


Multi-Pollutant Legislative Analysis: The Clean Air Planning Act

(Carper, S.843 in 108th)

U.S. Environmental Protection Agency

Office of Air and Radiation

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Section #1
Multi-Pollutant Background

Introduction

This technical support package is part of a comprehensive U.S. Environmental Protection Agency (EPA) analysis of various multi-pollutant proposals. The analysis is based on air quality, health benefits, and power sector modeling and provides projections for each proposal for the years 2010, 2015, and 2020.

EPA has modeled the following multi-pollutant approaches:

1. Clean Air Planning Act (Carper, S.843 in 108th)
2. Clean Power Act (Jeffords, S.150 in 109th)
3. Clear Skies Act of 2005 (Inhofe, S.131 in 109th)
4. Clear Skies Act of 2003 (Inhofe/Voinovich at the Administration's request, S.485 in 108th)
5. Clear Skies Manager's Mark (of S.131 in 109th)
6. Clean Air Interstate Rule, Clean Air Mercury Rule, and the Clean Air Visibility Rule

These approaches to reducing emissions from the power sector generally have several things in common:

- Improvement in human health;
- Adoption of a market-based cap and trade program;
- Substantial reduction in the number of $PM_{2.5}$ and ozone nonattainment areas;
- Installation of additional pollution controls on power plants;
- Alteration of existing regulations;
- Reduction in emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg).

Methodology for Evaluating Impacts of the Proposals

- When analyzing the costs and benefits of a particular legislative or regulatory scenario, EPA compares the scenario being analyzed to a “baseline”. The costs and benefits are typically presented as incremental to this baseline (e.g., the annual cost of the program in 2010 is the additional cost utilities will incur in 2010 beyond the costs in the 2010 baseline).
- Without using a baseline, many costs and benefits could be quantified only in comparison to current conditions (e.g., the annual cost of the program in 2010 would be the projected cost in 2010 compared to the costs they incur currently). Comparing costs to current conditions would combine the compliance costs of the scenario being analyzed with increased costs due to growth in electricity demand or changes in other circumstances. The baseline helps to account for such variables, providing another method for comparing various alternatives. The baseline is not intended to be a projection of what will happen in the absence of new legislation or to serve as a projection of future implementation of the Clean Air Act.
- The projected costs and benefits of different scenarios can be compared to each other when all scenarios are analyzed using the same baseline.
- For the economic modeling of the utility industry, the baseline includes Title IV, the NO_x SIP Call, New Source Review (NSR) settlements, and State-specific rules, regulations, and/or agreements in Connecticut, Illinois, Maine, Massachusetts, Minnesota, Missouri, New Hampshire, New York, North Carolina, Oregon, Texas, and Wisconsin that were finalized by mid-2004.
- For air quality modeling, the baseline also includes the Tier II, Heavy Duty Diesel, and Non-Road Diesel Rules.
- The baseline does not include control programs that have not been adopted (e.g., yet-to-be-developed regulations and necessary local controls to implement the National Ambient Air Quality Standards (NAAQS) and meet relevant NAAQS attainment deadlines).

Short-Term Feasibility Constraint and Provisions not Directly Modeled

- In the short-term, modeling of the power sector incorporates a feasibility constraint on the amount of pollution controls that can be installed to meet the caps set forth in the proposal. This constraint is largely based upon the short-term shortage of boilermaker labor that is critical for installing SO_2 and NO_x controls. Post 2010, there is no feasibility constraint as additional boilermakers enter the workforce. EPA has also conducted analysis of the proposals if no such constraint exists, the results of which can be found in Section #6. While EPA believes that there are significant limitations regarding the amount of activated carbon injection (ACI) for mercury control or new generation* that can by built by 2010, these limitations have not been factored into the power sector modeling and results need to be reviewed with this in mind.
- Due to modeling limitations, some provisions of the Clean Air Planning Act (Carper, S.843) are not directly modeled. These provisions include the carbon offset provision. Some additional information on this provision is provided in Section #6.

*For more discussion, see pages 44-45.

Description of Modeling Tools

The Integrated Planning Model (IPM)

- IPM is an electric generation cost model that is used for power sector and environmental applications.
- IPM finds the least-cost solution to meeting electricity demand subject to environmental, transmission, reserve margin, and other system operating constraints for any specified region and time period.
- IPM provides both a broad and detailed analysis of control options for major emissions from the power sector, such as power generation adjustments, pollution control actions, air emissions changes (national, regional/state, and local), major fuel use changes, and economic impacts (costs, wholesale electricity prices, closures, allowance values, etc.).

Retail Electricity Pricing Model

- The Retail Electricity Pricing Model provides a forecast of average retail electricity prices for 13 regions in the contiguous U.S.; it considers areas of the country that (1) will have competitive pricing of power generation and (2) are likely to price retail power on a cost-of-service basis.

Air Quality Modeling (CMAQ and CAMx)

- The Community Multi-scale Air Quality (CMAQ) model is a photochemical air quality model that simulates the transport and fate of multiple pollutants across large geographic areas. CMAQ was applied to model the impacts on $PM_{2.5}$ of annual SO_2 and NO_x emissions reductions.
- The Comprehensive Air quality Model with extensions (CAMx) simulates the formation and fate of photochemical oxidants including ozone over multiple spatial scales. CAMx is applied for selected summer episodes in the eastern U.S. to model the ozone impacts associated with NO_x emissions reductions.

Benefits Modeling (BENMap)

- BENMap estimates expected health improvements across the population (avoided premature mortality, hospital visits, heart attacks, asthma attacks, etc.) using results from the air quality modeling. BENMap can also be used to calculate the monetary value of those health improvements.

Greenhouse Gas Models for CO_2 Offsets

- A suite of respected and widely used models was employed for the analysis of the Clean Air Planning Act (Carper, S.843). For further details see Section #6.

Uncertainty in Projections of Costs and Technological Feasibility

There are a number of factors that can lead to uncertainty in cost estimates including:

- Differences in assumptions about key variables such as natural gas prices or electricity demand – EPA has addressed this uncertainty by performing sensitivity analyses on both natural gas prices and electric demand.

- Uncertainty about availability, cost, and performance of control technologies.
    - If technology is not available to meet emission constraints (such as the first phase unit-specific mercury constraints under the Clean Air Planning Act (Carper, S.843), or the first phase CO_2 caps or mercury requirements under the Clean Power Act (Jeffords, S.150)), costs could be significantly higher for those bills.
    - If there are technical innovations (including new technologies or improvements in existing technologies), this could lead to lower costs. This is particularly true in the longer term.

- Unquantified costs of regulation vs. legislation.
    - State-by-State plan development process under CAIR, CAMR, and CAVR and source-specific determinations under CAVR results in additional unquantified costs. These costs are borne by both State regulators and interested parties, such as the power sector and environmental groups, that participate in this process.
    - Uncertainty of litigation under regulation can delay pollution control decision-making, increasing costs in later “rush to compliance”.

Uncertainty in Projections of Benefits

There are a number of factors that can lead to uncertainty in the benefits estimated including*:

- Gaps in scientific knowledge that prevent us from quantifying certain types of benefits.

- Variability in estimated pollution concentrations and response relationships, introduced through differences in study design and statistical modeling.

- Errors in measurement and projection for important variables in analysis such as population growth rates, changes in emissions and pollutant concentrations derived from air quality modeling.

In addition, if emission reductions occur more slowly than projected, benefits would be less.

- If litigation results in delaying CAIR, CAMR, or CAVR, benefits would be less. Litigation could result in other changes to timing or control levels that would impact benefits.

- If emission controls cannot be installed quickly enough, or if allowance costs exceed projected prices so that safety valves are triggered, benefits could be less.

*For a more complete discussion of uncertainties related to benefits estimates for fine particles ($PM_{2.5}$) and Ozone, see "Regulatory Impact Analysis for the Final Clean Air Interstate Rule", EPA-452/R-/05-002, March 2005, U.S. EPA

Section #2

Provisions of the Clean Air Planning Act

(Carper, S.843 in 108^{th})

Clean Air Planning Act (Carper, S.843) – Overview

General:

- Caps power plant emissions of SO_2, NO_x, Hg, and CO_2, and establishes unit-specific limits for Hg emissions.
- Retains existing Title IV until new requirements take effect, and retains the NO_x SIP Call as a separate requirement.
- Amends certain provisions of Title I of the Clean Air Act that currently apply to those sources that will be covered by the new Title IV emission caps.

Allowance System: Creates new trading programs for SO_2, NO_x, Hg, and CO_2 by adding a new title to the Clean Air Act.

Regulatory Exemptions: Provides regulatory relief from NSR by changing the definition of "modification" in attainment areas, capping Lowest Achievable Emissions Rate (LAER) at twice Best Available Control Technology (BACT) cost and adding cost considerations, and eliminating offsets for new units in non-attainment areas.

- Also exempts affected units from mercury Maximum Achievable Control Technology (MACT) and Best Available Retrofit Technology (BART) (for 20 years).

Birthday provision: Starting in 2020, any affected unit on which construction commenced before August 17, 1971 must meet the following performance standards:

- 4.5 lbs/MWh for SO_2
- 2.5 lbs/MWh for NO_x

Penalties: Facilities must offset excess emissions or face penalties of:

- SO_2: \$2,000 per ton
- NO_x: \$5,000 per ton
- Hg: \$10,000 per pound

Re-opener: Caps reviewed 15 years after enactment of legislation and sunset at 20 years.

Clean Air Planning Act (Carper, S.843) SO_2 Program

Applicability: Retains Acid Rain Program applicability definition.

- For units commencing operation before November 15, 1990: utility units and some cogeneration and independent power production units with a nameplate capacity above 25 MW.
- For units commencing operation on or after November 15, 1990: utility units and some cogeneration and independent power production units regardless of nameplate capacity.

Caps and Timing: Annual SO_2 emissions for affected units are capped at 4.5 million tons starting in 2009, 3.5 million tons starting in 2013, and 2.25 million tons in 2016.

- A separate cap and trade program for the Western Regional Air Partnership (WRAP) states is triggered three years after projected emissions in WRAP states for 2016 or later exceed 271,000.

Allowance Allocations: For existing sources, allocations determined based on existing Title IV allocation rules, with adjustments to provide for existing units that did not receive Title IV allocations; new units receive allocations from new unit set-aside, the size of which is determined by EPA and the U.S. Department of Energy (DOE) every five years.

Interaction with Title IV: Banked pre-2010 Title IV SO_2 allowances can be used at a 1:1 ratio.

Safety Valve-like Penalty: Excess emissions penalty for SO_2 of $2,000 per ton can act as a safety valve if allowance prices reach that level.

Clean Air Planning Act (Carper, S.843) NO_x Program

Applicability: Covers *existing* and *new* fossil fuel-fired electricity generating units, including cogeneration facilities, with a generator having a nameplate capacity > 25 MW and generating electricity for sale.

Caps and Timing: Annual NO_x emissions from affected units capped at 1.87 million tons starting in 2009 and 1.7 million tons starting in 2013.

- NO_x SIP Call would exist separately from the Clean Air Planning Act (Carper, S.843), and requirements would continue to apply.

Allowance Allocations: Allowances allocated using an updating, output-based system, with a set aside for new units.

- Allocation to existing units based on average annual net generation during most recent three-year period.
- Allocation to new units based on projected emissions.

Safety Valve-like Penalty: Excess emissions penalty for NO_x of $5,000 per ton can act as a safety valve if allowance prices reach that level.

Clean Air Planning Act (Carper, S.843) Mercury Program

Applicability: Covers *existing* and *new* coal-fired electricity generating units, including cogeneration facilities, with a generator having a nameplate capacity > 25 MW and generating electricity for sale.

Caps and Timing: Annual mercury emissions from affected units capped at 24 tons starting in 2009 and 10 tons starting in 2013.

Allowance Allocations: Allowances allocated using an updating, output-based system, with a set-aside for new units.

- Allocation to existing units based on average annual net generation during most recent three-year period.
- Allocation to new units based on projected emissions.

Unit-specific Emission Limit: For 2009 – 2012, emissions cannot exceed 50% of total Hg content of delivered coal; reduced to 30% in 2013.

- Unit can opt to comply with output-based emission rate determined by EPA instead.

Safety Valve-like Penalty: Excess emissions penalty for Hg of $10,000 per pound can act as a safety valve if allowance prices reach that level.

Clean Air Planning Act (Carper, S.843) CO_2 Program

Applicability: Covers *existing* and *new* fossil fuel-fired, nuclear, and renewable electricity generating units including cogeneration facilities, with a generator having a nameplate capacity > 25 MW and generating electricity for sale.

Caps and Timing: Annual carbon dioxide emissions from affected units capped at 2006 emissions levels (2.655 billion tons) starting in 2009 and 2001 emissions levels (2.454 billion tons) starting in 2013.

Allowance Allocations: Allowances allocated using an updating, output-based system, with a set aside for new units.

- Allocation to existing units based on average annual net generation during most recent three-year period.
- Allocation to new units based on projected share of total generation.
- Nuclear units receive (and submit for compliance) allocations based only on their incremental generation from 1990 levels.

Offsets: Domestic and international greenhouse gas (GHG) offsets are permitted for compliance with the CO_2 cap. Offsets may come from non-capped sources and either sequestration or non-sequestration projects.

- Additional allowances (up to 10% of the 2009 cap level) may be allocated for project-based reductions during calendar years 1990-2008 and can be used in 2009 or thereafter.

Safety Valve-like Penalty: Excess emissions penalty for CO_2 of $100 per short ton can act as a safety valve if allowance prices reach that level.

Caps and Timing for the Electric Power Sector under the Clean Air Planning Act (Carper, S.843)

2004: The NO_x SIP Call (summertime NO_x cap in 19 Eastern States + DC)

2004

2008

2009: S.843 NO_x Phase I (1.87 million tons annual cap with a national trading program)

2009: S.843 CO_2 Phase I (2.655 billion tons annual cap with a national trading program)

2009: S.843 Hg Phase I (24 ton annual cap with a national trading program)

2009: S.843 SO_2 Phase I (4.5 million ton annual cap with a national trading program)

2012

2013: S.843 NO_x Phase II (1.7 million ton annual cap with a national trading program)

2013: S.843 CO_2 Phase II (2.454 billion tons annual cap with a national trading program)

2013: S.843 Hg Phase II (15 ton annual cap with a national trading program)

2013: S.843 SO_2 Phase II (3.5 million ton annual cap with a national trading program)

2016

2016: S.843 SO_2 Phase III (2.25 million ton annual cap with a national trading program)

2020

Section #3
Air Quality Improvements

Nonattainment under the Clean Air Act

- Section 107(d) of the CAA requires the EPA Administrator to designate areas as attainment, nonattainment, or unclassifiable within 2 years after promulgation of a new or revised NAAQS.
- Section 171 requires that within 3 years of designation, areas designated nonattainment must submit a State Implementation Plan (SIP) containing measures sufficient to provide for attainment of the NAAQS.
- Attainment deadlines are defined by the statute and are triggered by effective date of designations.
- In 1997, new NAAQS were established for both ozone and fine particles. Because of court challenges, the schedule for designations, SIP submittal, and attainment was delayed.
- The current schedule for attainment is as follows:

Pollutant	Effective Date of Designations	SIP Submittal Deadline	Attainment Deadline
Ozone	June 15, 2004	June 15, 2007	Subpart 1 areas: 2009 (maximum possible extension 2014)* Subpart 2 areas: Marginal 2007 Moderate 2010 Serious 2013 Severe (15) 2019 Severe (17) 2021 Extreme 2024 (no areas in this classification)
$PM_{2.5}$	April 5, 2005	April 5, 2008	All areas: 2010 (maximum possible extension 2015)*

- The CAA requires that States reach attainment by these deadlines. The analyses contained in this presentation reflect only the impact of regional and national measures on air quality and attainment status. In many cases, it may be necessary for States to adopt additional local controls to meet the NAAQS.

*Under Subpart 1 areas may request 2 one-year extensions.

Number of Areas[1] Projected to Meet or Exceed the $PM_{2.5}$ and 8-Hour Ozone Standards

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules[2] Absent Additional Local Controls

$PM_{2.5}$				
	Designated Nonattainment Areas (Based on 2001- 2003 Ambient Data)	**2010 with S.843**	**2015 with S.843**	**2020 with S.843**
# of Nonattainment Areas	**39**	**11**	**12***	**14***
# of Areas Projected to Come into Attainment		**28**	**27**	**25**

8-Hour Ozone[3]				
	Designated Nonattainment Areas (Based on 2001- 2003 Ambient Data)	**2010 with S.843**	**2015 with S.843**	**2020 with S.843**
# of Nonattainment Areas	**126**	**20**	**11**	**10**
# of Areas Projected to Come into Attainment		**106**	**115**	**116**

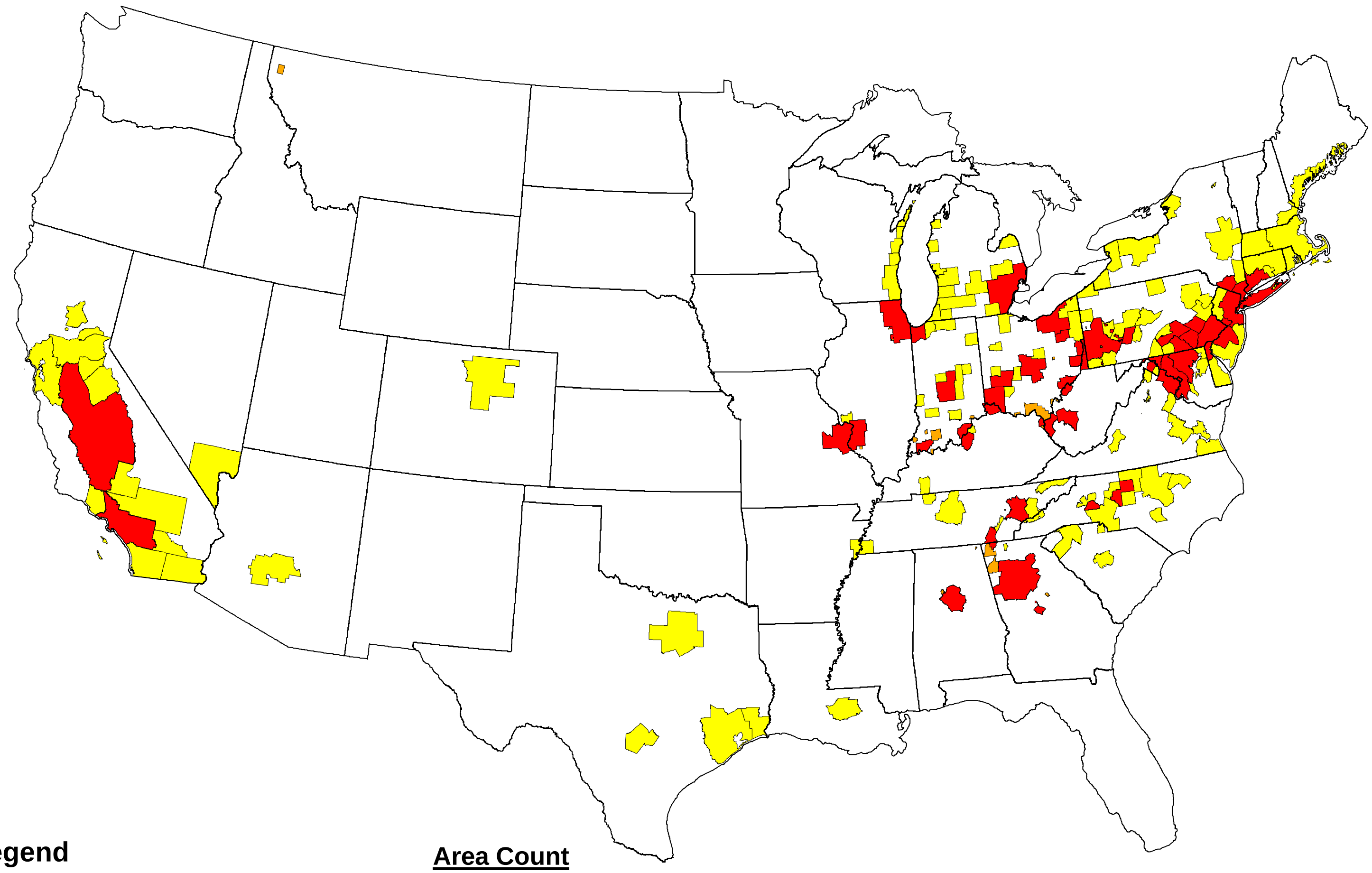
*The increase in $PM_{2.5}$ nonattainment areas from 2010 to 2015 and 2020 is primarily due to growth in emissions of SO_2 and directly emitted $PM_{2.5}$ from industrial and unaffected smaller Electric Generating Unit (EGU) sources. There are no increases in other emissions from these sources.

[1] This table provides information on nonattainment areas. For information on nonattainment counties, see pages 57-61.

[2] Current rules in place by the time IPM was updated in 2004. These include Title IV, the NO_x SIP Call and a number of State regulations. See http://www.epa.gov/airmarkets/epa-ipm/section3powsysop.pdf for more details.

[3] Ozone in the West was not modeled as part of this analysis. Future year ozone nonattainment in the West is based on modeling that was performed for the Nonroad Engine Rule.

129 Areas Designated as Nonattainment for 8-Hour Ozone and/or $PM_{2.5}$



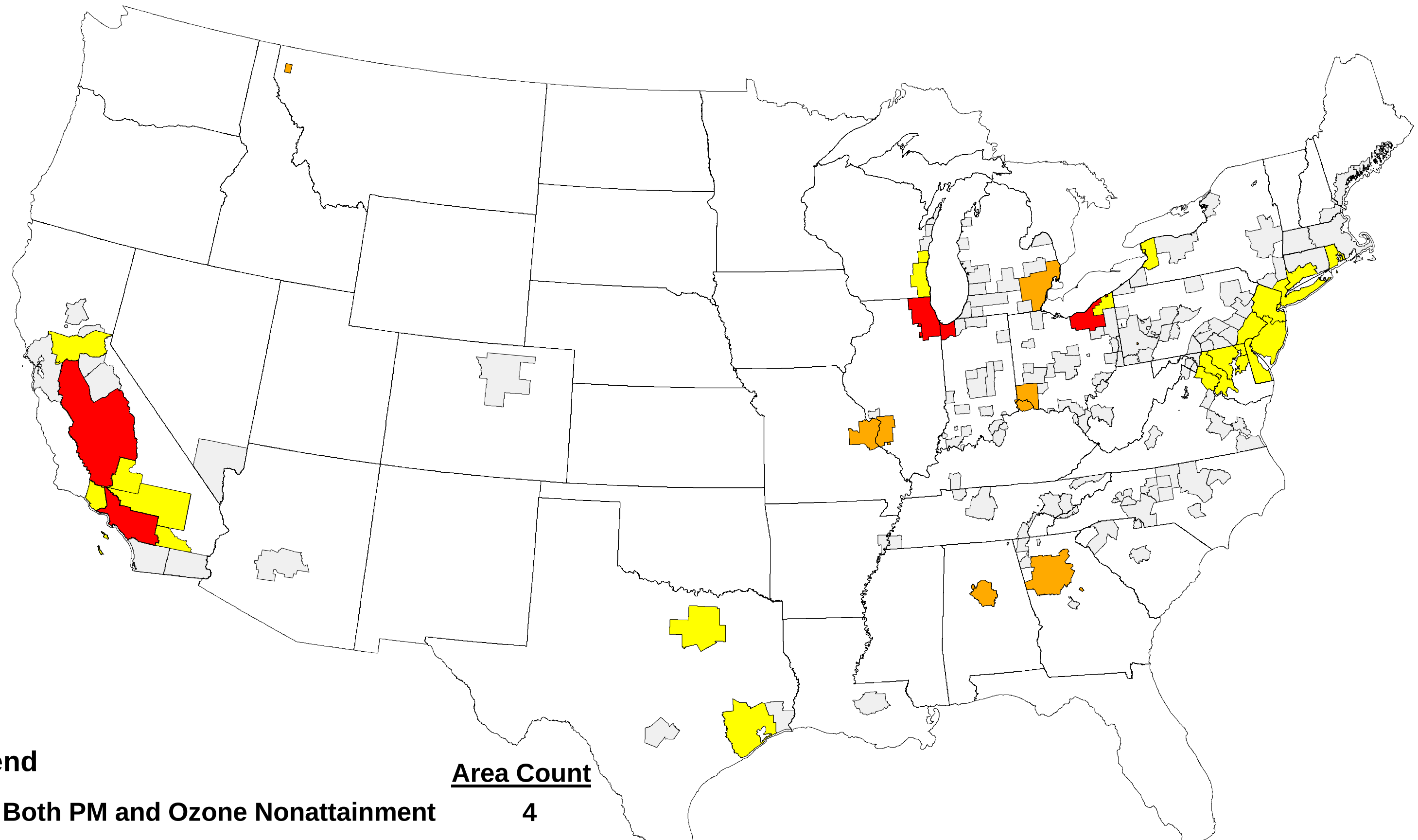
Legend

	Area Count
Both PM and Ozone Nonattainment	**36**
PM Only Nonattainment	**3**
Ozone Only Nonattainment	**90**

For further information on designations and related requirements, see
http://www.epa.gov/air/oaqps/glo/designations/index.htm
http://www.epa.gov/pmdesignations/

102 Areas Projected to Meet the $PM_{2.5}$ and 8-Hour Ozone Standards in 2010

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls



Legend

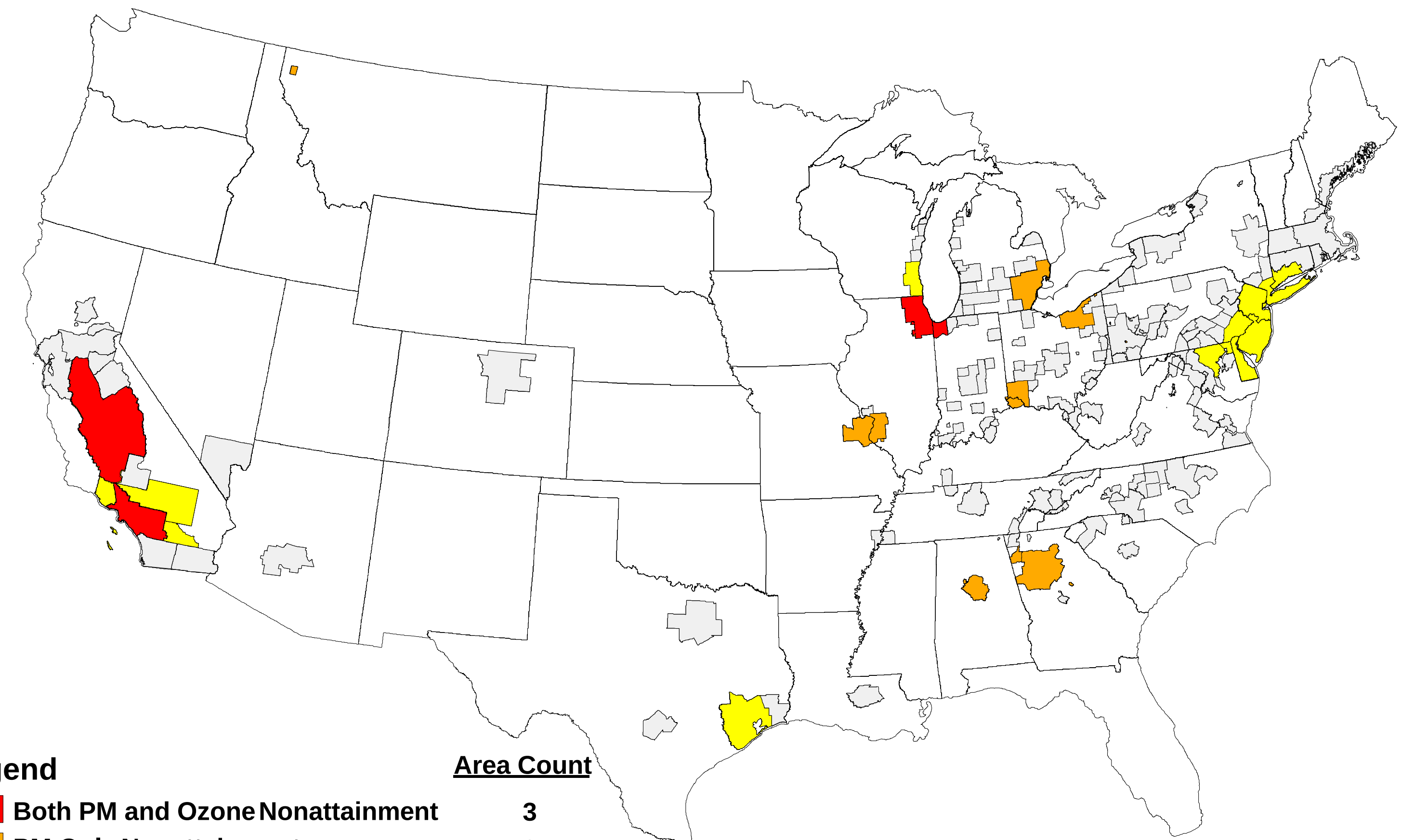
	Area Count
Both PM and Ozone Nonattainment	4
PM Only Nonattainment	7
Ozone Only Nonattainment	16
Nonattainment areas projected to attain	102

**Areas forecast to remain in nonattainment may need to adopt additional local or regional controls to attain the standards by dates set pursuant to the Clean Air Act. These additional local or regional measures are not forecast here, and therefore this figure overstates the extent of expected nonattainment.

*Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.

109 Areas Projected to Meet the $PM_{2.5}$ and 8-Hour Ozone Standards in 2015

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls



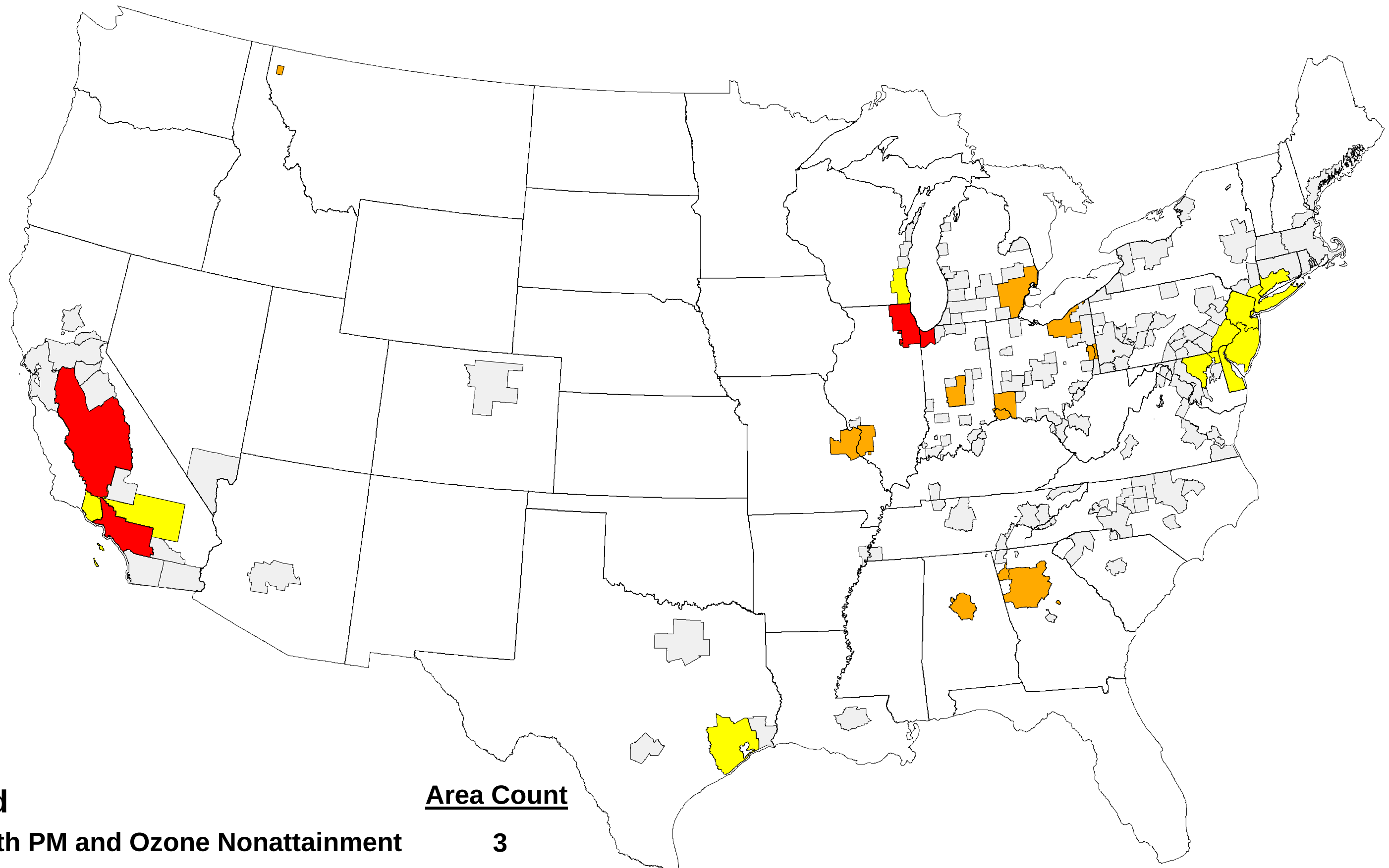
Legend	Area Count
Both PM and Ozone Nonattainment	3
PM Only Nonattainment	9
Ozone Only Nonattainment	8
Nonattainment areas projected to attain	109

**Areas forecast to remain in nonattainment may need to adopt additional local or regional controls to attain the standards by dates set pursuant to the Clean Air Act. These additional local or regional measures are not forecast here, and therefore this figure overstates the extent of expected nonattainment.

*Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.

108 Areas Projected to Meet the $PM_{2.5}$ and 8-Hour Ozone Standards in 2020

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls



Legend

	Area Count
Both PM and Ozone Nonattainment	3
PM Only Nonattainment	11
Ozone Only Nonattainment	7
Nonattainment areas projected to attain	108

**Areas forecast to remain in nonattainment may need to adopt additional local or regional controls to attain the standards by dates set pursuant to the Clean Air Act. These additional local or regional measures are not forecast here, and therefore this figure overstates the extent of expected nonattainment.

*Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.

Areas Projected to Exceed the $PM_{2.5}$ and 8-Hour Ozone Standards in 2010-2020

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls

The following areas are projected to be in nonattainment:**

- **2010**
  - **PM:** Atlanta, GA, Birmingham, AL, Chicago-Gary-Lake County, IL-IN, Cincinnati-Hamilton, OH-KY-IN, Cleveland-Akron-Lorain, OH, Detroit-Ann Arbor, MI, Libby, MT, Los Angeles-South Coast Air Basin, CA, Pittsburg-Liberty-Clairton, PA, San Joaquin Valley, CA, St. Louis, MO-IL
  - **Ozone:** Baltimore, MD, Buffalo-Niagara Falls, NY, Chicago-Gary-Lake County, IL-IN, Cleveland-Akron-Lorain, OH, Dallas-Fort Worth, TX, Houston-Galveston-Brazoria, TX, Kent and Queen Anne's Counties, MD, Kern County, CA, Los Angeles South Coast Air Basin, CA, Los Angeles-San Bernardino Counties (W Mojave), CA, Milwaukee-Racine, WI, New York-New Jersey-Long Island, NY-NJ-CT, Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE, Providence (All RI), RI, Riverside County, CA, Sacramento Metro, CA, San Joaquin Valley, CA, Sheboygan, WI, Ventura County, CA, Washington, DC-MD-VA
- **2015**
  - **PM:** Atlanta, GA, Birmingham, AL, Chicago-Gary-Lake County, IL-IN, Cincinnati-Hamilton, OH-KY-IN, Cleveland-Akron-Lorain, OH, Detroit-Ann Arbor, MI, Floyd County, GA, Libby, MT, Los Angeles-South Coast Air Basin, CA, Pittsburg-Liberty-Clairton, PA, San Joaquin, St. Louis, MO-IL
  - **Ozone:** Baltimore, MD, Chicago-Gary-Lake County, IL-IN, Houston-Galveston-Brazoria, TX, Los Angeles South Coast Air Basin, CA, Los Angeles-San Bernardino Counties (W Mojave), CA, Milwaukee-Racine, WI, New York-New Jersey-Long Island, NY-NJ-CT, Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE, Riverside County, CA, San Joaquin Valley, CA, Ventura County, CA
- **2020**
  - **PM:** Atlanta, GA, Birmingham, AL, Chicago-Gary-Lake County, IL-IN, Cincinnati-Hamilton, OH-KY-IN, Cleveland-Akron-Lorain, OH, Detroit-Ann Arbor, MI, Floyd County, GA, Indianapolis, IN, Libby, MT, Los Angeles-South Coast Air Basin, CA, Pittsburg-Liberty-Clairton, PA, San Joaquin Valley, CA, St. Louis, MO-IL, Steubenville-Weirton, OH-WV
  - **Ozone:** Baltimore, MD, Chicago-Gary-Lake County, IL-IN, Houston-Galveston-Brazoria, TX, Los Angeles South Coast Air Basin, CA, Los Angeles-San Bernardino Counties (W Mojave), CA, Milwaukee-Racine, WI, New York-New Jersey-Long Island, NY-NJ-CT, Philadelphia-Wilmington-Atlantic City, PA-NJ-MD-DE, San Joaquin Valley, CA, Ventura County, CA

*Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.
**For a more detailed listing of projected nonattainment areas and PM/Ozone concentrations, see accompanying Air Quality Technical Support Document.

Section #4
Health and Environmental Benefits

Annual Human Health Benefits of Reducing $PM_{2.5}$ and Ozone under the Clean Air Planning Act of 2003 (Carper, S.843)

- Reductions in fine particles ($PM_{2.5}$) and ozone under the Clean Air Planning Act (Carper, S.843) improve public health by reducing the incidence of various respiratory and cardiovascular health effects. The number of cases of various health effects estimated to be avoided each year under the Clean Air Planning Act (Carper, S.843) are presented in the table below.

Health Effect Avoided	2010 Estimated Reduction (Incidence)	2015 Estimated Reduction (Incidence)	2020 Estimated Reduction (Incidence)
Premature mortality*	23,000	23,000	26,000
Chronic bronchitis	12,000	12,000	13,000
Non-fatal heart attacks	29,000	30,000	33,000
Hospital admissions/ER visits	34,000	35,000	37,000
Acute bronchitis	28,000	26,000	28,000
Lower respiratory symptoms	330,000	310,000	340,000
Upper respiratory symptoms	260,000	240,000	260,000
Asthma exacerbations	420,000	390,000	420,000
Minor restricted activity days	15,000,000	14,000,000	15,000,000
Work loss days	2,400,000	2,200,000	2,300,000
School absence days	310,000	600,000	490,000

*These estimates include preliminary estimates of premature mortality associated with exposure to ozone of 320, 620, and 590 for 2010, 2015, and 2020, respectively. EPA is currently in the process of examining a variety of ozone quantification methods that would convey the uncertainty associated with these potential additional benefits. In addition, we note that in the recent CAIR Regulatory Impact Analysis, the range of uncertainty reflecting the statistical error in the underlying epidemiological function between the 5th and 95th percentile is roughly a factor of four.

Annual Monetary Health Benefits of Reducing $PM_{2.5}$ and Ozone under the Clean Air Planning Act of 2003 (Carper, S.843)*

- The improvements in health that would be achieved each year under the Clean Air Planning Act (Carper, S.843) would result in substantial monetary benefits.

- The projected annual quantified health benefits of the Clean Air Planning Act (Carper, S.843) would be:
  - $109 to 128 billion in 2010
  - $117 to 137 billion in 2015
  - $137 to 161 billion in 2020

- The monetized benefits estimated for the Clean Air Planning Act (Carper, S.843) are from reductions in ozone and fine particle concentrations resulting from lower SO_2 and NO_x emissions. EPA is not estimating the benefits from the Hg or CO_2 reductions that also occur.

- Fine particle concentration reductions provide the vast majority of the monetized benefits. From past analysis that has been done of SO_2 and NO_x reductions, it is clear that each ton of SO_2 reduction that occurs to lower fine particle emissions provides more benefits than the NO_x reductions that occur to lower fine particles in the same area. Therefore, we believe that the total monetized benefits of a ton of SO_2 reduction are significantly higher than a ton of NO_x reduction.

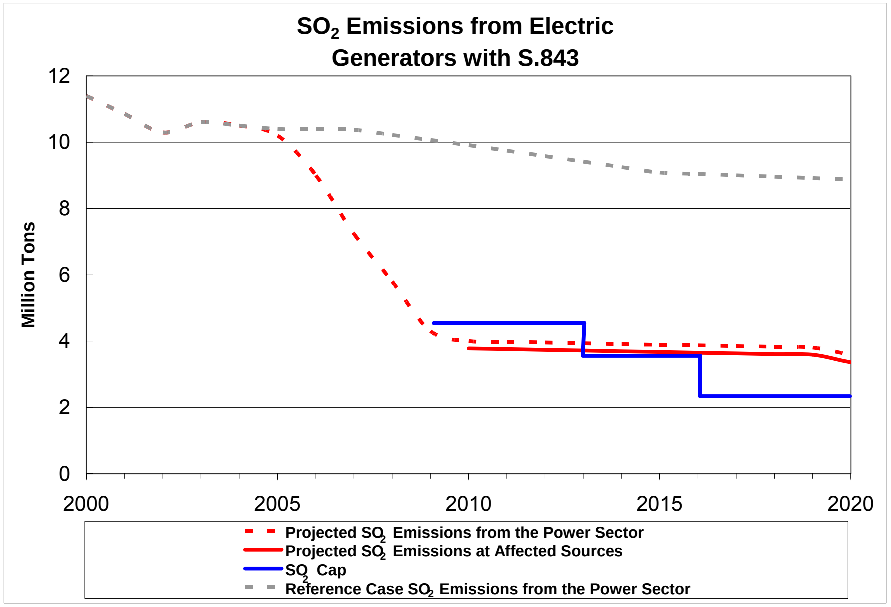
*All dollar values in this analysis are recorded in $1999. The range in benefits estimates reflects the use of a 3 percent and a 7 percent discount rate. There are other elements of uncertainty as described on pages 8 and 25. In recent RIAs, the uncertainty analysis has suggested a distribution of total benefits in which the 95th percentile is nearly twice the mean and the 5th percentile is approximately one-fourth the mean - the overall range from the 5th to the 95th percentile for the total benefits represents approximately one order of magnitude. Notably, because any of these errors are the same in all the multi-pollutant analyses, the overlapping of the uncertainty ranges between benefits estimates does not infer there is no difference in the benefits of the proposals.

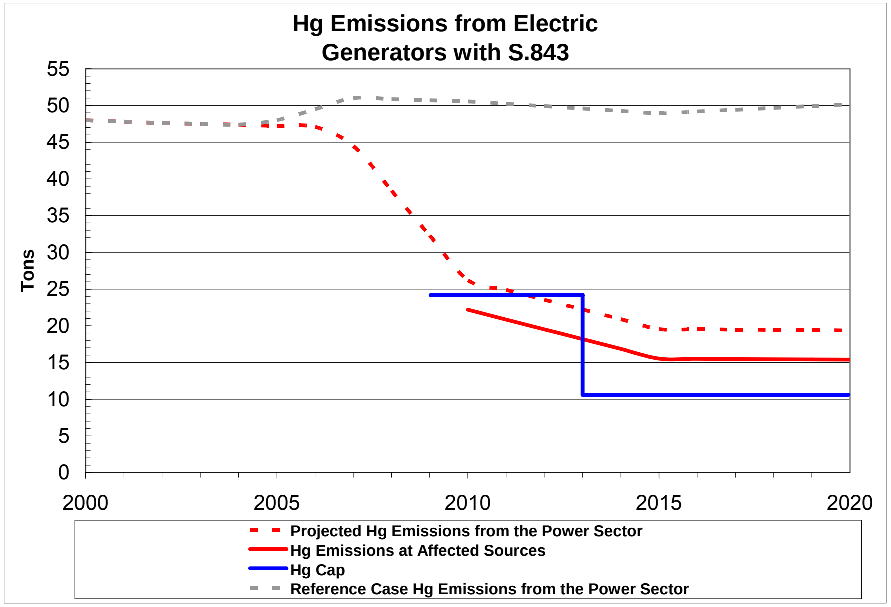
Additional Unquantified Benefits under the Clean Air Planning Act (Carper, S.843)

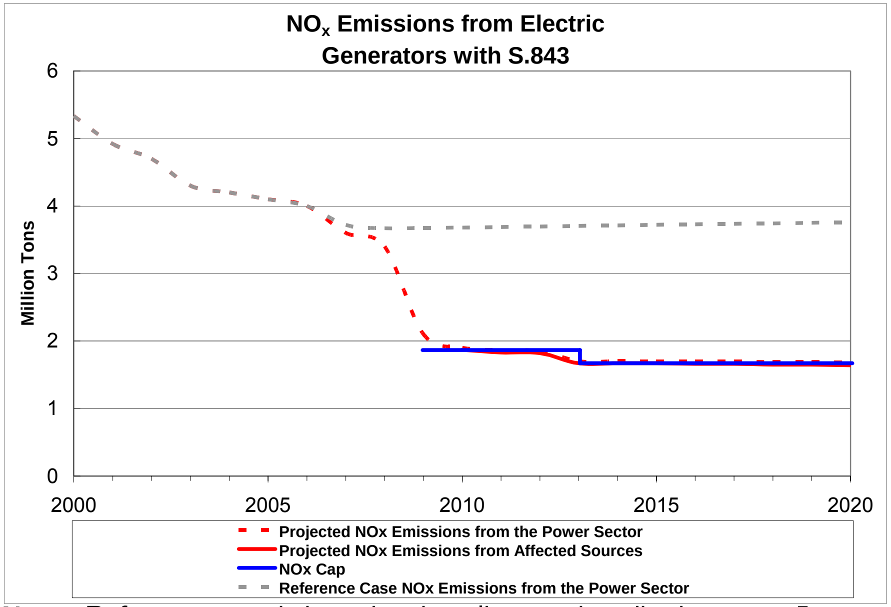
- Additional health, environmental benefits, and changes in risk that would result from the Clean Air Planning Act (Carper, S.843) have not been quantified here. These would include:
  - Improvements in visibility in national parks and recreational areas
  - Improvements in visibility in residential areas
  - Decreases in sulfur deposition (resulting in reduced acidification of surface waters and damage to forest ecosystems and soils)
  - Decreases in nitrogen deposition (resulting in reduced acidification of surface waters, damage to forest ecosystems and soils, and coastal eutrophication)
  - Exposure to mercury through eating fish containing mercury
  - Decreases in ozone-related damage to agriculture
  - Reduced risks associated with the impacts of climate change

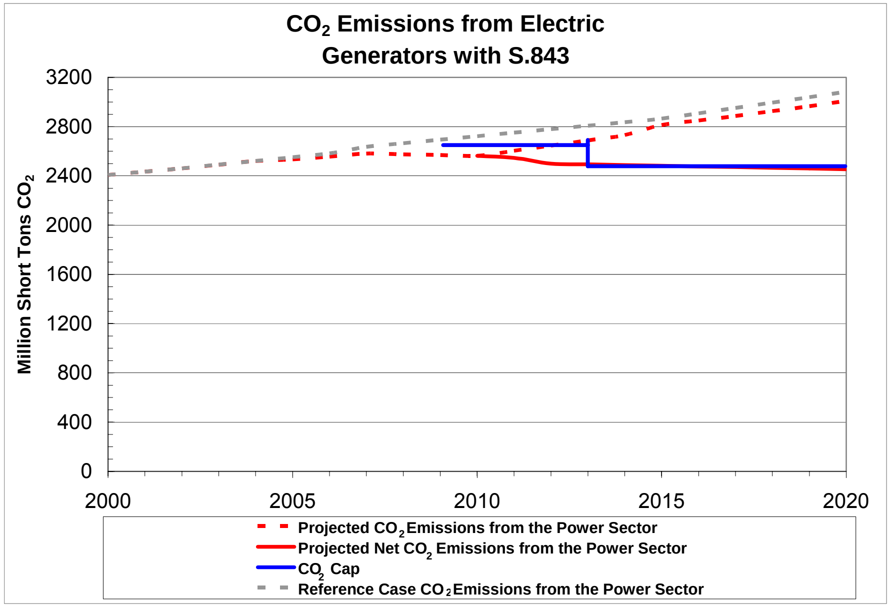
Section #5
Pollution Control Additions and Impacts to the Power Sector, Fuels, and Electricity Prices

Projected Emissions from Electric Generating Units



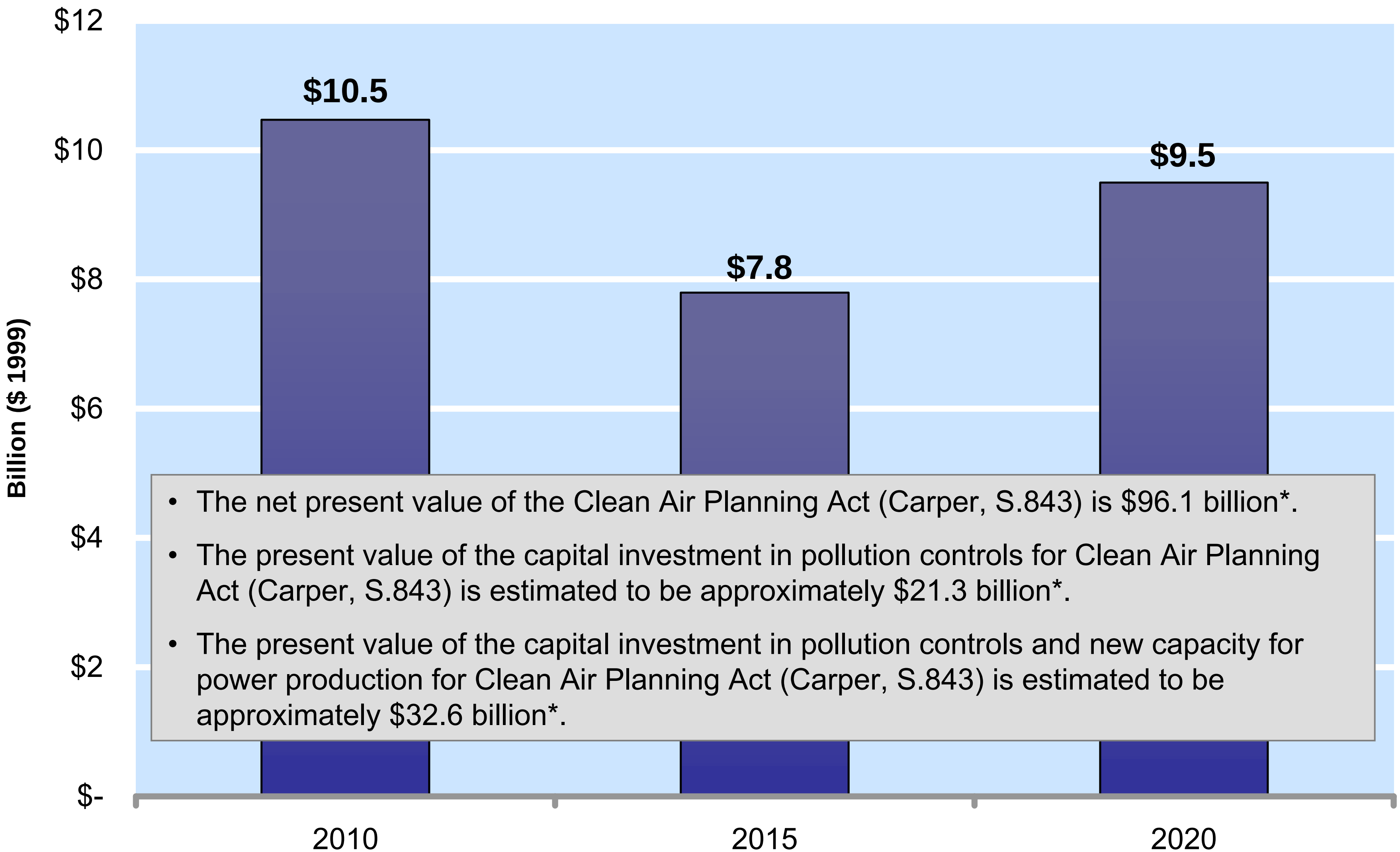






Note: Reference case is based on baseline, as described on page 5.

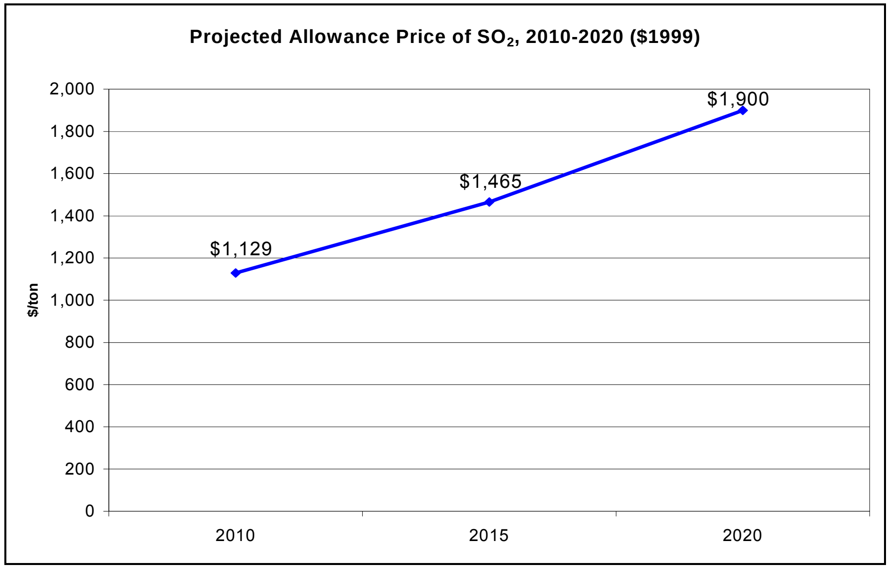
Projected Annual Costs of the Clean Air Planning Act (Carper, S.843)

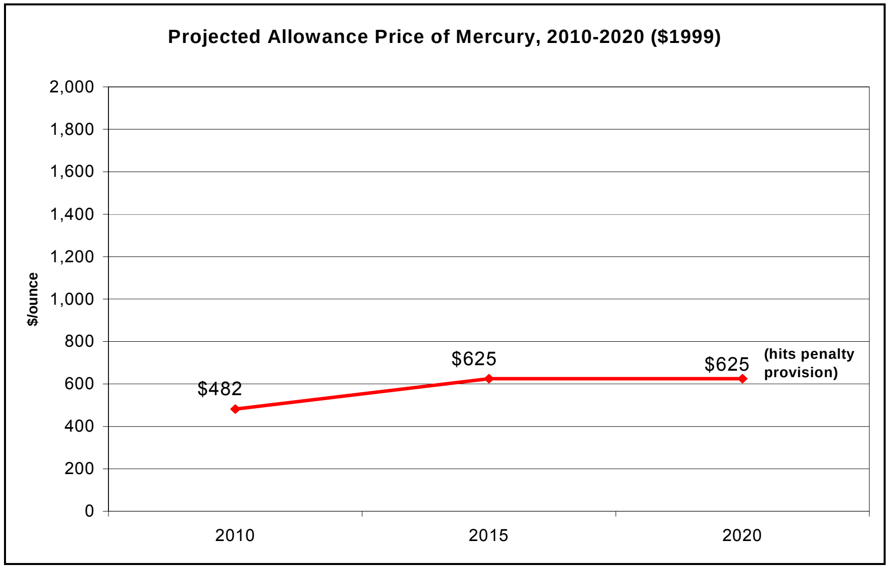


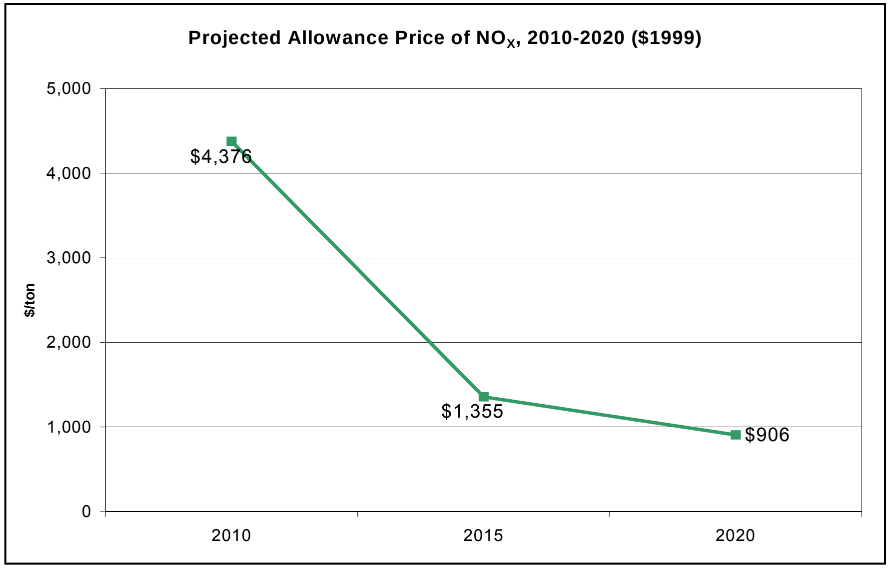
- The net present value of the Clean Air Planning Act (Carper, S.843) is $96.1 billion*.
- The present value of the capital investment in pollution controls for Clean Air Planning Act (Carper, S.843) is estimated to be approximately $21.3 billion*.
- The present value of the capital investment in pollution controls and new capacity for power production for Clean Air Planning Act (Carper, S.843) is estimated to be approximately $32.6 billion*.

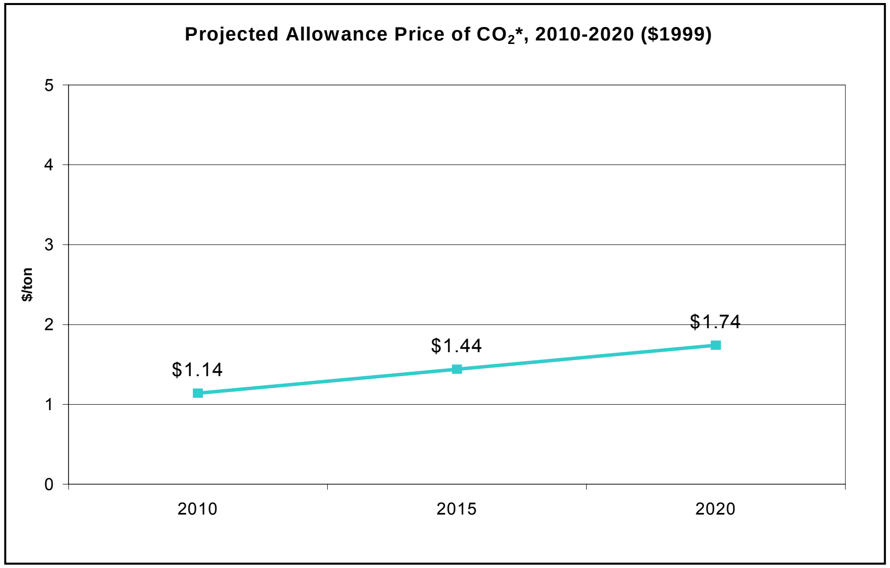
*Present value calculations are incremental to the baseline for the years 2007-2025 and are recorded in 1999 dollars. The discount rate used is between 5% and 7%.

Projected Allowance Prices under the Clean Air Planning Act (Carper, S.843)







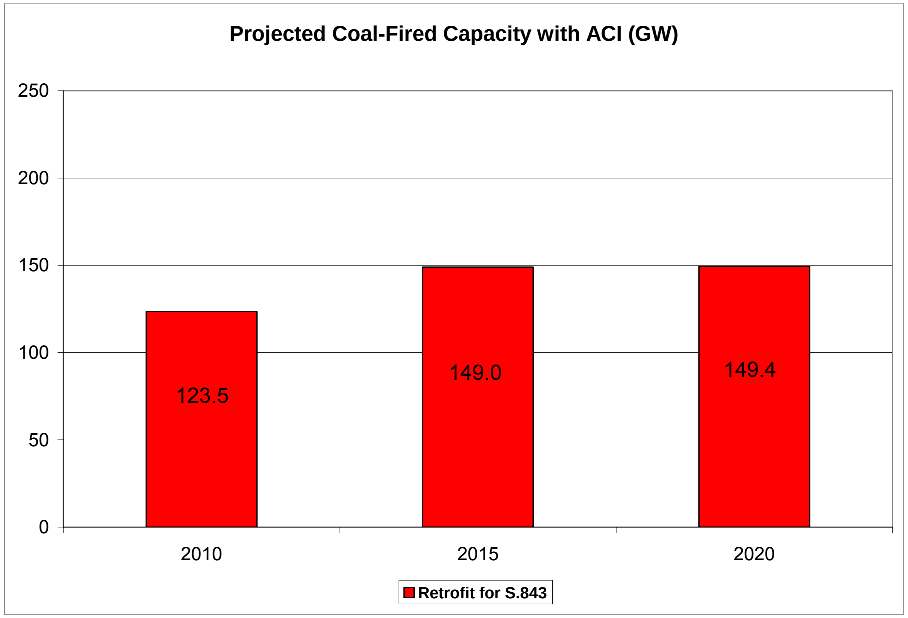


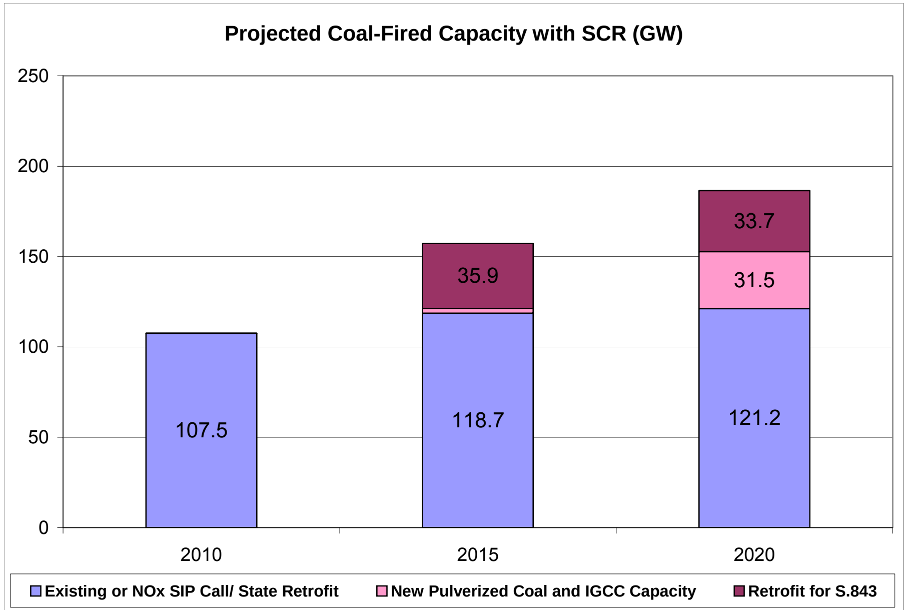
*CO_2 allowance prices are from the SGM-based analysis. For additional information regarding the cost of GHG offsets, see Section #6

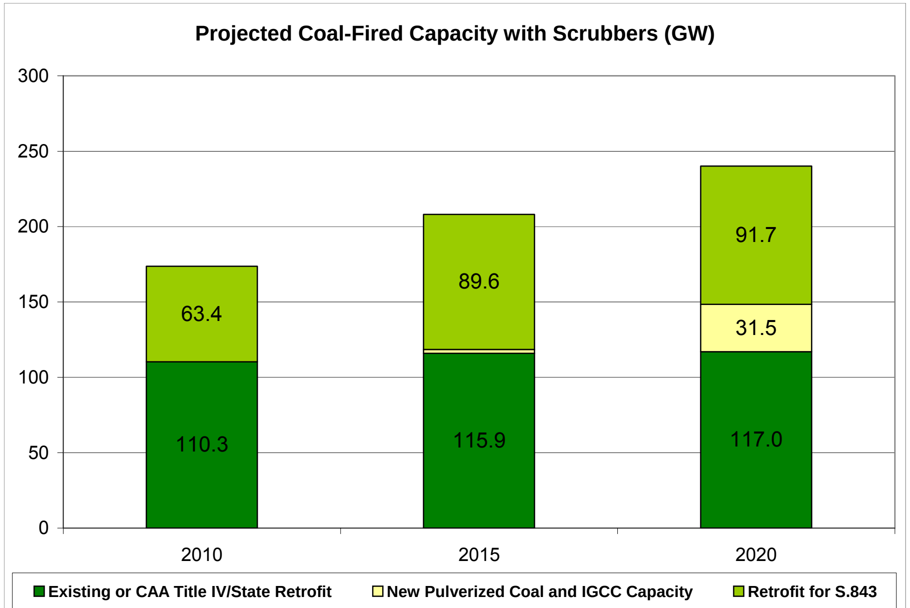
Projected Coal Capacity with Further Emissions Controls

- There is currently around 305 GW of coal-fired capacity. That number is projected to increase to about 325 GW of coal-fired capacity by 2020 with the Clean Air Planning Act (Carper, S.843).
- The graphics show cumulative capacity with existing controls, controls projected to be retrofitted under the NO_x SIP Call, NSR settlements, state enacted programs, CAA Title IV, and controls projected to be retrofitted under the Clean Air Planning Act (Carper, S.843).
- There are concerns regarding the ability of the power sector to manage the installation of the significant amounts of pollution controls required by the Clean Air Planning Act (Carper, S.843) by 2010 (see Section #6 for additional analysis).

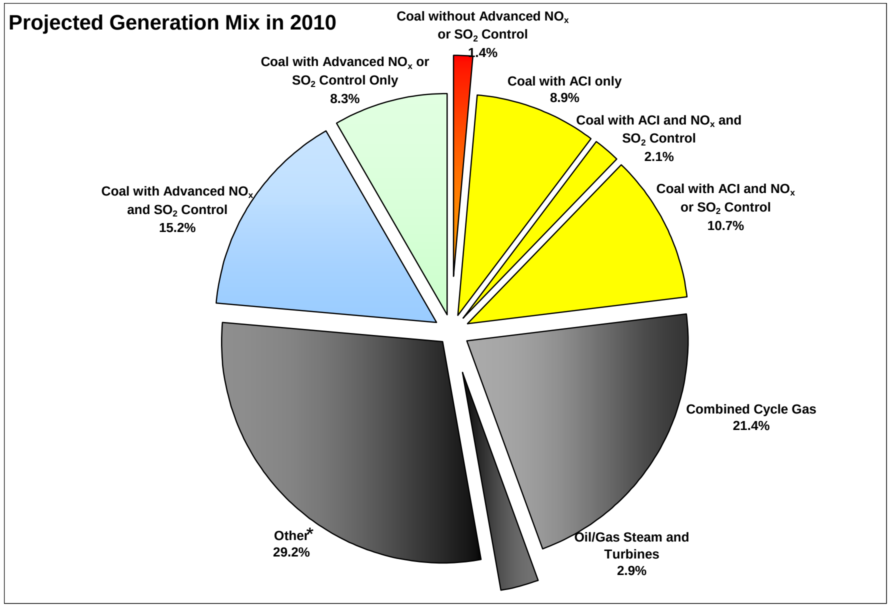
Note: The birthday provision in the Clean Air Planning Act (Carper, S.843) requires all coal-fired units to have advanced SO_2 and NO_x controls by 2020. Because of model limitations, the analysis shows a small amount of coal-fired capacity (units less than 100 MW in size) without these controls. There are no constraints on the feasibility of ACI for mercury control in IPM and results need to be reviewed with this in mind. In 2010, ACI produces about a 50% reduction in mercury, with greater effectiveness in later years of use.







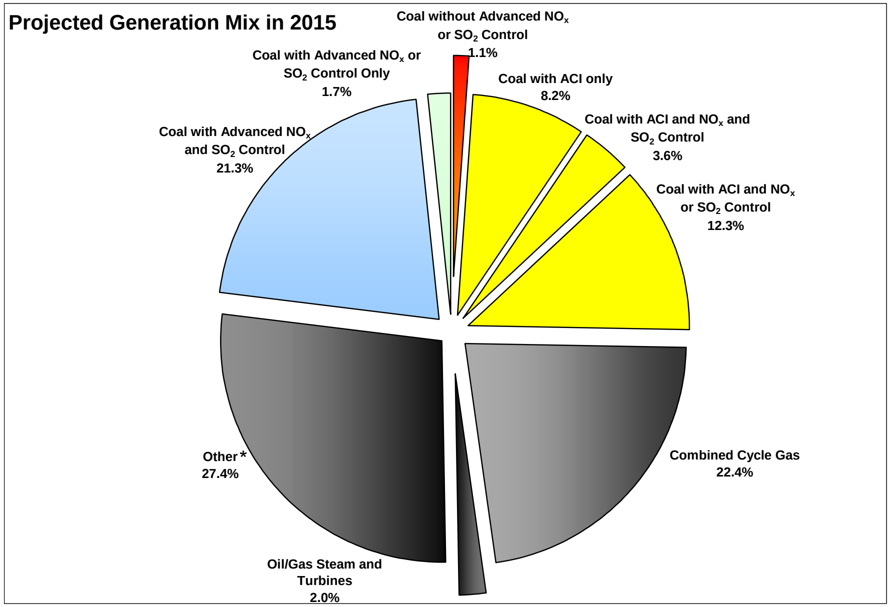
Projected Generation Mix (TWh)

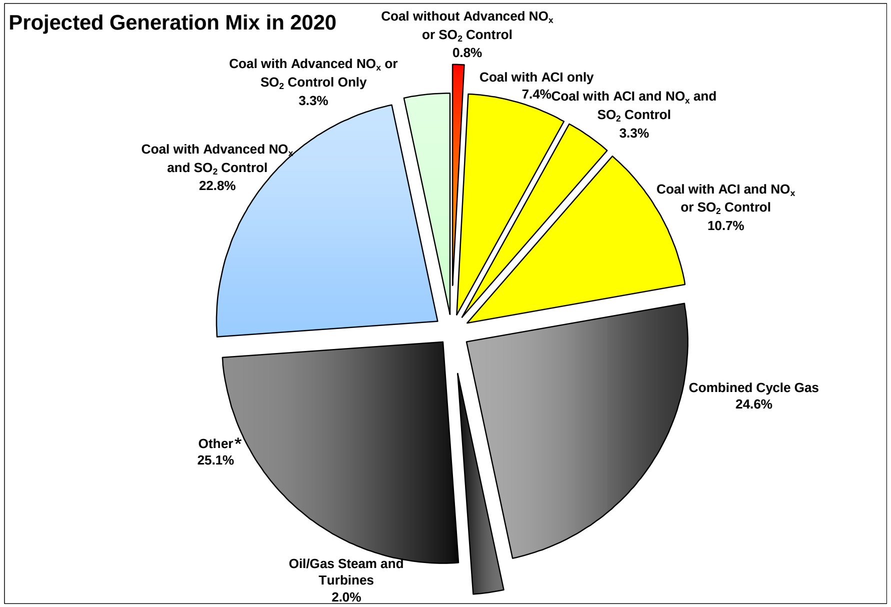


- In 2003, coal-fired generation totaled 1,970 billion kWhs. That number is projected to increase to 2,339 billion kWhs by 2020 under the Clean Air Planning Act (Carper, S.843).
- The graphics show percent of electricity generated from coal by control type installed.

Note: The birthday provision in the Clean Air Planning Act (Carper, S.843) requires all coal-fired units to have advanced SO_2 and NO_x controls by 2020. Because of model limitations, the analysis shows a small amount of coal-fired capacity (units less than 100 MW in size) without these controls.

*“Other” category includes nuclear, hydroelectric, and renewable energy generation.

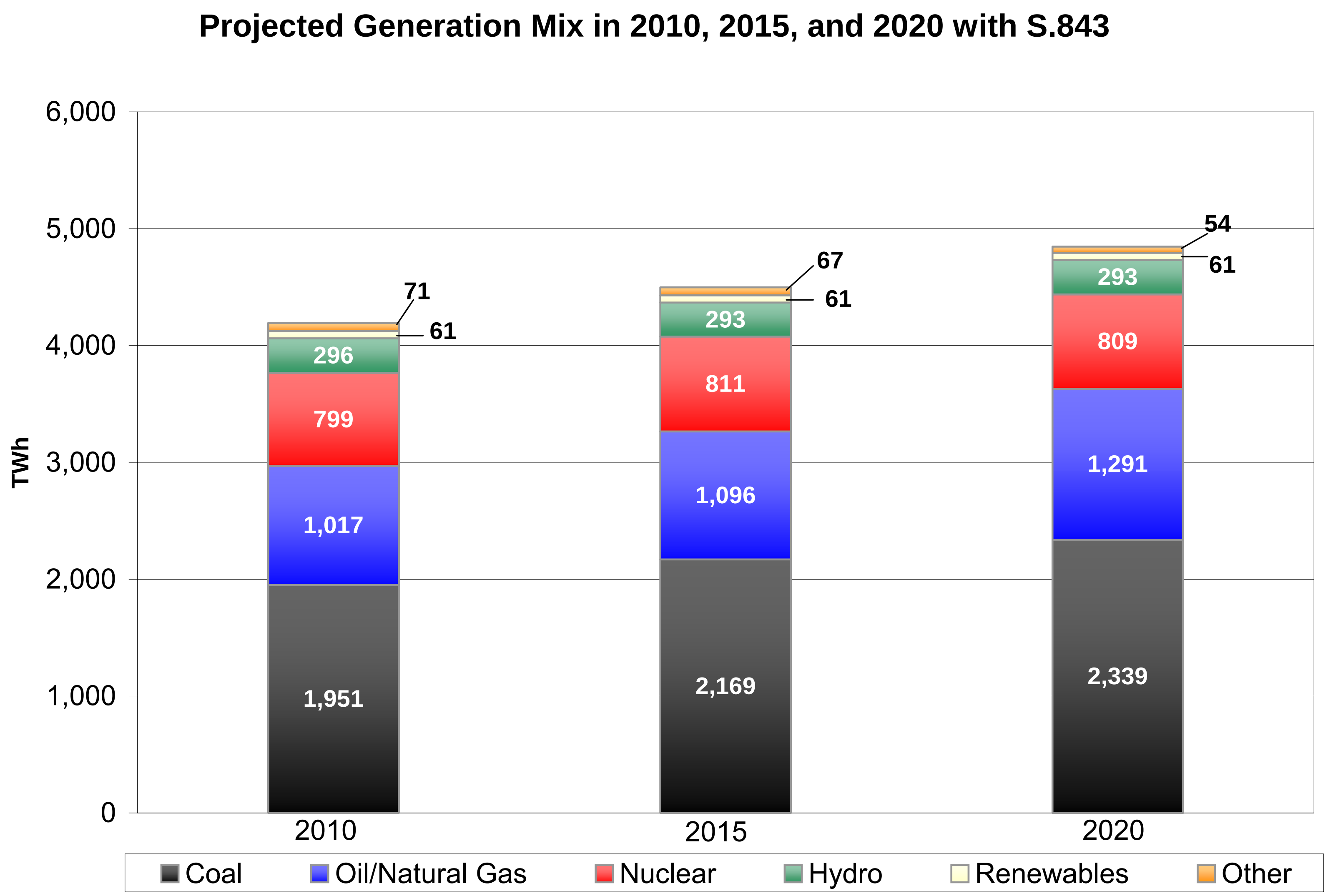




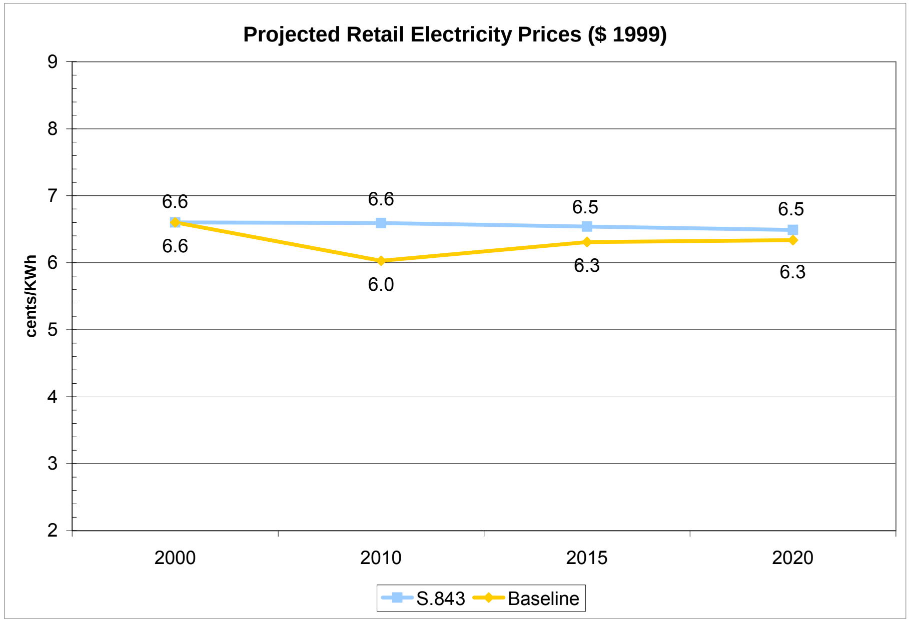
Average Emission Rates

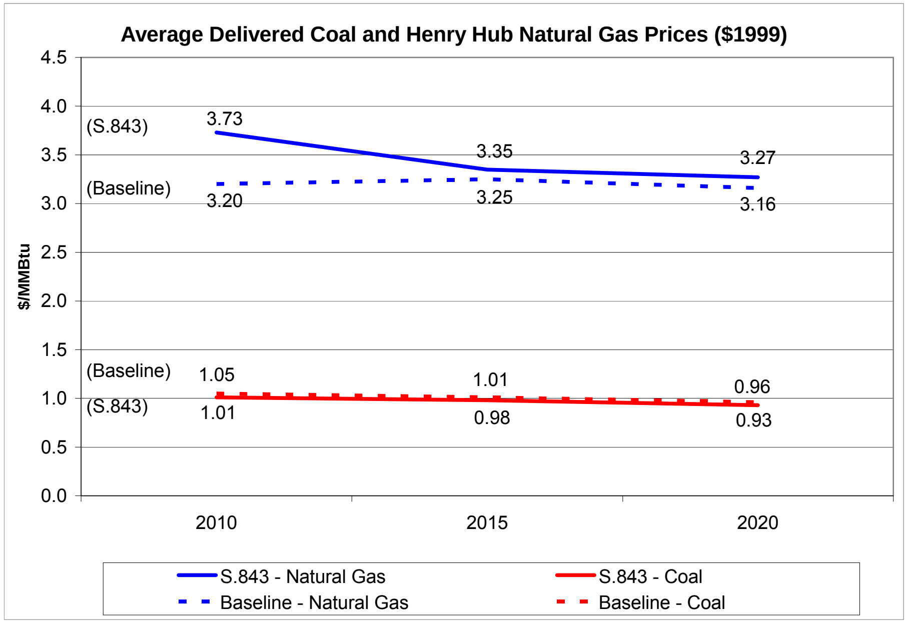
Average Emission Rates in lbs/MMBtu under the Clean Air Planning Act (Carper, S.843)				
	All Fossil Generation		Pulverized Coal	
	SO_2	NO_x	SO_2	NO_x
2010	0.28	0.14	0.38	0.17
2015	0.25	0.11	0.33	0.14
2020	0.21	0.11	0.29	0.13

Projected Total Generation Mix

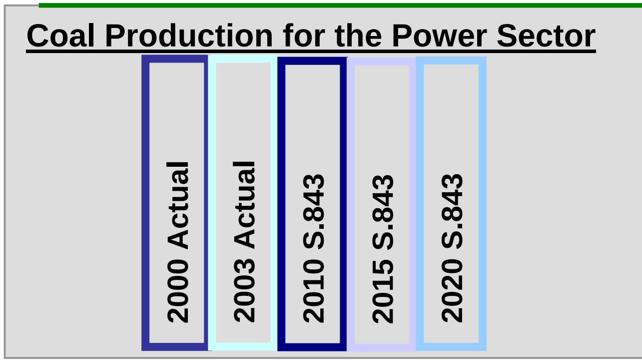


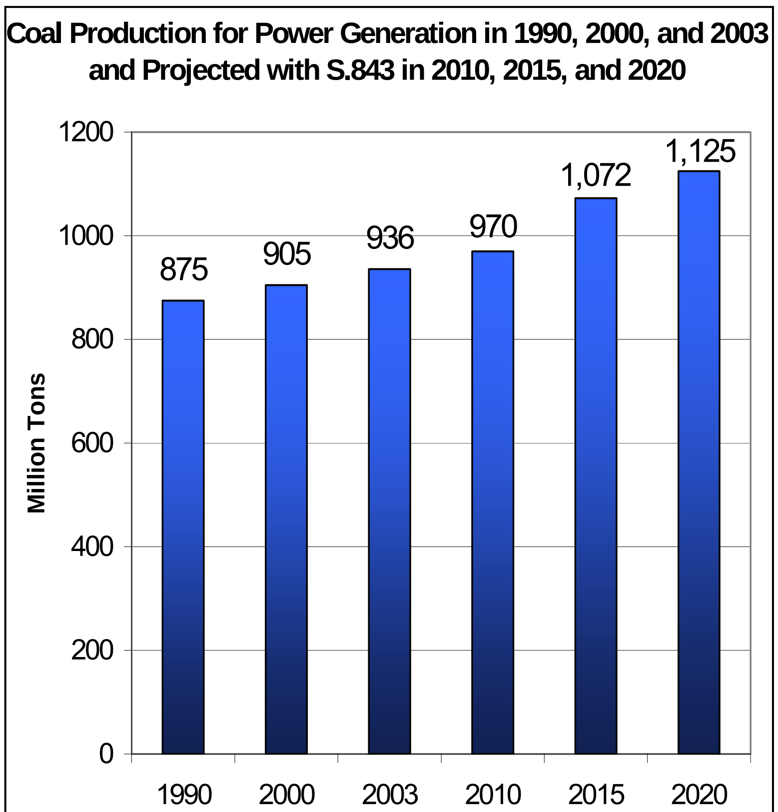
Impact on Electricity Prices and Fuel Prices

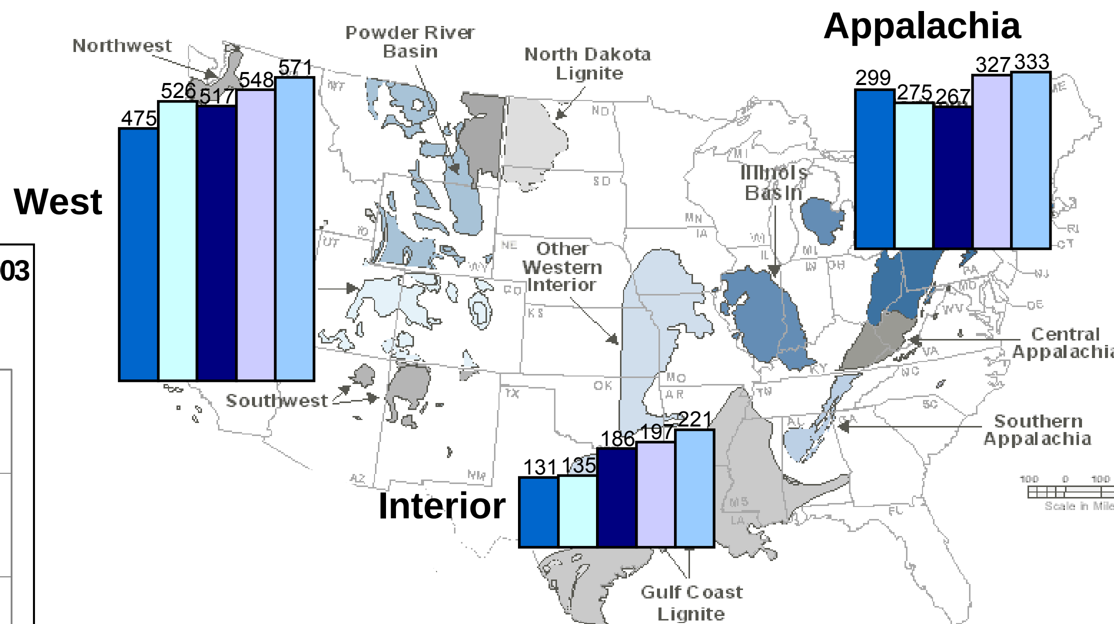




Coal Production for Electricity Generation (Historical and Projected) with the Clean Air Planning Act (Carper, S.843)







Notes: National coal production projections are EPA estimates from IPM. Historical data is from EIA.

Units Repowering or Uneconomic to Maintain Due to the Clean Air Planning Act (Carper, S.843)

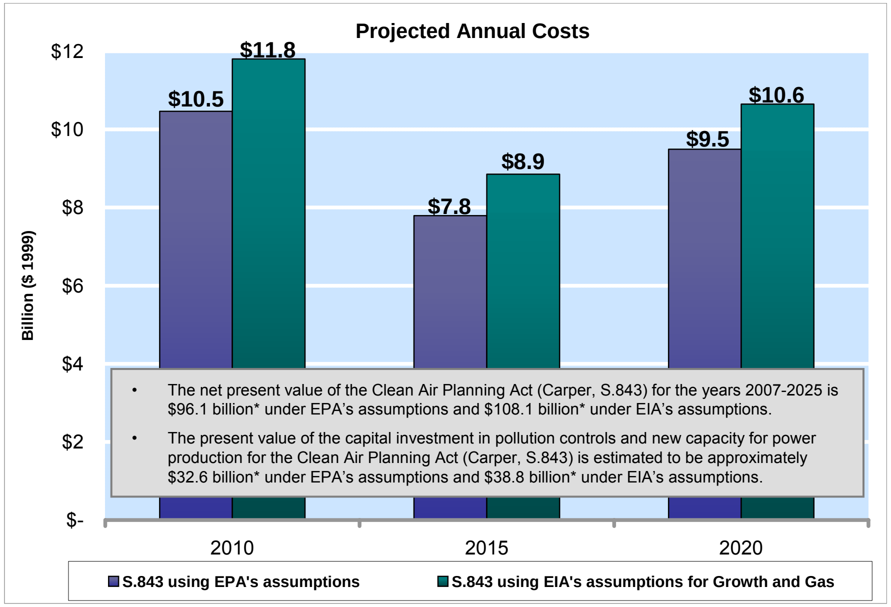
- "Repowering" converts coal units to combined cycle natural gas (CC) or IGCC and oil/gas units to combined cycle natural gas.
- The IPM model can determine that specific generating units are uneconomic to maintain, based on their fuel, operating and fixed costs, and whether they are needed to meet both demand and reliability reserve requirements.
- In practice, units projected as uneconomic to maintain may be "mothballed", actually retired, or kept in service to ensure transmission reliability in certain parts of the grid. Our modeling is unable to distinguish between these potential outcomes.
- The uneconomic coal units would be highly unlikely to retire if not for the recent overbuild of combined cycle capacity in many areas.

Units Re-Powering or Uneconomic to Maintain Due to S.843	
	GW
Coal Re-Powering	0.6
Uneconomic Pulverized Coal	9.6
Oil/Gas Re-Powering to CC	2.9
Uneconomic Oil/Gas Steam	-0.9*

*****Negative value indicates less uneconomic oil/gas steam than without the Clean Air Planning Act (Carper, S.843). Some plants that would have been profitable in the baseline (reference case) now are economically viable.

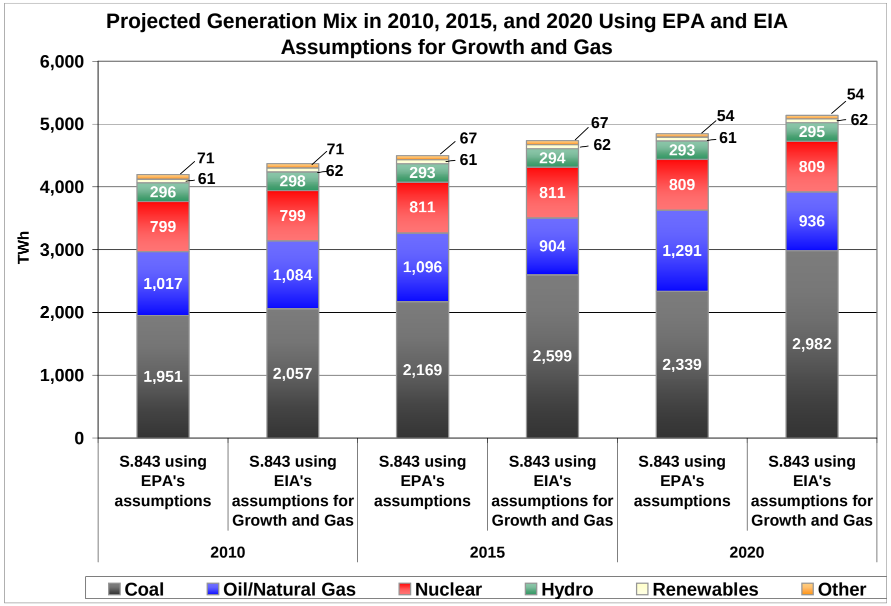
Section #6
Additional Analyses of Key Provisions and Modeling Assumptions

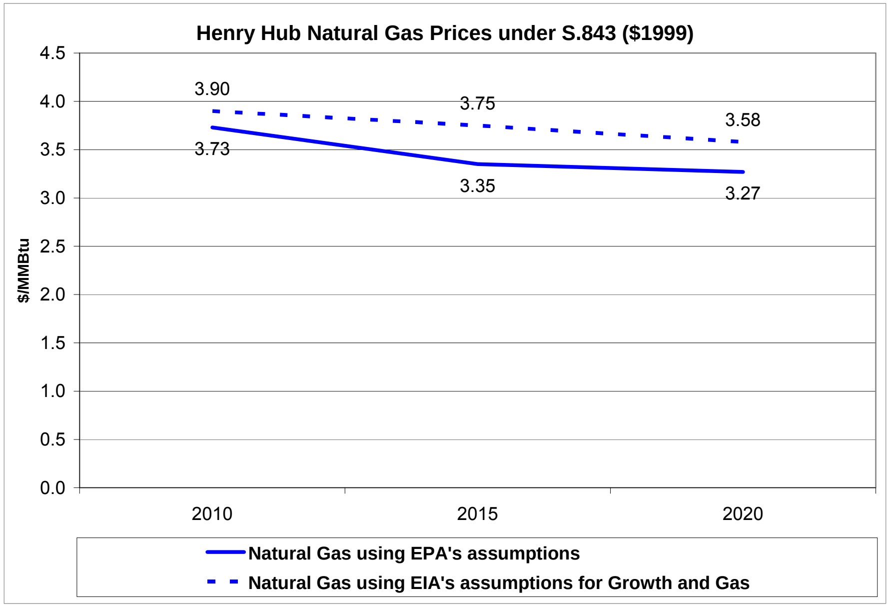
Effects of Assumptions for Natural Gas Prices and Electricity Growth



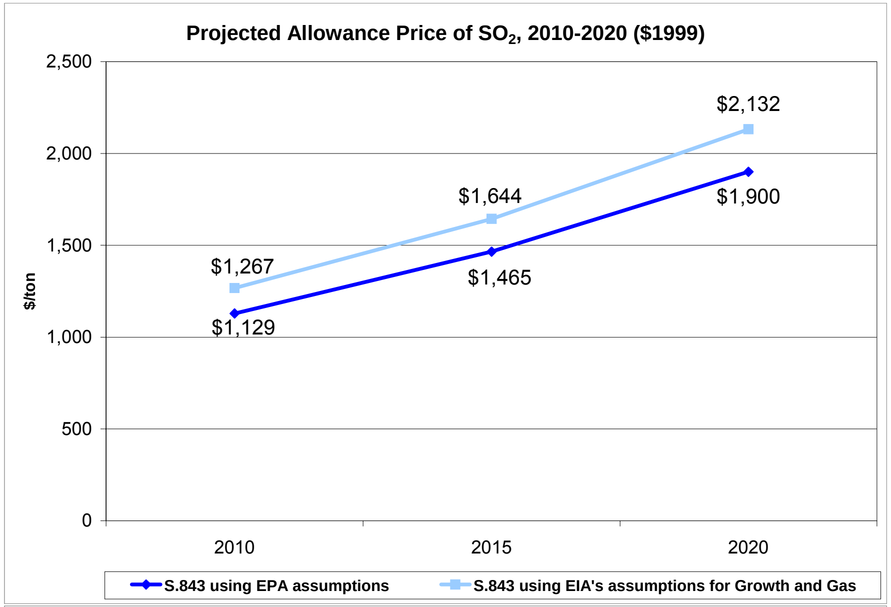
- Projected annual costs are higher when the model is run with the U.S. Energy information Administration's (EIA) natural gas and electricity growth assumptions. Assumptions lead to building much cleaner new coal-fired capacity that leads to similar overall cost by 2020.
- Coal-fired generation increases because of new capacity that is built to meet the higher demand.
- Natural gas prices are 5%-12% higher with EIA assumptions, depending on the year, and annual electricity growth is about 1.55% under EPA assumptions and 1.83% under EIA assumptions.

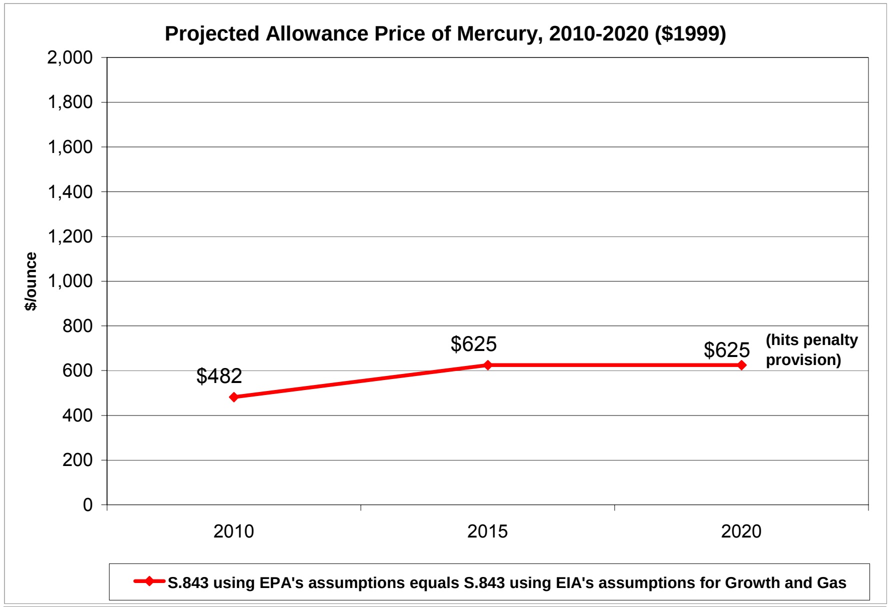
*Present value calculations are incremental to the baseline for the years 2007-2025 and are recorded in 1999 dollars.

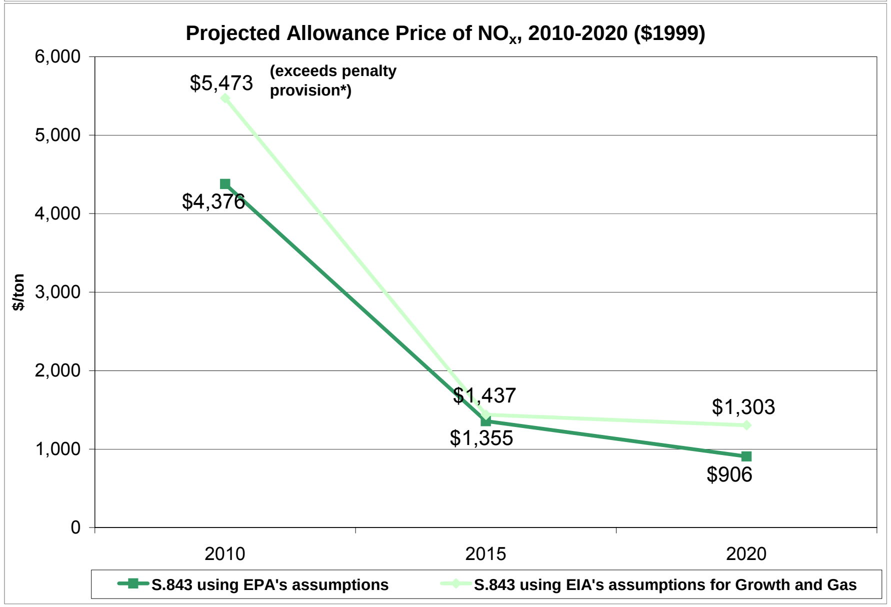


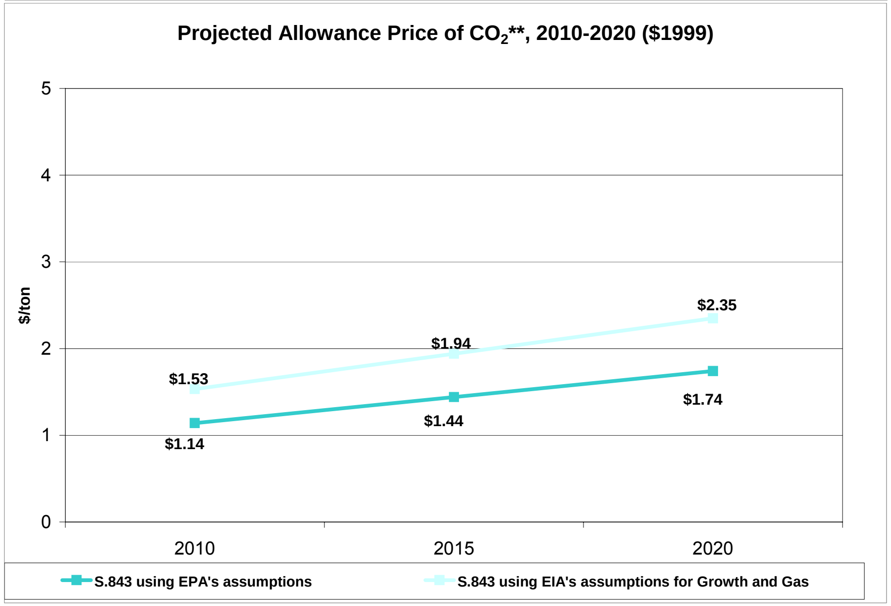


Effects of Assumptions for Natural Gas Prices and Electricity Growth on Allowance Prices





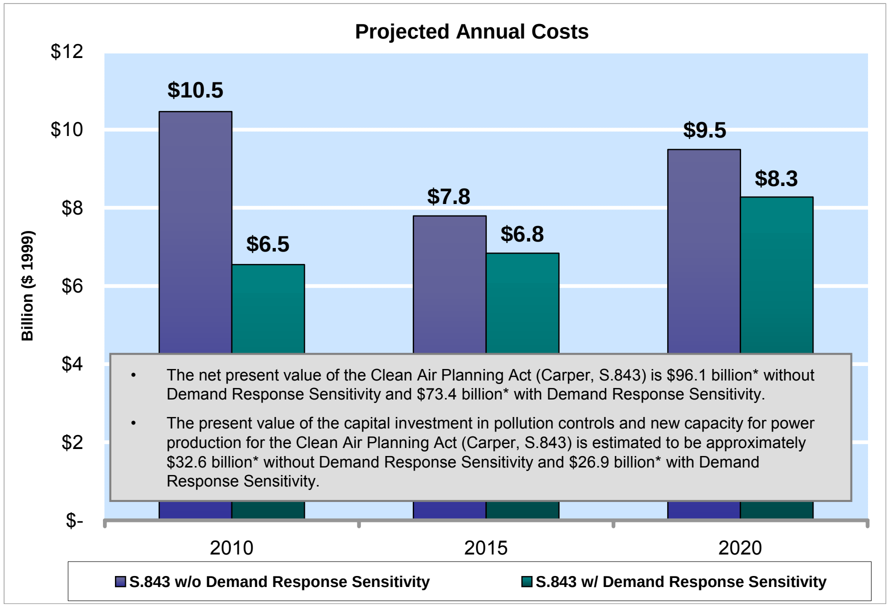




*In practice NO_x allowance prices for the Clean Air Planning Act (Carper, S.843) would not exceed the $5,000 penalty.

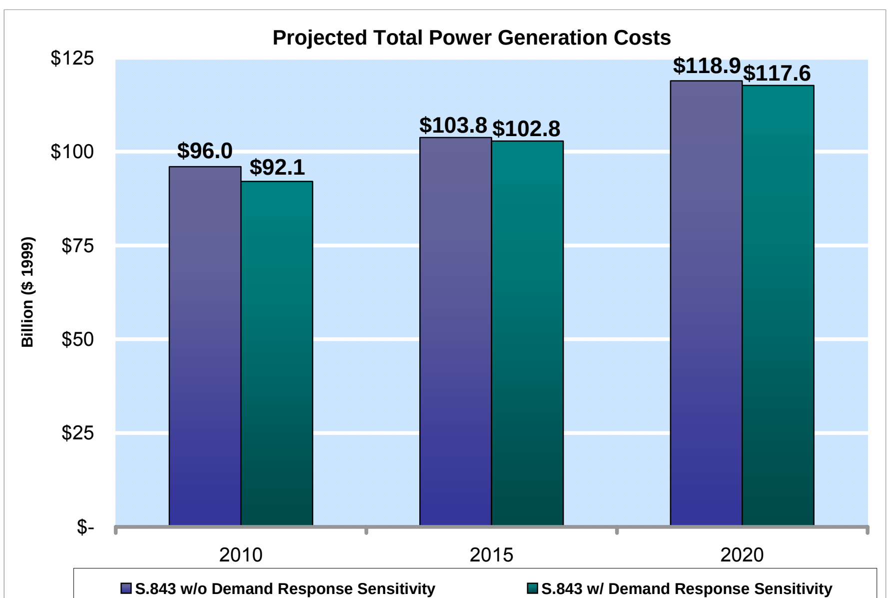
*CO_2 allowance prices are from the SGM-based analysis. For additional information regarding the cost of GHG offsets, see Section #6

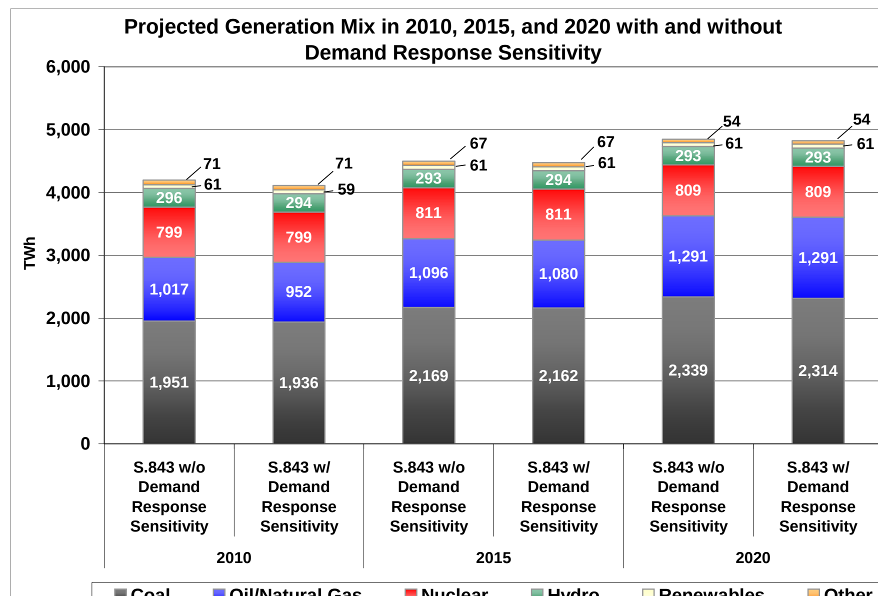
Effects of Demand Response



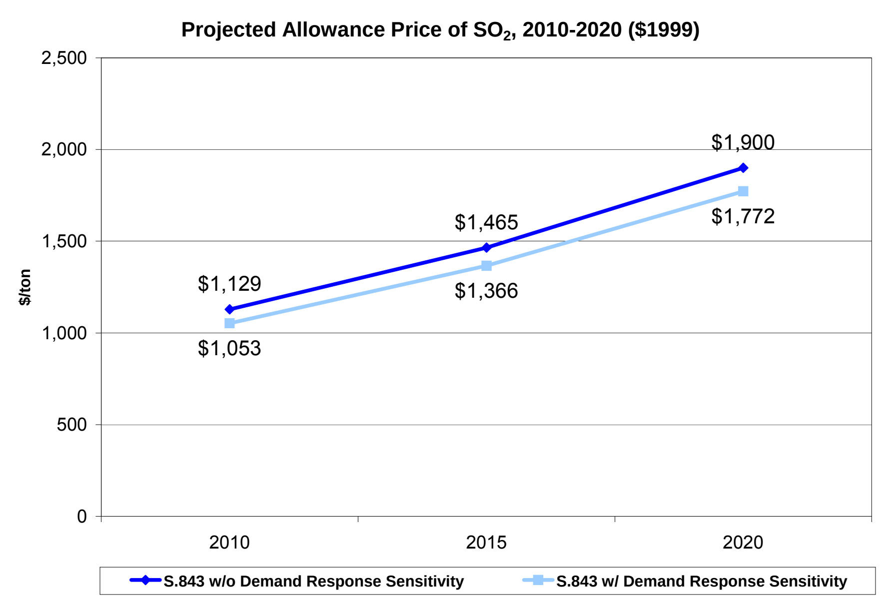
- EPA performed sensitivity analysis on the impact of higher prices on energy consumption (demand response). Demand response is characterized as the reduced consumption of a good as the price of that good rises. This relationship was directly included in EPA's power sector model as a sensitivity.
- Projected annual costs decrease when the model is run with Demand Response Sensitivity. Assumptions lead to reduced energy use and reduced overall cost.
- Both coal and gas-fired generation decrease slightly because of reduced demand.

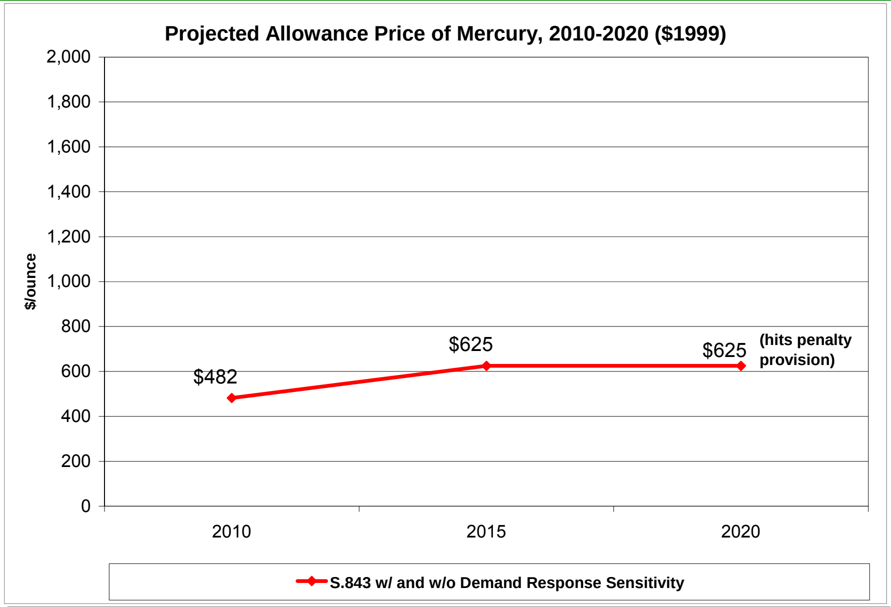
*Present value calculations are incremental to the baseline for the years 2007-2025 and are recorded in 1999 dollars.

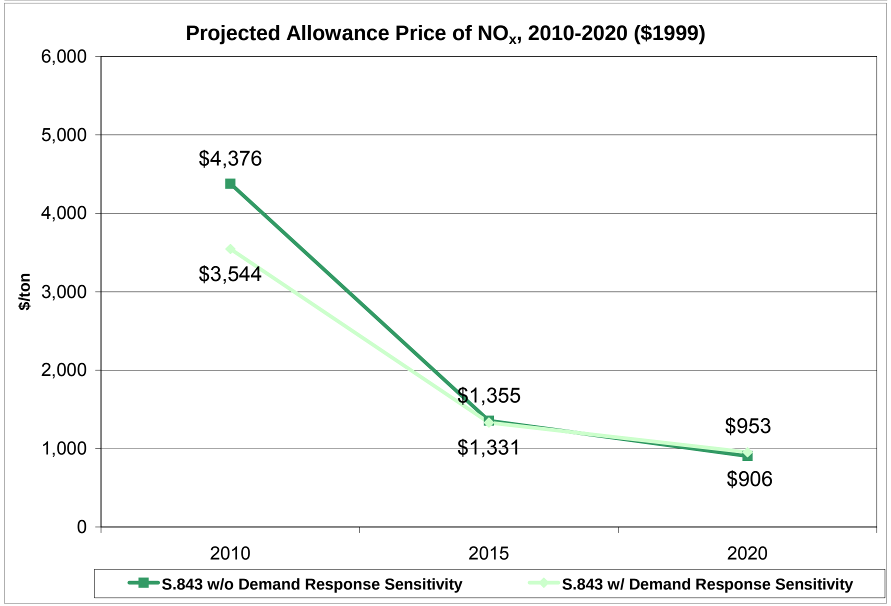


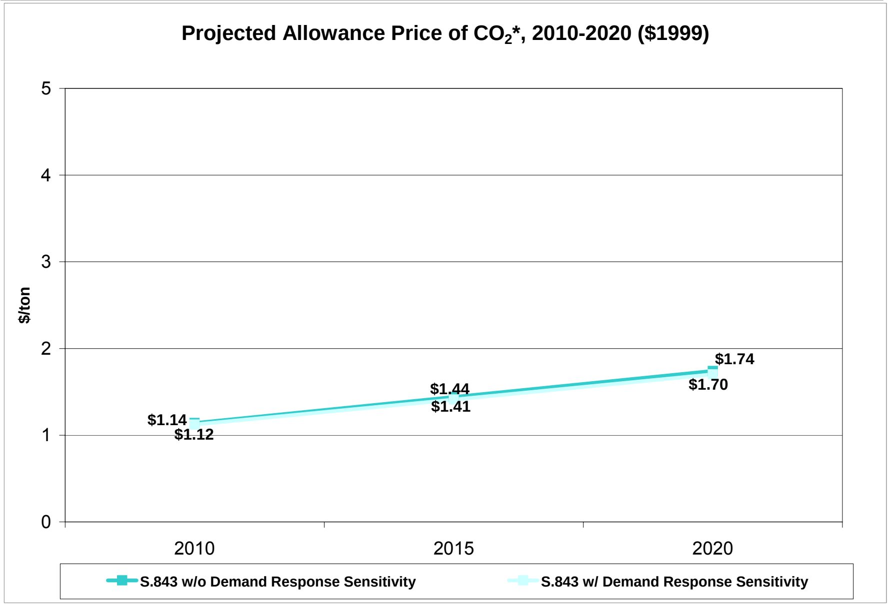


Effects of Demand Response on Allowance Prices





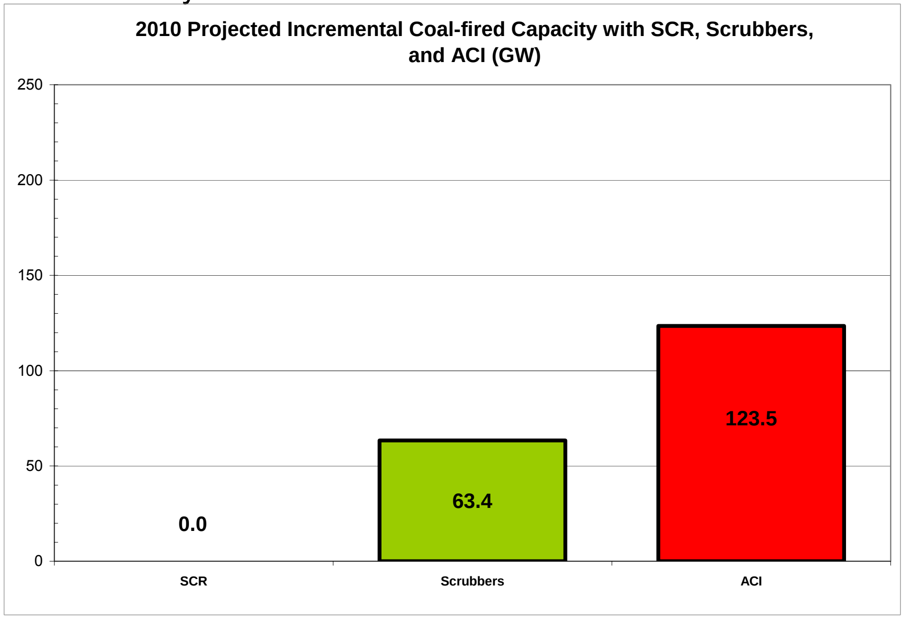


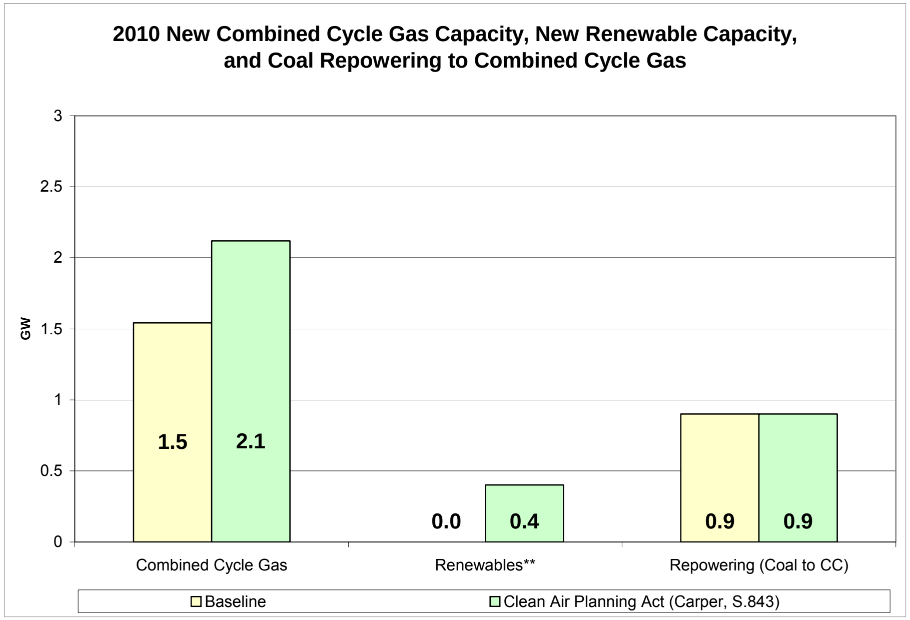


*CO_2 allowance prices are from the SGM-based analysis. For additional information regarding the cost of GHG offsets, see Section #6

Feasibility of Installing Equipment Necessary to Meet the First Phase Compliance Deadlines of the Clean Air Planning Act (Carper, S.843)

- EPA's analysis assumed constraints on installation of SCR and flue gas desulfurization (scrubbers). The analysis did not consider constraints on ACI, new combined cycle gas required to meet various caps, and renewables.
- In this analysis, EPA assumes that ACI leads to the removal of 50%-90% of mercury in coal. Initially, the Agency assumes 50% removal (this is assumed because it is the minimum level needed to achieve the source specific requirements of the Clean Air Planning Act (Carper, S.843), it does not imply that EPA has examined the availability of the technology at this level*) and then increasing levels in later parts of the analysis.
- EPA does not believe that it would be possible to manage the installation of over 100 GW of ACI at any level of mercury removal in addition to the substantial amounts of scrubbers needed to comply with the Clean Air Planning Act (Carper, S.843) by 2010.
- Alternatives to installation of ACI, such as switching to newly built gas-fired capacity (which occurs to a limited extent), would substantially increase costs of complying with the Clean Air Planning Act (Carper, S.843) and would raise similar feasibility concerns.

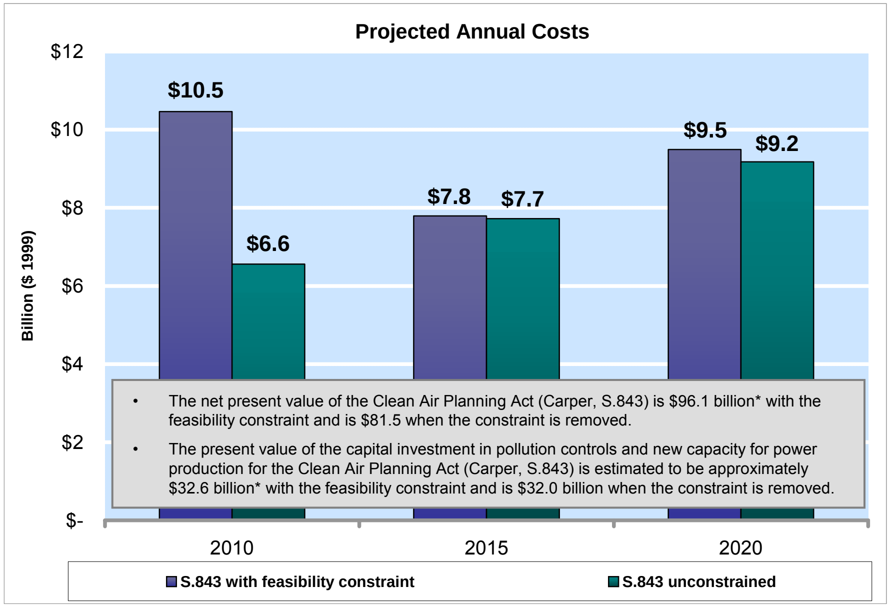




*For further discussion of mercury technology, see EPA's Office of Research and Development (ORD) Control of Emissions from Coal Fired Electric Boilers, an Update – March 2005

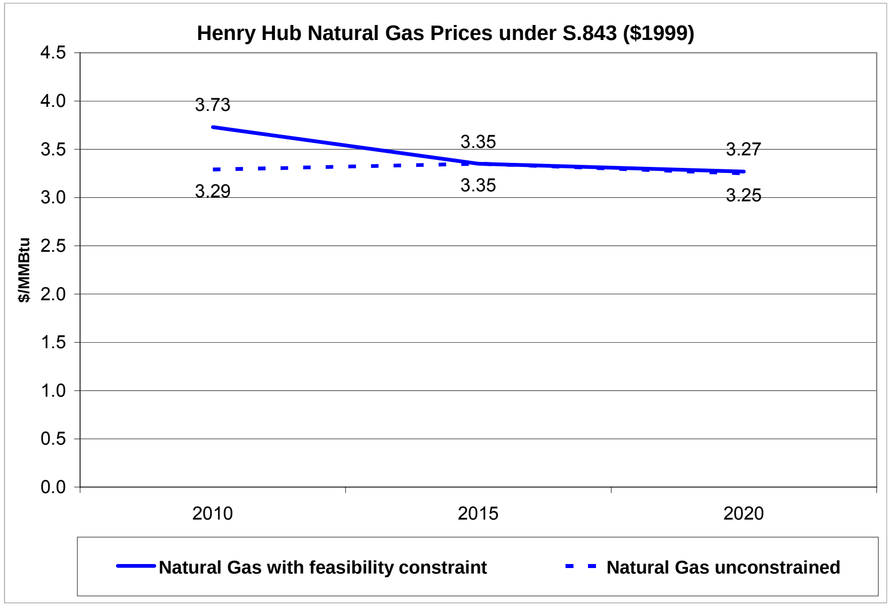
**"Renewables" include wind, biomass, geothermal, and landfill gas.

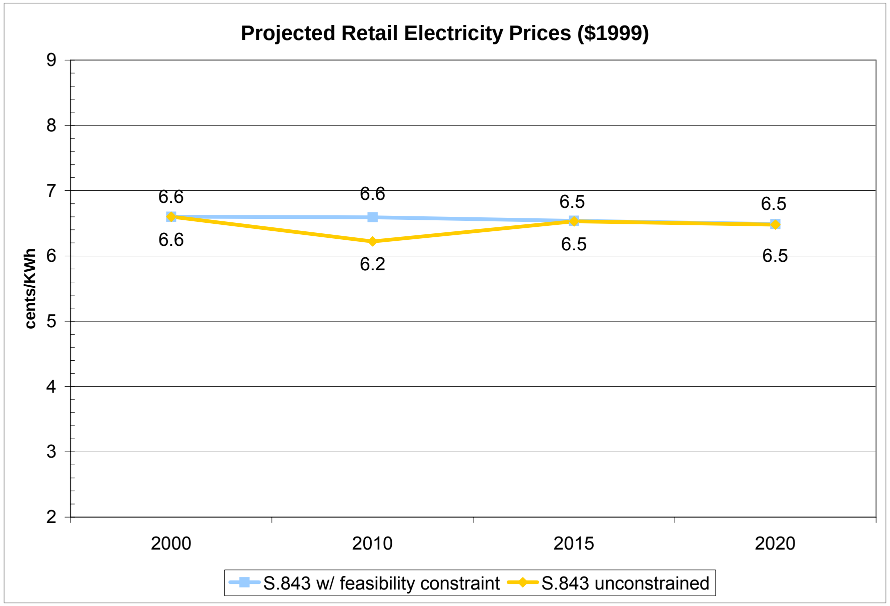
Sensitivity Analysis of Short-term Feasibility Constraint



- While EPA believes there are constraints to the amount of emission control equipment and new generation that can be built by 2010, this sensitivity provides insight into the impacts that constraints on installing technology can have.
- Without the constraint, there would be an additional 35.6 GW of SCR and 36.1 GW of scrubbers in 2010.
- 2010 cost, gas price, and electricity price substantially decline if there is no constraint on the ability to install controls and new generation.
- This sensitivity also gives some sense of the value of reconsidering the shorter-term approach to cap levels and timing to account for labor and engineering uncertainties and challenges.

*Present value calculations are for the years 2007-2025 and are recorded in 1999 dollars.





Analysis of Greenhouse Gas Provisions of the Clean Air Planning Act (Carper, S.843)

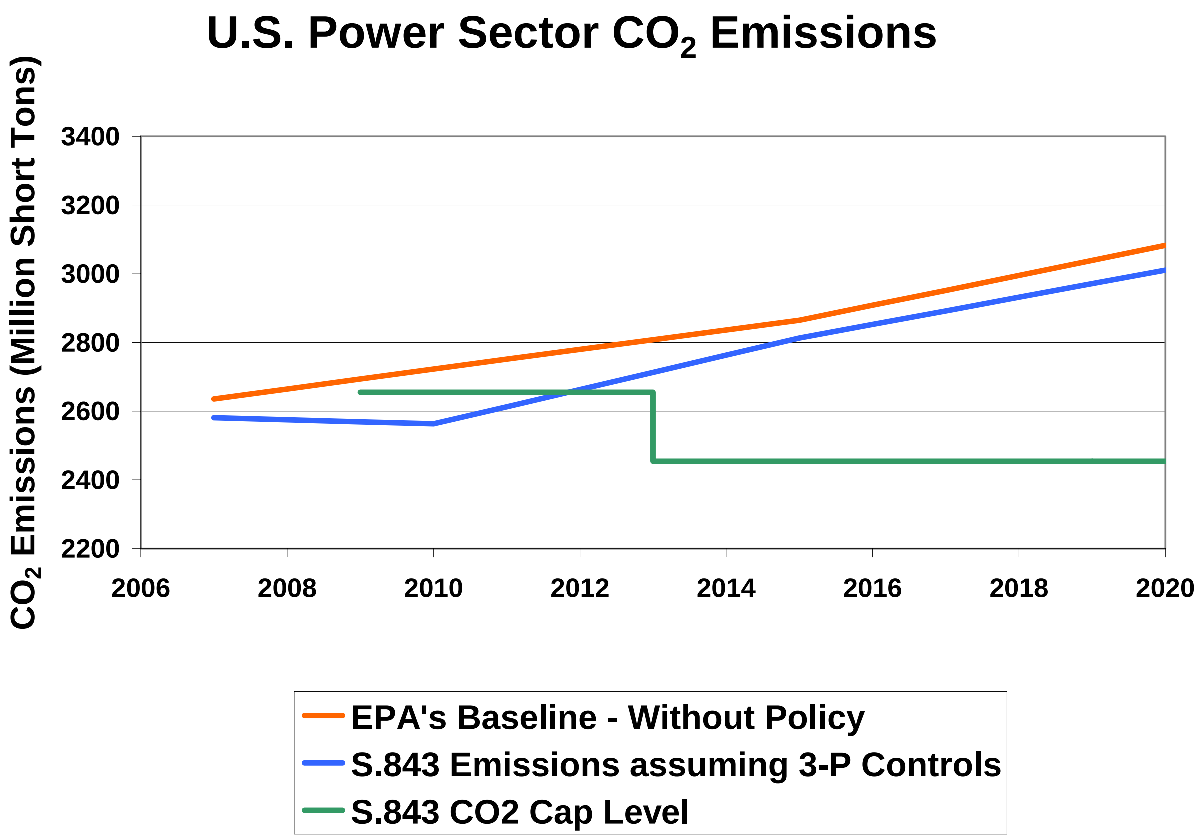
Introduction

- This analysis shows that most greenhouse gas (GHG) emission reductions due to the Clean Air Planning Act (Carper, S.843) would come from emission reductions projects ("offsets") in uncapped sources outside of the power sector.
- Sources may acquire allowances to comply with the CO_2 reduction requirement of the Clean Air Planning Act (Carper, S.843) through GHG emission reduction projects in any sector, in any region of the world.

Assumptions

- **Offset Program Effectiveness:** CO_2 offset prices are highly dependent on the design of the offset program. Public awareness of the program, the complexity of the requirements, and the effectiveness of the approval process all influence offset prices. The Clean Air Planning Act (Carper, S.843) leaves design decisions to the Administrator and an Independent Review Board. This analysis uses a methodology similar to the methodology used in EPA's 2001 analysis for Smith, Voinovich, and Brownback.
- **International Demand for Offsets:** Because the Clean Air Planning Act (Carper, S.843) allows U.S. affected sources to generate additional allowances by investing in projects in other countries, they will compete for project opportunities with Annex B parties to the Kyoto Protocol.
  - The most likely scenario assumes that Kyoto parties do not agree to targets post 2012. The EU Emission Trading System remains in place and EU countries acquire offsets outside of the EU through offsets projects
  - A sensitivity case assumes that the Kyoto parties maintain their emission reduction targets at currently agreed levels past the first commitment period
- **Transactions Costs:** Certain "deal-making costs" are incurred in the purchase of offsets. These include search costs, attorney fees, insurance costs, emissions monitoring, approval costs, etc. Transactions costs would add to the costs of offsets. There is little experience with a functioning GHG offsets program and the resulting transactions costs, but research suggests an average of \$0.33 per short ton of CO_2 (~\$0.40 per metric ton of CO_2 equivalent).

Required Offsets under the Clean Air Planning Act (Carper, S.843)



- The S.843 CO_2 projection of emission levels assuming controls for SO_2, NO_x and Hg is lower than EPA's Baseline due to co-benefits.
- The S.843 2009-2012 cap level is the AEO 2005 projection for emissions in 2006. The cap after 2012 is set at 2001 emissions levels.
- The number of offsets required in a given year is the difference between the S.843 emissions assuming 3-P controls and the S.843 cap level.
- There is no binding offset requirement in 2010, but offsets equivalent to 557 million short tons of CO_2 would be required by 2020.
- Sources will overcomply in 2010 and bank allowances for later use.

Notes:

1) S.843 allows "early reduction credits" of up to ten percent of 2009 cap level (early credits total 268 million short tons). These allowances are assumed to be used between 2010 and 2020.

2) S.3135 (the Clean Air Planning Act of 2002) expresses the CO_2 constraint in terms of "short tons of CO_2." One million short tons of CO_2 is equivalent to 0.25 million metric tons of carbon and 0.91 million metric tons of CO_2.

Clean Air Planning Act (Carper, S.843) Offsets Analysis: Results[1]

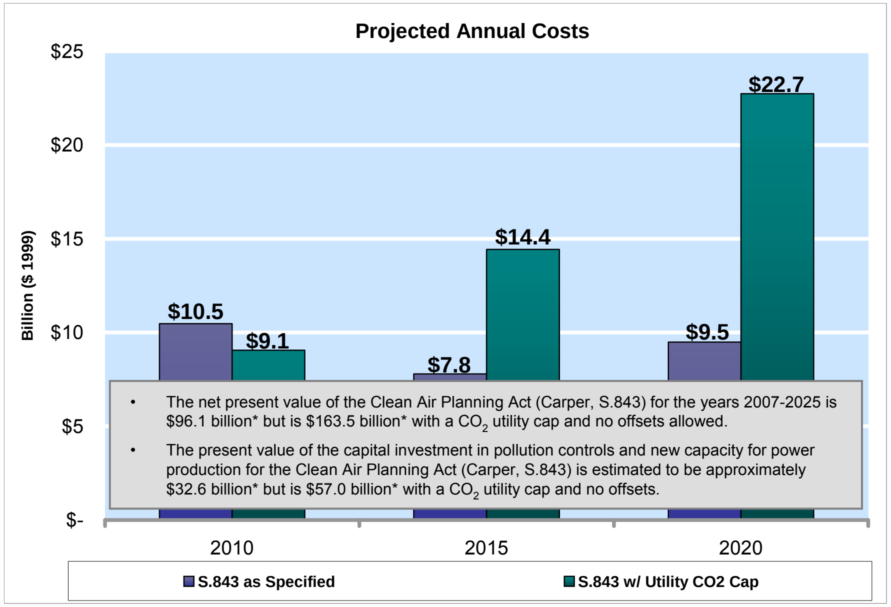
Scenario: Kyoto ends in 2012, EU Caps Continue[2]	2010	2015	2020
U.S. Emission Reduction Required (MSTCO_2E)	0	278	557
Kyoto Region Emission Reduction (MSTCO_2E)	267	366	465
Price of Allowances (1999/STCO_2E) (*Range)*	1.14 *(1.12 – 1.56*)	1.44 *(1.40–1.98)*	1.74 (*1.68-2.39*)
Total Cost (Million 1999$) (*Range)*	308 *(308 – 479)*	771 *(725 -1,053)*	1,233 (*1,143-1,627*)

[1] Other analyses which do not model, for example, voluntary programs, non-CO_2 or forestry abatement options, will likely find higher prices and abatement costs.

[2] The following table shows the results of the sensitivity analysis which assumes the Kyoto Region maintains its commitments through 2020. The U.S. emission reduction required would be the same, but the additional demand raises prices and total costs.

Sensitivity Case: Kyoto through 2020	**2010**	**2015**	**2020**
Kyoto Region Emission Reduction (MSTCO_2E)	602	724	845
Price of Allowances (1999$/ST$CO_2$E) (*Range)*	1.52 *(1.51 – 2.12*)	1.92 *(1.90–2.71)*	2.33 (*2.31-3.30*)
Total Cost (Million 1999$) (*Range)*	570 *(570 – 947)*	1,791 *(1,724 - 2,501)*	3,012 (*2,879-4,054*)

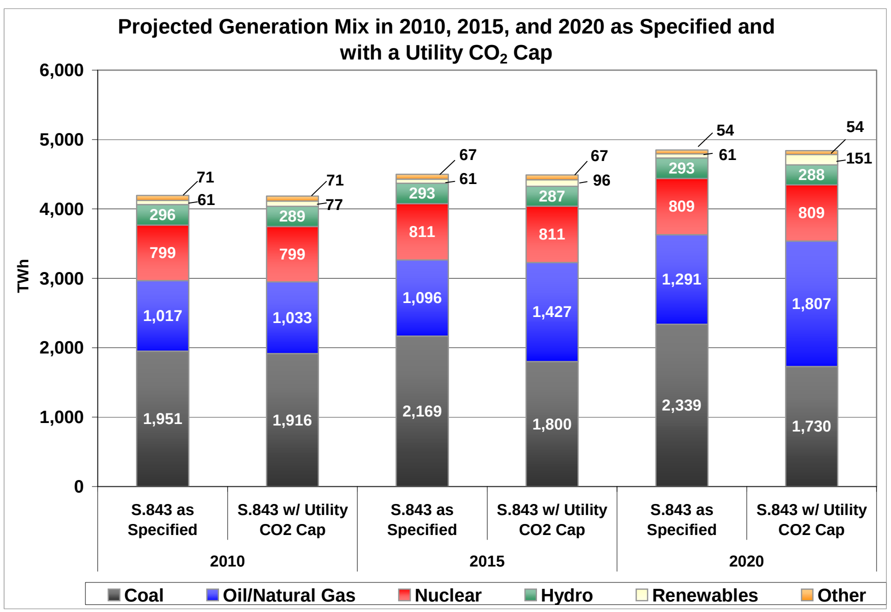
Sensitivity Analysis of CO_2 Requirements for the Clean Air Planning Act (Carper, S.843)

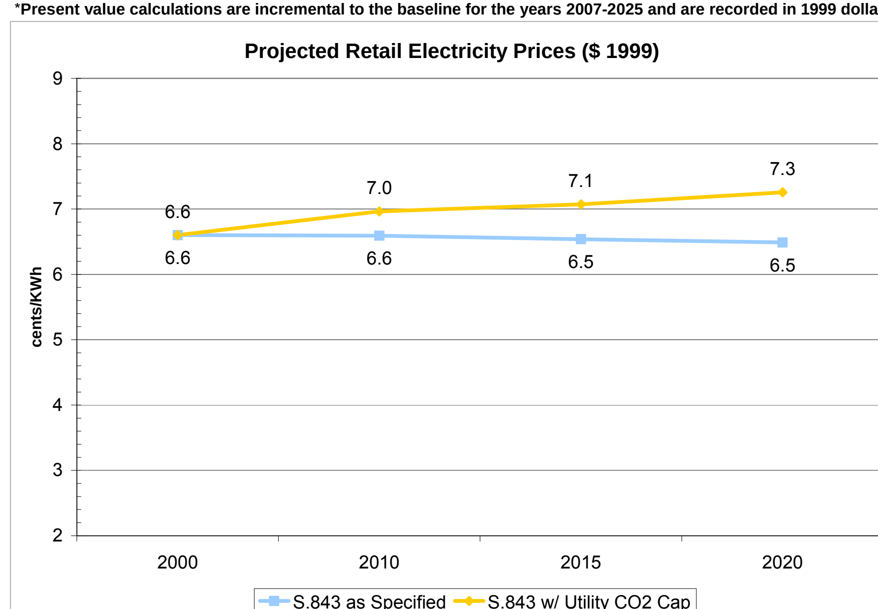


The Clean Air Planning Act (Carper, S.843) allows for the use of international offsets, an efficient way to lower greenhouse gas emissions. EPA performed a sensitivity analysis to determine the impacts if the Act did not contain this provision, but instead required reductions only through CO_2 reductions within the power sector (without offsets).

- Projected annual costs would be lower in 2010 and much higher in 2015 and 2020 if all CO_2 reductions were required to be achieved through the power sector. Sources would install fewer scrubbers in 2010 and rely on fuel-switching to meet the caps in later years.
- Coal-fired generation would decrease and gas-fired generation and renewables would increase markedly starting in 2015 as sources switch fuels to meet the CO_2 requirements.
- Electricity prices would be 6%-12% higher, depending on the year.

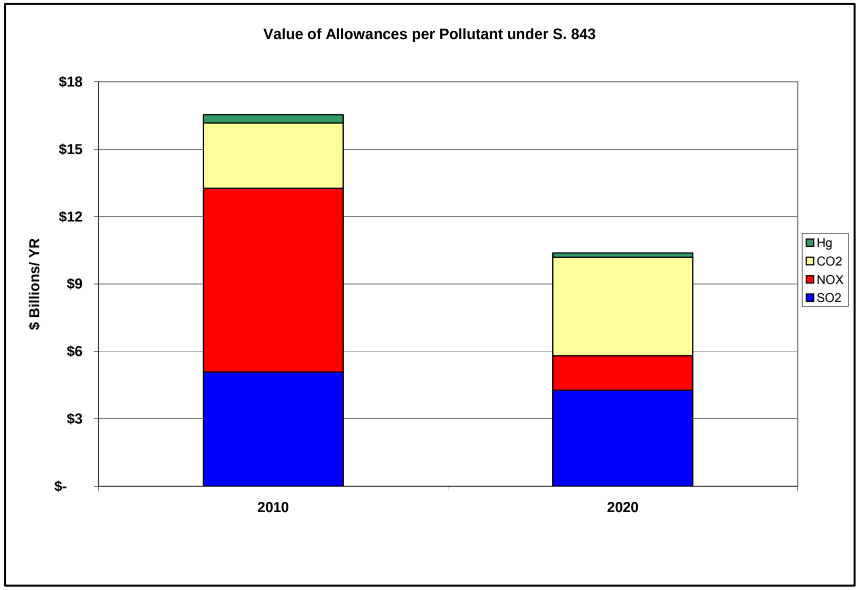
*Present value calculations are incremental to the baseline for the years 2007-2025 and are recorded in 1999 dollars.

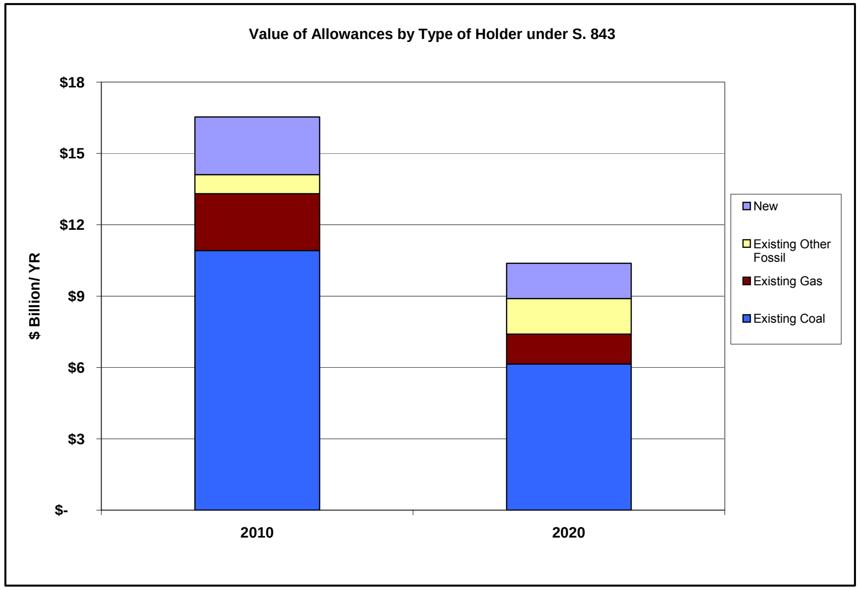


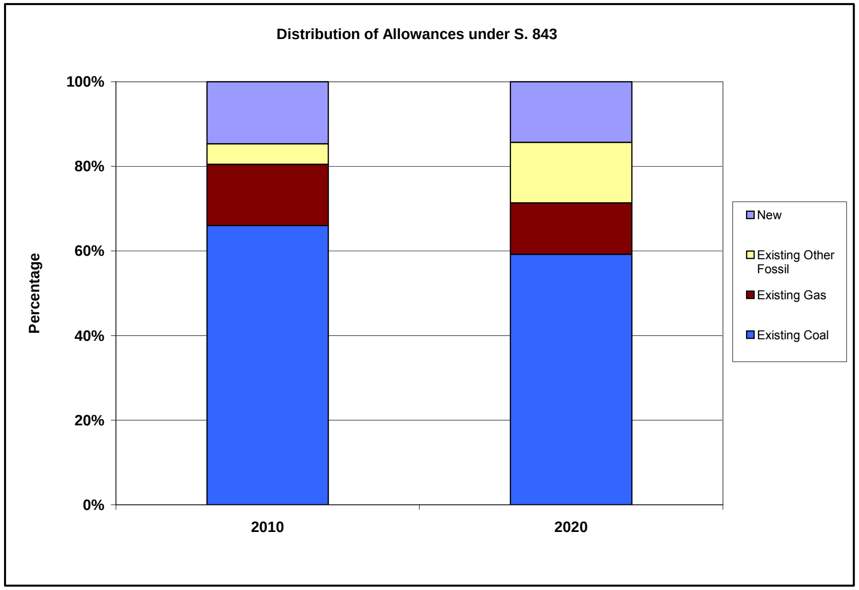


Allocations – Value of Allowances ($1999)

- Allocations for SO_2 based on existing Acid Rain Program Allowances with adjustments to provide for new and existing units that did not receive allocations under Title IV.
- NO_x and Hg allowances allocated using an updating, output-based system, with a set-aside for new units.
    - Allocation to existing units based on generation during most recent 3-year period.
    - New units are allocated allowances based on projected emissions.
- **Effects of updating:** The incentives created by updating allowance allocations using generation can lead to increased electricity supply, reduced electricity prices, lower electricity revenues, and increased compliance costs. The impacts of these incentives were estimated separately, and discussed on page 52. Results on pages 50 and 51 do not account for these impacts.

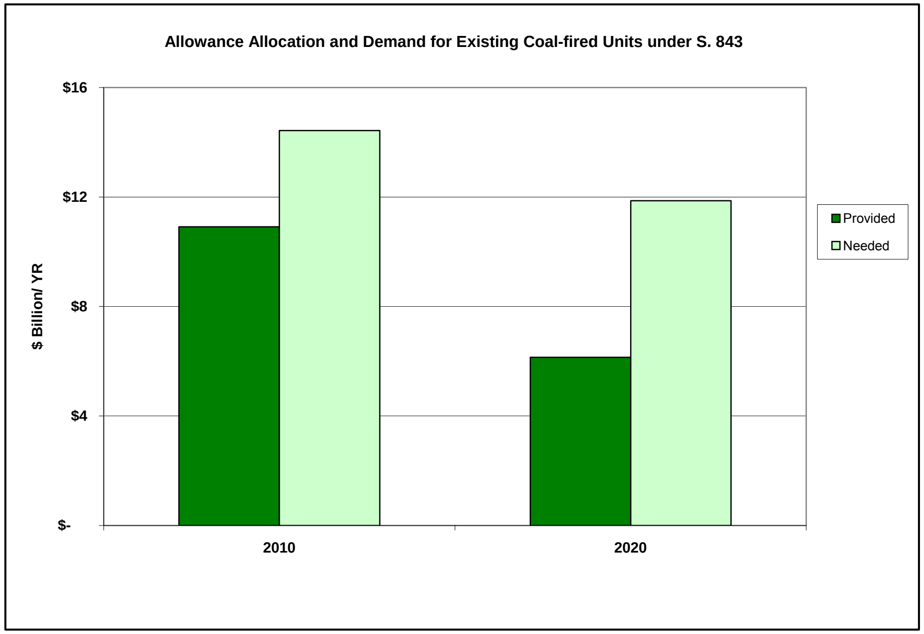


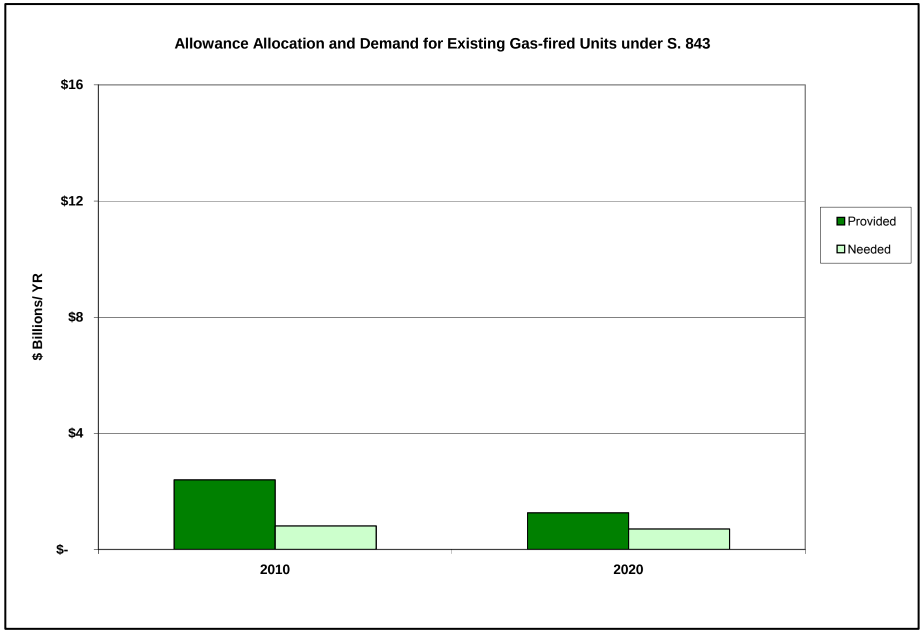




Allocations – Impact on Existing Coal and Gas ($1999)

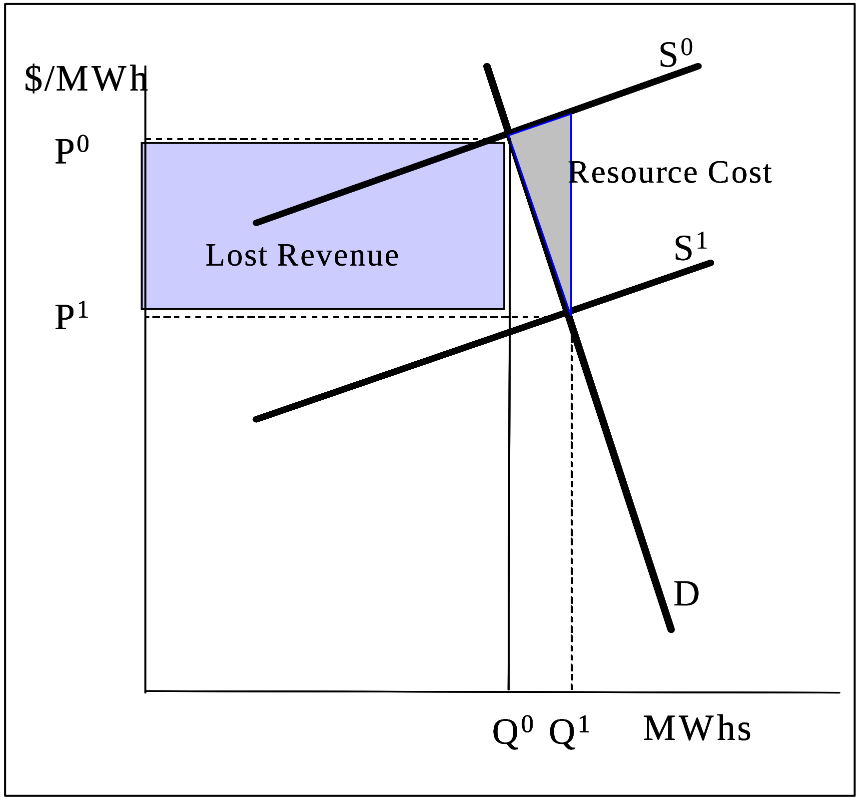
- Updating allocation methodology causes distribution of allowances to change between 2010 and 2020 to reflect changes in the generation profile.
- Total net cost of allowances for existing coal units increases by 2020.
- Existing gas units, in aggregate, have a surplus of allowances, which decreases in value between 2010 and 2020.





Allocations – Impact of Updating

- Updating allocations using generation data can create an incentive for sources to increase their electricity production, shifting the electricity supply curve (S), down.
- Change in electricity price results in revenue loss on initial supply (P^0 - P^1). This same area represents a savings to electricity consumers.
- Increased generation results in increased resource cost of compliance with caps.
- Can result in overall efficiency loss to society.
- EPA estimated the present value of this efficiency loss over the years 2007 through 2014 (which reflect allocations through 2020) of $58 million.
- EPA estimates increased electricity production of about 14,000 GWh in 2010. The corresponding movement along the demand curve would partially offset the projected demand response of -84,000 GWh that results from increased electricity prices under the bill.[1]



[1] Demand response projections are discussed on pages 42 and 43.

Section #7
Appendix and Notes

Supplemental Materials – State Emissions and Electricity Prices under the Clean Air Planning Act (Carper, S.843)

State Projections for the Clean Air Planning Act (Carper, S.843)

		2003 Power Sector Emissions (thousand tons)		Fossil-Fuel Fired Power Generation Emissions with the Clean Air Planning Act (Carper, S.843)[1]															Average Retail Electricity Prices (mills/kWh, $1999)**			
				Clean Air Planning Act (Carper, S.843)															Historical	Clean Air Planning Act (Carper, S.843)		
	IPM Region			SO_2 (thousand tons)			Ozone Season NO_x (thousand tons)			Annual NO_x (thousand tons)			Hg (tons)[2]			CO_2 (million short tons)						
		SO_2	NO_x	2010	2015	2020	2010	2015	2020	2010	2015	2020	2010	2015	2020	2010	2015	2020	2000	2010	2015	2020
Alabama	STV	458.6	155.1	118.3	133.6	121.8	22.4	21.2	20.7	47.9	46.4	43.7	0.4	0.4	0.3	82.6	98.9	104.3	59.3	60.1	57.3	57.2
Arizona	RM	69.4	82.6	60.3	54.6	52.6	26.4	26.7	27.2	60.0	60.4	61.5	0.5	0.3	0.3	69.1	70.7	78.8	64.1	66.9	66.4	65.5
Arkansas	STV	73.0	41.7	82.4	82.4	82.6	14.2	14.3	14.4	31.8	32.0	32.3	0.4	0.3	0.3	41.7	41.9	43.5	59.3	60.1	57.3	57.2
California	CALI	0.2	9.6	5.1	5.1	5.1	7.9	9.3	10.4	17.9	21.1	23.4	0.1	0.1	0.1	55.8	75.9	90.5	94.7	97.2	99.1	99.8
Colorado	RM	73.1	71.9	87.7	73.1	70.5	20.1	20.5	20.8	46.2	46.6	47.0	0.2	0.2	0.2	42.7	43.6	44.6	64.1	66.9	66.4	65.5
Connecticut	NE	8.1	4.9	1.2	3.0	3.5	2.3	2.2	1.9	5.4	5.5	5.0	0.0	0.0	0.0	6.4	8.4	9.7	89.9	84.2	84.7	83.5
Delaware	MAAC	37.4	10.3	6.9	7.8	7.1	1.5	2.8	3.0	3.4	6.5	6.7	0.1	0.2	0.2	4.5	7.0	7.2	80.4	70.6	73.2	73.2
District of Columbia*	MAAC	0.3	0.1	0.0	0.0	0.6	0.0	0.0	0.2	0.0	0.1	0.4	0.0	0.0	0.0	0.0	0.1	1.2	80.4	70.6	73.2	73.2
Florida	FRCC	475.3	252.6	128.6	128.9	119.0	52.6	27.0	25.7	111.4	55.7	53.2	0.8	0.4	0.4	120.9	129.3	136.3	67.9	74.3	72.9	71.0
Georgia	STV	540.7	104.4	164.5	155.6	157.6	26.9	29.1	28.8	58.9	61.9	63.2	0.7	0.6	0.5	99.1	117.3	131.9	59.3	60.1	57.3	57.2
Idaho	PNW	0.0	0.1	0.0	0.0	0.0	0.3	0.3	0.3	0.6	0.6	0.6	0.0	0.0	0.0	1.3	1.3	1.4	45.9	50.8	47.9	47.3
Illinois	MAIN	365.3	145.9	226.4	227.8	214.5	31.5	29.9	28.9	69.8	66.6	65.0	1.0	0.7	0.7	114.6	119.7	120.1	61.2	60.9	61.6	63.2
Indiana	ECAR	804.8	261.5	298.4	296.9	284.9	55.1	31.1	30.1	125.2	71.4	69.7	1.3	0.8	0.8	145.6	152.9	157.7	57.4	60.3	59.8	58.2
Iowa	MAPP	131.8	76.4	152.5	149.9	153.1	20.9	21.5	23.1	48.3	50.6	52.4	0.6	0.4	0.4	47.2	48.2	50.8	57.4	54.1	50.5	49.0
Kansas	SPP	141.0	94.1	61.1	60.1	58.5	14.8	14.9	15.0	33.2	33.7	33.6	0.6	0.4	0.4	45.0	45.6	46.5	59.3	58.7	58.4	58.0
Kentucky	ECAR	529.7	185.4	219.8	216.6	160.2	44.9	31.9	31.4	101.6	72.7	71.3	0.9	0.6	0.5	113.6	113.9	116.8	57.4	60.3	59.8	58.2
Louisiana	STV	104.9	68.7	62.0	62.0	62.4	16.6	16.2	16.7	36.8	36.0	37.0	0.3	0.2	0.2	43.1	39.4	44.4	59.3	60.1	57.3	57.2
Maine	NE	4.8	1.9	4.1	3.9	3.1	0.8	0.7	0.7	1.8	1.7	1.6	0.0	0.0	0.0	2.8	3.1	3.6	89.9	84.2	84.7	83.5
Maryland	MAAC	269.0	68.4	36.8	23.8	30.9	6.1	6.1	7.6	12.3	12.9	16.6	0.3	0.2	0.3	34.8	38.3	51.7	80.4	70.6	73.2	73.2
Massachusetts	NE	85.6	24.4	13.1	12.2	10.6	8.0	5.4	5.1	18.5	12.8	12.0	0.2	0.1	0.2	28.0	28.2	30.2	89.9	84.2	84.7	83.5
Michigan	ECAR	350.8	118.8	289.3	286.9	247.6	30.0	33.7	33.5	70.0	79.1	77.6	0.8	0.5	0.5	83.7	95.9	111.8	57.4	60.3	59.8	58.2
Minnesota	MAPP	111.5	89.6	68.6	69.9	70.1	16.6	17.4	17.8	37.4	39.6	39.9	0.4	0.3	0.3	38.8	39.5	40.1	57.4	54.1	50.5	49.0
Mississippi	STV	80.8	46.6	12.5	21.8	20.7	4.9	5.7	6.2	9.7	12.2	13.1	0.0	0.1	0.1	18.6	28.1	32.3	59.3	60.1	57.3	57.2
Missouri[3]	MAIN	257.0	144.8	212.8	213.7	210.5	25.8	28.5	29.1	58.0	65.2	65.3	0.9	0.7	0.7	76.1	88.1	90.0	61.2	60.9	61.6	63.2
Montana	RM	20.4	36.9	17.8	16.9	18.1	7.0	7.0	7.1	15.9	15.9	16.0	0.2	0.1	0.1	19.9	19.9	20.1	64.1	66.9	66.4	65.5
Nebraska	MAPP	67.7	49.6	69.3	69.6	67.3	14.2	14.5	14.5	32.1	32.9	32.7	0.3	0.2	0.2	25.5	26.5	26.3	57.4	54.1	50.5	49.0
Nevada	RM	51.5	42.1	27.0	27.0	25.8	10.9	9.1	9.2	24.4	20.6	20.8	0.2	0.1	0.1	28.4	28.6	30.8	64.1	66.9	66.4	65.5
New Hampshire	NE	54.7	8.9	1.4	1.4	1.8	0.8	0.8	0.8	1.7	1.8	1.9	0.0	0.0	0.0	7.5	8.1	9.4	89.9	84.2	84.7	83.5
New Jersey	MAAC	50.7	23.5	21.7	18.0	14.1	5.3	5.0	4.5	12.3	10.9	9.7	0.2	0.2	0.1	24.2	21.6	22.0	80.4	70.6	73.2	73.2
New Mexico	RM	50.8	77.2	52.9	52.9	51.7	10.2	10.2	10.0	22.7	22.7	22.2	0.4	0.3	0.3	32.3	32.5	34.0	64.1	66.9	66.4	65.5
New York	NY	253.8	65.7	26.4	29.6	29.1	12.9	12.3	12.5	29.1	27.7	28.6	0.6	0.4	0.5	42.5	45.0	53.8	104.3	89.4	90.2	89.2
North Carolina	STV	462.0	132.7	62.2	66.2	71.0	19.9	22.1	19.5	45.0	50.1	43.0	0.7	0.5	0.5	85.5	112.9	122.2	59.3	60.1	57.3	57.2
North Dakota	MAPP	139.8	75.3	57.6	58.3	46.4	7.5	9.4	9.9	17.9	22.6	22.8	0.3	0.3	0.3	16.9	25.7	25.8	57.4	54.1	50.5	49.0
Ohio	ECAR	1,175.9	355.2	182.0	175.3	175.6	36.0	33.4	33.3	83.7	76.1	75.7	1.2	1.1	1.0	137.1	165.5	174.5	57.4	60.3	59.8	58.2
Oklahoma	SPP	109.8	86.5	97.3	97.3	97.3	21.5	21.7	20.9	44.7	44.9	44.2	0.6	0.3	0.3	59.0	60.9	62.5	59.3	58.7	58.4	58.0
Oregon	PNW	13.1	10.6	10.0	10.0	10.0	4.7	4.7	4.7	10.7	10.7	10.8	0.0	0.0	0.0	12.8	12.7	13.4	45.9	50.8	47.9	47.3
Pennsylvania[4]	MAAC	967.2	174.3	118.9	103.1	96.0	54.8	31.9	31.4	124.1	72.3	70.3	2.2	1.3	1.4	127.5	131.9	134.5	80.4	70.6	73.2	73.2
Rhode Island	NE	0.0	0.3	0.0	0.0	0.1	0.2	0.2	0.2	0.5	0.5	0.5	0.0	0.0	0.0	2.0	1.9	2.1	89.9	84.2	84.7	83.5
South Carolina	STV	204.0	77.4	97.6	75.6	44.3	13.0	12.9	13.5	30.2	30.0	30.3	0.2	0.2	0.2	49.1	53.1	66.0	59.3	60.1	57.3	57.2
South Dakota	MAPP	12.3	16.0	12.1	12.1	12.1	0.8	0.8	0.8	1.8	1.8	1.8	0.0	0.0	0.0	3.8	3.8	3.9	57.4	54.1	50.5	49.0
Tennessee	STV	337.8	133.7	87.8	90.4	59.6	6.1	10.8	10.5	13.4	24.6	23.0	0.3	0.3	0.2	44.1	59.7	54.2	59.3	60.1	57.3	57.2
Texas	ERCOT	577.7	211.1	358.5	307.9	273.0	80.5	77.5	81.1	161.9	156.6	160.9	2.4	1.5	1.4	244.7	245.4	265.6	65.1	64.7	65.5	63.5
Utah	RM	34.6	69.6	34.9	35.1	34.9	21.1	21.4	21.3	47.7	48.4	48.3	0.2	0.2	0.2	33.3	33.8	33.8	64.1	66.9	66.4	65.5
Vermont	NE	0.0	0.3	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.4	89.9	84.2	84.7	83.5
Virginia	STV	215.7	69.3	64.1	64.5	30.3	17.8	14.9	12.9	41.6	34.6	29.4	0.4	0.2	0.2	42.7	51.8	60.1	59.3	60.1	57.3	57.2
Washington	PNW	8.3	20.7	10.9	9.0	10.2	6.7	6.7	6.8	15.1	15.1	15.3	0.2	0.1	0.1	19.3	19.3	20.6	45.9	50.8	47.9	47.3
West Virginia	ECAR	539.9	203.1	95.0	99.5	95.0	21.9	18.8	19.1	49.5	42.6	43.4	0.7	0.6	0.6	93.3	111.1	116.3	57.4	60.3	59.8	58.2
Wisconsin	MAIN	192.8	82.0	125.6	127.6	119.6	17.9	19.3	18.6	41.5	44.4	42.1	0.6	0.4	0.4	48.1	57.4	64.7	61.2	60.9	61.6	63.2
Wyoming	RM	81.2	83.4	53.2	44.8	44.5	22.3	22.3	22.3	50.4	50.4	50.4	0.5	0.4	0.4	47.7	48.4	48.5	64.1	66.9	66.4	65.5
Nationwide		10,595.1	4,165.0	3,996.8	3,881.9	3,575.3	864.2	784.2	784.0	1,923.5	1,749.4	1,736.4	23.0	16.3	16.1	2,563.1	2,813.0	3,010.6	66.0	65.9	65.4	64.9

Notes:

[1] Includes all fossil-fuel fired sources.

[2] The mercury emissions here do not include those of Municipal Solid Waste or Geothermal power generation.

[3] Missouri is located in two IPM Regions, MAIN and SPP. Since the majority share of Missouri's power generation occurs in the MAIN region, electricity price impacts are taken from MAIN data.

[4] Pennsylvania is located in two IPM Regions, MAAC and ECAR. Since the majority share of Pennsylvania's power generation occurs in the MAAC region, electricity prices impacts are taken from MAAC data.

** District of Columbia emissions are less that 1,000 tons.*

*** mill = one-tenth of a cent*

Modeling Tools Used in Clean Air Planning Act (Carper, S.843) CO_2 Offsets Analysis

- Power sector CO_2 emissions trends are taken from IPM
- International CO_2 emissions are taken from EIA[1]
- Non-CO_2 emissions projections, including fluorinated gases,[2] methane, and nitrous oxide,[3] are taken from EPA's modeling.
  - Used by EIA and the Stanford Energy Modeling Forum's "EMF 21."

- Potential mitigation of CO_2 emissions from energy sources is represented by Marginal Abatement Cost (MAC) curves from four models
  - SGM (developed by Pacific Northwest National Laboratory)[4]
  - EPPA (developed by MIT)[5]
  - MERGE (developed by Manne and Richels)[6]
  - IGEM (developed by Jorgenson, et al.)[7]
    - (IGEM is a domestic model – it is paired with international energy sector mitigation represented as an average of the MACs from SGM, EPPA, and MERGE)

[1] U.S. Department of Energy, Energy Information Administration. April, 2004. *International Energy Outlook 2004.* DOE/EIA-0484(2004). Washington, DC.
[2] Ottinger-Schaefer, D., D. Godwin, and J. Harnisch, 2004. *Estimating Future Emissions and Potential Reductions of HFCs, PFCs, and SF6*. Energy Journal (forthcoming).
[3] Scheehle, Elizabeth and D. Kruger, 2005. *Methane and Nitrous Oxide Baselines and Projections*. Energy Journal (forthcoming).
[4] Sands, Ronald D. 2004. "Dynamics of Carbon Abatement in the Second Generation Model," *Energy Economics* 26(4):721-738.
[5] Babiker, M., J. Reilly, M. Mayer, R. S. Eckaus, I. Sue Wing, and R. Hyman, 2001. "The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Revisions, Sensitivities, and Comparisons of Results." MIT Joint Program on the Science and Policy of Global Change, Report 71, Cambridge, MA.
[6] Manne, Alan, Robert Mendelsohn, Richard G. Richels. 1995. "MERGE: A Model for Evaluating Regional and Global Effects of GHG Reduction Policies." *Energy Policy* 23:17.
[7] Jorgenson, Dale, and Peter Wilcoxen. 1993. "The Economic Impact of the Clean Air Act Amendments of 1990." *Energy Journal* 14:1

Modeling Tools Used in Clean Air Planning Act (Carper, S.843) CO_2 Offsets Analysis (cont.)

- Potential non-CO_2 mitigation costs from EPA
  - Taken from EMF 21 MACs[1, 2]
  - Also used by EIA
- Forestry abatement is represented by
  - U.S. Abatement
    - FASOM[3] (developed by McCarl, et al.)
  - International Abatement
    - GTM[4] (developed by Mendelsohn, Sedjo, and Sohngen)

[1] Delhotal, K. Casey, F. C. de la Chesnaye, A. Gardiner, J. Bates, and A. Sankovski, 2005. *Mitigation of Methane and Nitrous Oxide Emissions from Waste, Energy and Industry.* Energy Journal (forthcoming).
[2] Ottinger-Schaefer, D., D. Godwin, and J. Harnisch, 2004. *Estimating Future Emissions and Potential Reductions of HFCs, PFCs, and SF6*. Energy Journal (forthcoming).
[3] Lee, H-C., B.A. McCarl, D. Gillig, and B.C. Murray, "U.S. Agriculture and Forestry based Greenhouse Gas Emission Mitigation: An Economic Exploration of Time Dependent Effects," in Rural Lands, Agriculture and Climate beyond 2015: Usage and Management Responses, F. Brouwer and B.A. McCarl (eds), Kluwer Press, 2005.
[4] Sohngen, B. "Marginal Cost Curves for Carbon Sequestration in Forests: Estimates for Boreal, Temperate, and Tropical Regions of the World." at http://aede.osu.edu/people/sohngen.1/forests/ccforest.htm

Number of Counties Projected to Meet or Exceed the $PM_{2.5}$ and 8-Hour Ozone Standards

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules[1] Absent Additional Local Controls

$PM_{2.5}$				
	1999 – 2003 Average Design Values Exceed NAAQS	2010 with S.843	2015 with S.843	2020 with S.843
# of Nonattainment Counties	115	21	26	30*
# of Counties Projected to Come into Attainment		94	89	85

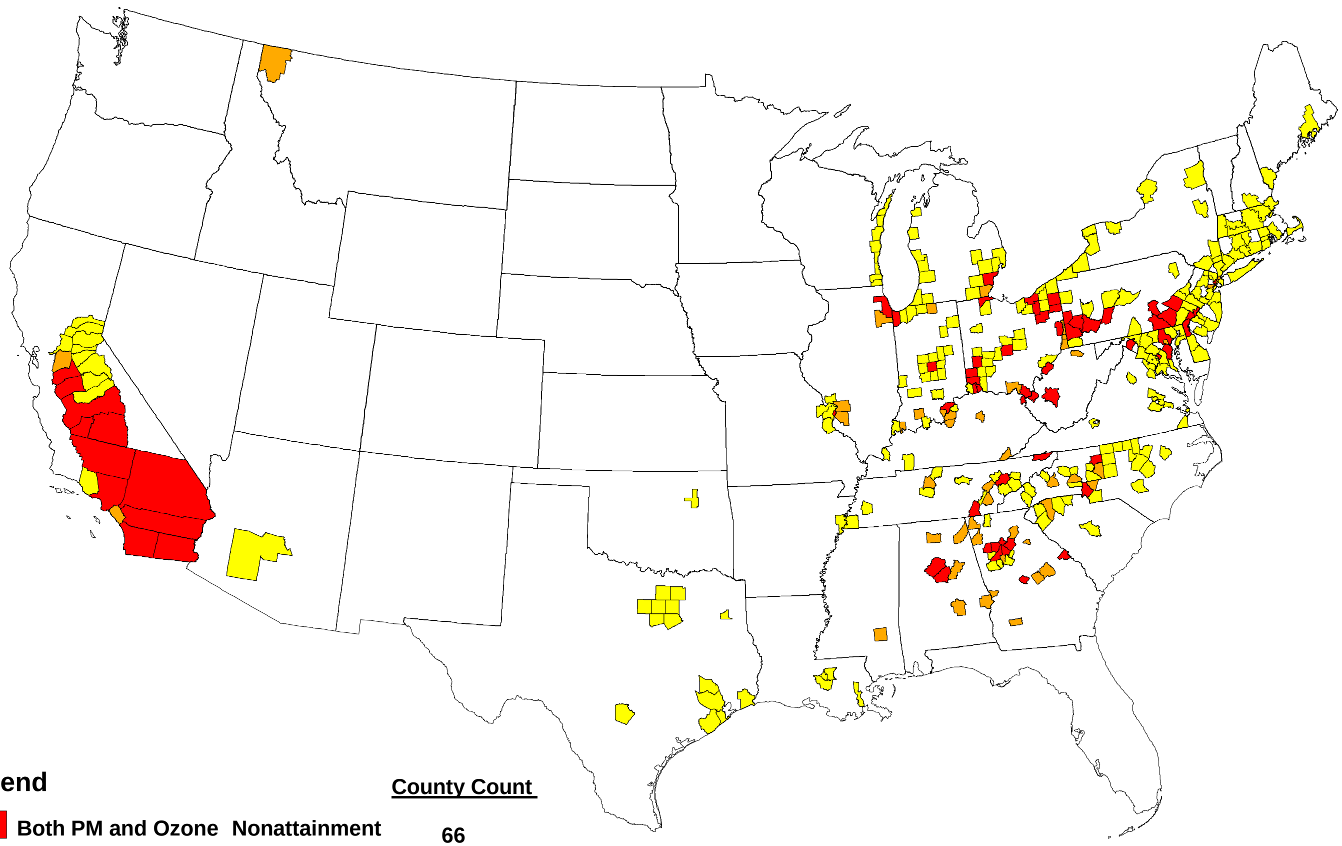
8-Hour Ozone[2]				
	1999 – 2003 Average Design Values Exceed NAAQS	2010 with S.843	2015 with S.843	2020 with S.843
# Nonattainment Counties	292	44	26	21
# of Counties Projected to Come into Attainment		248	266	271

*The increase in $PM_{2.5}$ nonattainment counties from 2015 to 2020 is primarily due to growth in emissions of SO_2 and directly emitted $PM_{2.5}$ from industrial and smaller EGU sources.

[1] Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.

[2] Ozone in the West was not modeled as part of this analysis. Future year ozone nonattainment in the West is based on modeling that was performed for the Nonroad Engine Rule.

341 Counties with Average Measured Concentrations* Exceeding the Annual $PM_{2.5}$ and 8-Hour Ozone NAAQS



Legend

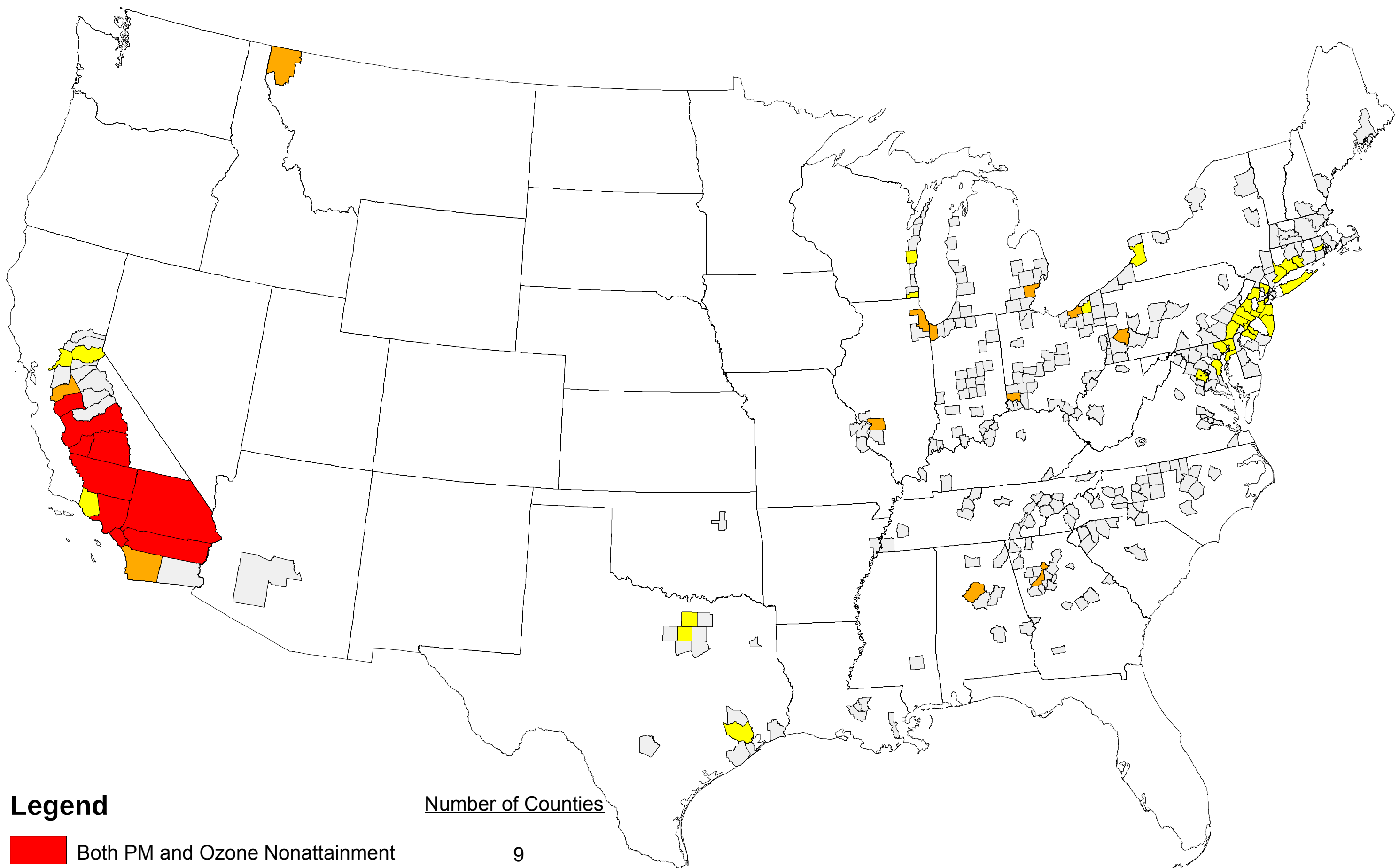
	County Count
Both PM and Ozone Nonattainment	66
PM Only Nonattainment	49
Ozone Only Nonattainment	226

*Based on the average of design values for the three periods 1999-2001, 2000-2002, and 2001-2003; except for ozone in the West which is based on 1999-2001 design values.

For further information on designations and related requirements, see
http://www.epa.gov/air/oaqps/glo/designations/index.htm   http://www.epa.gov/pmdesignations/

285 Counties Projected to Meet the $PM_{2.5}$ and 8-Hour Ozone Standards in 2010

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls



Legend

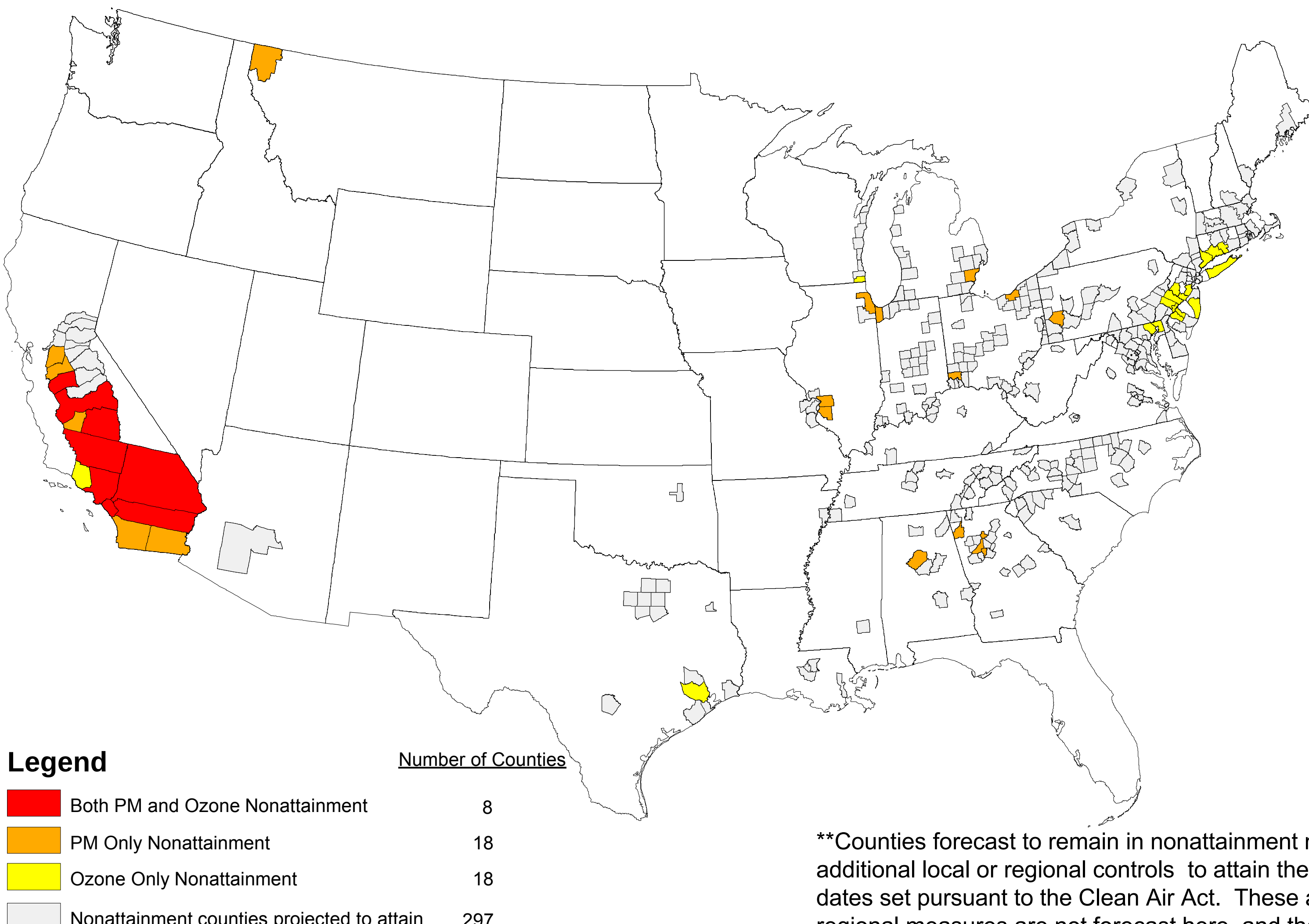
	Number of Counties
Both PM and Ozone Nonattainment	9
PM Only Nonattainment	12
Ozone Only Nonattainment	35
Nonattainment counties projected to attain	285

**Counties forecast to remain in nonattainment may need to adopt additional local or regional controls to attain the standards by dates set pursuant to the Clean Air Act. These additional local or regional measures are not forecast here, and therefore this figure overstates the extent of expected nonattainment.

*Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.

297 Counties Projected to Meet the $PM_{2.5}$ and 8-Hour Ozone Standards in 2015

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls

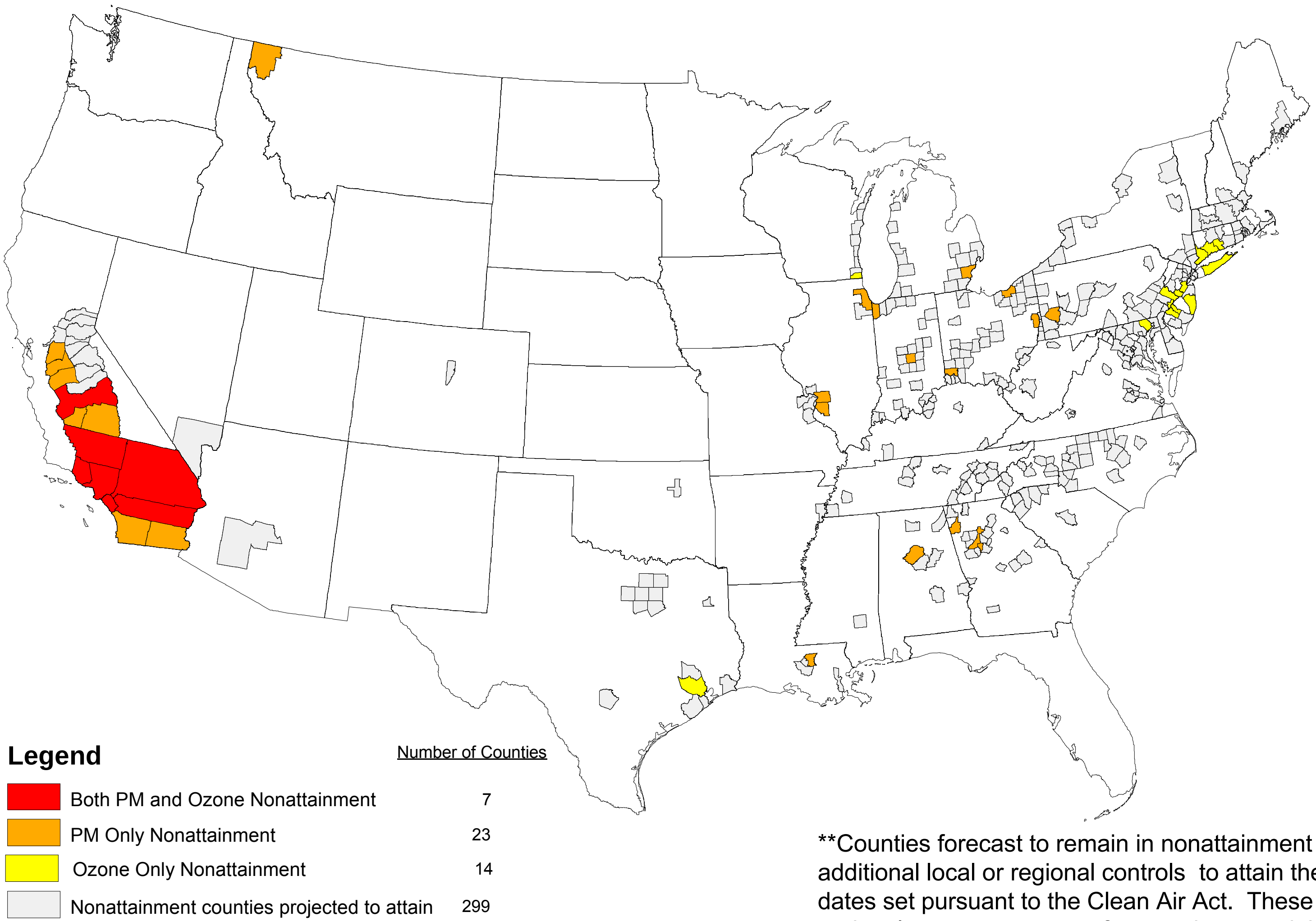


**Counties forecast to remain in nonattainment may need to adopt additional local or regional controls to attain the standards by dates set pursuant to the Clean Air Act. These additional local or regional measures are not forecast here, and therefore this figure overstates the extent of expected nonattainment.

*Current rules include Title IV of CAA, NO_x SIP Call, and some existing State rules.

299 Counties Projected to Meet the $PM_{2.5}$ and 8-Hour Ozone Standards in 2020

with the Clean Air Planning Act (Carper, S.843) and Some Current Rules* Absent Additional Local Controls



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