% (95th percentile)	$740 to $1300	$720 to $1200	$66
More Stringent Alternative			
5%	$700 to $1300	$680 to $1200	$6.5
3%	$720 to $1300	$700 to $1200	$23
2.5%	$730 to $1300	$710 to $1200	$35
3% (95th percentile)	$760 to $1300	$740 to $1300	$66
Less Stringent Alternative			
5%	$190 to $340	$190 to $330	$7.6
3%	$210 to $360	$210 to $350	$27
2.5%	$230 to $380	$220 to $370	$41
3% (95th percentile)	$260 to $410	$260 to $400	$78

*All estimates are rounded to two significant figures. Climate benefits are based on reductions in CO_2 emissions. Co-benefits are based on regional benefit-per-ton estimates. Co-benefits for ozone are based on ozone season NOx emissions. Ozone benefits occur in analysis year, so they are the same for all discount rates. The health benefits reflect the sum of the $PM_{2.5}$ and ozone co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski *et al.* (2009) with Smith *et al.* (2009) to Lepeule *et al.* (2012) with Zanobetti and Schwartz (2008)). The monetized health co-benefits do not include reduced health effects from direct exposure to NO_2 and HAP; ecosystem effects; or visibility impairment.
**As discussed in section 6.3, the SC-CO_2 estimates are calculated with four different values of a one ton reduction.

6.5 Unquantified Co-benefits

The monetized co-benefits estimated in this RIA reflect a subset of co-benefits attributable to the health effect reductions associated with ambient fine particles and ozone. Data, time, and resource limitations prevented the EPA from quantifying the impacts to, or monetizing the co-benefits from several important benefit categories, including co-benefits associated with exposure to several HAP and NO_2, as well as ecosystem effects, and visibility impairment due to the absence of air quality modeling data for these pollutants in this analysis. This does not imply that there are no co-benefits associated reductions in exposures to NO_2. In this section, we provide a qualitative description of these benefits, which are listed in Table 6-10.

Table 6-10. Unquantified Health and Welfare Co-benefits Categories

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Human Health				
Reduced incidence of morbidity from exposure to NO_2	Asthma hospital admissions (all ages)	—	—	NO_2 ISA[1]
	Chronic lung disease hospital admissions (age > 65)	—	—	NO_2 ISA[1]
	Respiratory emergency department visits (all ages)	—	—	NO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–18)	—	—	NO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	NO_2 ISA[1]
	Premature mortality	—	—	NO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	NO_2 ISA[2,3]
Reduced incidence of morbidity from exposure to SO_2	Respiratory hospital admissions (age > 65)	—	—	SO_2 ISA[1]
	Asthma emergency department visits (all ages)	—	—	SO_2 ISA[1]
	Asthma exacerbation (asthmatics age 4–12)	—	—	SO_2 ISA[1]
	Acute respiratory symptoms (age 7–14)	—	—	SO_2 ISA[1]
	Premature mortality	—	—	SO_2 ISA[1,2,3]
	Other respiratory effects (e.g., airway hyperresponsiveness and inflammation, lung function, other ages and populations)	—	—	SO_2 ISA[1,2]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[1]
	Visibility in residential areas	—	—	PM ISA[1]
Reduced effects on materials	Household soiling	—	—	PM ISA[1,2]
	Materials damage (e.g., corrosion, increased wear)	—	—	PM ISA[2]
Reduced effects from PM deposition (metals and organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[1]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[1]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[1]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[1]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]
Reduced effects from acid deposition	Recreational fishing	—	—	NO_x SO_x ISA[1]
	Tree mortality and decline	—	—	NO_x SO_x ISA[2]
	Commercial fishing and forestry effects	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and aquatic ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles)	—	—	NO_x SO_x ISA[2]

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Reduced effects from nutrient enrichment	Species composition and biodiversity in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Coastal eutrophication	—	—	NO_x SO_x ISA[2]
	Recreational demand in terrestrial and estuarine ecosystems	—	—	NO_x SO_x ISA[2]
	Other non-use effects			NO_x SO_x ISA[2]
	Ecosystem functions (e.g., biogeochemical cycles, fire regulation)	—	—	NO_x SO_x ISA[2]
Reduced vegetation effects from ambient exposure to SO_2 and NO_x	Injury to vegetation from SO_2 exposure	—	—	NO_x SO_x ISA[2]
	Injury to vegetation from NO_x exposure	—	—	NO_x SO_x ISA[2]

[1] We assess these co-benefits qualitatively due to data and resource limitations for this RIA.

[2] We assess these co-benefits qualitatively because we do not have sufficient confidence in available data or methods.

[3] We assess these co-benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

6.5.1 HAP Impacts

Due to methodology and resource limitations, we were unable to estimate the impacts associated with changes in emissions of the hazardous air pollutants in this analysis. The EPA's SAB-HES concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAPs) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008). In 2009, the EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn *et al.*, 2011).

6.5.2 Additional NO_2 Health Co-Benefits

In addition to being a precursor to $PM_{2.5}$ and ozone, NOx emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health co-benefits associated with reduced NO_2 exposure in this analysis. Therefore, this analysis only quantified and monetized the $PM_{2.5}$ and ozone co-benefits associated with the reductions in NO_2 emissions.

Following a comprehensive review of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Nitrogen —Health Criteria* (NOx ISA) (U.S. EPA, 2008c) concluded that there is a likely causal relationship between respiratory health effects and short-term exposure to NO_2. These epidemiologic and experimental studies encompass a number of endpoints including emergency department visits and hospitalizations, respiratory symptoms, airway hyperresponsiveness, airway inflammation, and lung function. The NOx ISA also concluded that the relationship between short-term NO_2 exposure and premature mortality was "suggestive but not sufficient to infer a causal relationship," because it is difficult to attribute the mortality risk effects to NO_2 alone. Although the NOx ISA stated that studies consistently reported a relationship between NO_2 exposure and mortality, the effect was generally smaller than that for other pollutants such as PM.

6.5.3 Additional SO_2 Health Co-Benefits

In addition to being a precursor to $PM_{2.5}$, SO_2 emissions are also linked to a variety of adverse health effects associated with direct exposure. We were unable to estimate the health co-benefits associated with reduced SO_2 in this analysis because we do not have air quality modeling data available. Therefore, this analysis only quantifies and monetizes the $PM_{2.5}$ co-benefits associated with the reductions in SO_2 emissions.

Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the *Integrated Science Assessment for Oxides of Sulfur —Health Criteria* (SO_2 ISA) concluded that there is a causal relationship between respiratory health effects and short-term exposure to SO_2 (U.S. EPA, 2008a). The immediate effect of SO_2 on the respiratory system in humans is bronchoconstriction. Asthmatics are more sensitive to the effects of SO_2 likely resulting from preexisting inflammation associated with this disease. A clear concentration-response relationship has been demonstrated in laboratory studies following exposures to SO_2 at concentrations between 20 and 100 ppb, both in terms of increasing severity of effect and percentage of asthmatics adversely affected. Based on our review of this information, we identified three short-term morbidity endpoints that the SO_2 ISA identified as a "causal relationship": asthma exacerbation, respiratory-related emergency department visits, and respiratory-related hospitalizations. The differing evidence and associated strength of the evidence for these different effects is described in detail in the SO_2 ISA. The SO_2 ISA also concluded that the relationship between short-term SO_2 exposure and premature mortality was "suggestive of a causal relationship" because it is difficult to attribute the mortality risk effects to SO_2 alone. Although the SO_2 ISA stated that studies are generally consistent in reporting a relationship between SO_2 exposure and mortality, there was a lack of robustness of the observed associations to adjustment for other pollutants. We did not quantify these co-benefits due to data constraints.

6.5.4 Additional NO_2 and SO_2 Welfare Co-Benefits

As described in the *Integrated Science Assessment for Oxides of Nitrogen and Sulfur — Ecological Criteria* (NOx/SOx ISA) (U.S. EPA, 2008d), SO_2 and NOx emissions also contribute to a variety of adverse welfare effects, including those associated with acidic deposition, visibility impairment, and nutrient enrichment. Deposition of nitrogen causes acidification, which can cause a loss of biodiversity of fishes, zooplankton, and macro invertebrates in aquatic ecosystems, as well as a decline in sensitive tree species, such as red spruce (Picea rubens) and sugar maple (Acer saccharum) in terrestrial ecosystems. In the northeastern U.S., the surface waters affected by acidification are a source of food for some recreational and subsistence fishermen and for other consumers and support several cultural services, including aesthetic and educational services and recreational fishing. Biological effects of acidification in terrestrial ecosystems are generally linked to aluminum toxicity, which can cause reduced root growth, restricting the ability of the plant to take up water and nutrients. These direct effects can, in turn, increase the sensitivity of these plants to stresses, such as droughts, cold temperatures, insect pests, and disease leading to increased mortality of canopy trees. Terrestrial acidification affects several important ecological services, including declines in habitat for threatened and endangered species (cultural), declines in forest aesthetics (cultural), declines in forest productivity (provisioning), and increases in forest soil erosion and reductions in water retention (cultural and regulating). (U.S. EPA, 2008d)

Deposition of nitrogen is also associated with aquatic and terrestrial nutrient enrichment. In estuarine waters, excess nutrient enrichment can lead to eutrophication. Eutrophication of estuaries can disrupt an important source of food production, particularly fish and shellfish production, and a variety of cultural ecosystem services, including water-based recreational and aesthetic services. Terrestrial nutrient enrichment is associated with changes in the types and number of species and biodiversity in terrestrial systems. Excessive nitrogen deposition upsets the balance between native and nonnative plants, changing the ability of an area to support biodiversity. When the composition of species changes, then fire frequency and intensity can also change, as nonnative grasses fuel more frequent and more intense wildfires. (U.S. EPA, 2008d)

Reductions in emissions of NO_2 and SO_2 will improve the level of visibility throughout the United States because these gases (and the particles of nitrate and sulfate formed from these gases) impair visibility by scattering and absorbing light (U.S. EPA, 2009). Visibility is also referred to as visual air quality (VAQ), and it directly affects people's enjoyment of a variety of daily activities (U.S. EPA, 2009). Good visibility increases quality of life where individuals live and work, and where they travel for recreational activities, including sites of unique public value, such as the Great Smoky Mountains National Park (U. S. EPA, 2009).

6.5.5 Ozone Welfare Co-Benefits

Exposure to ozone has been associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013b). Sensitivity to ozone is highly variable across species, with over 65 plant species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage or impair the intended use of the plant or ecosystem. Such effects can include reduced growth and/or biomass production in sensitive plant species, including forest trees, reduced yield and quality of crops, visible foliar injury, species composition shift, and changes in ecosystems and associated ecosystem services.

6.5.6 Visibility Impairment Co-Benefits

Reducing secondary formation of $PM_{2.5}$ would improve levels of visibility in the U.S. because suspended particles and gases degrade visibility by scattering and absorbing light (U.S. EPA, 2009b). Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Visibility has direct significance to people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Particulate sulfate is the dominant source of regional haze in the eastern

U.S. and particulate nitrate is an important contributor to light extinction in California and the upper Midwestern U.S., particularly during winter (U.S. EPA, 2009b). Previous analyses (U.S. EPA, 2011a) show that visibility co-benefits can be a significant welfare benefit category. Without air quality modeling, we are unable to estimate visibility-related benefits, and we are also unable to determine whether the emission reductions associated with the final emission guidelines would be likely to have a significant impact on visibility in urban areas or Class I areas.

6.6 References

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APPENDIX 6A: ESTIMATING THE BENEFIT-PER-TON OF REDUCING $PM_{2.5}$ AND OZONE PRECURSORS

This appendix reports additional detail regarding our approach for estimating the benefit-per-ton (BPT) of reducing $PM_{2.5}$ and ozone precursor emissions. These BPT were applied in Chapter 6 of this Regulatory Impact Analysis (RIA). Specifically, this appendix describes the methods for estimating these values for the contiguous U.S. for $PM_{2.5}$ and ozone precursor NO_x emissions from by the electrical generating unit (EGU) sector in the proposed CSAPR Update for the 2008 Ozone NAAQS Rule.

6A.1 Overview of Benefit-per-Ton Estimates

As described in the *Technical Support Document: Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors* (U.S. EPA, 2013), the general procedure for calculating average benefit-per-ton coefficients generally follows three steps. As an example, in order to calculate average benefit-per-ton estimates for the key precursor pollutant emitted from EGU sources, we:

1. Use air quality modeling to predict changes in ambient concentrations of primary $PM_{2.5}$, nitrate, sulfate, and ozone at a $12km^2$ grid resolution across the contiguous U.S. that are attributable to the illustrative control strategy.

2. For each grid cell, estimate the health impacts, and the economic value of these impacts, associated with the attributable ambient concentrations using the environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE v1.1).[115,116] Aggregate those impacts and economic values to the United States.

3. Divide the national health impacts attributable to each precursor, and the national monetary value of these impacts, by the amount of associated national precursor emissions. For example, ozone benefits are divided by ozone-season NO_X emissions.

115 When estimating these impacts we apply effect coefficients that relate changes in total $PM_{2.5}$ mass to the risk of adverse health outcomes; we do not apply effect coefficients that are differentiated by $PM_{2.5}$ species.

116 Previous RIAs have used earlier versions of the BenMAP software. BenMAP-CE v1.1 provides results consistent with earlier versions of BenMAP and is available for download at http://www.epa.gov/air/benmap/.

6A.2 Air Quality Modeling for the Proposed Transport Rule

The EPA ran the Comprehensive Model with Extensions (CAMx) photochemical model (ENVIRON, 2014) to predict ozone and $PM_{2.5}$ concentrations. The model predictions for the 2011 base year, the 2017 baseline, and the 2017 illustrative control case were combined with ambient air quality observations to calculate seasonal mean ozone air quality metrics and annual mean PM2.5 for the 2017 baseline and 2017 illustrative control case, which were then used as input for the benefits analysis.

Each of the CAMx model simulations was performed for a nationwide modeling domain[117] using a full year of meteorological conditions for 2011. The modeling for 2011 was used as the anchor point for projecting ozone and annual $PM_{2.5}$ concentration values for the 2017 base case and for the 2017 illustrative control scenario using methodologies consistent with the EPA's air quality modeling guidance (U.S. EPA, 2007). The air quality modeling results for the 2017 base case served as the baseline for gauging the future year impacts on ozone and annual $PM_{2.5}$ of the illustrative control case scenario. The 2017 base case reflects emissions reductions between 2011 and 2017 that are expected to result from regional and national rules including the Cross-State Air Pollution Rule, the Mercury and Air Toxics Standards (MATS), mobile source rules up through Tier-3, and various state emissions control programs and consent decrees. The methods for estimating the EGU emissions for the proposal are described in Chapter 3 of this RIA. The data indicate that, overall nationwide, EGU emissions with the illustrative control case scenario would be about 14% lower than the 2017 base case.

As indicated above, the air quality modeling was used to project gridded ozone and annual $PM_{2.5}$ concentrations at the 12km by 12km resolution for the 2017 base case and the illustrative control case scenario modeled for this analysis. The air quality modeling results were combined with monitored ozone and $PM_{2.5}$ data to create projected spatial fields of annual $PM_{2.5}$ and seasonal mean (May through September) 8-hour daily maximum ozone for the 2017 base case and for the illustrative control scenario. These spatial fields were then used as inputs to estimate the health co-benefits of the proposed rule as described below.

[117] The modeling domain (i.e., region modeled) includes all of the lower 48 states plus adjacent portions of Canada and Mexico) at a spatial resolution of 12 km.

6A.3 National $PM_{2.5}$ Benefit-per-Ton Estimates for EGUs Derived from Air Quality Modeling of the Proposed Transport Rule

After estimating the 12km by 12km resolution $PM_{2.5}$ benefits for each of the analysis years applied in this RIA (i.e., 2017), we aggregated the benefits results nationally.[118] In order to calculate the benefit-per-ton estimates, we divided the regional benefits estimates by the corresponding emissions, as shown in Table 4A-1. Lastly, we adjusted the benefit-per-ton estimates for a currency year of 2011$.[119]

This method provides estimates of the national average benefit-per-ton for a subset of the major $PM_{2.5}$ precursors emitted from EGU sources. For precursor emissions of NO_X, there is generally a non-linear relationship between emissions and formation of $PM_{2.5}$. This means that each ton of NO_X reduced would have a different impact on ambient $PM_{2.5}$ depending on the initial level of emissions and potentially on the levels of emissions of other pollutants. In contrast, SO_2 is generally linear in forming $PM_{2.5}$. For precursors like NO_X which form $PM_{2.5}$ non-linearly, a marginal benefit-per-ton approach would better approximate the specific benefits associated with an emissions reduction scenario for a given set of base case emissions, because it would allow the benefit-per-ton to vary depending on the level of emissions reductions and the baseline emissions levels. However, we do not have sufficient air quality modeling data to calculate marginal benefit-per-ton estimates for the EGU sector. Therefore, using an average benefit-per-ton estimate for NO_X adds uncertainty to the co-benefits estimated in this RIA.

In this RIA, we estimate emission reductions from EGUs using IPM.[120] IPM outputs provide endogenously projected unit level emissions of SO_2, NO_X, CO_2, Hg, hydrogen chloride (HCl) from EGUs, but carbon monoxide, volatile organic compounds, ammonia and total directly emitted $PM_{2.5}$ and PM_{10} emissions are post-calculated.[121] In addition, directly emitted particle emissions calculated from IPM outputs do not include speciation, i.e. they are only the total emissions. In order to conduct air quality modeling, directly emitted $PM_{2.5}$ from EGUs is

[118] This aggregation is identified as the shapefile "Report Regions" in BenMAP's grid definitions.

119 Currently, BenMAP does not have an inflation adjustment to 2011$. We ran BenMAP for a currency year of 2010$ and calculated the benefit-per-ton estimates in 2010$. We then adjusted the resulting benefit-per-ton estimates to 2011$ using the Consumer Price Index.

120 See Chapter 3 of this RIA for additional information regarding the Integrated Planning Model (IPM).

[121] Detailed documentation of this post-processing is available at http://www.epa.gov/powersectormodeling/docs/v513/FlatFile_Methodology.pdf

speciated into components during the emissions modeling process based on emission profiles for EGUs by source classification code. Even though these speciation profiles are not unit-specific, an emission profile based on the source classification code reflects the fuel and the unit configuration. Model-predicted concentrations of nitrate and sulfate include both the directly emitted nitrate and sulfate from speciated $PM_{2.5}$ and secondarily formed nitrate and sulfate from emissions of NO_X and SO_2, respectively. Because this proposed rule is not expected to greatly affect the levels of directly emitted $PM_{2.5}$ or SO_2, we do not quantify a benefit per-ton value for either pollutant.

Although it is possible to calculate 95th percentile confidence intervals using the approach described in this appendix (e.g., U.S. EPA, 2011b), we generally do not calculate confidence intervals for benefit-per-ton estimates because of the additional unquantified uncertainties that result from the benefit transfer methods, including those related to the transfer of air quality modeling information. Instead, we refer the reader to Chapter 5 of PM NAAQS RIA (U.S. EPA, 2012a) for an indication of the combined random sampling error in the health impact and economic valuation functions using Monte Carlo methods. In general, the 95th percentile confidence interval for the total monetized $PM_{2.5}$ benefits ranges from approximately -90% to +180% of the central estimates based on concentration-response functions from Krewski *et al.* (2009) and Lepeule *et al.* (2012). The 95th percentile confidence interval for the health impact function alone ranges from approximately ±30% for mortality incidence based on Krewski *et al.* (2009) and ±46% based on Lepeule *et al.* (2012). These confidence intervals do not reflect other sources of uncertainty inherent within the estimates, such as baseline incidence rates, populations exposed, and transferability of the effect estimate to diverse locations. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the benefits estimates.

Table 6A-1 reports the national benefit-per-ton estimates for the EGU sector at discount rates of 3% and 7% in 2017. Tables 6A-2 reports the incidence per ton estimates (which follows the same general methodology as for the benefit-per-ton calculations) for the EGU sector in 2017 for the set of health endpoints used to calculate the benefit-per-ton estimates.

Table 6A-1. Summary of Regional $PM_{2.5}$ Benefit-per-Ton Estimates Based on Air Quality Modeling from the Illustrative Control Case in 2017 (2011$)*

Pollutant	Discount Rate	Benefit per ton
NO_X (as $PM_{2.5}$)	3%	$2,100 to $4,700
	7%	$1,900 to $4,300

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for $PM_{2.5}$. All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles. The estimates do not include reduced health effects from direct exposure to ozone, NO_2, SO_2, ecosystem effects, or visibility impairment.

Table 6A-2. Summary of Regional $PM_{2.5}$ Incidence-per-Ton Estimates Based on Air Quality Modeling from the Illustrative Control Case in 2017*

Health Endpoint	NOx Incidence per ton
Premature Mortality	
Krewski *et al.* (2009) – adult	0.00024
Lepeule *et al.* (2012) – adult	0.00054
Woodruff *et al.* (1997) – infants	0.00001
Morbidity	
Emergency department visits for asthma	0.00013
Acute bronchitis	0.00034
Lower respiratory symptoms	0.00436
Upper respiratory symptoms	0.00623
Minor restricted-activity days	0.17575
Lost work days	0.02947
Asthma exacerbation	0.00642
Hospital Admissions, Respiratory	0.00007
Hospital Admissions, Cardiovascular	0.00009
Non-fatal Heart Attacks (age>18)	
Peters et al (2001)	0.00028
Pooled estimate of 4 studies	0.00003

* All estimates are rounded to two significant figures. All fine particles are assumed to have equivalent health effects, but the incidence-per-ton estimates vary depending on the location and magnitude of their impact on $PM_{2.5}$ levels, which drive population exposure. The incidence benefit-per-ton estimates incorporate the conversion from precursor emissions to ambient fine particles.

6A.4 Regional Ozone Benefit-per-Ton Estimates

The process for generating the ozone benefit-per-ton estimates is consistent with the process for $PM_{2.5.}$ Ozone is not directly emitted, and is a non-linear function of NO_X and VOC emissions. For the purpose of estimating benefit-per-ton for this RIA, we assume that all of the ozone impacts from EGUs are attributable to NO_X emissions. VOC emissions, which are also a precursor to ambient ozone formation, are insignificant from the EGU sector relative to both NO_X emissions from EGUs and the total VOC emissions inventory. Therefore, we believe that our assumption that EGU-attributable ozone formation at the regional-level is due to NO_X alone is reasonable.

Similar to $PM_{2.5}$, this method provides estimates of the regional average benefit-per-ton. Due to the non-linear chemistry between NO_X emissions and ambient ozone, using an average benefit-per-ton estimate for NO_X adds uncertainty to the ozone co-benefits estimated for the proposed guidelines.

In the ozone co-benefits estimated in this RIA, we apply the benefit-per-ton estimates calculated using NO_X emissions derived from modeling the the Illustrative Control Case during the ozone-season only (May to September). Because we estimate ozone health impacts from May to September only, this approach underestimates ozone co-benefits in areas with longer ozone seasons such as southern California and Texas. When the underestimated benefit-per-ton estimate is multiplied by ozone-season only NO_X emission reductions, this results in an underestimate of the monetized ozone co-benefits. Table 6A-3 reports the ozone benefit-per-ton estimates using ozone-season only NO_X for 2017. Table 6A-4 reports the ozone season incidence-per-ton estimates for 2017.

Table 6A-3. Summary of National Ozone Benefit-per-Ton Estimates Based on Air Quality Modeling from the Illustrative Control Case in 2017 (2011$)*

Ozone precursor Pollutant	Benefit per ton
Ozone season NO_X	$4,300 to $20,000

* The range of estimates reflects the range of epidemiology studies for avoided premature mortality for ozone. All estimates are rounded to two significant figures. The monetized benefits incorporate the conversion from NO_X precursor emissions to ambient ozone.

Table 6A-4. Summary of National Ozone Incidence-per-Ton Estimates Based on Air Quality Modeling from Proposed Transport Rule in 2017*

Health Endpoint	Incidence per ton
Premature Mortality – adult	
Smith *et al.* (2009)	0.000569
Zanobetti & Schwartz (2008)	0.000956
Morbidity	
Hospital Admissions, Respiratory (ages < 2 & > 65)	0.000927
Emergency Room Visits, Respiratory	0.003771
Acute Respiratory Symptoms	2.781551
School Loss Days	0.903847

* All estimates are rounded to two significant figures. The incidence benefit-per-ton estimates incorporate the conversion from NO_X precursor emissions to ambient ozone. These estimates reflect ozone-season NO_X emissions.

6A.5 References

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CHAPTER 7: STATUTORY AND EXECUTIVE ORDER REVIEWS

Overview

This section explains the statutory and executive orders applicable to EPA rules, and discusses EPA's actions taken pursuant to these orders.

7.1 Executive Order 12866: Regulatory Planning and Review

This action is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to OMB recommendations have been documented in the docket. This RIA estimates the costs and monetized human health and welfare benefits of the proposal. Consistent with Executive Order (EO) 12866 and EO 13563, the EPA estimated the costs and benefits for three regulatory control alternatives: the proposed EGU NO_X ozone-season emissions budgets and more and less stringent alternatives. The proposed action would reduce ozone-season NO_X emissions from EGUs in 23 eastern states. Actions taken to comply with the proposed EGU NO_X ozone-season emissions budgets would also reduce emissions of other criteria air pollution and hazardous air pollution emissions, including annual NO_X, and CO_2. The benefits associated with these co-pollutant reductions are referred to as co-benefits, as these reductions are not the primary objective of the rule.

7.2 Paperwork Reduction Act

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.* The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2527.01. You can find a copy of the ICR in the docket for the proposed rule, and it is briefly summarized here.

The information generated by information collection activities under CSAPR is used by the EPA to ensure that affected facilities comply with the emission limits and other requirements. Records and reports are necessary to enable EPA or states to identify affected facilities that may not be in compliance with the requirements. The recordkeeping requirements require only the specific information needed to determine compliance. These recordkeeping and reporting requirements are established pursuant to CAA sections 110(a)(2)(D) and (c) and 301(a) (42

U.S.C. 7410(a)(2)(D) and (c) and 7601(a)) and are specifically authorized by CAA section 114 (42 U.S.C. 7414). Reported data may also be used for other regulatory and programmatic purposes. All information submitted to the EPA for which a claim of confidentiality is made will be safeguarded according to EPA policies in 40 CFR part 2, subpart B, Confidentiality of Business Information.

All of the EGUs that would be subject to changed information collection requirements under this proposed rule are already subject to information collection requirements under CSAPR. Most of these EGUs also are already subject to information collection requirements under the Acid Rain Program (ARP) established under Title IV of the 1990 Clean Air Act Amendments. Both CSAPR and the ARP have existing approved ICRs or pending renewals: EPA ICR Number 2391.03/OMB Control Number 2060-0667 (CSAPR) and EPA ICR Number 1633.16/OMB Control Number 2060-0258 (ARP). The burden and costs of the information collection requirements covered under the CSAPR ICR are estimated as incremental to the information collection requirements covered under the ARP ICR. Most of the information used to estimate burden and costs in this ICR was developed for the existing CSAPR and ARP ICRs.

This proposed rule would change the universe of sources subject to certain information collection requirements under CSAPR but would not change the substance of any CSAPR information collection requirements. The burden and costs associated with the proposed changes in the reporting universe are estimated as reductions from the burden and costs under the existing CSAPR ICR. (This proposed rule would not change any source's information collection requirements with respect to the ARP.) The EPA intends to incorporate the burden and costs associated with the proposed changes in the reporting universe under this rule into the next renewal of the CSAPR ICR.

Respondents/affected entities: Entities potentially affected by this proposed action are EGUs in the states of Florida, Kansas, and South Carolina that meet the applicability criteria for the CSAPR NO_X Ozone Season Trading Program in 40 CFR 97.404.

Respondent's obligation to respond: Mandatory (sections 110(a) and 301(a) of the Clean Air Act).

Estimated number of respondents: 116 sources in Florida, Kansas, and South Carolina with one or more EGUs.

Frequency of response: Quarterly, occasionally.

Total estimated burden: reduction of 14,064 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: reduction of $1,472,047 (per year), includes reduction of $450,951 operation and maintenance costs.

The burden and cost estimates above reflect the reduction in burden and cost for Florida sources with EGUs that would no longer be required to report NO_X mass emissions and heat input data for the ozone season to the EPA under the proposed rule and that are not subject to similar information collection requirements under the Acid Rain Program. Because these EGUs would no longer need to collect NO_X emissions or heat input data under 40 CFR part 75, the estimates above also reflect the reduction in burden and cost to collect and quality assure these data and to maintain the associated monitoring equipment.

The EPA estimates that the proposed rule would cause no change in information collection burden or cost for EGUs in Kansas that would be required to report NO_X mass emissions and heat input data for the ozone season to the EPA or for EGUs in South Carolina that would no longer be required to report NO_X emissions and heat input data for the ozone season to the EPA. The EGUs in both Kansas and South Carolina already are and would remain subject to requirements to report NO_X mass emissions and heat input data for the entire year to the EPA under the CSAPR NO_X Annual Trading Program, and the requirements related to ozone season reporting are a subset of the requirements related to annual reporting. Similarly, the EPA estimates that the proposed rule would cause no change in information collection burden or cost for EGUs in Florida that are subject to the Acid Rain Program because of the close similarity between the information collection requirements under CSAPR and under the Acid Rain Program.

More information on the ICR analysis is included in the docket for the proposed rule.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

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7.3 Regulatory Flexibility Act

The EPA certifies that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses, small organizations, and small governmental jurisdictions. The EPA has determined that 1 entity (of 7 small entities identified as potentially affected) may experience an impact of greater than 3 percent of annual revenues. Details of this analysis are presented below.

The Regulatory Flexibility Act (5 U.S.C. 601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104 121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. 605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions.

The EPA conducted regulatory flexibility analysis at the ultimate (i.e., highest) level of ownership, evaluating parent entities with the largest share of ownership in at least one potentially-affected EGU included in EPA's base case using the IPM v.5.15, used in this RIA.[1] This analysis draws on the "parsed" unit-level estimates using IPM results for 2018,[2] as well as ownership, employment, and financial information for the potentially affected small entities drawn from other resources described in more detail below.

The EPA identified the size of ultimate parent entities by using the Small Business Administration (SBA) size threshold guidelines.[3] The criteria for size determination vary by the organization/operation category of the ultimate parent entity, as follows:

- Privately-owned (non-government) entities (see Table 7-1)

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[1] Detailed documentation for IPM v.5.15 is available at: http://www.epa.gov/airmarkets/powersectormodeling.html.

[2] For this analysis, the 2018 parsed file is used to represent 2017 for the purposes of RIA analysis.

[3] U.S. Small Business Administration (SBA). 2014. Small Business Size Standards. Effective as of July 14, 2014. See: http://www.sba.gov/sites/default/files/Size_Standards_Table.pdf.

    - Privately-owned entities include investor-owned utilities, non-utility entities, and entities with a primary business other than electric power generation.
    - For entities with electric power generation as a primary business, small entities are those with less than the threshold number of employees specified by SBA for each of the relevant North American Industry Classification System (NAICS) sectors (NAICS 2211).
    - For entities with a primary business other than electric power generation, the relevant size criteria are based on revenue, assets, or number of employees by NAICS sector.[4]
- Publicly-owned entities
    - Publicly-owned entities include federal, state, municipal, and other political subdivision entities.
    - The federal and state governments were considered to be large. Municipalities and other political units with population fewer than 50,000 were considered to be small.
- Rural Electric Cooperatives
    - Small entities are those with fewer than the threshold level of employees or revenue specified by SBA for each of the relevant NAICS sectors.

7.3.1 Identification of Small Entities

In this analysis, the EPA considered EGUs which meet the following five criteria: 1) EGU is represented in NEEDS v5.15; 2) EGU is fossil fuel-fired; 3) EGU is located in a state covered by this proposed rule; 4) EGU is neither a cogeneration unit nor solid waste incineration unit; 5) EGU capacity is 25MW or larger. The EPA next refined this list of EGUs, narrowing it to those that exhibit at least one of the following changes under the proposal, in comparison to the baseline.

[4] Certain affected EGUs are owned by ultimate parent entities whose primary business is not electric power generation.

- Summer fuel use (BTUs) changes by +/- 1% or more
- Summer generation (GWh) changes by +/- 1% or more
- NOx summer emissions (tons) changes by +/- 1% or more

Based on these criteria, the EPA identified a total of 318 potentially affected EGUs warranting examination in this RFA analysis. Next, we determined power plant ownership information, including the name of associated owning entities, ownership shares, and each entity's type of ownership. We primarily used data from SNL and Ventyx, supplemented by limited research using publicly available data.[5] Majority owners of power plants with affected EGUs were categorized as one of the seven ownership types.[6] These ownership types are:

1. **Investor-Owned Utility (IOU)**: Investor-owned assets (e.g., a marketer, independent power producer, financial entity) and electric companies owned by stockholders, etc.
2. **Cooperative (Co-Op)**: Non-profit, customer-owned electric companies that generate and/or distribute electric power.
3. **Municipal**: A municipal utility, responsible for power supply and distribution in a small region, such as a city.
4. **Sub-division**: Political subdivision utility is a county, municipality, school district, hospital district, or any other political subdivision that is not classified as a municipality under state law.
5. **Private**: Similar to an investor-owned utility, however, ownership shares are not openly traded on the stock markets.
6. **State**: Utility owned by the state.
7. **Federal**: Utility owned by the federal government.

[5] SNL Financial data covers the energy market and other industries, and includes detailed immediate and ultimate ownership at the EGU level. For more information, see: www.snl.com. The Ventyx Energy Velocity Suite database consists of detailed ownership and corporate affiliation information at the EGU level. For more information, see: www.ventyx.com.

[6] Throughout this analysis, the EPA refers to the owner with the largest ownership share as the "majority owner" even when the ownership share is less than 51 percent.

Next, the EPA used both the Hoover's online database and the SNL database to identify the ultimate owners of power plant owners identified in the SNL and Ventyx databases. This was necessary, as many majority owners of power plants (listed in SNL or Ventyx) are themselves owned by other ultimate parent entities (listed in Hoover's or SNL).[7] In these cases, the ultimate parent entity was identified via Hoover's or SNL, whether domestically or internationally owned.

The EPA followed SBA size standards to determine which non-government ultimate parent entities should be considered small entities in this analysis. These SBA size standards are specific to each industry, each having a threshold level of either employees, revenue, or assets below which an entity is considered small. SBA guidelines list all industries, along with their associated NAICS code and SBA size standard. Therefore, it was necessary to identify the specific NAICS code associated with each ultimate parent entity in order to understand the appropriate size standard to apply. Data from Hoover's was used to identify the NAICS codes for most of the ultimate parent entities. In many cases, an entity that is a majority owner of a power plant is itself owned by an ultimate parent entity with a primary business other than electric power generation. Therefore, it was necessary to consider SBA entity size guidelines for the range of NAICS codes listed in Table 7-1. This table represents the range of NAICS codes and areas of primary business of ultimate parent entities which are majority owners of potentially affected EGUs in the EPA's IPM base case.

[7] The Hoover's Inc. online platform includes company records that can contain NAICS codes, number of employees, revenues, and assets. For more information, see: http://www.hoovers.com

Table 7-1. SBA Size Standards by NAICS Code

NAICS Code	NAICS Description	SBA Size Standard
221112	Fossil Fuel Electric Power Generation	750 employees
221118	Other Electric Power Generation	250 employees
221122	Electric Power Distribution	1,000 employees
221210	Natural Gas Distribution	500 employees
238210	Electrical Contractors and Other Wiring Installation Contractors	$15 million in revenue
324110	Petroleum Refineries	1,500 employees
325180	Other Basic Inorganic Chemical Manufacturing	1,000 employees
325320	Pesticide and Other Agricultural Chemical Manufacturing	500 employees
331313	Alumina Refining and Primary Aluminum Production	1,000 employees
333613	Mechanical Power Transmission Equipment Manufacturing	500 employees
424720	Petroleum and Petroleum Products Merchant Wholesalers (except Bulk Stations and Terminals)	100 employees
486210	Pipeline Transportation of Natural Gas	$27.5 million in revenue
522110	Commercial Banking	$550 million in assets
522220	Sales Financing	$38.5 million in revenue
523120	Securities Brokerage	$38.5 million in revenue
523910	Miscellaneous Intermediation	$38.5 million in revenue
523930	Investment Advice	$38.5 million in revenue
524126	Direct Property and Casualty Insurance Carriers	1,500 employees
525120	Health and Welfare Funds	$32.5 million in revenue
525990	Other Financial Vehicles	$32.5 million in revenue
541611	Administrative Management and General Management Consulting Services	$15 million in revenue
551112	Offices of Other Holding Companies	$20.5 million in revenue

Note: Based on size standards effective at the time the EPA conducted this analysis (SBA size standards, effective July 14, 2014)
Source: SBA, 2014

The EPA compared the relevant entity size criterion for each ultimate parent entity to the SBA threshold value noted in Table 7-1. We used the following data sources and methodology to estimate the relevant size criterion values for each ultimate parent entity:

1. **Employment, Revenue, and Assets**: The EPA used the Hoover's database as the primary source for information on ultimate parent entity employee numbers, revenue, and assets.[8] In parallel, the EPA also considered estimated revenues from affected EGUs based on analysis of parsed-file estimates for the proposal. The EPA assumed that the ultimate parent entity revenue was the larger of the two revenue estimates. In limited

[8] Estimates of sales were used in lieu of revenue estimates when revenue data was unavailable.

instances, supplemental research was also conducted to estimate an ultimate parent entity's number of employees, revenue, or assets.

2. **Population**: Municipal entities are defined as small if they serve populations of less than 50,000. The EPA primarily relied on data from the Ventyx database and the U.S. Census Bureau to inform this determination. Supplemental research of individual municipalities was also conducted in some instances.

Ultimate parent entities for which the relevant measure is less than the SBA size criterion were identified as small entities and carried forward in this analysis. In the case of one entity, data limitations prevented the comparison of the entity against its appropriate SBA size standard. For the purposes of this analysis, the EPA assumed that this entity is a small entity. Overall, the EPA identified 16 potentially affected EGUs owned by 7 small entities included in the EPA's Base Case.

7.3.2 Overview of Analysis and Results

This section presents the methodology and results for estimating the impact of the proposed CSAPR update to small entities in 2017 based on the following endpoints:

- annual economic impacts of the proposed CSAPR update on small entities, and
- ratio of small entity impacts to revenues from electricity generation.

7.3.2.1 Methodology for Estimating Impacts of the Proposed CSAPR update on Small Entities

An entity can comply with the proposed CSAPR update through some combination of the following: optimizing existing SCR and SNCRs, turning on idled SCR or SNCR controls, upgrading to state of the art combustion controls, using allocated allowances, purchasing allowances, or reducing emissions through a reduction in generation or improved efficiency. Additionally, units with more allowances than needed can sell these allowances in the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units.

To attempt to account for each potential control strategy, the EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ C_{Allowances} + \Delta\ C_{Transaction} + \Delta\ R$$

where C represents a component of cost as labeled, and Δ R represents the value of foregone electricity generation, calculated as the difference in revenues between the base case and the proposed CSAPR update in 2017.

In reality, compliance choices and market conditions can combine such that an entity may actually experience a savings in any of the individual components of cost. Under the proposed CSAPR update, some units will forgo some level of electricity generation (and thus revenues) to comply and this impact will be lessened on these entities by the projected increase in electricity prices under the proposed CSAPR update. On the other hand, those increasing generation levels will see an increase in electricity revenues and as a result, lower net compliance costs. If entities are able to increase revenue more than an increase in fuel cost and other operating costs, ultimately they will have negative net compliance costs (or savings). Overall, small entities are not projected to install relatively costly emissions control retrofits, but may choose to do so in some instances. Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures savings or gains such as those described. As a result, what we describe as cost is really more of a measure of the net economic impact of the rule on small entities.

For this analysis, the EPA used IPM-parsed output to estimate costs based on the parameters above, at the unit level. These impacts were then summed for each small entity, adjusting for ownership share. Net impact estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under the proposed CSAPR update relative to the base case. These individual components of compliance cost were estimated as follows:

(1) **Operating and retrofit costs:** Using the IPM-parsed output for the base case and the proposed CSAPR update, the EPA identified units that install control technology under the proposed CSAPR update, and what technology was installed. The equations for calculating retrofit costs were adopted from the EPA's version of IPM. The model calculates the capital cost (in \$/MW); the fixed operation and maintenance (O&M) cost (in \$/MW-year); the variable O&M cost (in \$/MWh); and the total annual cost for units projected to optimize and/or turn on existing idled SCR or SNCR.

(2) **Sale or purchase of allowances:** To estimate the value of allowances holdings, allocated allowances were subtracted from projected emissions, and the difference was then multiplied by $1,300 per ton. $1,300 per ton is the marginal cost of NO_X reductions used to set the proposed budgets in the proposed CSAPR update. While this is a reasonable approximation, it is possible that the actual allowance price could be lower. Units were assumed to purchase or sell allowances to exactly cover their projected emissions under the proposed CSAPR update.

(3) **Fuel costs:** The change in fuel expenditures under the proposed CSAPR update was estimated by taking the difference in projected fuel expenditures between the IPM estimates for the proposed CSAPR update and the base case.

(4) **Value of electricity generated:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional-adjusted retail electricity price ($/MWh) estimate, for all entities except those categorized as Private in Ventyx. For private entities, the EPA used wholesale electricity price instead retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities and thus their revenue was estimated with wholesale electricity prices.

(5) **Administrative costs:** Because most affected units are already monitored as a result of other regulatory requirements, the EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. The EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of the difference between a unit's allocation and projected NOX emissions. This assumption is based on market research by ICF International.

7.3.2.2 Results

The potential impacts of the proposed CSAPR update on small entities are summarized in Table 7-2. All costs are presented in $2011. The EPA estimated the annual net compliance cost to small entities to be approximately - $38.3 million in 2017 or savings of $38.3 million. The fact that the net compliance costs for all entities are actually net savings does not mean that each small entity would benefit from the proposal to update CSAPR. The net savings are driven by entities that are able to increase their revenues by increasing generation.

Table 7-2. Projected Impact of the Proposed CSAPR Update on Small Entities in 2017

EGU Ownership Type	Number of Potentially Affected Entities	Total Net Compliance Cost ($2011 millions)	Number of Small Entities with Compliance Costs >1% of Generation Revenues	Number of Small Entities with Compliance Costs >3% of Generation Revenues
Cooperative	2	$0.2	0	0
Investor-Owned Utility	1	-$38	0	0
Municipal	2	-$0.1	*	*
Private	2	-$0.4	0	0
Total	7	-$38.3	*	*

Note: The total number of entities with costs greater than 1 percent or 3 percent of revenues includes only entities experiencing positive costs. A negative cost value implies that the group of entities experiences a net savings under the proposed CSAPR update.

* One entity may experience compliance costs greater than 1 or 3 percent of generation revenues in 2017. Since this entity is not projected to operate in the base case, we are unable to compare the estimated compliance costs to base case generation revenues.

Source: IPM analysis

The EPA assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation, focusing in particular on entities for which this measure is greater than 1 percent. Although this metric is commonly used in the EPA impact analyses, it makes the most sense when as a general matter an analysis is looking at small businesses that operate in competitive environments. However, small businesses in the electric power industry often operate in a price -regulated environment where they are able to recover expenses through rate increases. Given this, the EPA considers the 1 percent measure in this case a crude measure of the price increases these small entities will be asking of rate commissions or making at publicly owned companies.

Of the 7 small entities considered in this analysis, 1 entity may experience compliance costs greater than 1 or 3 percent of generation revenues in 2017. Since this entity is not projected to operate in the base case, we are unable to compare the estimated compliance costs to base case generation revenues. However, we note that this entity is located in a cost of service market, where typically we expect entities should be able to recover all of their costs of complying with the proposed CSAPR update. Entities that experience negative net costs under the proposed CSAPR update are excluded from these totals. The EPA has concluded that there is no significant economic impact on a substantial number of small entities (No SISNOSE) for this rule. The number of entities with compliance costs exceeding 3 percent of generation revenues is also included in Table 7-2.

The distribution across entities of economic impacts as a share of base case revenue is summarized in Table 7-3. Since there are few potentially-impacted small entities included in this analysis, the distributions of economic impacts on each ownership type are in general fairly tight. Note that one municipal entity is not projected to operate in the base case, and we are therefore unable to compare the estimated compliance costs to generation revenues. We estimate a positive compliance cost for this entity.

Table 7-3. Summary of Distribution of Economic Impacts of the Proposed CSAPR Update on Small Entities in 2017

EGU Ownership Type	Capacity-Weighted Average Economic Impacts as a % of Generation Revenues	Min	Max
Cooperative	0.3%	0.1%	0.5%
Investor-owned utility	-60.1%	-60.1%	-60.1%
Municipal*	-0.5%	-0.5%	N/A*
Private	-2.3%	-4.2%	-1.5%

*Note: One municipal entity is not projected to operate in the base case, and we are therefore unable to compare the estimated compliance costs to generation revenues.

Source: IPM analysis

The separate components of annual costs to small entities under the proposed CSAPR update are summarized in Table 7-4. The most significant components of incremental cost to these entities under the proposed CSAPR update are due to lower electricity revenues and increased fuel costs. Fuel costs increase over all ownership groups except the ones under the ownership type “Private” because an entity with the second largest generation under “Private” is projected to cut its generation by 25 percent under the proposed CSAPR update, which translates to lower fuel costs for the whole group. Additionally, increases in electricity generation revenue, shown as cost savings or negative costs are experienced by cooperative, investor-owned utility, municipal and subdivision entities. This is due largely to the projected increase in electricity prices under the proposed CSAPR update. Among the private category, however, reduced generation by the one entity with a large share of generation leads to higher net costs for the entire category. Our data suggests this entity owns a group of combined cycle units and which are presumably marginal units in their respective load segments under the base case.

Table 7-4. Incremental Annual Costs under the Proposed CSAPR Update Summarized by Ownership Group and Cost Category in 2017 (2011$ millions)

EGU Ownership Type	Operating Cost	Net Purchase of Allowances	Fuel Cost	Lost Electricity Revenue	Administrative Cost
Cooperative	$0.1	$0.2	-$0.5	$0.4	$0.00
Investor-Owned Utility	$1.9	$0.0	$26.8	-$66.7	$0.00
Municipal	$0.1	$0.0	-$0.2	-$0.1	$0.00
Private	-$0.5	-$0.3	-$3.9	$4.4	$0.00

Source: IPM analysis.

7.3.3 Summary of Small Entity Impacts

The EPA examined the potential economic impacts to small entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet their emissions. To summarize, of the 7 small entities potentially affected, 1 may experience compliance costs in excess of 1 percent of revenues in 2017, based on assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rulemaking. Potentially affected small entities experiencing compliance costs in excess of

1 percent of revenues have some potential for significant impact resulting from implementation of the proposed CSAPR update. However, as noted above, it is the EPA's position that because this entity does not operate in a competitive market environment, they should generally be able to pass the costs of complying with the proposed CSAPR update on to rate-payers.

The EPA has lessened the impacts for small entities by excluding all units smaller than 25 MW. This exclusion, in addition to the exemptions for cogeneration units and solid waste incineration units, eliminates the burden of higher costs for a substantial number of small entities located in the 23 states for which the EPA is proposing FIPs.

7.4 Unfunded Mandates Reform Act

Title II of the UMRA of 1995 (Public Law 104-4)(UMRA) establishes requirements for federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of the UMRA, 2 U.S.C. 1532, the EPA generally must prepare a written statement, including a cost-benefit analysis, for any proposed or final rule that includes any Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100,000,000 or more in any one year. A Federal mandate is defined under Section 421(6), 2 U.S.C. 658(6), to include a Federal intergovernmental mandate and a Federal private sector mandate. A Federal intergovernmental mandate, in turn, is defined to include a regulation that would impose an enforceable duty upon State, Local, or Tribal governments, Section 421(5)(A)(i), 2 U.S.C. 658(5)(A)(i), except for, among other things, a duty that is a condition of Federal assistance, Section 421(5)(A)(i)(I). A Federal private sector mandate includes a regulation that would impose an enforceable duty upon the private sector, with certain exceptions, Section 421(7)(A), 2 U.S.C. 658(7)(A).

Before promulgating an EPA rule for which a written statement is needed under Section 202 of the UMRA, Section 205, 2 U.S.C. 1535, of the UMRA generally requires the EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. Moreover, section 205 allows the EPA to adopt an alternative other than the least costly, most cost-effective or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted.

Furthermore, as the EPA stated in the proposal, the EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments. Thus, under the proposed CSAPR update, the EPA is not obligated to develop under Section 203 of the UMRA a small government agency plan.

The EPA did analyze the economic impacts of the proposed CSAPR update on government entities, however. This analysis does not examine potential indirect economic impacts associated with the proposed CSAPR update, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on industries and households.

7.4.1 Identification of Government-Owned Entities

In this analysis, the EPA considered EGUs which meet the following five criteria: 1) EGU is represented in NEEDS v5.15; 2) EGU is fossil-fuel fired; 3) EGU is located in a state covered by this proposed rule; 4) EGU is neither a cogeneration unit nor solid waste incineration unit; and 5) EGU capacity is 25 MW or larger.

The EPA next refined this list of EGUs, narrowing it to those that exhibit at least one of the following changes under the proposal, in comparison to the base case.

- Summer fuel use (BTUs) changes by +/- 1% or more
- Summer generation (GWh) changes by +/- 1% or more
- NOx summer emissions (tons) changes by +/- 1% or more

From the inventory of units meeting the criteria above, the EPA used Ventyx data to identify state and municipality-owned utilities and subdivisions in the proposed CSAPR update region. The EPA then used IPM-parsed output to associate these plants with individual generating units. The EPA identified nine municipality-owned utilities that are potentially affected by the proposed CSAPR update.

7.4.2 Overview of Analysis and Results

After identifying potentially affected government entities, the EPA estimated the impact of the proposed CSAPR update in 2017 based on the following:

- total impacts of compliance on government entities; and
- ratio of government entity impacts to revenues from electricity generation.

The financial burden to owners of EGUs under the proposed CSAPR update is composed of compliance and administrative costs. This section outlines the compliance and administrative costs for the nine potentially affected government-owned units in the proposed CSAPR update region.

7.4.2.1 Methodology for Estimating Impacts of the proposed CSAPR update on Government Entities

An entity can comply with the proposed CSAPR update through any combination of the following: optimizing existing SCR and SNCRs, turning on idled SCR or SNCR controls, upgrading to state of the art combustion controls, using allocated allowances, purchasing allowances, or reducing emissions through a reduction in generation or improved efficiency. Additionally, units with more allowances than needed can sell these allowances on the market. The chosen compliance strategy will be primarily a function of the unit's marginal control costs and its position relative to the marginal control costs of other units.

To attempt to account for each potential control strategy, the EPA estimates compliance costs as follows:

$$C_{Compliance} = \Delta\ C_{Operating+Retrofit} + \Delta\ C_{Fuel} + \Delta\ C_{Allowances} + \Delta\ C_{Transaction} + \Delta\ R$$

where C represents a component of cost as labeled, and $\Delta\ R$ represents the retail value of foregone electricity generation.

In reality, compliance choices and market conditions can combine such that an entity may actually experience a savings in any of the individual components of cost. Under the proposed CSAPR update, for example, some units will forgo some level of electricity generation (and thus revenues) to comply, this impact will be lessened on these entities by the projected increase in electricity prices under the proposed CSAPR update, while those not reducing generation levels will see an increase in electricity revenues. Because this analysis evaluates the total costs along each of the compliance strategies laid out above for each entity, it inevitably captures savings or gains such as those described. As a result, what we describe as cost is really more of a measure of the net economic impact of the rule on small entities.

In this analysis, the EPA used IPM-parsed output for the base case and the proposed CSAPR update to estimate compliance cost at the unit level. These costs were then summed for each small entity, adjusting for ownership share. Compliance cost estimates were based on the following: operating and retrofit costs, sale or purchase of allowances, and the change in fuel costs or electricity generation revenues under the proposed CSAPR update relative to the base case. These components of compliance cost were estimated as follows:

(1) **Operating and retrofit costs:** Using the IPM-parsed output for the base case and the proposed CSAPR update, the EPA identified units that install control technology under the proposed CSAPR update and the technology installed. The equations for calculating retrofit costs were adopted from the EPA's version of IPM. The model calculates the capital cost (in \$/MW); the fixed operation and maintenance (O&M) cost (in \$/MW-year); the variable O&M cost (in \$/MWh); and the total annual cost for units projected to optimize and/or turn on existing idled SCR or SNCR.

(2) **Sale or purchase of allowances:** To estimate the value of allowances holdings, allocated allowances were subtracted from projected emissions, and the difference was then multiplied by \$1,300 per ton. \$1,300 per ton is the marginal annualized cost of NO_X reductions used to set the proposed budgets. While this is a reasonable approximation, it is possible that the actual allowance price could be lower. Units were assumed to purchase or sell allowances to exactly cover their projected emissions under the proposed CSAPR update.

(3) **Fuel costs:** The change in fuel expenditures under the proposed CSAPR update was estimated by taking the difference in projected fuel expenditures between the proposed CSAPR update and the base case.

(4) **Value of electricity generated:** To estimate the value of electricity generated, the projected level of electricity generation is multiplied by the regional-adjusted retail electricity price ($/MWh) estimate, for all entities except those categorized as Private in Ventyx. For private entities, the EPA used wholesale electricity price instead retail electricity price because most of the private entities are independent power producers (IPP). IPPs sell their electricity to wholesale purchasers and do not own transmission facilities and thus their revenue was estimated with wholesale electricity prices.

(5) **Administrative costs:** Because most affected units are already monitored as a result of other regulatory requirements, the EPA considered the primary administrative cost to be transaction costs related to purchasing or selling allowances. The EPA assumed that transaction costs were equal to 1.5 percent of the total absolute value of the difference between a unit's allocation and projected NO_X emissions. This assumption is based on market research by ICF International.

7.4.2.2 Results

A summary of economic impacts on government owned entities is presented in Table 7-5. According to the EPA's analysis, the total net economic impact on government -owned entities (state- and municipality-owned utilities and subdivisions) is expected to be negative in 2014.9 Note that we expect the proposed CSAPR update to potentially have an impact on only one category of government-owned entities (municipality-owned entities).

[9] All costs are reported in 2011 dollars.

Table 7-5. Summary of Potential Impacts on Government Entities under the Proposed CSAPR Update in 2017

EGU Ownership Type	Potentially Affected Entities	Projected Annualized Costs ($2011 millions)	Number of Government Entities with Compliance Costs >1% of Generation Revenues	Number of Government Entities with Compliance Costs >3% of Generation Revenues
Municipal	9	-$4.6	4	2
Total	**9**	**-$4.6**	**4**	**2**

Note: The total number of entities with costs greater than 1 percent or 3 percent of revenues includes only entities experiencing positive costs, and includes one entity for which we are unable to estimate base case generation revenues due to projected closure in the base case. A negative cost value implies that the group of entities experiences a net savings under the proposed CSAPR update.

As was done for the small entities analysis, the EPA further assessed the economic and financial impacts of the rule using the ratio of compliance costs to the value of revenues from electricity generation in the base case, also focusing specifically on entities for which this measure is greater than 1 percent.[10] The EPA projects that four government entities will have compliance costs greater than 1 percent of revenues from electricity generation in 2017. One municipal entity is not projected to operate in the base case, and we are therefore unable to compare the estimated compliance costs to generation revenues. We include this entity in the >3% category. The majority of the units that have higher costs are not expected to make operational changes as a result of this rule (e.g., turn on controls). Their increased costs are largely due to a change in generation level, which results in either a decrease in electricity revenue or increased fuel cost, coupled with a relatively low base case revenue estimate. The EPA notes that increased fuel costs are often passed through to rate-payers as common practice in many areas of the U.S. due to fuel adder arrangements instituted by state public utility commissions. Entities that are projected to experience negative compliance costs under the proposed CSAPR update are not included in those totals. This approach is more indicative of a

[10] Neither the costs nor the revenues of units that retire under the proposed CSAPR update are included in this portion of the analysis. Because these units are better off retiring under the proposed CSAPR update than continuing operation, the true cost of the rule on these units is not represented by our modeling. The true cost of the proposed CSAPR update for these units is the differential between their costs in the base case and the costs of meeting their customers' demand under the rule.

significant impact when an analysis is looking at entities operating in a competitive market environment. Government-owned entities do not operate in a competitive market environment and therefore will be able to recover expenses under the proposed CSAPR update through rate increases. Given this, the EPA considers the 1 percent measure in this case a crude measure of the extent to which rate increases will be made at publicly owned companies.

For municipality-owned entities, the capacity-weighted average economic impact as a share of base case revenue is 4.6 percent. This average is heavily influenced by an outlier, for which the maximum economic impact as a share of base case revenues is 470 percent. This entity holds two small combustion turbines that are not projected to make any operational changes (e.g., turn on controls), but rather is projected to operate more under the proposed CSAPR update in 2017 than it was projected to operate in the base case. The relatively large impact estimate on a percent basis results from the low level of generation and thus revenue in the base case. This is the only entity that experiences economic impacts that are significantly higher than the capacity-weighted average for this group. The next highest economic impact in this group is 2.1 percent.

Additionally, four of the nine entities are projected to experience a negative economic impact as a share of base case revenue, which implies that this group of four entities experiences a net savings under the proposed CSAPR update.

The various components of annual incremental cost under the proposed CSAPR update to government entities are summarized in Table 7-6. In 2017, municipals are a net purchaser of allowances, and experience both an increase in fuel expenditures and an increase in electricity revenue under the proposed CSAPR update. Incremental fuel costs are positive because these entities are projected to increase generation and face higher fuel prices. Overall, increases in total electricity revenue by government entities under the proposed CSAPR update exceed the increases in fuel and operating costs.

Table 7-6. Incremental Annual Costs under the Proposed CSAPR Update Summarized by Ownership Group and Cost Category (2011$ millions) in 2017

EGU Ownership Type	Retrofit + Operating Cost	Net Purchase of Allowances	Fuel Cost	Lost Electricity Revenue	Administrative Cost
Municipal	$2.7	$0.7	$1.4	-$9.4	$0.0

Source: IPM analysis

7.4.3 Summary of Government Entity Impacts

The EPA examined the potential economic impacts on government-owned entities associated with this rulemaking based on assumptions of how the affected states will implement control measures to meet their emissions. According to the EPA's analysis, the total net economic impact on government-owned entities is expected to be -$4.6 million in 2017 or a net savings of $4.6 million. This does not mean that each government entity will experience net savings as the overall net savings is driven by some entities garnering savings. Of the nine government entities considered in this analysis, four may experience compliance costs in excess of 1 percent of revenues in 2017, based on our assumptions of how the affected states implement control measures to meet their emissions budgets as set forth in this rulemaking.

Government entities projected to experience compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the proposed CSAPR update. However, as noted above, it is the EPA's position that because these government entities can pass on their costs of compliance to rate-payers, they will not be significantly affected.

7.5 Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

7.6 Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This action has tribal implications as specified in Executive Order 13175. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

This action proposes to implement EGU NO_X ozone-season emissions reductions in 23 eastern states. However, at this time, none of the existing or planned EGUs affected by this rule are owned by tribes or located in Indian country. This action may have tribal implications if a new affected EGU is built in Indian country. Additionally, tribes have a vested interest in how this proposed rule would affect air quality.

In developing CSAPR, which was promulgated on July 6, 2011 to address interstate transport of ozone pollution under the 1997 ozone NAAQS,[11] the EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing that regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in 76 FR 48346 (August 8, 2011).

The EPA received comments from several tribal commenters regarding the availability of CSAPR allowance allocations to new units in Indian country. The EPA responded to these comments by instituting Indian country new unit set-asides in the final CSAPR. In order to protect tribal sovereignty, these set-asides are managed and distributed by the federal government regardless of whether CSAPR in the adjoining or surrounding state is implemented through a FIP or SIP. While there are no existing affected EGUs in Indian country covered by this proposal, the Indian country set-asides will ensure that any future new units built in Indian country will be able to obtain the necessary allowances. This proposal

[11] CSAPR also addressed interstate transport of fine particulate matter (PM2.5) under the 1997 and 2006 PM2.5 NAAQS.

maintains the Indian country new unit set-aside and adjusts the amounts of allowances in each set-aside according to the same methodology of the original CSAPR rule.

The EPA has informed tribes of our development of this proposal through a National Tribal Air Association – EPA air policy conference call (January 29, 2015). The EPA plans to further consult with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. The EPA will facilitate this consultation before finalizing this proposed rule.

As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the executive order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for the proposed rule.

7.7 Executive Order 13045: Protection of Children from Environmental Health & Safety Risks

The EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the Order has the potential to influence the regulation. This action is not subject to EO 13045 because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the ozone-related benefits, $PM_{2.5}$-related co-benefits, and CO_2-related co-benefits would further improve children's health.

7.8 Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use

This action, which is a significant regulatory action under EO 12866, is likely to have a significant effect on the supply, distribution, or use of energy. The EPA notes that one aspect of this proposal that may affect energy supply, disposition or use is the EPA's proposing and taking comment on a range of options with respect to use of 2015 vintage and 2016 vintage CSAPR NO_X ozone-season allowances for compliance with 2017 and later ozone-season requirements.

The EPA has prepared a Statement of Energy Effects for the proposed regulatory control alternative as follows. We estimate a much less than 1 percent change in retail electricity prices on average across the contiguous U.S. in 2017, and a much less than 1 percent change in coal-fired electricity generation in 2017 as a result of this rule. The EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2017. For more information on the estimated energy effects, please see chapter 5 of this RIA.

7.9 National Technology Transfer and Advancement Act

The proposed rulemaking does not involve technical standards.

7.10 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this proposal will **not** have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations.

The EPA notes this action proposes to update CSAPR to reduce interstate ozone transport with respect to the 2008 ozone NAAQS. The rule uses EPA's authority in CAA section 110(a)(2)(d) to reduce (nitrogen oxides) NO_X pollution that significantly contributes to downwind ozone nonattainment or maintenance areas. As a result, the rule will reduce exposures to ozone in the most-contaminated areas (i.e., areas that are not meeting the 2008 ozone National Ambient Air Quality Standards (NAAQS)). In addition, the rule separately identifies both nonattainment areas and maintenance areas. This requirement reduces the likelihood that areas close to the level of the standard will exceed the current health-based standards in the future. The EPA proposes to implement these emission reductions using the CSAPR EGU NO_X ozone-season emissions trading program with assurance provisions.

The EPA recognizes that many environmental justice communities have voiced concerns in the past about emission trading and the potential for any emission increases in any location. The EPA believes that CSAPR mitigated these concerns and that this proposal, which applies the CSAPR framework to reduce interstate ozone pollution and implement these reductions, will also minimize community concerns. The EPA seeks comment from communities on this proposal.

Ozone pollution from power plants have both local and regional components: part of the pollution in a given location—even in locations near emission sources—is due to emissions from nearby sources and part is due to emissions that travel hundreds of miles and mix with emissions from other sources.

It is important to note that the section of the Clean Air Act providing authority for this rule, section 110(a)(2)(D), unlike some other provisions, does not dictate levels of control for particular facilities. CSAPR allows sources to trade allowances with other sources in the same or different states while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling in each state (the assurance level). In addition, assurance provisions in the rule outline the allowance surrender penalties for failing to meet the assurance level; there are additional allowance penalties as well as financial penalties for failing to hold an adequate number of allowances to cover emissions.

This approach reduces EGU emissions in each state that significantly contribute to downwind nonattainment or maintenance areas, while allowing power companies to adjust generation as needed and ensure that the country's electricity needs will continue to be met. The EPA maintains that the existence of these assurance provisions, including the penalties imposed when triggered, will ensure that state emissions will stay below the level of the budget plus variability limit.

In addition, all sources must hold enough allowances to cover their emissions. Therefore, if a source emits more than its allocation in a given year, either another source must have used less than its allocation and be willing to sell some of its excess allowances, or the source itself had emitted less than its allocation in one or more previous years (i.e., banked allowances for future use).

In summary, the CSAPR minimizes community concerns about localized hot spots and reduces ambient concentrations of pollution where they are most needed by sensitive and vulnerable populations by: considering the science of ozone transport to set strict state emissions budgets to reduce significant contributions to ozone nonattainment and maintenance (i.e., the most polluted) areas; implementing air quality-assured trading; requiring any emissions above the level of the allocations to be offset by emission decreases; and imposing strict penalties for sources that contribute to a state's exceedance of its budget plus variability limit. In addition, it is important to note that nothing in this final rule allows sources to violate their title V permit or any other federal, state, or local emissions or air quality requirements.

Finally, it is also important to note that CAA section 110(a)(2)(d), which addresses transport of criteria pollutants between states, is only one of many provisions of the CAA that provide EPA, states, and local governments with authorities to reduce exposure to ozone in communities. These legal authorities work together to reduce exposure to these pollutants in communities, including for minority, low-income, and tribal populations, and provide substantial health benefits to both the general public and sensitive sub-populations.

The EPA has informed communities of our development of this proposal through an Environmental Justice community call (January 28, 2015) and a National Tribal Air Association – EPA air policy conference call (January 29, 2015). The EPA plans to further consult with communities early in the process of developing this regulation to permit them to have meaningful and timely input into its development. The EPA will facilitate this engagement before finalizing the proposed rule.

CHAPTER 8: COMPARISON OF BENEFITS AND COSTS

Overview

The EPA performed an illustrative analysis to estimate the costs, human health benefits, and climate co-benefits of compliance with the proposed and more and less stringent alternatives. The EPA is proposing EGU NOx ozone season emissions budgets for 23 states.[1] The emissions reductions evaluated in the proposal reflect EGU NO_X reduction strategies that are achievable for the 2017 ozone season. The EPA proposes to quantify EGU NO_X ozone-season emissions budgets reflecting EGU NO_X reduction strategies that are widely available at a uniform annualized cost of $1,300 per ton (2011$). For the RIA, in order to implement the OMB Circular A-4 requirement to assess one less stringent and one more stringent alternative to the proposal, the EPA is also analyzing EGU NO_X ozone season emissions budgets reflecting NO_X reduction strategies that are widely available at a uniform cost of $500 per ton (2011$) and strategies that are widely available at a uniform cost of $3,400 per ton (2011$). This chapter summarizes these results.

8.1 Results

As shown in Chapter 5, the estimated annualized costs to implement the proposal, as described in this document, are approximately $93 million (2011 dollars). As shown in Chapter 6, the total estimated combined benefits from implementation of the proposal are approximately $660 to $1,300 million in 2017 (2011 dollars, based on a discount rate of 3 percent and 7 percent for health benefits (ozone benefits and $PM_{2.5}$ co-benefits), a range of 2.5% to 5% for climate co-benefits, and rounded to two significant figures). EPA can thus calculate the net benefits of the proposal by subtracting the estimated annualized costs from the estimated benefits in 2017. The net benefits of the proposal are approximately $600 to $1,100 million (based on air quality benefits discounted at 3 percent, the central estimate of CO_2 co-benefits, and annualized cost estimates) or $580 to $1,100 million (based on air quality benefits discounted at 7 percent, the central estimate of CO_2 co-benefits, and annualized cost estimates). Therefore, the EPA expects that implementation of this rule, based solely on economic efficiency criteria, will provide

[1] Alabama, Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

society with a significant net gain in social welfare, notwithstanding the expansive set of health and environmental effects we were unable to quantify. Further quantification of acidification-, and eutrophication-related impacts would increase the estimated net benefits of the rule. Table 8-1 presents a summary of the benefits, costs, and net benefits of the proposal and also the more and less stringent alternatives.

Table 8-1. Total Costs, Total Monetized Benefits, and Net Benefits of the Proposal and More or Less Stringent Alternatives for 2017 for U.S. (millions of 2011$)[a,b,c]

	Proposal	More Stringent	Less Stringent
Climate Co-Benefits	$23	$23	$27
Air Quality Health Benefits	$670 to $1200	$690 to $1,300	$190 to $340
Total Benefits	$700 to $1200	$720 to $1300	$210 to $360
Annualized Compliance Costs	$93	$96	$4.7
Net Benefits	$600 to $1100	$620 to $1200	$210 to $360
Non-Monetized Benefits[d]	Non-quantified climate benefits Reductions in exposure to ambient NO_2 and SO_2 Ecosystem benefits assoc. with reductions in emissions of NOx, SO_2, and PM Visibility impairment		

[a] Estimating multiple years of costs and benefits is limited for this RIA by data and resource limitations. As a result, we provide compliance costs and social benefits in 2017, using the best available information to approximate compliance costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Benefits ranges represent discounting of health benefits and climate co-benefits at a discount rate of 3 percent. See Chapter 6 for additional detail and explanation. The costs presented in this table reflect compliance costs annualized at 4.77 percent discount rate possible and monitoring, recordkeeping, and reporting costs. See Chapter 5 for additional detail and explanation.
[c] All costs and benefits are rounded to two significant figures; columns may not appear to add correctly.
[d] Non-monetized benefits descriptions are for all three alternatives and are qualitative.

In accordance with Circular A-4 Guidance (OMB, 2003), the EPA also analyzed the costs and benefits of two regulatory control alternatives that impose relatively more stringent and relatively less stringent EGU NOx emissions budgets, compared to the proposed rule. These alternatives are illustrative of the cost and benefit impacts of varying program stringency. They are designed to show the effects of more stringent and less stringent NOx reduction requirements in a regulatory structure that is otherwise the same as the proposed NOx emissions budgets. Air quality modeling was not conducted for the proposal or the more and less stringent alternatives. EPA applied a benefit-per-ton approach appropriate for deriving benefits for the evaluated regulatory control alternatives, as described in Chapter 6. The proposal and alternatives' compliance costs are estimated using the IPM model, as described in Chapter 5. Table 8-2 presents the projected emissions reductions for ozone season NOx, as well as reductions in co-pollutant annual NO_X, annual SO_2, and annual CO_2, in 2017 under the proposed rule and the more and less stringent alternatives.

Table 8-2. Projected 2017* Reductions in Emissions of NOx, SO_2, and CO_2 with the proposed NOx Emissions Budgets and More or Less Stringent Alternatives (Tons)

	Proposal	More Stringent Alternative	Less Stringent Alternative
NOx (annual)	90,000	93,000	24,000
NOx (ozone season)	85,000	87,000	24,000
SO_2 (annual)	1,200	1,200	1,100
CO_2 (annual short tons)	660,000	710,000	770,000

*Annual reductions are based on 2018 IPM direct model outputs relied upon in this RIA to represent 2017 co-pollutant reductions

In this RIA, we quantify an array of adverse health impacts attributable to ozone and $PM_{2.5}$. The Integrated Science Assessment for Ozone and Related Photochemical Oxidants ("Ozone ISA") (U.S. EPA, 2013a) identifies the human health effects associated with ozone exposure, which include premature death and a variety of illnesses associated with acute (days-long) and chronic (months to years-long) exposures. Similarly, the Integrated Science Assessment for Particulate Matter ("PM ISA") (U.S. EPA, 2009) identifies the human health effects associated with ambient particles, which include premature death and a variety of illnesses associated with acute and chronic exposures.

8.2 Net Present Value of a Stream of Costs and Benefits

The EPA believes that providing comparisons of social costs and social benefits at discount rates of 3 and 7 percent is appropriate to the extent this is possible given available models and techniques. The three different uses of discounting in the RIA – (i) construction of annualized costs, (ii) adjusting the value of mortality risk for lags in mortality risk decreases, and (iii) adjusting the cost of illness for non-fatal heart attacks to adjust for lags in follow up costs -- are all appropriate. We explain our discounting of benefits in Chapter 6 of the RIA, specifically the application of 3 and 7 percent to air quality benefits and 2.5, 3, and 5 percent to climate co-benefits; we explain our discounting of costs, in which we use a single discount rate of 4.77 percent, in Chapter 5. Our estimates of net benefits are the approximations of the net value (in 2017) of benefits attributable to emissions reductions needed to attain just for the year 2017.

The EPA presents annualized costs and benefits in a single year for comparison in this RIA because there are a number of methodological complexities associated with calculating the net present value (NPV) of a stream of costs and benefits for a rulemaking requiring emissions reductions. While NPV analysis allows evaluation of alternatives by summing the present value of all future costs and benefits, insights into how costs will occur over time are limited by underlying assumptions and data. Calculating a present value (PV) of the stream of future benefits also poses special challenges, which we describe below. In addition, the method requires definition of the length of that future time period, which is not straightforward for this analysis and subject to uncertainty. We provide annualized costs of compliance instead of using NPV or alternatives in this RIA, and our explanation for this is in Chapter 5.

Further, because we do not know when a facility will stop using a control measure or change to another measure based on economic or other reasons, the EPA assumes the control equipment and measures applied in the proposed option, and in the more and less stringent options, remain in service for their full useful life. As a result, the annualized cost of controls in a single future year is the same throughout the lifetimes of control measures analyzed, allowing the EPA to compare the annualized control costs with the benefits in a single year for consistent comparison.

The EPA's RIAs for air quality rules generally report the estimated net benefits of improved air quality for a single year. The estimated NPV can better characterize the stream of benefits and costs over a multi-year period. However, calculating the PV of improved air quality is generally quite data-intensive and costly. Further, the results are sensitive to assumptions regarding the time period over which the stream of benefits is discounted.

The theoretically appropriate approach for characterizing the PV of benefits is the life table approach. The life table, or dynamic population, approach explicitly models the year-to-year influence of air pollution on baseline mortality risk, population growth and the birth rate—

typically for each year over the course of a 50-to-100 year period (U.S. EPA SAB, 2010; Miller, 2003). In contrast to the pulse approach[2], a life table models these variables endogenously by following a population cohort over time. For example, a life table will "pass" the air pollution-modified baseline death rate and population from year to year; impacts estimated in year 50 will account for the influence of air pollution on death rates and population growth in the preceding 49 years.

Calculating year-to-year changes in mortality risk in a life table requires some estimate of the annual change in air quality levels. It is both impractical to model air quality levels for each year and challenging to account for changes in federal, state and local policies that will affect the annual level and distribution of pollutants. For each of these reasons, the EPA has not generally reported the PV of benefits for air rules but has instead pursued a pulse approach.

[2] The pulse approach assumes changes in air pollution in a single year and affects mortality estimates over a 20-year period.