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Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector

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List of Acronyms

µg/m^3: Micrograms per Cubic Meter

ACI: Activated Carbon Injection
AEO: Annual Energy Outlook
BART: Best Available Retrofit Technology
BEV: Battery Electric Vehicle
BTA: Best Technology Available
CAIR: Clean Air Interstate Rule
CAMR: Clean Air Mercury Rule
CASAC: Clean Air Scientific Advisory Committee

CAVR: Clean Air Visibility Rule
CCR: Coal Combustion Residuals
CCS: Carbon Capture and Storage
CGE: Computable General Equilibrium
CSAPR: Cross State Air Pollution Rule
DIF: Design Intake Flow
DSM: Demand-Side Management
EGU: Electric Generating Unit
EIA: Energy Information Administration
EPA: Environmental Protection Agency
EUR: Expected Ultimate Recovery
FGD: Flue Gas Desulfurization
FIP: Federal Implementation Plan
GDP: Gross Domestic Product
gpm: Gallons per Minute
GW: Gigawatt
HAP: Hazardous Air Pollutant
HCl: Hydrogen Chloride

MACT: Maximum Achievable Control Technology
MATS: Mercury and Air Toxics Standard
MGD: Millions of Gallons per Day
MRIF: Maximum Reported Intake Flow
MW: Megawatt
NAAQS: National Ambient Air Quality Standard
NEI: National Emissions Inventory
NODA: Notice of Data Availability
NPDES: National Pollution Discharge Elimination System
NSR: New Source Review
O&M: Operation and Maintenance
PHEV: Plug-In Hybrid Vehicle
PM: Particulate Matter
PM_{10}: Coarse Particulate Matter
$PM_{2.5}$: Fine Particulate Matter
ppb: Parts per Billion
PRB: Powder River Basin
RCRA: Resource Conservation and Recovery Act
REC: Renewable Energy Credit
RHR: Regional Haze Rule
RIA: Regulatory Impact Analysis
RPS: Renewable Portfolio Standard
SIP: State Implementation Plan
SO_2: Sulfur Dioxide
VMT: Vehicle-Miles Traveled
VOC: Volatile Organic Compound
xEV: Electric Vehicle

Executive Summary

This report evaluates the potential energy and economic impacts of seven major recent and anticipated U.S. Environmental Protection Agency (EPA) regulations affecting the electricity sector. The regulations include a major air regulation specifically affecting electric generation emissions—the Mercury and Air Toxics Standards (MATS) Rule—and several air regulations that will strongly affect emissions in the electricity generating sector as well as other sectors. These are the Regional Haze Rule (RHR) and revisions of national ambient air quality standards (NAAQS) for two ambient pollutants—ozone and fine particulate matter ($PM_{2.5}$)—as well as the recent revision of the NAAQS for sulfur dioxide (SO_2). Two non-air EPA regulations affecting electricity generators are also evaluated in this analysis: regulation of coal combustion residuals (CCR) under the Resource Conservation and Recovery Act (RCRA) and regulation of cooling water intake under Section 316(b) of the Clean Water Act. Although all the regulations addressed in this analysis affect the electricity generating sector, some will also affect other sectors, and we include those additional compliance costs in our assessment of their energy and economic impacts.

A. Objectives and Methodology

We focus on the potential cumulative implications of these seven regulations on electricity markets, other energy markets, and the national economy over the period from 2013 through 2034. The regulations we consider have been or will be promulgated after 2008. In the case of regulations that have not yet been promulgated, we develop assessments of the likely requirements for the anticipated regulations based on review of the available regulatory development record from EPA.

We use NERA's integrated N_{ew}ERA model to develop estimates of the effects of these policies in two major areas:

1. *Electricity and other energy market impacts*. These impacts include the potential effects on energy markets—including electricity, coal, and natural gas—as well as on overall compliance costs. The electricity market effects include estimates of coal unit retirements due to the policies beyond baseline levels.[1] We report national and regional totals and averages for electricity and other energy market impacts.

2. *Economic impacts*. These effects include impacts on economic activity as measured by employment, GDP, and personal income. We report national and regional totals for economic impacts.

N_{ew}ERA is an economy-wide integrated energy and economic model that includes a detailed representation of the electric sector. It has been designed to assess, on an integrated basis, the effects of major policies on electricity, other energy markets, and the overall economy. The model performs its analysis with regional detail, accounting for over 30 electricity market

[1] Some natural gas units are also projected to retire in response to the environmental regulations.

regions and 11 regions for other economic activities. Appendix A provides a detailed description of the N_{ew}ERA model.

B. Cases Evaluated

We have developed comprehensive and accurate assessments of the impacts of these seven policies, but the results are subject to considerable uncertainties. We have evaluated three cases to bracket some of these uncertainties. The first two cases address uncertainty related to the timing and form of compliance costs for the ozone standard. The third case evaluates the seven regulations based upon an assumption of higher future natural gas prices than in our other cases, a case motivated by the uncertainty that surrounds projections of future natural gas availability and prices.

The following list summarizes the three cases.

1. *Lower ozone costs.* This case is based upon EPA's annualized cost estimates for complying with a 65 parts per billion (ppb) ozone standard. This case uses EPA's estimates of annualized costs and assumes the costs start in the year in which attainment is required for each nonattainment area. This provides a lower bound because some costs would be incurred earlier (*i.e.*, before the year in which attainment is required).

2. *Higher ozone costs.* This case is also based upon EPA's annualized costs for the 65 ppb ozone standard, but it assumes that EPA's estimates of annualized costs would be incurred as capital costs and would occur before and during the year in which attainment is required for each nonattainment area. This provides an upper bound because some costs would be incurred later (*i.e.*, after the year in which attainment is required).

3. *Higher natural gas prices.* This case assumes that the baseline natural gas price is approximately $1 per million Btu (MMBtu) higher, an assumption similar to a high gas price case developed by the U.S. Energy Information Administration. This case uses compliance costs for the lower ozone costs case.

Note that we do not include the effects of other potential regulations—notably those related to greenhouse gases and water discharges (effluent guidelines)—and the impacts do not include potential effects of rapid coal unit retirements and retrofits on electricity system reliability. These omitted regulations could lead to additional impacts beyond those estimated in this study.

C. Results of This Study – Lower Ozone Costs

This section provides the modeling results for the lower ozone costs case.

1. Electricity and Energy Market Effects

The potential costs of the seven policies are estimated to lead to 42 additional gigawatts (GW) of prematurely retired coal-fired capacity by 2019 in the lower ozone costs case.[2] This estimate is in addition to 27 GW of retirements by 2019 that are in the baseline scenario (*i.e.*, a future without the seven regulations in place).[3] The result is a total of 69 GW of coal retirements projected to occur by 2019, a total that represents about 20 percent of the 2012 U.S. coal-fired electricity generating capacity. As noted, this estimate does not include the effects of other potential requirements, such as greenhouse gas emission regulations or effluent guidelines, or potential concerns related to electricity system reliability. (There are a few additional retirements of non-coal units subject to one or more of the policies.)

Table ES-1 summarizes the incremental costs for the electricity sector, given the projected retirements and other actions necessary to comply with the seven regulations in the lower ozone costs case. These costs include compliance spending for units that do not retire (*i.e.*, retrofits), capital costs for new generating capacity that would replace retiring units, and changes in fuel costs. Incremental costs to the electricity sector are projected to be about $15 billion (in 2012$) on an annualized basis over the period from 2013 through 2034. The costs represent a total of $203 billion (present value in 2012$ as of January 1, 2013) over the period from 2013 through 2034. The largest cost category is retrofit environmental controls, which account for about $13 billion on an annualized basis.

Table ES-1. Electricity Sector Costs, 2013-2034 (billions, 2012$) : Lower Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Environmental Controls and O&M	$12.8	$168
Replacement Capacity	$1.9	$25
Fuel	$0.7	$10
Total	$15.4	$203

Note: (a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
Source: NERA calculations as explained in text.

The retirement of coal units, the construction of replacement capacity, and the compliance costs affect electricity sector fuel consumption, fuel prices, and electricity prices. Table ES-2 summarizes the average potential energy market effects of the seven regulations from 2013 through 2034. Appendix C provides information on the annual effects for 2013 through 2034, with effects that are both higher and lower in individual years than these average values.

[2] The additional retirements are projected by the N_{ew}ERA model and are not based on any retirement announcements. Thus, they are entirely attributable to the combination of seven policies.

[3] These baseline scenario retirements are also projected by the model and are not based on announced retirements.

Table ES-2. Annual Energy Market Impacts, 2013-2034: Lower Ozone Costs Case

	Total Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2012$/ton)	Natural Gas-Fired Generation (million MWh)	Natural Gas Price at Henry Hub (2012$/MMBtu)	Avg. Retail Electricity Price (2012$/MWh)
Baseline	27	2,018	$35.67	1,027	$5.48	$100.25
Policies	69	1,845	$36.11	1,124	$5.64	$103.12
Change	+42	-172	+$0.44	+97	+$0.15	+$2.87
% Change	+156%	-8.5%	+1.2%	+9.5%	+2.8%	+2.9%

Note: Coal retirements are cumulative from 2013 through 2034.
Source: NERA calculations as explained in text.

Coal-fired generation is projected to decrease by an average of 8.5 percent over the period from 2013 through 2034. The shift in coal demand among different coal regions, with a lower share of low-cost subbituminous coal, results in a projected increase in average coal prices of 1.2 percent on average over the model horizon.[4] In contrast, the seven regulations are projected to increase natural gas-fired generation by 9.5 percent on average over the period and increase Henry Hub natural gas prices by 2.8 percent on average. Average U.S. retail electricity prices are projected to increase by an average of 2.9 percent over the period. However, the change in electricity prices varies by region, as can be seen in Appendix C.

2. Economic Impacts

Table ES-3 summarizes the potential economic impacts of the seven regulations in the lower ozone costs case. Table ES-3 reports impacts in terms of the overall U.S. economy, as measured by changes in GDP and disposable income. U.S. GDP would be reduced by $38 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $500 billion (2012$). U.S. disposable income would be reduced by $29 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $375 billion (2012$). Disposable income per household would be reduced by $226 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $3,000 (2012$).

[4] While almost all of the 24 individual coal types in the N_{ew}ERA model experience declines in demand and declines in price, the weighted average coal price increases due to a shift in the mix of coal. In particular, the requirement to install scrubbers to remove sulfur—largely due to the MATS Rule—decreases the demand for low-sulfur coals, which generally have low prices per ton, and increases the demand for high-sulfur coals, which generally have higher prices per ton. The net effect of the shift from low-price-per-ton coal to higher-price-per-ton coal results in a small increase in the average coal price in the policy case.

Table ES-3. U.S. GDP and Disposable Income Impacts, 2013-2034: Lower Ozone Costs Case

	Annual [(a)]	**Present Value [(b)]**
Gross Domestic Product Loss	$38 billion	$500 billion
Disposable Income Loss [(c)]	$29 billion	$375 billion
Disposable Income Loss per Household	$226	$3,000

Note: All dollar values are in 2012$.
(a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Disposable income includes income from labor and from capital investments.
Source: NERA calculations as explained in text.

Table ES-4 focuses on the specific impacts to workers as a result of the seven regulations, impacts that are important to policy evaluations. The N_{ew}ERA model results indicate that the seven policies would result in an average annualized reduction in labor income of $33 billion in the lower ozone costs case, with a cumulative present value loss over the period from 2013 to 2034 of $430 billion. (See Appendix A for a summary of N_{ew}ERA's modeling of labor impacts.) Labor income per household would be reduced by $249 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $3,300 (2012$). The labor income loss can be expressed in terms of job equivalents, *i.e.*, total loss in labor income divided by the average salary,[5] resulting in an estimated reduction of 590,000 job-equivalents on average each year from 2013 to 2034.

[5] Average salary in the baseline scenario is a function of labor income and estimated employment in the baseline scenario.

Table ES-4. U.S. Labor Income Impacts, 2013-2034: Lower Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Labor Income Loss [(c)]	$33 billion	$430 billion
Labor Income Loss per Household	$249	$3,300
Labor Income Loss as Job-Equivalents [(d)]	590,000	n/a

Notes: "n/a" denotes that the result category is not applicable.
All dollar values are in 2012$.
(a) Annual values for labor income loss and labor income loss per household are annualized values based on the respective present values. Annual value for labor income loss as job-equivalents is the average of impacts in each year.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Labor income loss consists of two effects: (1) reductions in real wage per hour worked; and (2) reductions in labor market participation (hours worked) in response to lower wages.
(d) Job-equivalents are calculated as the total loss in labor income divided by the average salary. This is not a precise measure of the number of discrete jobs that would be lost, but one that allows us to express income loss to workers in terms of the equivalent number of employees earning the average salary.
Source: NERA calculations as explained in text.

Annual economic impacts from 2013 to 2034 are provided in Appendix C for the case with the lower ozone cost estimates that has been summarized in the tables above.

D. Results of This Study – Higher Ozone Costs

This section provides modeling results for the higher ozone costs case.

1. Electricity and Energy Market Effects

The electricity and energy market effects resulting from the higher ozone costs case are nearly identical to those of the lower ozone costs case because the only difference in the cases is the timing of ozone compliance costs on the non-electric sectors. As a result, the incremental coal-unit retirements are similar. Table ES-5 summarizes the incremental costs for the electricity sector, given the projected retirements and other actions necessary to comply with the seven regulations. Incremental costs to the electricity sector are projected to be about $15 billion (in 2012$) on an annualized basis over the period from 2013 through 2034. The costs represent a total of $198 billion (present value in 2012$ as of January 1, 2013) over the period from 2013 through 2034. The largest cost category is retrofit environmental controls, which account for almost $13 billion on an annualized basis.

Table ES-5. Electricity Sector Costs, 2013-2034 (billions, 2012$): Higher Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Environmental Controls and O&M	$12.7	$167
Replacement Capacity	$1.8	$24
Fuel	$0.5	$7
Total	$15.0	$198

Note: (a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
Source: NERA calculations as explained in text.

Table ES-6 summarizes the average potential energy market effects of the seven regulations from 2013 through 2034 in the higher ozone costs case. Appendix D provides information on the annual effects for 2013 through 2034, with effects that are both higher and lower in individual years than these average values.

Table ES-6. Annual Energy Market Impacts, 2013-2034: Higher Ozone Costs Case

	Total Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2012$/ton)	Natural Gas-Fired Generation (million MWh)	Natural Gas Price at Henry Hub (2012$/MMBtu)	Avg. Retail Electricity Price (2012$/MWh)
Baseline	27	2,018	$35.67	1,027	$5.48	$100.25
Policies	69	1,843	$36.16	1,122	$5.63	$103.07
Change	+42	-174	+$0.49	+95	+$0.15	+$2.82
% Change	+156%	-8.6%	+1.4%	+9.3%	+2.7%	+2.8%

Note: Coal retirements are cumulative from 2013 through 2034.
Source: NERA calculations as explained in text.

Coal-fired generation is projected to decrease by an average of 8.6 percent over the period from 2013 through 2034. The shift in coal demand among different coal regions, with a lower share of low-cost subbituminous coal, results in a projected increase in average coal prices of 1.4 percent on average over the model horizon. In contrast, the seven regulations are projected to increase natural gas-fired generation by 9.3 percent on average over the period and increase Henry Hub natural gas prices by 2.7 percent on average. Average U.S. retail electricity prices are projected to increase by an average of 2.8 percent over the period. However, the change in electricity prices varies by region, as can be seen in Appendix D.

2. Economic Impacts

Table ES-7 summarizes the potential economic impacts of the seven regulations in the higher ozone cost case. Table ES-7 reports impacts in terms of the overall U.S. economy, as measured by changes in GDP and disposable income. U.S. GDP would be reduced by $63 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $830 billion (2012$). U.S. disposable income would be reduced by $66 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $870 billion (2012$). Disposable income per household would be reduced by $512 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $6,700 (2012$). These economic impacts are substantially larger than in the lower ozone costs case because the costs are borne earlier.

Table ES-7. U.S. GDP and Disposable Income Impacts, 2013-2034: Higher Ozone Costs Case

	Annual [(a)]	**Present Value [(b)]**
Gross Domestic Product Loss	$63 billion	$830 billion
Disposable Income Loss [(c)]	$66 billion	$870 billion
Disposable Income Loss per Household	$512	$6,700

Note: All dollar values are in 2012$.
(a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Disposable income includes income from labor and from capital investments.
Source: NERA calculations as explained in text.

Table ES-8 focuses on the specific impacts to workers as a result of the seven regulations in the higher ozone costs case. The N_{ew}ERA model results indicate that the seven policies would result in an average annualized reduction in labor income of $54 billion, with a cumulative present value loss over the period from 2013 to 2034 of $710 billion. Labor income per household would be reduced by $416 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $5,500 (2012$). The labor income loss can be expressed in terms of job equivalents, *i.e.*, total loss in labor income divided by the average salary, resulting in an estimated reduction of 887,000 job-equivalents on average each year from 2013 to 2034.

Table ES-8. U.S. Labor Income Impacts, 2013-2034: Higher Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Labor Income Loss [(c)]	$54 billion	$710 billion
Labor Income Loss per Household	$416	$5,500
Labor Income Loss as Job-Equivalents [(d)]	887,000	n/a

Notes: "n/a" denotes that the result category is not applicable.
All dollar values are in 2012$.
(a) Annual values for labor income loss and labor income loss per household are annualized values based on the respective present values. Annual value for labor income loss as job-equivalents is the average of impacts in each year.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Labor income loss consists of two effects: (1) reductions in real wage per hour worked; and (2) reductions in labor market participation (hours worked) in response to lower wages.
(d) Job-equivalents are calculated as the total loss in labor income divided by the average salary. This is not a precise measure of the number of discrete jobs that would be lost, but one that allows us to express income loss to workers in terms of the equivalent number of employees earning the average salary.
Source: NERA calculations as explained in text.

Annual economic impacts from 2013 to 2034 are provided in Appendix D for the higher ozone costs case.

E. Results of This Study – Higher Natural Gas Prices

This section provides modeling results for the higher natural gas prices case. As noted above, this case uses the lower ozone costs and uses natural gas prices that are approximately $1/MMBtu higher than in the previous two cases and roughly correspond to EIA's Low Estimated Ultimate Recovery (EUR) case in *AEO 2012*.

1. Electricity and Energy Market Effects

The higher natural gas prices case leads to higher future electricity prices, which provide coal units with potentially larger margins to cover the costs of pollution control retrofits. As a result, this case has fewer prematurely-retired coal units by 2019 and more retrofits to comply with the seven regulations.

Table ES-9 summarizes the incremental costs for the electricity sector, given the projected retirements and other actions necessary to comply with the seven regulations. Incremental costs to the electricity sector are projected to be more than $16 billion (in 2012$) on an annualized basis over the period from 2013 through 2034. The costs represent a total of $220 billion (present value in 2012$ as of January 1, 2013) over the period from 2013 through 2034. The largest cost category is retrofit environmental controls, which account for about $15 billion on an annualized basis. Compared to the lower ozone costs case, the higher natural gas price case includes higher retrofit costs and lower replacement capacity costs. On net, the electric sector faces slightly higher costs in the higher natural gas prices case than in the lower ozone costs case.

Table ES-9. Electricity Sector Costs, 2013-2034 (billions, 2012$): Higher Natural Gas Prices Case

	Annual [(a)]	Present Value [(b)]
Environmental Controls and O&M	$15.1	$199
Replacement Capacity	$0.9	$12
Fuel	$0.7	$9
Total	$16.7	$220

Note: (a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
Source: NERA calculations as explained in text.

The retirement of coal units, the construction of replacement capacity, and the compliance costs affect electricity sector fuel consumption, fuel prices, and electricity prices. Table ES-10 summarizes the average potential energy market effects of the seven regulations from 2013 through 2034 (relative to a baseline that also has higher natural gas prices). Appendix E provides information on the annual effects for 2013 through 2034, with effects that are both higher and lower in individual years than these average values.

Table ES-10. Annual Energy Market Impacts, 2013-2034: Higher Natural Gas Prices Case

	Total Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2012$/ton)	Natural Gas-Fired Generation (million MWh)	Natural Gas Price at Henry Hub (2012$/MMBtu)	Avg. Retail Electricity Price (2012$/MWh)
Baseline	23	2,077	$36.65	845	$6.58	$105.00
Policies	54	1,965	$36.80	898	$6.72	$107.78
Change	+31	-112	+$0.16	+53	+$0.14	+$2.79
% Change	+133%	-5.4%	+0.4%	+6.3%	+2.1%	+2.7%

Note: Coal retirements are cumulative from 2013 through 2034.
Source: NERA calculations as explained in text.

Coal-fired generation is projected to decrease by an average of 5.4 percent over the period from 2013 through 2034. The shift in coal demand among different coal regions, with a lower share of low-cost subbituminous coal, results in a projected increase in average coal prices of 0.4 percent on average over the model horizon. In contrast, the seven regulations are projected to increase natural gas-fired generation by 6.3 percent on average over the period and increase Henry Hub natural gas prices by 2.1 percent on average. Average U.S. retail electricity prices are projected to increase by an average of 2.7 percent over the period. However, the change in electricity prices varies by region, as can be seen in Appendix E. There is less shifting from coal to natural

gas when natural gas prices are higher (as compared to the lower ozone costs case), but from a cost perspective there is little difference because of the increased costs from retrofitting.

2. Economic Impacts

Table ES-11 summarizes the potential economic impacts of the seven regulations for the higher natural gas prices case. Table ES-11 reports impacts in terms of the overall U.S. economy, as measured by changes in GDP and disposable income. U.S. GDP would be reduced by $36 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $480 billion (2012$). U.S. disposable income would be reduced by $27 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $360 billion (2012$). Disposable income per household would be reduced by $217 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $2,900 (2012$). These results are quite similar to those for the lower ozone costs case.

Table ES-11. U.S. GDP and Disposable Income Impacts, 2013-2034: Higher Natural Gas Prices Case

	Annual [(a)]	**Present Value [(b)]**
Gross Domestic Product Loss	$36 billion	$480 billion
Disposable Income Loss [(c)]	$27 billion	$360 billion
Disposable Income Loss per Household	$217	$2,900

Note: All dollar values are in 2012$.
(a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Disposable income includes income from labor and from capital investments.
Source: NERA calculations as explained in text.

Table ES-12 focuses on the specific impacts to workers as a result of the seven regulations for the higher natural gas prices case. The N_{ew}ERA model results indicate that the seven policies would result in an average annualized reduction in labor income of $30 billion in the higher natural gas prices case, with a cumulative present value loss over the period from 2013 to 2034 of $390 billion. Labor income per household would be reduced by $226 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $3,000 (2012$). The labor income loss can be expressed in terms of job equivalents, *i.e.*, total loss in labor income divided by the average salary, resulting in an estimated reduction of 544,000 job-equivalents on average each year from 2013 to 2034.

Table ES-12. U.S. Labor Income Impacts, 2013-2034: Higher Natural Gas Prices Case

	Annual [(a)]	**Present Value** [(b)]
Labor Income Loss [(c)]	$30 billion	$390 billion
Labor Income Loss per Household	$226	$3,000
Labor Income Loss as Job-Equivalents [(d)]	544,000	n/a

Notes: "n/a" denotes that the result category is not applicable.
All dollar values are in 2012$.
(a) Annual values for labor income loss and labor income loss per household are annualized values based on the respective present values. Annual value for labor income loss as job-equivalents is the average of impacts in each year.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Labor income loss consists of two effects: (1) reductions in real wage per hour worked; and (2) reductions in labor market participation (hours worked) in response to lower wages.
(d) Job-equivalents are calculated as the total loss in labor income divided by the average salary. This is not a precise measure of the number of discrete jobs that would be lost, but one that allows us to express income loss to workers in terms of the equivalent number of employees earning the average salary.
Source: NERA calculations as explained in text.

Annual economic impacts from 2013 to 2034 are provided in Appendix E for the higher natural gas prices case.

I. Introduction

This report examines various effects of major environmental regulations affecting the electricity sector that have either been promulgated by the U.S. Environmental Protection Agency (EPA) or have been slated to be promulgated after 2008. We focus on the cumulative effects of these major environmental regulations on the energy sector and on economic activity.

A. Background

EPA has proposed and promulgated two major air emissions regulations affecting the electricity sector since the beginning of 2009, the Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS). CSAPR was vacated by the U.S. Circuit Court of Appeals in August 2012, however, and it is unclear when the U.S. Environmental Protection Agency (EPA) will put an alternative regulation in place. In the meantime, the Clean Air Interstate Rule (CAIR)—the regulation that CSAPR would have replaced—will continue to be in effect; since CAIR was developed before 2009, it constitutes part of the baseline scenario for evaluating post-2009 regulations.

In addition to MATS, other major anticipated air regulations that will affect the electricity sector include the Regional Haze Rule (RHR) and three national ambient air quality standards (NAAQS): a revised standard for ozone (presently in regulatory review prior to the proposed revision), the newly promulgated 1-hour NAAQS for sulfur dioxide (SO_2), and the proposed revision of the NAAQS for fine particulate matter ($PM_{2.5}$). To the extent that these NAAQS revisions will create new nonattainment areas and a greater degree of nonattainment in existing nonattainment areas, additional emission reductions will be required by revised State Implementation Plans (SIPs). These will include additional controls for electricity generating facilities as well as for other sources of each of the relevant emissions that affect those ambient concentrations. Indeed, given the substantial anticipated reductions in electricity emissions due to other rules in our analysis (notably CAIR, MATS, and RHR), a large share of the emission reductions to meet the anticipated new NAAQS levels will almost certainly come from outside the electricity sector.

In addition to controls on their air emissions, electric generating units face other potential environmental regulatory requirements that would require additional investments. EPA in April 2011 proposed a regulation under Section 316(b) of the Clean Water Act that regulates cooling water intake structures from electric power plants (and other facilities) in order to reduce losses of fish and other aquatic organisms. The EPA has announced that a final regulation will be promulgated in 2013. In addition, EPA has proposed regulations under the Resource Conservation and Recovery Act (RCRA) that would change how some plants manage their primary solid waste streams, which are the ashes from the burned coal and the byproducts from their flue gas desulfurization (FGD) systems.

Our assessments focus on these various air emission regulations and the 316(b) and coal combustion residual (CCR) regulations. Electricity generating units could face environmental

costs for other potential regulatory requirements—notably including those related to greenhouse gases and water discharges (effluent guidelines)—that are not included in our estimated impacts.

The EPA has developed assessments of the potential impacts of some of these regulations and proposed regulations in separate regulatory impact analyses (RIAs). These RIAs provide estimates of the potential social costs and social benefits of the proposed regulations as well as their potential effects on the energy sector. The public comments provide other information on the potential effects of the individual rules. Information on individual regulations, however, is limited because it does not measure the cumulative effects of many potential regulatory requirements either on individual power plants or on energy markets and the economy.

B. Objectives of This Report

The overall objective of this report is to provide estimates of the cumulative energy and economic effects of these major environmental regulations. That is, we consider the potential effects of these regulations on energy markets as well as on gross domestic product (GDP) and other measures of economic activity. We use a state-of-the-art integrated energy and economic model, the N_{ew}ERA model, to estimate these various effects. We emphasize, however, that we have not developed estimates of the potential social benefits and do not evaluate whether the individual regulations—or possible regulatory alternatives—would be desirable from a societal perspective.

In this analysis, regulatory "impacts" are stated as changes in economic outcomes relative to a baseline scenario. The baseline for this analysis is an integrated economic forecast that was first calibrated to the reference case from the *Annual Energy Outlook 2012* (*AEO 2012)* of the Energy Information Administration (EIA) and then was modified to account for the pre-2009 environmental regulations. The assessments presented in this study cover two general categories of regulatory impacts:

1. *Energy market effects*. The N_{ew}ERA model generates estimates of the potential future coal unit retirements—based upon the future potential compliance costs and other information we have developed for the various individual regulations—as well as estimates of control costs for units that are not expected to retire. This information is developed simultaneously with estimates of the potential effects of the policies on electricity and other energy markets, notably those for coal and natural gas. The results include estimates of the total compliance costs for the electricity sector due to the regulations, including control costs (capital as well as operation and maintenance), changes in fuel costs, and the costs of additional capacity added.

2. *Economic impacts*. The economic impacts of the regulations—including effects on GDP and measures of labor impacts—are estimated by N_{ew}ERA based upon the electricity sector costs and impacts as well as the costs of the regulations that are imposed on non-electricity sectors.

There are substantial uncertainties involved in developing these estimates of the effects of future environmental regulation—including the possibility that coal and other units will face potential regulations related to greenhouse gases and other requirements—and thus the projections

presented in this report should be viewed as estimates of the likely impacts of only the policies evaluated. In addition, there are uncertainties regarding the nature, timing, and size of the regulatory costs—particularly for the ozone standard—and the baseline energy conditions, particularly the future projections for natural gas prices.

To deal with major uncertainties, the report develops a range of estimates based upon three cases.

1. *Lower ozone costs.* This case is based upon EPA's annualized cost estimates for complying with a 65 parts per billion (ppb) ozone standard. This case uses EPA's estimates of annualized costs and assumes the costs start in the year in which attainment is required for each nonattainment area. This provides a lower bound because some costs would be incurred earlier (*i.e.*, before the year in which attainment is required).

2. *Higher ozone costs.* This case is also based upon EPA's annualized costs for the 65 ppb ozone standard, but it assumes that EPA's estimates of annualized costs would be incurred as capital costs and would occur before and during the year in which attainment is required for each nonattainment area. This provides an upper bound because some costs would be incurred later (*i.e.*, after the year in which attainment is required).

3. *Higher natural gas prices.* This case assumes that the baseline natural gas price is approximately $1 per million Btu (MMBtu) higher, an assumption similar to a high gas price case developed by the U.S. Energy Information Administration. This case uses compliance costs for the lower ozone costs case.

C. Outline of This Report

The remainder of this report is organized as follows. Chapter II provides an overview of the N_{ew}ERA model and summaries of the policies that are evaluated in the study. Chapter III presents the results of the analyses. The appendices provide details on the N_{ew}ERA model, compliance assumptions, methodologies, and detailed results for all three cases.

II. Overview of Methodologies and Policies

This chapter provides summary information on the N_{ew}ERA model used to estimate the potential economic impacts of the seven policies. We also provide overviews of the seven environmental policies that are modeled. Additional details on the N_{ew}ERA model are provided in Appendix A, and additional details on the policies and modeling inputs are provided in Appendix B.

A. N_{ew}ERA Model

NERA's N_{ew}ERA modeling system is an integrated energy and economic model that includes a bottom-up representation of the electricity sector, including all of the unit-level details that are required to accurately evaluate changes in the electric sector. N_{ew}ERA integrates the electricity sector model with a macroeconomic model that includes all other sectors of the economy (except for the electricity sector) using a top-down representation. The model produces integrated forecasts for future years; the modeling for this study was for the period from 2013 to 2034 with modeling inputs and results for every third year in that period. The model produces a standard set of reports that includes the following information.

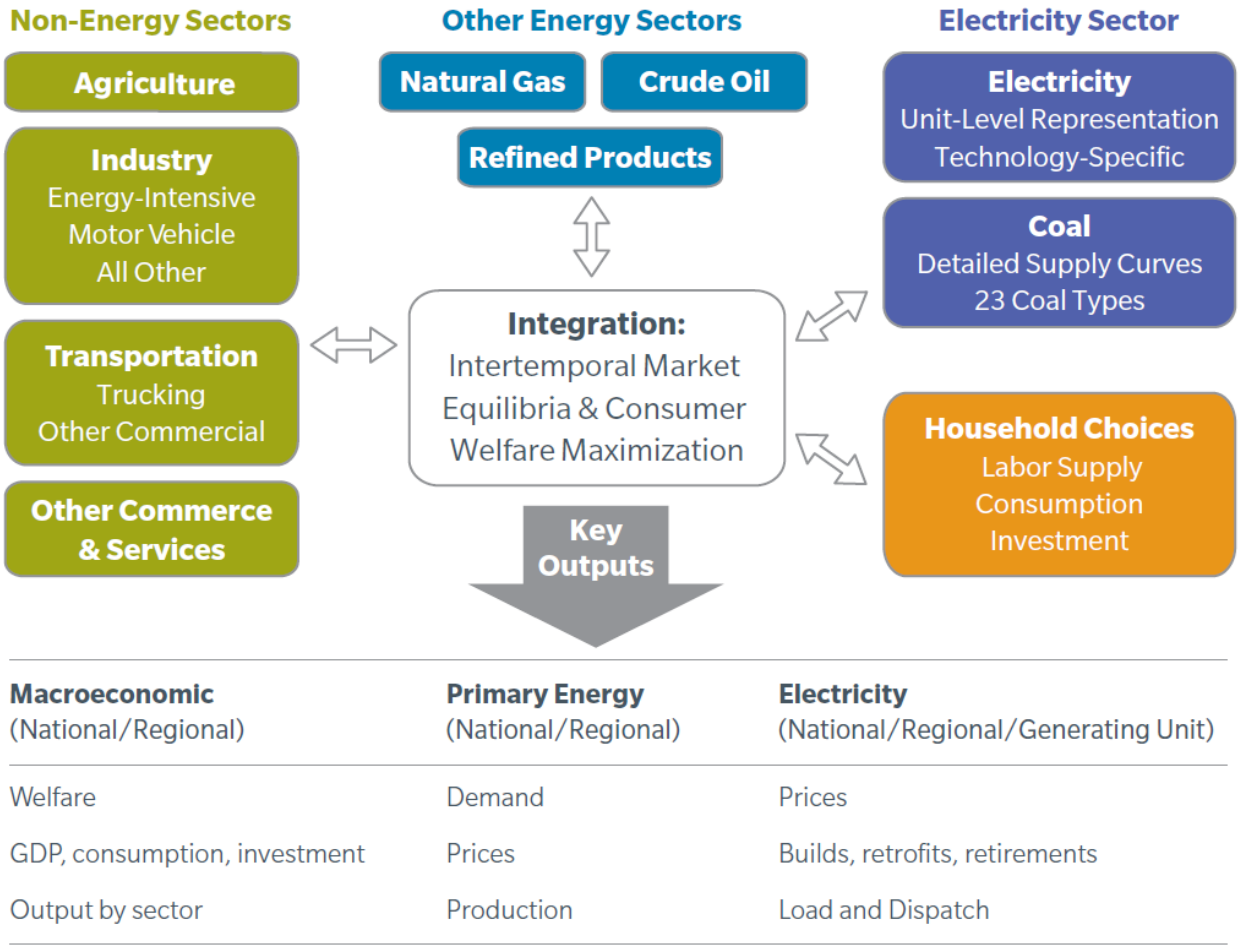
- *Unit-level investments in the electric sector* – retrofits in response to environmental policies, new builds (full range of new generation technologies represented), retirements based on economics.

- *Prices* – wholesale electricity prices for each of 32 U.S. regions, capacity prices for each U.S. region, delivered electricity prices by sector for each of 11 macroeconomic regions in N_{ew}ERA, Henry Hub natural gas prices and delivered natural gas prices to the electric sector for each U.S. region, minemouth coal prices for 24 different types of coal, delivered coal prices by coal unit, refined oil product prices (gasoline and diesel fuel), renewable energy credit (REC) prices for each state/regional renewable portfolio standard (RPS), and emissions prices for all regional and national programs with tradable credits.

- *Macroeconomic results* – gross domestic product (and gross regional product for each macroeconomic region), welfare, changes in disposable income, and changes in labor income and real wage rates (used to estimate labor market changes in terms of an equivalent number of jobs).

Figure 1 provides a simplified representation of the key elements of the N_{ew}ERA modeling system. Appendix A provides additional information on the N_{ew}ERA modeling system.

Figure 1: N_{ew}ERA Modeling System Representation



B. Overview of Policies Modeled

This section summarizes the baseline scenario, seven environmental policies, and the alternate natural gas prices case evaluated in this report. Appendix B provides additional details on how the baseline case and the policies are defined and modeled, including information on the control cost assumptions that are used. In general, we rely upon EPA's estimates of control costs for individual control technologies.

1. Baseline Scenario

The baseline scenario is constructed from a version of the N_{ew}ERA model that is calibrated to the most recent *AEO 2012* reference case forecast. That is, the model's parameters and key inputs such as natural gas supply/prices are first set so that if we impose the same policies as are in *AEO 2012*, N_{ew}ERA will produce very similar projected fuel prices and consumption. The specific *AEO 2012* forecast is not used as our baseline because our baseline scenario consists of a somewhat different set of environmental policies than are included in *AEO 2012*.

The *AEO 2012* forecast assumes that the MATS and CSAPR rules will be in effect because these policies were finalized when the forecast was developed. In contrast, for purposes of this analysis MATS is part of the policy scenario and CSAPR is not included because it has been vacated by the Court. Thus, for the current analysis, we create a baseline scenario by adjusting the N_{ew}ERA model assumptions to eliminate the MATS and CSAPR provisions, replacing them with an earlier set of policies. As noted, we define the baseline scenario in terms of those electric sector policies that were in effect at the end of 2008. The following policies are thus in our baseline case.

- Clean Air Interstate Rule (CAIR), including Phase II (as of January 2009, the court had reinstated CAIR until a replacement rule could be promulgated);
- State-specific mercury rules (as of January 2009, the Clean Air Mercury Rule (CAMR) rule had been vacated, but certain state rules remained in effect);
- New Source Review (NSR) settlements agreed to prior to January 2009;
- RHR proposals whose planning process started prior to January 2009; and
- Anticipated further actions necessary to attain the current NAAQS ozone and $PM_{2.5}$ rules.

In addition, the baseline scenario includes all of the current state RPS policies as well as the energy efficiency standards included in the *AEO 2012* reference case.

To create this reference scenario, we solve the N_{ew}ERA model in two steps. In the first step, the N_{ew}ERA model is calibrated to the most recent *AEO 2012* reference case forecast, which is an internally consistent outlook on energy prices and demands and sectoral outputs. The *AEO 2012* reference case projections take into account current legislation and environmental regulations, including government actions taken as of December 31, 2011. In particular, as noted, the *AEO 2012* reference case forecast assumes the effects of the MATS and CSAPR rules in its projections. The calibration process involves matching economic growth projections, energy consumption over time, and energy price projections. After the calibration of the first step, the N_{ew}ERA model produces an equilibrium economic outlook consistent with the *AEO 2012* reference case.

In the second step, we construct the state of the regulatory outlook that prevailed at the end of 2008. This step involves running a scenario that removes the MATS and CSAPR rules from the N_{ew}ERA model input assumptions. The revised integrated projection generated by the N_{ew}ERA model is our baseline scenario. By design, this baseline scenario contains a different set of policies than those included in the *AEO 2012* projections. We use this baseline scenario as a reference point to estimate the incremental energy and economic impacts of the specific set environmental policies promulgated or anticipated to be promulgated after the end of 2008.

2. Federal Air Emissions Standards

a. Mercury and Air Toxics Standard

In February 2008, the U.S. District Court for the D.C. Circuit vacated the Clean Air Mercury Rule (CAMR). As a result, EPA developed standards regarding emissions of mercury and hazardous air pollutants (HAPs) from coal-fired and oil-fired electric generating units (EGUs). The statutory authority for this regulation is Section 112 of the Clean Air Act, which has led EPA to regulate facilities emitting regulated pollutants based on the maximum achievable control technology (MACT).

In December 2011, EPA promulgated the MATS Rule, which sets MACT standards for mercury and other HAP emissions from EGUs that consume coal or oil and have a minimum nameplate capacity of 25 megawatts (MW). The MATS Rule requires covered EGUs to comply with emission rate limits for the following categories: (1) mercury; (2) particulate matter (PM), as a proxy for non-mercury metals; and (3) hydrogen chloride (HCl), as a proxy for acid gases. Covered power plants must comply with the MATS Rule by 2015, with the possibility of up to two years of extension from various authorities.

The table below summarizes our modeling inputs for the MATS Rule.

Table 1. Modeling Inputs for Mercury and Air Toxics Standard Rule

Policy	Modeling Inputs
MATS Rule	Mercury: Applied emission rate limits in N_{ew}ERA and allowed N_{ew}ERA to select compliance measures that minimize compliance costs Non-Hg metal HAPs: Required fabric filter retrofits or electrostatic precipitator upgrades on certain units (as per EPA's MATS RIA documentation) HCl: Required scrubbers (either wet or dry) or dry sorbent injection All requirements are assumed to take effect in the model year 2016 (that is, it is assumed that power plants are able to obtain one-year extensions from their states)

Source: NERA assumptions as explained in text.

b. Regional Haze Rule

In 1999 the EPA released the RHR, to improve visibility in 156 national parks and wilderness areas (Class I areas) by limiting emissions of the pollutants that most significantly contribute to haze, such as SO_2, NO_X, and PM. The rule requires each state to develop and implement plans to reduce haze with the goal of reaching "naturally-occurring" visibility conditions by 2064.

SIPs for the first phase of the RHR were required to provide details on (1) how the states will reduce emissions to 2018 target levels such that they will be on a consistent path to achieve their 2064 goals of naturally-occurring visibility; and (2) which facilities within the state will have to implement Best Available Retrofit Technology (BART). Facilities are subject to BART requirements if the facilities were brought online between 1962 and 1977, contribute significantly to visibility impairment at a Class I area, and fall within one of 26 covered source

categories. For this analysis, we focus our attention on the first phase of the RHR: the methods (including BART) by which states will reduce visibility impairment by 2018. Since SIPs for the second phase are not due until July 31, 2018, and likely actions for all subsequent phases are unlikely to be identified even in draft form until after about 2016, our analysis has not attempted to project any requirements of the RHR beyond those of Phase I.

If a SIP (or its subsequent revisions) receives disapproval or limited disapproval from the EPA, a Federal Implementation Plan (FIP) may be developed by the EPA to specify emission reduction actions to be required for facilities as well as the BART requirements for particular facilities in the state. These FIPs have been developed by the federal government after 2008 and thus represent one of the additional air emission requirements. In contrast, we presume that the SIPs represent pre-2009 activities and thus are in the baseline scenario.

In June 2012, EPA rescinded its policy that compliance with CAIR satisfied BART for the CAIR states in favor of a determination that CSAPR would satisfy BART in the CSAPR states. However, since CSAPR was vacated by the D.C. Circuit Court of Appeals in August 2012, CAIR does not currently satisfy BART. Thus, we assume that additional BART controls for NO_x will be required for large BART-eligible EGUs in the CAIR states (and we assume that SO_2 controls installed for compliance with MATS and the $PM_{2.5}$ standard will suffice for BART).

The table below summarizes our modeling inputs for the Regional Haze Rule.

Table 2. Modeling Inputs for Regional Haze Rule

Policy	Modeling Inputs
RHR	Applied compliance measures for Phase 1 (required by 2018) in the SIPs to EGUs in baseline scenario
	Applied compliance measures for Phase 1 (required by 2018) in the FIPs to EGUs in policy scenario
	BART-eligible units greater than 200 MW located in CAIR states are required in the policy scenario to meet BART-specific NO_x rates based on coal boiler type and coal rank (required by 2018)
	Non-EGU compliance costs not included

Source: NERA assumptions as explained in text.

3. National Ambient Air Quality Standards

a. Ozone

The Clean Air Act requires EPA to evaluate NAAQS levels for ozone and other air pollutants every five years. In 1997, EPA set the ozone primary 8-hour NAAQS at 80 parts per billion (ppb). Due to the limited sensitivity of ozone monitors, EPA considers areas with ozone levels as high as 84 ppb as in attainment with the 1997 standard. In 2008, EPA lowered the ozone primary 8-hour NAAQS to 75 ppb.

In early 2009, EPA announced that it was reconsidering the 2008 ozone standard of 75 ppb because it exceeded the level recommended by the Clean Air Scientific Advisory Committee

(CASAC). EPA said it was considering lowering the standard to the range recommended by CASAC, which was between 60 and 70 ppb. In September 2011, the Obama Administration instructed EPA to terminate its reconsideration of the 2008 ozone standard. Thus, the current ozone primary 8-hour NAAQS is the level established in 2008, 75 ppb, and EPA resumed its 5-year periodic review of the ozone NAAQS in light of new scientific information since the 2008 standard was set. EPA is expected to complete its current review of the ozone NAAQS in 2014.

The table below summarizes our modeling inputs for the ozone NAAQS, which presumes that EPA will promulgate a standard of 65 ppb, the mid-point of the range identified by CASAC in its previous review.

Table 3. Modeling Inputs for Ozone NAAQS

Policy	Modeling Inputs
Ozone NAAQS	Baseline scenario: Apply EGU controls for 75 ppb based on EPA RIA data Policy scenario: Apply compliance costs for non-electricity sectors for 65 ppb based on EPA RIA data for both "known" controls and "unknown" controls with regionally staggered implementation between 2019 and end of modeling period

Source: NERA assumptions as explained in text.

The potential costs associated with the ozone rule are large, and their timing (including the timing of capital expenditures) is uncertain. In EPA's RIA, the costs are presented as annualized costs in 2020 (an assumed representative year); but it seems likely that many of these costs would be for capital goods and thus incurred in relatively early years. We developed two cases to bound the potential costs of the ozone rule (and thus the potential economic impacts).

1. *Lower ozone costs case*. This case is based upon EPA's annualized cost estimates for complying with a 65 parts per billion (ppb) ozone standard. This case uses EPA's estimates of annualized costs and assumes the costs start in the year in which attainment is required for each nonattainment area. This provides a lower bound because some costs would be incurred earlier (*i.e.*, before the year in which attainment is required).

2. *Higher ozone costs case*. This case is also based upon EPA's annualized costs for the 65 ppb ozone standard, but it assumes that EPA's estimates of annualized costs would be incurred as capital costs and would occur before and during the year in which attainment is required for each nonattainment area. This case converts the EPA annualized costs into capital costs using an assumed 7 percent discount rate and an assumed 20-year capitalization period. This case provides an upper bound because some costs would be incurred later (*i.e.*, after the year in which attainment is required).

b. Sulfur Dioxide

SO_2 is a gaseous chemical compound released into the atmosphere by power plants and various industrial processes. The first SO_2 NAAQS was established in 1971 with the goal of reducing SO_2 air pollution to below 140 ppb within any given 24-hour period. This goal was to be achieved through emissions controls on eligible electric sector and non-electric sector facilities that contribute to SO_2 pollution as determined in SIPs.

Since 1971, the SO_2 NAAQS has been revised several times. In June 2010, EPA limited SO_2 air pollution to 75 ppb or below, based on a three-year average of the annual 99th percentile of 1-hour daily maximum concentrations. Like its predecessors, the policy will involve the development of SIPs that require emissions controls for various SO_2-emitting units.

The SO_2 1-hour NAAQS also mandates the creation of an expanded SO_2 monitoring system. Currently, only 488 monitors are in place to evaluate SO_2 levels, an estimated one-third of the number required to adequately measure SO_2 levels in all areas of maximum concentration. EPA does not provide cost estimates for expanding the monitoring network to cover all areas.

The table below summarizes our modeling inputs for the SO_2 NAAQS.

Table 4. Modeling Inputs for SO_2 NAAQS

Policy	Modeling Inputs
SO_2 NAAQS	Electricity sector: Assume that SO_2 reductions from other policies would eliminate the need for SO_2 reductions for NAAQS Non-electricity sectors: Apply compliance costs beginning in 2019 using cost estimates from EPA's SO_2 NAAQS RIA

Source: NERA assumptions as explained in text

c. $PM_{2.5}$

Under the authority of the Clean Air Act, EPA sets NAAQS related to PM for $PM_{2.5}$ (fine PM) and two other PM categories. EPA also sets standards both on average annual ambient levels and 24-hour ambient levels. Our focus is on the $PM_{2.5}$ primary annual NAAQS, since this is the portion of the PM standard that accounts for the vast majority of non-attainment and thus is the standard that could lead to the most substantial compliance costs.

EPA set the $PM_{2.5}$ primary annual NAAQS at 15 micrograms per cubic meter ($\mu g/m^3$) in 1997 and maintained it at this level in the review completed in 2006. In addition to being designed to protect human health, the $PM_{2.5}$ standards also affect visibility and thus, as discussed below, our modeling assumptions for attainment of the $PM_{2.5}$ NAAQS have substantial overlap with those for Phase I of the RHR.

In June 2012, EPA proposed lowering the $PM_{2.5}$ primary annual NAAQS from the current level of 15 $\mu g/m^3$ to between 12 and 13 $\mu g/m^3$. In the RIA for the new $PM_{2.5}$ standard, EPA evaluated 14, 13, 12, and 11 $\mu g/m^3$ as the potential new primary annual level. Although the ***Federal***

Register notice speaks only of lowering the standard to between 12 and 13 μg/m^3, an EPA presentation to OMB (also from June 2012) indicates that EPA was inclined to lower the standard to 12 μg/m^3.

EPA intends to make final designations for $PM_{2.5}$ non-attainment areas in 2014. By 2018, implementation plans will be due to the EPA. Plans can include federal measures, as well as any needed local measures, to demonstrate that an area will meet the standards. By 2020, states are required to meet primary standards. A state may request a possible extension to 2025, depending on the severity of fine particle pollution and the availability of controls.

The table below summarizes our modeling methodology for the $PM_{2.5}$ NAAQS. Our analysis assumes that EPA will set a standard of 12 μg/m^3.

Table 5. Modeling Inputs for $PM_{2.5}$ NAAQS

Policy	Modeling Inputs
$PM_{2.5}$ NAAQS	Due to the NAAQS, EGUs in CSAPR states and California (the states that are most likely to be in non-attainment areas) would not have the option of using DSI for MATS compliance but would instead have to use the more expensive wet or dry scrubber (depending on the relative economics of the two scrubber options), or else retire

Source: NERA assumptions as explained in text.

4. Coal Combustion Residuals

CCR, which include fly ash, bottom ash, boiler slag, and scrubber waste, are regulated under RCRA. Enacted in 1976, RCRA gives EPA the authority to control hazardous waste throughout its lifespan (*i.e.*, generation, transportation, treatment, storage, and disposal). In 1986, amendments to RCRA enabled EPA to further address environmental problems associated with hazardous waste. Under the current statute, CCR are considered exempt wastes and are not subject to the same level of regulation as hazardous wastes.

EPA has considered several alternative forms of regulations for the disposal of CCR. The alternative forms of regulation differ in their classification under Subtitles C and D of the RCRA. Subtitles C and D propose different waste classifications (hazardous and non-hazardous, respectively), as well as different compliance measures (*e.g.*, requiring liners at all surface impoundments or only at new surface impoundments) and regulatory requirements.

Recently, there has been some congressional support to regulate CCR under Subtitle D. In October of 2011, the House passed H.R. 2273, a bill to regulate CCR as a non-hazardous waste. In August 2012, a similar bill was introduced in the Senate with bipartisan support; it would also set up a non-hazardous-waste regulatory scheme for CCR.

The table below summarizes our compliance assumptions for CCR regulations.

Table 6. Compliance Assumptions for CCR Regulations

Policy	Compliance Assumptions
CCR	Assign costs to coal units in 2019 based on EPA Subtitle D in initial EPA proposal

Source: NERA assumptions as explained in text.

5. Clean Water Act Section 316(b)

Section 316(b) of the Clean Water Act calls for EPA to develop regulations for the intake of cooling water by power plants and other facilities. These regulations provide the basis for individual 316(b) requirements imposed on power plants and other facilities in their National Pollution Discharge Elimination System (NPDES) permits, typically issued by states that have assumed regulatory responsibility for the NPDES program. The key regulatory requirement under Section 316(b) is that the location, design, construction, and capacity of a facility's cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. These facilities withdraw water and in the process, fish and other aquatic organisms may be lost if they become trapped against intake screens ("impingement") or pulled into the cooling system ("entrainment").

In April 2011, EPA proposed new 316(b) cooling water intake requirements for existing power plants and other industrial facilities. The regulations would affect the design of cooling water intake structures (to reduce impingement) and the flow rates through cooling water systems (to reduce entrainment) at the facilities. Various technologies reduce impingement and entrainment losses, including the retrofitting of plants with cooling towers to provide closed-cycle cooling.

EPA has not finalized its 316(b) rule. In June 2012, EPA issued a Notice of Data Availability (NODA) providing the results of a willingness-to-pay survey to estimate the potential benefits of its 316(b) rule that it is considering using as an alternative to benefit estimation methods based primarily on valuing potential changes in commercial and recreational fish harvests (EPA 2012a). The survey results suggest that the benefits of each regulatory option could be larger than the costs, although commentators have questioned the reliability of these benefit results as indications of the value that households would place on fish protection benefits (see *e.g.*, NERA 2012). In July 2012, EPA entered into a settlement agreement with Riverkeeper to finalize its 316(b) rule by June 2013, about one year later than in the previous agreement.

The table below summarizes our modeling inputs for the 316(b) policy.

Table 7. Modeling Inputs for 316(b) Regulations

Policy	Modeling Inputs
316(b)	Impingement: Assign costs using EPA impingement compliance cost parameters to units based on EPA Option 1 (*i.e.*, standards at all facilities withdrawing more than 2 million gallons per day), unless the units also require entrainment measures Entrainment: Assign costs using EPA entrainment compliance cost parameters for closed-cycle cooling (*i.e.*, cooling towers) to units that withdraw more than 500 million gallons per day, have a capacity utilization rate of at least 35 percent, and do not operate on ponds or canals The assumed compliance deadlines are 2019 for fossil units and 2025 for nuclear units

Source: NERA assumptions as explained in text.

6. Higher Natural Gas Prices Case

The higher natural gas prices case was formed by increasing the Henry Hub natural gas prices in the baseline scenario by the amounts shown below in Table 8. The increases were based upon the differences in natural gas prices between *AEO 2012*'s Reference Case and *AEO 2012*'s Low EUR (Expected Ultimate Recovery) Case. We used the lower ozone costs for this case and did not make any other changes to inputs. Note that natural gas prices in this case would be affected by the environmental policies because of changes in demand.

Table 8. Increase in Henry Hub Natural Gas Prices in Baseline Scenario of Higher Natural Gas Prices Case (2010$/MMBtu)

	2013	2016	2019	2022	2025	2028	2031	2034
Henry Hub Price	$0.00	$0.50	$1.00	$1.00	$1.50	$1.50	$1.50	$1.50

Source: NERA assumptions as explained in text.

III. Study Results

This chapter summarizes the study results for our analyses of the cumulative energy and economic impacts of the seven major environmental policies. The results are grouped into two categories: (1) electricity and energy market effects; and (2) economic impacts. Results for each of the three cases are shown within each category of results. Additional results for the three cases are provided in separate appendices.

A. Electricity and Energy Market Impacts

As described in the previous section, we used N_{ew}ERA to estimate net changes in various electricity and energy impacts, including impacts on coal-unit retirements, coal-fired generation, natural gas-fired generation, fuel prices, and electricity prices due to the seven policies. As noted, we developed results for two cases that differ in the treatment of ozone costs and for one case with different future natural gas prices.

1. National Results

Table 9 shows the retrofits in the baseline scenario and both ozone cost cases. Retrofits in the baseline scenario are attributable to CAIR, state rules, pre-2009 NSR settlements, and pre-2009 ozone and RHR compliance. The policy scenario retrofits are due to a combination of the seven regulations. The cooling tower retrofit numbers include 43 GW installed on nuclear units, with the remainder on coal units. (Cooling towers were projected to be required on some natural gas- and oil-fired units, but it was assumed to not be cost-effective for those units.) The incremental additions of retrofits are nearly identical whether lower or higher ozone costs are used.

Table 9. Electricity Sector Retrofits, 2013-2034: Lower and Higher Ozone Costs Cases

	Baseline	Lower Ozone Costs		Higher Ozone Costs	
	GW	GW	Change	GW	Change
Wet Scrubbers	18.1	20.5	2.4	21.4	3.3
Dry Scrubbers	5.6	62.2	56.6	62.0	56.4
Dry Sorbent Injection	0.7	3.4	2.7	3.4	2.7
Selective Catalytic Reduction	20.9	30.0	9.1	30.9	10.0
Selective Non-Catalytic Reduction	0.0	3.0	3.0	3.0	3.0
Activated Carbon Injection	28.3	83.6	55.3	84.3	56.0
Cooling Towers	0.0	98.2	98.2	98.0	98.0
CCR Controls	0.0	189.4	189.4	189.1	189.1

Note: Includes retrofits on nuclear units for entrainment; all other retrofits are on coal units.
Source: NERA calculations from N_{ew}ERA model.

Table 10 shows the retrofits in the baseline scenario and higher natural gas prices case. There are greater retrofits in the higher natural gas prices case (as compared to the other two policy

scenarios). This is attributable to higher natural gas prices translating to higher wholesale electricity prices, which provide dispatched coal units with higher energy margins to cover the costs of retrofits. As a result, fewer coal units are projected to retire.

Table 10. Electricity Sector Retrofits, 2013-2034: Higher Natural Gas Prices Case

	Baseline	**Higher Natural Gas Prices**	
	GW	GW	Change
Wet Scrubbers	19.7	22.0	2.3
Dry Scrubbers	6.2	69.8	63.6
Dry Sorbent Injection	0.7	4.5	3.8
Selective Catalytic Reduction	21.0	30.8	9.8
Selective Non-Catalytic Reduction	0.0	2.9	2.9
Activated Carbon Injection	29.2	91.8	62.6
Cooling Towers	0.0	102.1	102.1
CCR Controls	0.0	202.6	202.6

Note: Includes retrofits on nuclear units for entrainment; all other retrofits are on coal units.
Source: NERA calculations from N_{ew}ERA model.

Table 11 summarizes the national costs for the electricity sector with lower ozone costs, given the coal unit retirements (and to a lesser extent retirements of other units subject to any of the policies) and other actions necessary to comply with the seven regulations. These costs include compliance costs for coal units that do not retire (*i.e.*, retrofits), capital costs for new generating capacity that would replace retiring coal units, and changes in fuel costs. Incremental costs to the electricity sector are projected to be approximately $15 billion (in 2012$) per year on average over the period from 2013 through 2034. The costs represent a total of $203 billion (present value in 2012$ as of January 1, 2013) over the period from 2013 through 2034. The largest cost category is environmental controls and replacement capacity, which total more than $12 billion per year on an annualized basis.

Table 11. Electricity Sector Costs, 2013-2034 (billion 2012$): Lower Ozone Costs Case

	Annual [(a)]	**Present Value** [(b)]
Environmental Controls and O&M	$12.8	$168
Replacement Capacity	$1.9	$25
Fuel	$0.7	$10
Total	$15.4	$203

Note: (a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
Source: NERA calculations as explained in text.

Table 12 summarizes the national costs for the electricity sector with higher ozone costs. Again, because the differences between the lower and higher ozone costs cases are the timing for ozone

compliance costs in the non-electric sectors, there is little difference in the electricity sector costs whether lower or higher ozone costs are used.

Table 12. Electricity Sector Costs, 2013-2034 (billion 2012$): Higher Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Environmental Controls and O&M	$12.7	$167
Replacement Capacity	$1.8	$24
Fuel	$0.5	$7
Total	$15.0	$198

Note: (a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
Source: NERA calculations as explained in text.

Table 13 summarizes the national costs for the electricity sector with higher natural gas prices. The higher natural gas prices in the baseline and in the scenario allow more coal units to absorb the costs of environmental controls leading to fewer retirements and the need for less new capacity. Overall, the electricity sector costs are somewhat higher than the other two cases.

Table 13. Electricity Sector Costs, 2013-2034 (billion 2012$): Higher Natural Gas Prices Case

	Annual [(a)]	Present Value [(b)]
Environmental Controls and O&M	$15.1	$199
Replacement Capacity	$0.9	$12
Fuel	$0.7	$9
Total	$16.7	$220

Note: (a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
Source: NERA calculations as explained in text.

Table 14 summarizes the average annual energy effects of the seven policies at the national level over the period from 2013 through 2034 with lower ozone costs. (Detailed annual impacts are provided in Appendix C, with effects that are both higher and lower than these average values).

Table 14. Average Annual Energy Market Impacts, 2013-2034: Lower Ozone Costs Case

	Total Coal Retirements	Coal-Fired Generation	Coal Price at Minemouth	Natural Gas-Fired Generation	Natural Gas Price at Henry Hub	Avg. Retail Electricity Price
	(GW)	(million MWh)	(2012$/ton)	(million MWh)	(2012$/MMBtu)	(2012$/MWh)
Baseline	27	2,018	$35.67	1,027	$5.48	$100.25
Policies	69	1,845	$36.11	1,124	$5.64	$103.12
Change	+42	-172	+$0.44	+97	+$0.15	+$2.87
% Change	+156%	-8.5%	+1.2%	+9.5%	+2.8%	+2.9%

Note: Coal retirements are cumulative from 2013 through 2034.
Source: NERA calculations as explained in text.

The potential costs of the seven policies are estimated to lead to 42 gigawatts (GW) of additional prematurely retired coal-fired capacity. This estimate is in addition to the 27 GW that are in the baseline scenario (*i.e.*, retirements projected without the seven regulations in place). The total coal retirements are 69 GW, which represents about 20 percent of the 2012 U.S. coal-fired electricity generating capacity.[6] As noted, this estimate does not include the effects of other potential requirements—notably greenhouse gas emission regulations and new water discharge requirements (effluent guidelines)—or concerns related to electricity system reliability.

The potential impacts of the seven policies on energy markets are as follows:

- Coal-fired generation is projected to decrease by an average of 8.5 percent relative to baseline scenario levels over the 2013 through 2034 period.

- In contrast, natural gas-fired generation is projected to increase by an average of 9.5 percent relative to baseline scenario levels over the same period.

- Average minemouth coal prices for each coal type are projected to decline, reflecting the reduction in coal-fired generation. Weighted average coal prices however increase an average of 1.2 percent relative to baseline scenario levels over the same period.[7]

[6] This level of retirements is estimated in the N_{ew}ERA model and is not influenced by unit retirement announcements attributable to CSAPR, MATS or any other policies introduced in the policy scenarios.

[7] While almost all of the 24 individual coal types in the N_{ew}ERA model experience declines in demand and declines in price, the weighted average coal price increases due to a shift in the mix of coal. In particular, the requirement to install scrubbers to remove sulfur—largely due to the MATS Rule—decreases the demand for low-sulfur coals, which generally have low prices per ton, and increases the demand for high-sulfur coals, which generally have higher prices per ton. The net effect of the shift from low-price-per-ton coal to higher-price-per-ton coal results in a small increase in the average coal price in the policy case.

- Average natural gas prices are projected to increase, reflecting the increased demand for natural gas-fired generation. Henry Hub natural gas prices increase an average of 2.8 percent relative to baseline scenario levels over the 2013 through 2034 period.

- Average retail electricity prices are projected to increase an average of 2.9 percent relative to the baseline scenario prices over the same period.

Table 15 summarizes the average annual effects of the seven policies at the national level over the period from 2013 through 2034 with higher ozone costs. (Detailed annual impacts are provided in Appendix D, with effects that are both higher and lower than these average values). The differences between the lower and higher ozone costs cases relate to the timing of ozone compliance costs for non-electric sectors. Since electric sector costs do not differ, there are very small differences in the electric and energy results between the lower and higher ozone costs cases.

Table 15. Average Annual Energy Market Impacts, 2013-2034: Higher Ozone Costs Case

	Total Coal Retirements	**Coal-Fired Generation**	**Coal Price at Minemouth**	**Natural Gas-Fired Generation**	**Natural Gas Price at Henry Hub**	**Avg. Retail Electricity Price**
	(GW)	(million MWh)	(2012$/ton)	(million MWh)	(2012$/MMBtu)	(2012$/MWh)
Baseline	27	2,018	$35.67	1,027	$5.48	$100.25
Policies	69	1,843	$36.16	1,122	$5.63	$103.07
Change	+42	-174	+$0.49	+95	+$0.15	+$2.82
% Change	+156%	-8.6%	+1.4%	+9.3%	+2.7%	+2.8%

Note: Coal retirements are cumulative from 2013 through 2034.
Source: NERA calculations as explained in text.

Table 16 summarizes the average annual effects of the seven policies at the national level over the period from 2013 through 2034 with higher natural gas prices. (Detailed annual impacts are provided in Appendix E, with effects that are both higher and lower than these average values). The higher natural gas prices provide coal with a better competitive position in the generation supply stack in both the baseline and policy scenarios. As a result there are fewer retirements and a smaller decline in coal-fired generation (and a smaller increase in natural gas-fired generation) than in the other two cases.

Table 16. Average Annual Energy Market Impacts, 2013-2034: Higher Natural Gas Prices Case

	Total Coal Retirements (GW)	Coal-Fired Generation (million MWh)	Coal Price at Minemouth (2012$/ton)	Natural Gas-Fired Generation (million MWh)	Natural Gas Price at Henry Hub (2012$/MMBtu)	Avg. Retail Electricity Price (2012$/MWh)
Baseline	23	2,077	$36.65	845	$6.58	$105.00
Policies	52	1,965	$36.80	898	$6.72	$107.78
Change	+29	-112	+$0.16	+53	+$0.14	+$2.79
% Change	+125%	-5.4%	+0.4%	+6.3%	+2.1%	+2.7%

Note: Coal retirements are cumulative from 2013 through 2034.
Source: NERA calculations as explained in text.

2. Uncertainties Regarding Energy Market Impacts

The projected electricity and energy market impacts due to the seven environmental policies are significant. The impacts arise because of substantial compliance costs (which cause a substantial number of coal-fired units to retire and force other coal units to incur substantial retrofit costs in order to comply) and because of the market reactions to these initial impacts.

The impacts depend upon many factors, including the baseline conditions—including projected future natural gas prices—and the details of the market reactions to the policy changes that are embedded in N_{ew}ERA. The baseline scenario also includes assumptions on the nature of future regulatory requirements. As noted above, we modified the baseline scenario to reflect environmental policies enacted before 2009. For example, we include state mercury requirements in the baseline scenario, which tend to decrease the impacts relative to a baseline without the state requirements.

The electricity market impacts depend upon many aspects of the electricity systems that vary by region. The N_{ew}ERA results do not include considerations related to highly location-specific factors such as transmission security and the time constraints on retiring or retrofitting units, particularly relatively large units (ICF 2011). The N_{ew}ERA model makes the highly simplifying assumption that retirements and retrofits needed to achieve compliance can be accomplished with no timing constraints. To the extent there are constraints related to timing for retirement or retrofit, our analysis understates the costs of the rules we have analyzed.

3. Regional Results

N_{ew}ERA provides energy price results for various regions, including 32 U.S. electricity price regions. The electricity price impacts of the seven policies differ by region depending upon many factors including the following:

- Reliance on coal-fired generation under baseline conditions;
- Coal unit retirements;
- Need for replacement capacity;
- Type of replacement capacity that is most economical;
- Retrofits for coal units that continue to operate as well as the costs of those retrofits;
- Capacity factors for coal units;
- Regional delivered fuel prices;
- Inter-regional electricity trade; and
- Regulatory regime.

Table 17 provides estimates of the percentage increases in retail electricity rates in the 11 NewERA macroeconomic regions due to the seven policies (for all three policy scenarios). Regional definitions are shown in Appendix A. As with the prior results, these figures are based upon the average percentage changes over the period from 2013 through 2034 (detailed annual impacts are provided in Appendix C for lower ozone costs, Appendix D for higher ozone costs, and Appendix E for higher natural gas prices, with effects in individual years that are both higher and lower than these average values).

Table 17. Average Electricity Price Impacts by Region, 2013-2034

	Lower Ozone Costs	Higher Ozone Costs	Higher Natural Gas Prices
New York/New England	0.9%	0.9%	1.1%
Mid-Atlantic Coast	0.6%	0.6%	0.7%
Upper Midwest	8.5%	8.4%	7.9%
Southeast	3.1%	3.1%	2.4%
Florida	1.0%	1.0%	1.4%
Mississippi Valley	3.7%	3.5%	3.1%
Mid-America	8.0%	8.0%	5.6%
Texas, Oklahoma, Louisiana	1.0%	0.9%	1.4%
Arizona/Mountain States	2.3%	2.3%	1.6%
California	0.6%	0.5%	0.6%
Pacific Northwest	1.3%	1.2%	1.6%

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

Table 18 shows the distribution of coal-unit retirements across regions for both ozone cost cases.

Table 18. Estimated Coal Retirements by Region: Lower and Higher Ozone Costs Cases

	Baseline	Lower Ozone Costs		Higher Ozone Costs	
	GW	GW	Change	GW	Change
New York/New England	0.7	1.6	0.9	1.6	0.9
Mid-Atlantic Coast	2.9	6.1	3.2	6.1	3.2
Upper Midwest	8.2	18.8	10.5	18.8	10.6
Southeast	4.2	16.4	12.2	16.6	12.4
Florida	0.0	0.8	0.8	0.8	0.8
Mississippi Valley	5.9	8.5	2.7	8.6	2.7
Mid-America	0.1	5.6	5.5	5.6	5.5
Texas, Oklahoma, Louisiana	1.2	4.3	3.1	4.3	3.1
Arizona/Mountain States	2.1	5.2	3.0	4.8	2.7
California	0.3	0.3	0.0	0.1	-0.2
Pacific Northwest	1.3	1.3	0.0	1.3	0.0
United States	26.9	68.8	41.8	68.6	41.7

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

Table 19 shows the distribution of coal-unit retirements across regions for the higher natural gas prices case. There are fewer coal unit retirements in both the baseline and policy scenario, with fewer incremental retirements as well (compared to the other two cases).

Table 19. Estimated Coal Retirements by Region: Higher Natural Gas Prices Case

	Baseline	Higher Natural Gas Prices	
	GW	GW	Change
New York/New England	0.1	0.3	0.2
Mid-Atlantic Coast	2.1	5.2	3.1
Upper Midwest	7.7	16.4	8.7
Southeast	4.2	10.8	6.6
Florida	0.0	0.1	0.0
Mississippi Valley	3.8	7.6	3.7
Mid-America	1.0	4.5	3.5
Texas, Oklahoma, Louisiana	1.2	3.5	2.3
Arizona/Mountain States	1.4	2.3	0.9
California	0.3	0.3	0.0
Pacific Northwest	1.3	1.3	0.0
United States	23.1	52.1	29.0

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

B. Economic Impacts

N_{ew}ERA provides integrated estimates of the potential economic impacts of the seven policies along with the energy market impacts.

1. Results

Table 20 summarizes the potential economic impacts of the seven regulations for the lower ozone costs case in terms of the overall U.S. economy, as measured by changes in GDP and disposable income. U.S. GDP would be reduced by $38 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $500 billion (2012$). U.S. disposable income would be reduced by $29 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $375 billion (2012$). Disposable income per household would be reduced by $226 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $3,000 (2012$).

Table 20. U.S. GDP and Disposable Income Impacts, 2013-2034: Lower Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Gross Domestic Product Loss	$38 billion	$500 billion
Disposable Income Loss [(c)]	$29 billion	$375 billion
Disposable Income Loss per Household	$226	$3,000

Note: All dollar values are in 2012$.
(a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Disposable income includes income to labor and to capital.
Source: NERA calculations as explained in text.

Table 21 summarizes the potential economic impacts of the seven regulations under the higher ozone costs case in terms of the overall U.S. economy. U.S. GDP would be reduced by $63 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $830 billion (2012$). U.S. disposable income would be reduced by $66 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $870 billion (2012$). Disposable income per household would be reduced by $512 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $6,700 (2012$). The higher ozone costs lead to a substantially greater negative impact on the overall U.S. economy than in the lower ozone costs case; the earlier timing of these costs and greater concentration of these costs into fewer years leads to a greater shock to the economy and greater displacement of productive economic activities.

Table 21. U.S. GDP and Disposable Income Impacts, 2013-2034: Higher Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Gross Domestic Product Loss	$63 billion	$830 billion
Disposable Income Loss [(c)]	$66 billion	$870 billion
Disposable Income Loss per Household	$512	$6,700

Note: All dollar values are in 2012$.
(a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Disposable income includes income to labor and to capital.
Source: NERA calculations as explained in text.

Table 22 summarizes the potential economic impacts of the seven regulations in the higher natural gas prices case in terms of the overall U.S. economy. U.S. GDP would be reduced by $36 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $480 billion (2012$). U.S. disposable income would be reduced by $27 billion on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $360 billion (2012$). Disposable income per household would be reduced by $217 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $2,900 (2012$). These costs are similar to

those for the lower ozone costs case since the higher natural gas prices case also uses the lower ozone costs.

Table 22. U.S. GDP and Disposable Income Impacts, 2013-2034: Higher Natural Gas Prices Case

	Annual [(a)]	Present Value [(b)]
Gross Domestic Product Loss	$36 billion	$480 billion
Disposable Income Loss [(c)]	$27 billion	$360 billion
Disposable Income Loss per Household	$217	$2,900

Note: All dollar values are in 2012$.
(a) Annual values are annualized based on the respective present values.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Disposable income includes income to labor and to capital.
Source: NERA calculations as explained in text.

Table 23 shows the regional losses in average disposable income over the period from 2013 to 2034 on an annualized basis (for all three cases). In the near term, households face a large loss in disposable income due to the large investments that would be needed to ensure compliance with the MATS Rule in 2016. All regions would experience larger losses in average disposal income under the higher ozone cost scenario than the lower ozone costs case, while the lower ozone costs and higher natural gas prices cases have similar results. Annual results for loss in disposable income between 2013 and 2034 are shown in Appendix C, Appendix D, and Appendix E for the lower ozone costs, higher ozone costs, and higher natural gas prices cases, respectively.

Table 23. Loss in Disposable Income per Household, Annualized (2013-2034), by Region

	Lower Ozone Costs	Higher Ozone Costs	Higher Natural Gas Prices
New York/New England	$237	$490	$236
Mid-Atlantic Coast	$229	$559	$199
Upper Midwest	$503	$960	$448
Southeast	$175	$315	$112
Florida	$102	$168	$110
Mississippi Valley	$417	$1,020	$373
Mid-America	$248	$378	$165
Texas, Oklahoma, Louisiana	$173	$535	$140
Arizona/Mountain States	$144	$293	$57
California	$124	$521	$112
Pacific Northwest	$128	$227	$693

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

Table 24 focuses on the specific impacts to workers as a result of the seven regulations using the lower ozone compliance costs, impacts that are important to policy evaluations. The N_{ew}ERA model results indicate that the seven policies would result in an average annualized reduction in labor income of $33 billion, with a cumulative present value loss over the period from 2013 to 2034 of $430 billion. (See Appendix A for a summary of N_{ew}ERA's modeling of labor impacts.) Labor income per household would be reduced by $249 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $3,300 (2012$). The labor income loss can be expressed in terms of job equivalents, *i.e.*, total loss in labor income divided by the average salary, resulting in an estimated reduction of 590,000 job-equivalents on average each year from 2013 through 2034.

Table 24. U.S. Labor Income Impacts, 2013-2034: Lower Ozone Costs Case

	Annual [(a)]	**Present Value** [(b)]
Labor Income Loss [(c)]	$33 billion	$430 billion
Labor Income Loss per Household	$249	$3,300
Labor Income Loss as Job-Equivalents [(d)]	590,000	n/a

Notes: "n/a" denotes that the result category is not applicable.
All dollar values are in 2012$.
(a) Annual values for labor income loss and labor income loss per household are annualized values based on the respective present values. Annual value for labor income loss as job-equivalents is the average of impacts in each year.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Labor income loss consists of two effects: (1) reductions in real wage per hour worked; and (2) reductions in labor market participation (hours worked) in response to lower wages.
(d) Job-equivalents are calculated as the total loss in labor income divided by the average salary. This is not a precise measure of the number of discrete jobs that would be lost, but one that allows us to express income loss to workers in terms of the equivalent employees earning the average salary.
Source: NERA calculations as explained in text.

Table 25 includes the specific impacts to workers as a result of the seven regulations using the higher ozone costs. The N_{ew}ERA model results indicate that the seven policies would result in an average annualized reduction in labor income of $54 billion, with a cumulative present value loss over the period from 2013 to 2034 of $710 billion. Labor income per household would be reduced by $416 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $5,500 (2012$). The labor income loss is a reduction in 887,000 job-equivalents on average each year from 2013 through 2034. The larger economic impacts associated with the higher ozone costs thus would lead to substantially greater losses to workers as measured by all three labor metrics.

Table 25. U.S. Labor Income Impacts, 2013-2034: Higher Ozone Costs Case

	Annual [(a)]	Present Value [(b)]
Labor Income Loss [(c)]	$54 billion	$710 billion
Labor Income Loss per Household	$416	$5,500
Labor Income Loss as Job-Equivalents [(d)]	887,000	n/a

Notes: "n/a" denotes that the result category is not applicable.
All dollar values are in 2012$.
(a) Annual values for labor income loss and labor income loss per household are annualized values based on the respective present values. Annual value for labor income loss as job-equivalents is the average of impacts in each year.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Labor income loss consists of two effects: (1) reductions in real wage per hour worked; and (2) reductions in labor market participation (hours worked) in response to lower wages.
(d) Job-equivalents are calculated as the total loss in labor income divided by the average salary. This is not a precise measure of the number of discrete jobs that would be lost, but one that allows us to express income loss to workers in terms of the equivalent employees earning the average salary.
Source: NERA calculations as explained in text.

Table 26 includes the specific impacts to workers as a result of the seven regulations using the higher natural gas prices case. The N_{ew}ERA model results indicate that the seven policies would result in an average annualized reduction in labor income of $30 billion, with a cumulative present value loss over the period from 2013 to 2034 of $390 billion. Labor income per household would be reduced by $226 on an annualized basis, with a cumulative present value loss from 2013 to 2034 of $3,000 (2012$). The labor income loss is a reduction in 544,000 job-equivalents on average each year from 2013 through 2034. The economic impacts associated with the higher natural gas prices are similar to those with the lower ozone costs.

Table 26. U.S. Labor Income Impacts, 2013-2034: Higher Natural Gas Prices Case

	Annual [(a)]	Present Value [(b)]
Labor Income Loss [(c)]	$30 billion	$390 billion
Labor Income Loss per Household	$226	$3,000
Labor Income Loss as Job-Equivalents [(d)]	544,000	n/a

Notes: "n/a" denotes that the result category is not applicable.
All dollar values are in 2012$.
(a) Annual values for labor income loss and labor income loss per household are annualized values based on the respective present values. Annual value for labor income loss as job-equivalents is the average of impacts in each year.
(b) Present values are calculated over the period 2013-2034 using a real annual discount rate of 5 percent.
(c) Labor income loss consists of two effects: (1) reductions in real wage per hour worked; and (2) reductions in labor market participation (hours worked) in response to lower wages.
(d) Job-equivalents are calculated as the total loss in labor income divided by the average salary. This is not a precise measure of the number of discrete jobs that would be lost, but one that allows us to express income loss to workers in terms of the equivalent employees earning the average salary.
Source: NERA calculations as explained in text.

Table 27 shows the regional changes in income paid to workers for the three policy scenarios, stated as an equivalent number of jobs, on average over the period 2013 through 2034. While

some of the differences across regions are simply a function of their relative population size, other differences reflect the higher costs faced in some regions from the seven regulations.

Table 27. Average Annual Loss in Labor Income (Stated as the Equivalent Number of Jobs), by Region

	Lower Ozone Costs	Higher Ozone Costs	Higher Natural Gas Prices
New York/New England	40,000	56,000	39,000
Mid-Atlantic Coast	42,000	67,000	40,000
Upper Midwest	144,000	197,000	130,000
Southeast	84,000	98,000	70,000
Florida	10,000	3,000	10,000
Mississippi Valley	104,000	171,000	100,000
Mid-America	36,000	31,000	29,000
Texas, Oklahoma, Louisiana	64,000	117,000	66,000
Arizona/Mountain States	31,000	33,000	25,000
California	21,000	108,000	20,000
Pacific Northwest	13,000	6,000	15,000

Source: NERA calculations as explained in text.

2. Uncertainties Regarding Economic Impacts

The estimated economic impacts of the seven environmental policies over the period from 2013 through 2034 are substantial, particularly in the higher ozone costs case. These impacts include many factors, including: the positive impacts of expenditures on environmental controls and replacement electricity capacity; the negative effects of reduced coal sales and reduced coal production; the positive effects of increased natural gas sales; both the negative effects of higher natural gas prices on consumers and the positive effects on producers; and the negative effects of electricity price increases on consumers. In addition, the timing of impacts depends upon how the capital costs of pollution controls and increased replacement capacity are financed. The overall impacts are thus a complicated result of a large number of positive and negative factors.

These estimates are subject to various types of uncertainties that have not been modeled, including uncertainties regarding the energy market and other inputs. As noted above, the coal unit retirements and energy market impacts are subject to various uncertainties, which translate into uncertainties regarding the economic impacts. There are additional uncertainties regarding the modeling of these economic impacts. The model does not presume that environmental compliance expenditures use any unemployed or idle resources. In addition, the model assumes that consumers can shift away from more expensive energy and thus reduce the negative impacts of higher natural gas and electricity prices, an assumption that may understate the likely negative impacts of the price increases.

IV. References

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Appendix A: N_{ew}ERA Model

This appendix provides information on NERA's N_{ew}ERA modeling system.

A. Overview

NERA's N_{ew}ERA modeling system is an integrated energy and economic model that includes a bottom-up representation of the electricity sector, including all of the unit-level details that are required to accurately evaluate changes in the electric sector. N_{ew}ERA integrates the electricity sector model with a macroeconomic model that includes all other sectors of the economy (except for the electricity sector) using a top-down representation. The model produces integrated forecasts for future years; the modeling for this study was for the period from 2013 to 2034 with modeling inputs and results for every third year in that period. The model produces a standard set of reports that includes the following information.

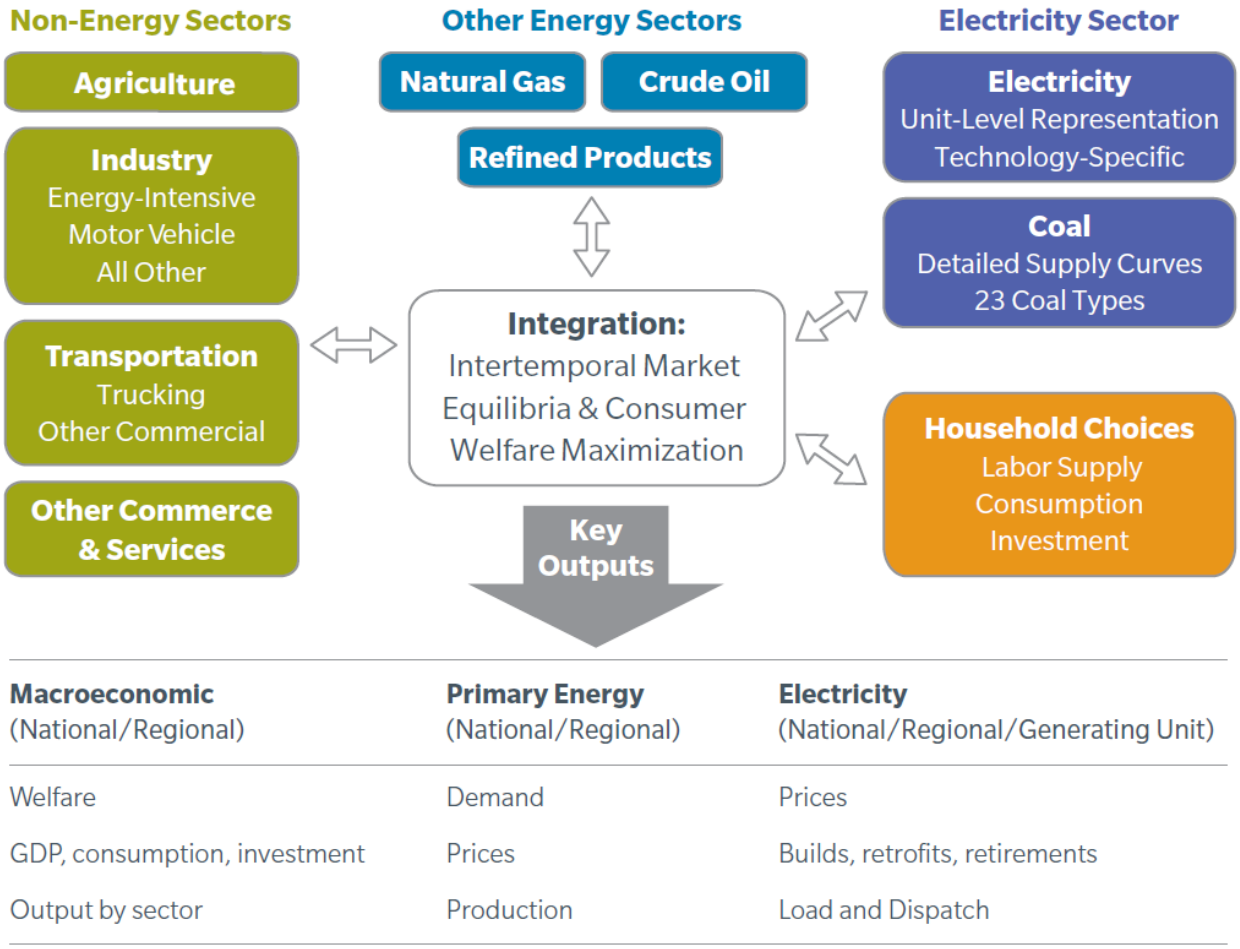
- *Unit-level investments in the electric sector* – retrofits in response to environmental policies, new builds (full range of new generation technologies represented), retirements based on economics.

- *Prices* – wholesale electricity prices for each of 32 U.S. regions, capacity prices for each U.S. region, delivered electricity prices by sector for each of 11 macroeconomic regions in N_{ew}ERA, Henry Hub natural gas prices and delivered natural gas prices to the electric sector for each U.S. region, minemouth coal prices for 24 different types of coal, delivered coal prices by coal unit, refined oil product prices (gasoline and diesel fuel), renewable energy credit (REC) prices for each state/regional renewable portfolio standard (RPS), and emissions prices for all regional and national programs with tradable credits.

- *Macroeconomic results* – gross domestic product (and gross regional product for each macroeconomic region), welfare, changes in disposable income, and changes in labor income and real wage rates (used to estimate labor market changes in terms of an equivalent number of jobs).

Figure A-1 provides a simplified representation of the key elements of the N_{ew}ERA modeling system.

Figure A-1: N_{ew}ERA Modeling System Representation



B. Electric Sector Model

The electric sector model that is part of the N_{ew}ERA modeling system is a bottom-up model of the electric and coal sectors. The model is fully dynamic and includes perfect foresight (under the assumption that future conditions are known). Thus, all decisions within the model are based on minimizing the present value of costs over the entire time horizon of the model while meeting all specified constraints, including demand, peak demand, emissions limits, transmission limits, RPS regulations, fuel availability and costs, and new build limits. The model set-up is intended to mimic (as much as is possible within a model) the approach that electric sector investors use to make decisions. In determining the least-cost method of satisfying all these constraints, the model endogenously decides:

- What investments to undertake (*e.g.*, addition of retrofits, build new capacity, repower unit, add fuel switching capacity, or retire units);
- How to operate each modeled unit (*e.g.*, when and how much to operate units, which fuels to burn) and what is the optimal generation mix; and

§ How demand will respond. The model thus assesses the trade-offs between the amount of demand-side management (DSM) to undertake and the level of electricity usage.

Each unit in the model has certain actions that it can undertake. For example, all units can retire, and many can undergo retrofits. Any publicly-announced actions, such as planned retirements, planned retrofits (for existing units), or new units under construction can be specified. Coal units have more potential actions than other types of units. These include retrofits to reduce emissions of SO_2, NO_X, mercury, and CO_2. The costs, timing, and necessity of retrofits may be specified as scenario inputs or left for the model to endogenously select. Coal units can also switch the type of coal that they burn (with practical unit-specific limitations). Finally, coal units may retire if none of the above actions will allow them to remain profitable, after accounting for their revenues from generation and capacity services.

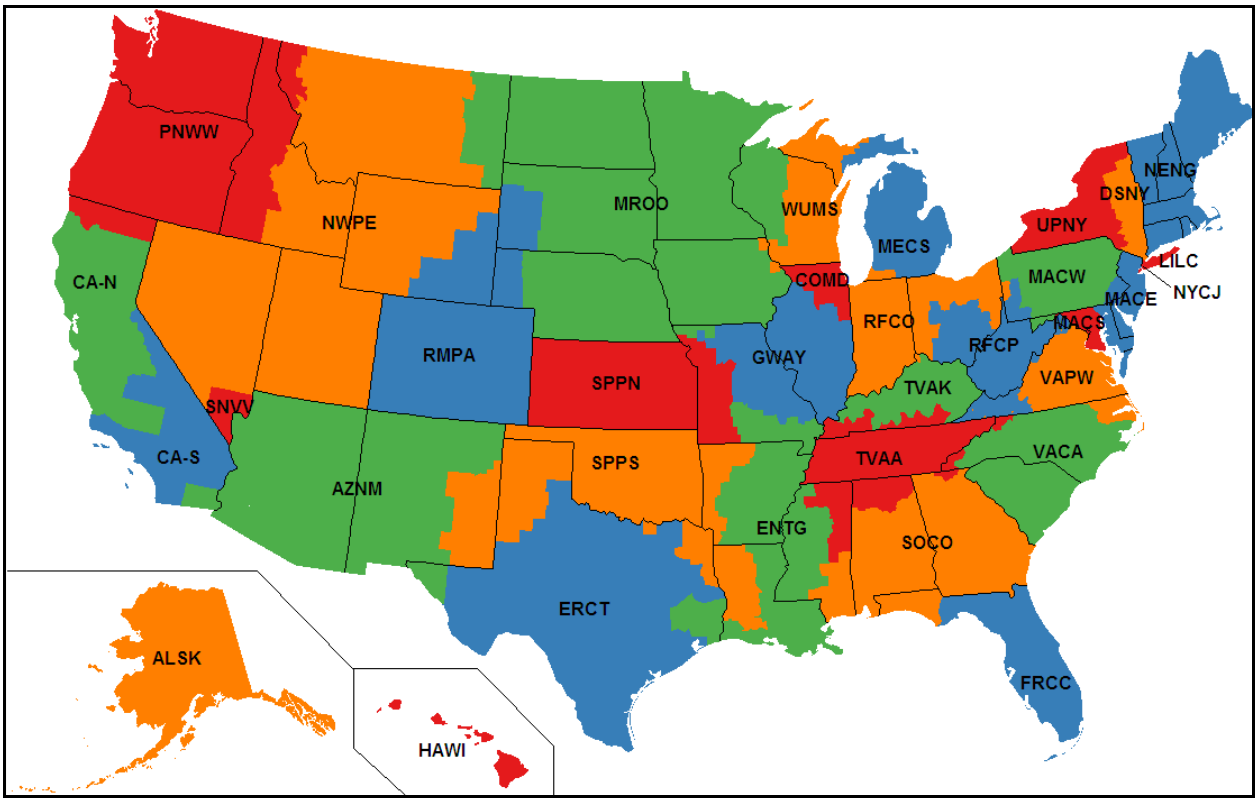
Most of the coal units' actions would be in response to environmental limits that can be added to the model. These include emission caps (for SO_2, NO_X, Hg, and CO_2) that can be applied at the national, regional, state or unit level. We can also specify allowance prices for emissions, emission rates (especially for toxics such as Hg) or heat rate levels that must be met.

Just as with investment decisions, the operation of each unit in a given year depends on the policies in place (*e.g.*, unit-level standards), electricity demand, and operating costs, especially energy prices. The model accounts for all these conditions in deciding when and how much to operate each unit. The model also considers system-wide operational issues such as environmental regulations, limits on the share of generation from intermittent resources, transmission limits, and operational reserve margin requirements in addition to annual reserve margin constraints.

To meet increasing electricity demand and reserve margin requirements over time, the electric sector must build new generating capacity. Future environmental regulations and forecasted energy prices influence which technologies to build and where. For example, if a national RPS policy is to take effect, some share of new generating capacity will need to come from renewable power. On the other hand, if there is a policy to address emissions, it might elicit a response to retrofit existing fossil-fired units with pollution control technology or enhance existing coal-fired units to burn different types of coals, biomass, or natural gas. Policies calling for improved heat rates may lead to capital expenditure spent on repowering existing units. All of these policies will also likely affect retirement decisions. The N_{ew}ERA electric sector model endogenously captures all of these different types of decisions.

The model contains 32 U.S. electricity regions (and six Canadian electricity regions). Figure A-2 shows the U.S. electricity regions.

Figure A-2: N_{ew}ERA Electric Sector Model – U.S. Regions



The electric sector model is fully flexible in the model horizon and the years for which it solves. To remain consistent with the macroeconomic model and to analyze long-term effects, the model is usually set up to solve out to twenty to thirty years in three-year time steps.

1. Generator Representation

Each of the more than 17,000 electric generating units in the United States is represented in the model. Coal units are subject to more decisions in the model than any other type of generator. These include choosing among different coal types, investing in different pollution control equipment and/or being forced to retire. Larger coal units (greater than 200 MW) are automatically individually represented in the model and smaller units are aggregated based on region, size, and existing controls for ease of computation. All other types of units are included in different regional aggregates based on their operating characteristics.

The model includes the following existing generating technologies:

- Coal (including IGCC)
- Natural gas combined cycle
- Natural gas combustion turbine
- Gas/oil steam
- Oil combustion turbine
- Nuclear
- Wind (on-shore)
- Pumped storage hydroelectric
- Biomass
- Geothermal
- Landfill gas
- Municipal solid waste
- Solar photovoltaic
- Solar thermal

- Hydroelectric (run-of-river and dispatchable)

Existing coal-fired generators have the option to install pollution controls. Available pollution controls in the model include wet flue gas desulfurization (wet FGD), dry FGD, dry sorbent injection (DSI), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), activated carbon injection (ACI), fabric filters (FF), cooling towers and coal combustion residual (CCR) controls. The costs for all but the cooling towers and CCR controls are from documentation produced by the EPA for the IPM model used in their MATS analysis. Costs for cooling towers and CCR controls are described in the sections on 316(b) and CCR rules.

New technology types that the model can build, in addition to the existing types, include advanced coal with carbon capture and storage (CCS), natural gas combined cycle with CCS, and off-shore wind. In addition, customer-owned distributed generation can also be simulated. Cumulative and annual addition rates and limits can be specified to reflect real world constraints.

The costs and characteristics for new electric generators in the current version of the N_{ew}ERA modeling system are from AEO 2012.

2. Electricity Demand

Electricity demand within the model is represented via load duration curves. These curves are created based on sorting the hourly demand for a region within a season and then aggregating together hours into a load block. The model has four seasons and a total of 25 load blocks (ten in the summer and five each in winter, spring, and fall). Four seasons are used to better capture the difference between hydroelectric generation in the spring and fall. Peak demand is also included and is used with reserve margins to determine capacity prices within the model.

The electric sector model is a non-linear program that is integrated with the macroeconomic model, so electricity demand can respond to changes in model inputs. Furthermore, the electric sector model's demand constraint allows demand to be satisfied either through electricity production or demand-side management (DSM) programs. Therefore, in the face of a policy such as a nationwide cap on greenhouse gas emissions, the model can choose among meeting demand as forecasted, meeting a lower level of demand (which results in lower values of consumer wellbeing), or implementing DSM programs. The model represents DSM programs through upward sloping supply curves for displaced electricity demand. These curves can be calibrated to the client's views on the cost and availability of various DSM programs. The resources required for the DSM programs are passed to the macroeconomic model just like other resource requirements for the electric sector.

The electricity demand in the model begins with the regional demands from AEO 2012. On a national level, the AEO 2012 forecast has a compound average growth rate of 0.7% from 2012 through 2035. The final electricity demand is not equal to the AEO 2012 levels, however, because the assumptions in each case differ from those of AEO 2012 (*e.g.*, the baseline includes CAIR instead of CSAPR and MATS, which results in lower electricity prices and therefore, higher electricity demand).

3. Coal Representation

The steam coal sector is represented within the electric sector model of the N_{ew}ERA modeling system. The model includes 24 steam coals:

- 3 Central Appalachian coals (differentiated by sulfur content);
- 4 Northern Appalachian coals (differentiated by sulfur content);
- 1 Southern Appalachian coal;
- 3 Illinois Basin coals (differentiated by sulfur content);
- 1 Arizona/New Mexico bituminous coal;
- 1 Montana bituminous coal;
- 1 Wyoming bituminous coal;
- 2 Rockies coals (1 in Colorado and 1 in Utah);
- 3 Powder River Basin (PRB) coals (2 in Wyoming and 1 in Montana);
- 2 lignite coals (1 in the Gulf and 1 in the Dakotas);
- 1 import coal – not represented with a supply curve, but instead represented with a price premium relative to a specified coal (Central Appalachian coal);
- 1 waste coal; and
- Pet Coke.

Existing coal units each have an initial coal specified and a maximum percentage of PRB coal that the unit can burn (based on recent historical percentages). Units can switch to burn more PRB coal than they currently burn, but they would incur capital costs as well as heat rate and capacity penalties in order to make the switch. Further, units can switch to burning other coals if the coal can be delivered to the unit (and the unit could be reasonably expected to be able to burn such a coal). In the near term, the model can limit this switching to reflect the coal market realities that would likely limit a good deal of switching in the first few years of an analysis. Coal use in the non-electric sectors and for exports is an exogenous input to the model, although it can be changed in each scenario.

The model utilizes coal supply curves that are paired with inputs for non-electric demand, export demand, and endogenously-determined electric sector demand to produce coal prices for each coal type available in the model. The supply curves are built up from mine-level data and include prices at each step of the curve, along with annual production levels and total reserves at the price step. Demand in prior years depletes the total reserves going forward, which generally would lead to higher prices if total reserves at a price step are fully depleted.

There is a complete coal transportation matrix within the model that maps each generating unit to the coals that can be delivered to it and assigns a transportation cost for each of the deliverable coals. This matrix accounts for costs associated with the different modes of transportation that may be used to deliver the coal along with the distance that the coal must travel.

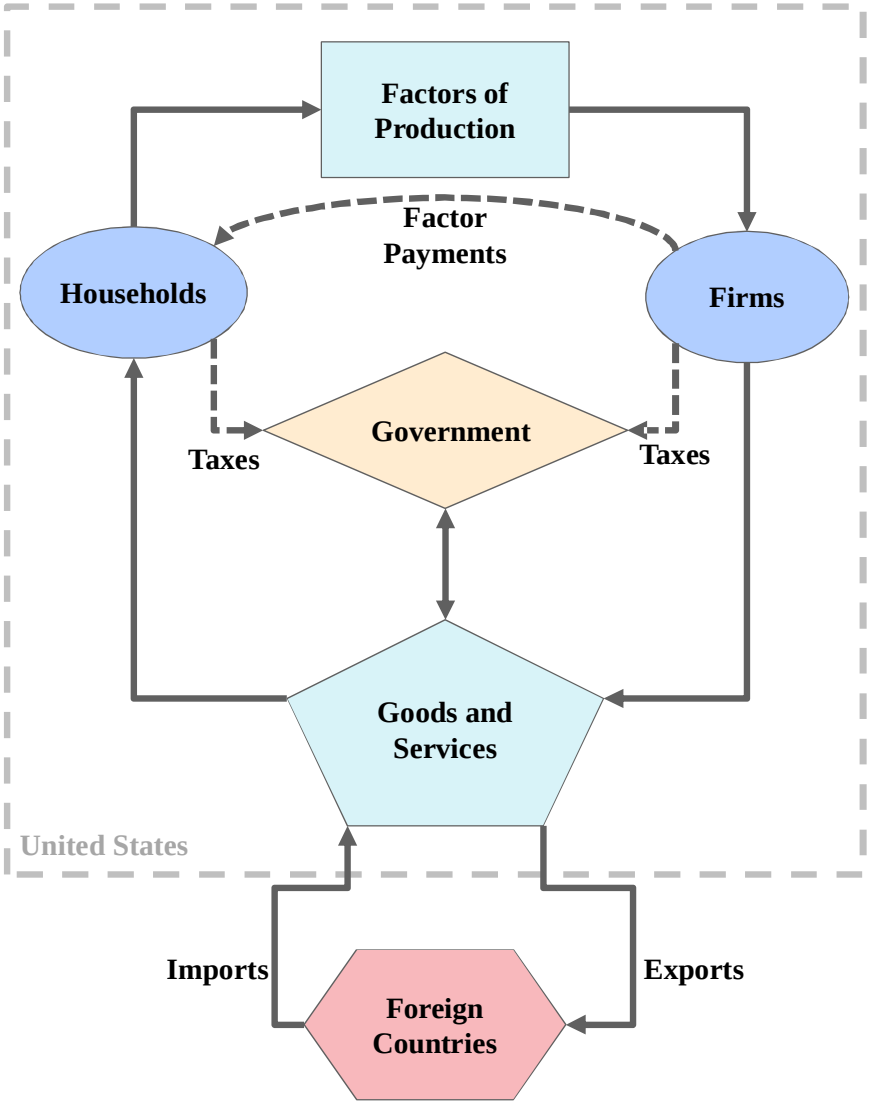
C. Macroeconomic Model

1. Overview

The N_{ew}ERA macroeconomic model is a forward-looking dynamic computable general equilibrium (CGE) model of the United States. The model simulates all economic interactions in the U.S. economy, including those among industry, households, and the government. Additional background information on CGE models can be found in Burfisher (2011).

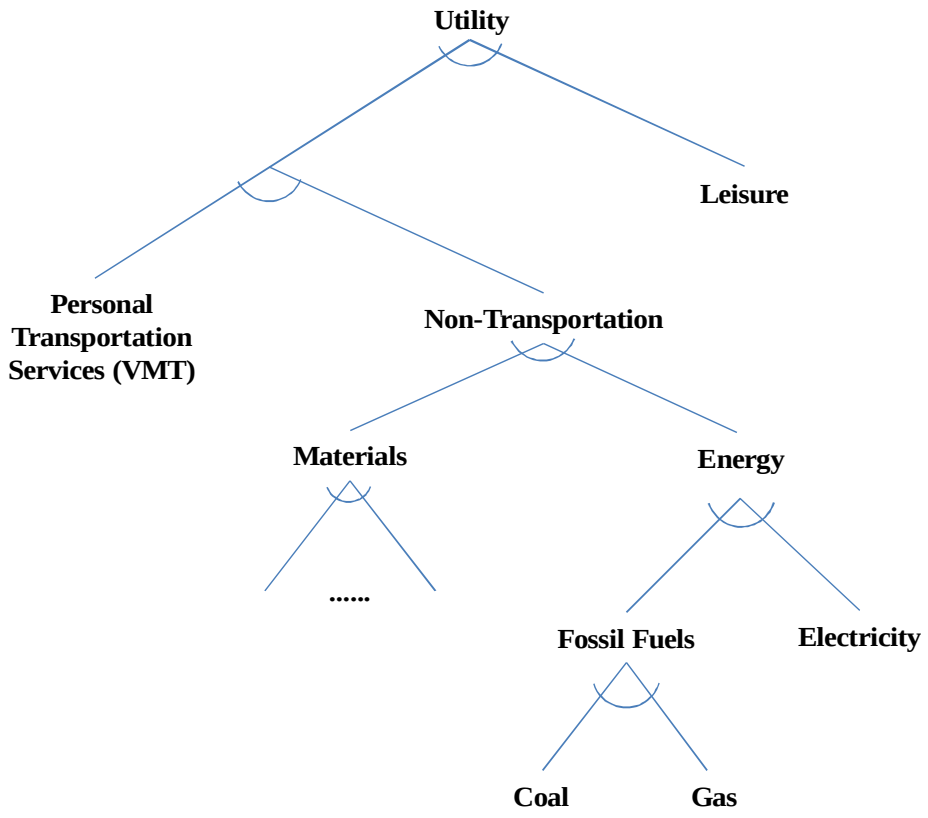
The N_{ew}ERA CGE framework uses the standard theoretical macroeconomic structure to capture the flow of goods and factors of production within the economy. A simplified version of these interdependent macroeconomic flows is shown in Figure A-3. The model implicitly assumes "general equilibrium," which implies that all sectors in the economy are in balance and all economic flows are endogenously accounted for within the model. In this model, households supply factors of production, including labor and capital, to firms. Firms provide households with payments for the factors of production in return. Firm output is produced from a combination of productive factors and intermediate inputs of goods and services supplied by other firms. Individual firm final output can be consumed within the United States or exported. The model also accounts for imports into the United States. In addition to consuming goods and services, households can accumulate savings, which they provide to firms for investments in new capital. Government receives taxes from both households and firms, contributes to the production of goods and services, and also purchases goods and services. Although the model assumes equilibrium, a region in the model can run deficits or surpluses in current accounts and capital accounts. In aggregate, all markets clear, meaning that the sum of regional commodities and factors of production must equal their demands, and the income of each household must equal its factor endowments plus any net transfers received.

Figure A-3: Interdependent Economic Flows in N_{ew}ERA's Macroeconomic Model



The model uses the standard CGE framework developed by Arrow and Debreu (1954). Behavior of households is represented by a nested Constant Elasticity of Substitution (CES) utility function. The model assumes that households seek to maximize their overall welfare, or utility, across time periods. Households have utility functions that reflect trade-offs between leisure (which reduces the amount of time available for earning income) and an aggregate consumption of goods and services. Households maximize their utility over all time periods subject to an intertemporal budget constraint based on their income from supplying labor, capital, and natural resource to firms. In each time period, household income is used to consume goods and services or to fund investment. Within consumption, households substitute between energy (including electricity, coal, natural gas, and petroleum), personal transportation, and goods and services based on the relative price of these inputs. Figure A-4 illustrates the utility function of the households.

Figure A-4: Household Consumption Structure in N_{ew}ERA's Macroeconomic Model



On the production side, Figure A-5 shows the production structure of the commercial transportation and the trucking sector. Production structure for the rest of the industries is shown in Figure A-6. The model assumes all industries maximize profits subject to technological constraints. The inputs to production are energy (including the same four types noted above for household consumption), capital, and labor. Production also uses inputs from intermediate products provided by other firms. The N_{ew}ERA model allows producers to change the technology and the energy source they use to manufacture goods. If, for example, petroleum prices rise, an industry can shift to a cheaper energy source. It can also choose to use more capital or labor in place of petroleum, increasing energy efficiency and maximizing profits with respect to industry constraints.

Figure A-5: Commercial Transportation and Trucking Sector Production Structure in N_{ew}ERA's Macroeconomic Model

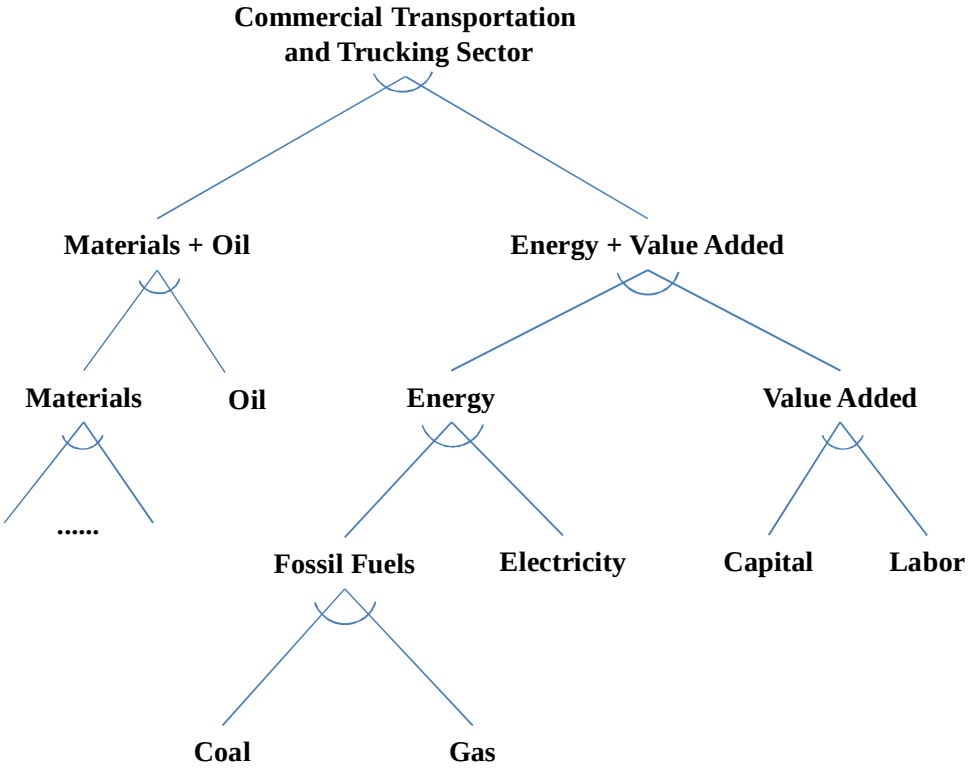
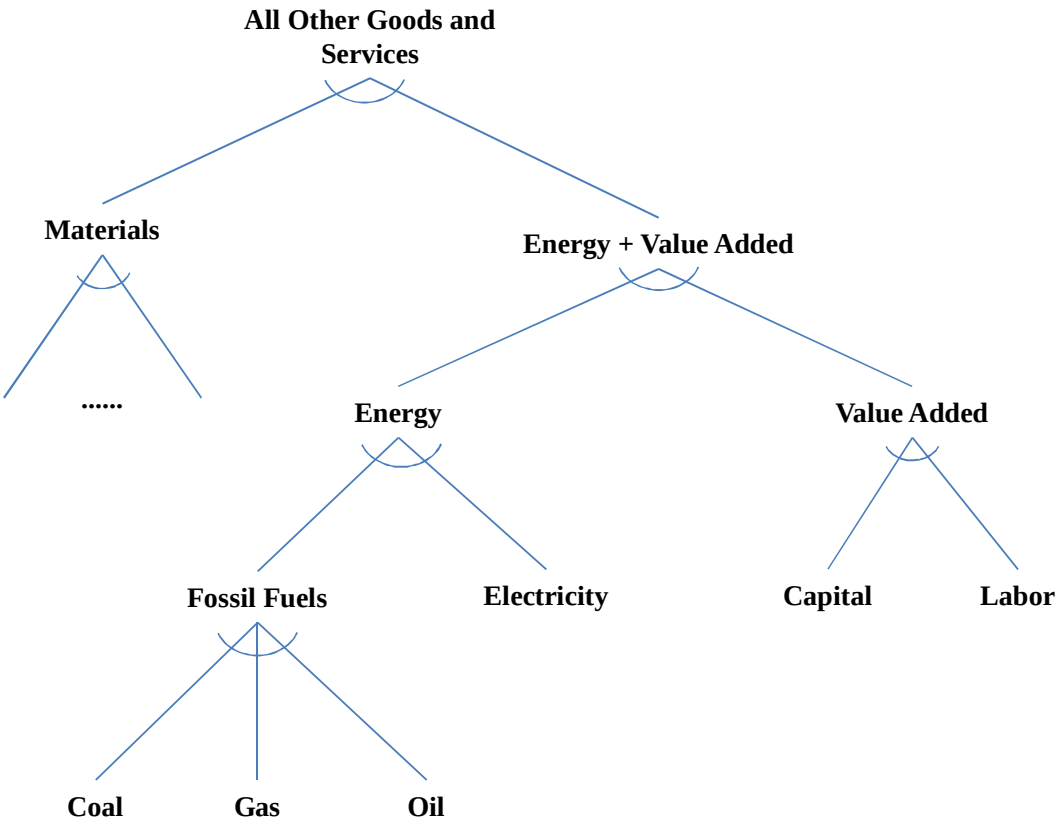


Figure A-6: Production Structure for Other Sectors in N_{ew}ERA's Macroeconomic Model



All goods and services, except crude oil, are treated as Armington goods, which assumes the domestic and foreign goods are differentiated and thus are imperfect substitutes (Armington 1969). The level of imports depends upon the elasticity of substitution between the imported and domestic goods. The Armington elasticity among imported goods is assumed to be twice as large as the elasticity between the domestic and imported goods, characterizing the greater substitutability among imported goods.

Business investment decisions are informed by future policies and outlook. The forward-looking characteristic of the model enables businesses and consumers to determine the optimal savings and investment levels while anticipating future policies with perfect foresight.

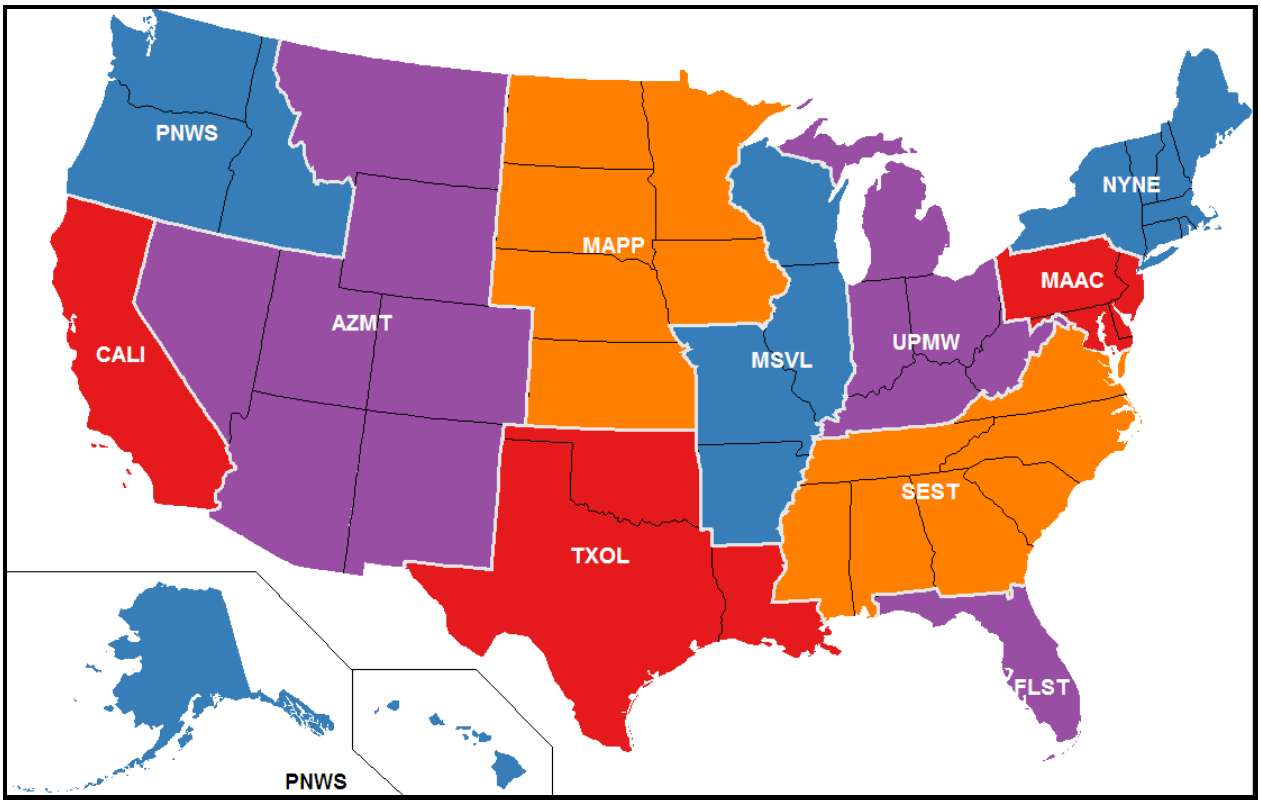
The benchmark year economic interactions are based on the IMPLAN 2008 database, which includes regional detail on economic interactions among 440 different economic sectors. The macroeconomic and energy forecasts that are used to project the benchmark year going forward are calibrated to EIA's Annual Energy Outlook (AEO) 2012.

2. Regional Aggregation

The N_{ew}ERA macroeconomic model includes 11 regions: NYNE (New York and New England), MAAC (Mid-Atlantic Coast), UPMW (Upper Midwest), SEST (Southeast), FLST (Florida), MSVL (Mississippi Valley), MAPP (Mid-America), TXOL (Texas, Oklahoma and Louisiana),

AZMT (Arizona and Mountain states), CALI (California) and (PNWS) Pacific Northwest. The aggregate model regions are built up from economic data for the 50 U.S. states and the District of Columbia. The 11 standard N_{ew}ERA macroeconomic model regions and the states within each N_{ew}ERA region are shown in Figure A-7.

Figure A-7: N_{ew}ERA Macroeconomic Model Regions



3. Sectoral Aggregation

The N_{ew}ERA model includes a standard set of 12 economic sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and seven non-energy sectors (services, manufacturing, energy-intensive[1], agriculture, commercial transportation excluding trucking, trucking, and motor vehicles). These sectors are aggregated up from the 440 IMPLAN sectors. The model has the flexibility to represent sectors at different levels of aggregation, when warranted, to better meet the needs of specific analyses.

4. Natural Gas and Oil Markets

There are great uncertainties about how the U.S. natural gas market will evolve, and the N_{ew}ERA modeling system is designed explicitly to address the key factors affecting future natural gas supply and prices. One of the major uncertainties is the availability of shale gas in the United

[1] The energy-intensive sector in the N_{ew}ERA modeling system includes pulp and paper, chemicals, glass, cement, primary metals, and aluminum.

States. To account for this uncertainty and the subsequent effect it could have on international markets, the N_{ew}ERA modeling system has the ability to represent supply curves for conventional natural gas and shale gas for each region of the model. By including each type of natural gas, it is possible to incorporate expert judgments and sensitivity analyses on a variety of uncertainties, such as the extent of shale gas reserves, the cost of shale gas production, and the impacts of environmental regulations.

The N_{ew}ERA model represents the domestic and international crude oil and refined petroleum markets. The international markets are represented by flat supply curves with exogenously specified prices. Because crude oil is treated as a homogeneous good, the international price for crude oil sets the U.S. price for crude oil.

Consumption of electricity as a transportation fuel could also affect the natural gas market. Along with alternative transportation fuels (including biofuels), the model also includes different vehicle choices that consumers can employ in response to changes in the fuel prices. The model includes different types of Electrified Vehicles (xEVs): Plug-in-Hybrid Electric Vehicles (PHEVs) and Battery Electric Vehicles (BEVs). In addition, the model accounts for both passenger vehicles and trucks powered by CNG.

5. Macroeconomic Outputs

As with other CGE models, the N_{ew}ERA macroeconomic model outputs include demand and supply of all goods and services, prices of all commodities, and terms of trade effects (including changes in imports and exports). The model outputs also include gross regional product, consumption, investment, cost of living or burden on consumers, and changes in "job equivalents" based on changes in labor wage income. All model outputs are calculated by time, sector, and region.

Impacts on workers are often considered an important output of policy evaluations. Impacts on workers are complicated to estimate and to explain because they can include several different impacts, including involuntary unemployment, reductions in wage rates for those who continue to work, and voluntary reductions in hours worked due to lower wage rates. No model addresses all of these potential impacts. The N_{ew}ERA model is a long-run equilibrium model based upon full employment, and thus its results relate to the longer-term effects on labor income and voluntary reductions in hours worked rather than involuntary unemployment impacts. It addresses long-run employment impacts, all of which are based on estimates of changes in labor income, also called the "wage bill" or "payments to labor." Labor income impacts consist of two effects: (1) changes in real wage per hour worked; and (2) changes in labor market participation (hours worked) in response to changed real wage rates. The labor income change can also be expressed on a per-household basis, which represents one of the key components of disposal income per household. (The other key components of disposable income are returns on investments or "payments to capital," and income from ownership of natural resources.) The labor income change can also be stated in terms of job-equivalents, by dividing the labor income change by the annual income from the average job. A loss of one job-equivalent does not necessarily mean one less employed person—it may be manifested as a combination of fewer people working and less income per person who is working. However, this measure allows us to

express employment-related impacts in terms of an equivalent number of employees earning the average prevailing wage.

D. Integrated N_{ew}ERA Model

The N_{ew}ERA modeling framework fully integrates the macroeconomic model and the electric sector model so that the final solution is a consistent equilibrium for both models and thus for the entire U.S. economy.

To analyze any policy scenario, the system first solves for a consistent baseline solution; it then iterates between the two models to find the equilibrium solution for the scenario of interest. For the baseline, the electric sector model is solved first under initial economic assumptions and forecasts for electricity demand and energy prices. The equilibrium solution provides the baseline electricity prices, demand, and supply by region as well as the consumption of inputs—capital, labor, energy, and materials—by the electric sector. These solution values are passed to the macroeconomic model.

Using these outputs from the electric sector model, the macroeconomic model solves the baseline while constraining the electric sector to replicate the solution from the electric sector model and imposing the same energy price forecasts as those used to solve the electric sector baseline. In addition to the energy price forecasts, the macroeconomic model's non-electric energy sectors are calibrated to the desired exogenous forecast (*e.g.*, EIA's latest AEO forecast) for energy consumption, energy production, and macroeconomic growth. The macroeconomic model solves for equilibrium prices and quantities in all markets subject to meeting these exogenous forecasts.

After solving the baseline, the integrated N_{ew}ERA modeling system solves for the scenario. First the electric sector model reads in the scenario definition. The electric sector model then solves for the equilibrium level of electricity demand, electricity supply, and inputs used by the electric sector (*i.e.*, capital, labor, energy, emission permits). The electric sector model passes these equilibrium solution quantities to the macroeconomic model, which solves for the equilibrium prices and quantities in all markets. The macroeconomic model then passes to the electric sector model the following (solved for equilibrium prices):

- Electricity prices by region;
- Prices of non-coal fuels used by the electric sector (*e.g.*, natural gas, oil, and biofuels); and
- Prices of any permits that are tradable between the non-electric and electric sectors (*e.g.*, carbon permits under a nationwide greenhouse gas cap-and-trade program).

The electric sector model then solves for the new electric sector equilibrium, taking the prices from the macroeconomic model as exogenous inputs. The models iterate—prices being sent from the macroeconomic model to the electric sector model and quantities being sent from the electric sector model to the macroeconomic model—until the prices and quantities in the two models differ by less than a fraction of a percent.

This decomposition algorithm allows the N_{ew}ERA model to retain the information in the detailed electricity model, while at the same time accounting for interactions with the rest of the economy. The detailed information on the electricity sector enables the model to represent regulatory policies that are imposed on the electricity sector in terms of their impacts at a unit level.

E. References

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Appendix B: Modeling Inputs

This appendix provides background on the regulations included in this analysis and details on our methodology for modeling each regulation in the N_{ew}ERA modeling system. We also note policies that are included in the baseline for purposes of the policy modeling. This appendix also includes information on modeling inputs for the higher natural gas prices case.

A. Mercury and Air Toxics Standard

1. Policy Background

In February 2008, the U.S. District Court for the D.C. Circuit vacated the Clean Air Mercury Rule (CAMR). As a result, EPA developed standards regarding emissions of mercury and hazardous air pollutants (HAPs) from coal-fired and oil-fired electric generating units (EGUs). The statutory authority for this regulation is Section 112 of the Clean Air Act, which has led EPA to regulate facilities emitting regulated pollutants based on the maximum achievable control technology (MACT).

In December 2011, EPA promulgated the MATS Rule, which sets MACT standards for mercury and other HAP emissions from EGUs that consume coal or oil and have a minimum nameplate capacity of 25 megawatts (MW) (EPA 2011a, 2012a). The MATS Rule requires covered EGUs to comply with emission rate limits for the following categories: (1) mercury; (2) particulate matter (PM), as a proxy for non-mercury metals; and (3) hydrogen chloride (HCl), as a proxy for acid gases. Covered power plants must comply with the MATS Rule by 2015, with the possibility of up to two years of extension from various authorities.

Table B-1 shows the mercury emission rate limits for existing coal units by coal rank.

Table B-1. Mercury Emission Rate Limits for Existing Coal Units from MATS Rule

Coal Rank	Mercury Limit (lbs/TBtu)
Bituminous	1.2
Subbituminous	1.2
Lignite	4.0

Note: "TBtu" denotes trillion British thermal units.
Source: EPA (2012, p. 9367)

After the MATS Rule was finalized, several industry and environmental stakeholders initiated lawsuits regarding various elements of the regulation (SNL Energy 2012). In August 2012, EPA announced that it was staying application of the MATS Rule to new units while it reconsiders those aspects of the rule (EPA 2012b).

2. Modeling Methodology

Table B-2 summarizes our modeling inputs for the MATS Rule.

Table B-2. Modeling Inputs for Mercury and Air Toxics Standard Rule

Policy	Modeling Inputs
MATS Rule	Mercury: Applied emission rate limits in N_{ew}ERA and allowed N_{ew}ERA to select compliance measures that minimize compliance costs PM: Required fabric filter retrofits or electrostatic precipitator upgrades on certain units (as per EPA MATS documentation) HCl: Required scrubbers (either wet or dry) or dry sorbent injection All requirements are assumed to take effect in the model year 2016 (that is, it is assumed that power plants are able to obtain a one-year extension from their states)

Source: NERA assumptions as explained in text

EPA's regulatory impact analysis (RIA) and supporting documentation for the MATS Rule provide information on emissions limits for mercury, HCl, and PM, as well as information on compliance measures at individual EGUs.[1] Combining these limits and compliance measures with the information in N_{ew}ERA's database of EGU operating characteristics and existing and potential emissions controls, we have identified potential compliance measures for each unit. The N_{ew}ERA model selects the least-cost compliance mechanism for each unit, or it retires the unit if its MATS compliance costs and other factors (including compliance with other regulations in this analysis) would make continued operation uneconomic (as described in Appendix A)..

As shown above in Table B-1, the mercury emission rate limits depend on the type of coal burned. Units can comply with the mercury standards by switching their type of coal or installing emission controls (or they can retire to avoid the compliance costs). The possible emission controls include non-mercury controls, such as scrubbers, fabric filters, and selective catalytic reduction (SCR), which also reduce mercury emissions as a co-benefit, and mercury-specific controls, such as activated carbon injection (ACI). All units burning lignite would require ACI. Some units burning bituminous or subbituminous coal would also require ACI, but many units burning bituminous or subbituminous coal would be able to comply with the mercury standards through a combination of SCRs, scrubbers, and (in some cases) fabric filters.

To comply with the PM portion of the MATS Rule, some units would require fabric filter retrofits or electrostatic precipitator upgrades. We apply these controls to individual EGUs based on EPA's unit-specific modeling results provided in the support documentation for the MATS Rule (EPA 2011b). To comply with the HCl portion of the MATS Rule, we assume that units would require either a scrubber (wet or dry) or a Dry Sorbent Injection (DSI) system.[2]

[1] The RIA and supporting documentation are collected in Docket No. EPA-HQ-OAR-2009-0234.

[2] Consistent with EPA assumptions, a few coal units would not require a scrubber or DSI because of their coal types. Additionally, in the model we restrict the ability to install DSI to units smaller than 300 MW in capacity that burn low-sulfur coals. Dry scrubber installation is also restricted to units burning low-sulfur coals.

To avoid overstating the cumulative impacts of the full set of policies, we examined actions required of each unit in the model due to all potential controls to ensure there was no double counting of retrofit requirements. As discussed below, as a way of incorporating the impact of the $PM_{2.5}$ NAAQS, we removed the installation of DSI as an option for units in California and states potential subject to the Cross State Air Pollution Rule (CSAPR), which means that these units would need to install either a wet or dry scrubber for the MATS Rule.

As noted in Appendix A, we customized the N_{ew}ERA modeling system to model 2013 and every third year thereafter, including 2016. We assume that covered EGUs would have to comply with the MATS Rule by 2016. This assumption is consistent with EGUs receiving permission from state authorities to postpone their compliance deadlines by one year beyond EPA's national deadline of 2015, as provided for in MATS.

3. References

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B. Regional Haze Rule

1. Policy Background

In 1999 the EPA released the Regional Haze Rule (RHR), a major effort to improve visibility in 156 national parks and wilderness areas (Class I areas) by limiting emissions of the pollutants that most significantly contribute to haze: SO_2, NO_X, and particulate matter (PM). The rule requires each state to develop and implement plans to reduce haze with the goal of reaching "naturally-occurring" visibility conditions by 2064.

State Implementation Plans (SIPs) for RHR are required to provide details on (1) how the states will reduce emissions to 2018 target levels such that they will be on a consistent path to achieve their 2064 goals of naturally-occurring visibility; and (2) which facilities within the state will have to implement Best Available Retrofit Technology (BART). Facilities could be subject to BART requirements if the facilities were brought online between 1962 and 1977, contribute significantly to visibility impairment at a Class I area, and fall within one of 26 covered source categories. For this analysis, we focus our attention on the first phase of the rule—in particular, the methods (including BART) by which states will reduce visibility impairment by 2018—since actions for subsequent phases are unlikely to be discussed prior to 2016. (SIPs for the second phase are not due until July 31, 2018.)

If a SIP (or its subsequent revisions) receives disapproval or limited disapproval from the EPA, a Federal Implementation Plan (FIP) may be developed by the EPA to specify emission reduction actions to be required for facilities as well as the BART requirements for particular facilities in the state.

2. Modeling Methodology

Table B-3 summarizes our modeling inputs for the Regional Haze Rule.

Table B-3. Modeling Inputs for Regional Haze Rule

Policy	Modeling Inputs
RHR	Baseline scenario includes compliance measures for Phase 1 (required by 2018) included for EGUs in SIPs Policy scenario includes compliance measures for Phase 1 (required by 2018) included for EGUs in FIPs BART-eligible units greater than 200 MW located in CAIR states are required in the policy scenario to meet BART-specific NO_x rates based on coal boiler type and coal rank (required by 2018) Non-EGU compliance costs not included

Source: NERA assumptions as explained in text.

We identified compliance measures when specified[3] for RHR by reviewing the SIPs of all 48 contiguous states[4] and all available FIPs. We modeled RHR compliance measures as part of the baseline scenario if they were proposed in the SIPs because planning of the proposals likely began prior to 2009 as initial SIP submissions were due in 2007. If the RHR compliance measures were proposed in the FIPs, we modeled them as part of the policy scenario because these were assumed to be put in place after 2009 (it is unlikely any FIPs would have been released prior to 2009 based on the schedule for SIPs and opportunities for states to revise them). See Table B-4 for a comparison of retrofit requirements by coal-fired EGUs under the baseline and policy scenario (note that not all of these retrofits are undertaken as some are uneconomical and units retire to avoid the retrofit requirement).

Table B-4. Summary of Modeled Retrofit Requirements for Coal-fired EGUs (GW)

	Wet Scrubbers	Dry Scrubbers	DSI	NO_X Controls	PM Controls
Baseline	7.4	2.3	0.9	5.5	9.7
Policy	10.4	2.3	0.9	19.7	9.7
Incremental	3.0	-	-	14.2	-

Source: NERA calculations as explained in text

With regard to specific technologies, we first considered the role of RHR requirements for the baseline scenario. We assumed that EGUs in CAIR states would comply with RHR through their compliance measures for CAIR, which is included in the baseline scenario. We assumed that facilities in non-CAIR states would comply with RHR through the BART requirements specified in their SIPs that, as noted, are also in the baseline scenario.[5]

For the policy scenario, to avoid overstating the potential compliance costs, we analyzed the emission control technologies employed from other policies in our analysis to determine whether additional emission controls would be necessary to meet RHR objectives. If the emission controls from the policies were sufficient to meet the requirements for RHR, we did not apply any further compliance measures for RHR.

Due to the more recent decision that CAIR is no longer better-than-BART (and the recent vacatur of CSAPR), further NO_X compliance measures were needed for the RHR policy scenario. We based emission rate requirements at coal units on emission limits from EPA's BART Final Rule (EPA 2005, Table 2) using each coal unit's most recent ozone-season NOx rate. The specific technology requirements were based upon the coal unit's NOx emission rate:

[3] The SIPs and FIPs varied in their level of detail regarding how units are required to comply with BART. We only included BART actions when a proposal specified which type of emission control technology the unit needed to adopt.

[4] One state – Montana – has not issued a SIP for RHR and is instead relying entirely on a FIP, which had not been released in time for inclusion in this analysis. Thus, only 47 states were ultimately modeled.

[5] Until the CSAPR was vacated by the U.S. Court of Appeals for the D.C. Circuit in August 2012, states intended to comply with Phase 1 of RHR through CSAPR. Since CAIR remains in effect after the *vacatur* of CSAPR, states now intend to comply with Phase 1 of RHR through CAIR.

1. Unit meets the NOx emission rate limit: No action;

2. Unit must reduce its NOx emission rate by less than 35 percent: Install selective non-catalytic reduction (SNCR); or

3. Unit must reduce its NOx emission rate by 35 percent of more: Install selective catalytic reduction (SCR).

Note that N_{ew}ERA retires coal units if the costs of these NOx emission controls and other relevant factors (including other emission control requirements) would make continued operation uneconomic, as noted in Appendix A.

With regard to non-coal EGUs, we modeled RHR emission reductions using information from the SIPs and FIPs. In particular, we calculated the costs of RHR emission controls based upon data provided in the proposals for non-coal EGUs and applied these costs in N_{ew}ERA as additional fixed O&M costs.

After reviewing the RHR compliance measures for non-electricity sectors, we determined that 97 percent of the costs for these measures would apply in the baseline scenario and only 3 percent would apply as additional costs in the policy scenario. Since the additional RHR costs for non-electricity sectors are so small—and we did not expect changes in the baseline scenario due to these controls to affect the policy results—we did not model RHR costs for non-electricity sectors in either the baseline scenario or policy scenario. This assumption slightly understates the potential costs and impacts of the RHR.

3. References

"Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, Final Rule." Federal Register 70:128 (6 July 2005) pp. 39104-39172.

"Regional Haze Regulations, Final Rule." Federal Register 64:126 (1 July 1999) pp. 35714-35774.

"Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans, Final Rule." Federal Register 77:110 (7 June 2012) pp. 35714-35774.

SNL Energy. August 21, 2012. "DC Circuit vacates Cross-state Air Pollution Rule." (http://www.snl.com/InteractiveX/article.aspx?ID=15267076)

Federal Implementation Plan References:

"Approval and Promulgation of Implementation Plans, Oklahoma, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and

Best Available Retrofit Technology Determinations, Final Rule." Federal Register 76:249 (28 December 2011) pp. 81727-81759.

"Approval and Promulgation of Implementation Plans, North Dakota, Regional Haze State Implementation Plan, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze, Final Rule." Federal Register 77:67 (6 April 2012) pp. 20893-20945.

"Approval and Promulgation of Air Quality Implementation Plans, State of New York, Regional Haze State Implementation Plan and Federal Implementation Plan, Proposed Rule." Federal Register 77:80 (25 April 2012) pp. 24793-24827.

"Approval, Disapproval and Promulgation of Air Quality Implementation Plans, Arizona, Regional Haze State and Federal Implementation Plans, Proposed Rule." Federal Register 77:140 (20 July 2012) pp. 42833-42871.

"Approval and Promulgation of Air Quality Implementation Plans, Michigan, Regional Haze State Implementation Plan, Federal Implementation Plan for Regional Haze, Proposed Rule." Federal Register 77:151 (6 August 2012) pp. 46911-46928.

"Approval and Promulgation of Implementation Plans, New Mexico, Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination, Final Rule." Federal Register 76:162 (22 August 2012) pp. 52388-52440.

"Approval and Promulgation of Air Quality Implementation Plans, Nevada, Regional Haze State and Federal Implementation Plans, BART Determination for Reid Gardner Generating Station, Final Rule." Federal Register 77:164 (23 August 2012) pp. 50936-50952.

State Implementation Plan References:

AL: "Regional Haze State Implementation Plan for the State of Alabama," Jul. 2008.

AR: "State of Arkansas Regional Haze Rule State Implementation Plan," Sept. 9, 2008.

AZ: "Arizona Regional Haze State Implementation Plan," Feb. 28, 2011.

CA: "California Regional Haze Plan," Jan. 22, 2009.

CO: "Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado," Jan. 1, 2011.

CT: "Connecticut Regional Haze SIP Revision," Nov. 2009.

DE: "Delaware's Visibility State Implementation Plan," Sept. 24, 2008.

FL: “Regional Haze Plan for Florida Class I Areas,” Aug. 31, 2010.

GA: “Georgia’s State Implementation Plan for Regional Haze,” Jun. 10, 2009.

IA: “Iowa State Implementation Plan for Regional Haze,” Mar. 2008.

ID: “State of Idaho Department of Environmental Quality,” Oct. 8, 2010.

IL: “Regional Haze State Implementation Plan for Illinois,” Aug. 3, 2009.

IN: “Indiana Regional Haze State Implementation Plan,” Nov. 2010.

KS: “State of Kansas Air Quality State Implementation Plan: Regional Haze,” Oct. 26, 2009.

KY: “Infrastructure State Implementation Plan,” Apr. 10, 2012.

LA: “Louisiana State Implementation Plan Revision for Regional Haze Program,” Jun. 2008.

MA: “Massachusetts Regional Haze State Implementation Plan,” Dec. 30, 2011.

MD: “State of Maryland Regional Haze State Implementation Plan,” Feb. 9, 2012.

ME: “State Implementation Plan for Regional Haze,” May 2, 2010.

MI: “State Implementation Plan Submittal for Regional Haze,” Oct. 2010.

MN: “Regional Haze State Implementation Plan,” Dec. 2009.

MS: “State Implementation Plan (SIP) Revision Regarding Federal Regional Haze Program Requirements,” Aug. 28, 2008.

MO: “State of Missouri Regional Haze Plan,” Jun. 25, 2009.

NE: “Nebraska Department of Environmental Quality State Implementation Plan for Regional Haze and Best Available Retrofit Technology (BART),” Jun. 30, 2011.

NH: “New Hampshire Regional Haze SIP Revision,” Aug. 26, 2011.

NJ: “State of New Jersey Department of Environmental Protection,” Jul. 2009.

NM: “New Mexico State Implementation Plan Regional Haze Section 309 (g),” Dec. 20, 2010.

NV: “Nevada Regional Haze State Implementation Plan,” Oct. 2009.

NY: “New York State Implementation Plan for Regional Haze,” Nov. 2009.

NC: “Regional Haze State Implementation Plan for North Carolina Class I Areas,” Dec. 17, 2007.

ND: “North Dakota State Implementation Plan for Regional Haze,” Feb. 24, 2010.

OH: “Regional Haze State Implementation Plan for Ohio,” Mar. 2011.

OK: “Regional Haze Implementation Plan Revision: State of Oklahoma,” Feb. 2, 2010.

OR: “Oregon Regional Haze Plan for Implementing Section 308 (40CFR 51.308) of the Regional Haze Rule,” Dec. 9, 2010.

PA: “Revision to the State Implementation Plan for Regional Haze,” Dec. 2010.

RI: “Rhode Island Regional Haze State Implementation Plan Revision,” Aug. 7, 2009.

SC: “Regional Haze State Implementation Plan for South Carolina Class I Federal Areas,” Dec. 21, 2007.

SD: “South Dakota’s Regional Haze State Implementation Plan.”

TN: ‘Regional Haze State Implementation Plan for Tennessee Class I Areas,” Apr. 4, 2008.

TX: “Revisions to the State Implementation Plan (SIP) Concerning Regional Haze,” Feb. 25, 2009.

UT: “Utah State Implementation Plan: Section XX, Regional Haze,” Sep. 3, 2008.

VT: “Vermont State Implementation Plan (SIP): Revision, Regional Haze,” Jun. 2009.

VA: “Regional Haze State Implementation Plan for Virginia Class I Areas – Shenandoah National Park and James River Face Wilderness Area,” Oct. 4, 2010.

WA: “Regional Haze State Implementation Plan,” Dec. 2010.

WI: “Regional Haze State Implementation Plan for Wisconsin,” Jan. 18, 2012.

WV: “West Virginia Regional Haze State Implementation Plan to Preserve, Protect, and Improve Visibility in Class I Federal Areas,” Jun. 2008.

WY: “Wyoming State Implementation Plan: Regional Haze,” Jan. 7, 2012.

C. Ozone National Ambient Air Quality Standards

This section provides background on the ozone primary 8-hour NAAQS and describes our modeling methodology for this regulation.

1. Policy Background

Ground-level ozone forms through reactions between nitrogen oxides (NO_x) and volatile organic compounds (VOC) in the presence of sunlight. The Clean Air Act requires EPA to evaluate NAAQS levels for ozone and other air pollutants every five years. In 1997, EPA set the ozone primary 8-hour NAAQS at 80 parts per billion (ppb).[6] Due to the limited sensitivity of ozone monitors, EPA considers areas with ozone levels as high as 84 ppb as in attainment with the 1997 standard. In 2008, EPA lowered the ozone primary 8-hour NAAQS to 75 ppb.

In early 2009, EPA announced that it was reconsidering the 2008 ozone standard of 75 ppb because it exceeded the level recommended by the Clean Air Scientific Advisory Committee (CASAC). EPA said it was considering lowering the standard to the range recommended by CASAC, which was between 60 and 70 ppb.

In September 2011, the Obama Administration instructed EPA to terminate its reconsideration of the 2008 ozone standard. In a letter to EPA, the Office of Management and Budget explained that the reconsideration should be terminated because EPA will need to evaluate ozone NAAQS levels anyway in 2013 under the timing provisions of the Clean Air Act, and because the Administration had already adopted several policies that would improve ozone levels, including heavy-duty truck regulations, MATS, and CSAPR (OMB 2011). Thus, the current ozone primary 8-hour NAAQS is the level established in 2008, 75 ppb.

In October 2011, EPA released a draft version of the ozone rule that it had intended to issue under the reconsideration. The rule would have lowered the ozone primary 8-hour NAAQS to 70 ppb. EPA said that it released the draft in the interests of transparency and that it planned to issue the results of its current review of the ozone standard, possibly with a proposed new standard, on schedule in 2013 (EPA 2011).[7] In the most recent CASAC meeting as part of the current review of the ozone standard, EPA summarized the preliminary conclusions of CASAC regarding ozone levels as follows:

> In identifying a range of levels for analysis, [CASAC] staff considered the scientific evidence and the advice received from CASAC in the last review. *In the last review and in the reconsideration*, CASAC recommended a focus on levels from 70 to 60 ppb. *In the current review*, [CASAC] staff reached the preliminary conclusion that the new evidence reinforces support for analyzing levels from 70 to 60 ppb. In addition, [CASAC] staff reached preliminary conclusion that the new evidence also supports analyzing standard levels somewhat below 60 ppb (EPA 2012a, p. 9; emphasis in the original).

[6] This is equivalent to 0.080 parts per million (ppm).

[7] It is our understanding that at the latest CASAC meeting the timeline was pushed back to 2014.

After EPA sets NAAQS levels, state environmental agencies bear primary responsibility for developing plans to bring the individual air quality areas in their states into attainment. Emissions in non-attainment areas are lowered through SIPs or in some cases FIPs. These state and federal plans set schedules for various emissions abatement measures. Although NAAQS take effect immediately upon publication by EPA, the schedules for implementation vary significantly among areas depending on baseline ozone levels, baseline emissions, opportunities for emissions abatement, and discussions between state environmental agencies and EPA. Indeed, some areas of the country, including parts of Southern and Central California, still far exceed the 1997 ozone standard of 84 ppb.

2. Modeling Methodology

The table below summarizes our modeling inputs for the ozone NAAQS.

Table B-5. Modeling Inputs for Ozone NAAQS

Policy	Modeling Inputs
Ozone NAAQS	Baseline scenario: Apply EGU controls for 75 ppb based on EPA RIA data Policy scenario: Apply compliance costs for non-electricity sectors for 65 ppb based on EPA RIA data for both "known" controls and "unknown" controls with regionally staggered implementation between 2019 and end of modeling period

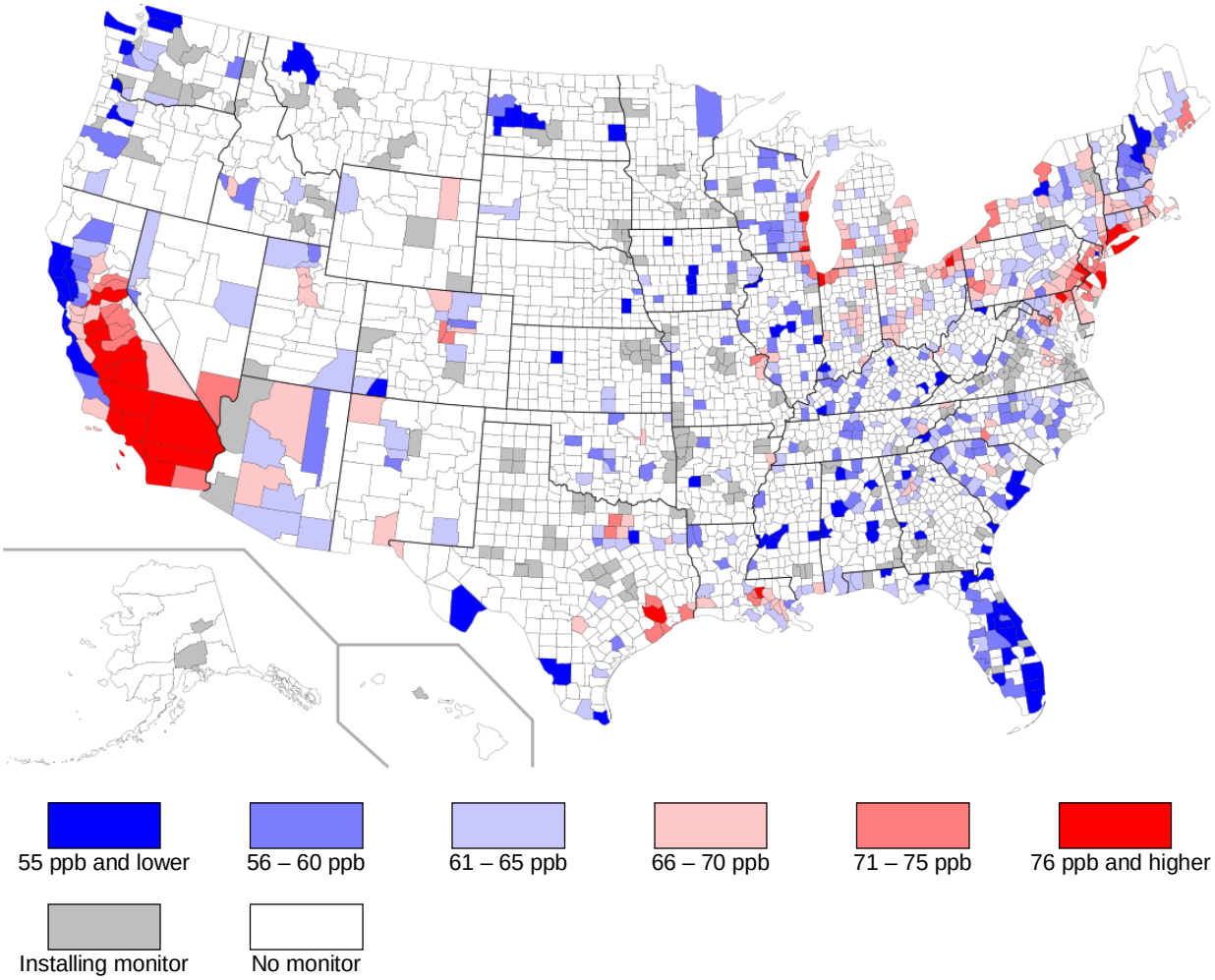
Source: NERA assumptions as explained in text.

As noted above, EPA announced in 2009 that it was considering lowering the ozone primary 8-hour standard to a level between 60 and 70 ppb, and CASAC's preliminary recommendation in the current review process is for EPA also to consider levels below 60 ppb. We assumed that the new ozone standard would be in the center of the range EPA identified in 2009, at 65 ppb.

Our data sources for this policy are the two regulatory impact analyses (RIAs) issued by EPA in 2008 and 2010 (EPA 2008, 2010) and supporting documentation in the ozone docket (EPA-HQ-OAR-2007-0225). The RIAs provide estimates of the costs and benefits of new ozone NAAQS at 79, 75, 70, 65, 60, or 55 ppb relative to a baseline standard of 84 ppb. The ozone RIAs include various policies affecting NO_x and VOC emissions in the baseline, including the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), Clean Air Visibility Rule (CAVR), Light-Duty Vehicle Tier 2 Rule, and Heavy-Duty Diesel Rule.

EPA modeled the costs and benefits of new ozone standards in a single future year: 2020. The RIAs include projections of baseline ozone concentrations in 2020 in the 660 counties that had ozone monitors as of 2008 (see Figure B-1). Based on these projections, EPA identified non-attainment areas for alternative ozone standards and modeled a hypothetical set of emission reductions to bring the areas into attainment. Areas without ozone monitors as of 2008 (the majority of the 3,000 counties in the United States) are assumed not to require emission reductions to address their own ozone concentrations (but low ozone standards would require emission reductions across large swaths of area to address ozone in particular smaller areas).

Figure B-1. EPA 2020 Baseline County Ozone Concentration Forecasts



Source: NERA map based on EPA (2008), Table 3a.18

As noted above, the RIAs evaluate alternative standards relative to a baseline standard of 84 ppb, but the current standard is 75 ppb. We accounted for this different baseline standard in two ways. First, we included EGU compliance measures for ozone standards down to 75 ppb in our baseline scenario. These compliance measures included installation of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) at approximately 4 GW of coal capacity.[8] Second, we lowered the emission reductions requirements for achieving the 65 ppb standard to reflect achievement of the 75 ppb standard under baseline conditions.

For each of the alternative ozone standards, EPA modeled emission reductions from "known" controls from five categories of emission source: (1) EGUs; (2) non-EGU point sources, such as industrial boilers, cement kilns, and petroleum refineries; (3) area sources, such as dry cleaners,

[8] We did not apply the costs of compliance measures for the 75 ppb standard to other sectors for the baseline scenario, because the costs are small and would not significantly affect our results for energy or economic impacts.

commercial buildings, and residential buildings; (4) onroad mobile, such as passenger cars, light-duty trucks, and heavy-duty trucks; and (5) nonroad mobile, such as lawn mowers, snowmobiles, locomotives, aircraft, and marine vessels. The RIAs and their supporting documentation include estimates of emission reductions and annualized costs by facility or state for these sectors to achieve the 65 ppb standard. We focused on ozone costs outside the EGU sector because emissions from the EGU sector are reduced through other policies included in this analysis.

After applying all "known" controls to the five categories of emission source listed above, EPA found that some areas still would not meet some of the alternative ozone standards. In such cases, EPA assumed that the areas would achieve the new standards through installation of "unknown" controls. To estimate the potential total costs of alternative standards, EPA estimated the costs of installing "known" controls to the five categories of emission source and then used various methods to estimate the costs of installing "unknown" controls. EPA (2008, p. 5-23) estimated the total annualized cost of "known" controls for 65 ppb as $4.5 billion and the total annualized cost of "unknown" controls as between $27 billion to $39 billion (all in 2006 dollars).[9] Thus, many tons of NO_x and VOC emissions would need to be reduced through "unknown" controls for 65 ppb, and these reductions would have a much larger total annualized cost than the reductions from "known" controls.

We model these costs in N_{ew}ERA as changes in tax rates on sector inputs such that the total tax increase for each sector would be equal to the compliance costs. N_{ew}ERA endogenously calculates the new tax rates that would achieve this equivalence. For sectors with capital among their inputs, we assume that the cost increase would be associated entirely with capital costs. Costs associated with area sources were imposed on the Services and Household Consumption sectors as higher costs for durable goods (including appliances such as natural gas space heaters and water heaters). Costs associated with onroad mobile sources were partly imposed on the Household Consumption sector as higher costs for personal transportation. The tables below provide additional detail on the N_{ew}ERA cost inputs.

We used information from EPA on the costs of "known" and "unknown" controls and converted from 2006 dollars to 2010 dollars using the GDP implicit price deflator. We allocated the costs of EPA's "known" controls to the relevant non-electricity sectors in N_{ew}ERA.[10] The "known" control costs for non-EGU point sources were allocated to N_{ew}ERA sectors based on sector codes by facility in the EPA data source (primarily to the Refining, Manufacturing, Energy-Intensive Industries, and Services sectors). The "known" control costs for area sources were divided between N_{ew}ERA's Services sector (75 percent) and Household Consumption sector (25 percent) based on information on the "known" area controls in the RIA (EPA 2008, pp. 3a-4 to 3a-11). The "known" control costs for onroad mobile sources were divided between N_{ew}ERA's Trucking sector (85 percent) and Household Consumption sector (15 percent) based on information on the "known" onroad mobile sources in the RIA (EPA 2008, pp. 3a-12 to 3a-20). EPA does not provide detailed cost information on "known" controls for nonroad mobile sources, and thus we

[9] As noted above, our total cost inputs for 65 ppb are lower than EPA's total cost estimates for 65 ppb, which are relative to a baseline of 84 ppb, because we removed the costs of meeting the new baseline of 75 ppb.

[10] Information on N_{ew}ERA's non-electricity sectors is provided in Appendix A

do not include such costs in our modeling.[11] Table B-6 summarizes our allocation of ozone "known" control costs to N_{ew}ERA sectors.

Table B-6. Allocation of Ozone "Known" Control Costs to N_{ew}ERA Sectors

Emission Source Category	Share of "Known" Control Costs	N_{ew}ERA Sector	Share of Category "Known" Costs	Notes
Non-EGU Point	51%	Refining	33%	Higher cost for capital
		Manufacturing	30%	"
		Energy-Intensive	20%	"
		Services	17%	"
		Motor Vehicle Mfg	1%	"
		Agriculture	0.02%	"
		Transportation	0.03%	"
Area	42%	Services	75%	Higher cost for durable goods
		Household Consumption	25%	Higher cost for durable goods
Onroad Mobile	7%	Trucking	85%	Higher cost for capital
		Household Consumption	15%	Higher cost for transportation
Nonroad Mobile	0%	N/A		

Note: "N/A" denotes "not applicable."
Rows may not sum to 100 percent because of independent rounding.
Source: NERA calculations and assumptions as explained in text

For the "unknown" controls, we used EPA's cost estimates using its "Hybrid" estimation approach with its "Mid" slope parameter, which EPA used to produce the $39 billion estimate cited above (in 2006 dollars).[12] We used a two-step process to allocate "unknown" control costs to non-EGU sectors in N_{ew}ERA.

We first allocated "unknown" control costs to the four non-EGU categories of emission sources listed above (non-EGU point, area, onroad mobile, and nonroad mobile) based on their shares of baseline projected national NOx emissions in 2020 (EPA 2008, p. 3-24). Thus, we allocated 25 percent of the "unknown" control costs to non-EGU point sources, 20 percent to area sources, 20 percent to onroad mobile sources, and 35 percent to nonroad mobile sources.

We then allocated these "unknown" control costs within each emission source category among various N_{ew}ERA sectors related to the category. For non-EGU point sources, we assumed that the allocation among NewERA sectors would be the same as for "known" control costs. For area

[11] Although EPA (2008, p. 3-24) provides a summary of emission reductions from "known" controls for nonroad mobile sources, which are small relative to emission reductions from other source categories, the main docket file summarizing emission reductions and control costs (No. 0290) does not contain any details on "known" controls for nonroad mobile sources.

[12] Details on EPA's "Hybrid" estimation approach and its "Mid" slope parameter are provided in EPA (2008, Chapter 5).

sources, we divided the "unknown" control costs between N_{ew}ERA's Services sector (75 percent) and Household Consumption sector (25 percent), just as for "known" control costs for area sources. For onroad mobile sources, we divided the "unknown" control costs between N_{ew}ERA's Trucking sector (50 percent) and Household Consumption sector (50 percent) based on the assumption that households would bear a larger share than for the "known" control costs for onroad mobile sources. Finally, we divided the "unknown" control costs for nonroad mobile sources between N_{ew}ERA's Manufacturing sector (50 percent) and Transportation sector (50 percent) to reflect the additional costs of producing and operating nonroad equipment (e.g., construction) and non-road transportation (e.g., rail) with lower emissions. Table B-7 summarizes our allocation of ozone "unknown" control costs to N_{ew}ERA sectors.

Table B-7. Allocation of Ozone "Unknown" Control Costs to N_{ew}ERA Sectors

Emission Source Category	Share of "Unknown" Control Costs	N_{ew}ERA Sector	Share of Category "Unknown" Costs	Notes
Non-EGU Point	25%	Refining	33%	Higher cost for capital
		Manufacturing	30%	"
		Energy-Intensive	20%	"
		Services	17%	"
		Motor Vehicle Mfg	1%	"
		Agriculture	0.02%	"
		Transportation	0.03%	"
Area	20%	Services	75%	Higher cost for durable goods
		Household Consumption	25%	Higher cost for durable goods
Onroad Mobile	20%	Trucking	50%	Higher cost for capital
		Household Consumption	50%	Higher cost for transportation
Nonroad Mobile	35%	Manufacturing	50%	Higher cost for capital
		Transportation	50%	"

Note: Rows may not sum to 100 percent because of independent rounding.
Source: NERA calculations and assumptions as explained in text

Given the staggered implementation of NAAQS levels, we used EPA information on the implementation schedule for the 2008 standard as an indication of the possible schedule for a potential new standard. In April 2012, EPA announced that areas would have between three and twenty years to come into attainment with the 2008 standards based on their current ozone levels (EPA 2012b). Table B-8 shows the attainment times for the various area classifications.

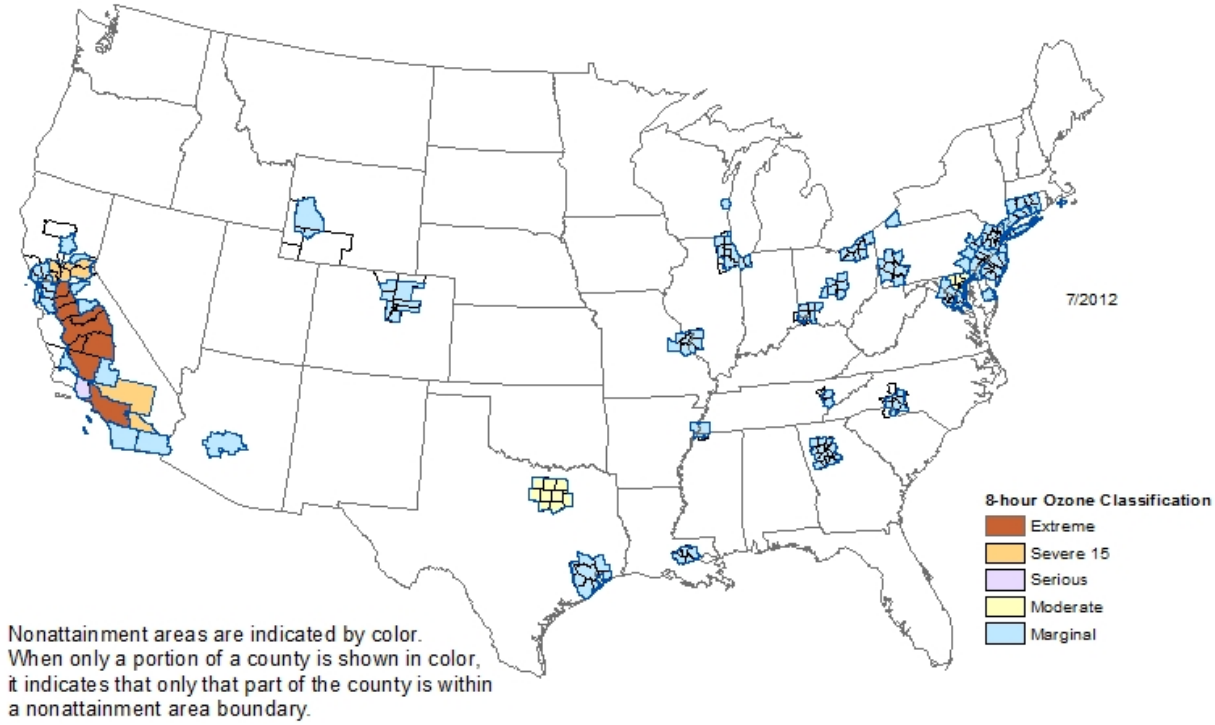
Table B-8. EPA Area Classifications and Attainment Times for 2008 Ozone Standard

Area Classification	Current Ozone Level	Attainment Time
Marginal	76-85 ppb	3 years
Moderate	86-99 ppb	6 years
Serious	100-112 ppb	9 years
Serious-15	113-118 ppb	15 years
Serious-17	119-174 ppb	17 years
Extreme	175 ppb and higher	20 years

Source: Adapted from EPA (2012b)

Figure B-2 shows the EPA area classifications for the 2008 ozone standard. Note that parts of Southern and Central California are classified as Extreme. As a result, these areas have twenty years to come into attainment with the 2008 ozone standard. Since the Dallas-Fort Worth area has been classified as Moderate, it has six years to come into attainment with the 2008 ozone standard.

Figure B-2. EPA Area Classifications for 2008 Ozone Standard



Source: EPA (2012c)

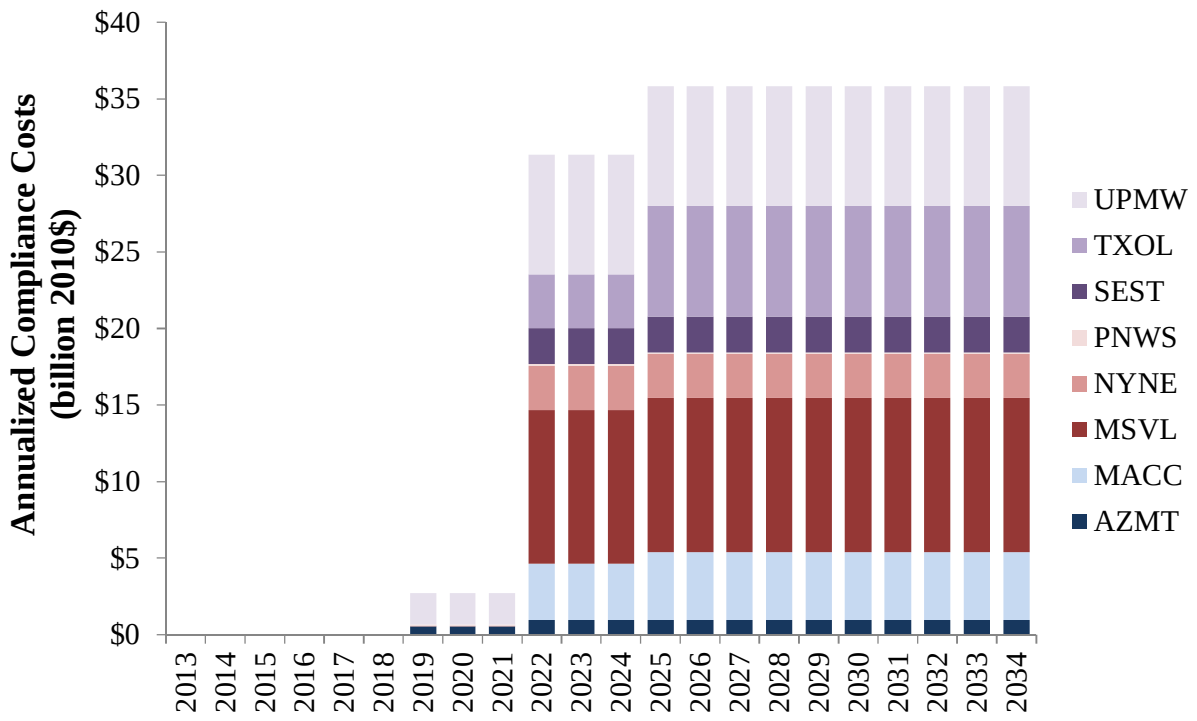
We used the area classifications and attainment times shown above as the basis for the assumed staggered implementation schedule in this analysis. We began by specifying assumptions regarding promulgation of new ozone NAAQS levels and a "default" attainment year. We assumed that EPA would promulgate new ozone NAAQS levels in 2014 and the "default" attainment year would be 2019. The areas in Figure B-2, however, would have more time because EPA already recognizes that they have special implementation schedules. For example,

the Dallas-Fort Worth area (which EPA has classified as Moderate) would have six extra years to come into attainment (*i.e.*, its attainment year would be 2025), and parts of Southern and Central California (which EPA has classified as Extreme) would have 20 extra years to come into attainment (*i.e.*, its attainment year would be 2039, though this is past the end of the modeling period). We entered ozone compliance costs into N_{ew}ERA beginning in these years for each area.

a. Lower Ozone Costs Case

Figure B-3 summarizes the costs that we entered into the N_{ew}ERA model for the ozone NAAQS of 65 ppb for the lower ozone costs case. The costs begin in 2019. The total annualized cost is approximately $36 billion (2010$). As discussed above, the costs are lower than EPA's (2008, p. 5-23) total cost estimates for 65 ppb ($44 billion in 2006$) because we removed costs for 75 ppb to update the baseline ozone level and we assumed that California would not incur costs during the modeling period.

Figure B-3. Annual Modeling Inputs for Ozone NAAQS: Lower Ozone Costs Case



Note: See Appendix A for map of N_{ew}ERA regions.
Source: NERA calculations as explained in text

b. Higher Ozone Costs Case

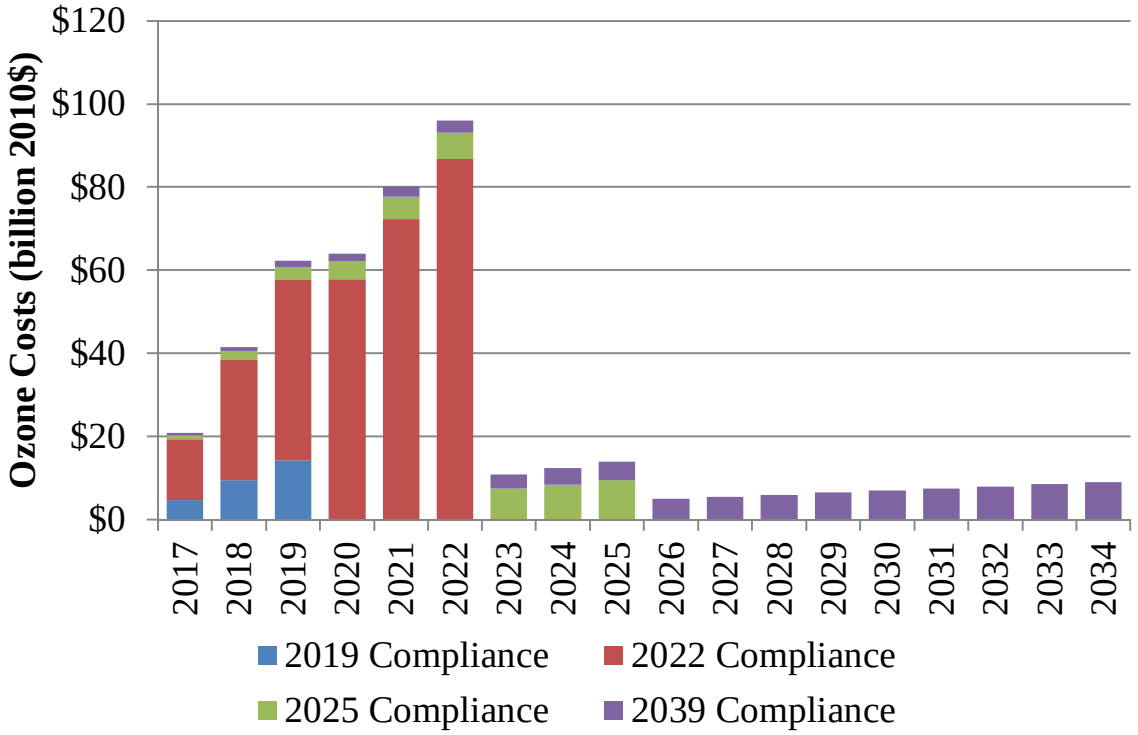
For the case with higher ozone costs, we first calculated the present values of compliance costs using the annualized costs from EPA's RIA. We calculated the present values using an assumed discount rate of 7 percent and an assumed capitalization period of 20 years. Note that EPA's RIA does not provide details on the components of annualized costs (including upfront capital costs

and recurring operating costs) or on the discount rate and period that EPA used for its calculations.

We then grouped the present values into the assumed compliance deadlines. As discussed above, states are assumed to comply by 2019, 2022, 2025, or (in the case of California) 2039. We calculated the total ozone compliance costs in present value terms for each of these four assumed compliance deadlines. Under the assumption that much of these compliance costs would be capital costs that would be incurred before the compliance deadline for each state, we divided the total ozone compliance costs in present value terms over the years between 2017, the assumed start of incurring capital costs, and the compliance deadline. We divided these costs so that they would be small shares of the total present value in early years (including 2017) and large shares of the total present value in late years (including the compliance deadline year). Specifically, we counted the number of years between 2017 and the compliance deadline (*e.g.*, three years for 2019 compliance), calculated the sum of the numbers up to the compliance year (*e.g.*, 1+2+3=6 for 2019 compliance), and assigned shares of costs to each year based on its number relative to the sum (*e.g.* for 2019 compliance, 1/6=17 percent for 2017, 2/6=33 percent for 2018, and 3/6=50 percent for 2019). Since the N_{ew}ERA modeling system models every third year, we developed total cost inputs for 2019 as the sum of costs in 2017, 2018, 2019, we developed total cost inputs in 2022 as the sum of costs in 2020, 2021, and 2022, *etc.*

Figure B-4 shows the annual ozone cost inputs for the higher ozone costs case (before summing costs up to develop cost inputs for 2019 and every third year thereafter). As discussed above, the costs for each compliance deadline begin in 2017 at relatively low levels and then gradually increase through the compliance deadline year. The total of these costs is $465 billion (2010$).

Figure B-4. Annual Modeling Inputs for Ozone NAAQS: Higher Ozone Costs Case



Source: NERA calculations as explained in text.

3. References

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D. Sulfur Dioxide National Ambient Air Quality Standards

1. Policy Background

Sulfur dioxide (SO_2) is a gaseous chemical compound released into the atmosphere by power plants and various industrial processes. The first SO_2 NAAQS was established in 1971 with the goal of reducing SO_2 air pollution to below 140 parts per billion (ppb) within any given 24-hour period. This goal was to be achieved through emissions controls on eligible electric sector and non-electric sector facilities that contribute to SO_2 pollution as determined in SIPs.

Since 1971, the SO_2 NAAQS has been revised several times. In June 2010, EPA limited SO_2 air pollution to 75 ppb or below, based on a three-year average of the annual 99th percentile of 1-hour daily maximum concentrations (EPA 2010a). Like its predecessors, the policy will involve the development of SIPs that require emissions controls for various SO_2-emitting units.

The SO_2 1-hour NAAQS also mandates the creation of an expanded SO_2 monitoring system. Currently, only 488 monitors are in place to evaluate SO_2 levels, an estimated one-third of the number required to adequately measure SO_2 levels in all areas of maximum concentration. EPA does not provide cost estimates for expanding the monitoring network to cover all areas.

2. Modeling Methodology

The table below summarizes our modeling inputs for the SO_2 NAAQS.

Table B-9. Modeling Inputs for SO_2 NAAQS

Policy	Modeling Inputs
SO_2 NAAQS	Electricity sector: Assume that SO_2 reductions from other policies would eliminate the need for SO_2 reductions for NAAQS Non-electricity sectors: Apply compliance costs beginning in 2019 using cost estimates from EPA's SO_2 NAAQS RIA

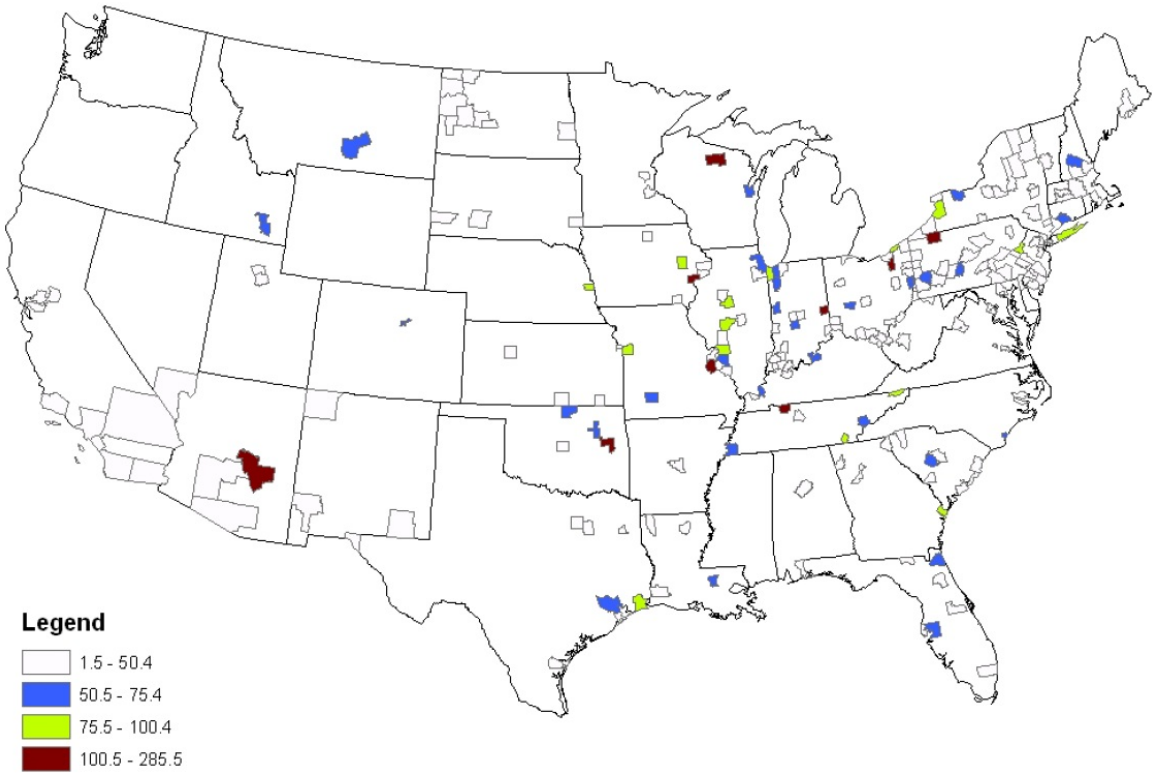
Source: NERA assumptions as explained in text

The MATS Rule, the ozone 8-hour NAAQS, and the $PM_{2.5}$ annual NAAQS would lead to significant reductions in SO_2 emissions from the electricity sector. Thus, we assume that the electricity sector would not have to reduce SO_2 emissions further for the NAAQS. Instead, we assume that all SO_2 emission reductions for the NAAQS would come entirely from other sectors.

The data we use to develop N_{ew}ERA inputs for the non-electricity sectors come from EPA's RIA for the SO_2 1-hour NAAQS (EPA 2010b). The RIA provides a list of 24 counties[13] projected to exceed the SO_2 75 ppb limit in 2020 (see Figure B-5 below), along with the annualized costs of identified controls needed to attain the SO_2 limit in each of these counties. The RIA also estimates that four counties would require additional unidentified controls, for which it provides an estimated number of tons of SO_2 these unidentified controls will reduce annually, along with a cost per ton. We use this information from EPA's RIA to calculate the total annualized cost of SO_2 1-hour NAAQS compliance for each county identified by EPA as requiring controls.

[13] Due to the limitations of the SO_2 monitoring system mentioned above, the EPA only addressed areas where projected 2020 SO_2 levels, based on the three-year average of the annual 99th percentile of 1-hour daily maximum concentrations, exceed 75 ppb within the 488 areas currently monitored.

Figure B-5. Projected 2020 Design Values (ppb) for the 99th Percentile Daily 1-hour Maximum SO_2 Concentrations by County



Source: EPA (2010b, p. 3-13)

While the RIA provides total compliance costs on a county-by-county basis, it does not provide details on the sectors that might incur these compliance costs at the county level. Instead, the RIA only provides information on the distribution of costs between the electricity sector and non-electricity sectors at the national level. We assumed that the share of non-electricity sector costs in each county relative to total compliance costs would be the same as the share of non-electricity sector costs at the national level. Table B-10 shows the breakdown of national SO_2 NAAQS compliance costs in the RIA between the electricity sector and other sectors.

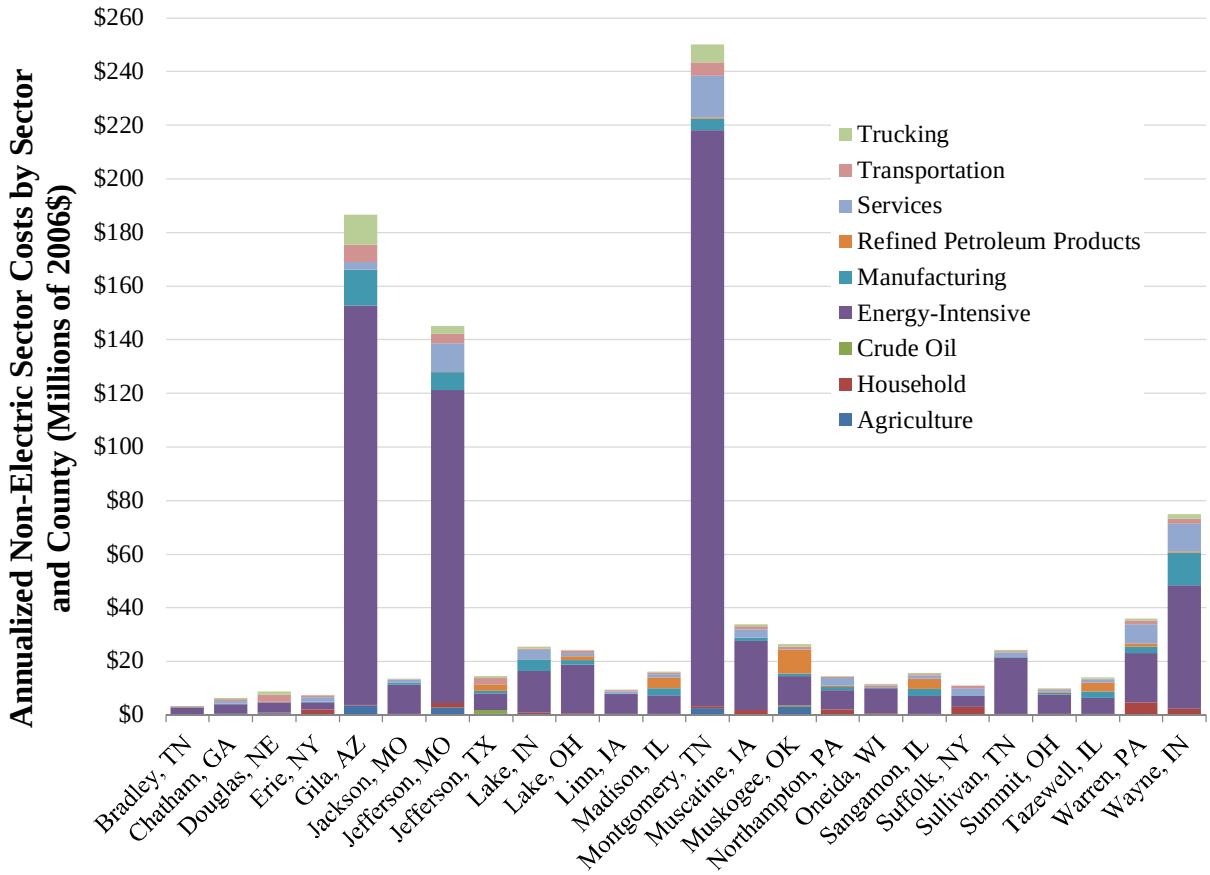
Table B-10. Total National Annualized SO_2 1-hour NAAQS Compliance Costs (2006$)

Source	Annualized Cost (millions)	% of Total
Electricity Sector	$777.0	51.8%
Other Sectors	$723.4	48.2%
Total	**$1,500.4**	**100.0%**

Source: NERA calculations using information in EPA (2010b)

To determine the allocation of costs to specific non-electricity sectors, we used the EPA's 2008 National Emissions Inventory (NEI) with SO_2 emissions by facility and sector (EPA 2008). We used the relative shares of SO_2 emissions in each sector and each state to allocate the county-level costs to the various non-electricity sectors within each region.[14] Figure B-6 below summarizes our modeled costs. We apply these costs in NewERA in 2019 based on the compliance schedule assumed by EPA in the 2010 SO_2 NAAQS.

Figure B-6. Annualized Non-Electricity Sector Costs per County and Sector (Millions of 2006$)



Source: EPA Final Regulatory Impact Analysis for the SO_2 National Ambient Air Quality Standards

We do not address the costs due to the expansion of the monitoring network, because EPA has not provided estimates of the likely costs.

3. References

U.S. Environmental Protection Agency. 2008. "2008 National Emissions Inventory Data." (http://www.epa.gov/ttn/chief/net/2008inventory.html)

[14] Information on N_{ew}ERA's non-electricity sectors is provided in Appendix A.

U.S. Environmental Protection Agency. 2010a. "Primary National Ambient Air Quality Standard for Sulfur Dioxide; Final Rule." 75 *Federal Register* 35520. June 22. (http://www.epa.gov/ttn/naaqs/standards/so2/fr/20100622.pdf)

U.S. Environmental Protection Agency. 2010b. "Final Regulatory Impact Analysis for the SO_2 National Ambient Air Quality Standards." June. (http://www.epa.gov/ttn/ecas/regdata/RIAs/fso2ria100602full.pdf)

E. $PM_{2.5}$ National Ambient Air Quality Standards

1. Policy Background

Under the authority of the Clean Air Act, EPA sets NAAQS related to PM for both $PM_{2.5}$ (fine PM) and PM_{10} (coarse PM). EPA also sets standards both on average annual ambient levels and 24-hour ambient levels. Our focus is on the $PM_{2.5}$ primary annual NAAQS, since this is the portion of the PM standard that accounts for the vast majority of non-attainment and thus is the standard that could lead to the most substantial compliance costs.

EPA set the $PM_{2.5}$ primary annual NAAQS at 15 micrograms per cubic meter ($\mu g/m^3$) in 1997 and maintained it at this level in the review completed in 2006. In addition to being designed to protect human health, the $PM_{2.5}$ standards also affect visibility and thus, as discussed below, the NAAQS interacts with requirements for the RHR.

In June 2012, EPA proposed lowering the $PM_{2.5}$ primary annual NAAQS from the current level of 15 $\mu g/m^3$ to between 12 and 13 $\mu g/m^3$ (EPA 2012a). In the RIA for the new $PM_{2.5}$ standard, EPA evaluated 14, 13, 12, and 11 $\mu g/m^3$ as the potential new primary annual level (EPA 2012b). Although the *Federal Register* notice (EPA 2012a) speaks only of lowering the standard to between 12 and 13 $\mu g/m^3$, an EPA presentation to OMB (also from June 2012) indicates that EPA was inclined to lower the standard to 12 $\mu g/m^3$ (EPA 2012c, p. 5).

Environmental and health organizations (including the American Lung Association) and some states have submitted petitions to the D.C. Circuit Court to require EPA to finalize the $PM_{2.5}$ standards in 2012 (Nelson 2011).

EPA intends to make final designations for $PM_{2.5}$ non-attainment areas in 2014. By 2018, implementation plans will be due to the EPA. Plans can include federal measures, as well as any needed local measures, to demonstrate that an area will meet the standards. By 2020, states are required to meet primary standards. A state may request a possible extension to 2025, depending on the severity of fine particle pollution and the availability of controls.

2. Modeling Methodology

The table below summarizes our modeling methodology for the $PM_{2.5}$ NAAQS. Our analysis assumes that EPA will set a standard of 12 $\mu g/m^3$.

Table B-11. Modeling Inputs for $PM_{2.5}$ NAAQS

Policy	Modeling Inputs
$PM_{2.5}$ NAAQS	Due to the NAAQS, EGUs in CSAPR states and California (the states that are most likely to be in non-attainment areas) would not have the option of using DSI for MATS compliance but would instead have to use the more expensive wet or dry scrubber (depending on the relative economics of the two scrubber options), or else retire

Source: NERA assumptions as explained in text

To model the lower annual $PM_{2.5}$ standard of 12 μg/m^3, NERA only considered actions in the electric sector. Further, the geographic scope of required actions was limited to the states that were to be subject to the CSAPR rule and California (the states that are most likely to be in non-attainment areas).[15] These are the states that would most likely be in non-attainment with the tighter annual $PM_{2.5}$ standard.

The MATS and RHR also directly seek to reduce PM emissions and thus it is important to assess the likely additional requirements after compliance actions for these two policies are taken into account in order to avoid overstating the total compliance costs. Other air policies in this analysis, including the ozone NAAQS, also would lower PM emissions as a co-benefit of reducing targeted emissions (NO_x and VOC). We accounted for overlap among all of the policies affecting PM emissions. Further, NO_x is a precursor of PM, but we believe the ozone NAAQS would lead to reductions of NO_x such that additional reductions from the PM NAAQS would be redundant.

With respect to the MATS policy, we conclude that compliance with the $PM_{2.5}$ NAAQS would require that EGUs in portions of the country that are in non-attainment areas (assumed to be the CSAPR states and California) maximize their SO_2 reductions via either a wet or dry scrubber. We do not believe that the lower SO_2 reductions provided by DSI would be sufficient to comply with $PM_{2.5}$ NAAQS, although we presume that DSI would be sufficient to comply with the acid gas portion of the MATS Rule (for those units for which DSI is an option). Thus, our modeling of the $PM_{2.5}$ rule eliminates DSI as a MATS compliance option for units in CSAPR states and California, since it is unlikely that any generator could recover an investment in DSI over a three-year period (the difference in compliance timing for MATS in 2016 and $PM_{2.5}$ in 2019).

3. References

Nelson, Gabriel. 2011. "Air Pollution: Health groups, states ask Court to force EPA soot crackdown." November 16. (http://www.eenews.net/Greenwire/2011/11/16/archive/2)

U.S. Environmental Protection Agency ("EPA"). 2011. "Cross-State Air Pollution Rule." December 15. (http://www.epa.gov/airtransport/pdfs/CSAPRPresentation.pdf)

U.S. Environmental Protection Agency ("EPA"). 2012a. "National Ambient Air Quality Standards for Particulate Matter; Proposed Rule." 77 *Federal Register* 38890. June 29. (http://www.gpo.gov/fdsys/pkg/FR-2012-06-29/pdf/2012-15017.pdf)

[15] See EPA (2011, p. 3) for a map of CSAPR states.

U.S. Environmental Protection Agency ("EPA"). 2012b. *Regulatory Impact Analysis for the Proposed Revisions to the National Ambient Air Quality Standards for Particulate Matter*. June. (http://www.epa.gov/ttn/ecas/regdata/RIAs/PMRIACombinedFile_Bookmarked.pdf)

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F. Coal Combustion Residuals

1. Policy Background

Coal combustion residuals (CCR), which include fly ash, bottom ash, boiler slag, and scrubber waste, are regulated under the Resource Conservation and Recovery Act (RCRA). Enacted in 1976, RCRA gives EPA the authority to control hazardous waste throughout its lifespan (*i.e.* generation, transportation, treatment, storage, and disposal). In 1986, amendments to the RCRA enabled EPA to further address environmental problems associated with hazardous waste. Under the current statute, CCR are considered exempt wastes and are not subject to the same level of regulation as hazardous wastes.

EPA has considered several alternative forms of regulations for the disposal of CCR (EPA 2009, 2010a). The alternative forms of regulation differ in their classification under Subtitles C and D of the RCRA. Subtitles C and D propose different waste classifications (hazardous and non-hazardous, respectively), as well as different compliance measures (*e.g.*, requiring liners at all surface impoundments or only at new surface impoundments) and regulatory requirements. Additional information on differences between Subtitles C and D is provided in EPA (2012).

Recently, there has been some congressional support to regulate CCR under Subtitle D. In October of 2011, the House passed H.R. 2273, a bill to regulate CCR as a non-hazardous waste. In August 2012, a similar bill was introduced in the Senate with bipartisan support; it would also set up a non-hazardous-waste regulatory scheme for CCR.

2. Modeling Methodology

Table B-12 summarizes our compliance assumptions for CCR regulations.

Table B-12. Compliance Assumptions for CCR Regulations

Policy	Compliance Assumptions
CCR	Assign costs to coal units in 2019 based on EPA Subtitle D in initial EPA proposal

Source: NERA assumptions as explained in text

For our modeling, we used EPA 2010 cost estimates for Subtitle D compliance at individual facilities (EPA 2010a, Exhibit J3) and assumed that coal units would need to comply with CCR requirements by 2019.

We used the EPA plant-specific information for Subtitle D costs to develop unit-specific information. EPA provides facility-specific costs for two categories, engineering control costs and land disposal treatment costs. We assigned costs to individual coal units within each plant based upon their relative electricity generating capacities (e.g., if a unit provides 60 percent of a plant's total coal capacity, we assume it would incur 60 percent of the CCR compliance costs for that plant).

Engineering control costs and land disposal treatment costs each consist of capital costs and fixed operation and maintenance (O&M) costs. EPA did not provide these cost breakdowns for plants but did provide summary totals (EPA 2009, p. 78), and we used this information to develop plant-specific (and unit-specific) estimates of capital costs and O&M costs. Of the ten categories that comprise engineering control costs, we assume that bottom ash liners, siting/location restrictions and closure capping are capital expenditures; the remaining costs are presumed to be O&M costs. These assumptions imply that capital expenditure and O&M costs account for about 88 percent and 12 percent, respectively, of the total engineering control costs. The specific ratios were applied at the unit level to calculate each unit's capital and O&M cost breakdown.

Similarly, EPA provided sector-level estimates of capital and O&M costs for land disposal and treatment (EPA 2009, p. 77). Using this information, we calculated that 93.34 percent of land disposal costs are capital expenditures and 0.66 percent are O&M costs. As with the engineering control costs, these ratios were applied to the land disposal treatment costs to develop detailed cost estimates for each unit. A breakdown of these costs is shown in Table B-13.[16]

Table B-13. CCR Compliance Cost Summary

		Capital Costs (million $)		Fixed O&M (million $)	Total Cost (million $)	
	Affected Facilities	Overnight Capital	Annualized Capital	Annual FOM	Overnight Capital	Annualized (Cap + FOM)
Engineering Controls + Ancillary Costs	348	$6,089	$436	$61	$6,089	$498
Land Disposal Treatment	158	$23,510	$1,684	$11	$23,510	$1,695
Total		$29,600	$2,120	$73	$29,600	$2,193

Source: NERA assumptions as explained in text. Facility and unit compliance costs are from EPA 2010.
Notes: Annualization estimates use a 7% discount rate over 50 years. All costs are in 2010 dollars.

Note that EPA information indicates that 348 facilities would require engineering controls and 158 of those facilities would require additional land disposal treatment costs. As shown in the table, the CCR compliance cost inputs have a present value of $29.6 billion (in 2010$).

[16] The costs in this analysis are slightly lower than the costs in Table B-13 because some of the plants to which EPA attributed CCR costs have since been retired.

3. References

U.S. House of Representatives. 2011. H.R. 2273. (http://www.gpo.gov/fdsys/pkg/BILLS-112hr2273pcs/pdf/BILLS-112hr2273pcs.pdf)

U.S. Environmental Protection Agency ("EPA"). 2009. "Regulatory Impact Analysis For EPA's Proposed Regulation Of Coal Combustion Residues Generated by the Electric Utility Industry – OMB Review Draft." Washington, D.C. (http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0010)

U.S. Environmental Protection Agency ("EPA"). 2010a. "Regulatory Impact Analysis For EPA's Proposed RCRA Regulation of Coal Combustion Residues Generated by the Electric Utility Industry." Washington, D.C. (http://www.regulations.gov/#!documentDetail;D=EPA-HQ-RCRA-2009-0640-0003)

U.S. Environmental Protection Agency ("EPA"). 2010b. "Coal Combustion Residuals (CCR) - Public Hearings." (http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/ccr-hearing.htm)

U.S. Environmental Protection Agency ("EPA"). 2012. "Coal Combustion Residuals - Key Differences Between Subtitle C and Subtitle D Options." (http://www.epa.gov/osw/nonhaz/industrial/special/fossil/ccr-rule/ccr-table.htm)

U.S. Senate. 2012. S. 3512. (http://www.gpo.gov/fdsys/pkg/BILLS-112s3512is/pdf/BILLS-112s3512is.pdf)

G. 316(b) Cooling Water Intake

1. Policy Background

Section 316(b) of the Clean Water Act calls for the EPA to establish regulations for the intake of cooling water by power plants and other facilities. These regulations provide the basis for individual 316(b) requirements imposed on power plants and other facilities in their National Pollution Discharge Elimination System (NPDES) permits, typically issued by states that have assumed regulatory responsibility for the NPDES program. The key regulatory requirement under Section 316(b) is that the location, design, construction, and capacity of a facility's cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. These facilities withdraw water and in the process, fish and other aquatic organisms may be lost if they become trapped against intake screens ("impingement") or pulled into the cooling system ("entrainment").

On April 20, 2011, EPA proposed new 316(b) cooling water intake requirements for existing power plants and other industrial facilities (EPA 2011a). The regulations would affect the design of cooling water intake structures (to reduce impingement) and the flow rates through cooling water systems (to reduce entrainment) at the facilities. Various technologies reduce impingement

and entrainment losses, including the retrofitting of plants with cooling towers to provide closed-cycle cooling.

Table B-14 shows the different impingement and entrainment provisions for the four regulatory options evaluated by EPA. In terms of impingement provisions, the options differ only in the intake flow threshold above which national impingement standards would apply. In terms of entrainment provisions, Options 1 and 4 would allow EPA and other permitting authorities to set requirements based on site-specific determinations of BTA using Best Professional Judgment (BPJ). Options 2 and 3, on the other hand, would require flow reductions commensurate with closed-cycle cooling (*i.e.*, cooling towers) at all facilities above the specified intake flow thresholds. EPA identified Option 1 as its preferred option.

EPA has not finalized its 316(b) rule. In June 2012, EPA issued a Notice of Data Availability (NODA) providing the results of a willingness-to-pay survey to estimate the potential benefits of its 316(b) rule that it is considering using as an alternative to benefit estimation methods based primarily on valuing potential changes in commercial and recreational fish harvests (EPA 2012a). The survey results suggest that the benefits of each regulatory option could be larger than the costs, although commentators have questioned the reliability of these benefit results as indications of the value that households would place on fish protection benefits (see *e.g.*, NERA 2012). In July 2012, EPA entered into a settlement agreement with Riverkeeper to finalize its 316(b) rule by June 2013 (EPA 2012b), about one year later than in the previous agreement.

Table B-14. Alternative Regulatory Approaches in EPA 316(b) Proposed Rule

	Impingement	Entrainment
Option 1	Standards at >2 MGD	Site-Specific
Option 2	Standards at >2 MGD	CCC at >125 MGD
Option 3	Standards at >2 MGD	CCC at >2 MGD
Option 4	Standards at >50 MGD	Site-Specific

Notes: "MGD" denotes million gallons per day design intake flow.
"CCC" denotes closed-cycle cooling (*i.e.*, cooling towers).
Sources: EPA (2011a)

2. Modeling Methodology

The table below summarizes our modeling inputs for the 316(b) policy.

Table B-15. Modeling Inputs for 316(b) Regulations

Policy	Modeling Inputs
316(b)	Impingement: Assign costs using EPA impingement compliance cost parameters to units based on EPA Option 1 (*i.e.*, standards at all facilities withdrawing more than 2 million gallons per day), unless the units also require entrainment measures Entrainment: Assign costs using EPA entrainment compliance cost parameters for closed-cycle cooling (*i.e.*, cooling towers) to units that withdraw more than 500 million gallons per day, have a capacity utilization rate of at least 35 percent, and do not operate on ponds or canals The assumed compliance deadlines are 2019 for fossil units and 2025 for nuclear units

Source: NERA assumptions as explained in text

Our assessment for impingement controls is based on the potential costs to individual units of EPA's Option 1 alternative. However, we do not enforce impingement controls at plants that also require the installation of cooling towers, which results in lower impingement compliance costs than those calculated by EPA. For entrainment, we assume that closed-cycle cooling would be required at facilities withdrawing more than 500 million gallons per day (MGD) and whose capacity utilization rate is at least 35 percent, assumptions that are consistent with those used by the Bipartisan Policy Center (BPC 2011, p. 48). We exclude facilities that use ponds or canals for cooling water. Note that our assumptions lead to lower compliance costs than those estimated by EPA for Options 2 and 3, which are the two options EPA identifies that include entrainment controls.

The following is a summary of the specific information and data sources used to develop the compliance cost estimates for each relevant facility.

We estimated 316(b) compliance costs for fossil-fired and nuclear units based on information provided by EPA in its technical development document supporting the proposed rule (EPA 2011b). Impingement mortality controls were based on EPA's model facility cost equations, which differ for facilities withdrawing less than 10 MGD and those withdrawing more than or equal to 10 MGD. Entrainment mortality controls were based on EPA's cost estimates for an "average difficulty" cooling tower retrofit, and assume that plume abatement is required at 25 percent of the existing power generating facilities and that these costs are spread across all retrofitted units within the facilities.

The table below summarizes our compliance cost assumptions.

Table B-16. 316(b) Compliance Cost Assumptions

	Description	Capital Cost ($/gpm)	Fixed O&M ($/gpm)	Variable O&M - Chemicals ($/gpm)	Variable O&M - Pump & Fan Power (MW/gpm)	Energy Penalty - Heat Rate (MW Loss)
Impingement	DIF >= 10 MGD	$13.25	$0.46	$0.33	N/A	N/A
	DIF < 10 MGD	$121.79	$3.46	$4.69	N/A	N/A
Entrainment	average difficulty cooling tower retrofit with 25% plume abatement costs	$296.37	$1.54	$1.26	0.0000245	1.5% for fossil-fired 2.5% for nuclear

Notes: "gpm" denotes gallons per minute and "DIF" denotes design intake flow.
Impingement costs are defined with respect to DIF while entrainment costs are defined with respect to maximum reported intake flow (MRIF). We used DIF figures for both sets of calculations.
All cost figures are in constant 2010 dollars. Adjustments to 2010 dollars were calculated using the GDP price deflator of the U.S. Bureau of Economic Analysis.

Sources: Adapted from EPA (2011b), p. 8-18 for entrainment controls and p. 8-41 for impingement controls.

Our capacity factor information comes from SNL Financial[17]. In order to determine the plant-level capacity factor, we took an average of the capacity factors for all the units for that plant for which there was information available in the SNL database for 2010 weighted by the units' capacities. When 2010 capacity factor information was not available, we first tried to use 2009 capacity factor information, and if unavailable, 2008 capacity factor information. When no capacity factor information was available for a plant, we assumed the plant did not meet the 35 percent capacity utilization threshold needed in order to require cooling towers[18].

EPA's cost estimates depend on the water withdrawn at the facilities, so we extracted facility intake data from the 2010 Form EIA-860 (EIA 2012). We first mapped N_{ew}ERA plants to plants in the EIA database and calculated the total intake at the plant-level, broken down into once-through cooling (which included once-through systems using both fresh and saline water[19], but not ones withdrawing water from ponds and canals as noted above) and cooling intake for all other types of cooling systems. We removed intake values for EIA entries whose status was noted as retired or when all the entries for a plant had status noted as out of service and not expected to return to service the following calendar year[20].

The plant-level intake information was used to determine if the assumed intake thresholds for requiring impingement and entrainment measures were met (>2 MGD and >500 MGD, respectively).

[17] http://www.snl.com/.

[18] We came to this conclusion after doing additional research on several of the units for which there was no capacity utilization information in the SNL database but our methodology would otherwise require cooling towers. We found that these units had either been or were scheduled to be shut down for an extended period of time or were operating in standby/backup mode.

[19] These are entries for which the COOLING_TYPE1 variable in the EIA database is either "OS" and "OF."

[20] These are entries for which the COOLING_STATUS variable in the EIA database is either "RE" or "OS."

We calculated plant-level costs using the total plant-level intake from the EIA database for impingement measures and only the total once-through cooling intake for entrainment measures. These plant-level costs were then allocated to units within a plant in proportion to the individual units' capacities as cooling water types were not available at the unit level. Note that this implies that units which currently operate cooling systems other than once-through cooling face entrainment compliance costs using this methodology.

Utilizing thresholds of intake greater than 500 MGD and capacity utilization rate of at least 35 percent, and excluding power plants that draw in water from on-site ponds or canals, our methodology results in the implementation of closed-cycle cooling (*i.e.*, cooling towers) at 92 facilities.[21] These facilities have a total of 358 units and 135 GW of capacity (including all types of cooling systems).[22]

Table B-17 summarizes the costs that we entered into the N_{ew}ERA model for compliance with 316(b) regulations.

Table B-17. 316(b) N_{ew}ERA Cost Inputs

	Overnight Capital Cost (million $)	Annual Fixed O&M (million $)	Annual Variable O&M - Chemicals (million $)	Annual Variable O&M - Pump and Fan Power (MW)	Annual Heat Rate Penalty (MW)
Impingement	$1,555	$53	$40	N/A	N/A
Entrainment	$23,912	$124	$102	1,977	2,543
Total	$25,467	$177	$142	1,977	2,543

Notes: All cost figures are in 2010 dollars.
Costs are only incurred in the years that the respective compliance measures are required.
Sources: NERA calculations as explained in text.

With regards to timing, as we noted above, EPA has entered into a settlement agreement to finalize its 316(b) rule by June 2013 (EPA 2012b). The Proposed Rule (EPA 2011a) states that facilities must comply with the impingement standards as soon as possible and sets the maximum compliance schedule as eight years from promulgation of the final rule for impingement. For entrainment, EPA notes that facilities should comply as soon as possible with a schedule that would be determining by the permitting authority. In our modeling, we assume the compliance deadlines are 2019 for fossil units and 2025 for nuclear units. Note that N_{ew}ERA assumes that capital costs would be incurred in the three years prior to the respective compliance years.

3. References

Bipartisan Policy Center ("BPC"). 2011. *Environmental Regulation and Electric System Reliability*. Washington, D.C.: BPC. June.

[21] The Bipartisan Policy Center cited 92 and 93 plants (depending on the gas price assumptions) requiring cooling towers (BPC 2011, p. 50).

[22] As noted, costs were allocated for entrainment to all units within a plant, so these statistics represent the total number of units and capacity for the 92 plants which required cooling towers (and not just the proportion which has once-through cooling).

(http://bipartisanpolicy.org/sites/default/files/BPC%20Electric%20System%20Reliability.pdf)

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U.S. Environmental Protection Agency ("EPA"). 2012b. Second Amendment to Settlement Agreement among the Environmental Protection Agency, Plaintiffs in CRONIN, ET AL. V. REILLY, 93 CIV. 314 (LTS) (SDNY), and Plaintiffs in RIVERKEEPER, ET AL. V. EPA, 06 CIV. 12987 (PKC) (SDNY). July 17. (http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/loader.cfm?csModule=security/getfile&PageID=627843)

H. Higher Natural Gas Prices Case

The higher natural gas prices case was formed by increasing the Henry Hub natural gas prices in the baseline scenario by the amounts shown below. The increases were based upon the differences in natural gas prices between *AEO 2012*'s Reference Case and *AEO 2012*'s Low EUR (Expected Ultimate Recovery) Case. We used the lower ozone costs for this case and did not make any other changes to inputs. Note that natural gas prices in this case would be affected by the environmental policies because of changes in demand.

Table B-18. Increase in Henry Hub Natural Gas Prices in Baseline Scenario of Higher Natural Gas Prices Case (2010$/MMBtu)

	2013	2016	2019	2022	2025	2028	2031	2034
Henry Hub Price	$0.00	$0.50	$1.00	$1.00	$1.50	$1.50	$1.50	$1.50

Source: NERA assumptions as explained in text.

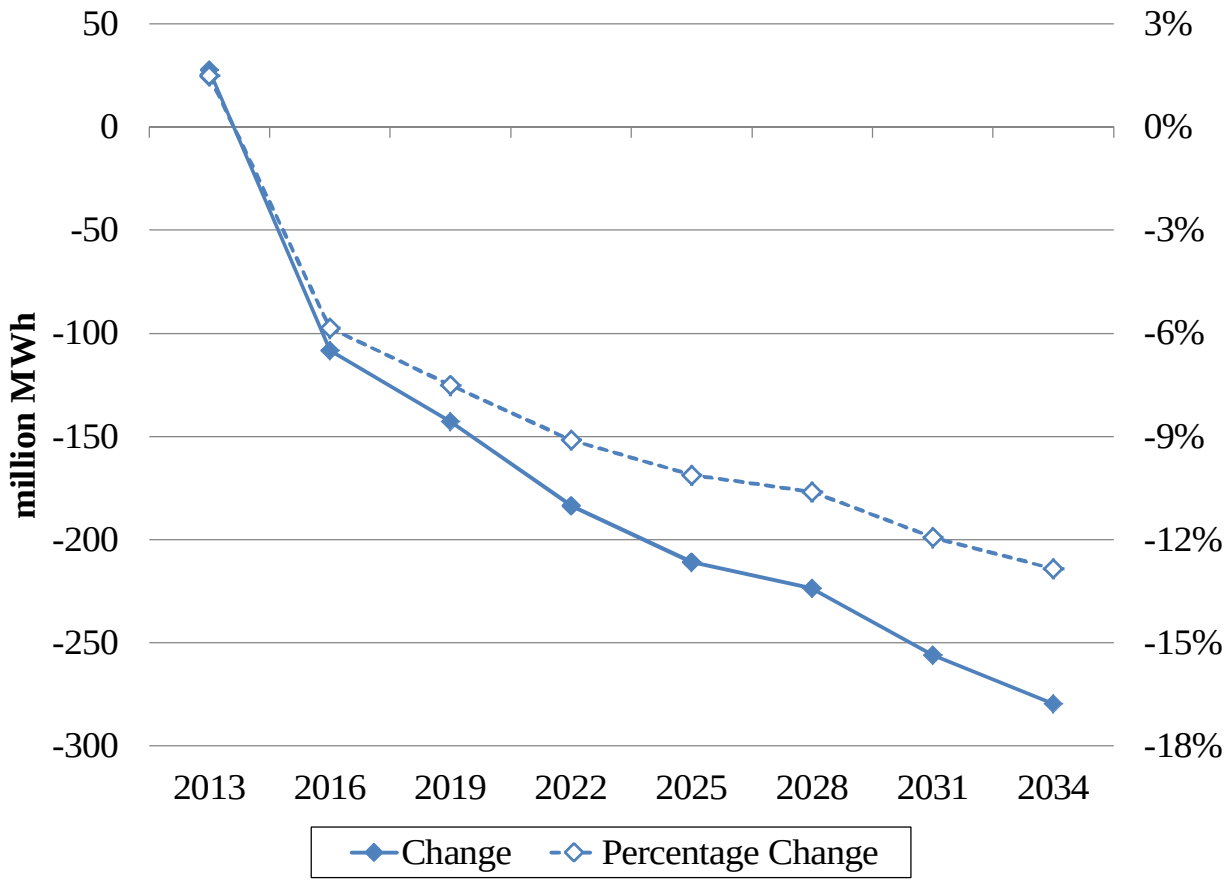
Appendix C: Results for Lower Ozone Costs Case

This appendix presents annual estimates of the energy and economic impacts of the seven recent and anticipated EPA regulations relative to the baseline scenario using the lower ozone costs case. As discussed in the report body and Appendix A, we used the N_{ew}ERA modeling system to develop estimates for every third year between 2013 and 2034.

A. Coal-Fired Generation

Figure C-1 shows the estimated change in coal-fired generation relative to the baseline scenario. Coal-fired generation is lower from 2016 through 2034 because of coal unit retirements and the marginal costs of coal unit retrofits, which reduce the competitiveness of the remaining coal units relative to other generation types, including natural gas and non-fossil energy sources.

Figure C-1. Change in Coal-Fired Generation Relative to Baseline Scenario

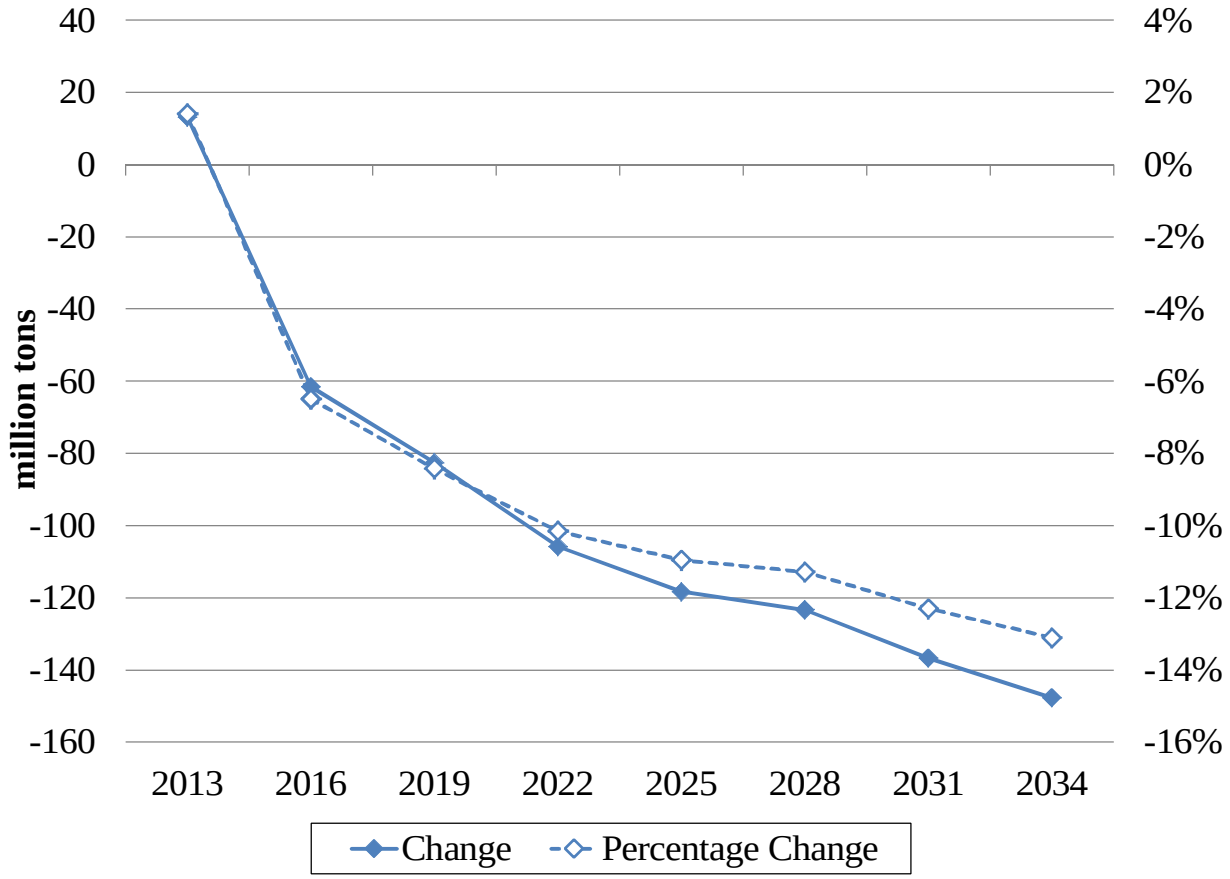


Source: NERA calculations as explained in text.

B. Electricity Sector Coal Demand

Figure C-2 shows the change in electricity sector coal demand relative to the baseline scenario. This figure is directly related to Figure C-1 on coal-fired generation and thus exhibits the same pattern with a slight increase in 2013 but a significant decrease from 2016 through 2034.

Figure C-2. Change in Electricity Sector Coal Demand Relative to Baseline Scenario

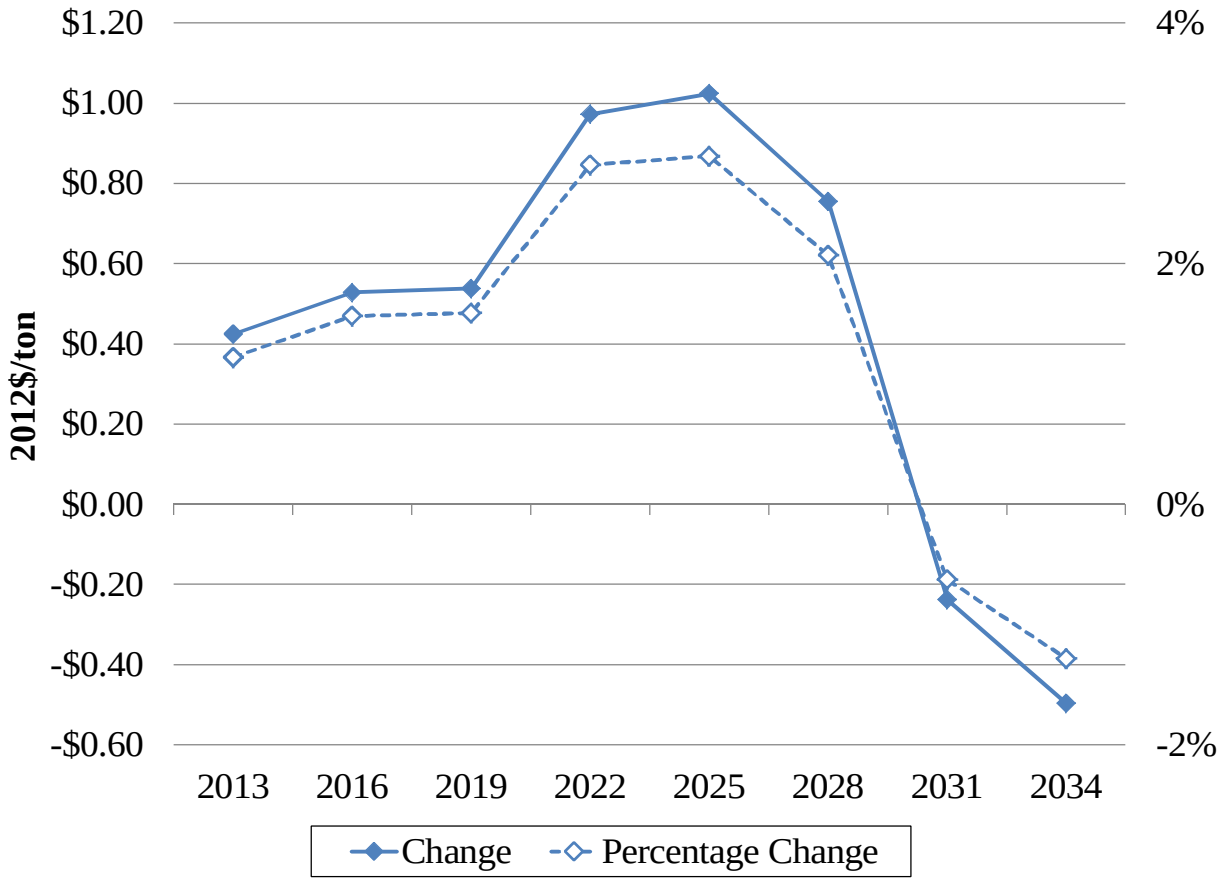


Source: NERA calculations as explained in text.

C. Coal Price

Figure C-3 shows the change in average U.S. coal minemouth prices relative to the baseline scenario. As discussed in the report body, while almost all of the 24 individual coal types in the NewERA model experience declines in demand and declines in price, the weighted average coal price increases due to a shift in the mix of coal. In particular, the requirement to install scrubbers to remove sulfur—largely due to the MATS Rule—decreases the demand for low-sulfur coals, which generally have low prices per ton, and increases the demand for high-sulfur coals, which generally have higher prices per ton. The net effect of the shift from low-price-per-ton coal to higher-price-per-ton coal results in a small increase in the average coal price in the policy case from 2013 to 2028.

Figure C-3. Change in Average Coal Minemouth Prices Relative to Baseline Scenario

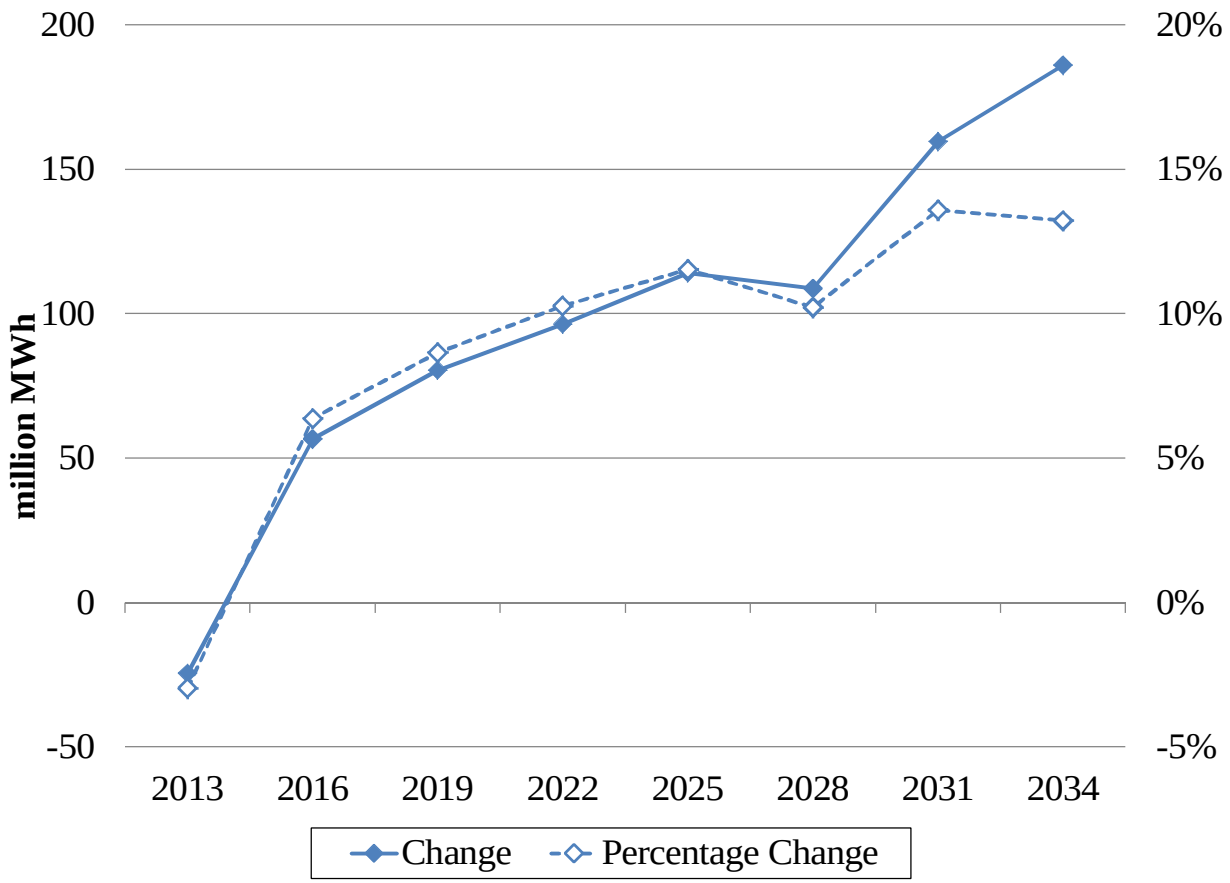


Source: NERA calculations as explained in text.

D. Natural Gas-Fired Generation

Figure C-4 shows the estimated change in natural gas-fired generation relative to the baseline scenario. The slight decrease in 2013 reflects the slight increase in coal-fired generation in that year, as shown above in Figure C-1. In later years, natural gas-fired generation increases to make up for some of the decrease in coal-fired generation. The increase in natural gas-fired generation from 2016 through 2034 is smaller than the decrease in coal-fired generation primarily because total electricity consumption decreases in response to higher electricity prices.

Figure C-4. Change in Natural Gas-Fired Generation Relative to Baseline Scenario

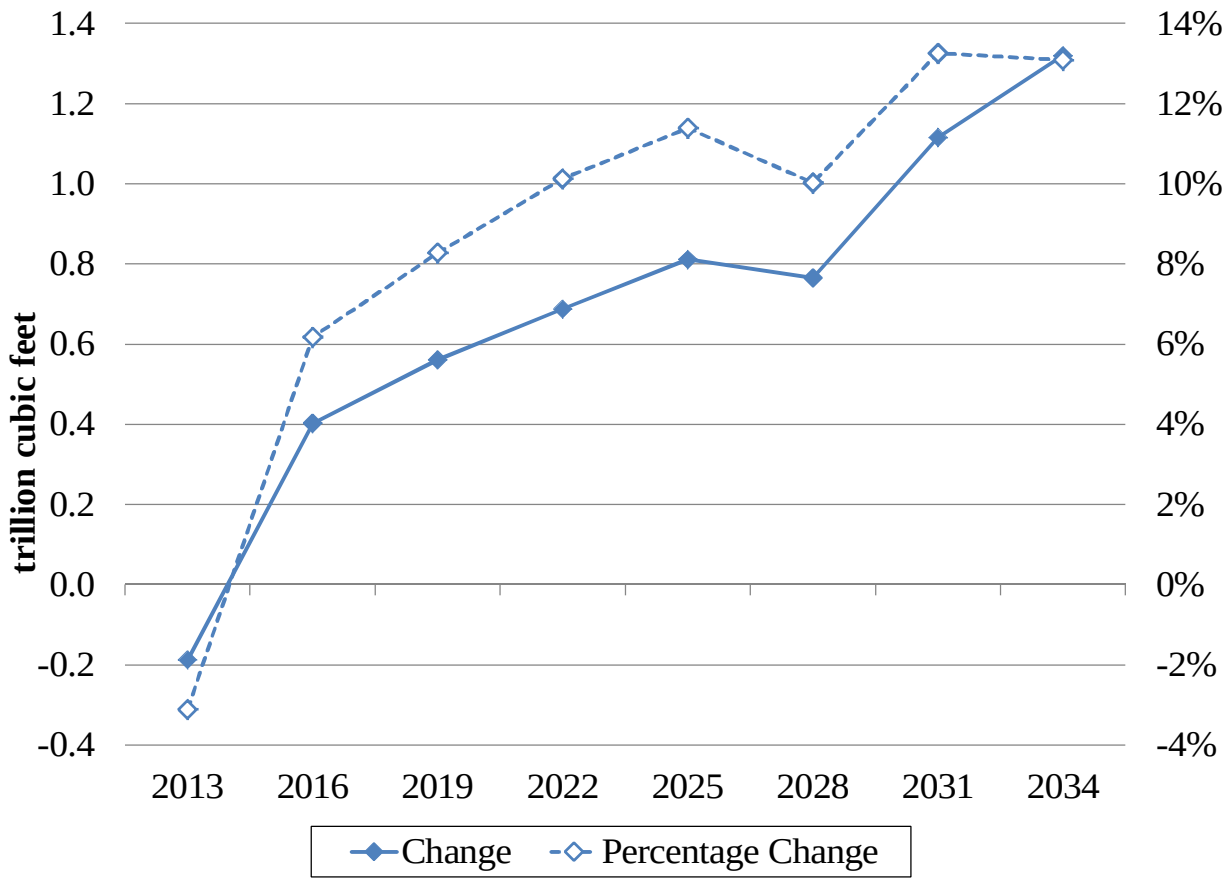


Source: NERA calculations as explained in text.

E. Electricity Sector Natural Gas Demand

Figure C-5 shows the estimated change in electricity sector natural gas demand relative to the baseline scenario. This figure is directly related to the figure above on natural gas-fired generation and thus exhibits the same pattern with a slight decrease in 2013 but a significant increase from 2016 through 2034.

Figure C-5. Change in Electricity Sector Natural Gas Demand Relative to Baseline Scenario

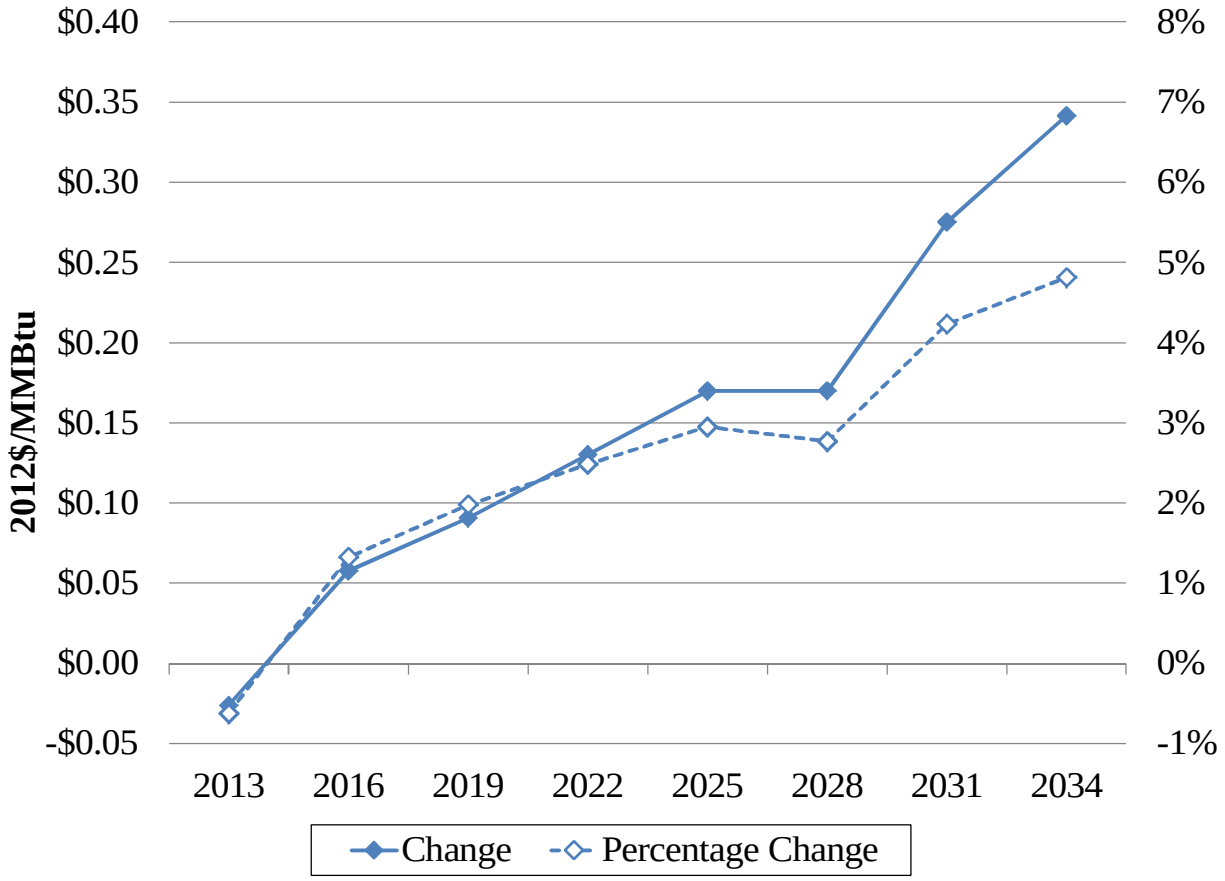


Source: NERA calculations as explained in text.

F. Natural Gas Price

Figure C-6 shows the estimated change in natural gas price at Henry Hub relative to the baseline scenario. This figure is directly related to the two figures above and thus exhibits the same pattern with a slight decrease in 2013 but a significant increase from 2016 through 2034 (non-electric demand for natural gas is not significantly different in the baseline and policy scenarios and therefore has limited impact on natural gas price changes).

Figure C-6. Change in Natural Gas Price at Henry Hub Relative to Baseline Scenario

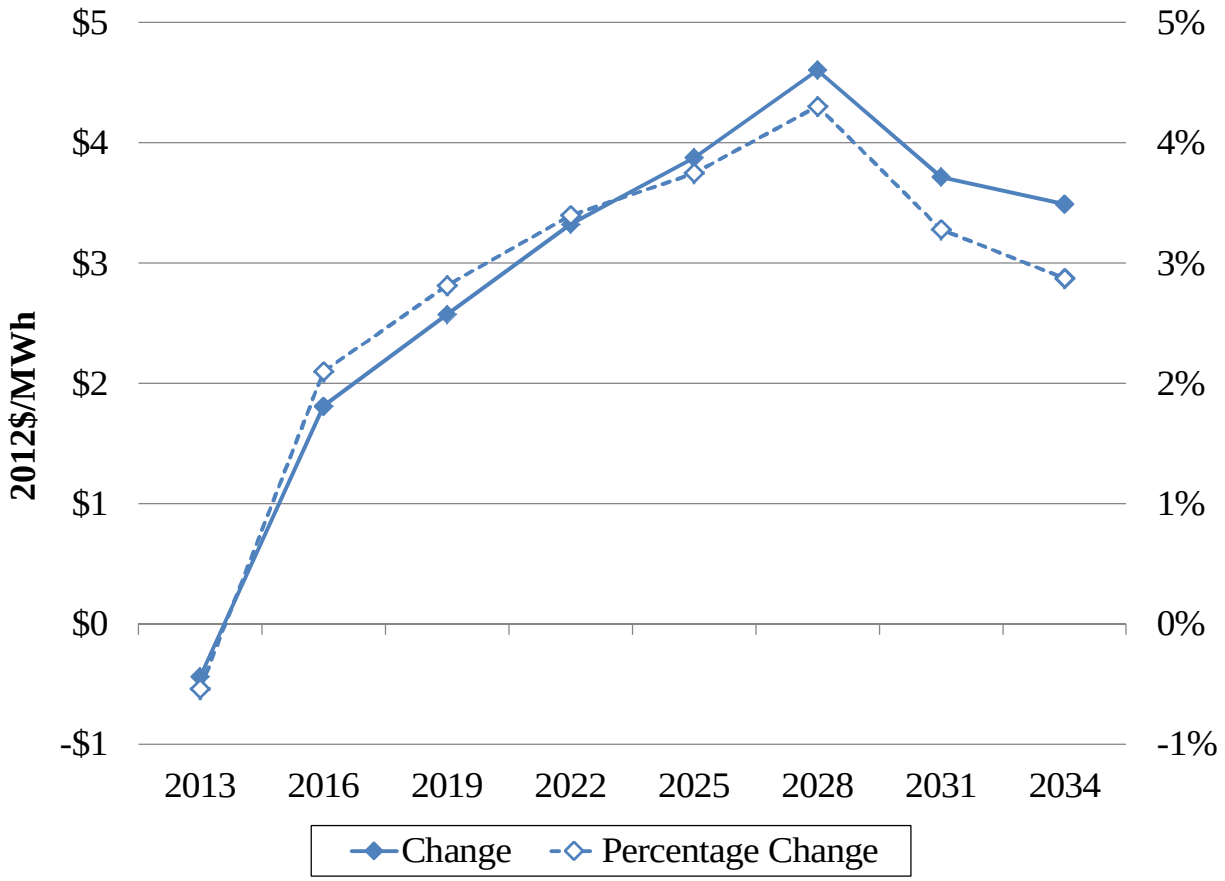


Source: NERA calculations as explained in text.

G. Electricity Price

Figure C-7 shows the estimated change in average U.S. electricity retail price relative to the baseline scenario. From 2016 through 2034, electricity prices are higher than in the baseline scenario because inexpensive coal units have retired or have incurred the costs of retrofitting with environmental controls. As a result, the generation mix has shifted toward more expensive generation types. In addition, some natural gas-fired units, oil-fired units, and nuclear units have incurred the costs of the 316(b) cooling water intake regulations. Lastly, natural gas prices are higher, which would increase electricity prices, particularly when natural gas-fired units are the marginal units.

Figure C-7. Change in Average U.S. Electricity Retail Price Relative to Baseline Scenario



Source: NERA calculations as explained in text.

Table C-1 shows the average electricity price impacts in percentage terms by macroeconomic region.

Table C-1. Average Electricity Price Impacts by Region

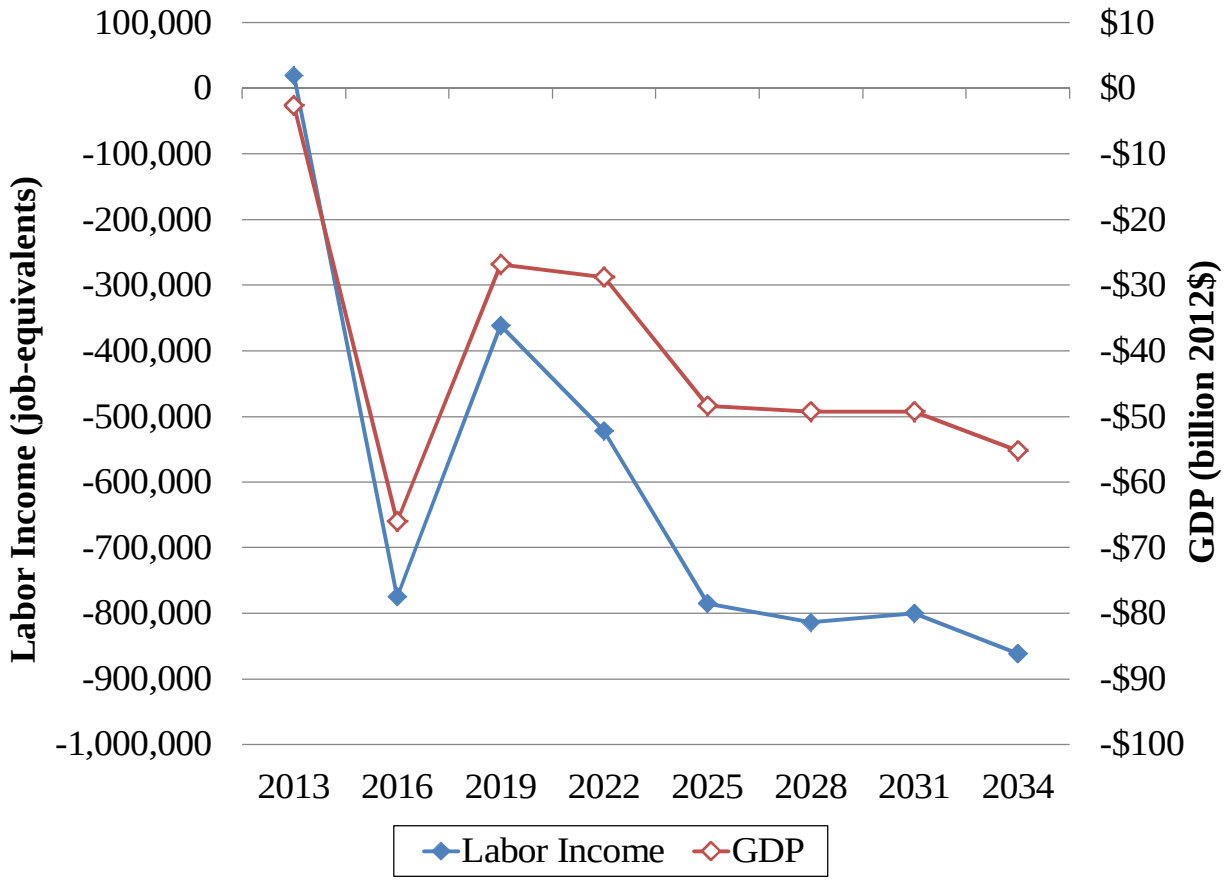
	2013	2016	2019	2022	2025	2028	2031	2034	Avg.
New York/New England	-0.1%	0.8%	0.5%	0.9%	1.0%	0.7%	2.4%	1.1%	0.9%
Mid-Atlantic Coast	-1.0%	0.5%	0.3%	0.6%	1.1%	0.8%	1.3%	1.2%	0.6%
Upper Midwest	0.0%	6.2%	9.4%	10.6%	11.5%	14.9%	8.5%	6.6%	8.5%
Southeast	-1.5%	2.3%	3.3%	3.3%	4.3%	7.5%	3.4%	2.5%	3.1%
Florida	-0.5%	0.8%	0.7%	0.4%	1.0%	1.0%	3.0%	1.8%	1.0%
Mississippi Valley	-0.5%	2.7%	3.6%	3.9%	6.1%	5.9%	3.6%	4.4%	3.7%
Mid-America	-0.2%	6.9%	8.8%	15.4%	12.7%	6.6%	6.9%	6.7%	8.0%
Texas, Oklahoma, Louisiana	-0.2%	0.6%	0.7%	0.8%	1.0%	1.0%	1.7%	1.8%	1.0%
Arizona/Mountain States	-0.2%	1.0%	4.0%	6.5%	1.9%	1.4%	2.1%	2.1%	2.3%
California	-0.1%	1.4%	0.4%	0.5%	0.5%	0.5%	0.7%	1.1%	0.6%
Pacific Northwest	-0.4%	0.6%	1.1%	0.9%	1.6%	1.7%	2.0%	2.7%	1.3%
United States	-0.5%	2.1%	2.8%	3.4%	3.7%	4.3%	3.3%	2.8%	2.9%

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

H. Labor Income and GDP

Figure C-8 shows the estimated change in U.S. labor income (measured in job-equivalents) and GDP relative to the baseline scenario. As discussed in the report body, these economic impacts reflect the net of negative effects (including higher costs for regulated industries, reduced coal production, higher natural gas prices, and higher electricity prices) and positive effects (including higher demand for low-emission technologies and lower coal prices). The negative net impacts on labor income and GDP are large in 2016 as MATS takes effect, less large in 2019 and 2022, and large again from 2025 to 2034 as industries bear the full costs of the new ozone standard (see Appendix B for its costs by year) and as high prices for electricity and natural gas increase costs for businesses and reduce purchasing power for households.

Figure C-8. Change in U.S. Labor Income (Measured in Job-Equivalents) and GDP Relative to Baseline Scenario



Source: NERA calculations as explained in text.

Table C-2 shows the change in labor income, stated as the equivalent number of jobs, by region.

Table C-2. Change in Labor Income by Region (Thousand Job-Equivalents)

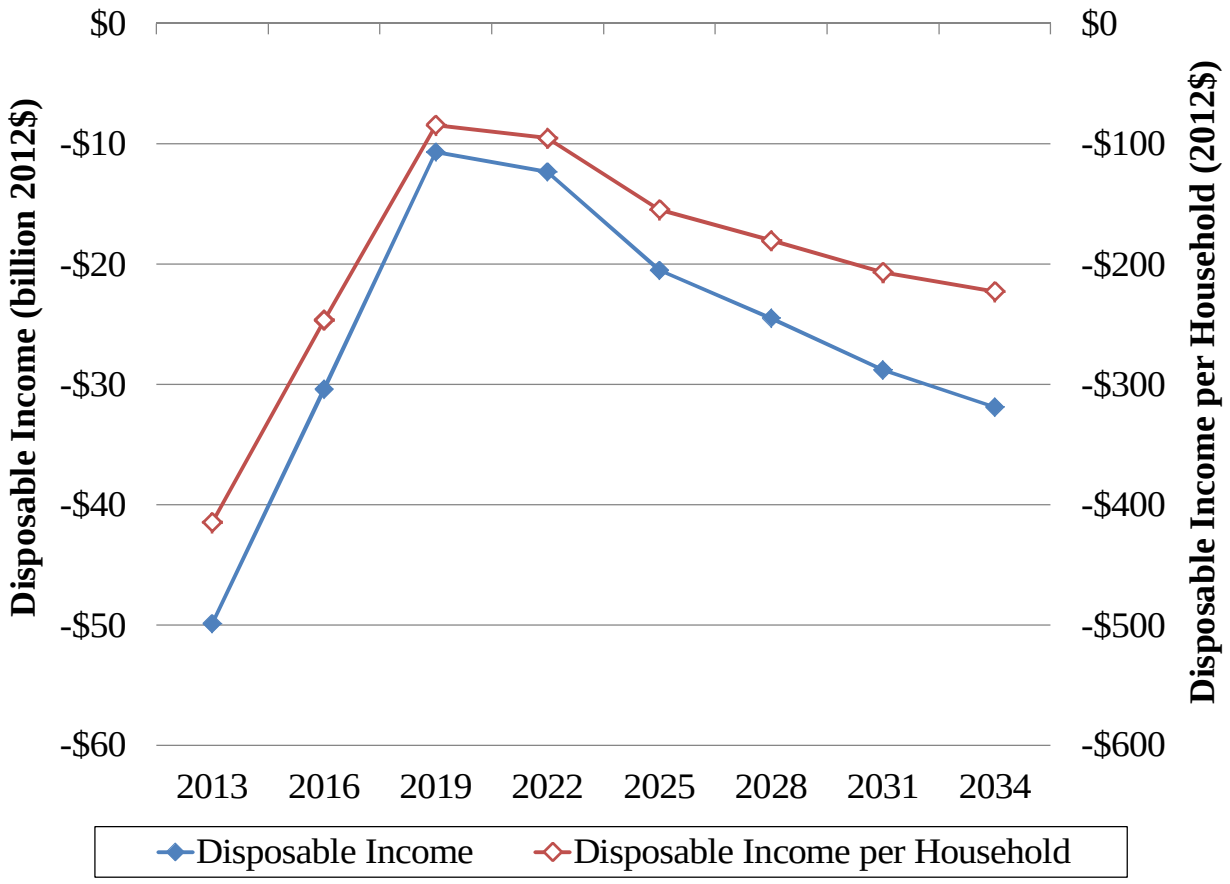
	2013	2016	2019	2022	2025	2028	2031	2034	Avg.
New York/New England	-17	-44	-23	-14	-44	-101	-30	-63	-40
Mid-Atlantic Coast	-1	-47	-17	-39	-59	-60	-64	-67	-42
Upper Midwest	35	-174	-108	-150	-188	-201	-207	-195	-144
Southeast	32	-116	-77	-69	-110	-115	-123	-106	-84
Florida	3	-4	-27	-4	-7	-11	-15	-19	-10
Mississippi Valley	15	-118	-46	-119	-146	-150	-147	-159	-104
Mid-America	-7	-62	-17	-31	-49	-40	-41	-48	-36
Texas, Oklahoma, Louisiana	7	-92	-25	-46	-88	-93	-98	-113	-64
Arizona/Mountain States	-11	-57	-10	-35	-34	-34	-35	-42	-31
California	-21	-38	-4	-10	-49	4	-24	-29	-21
Pacific Northwest	-15	-22	-6	-6	-12	-13	-16	-21	-13
United States	20	-774	-361	-522	-785	-814	-800	-862	-590

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

I. Disposable Income

Figure C-9 shows the estimated change in U.S. disposable income and disposable income per household relative to the baseline scenario.[1] This figure shows a large decrease in 2013 because the large investments in that year for compliance with the policies make less money available in the economy for consumption. As the investment requirements decrease by 2019 and 2022, the negative impact on disposable income decreases as well. From 2025 to 2034, however, the negative impact on disposable income becomes larger as industries bear the full costs of the new ozone standard (see Appendix B for its costs by year) and as high prices for electricity and natural gas increase costs for businesses and reduce purchasing power for households.

Figure C-9. Change in U.S. Disposable Income and Disposable Income per Household Relative to Baseline Scenario



Source: NERA calculations as explained in text.

[1] Disposable income in N_{ew}ERA is linked to household consumption.

Table C-3 shows the loss in disposable income per household by region each year and on an annualized basis.

Table C-3. Loss in Disposable Income per Household by Region

	2013	2016	2019	2022	2025	2028	2031	2034	Ann.
New York/New England	$387	$297	$105	$114	$194	$123	$220	$289	$237
Mid-Atlantic Coast	$409	$249	$77	$82	$170	$199	$235	$262	$229
Upper Midwest	$685	$408	$241	$371	$485	$575	$578	$589	$503
Southeast	$390	$208	$36	$30	$88	$148	$131	$125	$175
Florida	$270	$198	$17	-$50*	$8	$26	$56	$50	$102
Mississippi Valley	$654	$322	$135	$261	$416	$457	$480	$520	$417
Mid-America	$463	$250	$116	$139	$176	$163	$198	$234	$248
Texas, Oklahoma, Louisiana	$389	$199	$18	$12	$90	$143	$170	$187	$173
Arizona/Mountain States	$345	$148	$45	$61	$56	$68	$93	$108	$144
California	$227	$204	$93	$42	$12	$34	$89	$93	$124
Pacific Northwest	$300	$191	$55	$6	$28	$49	$67	$82	$128
United States	$415	$246	$84	$95	$155	$180	$207	$223	$226

Note: (*) Negative values indicate that disposable income per household increases relatives to the baseline. "Ann." is the annualized value based on the present value of impacts from 2013 through 2034. Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

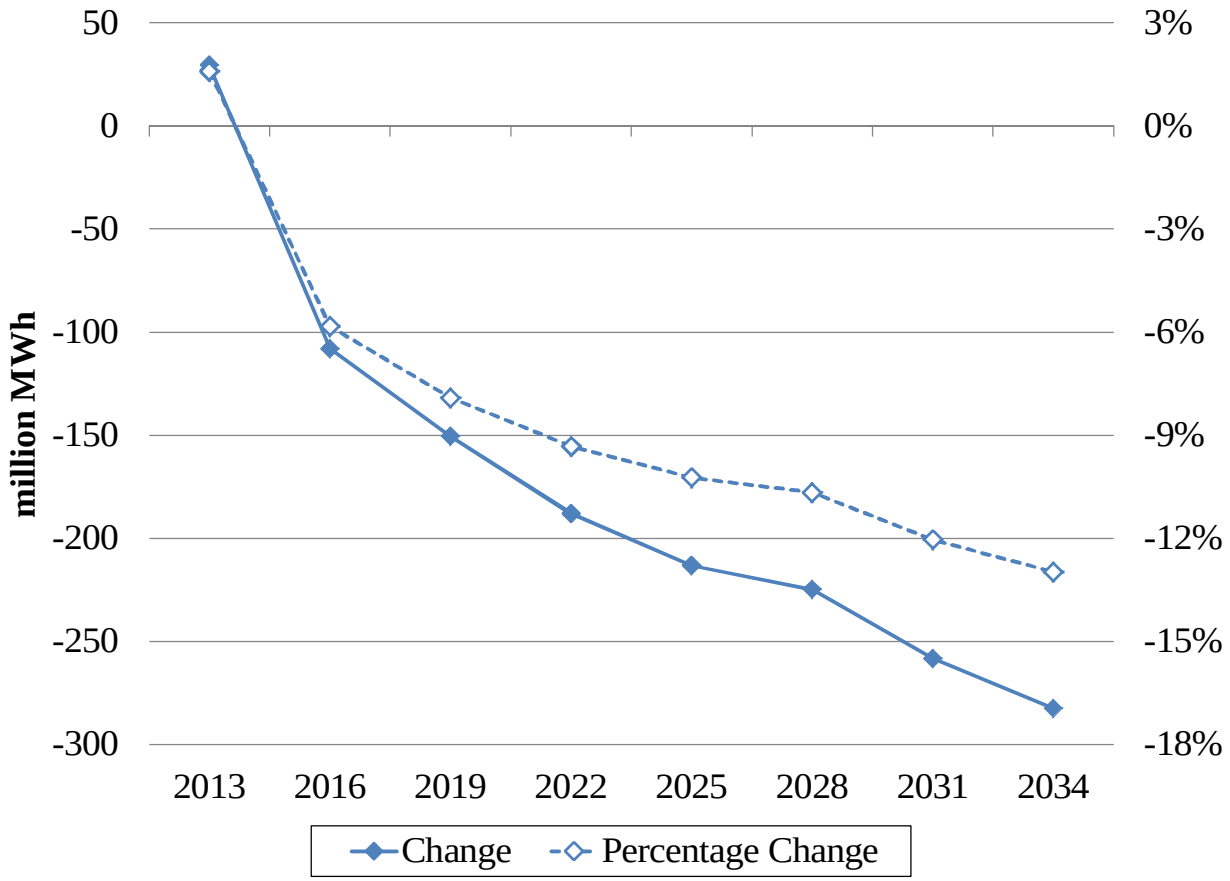
Appendix D: Results for Higher Ozone Costs Case

This appendix presents annual estimates of the energy and economic impacts of the seven recent and anticipated EPA regulations relative to the baseline scenario using the higher ozone costs case.

A. Coal-Fired Generation

Figure D-1 shows the estimated change in coal-fired generation relative to the baseline scenario.

Figure D-1. Change in Coal-Fired Generation Relative to Baseline Scenario

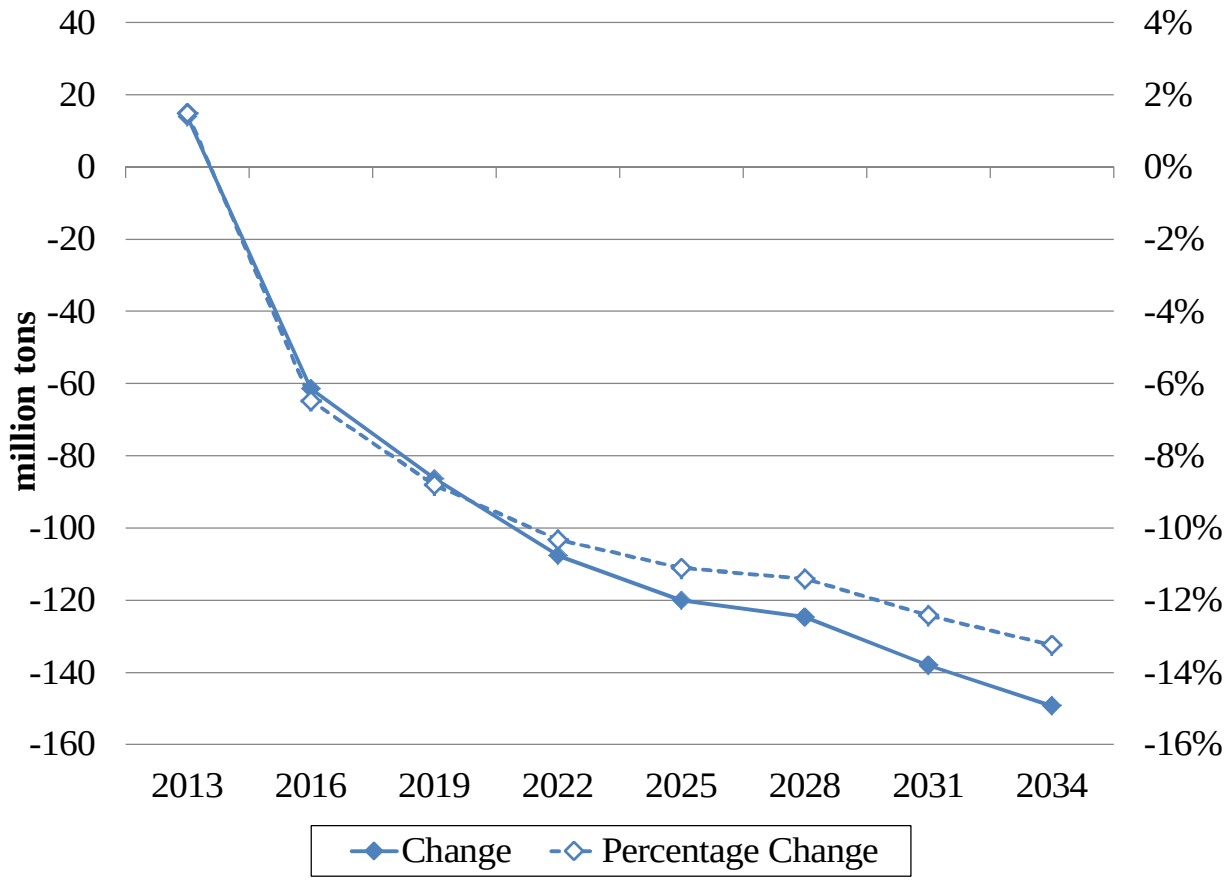


Source: NERA calculations as explained in text.

B. Electricity Sector Coal Demand

Figure D-2 shows the change in electricity sector coal demand relative to the baseline scenario.

Figure D-2. Change in Electricity Sector Coal Demand Relative to Baseline Scenario

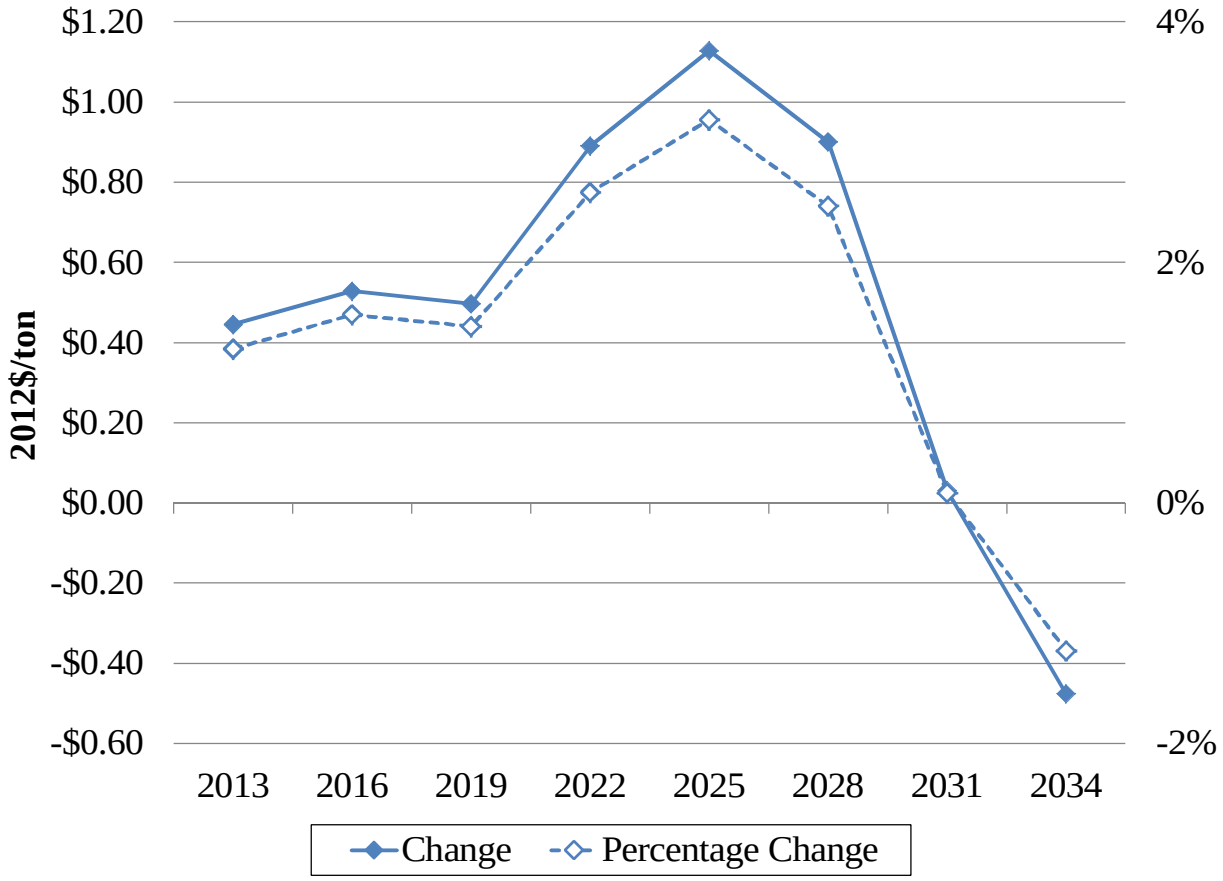


Source: NERA calculations as explained in text.

C. Coal Price

Figure D-3 shows the change in average U.S. coal minemouth prices relative to the baseline scenario.

Figure D-3. Change in Average Coal Minemouth Prices Relative to Baseline Scenario

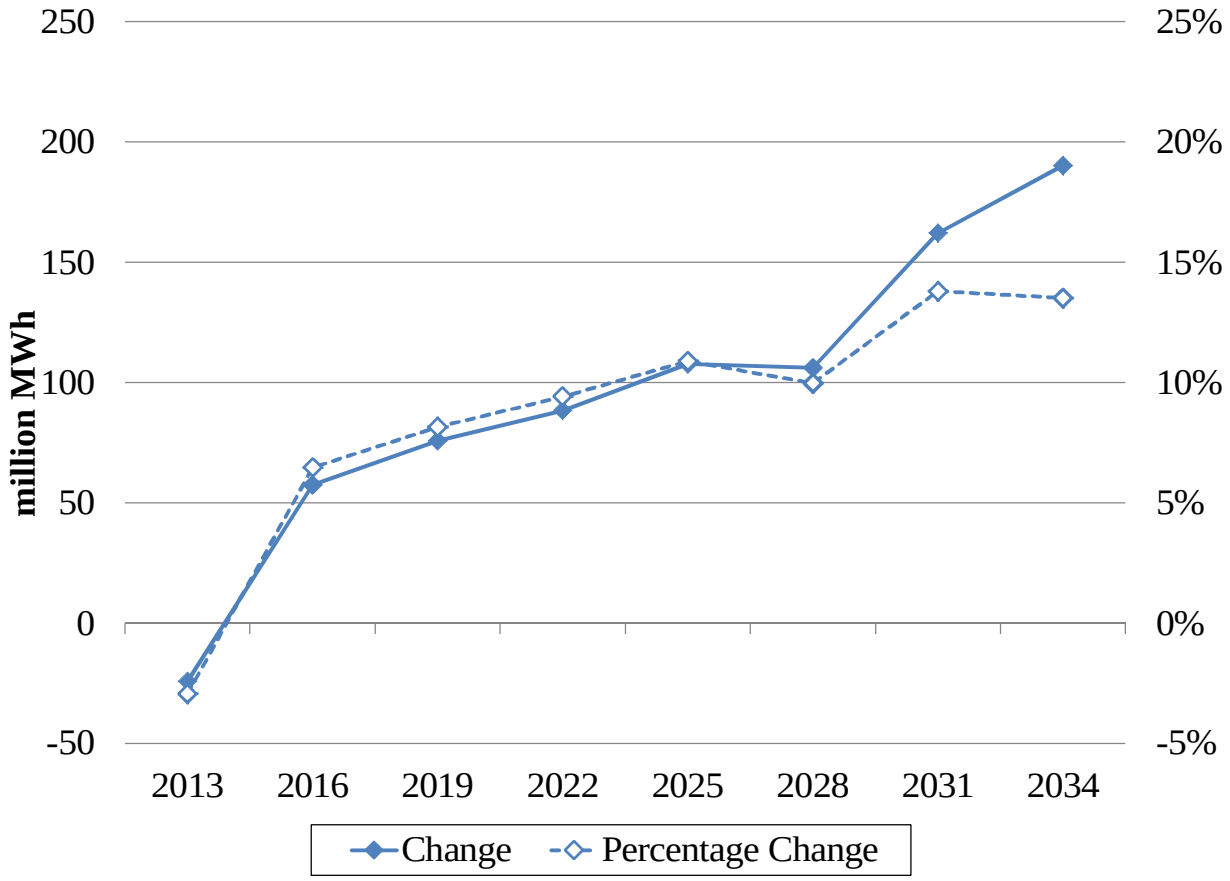


Source: NERA calculations as explained in text.

D. Natural Gas-Fired Generation

Figure D-4 shows the estimated change in natural gas-fired generation relative to the baseline scenario.

Figure D-4. Change in Natural Gas-Fired Generation Relative to Baseline Scenario

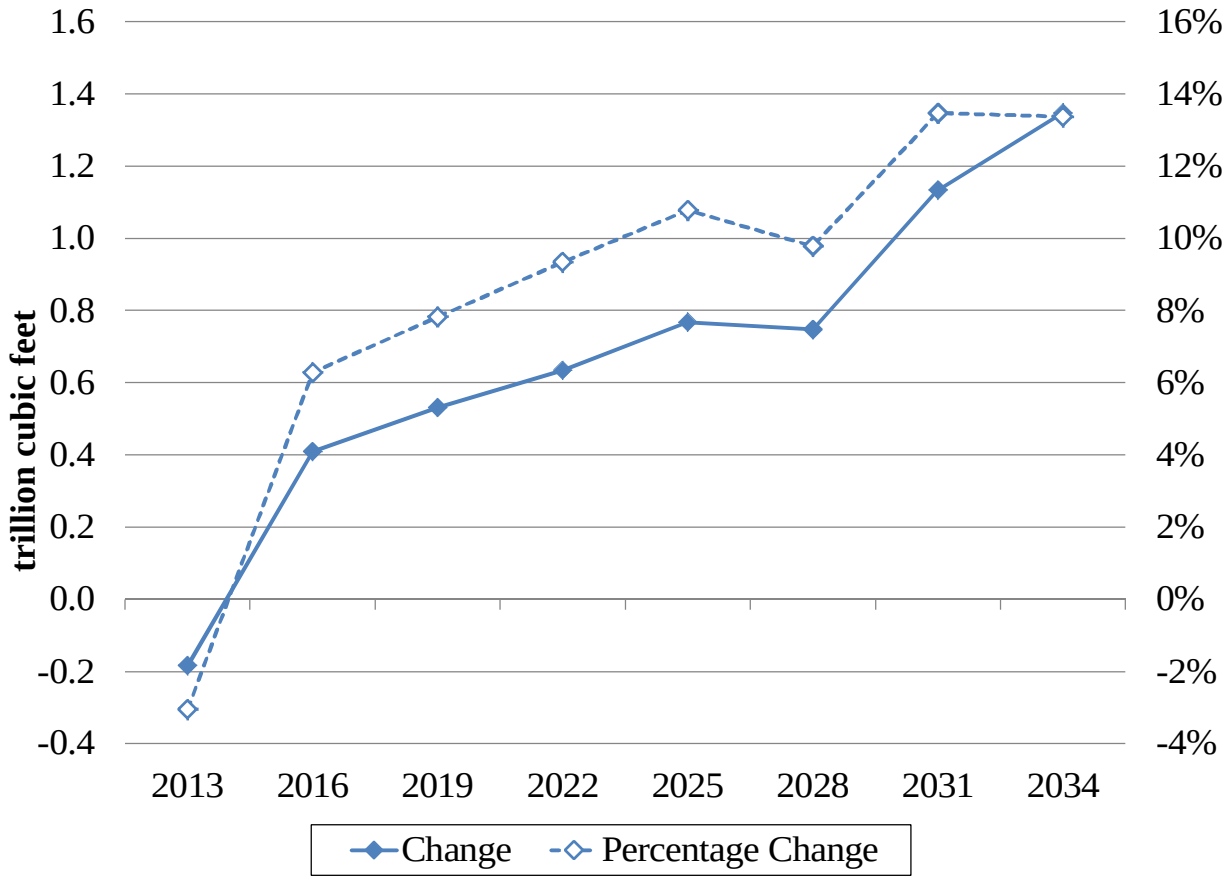


Source: NERA calculations as explained in text.

E. Electricity Sector Natural Gas Demand

Figure D-5 shows the estimated change in electricity sector natural gas demand relative to the baseline scenario.

Figure D-5. Change in Electricity Sector Natural Gas Demand Relative to Baseline Scenario

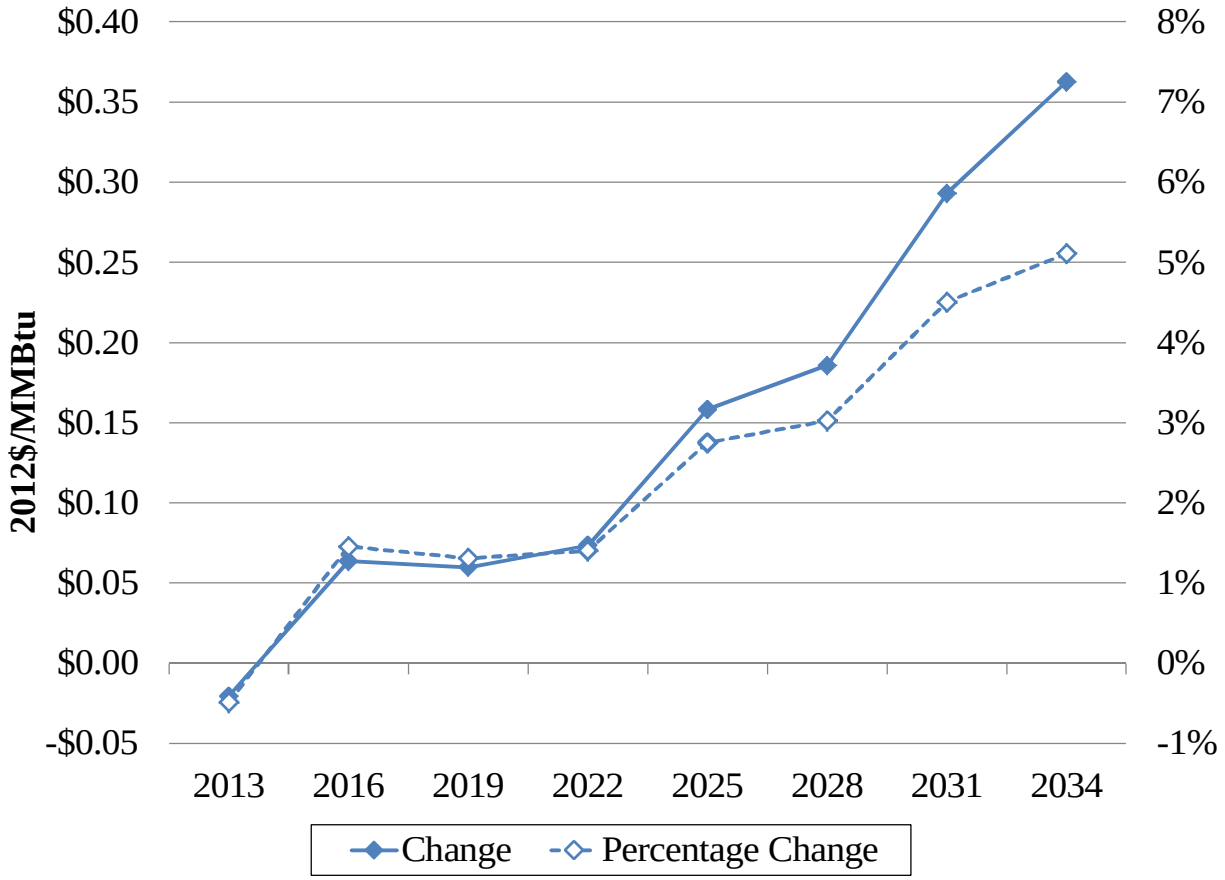


Source: NERA calculations as explained in text.

F. Natural Gas Price

Figure D-6 shows the estimated change in natural gas price at Henry Hub relative to the baseline scenario.

Figure D-6. Change in Natural Gas Price at Henry Hub Relative to Baseline Scenario

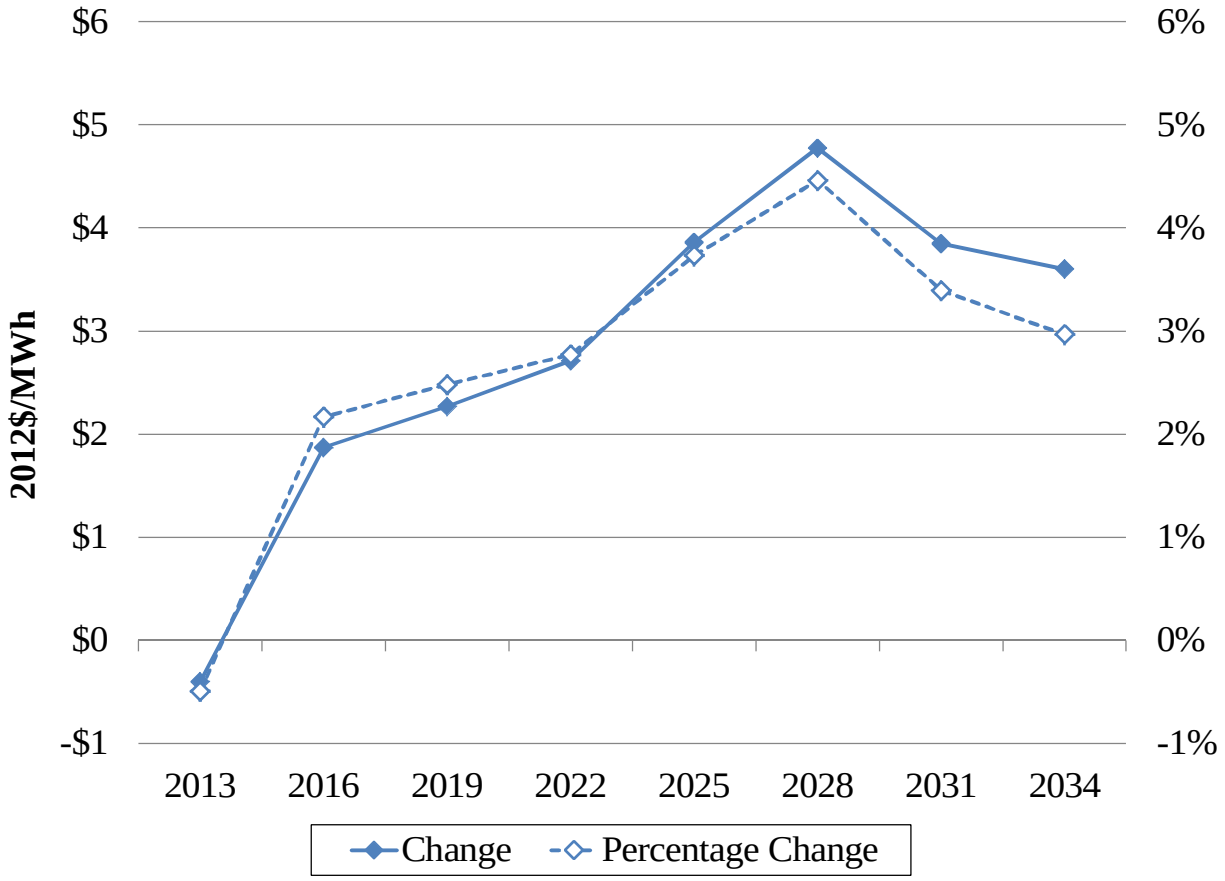


Source: NERA calculations as explained in text.

G. Electricity Price

Figure D-7 shows the estimated change in average U.S. electricity retail price relative to the baseline scenario.

Figure D-7. Change in Average U.S. Electricity Retail Price Relative to Baseline Scenario



Source: NERA calculations as explained in text.

Table D-1 shows the average electricity price impacts in percentage terms by macroeconomic region.

Table D-1. Average Electricity Price Impacts by Region

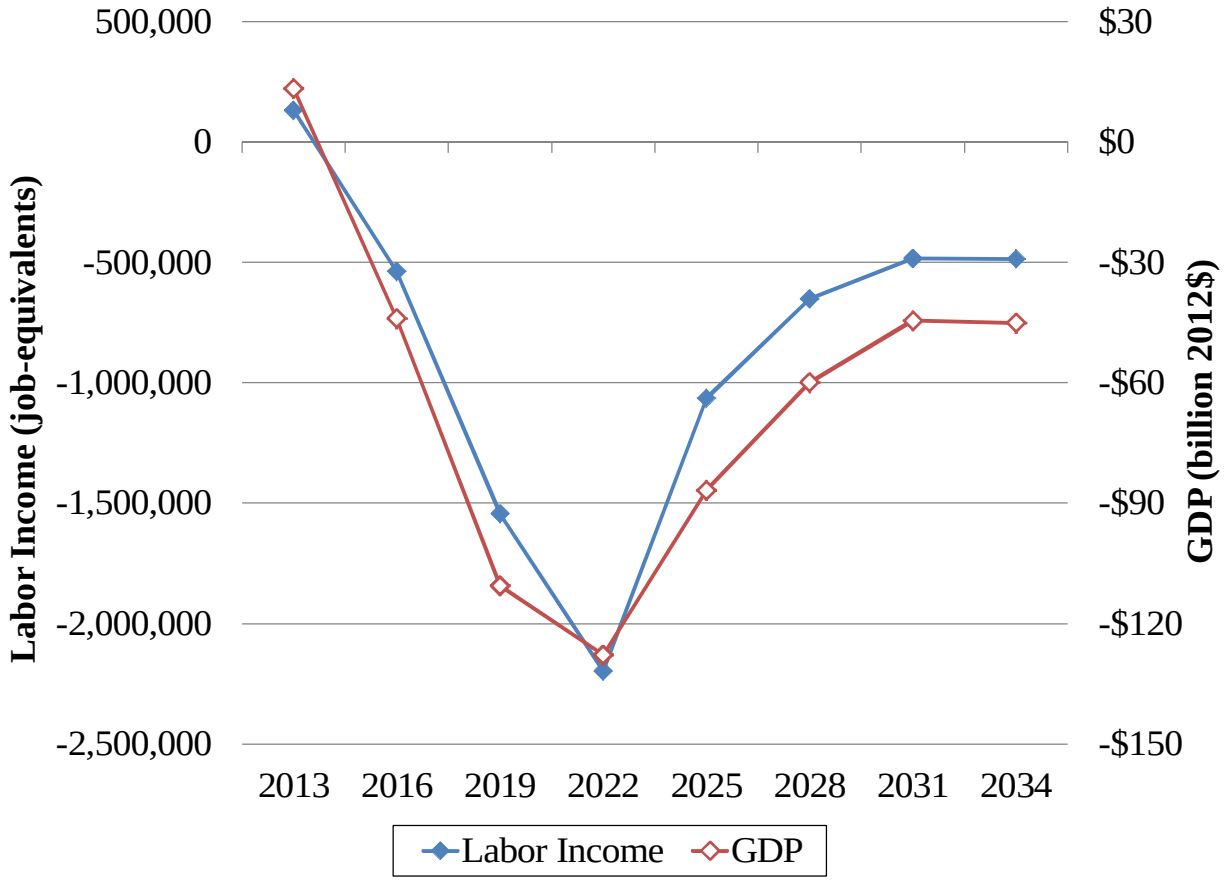
	2013	2016	2019	2022	2025	2028	2031	2034	Avg.
New York/New England	-0.1%	0.9%	0.3%	0.4%	1.0%	0.9%	2.4%	1.4%	0.9%
Mid-Atlantic Coast	-0.9%	0.5%	0.1%	0.2%	1.1%	0.9%	1.4%	1.4%	0.6%
Upper Midwest	0.0%	6.4%	8.8%	9.8%	11.6%	15.3%	8.8%	6.9%	8.4%
Southeast	-1.4%	2.4%	3.0%	2.5%	4.4%	7.7%	3.5%	2.7%	3.1%
Florida	-0.5%	0.8%	0.6%	0.0%	1.0%	1.1%	3.1%	1.9%	1.0%
Mississippi Valley	-0.5%	2.8%	2.9%	2.5%	6.1%	6.1%	3.8%	4.5%	3.5%
Mid-America	-0.2%	7.5%	8.3%	14.7%	12.7%	6.8%	7.2%	6.9%	8.0%
Texas, Oklahoma, Louisiana	-0.2%	0.7%	0.4%	0.2%	1.0%	1.2%	1.9%	2.0%	0.9%
Arizona/Mountain States	-0.2%	1.1%	3.5%	5.9%	1.9%	1.6%	2.2%	2.3%	2.3%
California	-0.1%	1.5%	0.2%	0.2%	0.4%	0.5%	0.7%	1.0%	0.5%
Pacific Northwest	-0.2%	0.7%	0.9%	0.3%	1.6%	1.7%	2.2%	2.7%	1.2%
United States	-0.5%	2.2%	2.5%	2.8%	3.7%	4.5%	3.4%	3.0%	2.8%

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

H. Labor Income and GDP

Figure D-8 shows the estimated change in U.S. labor income (measured in job-equivalents) and GDP relative to the baseline scenario.

Figure D-8. Change in U.S. Labor Income (Measured in Job-Equivalents) and GDP Relative to Baseline Scenario



Source: NERA calculations as explained in text.

Table D-2 shows the change in labor income, stated as the equivalent number of jobs, by region.

Table D-2. Change in Labor Income by Region (Thousand Job-Equivalents)

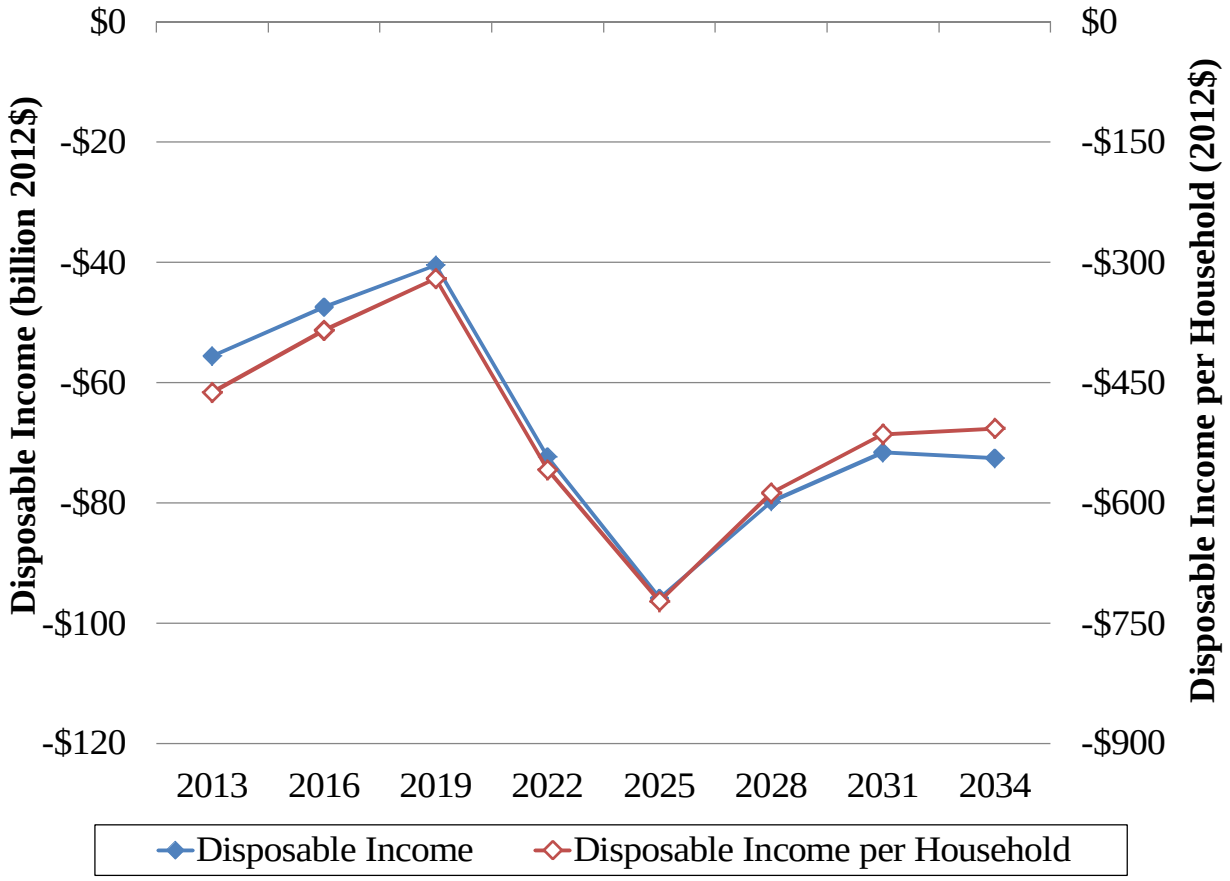
	2013	2016	2019	2022	2025	2028	2031	2034	Avg.
New York/New England	-7	-24	-112	-149	-47	-78	12	-14	-56
Mid-Atlantic Coast	5	-30	-129	-220	-79	-25	-13	-9	-67
Upper Midwest	54	-194	-426	-455	-170	-121	-108	-82	-197
Southeast	46	-85	-178	-208	-128	-87	-70	-37	-98
Florida	6	42	-26	-14	-11	-9	-5	-4	-3
Mississippi Valley	29	-122	-347	-591	-129	-48	-32	-33	-171
Mid-America	1	-26	-31	-55	-57	-35	-21	-20	-31
Texas, Oklahoma, Louisiana	18	-78	-166	-317	-221	-62	-21	-24	-117
Arizona/Mountain States	-4	-30	-67	-74	-33	-20	-10	-10	-33
California	-10	-5	-47	-100	-172	-157	-213	-252	-108
Pacific Northwest	-6	16	-15	-14	-15	-9	-2	0	-6
United States	132	-537	-1,543	-2,197	-1,064	-651	-483	-485	-887

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

I. Disposable Income

Figure D-9 shows the estimated change in U.S. disposable income and disposable income per household relative to the baseline scenario.[1]

Figure D-9. Change in U.S. Disposable Income and Disposable Income per Household Relative to Baseline Scenario



Source: NERA calculations as explained in text.

[1] Disposable income in N_{ew}ERA is linked to household consumption.

Table D-3 shows the loss in disposable income per household by region each year and on an annualized basis.

Table D-3. Loss in Disposable Income per Household by Region

	2013	2016	2019	2022	2025	2028	2031	2034	Ann.
New York/New England	$400	$397	$251	$503	$824	$530	$520	$555	$490
Mid-Atlantic Coast	$462	$408	$305	$635	$906	$657	$557	$561	$559
Upper Midwest	$812	$597	$793	$1,271	$1,197	$1,028	$964	$955	$960
Southeast	$379	$249	$106	$253	$467	$408	$299	$261	$315
Florida	$161	$250	$100	$32	$213	$207	$164	$128	$168
Mississippi Valley	$858	$613	$692	$1,583	$1,440	$952	$941	$968	$1,020
Mid-America	$402	$318	$161	$240	$567	$510	$420	$421	$378
Texas, Oklahoma, Louisiana	$503	$375	$273	$563	$871	$702	$464	$456	$535
Arizona/Mountain States	$311	$218	$199	$296	$377	$329	$270	$252	$293
California	$375	$452	$394	$424	$592	$693	$741	$768	$521
Pacific Northwest	$200	$242	$154	$121	$301	$313	$241	$217	$227
United States	$462	$385	$320	$558	$723	$587	$514	$507	$512

Note: "Ann." is the annualized value based on the present value of impacts from 2013 through 2034. Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

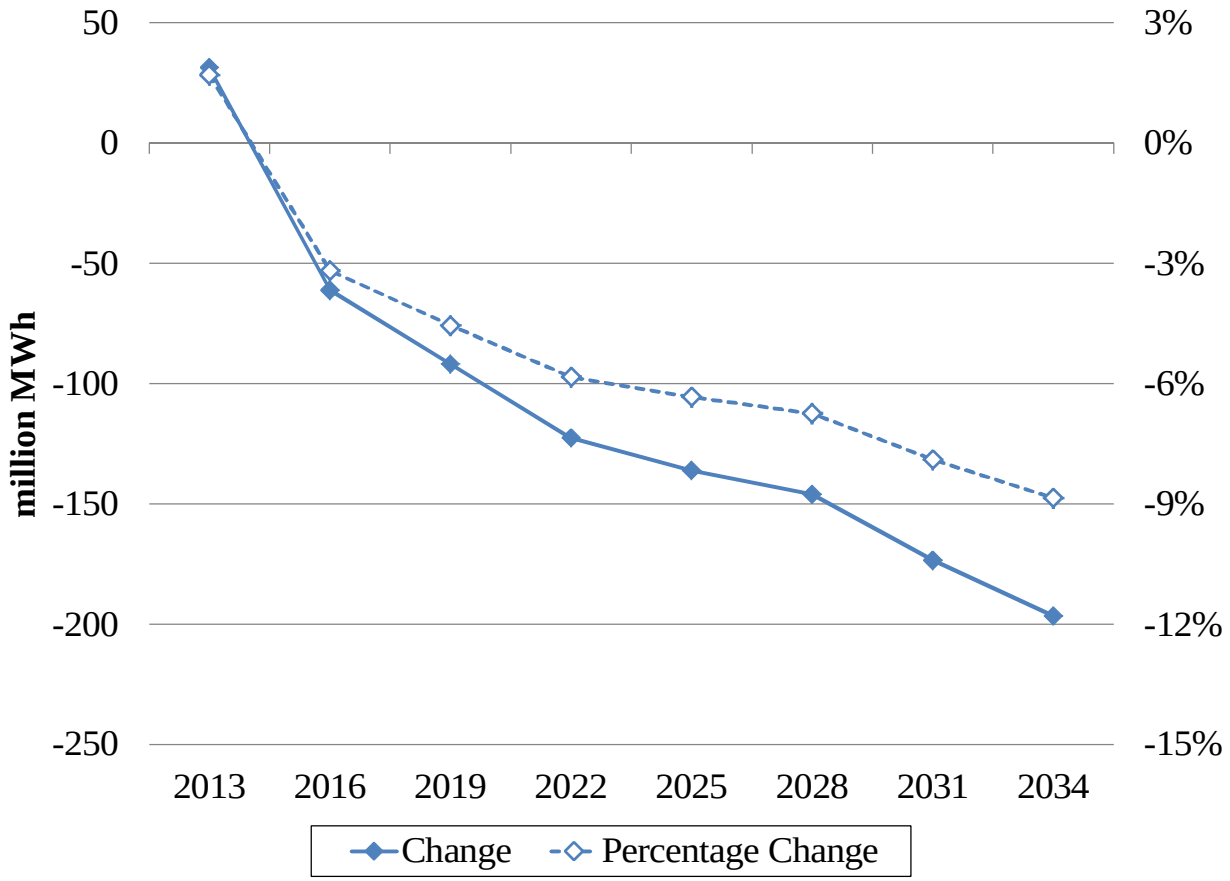
Appendix E: Results for Higher Natural Gas Prices Case

This appendix presents annual estimates of the energy and economic impacts of the seven recent and anticipated EPA regulations using the higher natural gas prices case. The results are relative to the modified baseline scenario with higher natural gas prices.

A. Coal-Fired Generation

Figure E-1 shows the estimated change in coal-fired generation relative to the baseline scenario.

Figure E-1. Change in Coal-Fired Generation Relative to Baseline Scenario

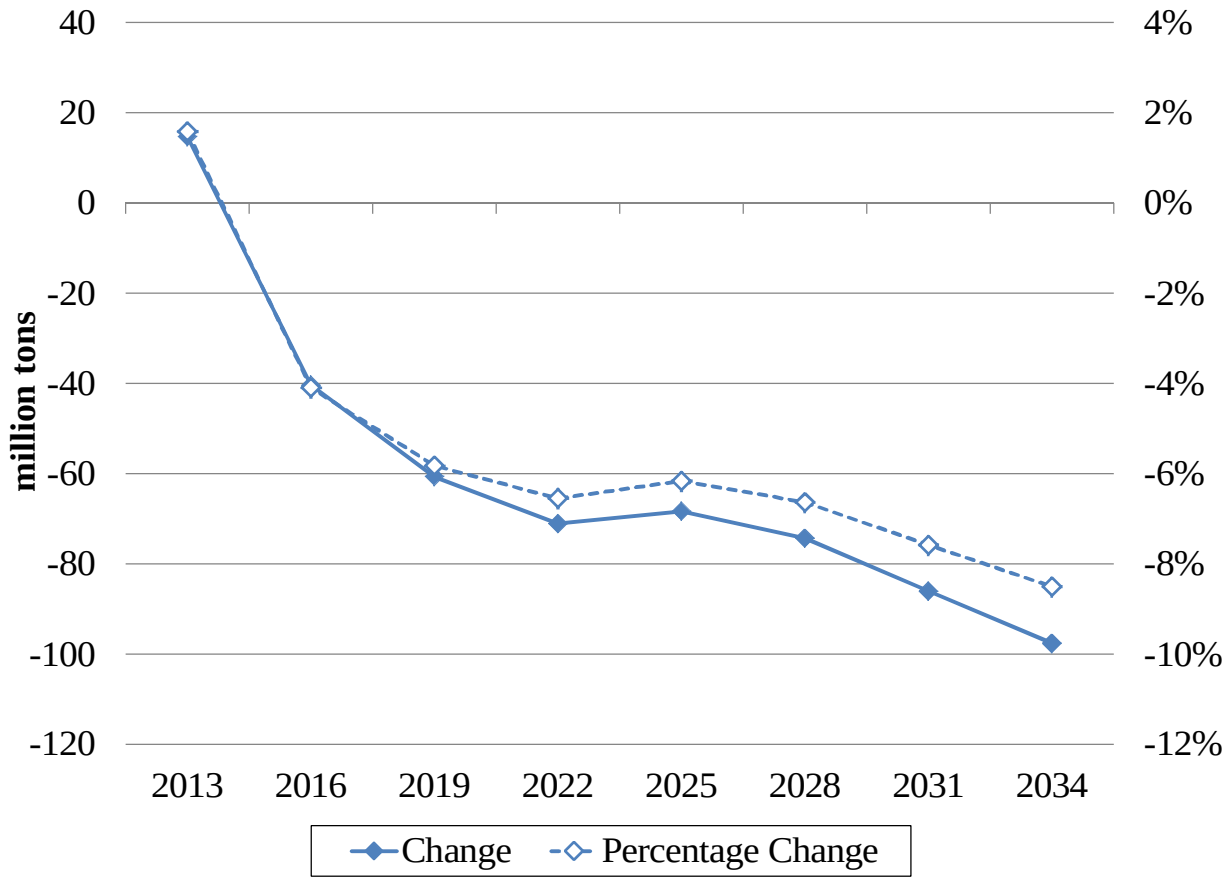


Source: NERA calculations as explained in text.

B. Electricity Sector Coal Demand

Figure E-2 shows the change in electricity sector coal demand relative to the baseline scenario.

Figure E-2. Change in Electricity Sector Coal Demand Relative to Baseline Scenario

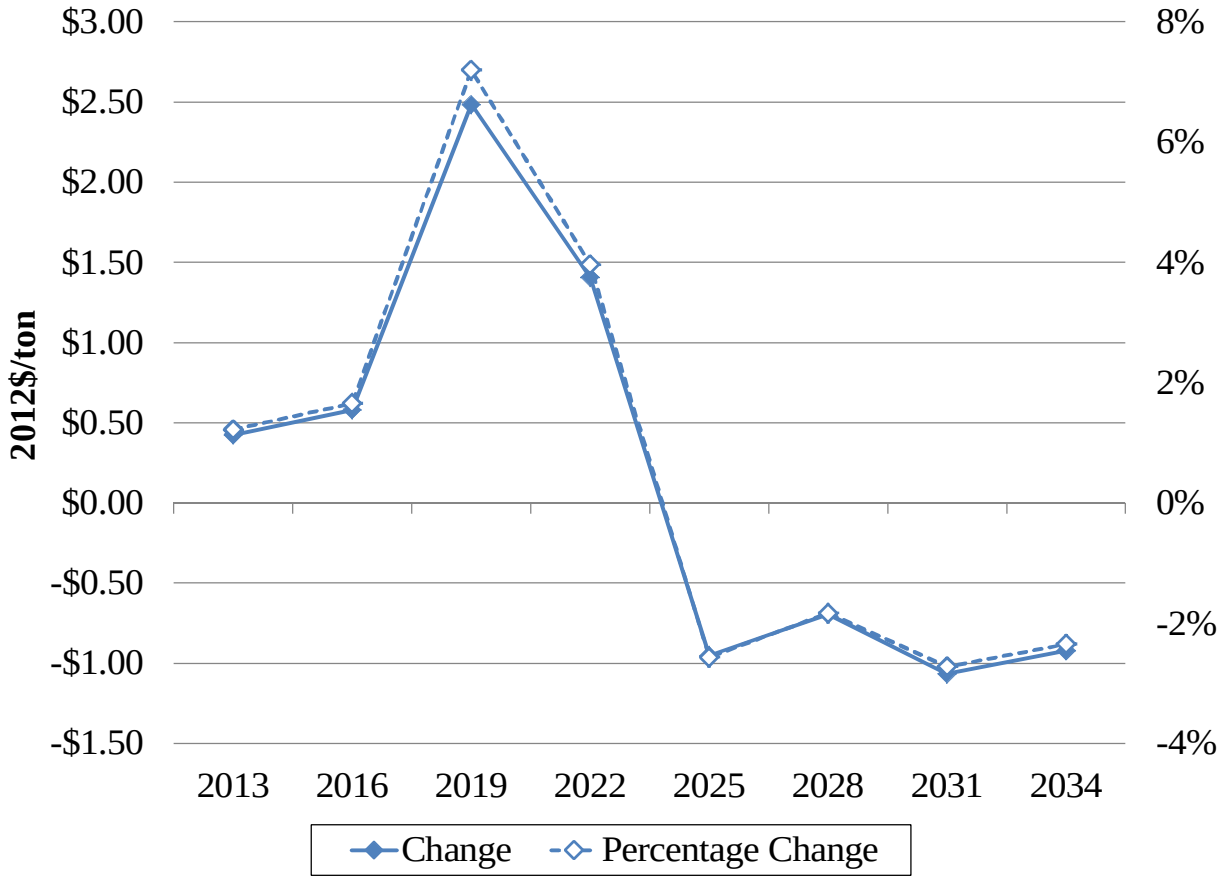


Source: NERA calculations as explained in text.

C. Coal Price

Figure E-3 shows the change in average U.S. coal minemouth prices relative to the baseline scenario.

Figure E-3. Change in Average Coal Minemouth Prices Relative to Baseline Scenario

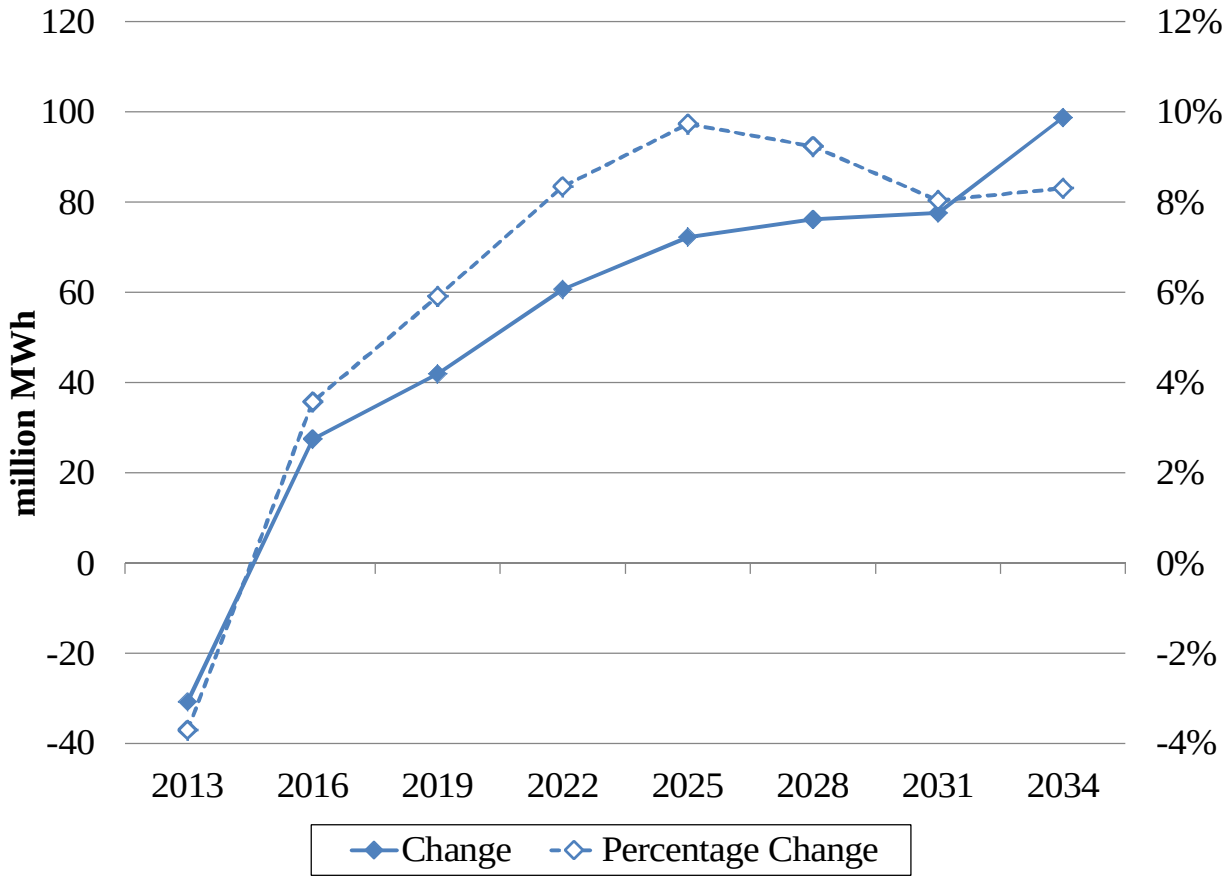


Source: NERA calculations as explained in text.

D. Natural Gas-Fired Generation

Figure E-4 shows the estimated change in natural gas-fired generation relative to the baseline scenario.

Figure E-4. Change in Natural Gas-Fired Generation Relative to Baseline Scenario

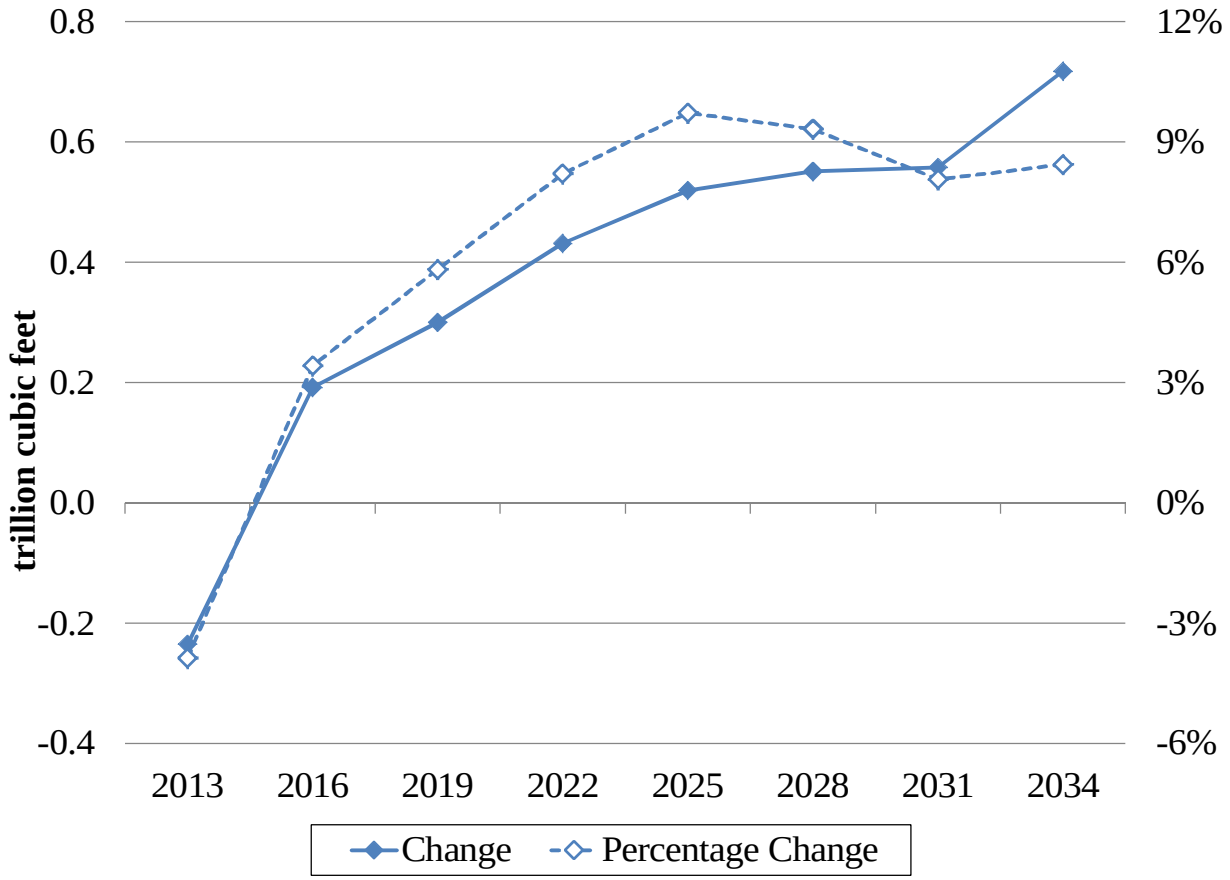


Source: NERA calculations as explained in text.

E. Electricity Sector Natural Gas Demand

Figure E-5 shows the estimated change in electricity sector natural gas demand relative to the baseline scenario.

Figure E-5. Change in Electricity Sector Natural Gas Demand Relative to Baseline Scenario

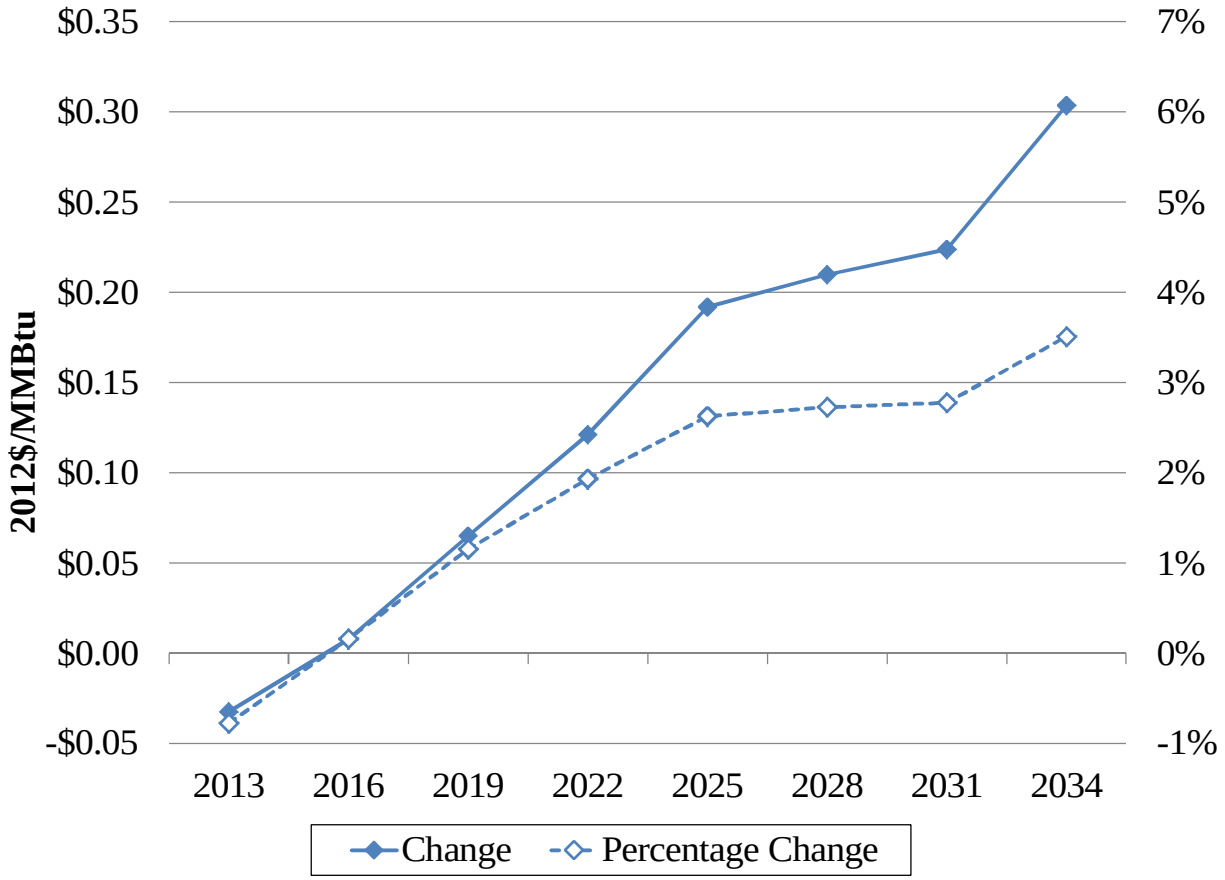


Source: NERA calculations as explained in text.

F. Natural Gas Price

Figure E-6 shows the estimated change in natural gas price at Henry Hub relative to the baseline scenario.

Figure E-6. Change in Natural Gas Price at Henry Hub Relative to Baseline Scenario

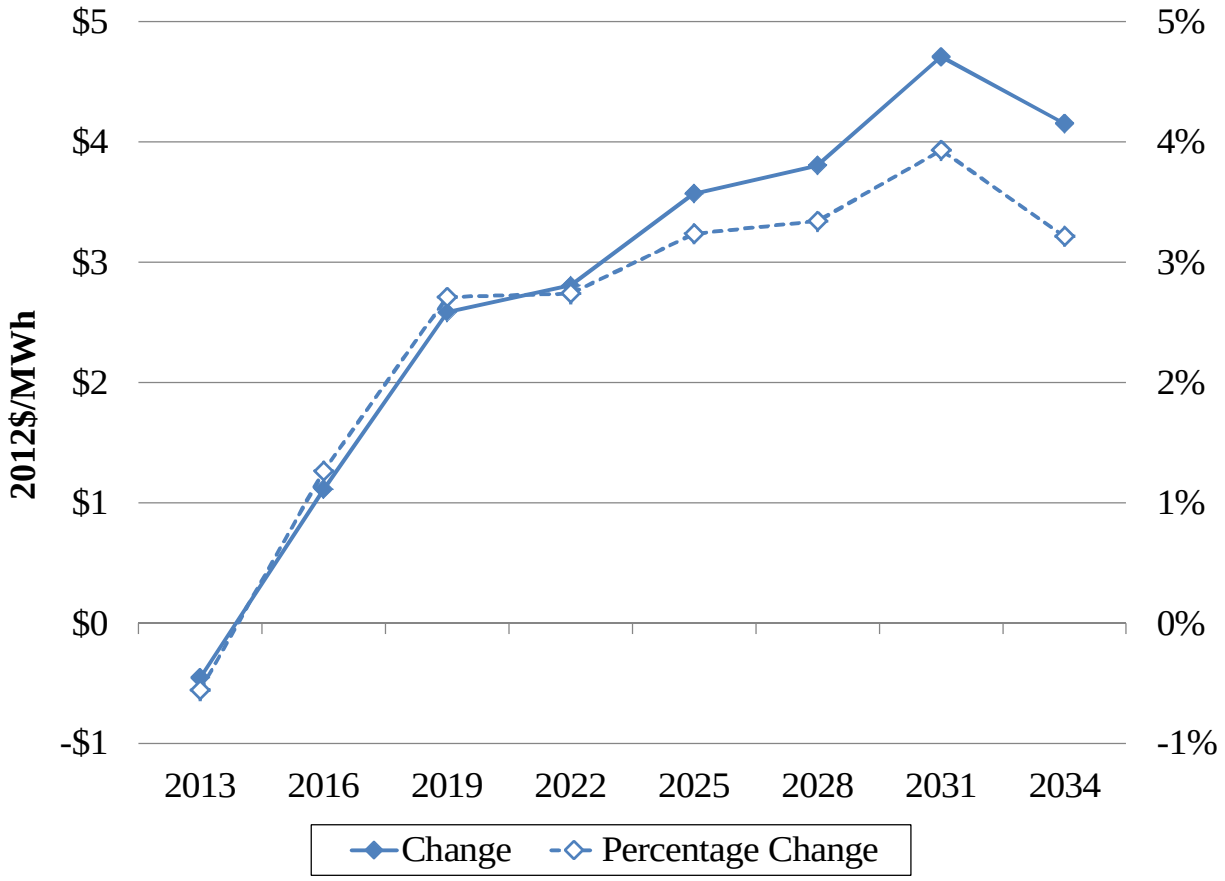


Source: NERA calculations as explained in text.

G. Electricity Price

Figure E-7 shows the estimated change in average U.S. electricity retail price relative to the baseline scenario.

Figure E-7. Change in Average U.S. Electricity Retail Price Relative to Baseline Scenario



Source: NERA calculations as explained in text.

Table E-1 shows the average electricity price impacts in percentage terms by macroeconomic region.

Table E-1. Average Electricity Price Impacts by Region

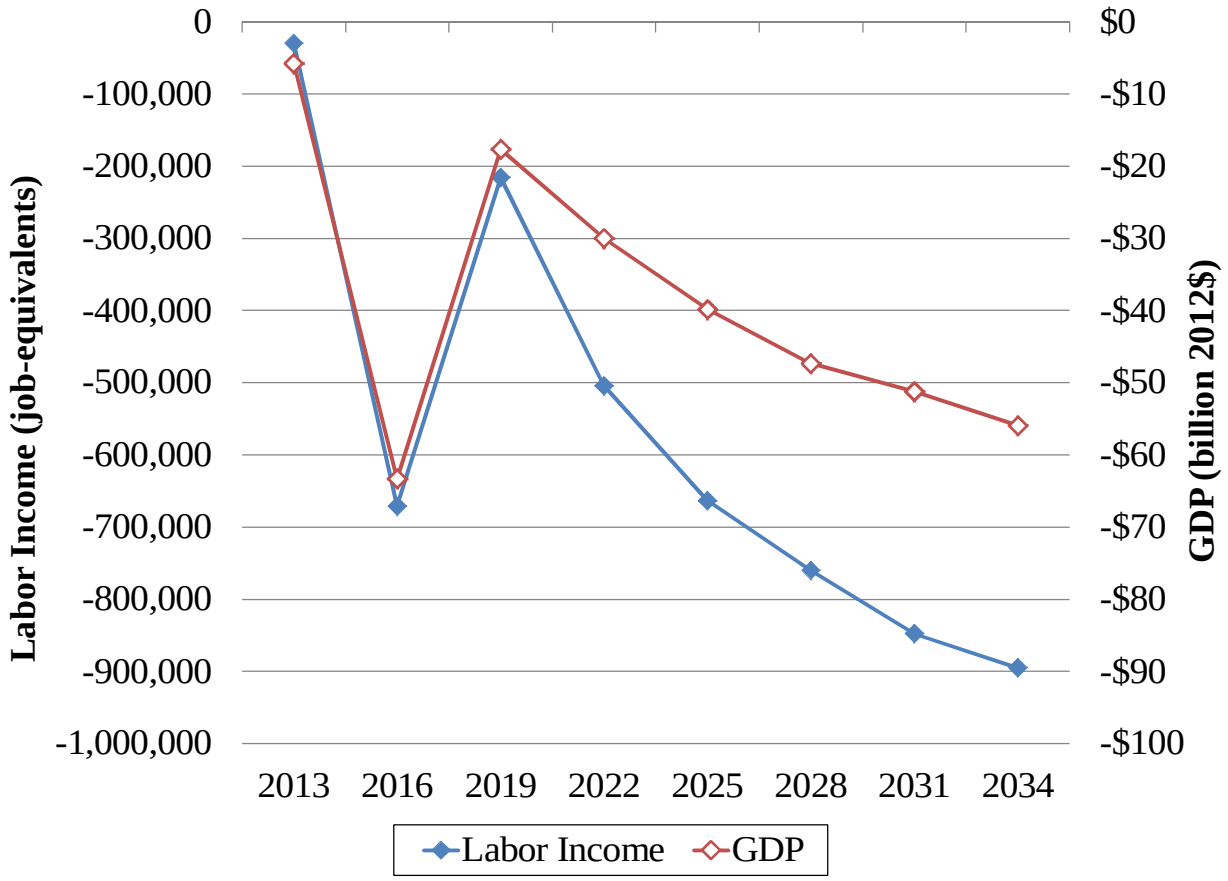
	2013	2016	2019	2022	2025	2028	2031	2034	Avg.
New York/New England	-0.2%	0.2%	1.3%	1.1%	2.1%	2.0%	1.3%	1.1%	1.1%
Mid-Atlantic Coast	-0.9%	-0.1%	0.6%	1.1%	1.0%	1.3%	1.5%	1.2%	0.7%
Upper Midwest	-0.3%	4.6%	7.2%	9.1%	7.7%	9.5%	15.2%	10.4%	7.9%
Southeast	-1.1%	0.6%	2.2%	2.7%	3.5%	3.3%	4.9%	3.2%	2.4%
Florida	-0.5%	0.1%	4.4%	0.5%	0.9%	0.9%	2.2%	2.2%	1.4%
Mississippi Valley	-0.6%	2.1%	2.5%	3.4%	4.6%	5.8%	3.7%	3.4%	3.1%
Mid-America	-0.6%	4.2%	4.3%	6.2%	11.8%	7.6%	3.7%	7.7%	5.6%
Texas, Oklahoma, Louisiana	-0.4%	1.7%	2.0%	1.4%	1.6%	1.7%	1.5%	1.4%	1.4%
Arizona/Mountain States	-0.4%	0.7%	2.4%	2.7%	2.3%	1.8%	1.5%	1.7%	1.6%
California	-0.2%	-0.4%	1.0%	0.8%	1.0%	0.9%	0.8%	0.9%	0.6%
Pacific Northwest	-0.9%	1.3%	2.8%	1.8%	2.2%	2.2%	1.9%	1.3%	1.6%
United States	-0.6%	1.3%	2.7%	2.7%	3.2%	3.3%	3.9%	3.2%	2.7%

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

H. Labor Income and GDP

Figure E-8 shows the estimated change in U.S. labor income (measured in job-equivalents) and GDP relative to the baseline scenario.

Figure E-8. Change in U.S. Labor Income (Measured in Job-Equivalents) and GDP Relative to Baseline Scenario



Source: NERA calculations as explained in text.

Table E-2 shows the change in labor income, stated as the equivalent number of jobs, by region.

Table E-2. Change in Labor Income by Region (Thousand Job-Equivalents)

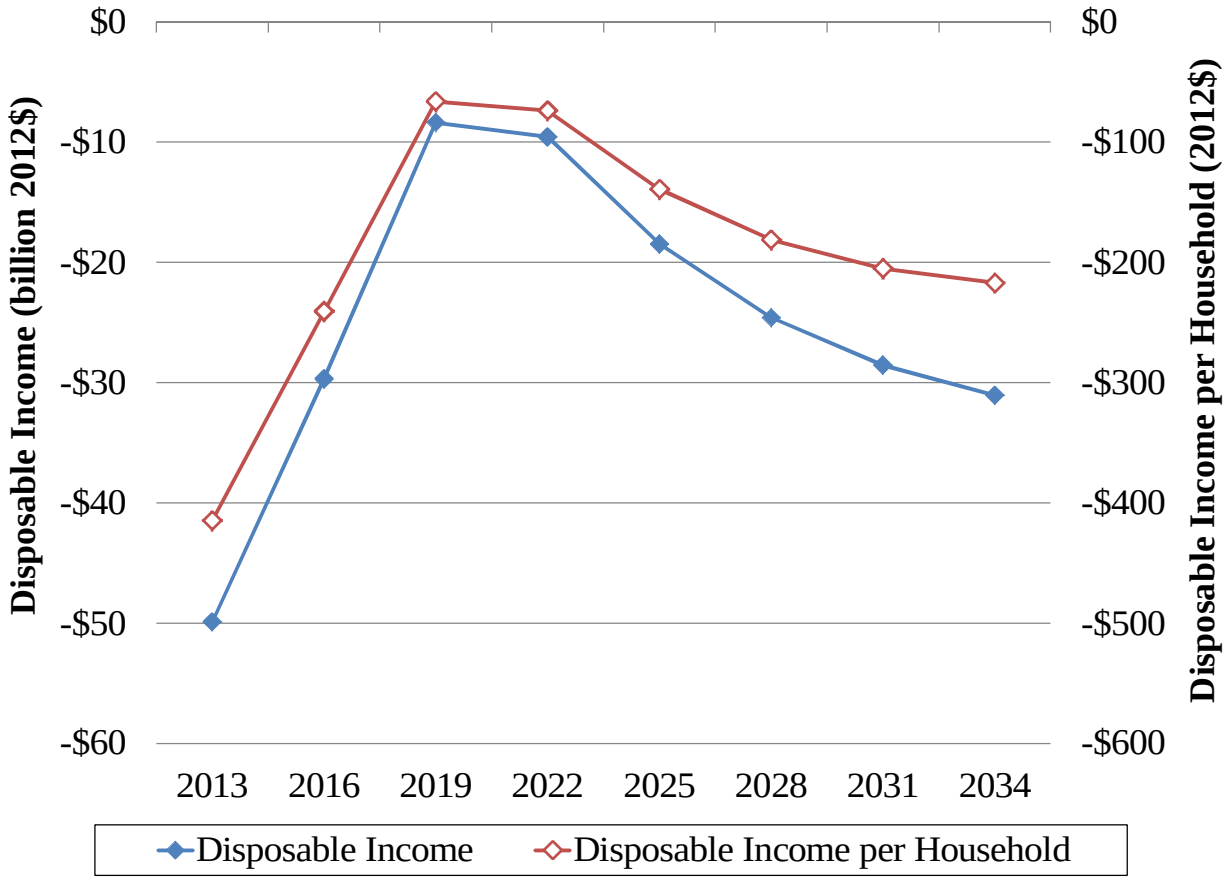
	2013	2016	2019	2022	2025	2028	2031	2034	Avg
New York/New England	-20	-35	-19	-36	-46	-56	-56	-56	-39
Mid-Atlantic Coast	-6	-28	-11	-36	-60	-62	-70	-70	-40
Upper Midwest	26	-140	-67	-135	-171	-177	-214	-236	-130
Southeast	17	-106	-32	-71	-66	-90	-129	-108	-70
Florida	-4	-5	-14	-7	-10	-11	-15	-20	-10
Mississippi Valley	16	-110	-35	-115	-132	-148	-155	-155	-100
Mid-America	-6	-52	-3	-18	-37	-41	-36	-50	-29
Texas, Oklahoma, Louisiana	-2	-91	-19	-51	-84	-100	-101	-114	-66
Arizona/Mountain States	-6	-51	-3	-21	-30	-30	-33	-35	-25
California	-27	-32	-6	-10	-16	-21	-25	-30	-20
Pacific Northwest	-17	-22	-8	-6	-13	-25	-15	-21	-15
United States	-30	-671	-216	-505	-664	-760	-848	-895	-544

Note: Regional definitions are shown in Appendix A.
Source: NERA calculations as explained in text.

I. Disposable Income

Figure E-9 shows the estimated change in U.S. disposable income and disposable income per household relative to the baseline scenario.[1]

Figure E-9. Change in U.S. Disposable Income and Disposable Income per Household Relative to Baseline Scenario



Source: NERA calculations as explained in text.

[1] Disposable income in N_{ew}ERA is linked to household consumption.

Table E-3 shows the loss in disposable income per household by region each year and on an annualized basis.

Table E-3. Loss in Disposable Income per Household by Region

	2013	2016	2019	2022	2025	2028	2031	2034	Ann.
New York/New England	$381	$300	$98	$71	$166	$214	$232	$261	$236
Mid-Atlantic Coast	$384	$239	$43	$49	$127	$174	$198	$210	$199
Upper Midwest	$650	$376	$177	$309	$385	$458	$593	$594	$448
Southeast	$358	$141	-$36*	-$37*	$28	$61	$76	$75	$112
Florida	$274	$181	$67	-$22*	-$2*	$25	$51	$59	$110
Mississippi Valley	$644	$296	$69	$202	$360	$421	$426	$449	$373
Mid-America	$427	$192	$10	$5	$89	$110	$87	$146	$165
Texas, Oklahoma, Louisiana	$357	$181	-$14*	-$25*	$52	$119	$130	$135	$140
Arizona/Mountain States	$295	$76	-$62*	-$50*	-$34*	-$9*	$3	$9	$57
California	$226	$178	$60	$16	$28	$53	$67	$77	$112
Pacific Northwest	$753	$709	$582	$557	$610	$650	$690	$738	$693
United States	$415	$241	$66	$74	$139	$181	$205	$217	$217

Note: (*) Negative values indicate that disposable income per household increases relatives to the baseline. "Ann." is the annualized value based on the present value of impacts from 2013 through 2034. Regional definitions are shown in Appendix A.

Source: NERA calculations as explained in text.