NERA
ECONOMIC CONSULTING

Potential Energy Impacts of the EPA Proposed Clean Power Plan

Prepared for:

American Coalition for Clean Coal Electricity

American Fuel & Petrochemical Manufacturers

Association of American Railroads

American Farm Bureau Federation

Electric Reliability Coordinating Council

Consumer Energy Alliance

National Mining Association

October 2014

Project Directors

David Harrison, Jr., Ph.D.
Anne E. Smith, Ph.D.

Project Team

Paul Bernstein, Ph.D.
Scott Bloomberg
Andrew Foss
Andrew Stuntz
Sugandha Tuladhar, Ph.D.

NERA Economic Consulting
200 Clarendon St, 11th Floor
Boston, Massachusetts 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com

Report Qualifications/Assumptions and Limiting Conditions

Information furnished by others, upon which all or portions of this report are based, is believed to be reliable, but has not been independently verified, unless otherwise expressly indicated. Public information and industry and statistical data are from sources we deem to be reliable; however, we make no representation as to the accuracy or completeness of such information. The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA Economic Consulting accepts no responsibility for actual results or future events.

The opinions expressed in this report are valid only for the purpose stated herein and as of the date of this report. No obligation is assumed to revise this report to reflect changes, events or conditions, which occur subsequent to the date hereof. The opinions expressed in this report are those of the authors and do not necessarily represent the views of NERA Economic Consulting, other NERA consultants, or NERA's clients.

All decisions in connection with the implementation or use of advice or recommendations contained in this report are the sole responsibility of the client. This report does not represent investment advice nor does it provide an opinion regarding the fairness of any transaction to any and all parties.

Contents

EXECUTIVE SUMMARY **S-1**

I. INTRODUCTION **1**
- A. Background on EPA Proposal 1
- B. Objectives of This Evaluation 2
- C. Organization of This Report 2

II. EPA CLEAN POWER PLAN PROPOSAL **4**
- A. Building Blocks Used to Calculate State Targets 4
- B. CO_2 Emission Rate Formula 6
- C. State CO_2 Emission Rate Targets 8

III. MODELING METHODOLOGY AND STATE COMPLIANCE SCENARIOS **11**
- A. N_{ew}ERA Model 11
- B. Modeling and Input Assumptions 11
- C. Compliance Scenarios 13

IV. RESULTS FOR STATE COMPLIANCE SCENARIOS **15**
- A. Impacts on U.S. Energy System 15
- B. Impacts on Regional Energy Systems 21
- C. Impacts on Electricity Prices 23

V. REFERENCES **28**

APPENDIX A: THE N_{EW}ERA MODEL **A-1**

APPENDIX B: REGIONAL SCENARIO **B-1**

APPENDIX C: COMPLICATIONS IN MODELING ENERGY EFFICIENCY **C-1**

Index of Figures

Figure ES-1: Overview of Energy System Impacts of State Unconstrained (BB1-4) and State Constrained (BB1-2) Scenarios (Annual Average, 2017-2031) S-6

Figure ES-2: Energy System Costs of State Unconstrained (BB1-4) and State Constrained (BB1-2) Scenarios S-7

Figure 1: Calculation of U.S. 2030 CO_2 Emission Rate Target from 2012 Rate and Building Blocks 8

Figure 2: 2030 CO_2 Emission Rate Targets for EPA Option 1 (lbs/MWh) 9

Figure 3: CO_2 Emission Rate Reduction for 2030 Target Relative to 2012 Rate 10

Figure 4: Overview of Energy System Impacts of State Compliance Scenarios (Annual Average, 2017-2031) 15

Figure 5: CO_2 Emission Impacts of State Compliance Scenarios (Million Metric Tons) 16

Figure 6: Coal Unit Retirement Impacts of State Compliance Scenarios 17

Figure 7: Capacity Impacts of State Compliance Scenarios (GW) 18

Figure 8: Generation Impacts of State Compliance Scenarios (TWh) 19

Figure 9: Coal and Natural Gas Consumption Impacts of State Compliance Scenarios 20

Figure 10: Natural Gas Wholesale Price (Henry Hub) Impacts of State Compliance Scenarios 20

Figure 11: Energy System Cost Impacts of State Compliance Scenarios (billion 2013 dollars) 21

Figure 12: Coal Unit Retirement Impacts by Region Through 2031 22

Figure 13: Natural Gas Combined Cycle Generation Impacts by Region of State Scenarios (Annual Average, 2017-2031, TWh) 23

Figure 14: Natural Gas Combined Cycle Fuel Consumption Impacts by Region of State Scenarios (Annual Average, 2017-2031, TBtu) 23

Figure 15: All Sectors Delivered Electricity Price Impacts of State Scenarios 24

Figure 16: Ratepayer Class Delivered Electricity Price Impacts of State Scenarios (Annual Average, 2017-2031, 2013 cents per kWh) 25

Figure 17: State All Sectors Delivered Electricity Price Impacts of State Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031) 25

Figure 18: State All Sectors Delivered Electricity Price Impacts of State Constrained (BB1-2) Scenario (Annual Average, 2017-2031) 26

Figure 19: Consumer Electricity-Related Cost Impacts of State Scenarios (Annual Average, 2017-2031, billion 2013 dollars) 27

Figure A-1: N_{ew}ERA Modeling System Representation A-2

Figure A-2: N_{ew}ERA Electric Sector Model – U.S. Regions A-4

Figure A-3: Interdependent Economic Flows in N_{ew}ERA's Macroeconomic Model A-6

Figure A-4: Household Consumption Structure in N_{ew}ERA's Macroeconomic Model............ A-6
Figure A-5: Commercial Transportation and Trucking Sector Production Structure in N_{ew}ERA's Macroeconomic Model A-7
Figure A-6: Production Structure for Other Sectors in N_{ew}ERA's Macroeconomic Model...... A-8
Figure A-7: N_{ew}ERA Macroeconomic Model Regions A-10
Figure B-1: 2030 Regional CO_2 Emission Rate Targets (lbs/MWh).. B-2
Figure B-2: Overview of Energy System Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031) B-2
Figure B-3: CO_2 Emission Impacts of Regional Unconstrained (BB1-4) Scenario B-3
Figure B-4: Coal Unit Retirement Impacts of Regional Unconstrained (BB1-4) Scenario B-3
Figure B-5: Capacity Impacts of Regional Unconstrained (BB1-4) Scenario (GW) B-4
Figure B-6: Generation Impacts of Regional Unconstrained (BB1-4) Scenario (TWh) B-5
Figure B-7: Coal and Natural Gas Consumption Impacts of Regional Unconstrained (BB1-4) Scenario.. B-5
Figure B-8: Natural Gas Wholesale Price (Henry Hub) Impacts of Regional Unconstrained (BB1-4) Scenario B-6
Figure B-9: Regulation Cost Impacts of Regional Unconstrained (BB1-4) Scenario (billion 2013 dollars) B-6
Figure B-10: Coal Unit Retirement Impacts by Region of Regional Unconstrained Scenario Through 2031.. B-7
Figure B-11: Natural Gas Combined Cycle Generation Impacts by Region of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, TWh) B-7
Figure B-12: Natural Gas Combined Cycle Fuel Consumption Impacts by Region of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, TBtu) B-8
Figure B-13: All Sectors Delivered Electricity Price Impacts of Regional Unconstrained (BB1-4) Scenario B-8
Figure B-14: Ratepayer Class Delivered Electricity Price Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, 2013 cents per kWh)......................... B-9
Figure B-15: State All Sectors Delivered Electricity Price Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031)... B-9
Figure B-16: Consumer Electricity-Related Cost Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, billion 2013 dollars)..................................... B-10

EXECUTIVE SUMMARY

This report evaluates the potential energy market impacts and energy costs of the U.S. Environmental Protection Agency's (EPA) proposed Clean Power Plan (CPP) to reduce carbon dioxide (CO_2) emissions from existing power plants. EPA proposed the CPP in June 2014 as a nationwide regulation (to be implemented by the states) under Section 111(d) of the Clean Air Act.

Overview of the Proposed Clean Power Plan

The proposed CPP sets state-specific CO_2 emission rate targets (in lbs/MWh) based upon EPA's calculation of the emission rates that EPA believes could be achieved in each state by implementing four types of changes, referred to as Building Blocks. The Building Blocks include heat rate improvements at coal units (Building Block 1), increased utilization of existing natural gas combined cycle (NGCC) units (Building Block 2), increases in renewables and nuclear energy (Building Block 3), and increases in end-use energy efficiency (Building Block 4). EPA identified two options based upon alternative stringencies and compliance timeframes. Option 1, which is EPA's preferred option, is projected by EPA to reduce U.S. CO_2 power plant emissions by 30% in 2030 (relative to the 2005 emission level). Option 2 would have less stringent emission rate targets and is projected by EPA to reduce U.S. CO_2 power plant emissions by about 24% by 2025 (relative to the 2005 level). This report focuses on Option 1, EPA's preferred option.

In its proposal, EPA emphasized that states would have flexibility to meet the CPP state targets. According to EPA, this means that, provided EPA's overall target emission rate is met, states would not be required to apply each of the Building Blocks at the levels that were used to set the target rates but could determine their preferred combination of the four Building Blocks. (The formula to show compliance would, nevertheless, still be limited to the emissions and generation from the covered sources EPA has specified in the Building Blocks; thus, for example, compliance accounting would exclude emissions from new NGCC units.[1])

There are some questions, however, as to whether all of the Building Blocks actually would be available for compliance. Some legal analysts have questioned whether EPA has the statutory authority to require states to extend regulation under Section 111(d) to account for emissions other than those from the specific existing electricity generation units in the listed source category. This concern calls into question whether the use of Building Blocks 2, 3, and 4 could be included for demonstrating compliance even though the proposed state targets have been

[1] In its proposal, EPA mentioned the possibility of including new NGCC units as part of the rate limit, and asked for comments on this possibility (EPA 2014a, p. 34924).

computed on the assumption they would be allowed.[2] In addition, some states may require legislation in order to impose measures that would be needed to implement Building Blocks 3 and 4 (such as renewable portfolio standards and energy efficiency resource standards), which could lead to constraints on the use of those Building Blocks. Also, it is the opinion of some legal analysts that EPA could not enforce Building Blocks 2, 3, and 4 if the Agency imposed a Federal Implementation Plan on states.

Study Objectives and Compliance Scenarios

Our principal objective is to evaluate the potential energy market impacts and energy costs of the CPP, focusing on results over the period from 2017 through 2031. (2017 marks the beginning of the ramp up of EPA's assumed end-use energy efficiency and renewable generation, and 2031 represents the most stringent rates that are achieved by 2029).[3] We develop impact estimates under two scenarios, both of which presume least-cost compliance by each state; while appropriate for modeling, this least-cost presumption may lead to understating the real-world impacts and costs of the CPP. The first scenario assumes that states are able to use all four Building Blocks and the second addresses the impact of legal and other potential constraints on state and Federal plans by assuming that states can only use Building Blocks 1 and 2 to show compliance with the targets set in the CPP.[4]

1. *State Unconstrained (BB1-4).* Each state complies with its targets, with all four Building Blocks available as compliance options.

2. *State Constrained (BB1-2).* Each state complies with its targets, but this scenario presumes that neither end-use energy efficiency (Building Block 4) nor renewables and additional nuclear energy (Building Block 3) would be available as compliance options.

We refer to the first scenario as a "state unconstrained" scenario to indicate that each state is presumed to comply using the least-cost mix across all four Building Blocks without any legal or implementation constraints. Further, the Building Blocks measures must occur within each state individually. (An appendix to the report provides results for a scenario that assumes states can meet the target rates on a regional, rather than state-by-state, basis.) We refer to the second scenario as a "state constrained" scenario to illustrate the impact of state-by-state compliance

[2] EPA requests comment on a separate set of target calculations based upon only Building Blocks 1 and 2 (EPA 2014a, p. 34878); however, the targets actually proposed by EPA assume all four Building Blocks would be allowed. This analysis focuses on the proposed targets.

[3] States are presumed to comply with the rate-based form of the goal, rather than with a translation of the CPP requirements to a mass-based form; EPA has not yet specified how such a translation could be accomplished.

[4] This report does not take a position on the legal and practical issues associated with use of the various Building Blocks, including whether EPA has authority under the Clean Air Act to base Section 111(d) standards on requirements concerning how generating units are dispatched. The second scenario reflects the likelihood that if coal-fired generation is to be used less, gas-fired generation will be used more.

with constraints, where states would only be able to use two of the four Building Blocks to demonstrate compliance with the state targets proposed by EPA. Despite the label "constrained," even in this scenario the states could still choose their preferred compliance mix, given the CO_2 rate constraint. For our analysis, we have assumed that each state chooses its own least-cost compliance strategy under both scenarios.

NERA Methodology

NERA evaluated the potential impacts of the various CPP scenarios using its proprietary N_{ew}ERA model and baseline conditions based upon U.S. government information. We reviewed the assumptions that EPA used in its Building Blocks and made various corrections and adjustments in modeling the likely effects of the proposed CPP.

N_{ew}ERA Model

The N_{ew}ERA model is an economy-wide integrated energy and economic model that includes a bottom-up unit-specific representation of the U.S. electricity sector and a top-down representation of all other sectors of the economy including households and governments. It has substantial detail for all of the energy sources used by the economy, with separate sectors for electricity, coal, natural gas, crude oil, and refined petroleum products. The model performs its analysis with regional and state detail, accounting for more than 30 electricity regions and 11 macroeconomic regions. N_{ew}ERA is a long-term model that includes the assumption that households and firms make optimal decisions over the entire modeling period, within regulatory constraints, and with full knowledge of future policies.

The N_{ew}ERA model used in this study is calibrated to the U.S. Energy Administration (EIA) *Annual Energy Outlook* (*AEO*) *2014* Reference Case projection. This reference case reflects current environmental regulations (*e.g.*, Mercury and Air Toxics Standards) and other policies, as well as the EIA's most recent projections of energy and economic activity. The Reference Case includes the effects of the two major existing programs to reduce CO_2 emissions, the Regional Greenhouse Gas Initiative (RGGI) and the California cap-and-trade program.

Building Block Assumptions

We developed assumptions about the costs and effectiveness of the different compliance options. As discussed above these compliance options (or Building Blocks) are heat rate improvements of coal units (Building Block 1), increased utilization of existing natural gas combined cycle (NGCC) units (Building Block 2), increases in renewable and nuclear energy (Building Block 3), and increases in end-use energy efficiency (Building Block 4). Below we discuss our assumptions for each building block (details are provided in the main body of the report).

Building Block 1 – Heat Rate Improvements for Coal Units

In its calculations of state targets, EPA assumed that all coal units could achieve a 6% improvement in their efficiency (*i.e*., reduction in heat rate), and in its cost modeling EPA also assumed this 6% improvement could be achieved at a capital cost of $100/kilowatt (kW). We understand that various industry experts have concluded that these assumptions are unrealistic in light of practical engineering considerations, actual industry experience, and the incentives owners of electricity generators already have to improve plant efficiency. Our clients suggested an alternative set of assumptions, in particular, (a) for a cost of $100/kW, a maximum efficiency improvement of 1.5% would be achievable for the most inefficient existing units and a 0.75% improvement would be available for units with average efficiency, and (b) no efficiency improvements would be available to the most efficient units. We investigated the significance to our incremental energy cost estimates of these alternative sets of assumptions regarding potential heat rate improvements and found that this set of assumptions did not have a major effect on the results; using EPA's heat rate assumption rather than the alternative set resulted in less than a 1% change in our estimate of the overall energy system cost of the CPP in the unconstrained scenario. Thus, although we are not indicating that we attempted to determine the most realistic set of assumptions, we adopted the alternative industry set of assumptions regarding potential heat rate improvements. We note that while this set of assumptions has *de minimis* impact on our estimates of the impacts of the proposed CPP, this issue would be much more significant if the Section 111(d) limits for legal reasons had to be based solely on systems of emissions controls that can be achieved on the existing fossil units themselves. In that legal situation, this uncertainty would warrant a more thorough treatment of heat rate improvement assumptions than we determined was necessary for our present analysis.

Building Block 2 – Increased Utilization of Existing NGCC

In its calculation of state targets, EPA assumed that existing NGCC units could increase their utilization to a 70% annual capacity factor (subject to the availability of coal- and oil-fired units to be backed down) regardless of any engineering, regulatory, or infrastructure constraints.[5] Increasing utilization of existing NGCC units up to each unit's maximum availability[6] is an option in all of our scenarios. The estimated incremental cost of this action depends upon the relative costs of the alternative sources of generation, which vary by electricity market region; the specific units backed down to achieve any increase in generation from existing NGCC units are determined in $\mathrm{N_{ew}ERA}$.

[5] Not all states are able to ramp up to 70%. Some states do not have sufficient coal- and oil-fired generation to be backed down; in this case, NGCC units were assumed to be able to ramp up to a level based upon backing out all coal- and oil-fired generation.

[6] For most units, the maximum availability is assumed to exceed 85%.

Building Block 3 – Increases in Renewable and Nuclear Generation

EPA's calculation of state targets includes the effects of added generation from existing and new non-hydroelectric units, existing nuclear generation termed "at risk," and new nuclear generation currently under construction. In all of our scenarios that include Building Block 3, additions of non-hydroelectric renewable and nuclear generation are presumed to be able to contribute to lowering emission rates, at the capital and operating costs that are standard in N_{ew}ERA.

Building Block 4 – Increases in End-Use Energy Efficiency

EPA's calculation of state targets was based upon its estimates of the quantities of end-use energy efficiency by state that could be added in each year based upon the programs adopted to-date in states with ambitious energy efficiency programs. EPA also provided estimates of the cost for this energy efficiency, with the first-year cost varying based on whether a state was adding less than 0.5% incremental energy efficiency ($550/MWh), between 0.5% and 1.0% ($660/MWh), or more than 1.0% ($770/MWh). EPA has translated the three first-year costs to levelized costs of 6.5¢/kWh, 7.8¢/kWh, and 9.1¢/kWh, respectively. We reviewed the literature and updated the cost estimates based upon a recent review by two prominent academic researchers (Allcott and Greenstone, 2012); the recommendation in this review implies a levelized cost of 10.6¢/kWh based on historical energy efficiency costs (including both utility costs and participant costs), which we presume relates to the EPA value for states adding less than 0.5% incremental energy efficiency. We scaled up EPA's first-year costs by the ratio of this value to the equivalent levelized cost for EPA (6.5¢/kWh), resulting in first-year energy efficiency costs of $896/MWh. We are not aware of any assessment regarding the extent to which energy efficiency costs may increase as the targets become more ambitious that is similar to the Allcott and Greenstone assessment on historical energy efficiency costs. Thus, we used the same assumptions as EPA regarding the changes, resulting in estimates of $1,075/MWh and $1,253/MWh (2011$) for the second and third levels of energy efficiency.

We modeled the adoption of energy efficiency as a compliance option based upon its cost relative to alternative means of reducing CO_2 compliance emission rates to comply with the CPP (using the same approach as EPA). As discussed in Appendix C, however, there is a strong conceptual argument that cost-effective energy efficiency would be adopted in the absence of the CPP, *i.e.*, in the baseline case to which the CPP case is compared in deriving the cost and impacts of the CPP.

Results for the State Compliance Scenarios

The following are estimates of the energy sector impacts and energy costs of the two state compliance scenarios. The first scenario presumes that compliance costs are minimized using all four of the Building Blocks identified by EPA for the CPP targets. The second presumes that the same interim and final CPP state targets would have to be met, but that states would be constrained to using only Building Blocks 1 and 2.

Figure ES-1 provides an overview of the average annual energy system impacts of these two scenarios over the period from 2017 through 2031. Chapter IV provides information on annual effects for individual years from 2017 through 2031, with effects that are both higher and lower in individual years than these average values.

The energy market impacts of the CPP would be substantial in the State Unconstrained (BB1-4) scenario. The annual average electricity sector CO_2 emissions would be reduced by about 22% relative to the reference case (not relative to 2005 emission levels) over the period from 2017 through 2031. Coal unit retirements would increase by about 45 gigawatts (GW). Coal-fired generation would decline by about 29% on average over the period, with natural gas-fired generation increasing by about 5% on average. The Henry Hub natural gas price would increase by about 2% on average. Delivered electricity prices would increase by about 12% on average over 2017 through 2031. However, these figures omit several factors that could add to impacts and costs.[7]

Figure ES-1: Overview of Energy System Impacts of State Unconstrained (BB1-4) and State Constrained (BB1-2) Scenarios (Annual Average, 2017-2031)

	Total Coal Retirements Through 2031	Coal-Fired Generation	Natural Gas-Fired Generation	Henry Hub Natural Gas Price	Delivered Electricity Price	Electricity Sector CO2 Emissions
	GW	TWh	TWh	2013$/MMBtu	2013 ¢/kWh	MM metric tons
Baseline	51	1,672	1,212	$5.25	10.8	2,080
State Unconstrained (BB1-4)	97	1,191	1,269	$5.36	12.0	1,624
Change from Baseline	+45	-481	+57	+$0.11	+1.3	-456
% Change from Baseline	+18%	-29%	+5%	+2%	+12%	-22%
State Constrained (BB1-2)	220	492	2,015	$6.78	12.6	1,255
Change from Baseline	+169	-1,180	+802	+$1.53	+1.9	-825
% Change from Baseline	+69%	-71%	+66%	+29%	+17%	-40%

Note: Coal retirements are cumulative from 2014. Percentage change in coal retirements is relative to total baseline 2031 coal capacity.
Source: NERA calculations as explained in text.

In the State Constrained (BB1-2) scenario, reductions in average annual electricity sector CO_2 emissions over the 2017 through 2031 timeframe would be 40%, almost twice the amount under

[7] Potential infrastructure costs related to natural gas pipelines, electricity transmission, and voltage support or ancillary services are not included. Low projected capacity utilization of non-retired coal units would lead to decreases in efficiency (*i.e.*, increases in heat rates), additional wear and tear costs from operating coal units in a cycling mode, and potentially additional retirements, none of which are included in our modeling. Costs related to unit ramp rate constraints, minimum load constraints, and delays in new build or retirement permitting are also not accounted for in our cost estimates.

the State Unconstrained (BB1-4) scenario.[8] Such a constrained compliance scenario would result in very large changes in the electricity system, including 169 GW of coal retirements, a 29% average increase in natural gas prices and a 17% increase in average delivered electricity prices.

Figure ES-2 shows the energy system costs of the two scenarios, expressed as present values in 2014 of spending incurred over the period from 2017 through 2031. The costs are broken down into three categories: (1) costs to serve electricity load; (2) costs of the end-use energy efficiency programs, both to the utilities and to the participants; and (3) costs of non-electricity natural gas use. Under the State Unconstrained (BB1-4) scenario, energy system costs are dominated by the costs to the utilities and to participants of the additional state energy efficiency programs, which are estimated to cost about $560 billion (in present value) over the period from 2017 through 2031. The reduction in electricity demand over the period 2017 through 2013 results in a net decrease in production costs to meet electricity load that has a present value in 2014 of about $209 billion; this partially offsets the investment costs of the energy efficiency programs. Higher gas prices are part of the higher cost to serve load, but they also affect consumers who purchase natural gas for non-electricity energy services; the higher consumer cost for direct consumption of natural gas adds another $15 billion to the present value of the CPP over the years 2017-2031. The net result is that energy system costs would be greater by about $366 billion in present value terms over the period from 2017 through 2031 under the State Unconstrained (BB1-4) scenario.

Figure ES-2: Energy System Costs of State Unconstrained (BB1-4) and State Constrained (BB1-2) Scenarios

	State Unconstrained (BB1-4)	State Constrained (BB1-2)
Present Value (Billion 2013$)		
Cost of Electricity, Excluding EE	-$209	$335
Cost of Energy Efficiency	$560	$0
Cost of Non-Electricity Natural Gas	$15	$144
Total Consumer Energy Costs	$366	$479

Notes: Present value is from 2017 through 2031, taken in 2014 using a 5% real discount rate
Source: NERA calculations as explained in text.

The net cost of the State Constrained (BB1-2) scenario—which excludes end-use energy efficiency, renewables and additional nuclear energy from compliance—is substantially greater than the State Unconstrained (BB1-4) scenario. There would be no costs for end-use energy

[8] While states are required to meet the same target CO_2 *rates* in both state scenarios, the State Constrained (BB1-2) scenario does not allow energy efficiency, renewables, and nuclear generation to contribute to the CO_2 rates (lbs/MWh) used to demonstrate compliance with the CPP targets. In order to achieve the compliant CO_2 rates using only fossil sources, states rely more heavily on reducing existing coal and natural gas generation in the State Constrained (BB1-2) scenario, which is replaced by new, lower emitting generation sources, resulting in lower *total* emissions than in the State Unconstrained (BB1-4) scenario.

efficiency (because this would not be allowed as part of compliance), but the additional costs of providing electricity services would be about $335 billion. The higher natural gas prices would result in an increase in natural gas costs for non-electricity uses of about $144 billion. The net result would be an increase in energy system costs by about $479 billion in present value terms over the period from 2017 through 2031.

I. INTRODUCTION

This report provides an assessment of the U.S. Environmental Protection Agency's (EPA) Clean Power Plan (CPP) proposal to reduce carbon dioxide (CO_2) emissions from existing power plants nationwide. In particular, we use the state-of-the-art N_{ew}ERA model to analyze the potential impacts of the proposal on U.S. energy markets and on energy sector costs.

A. Background on EPA Proposal

EPA proposed the CPP in June 2014 as a nationwide regulation under Section 111(d) of the Clean Air Act (EPA 2014a). The proposal would set maximum limits on CO_2 emission rates (measured in pounds of CO_2 per megawatt-hour (MWh) of generation and end-use energy efficiency according to a formula described below) for electricity systems within relevant states.[9] In EPA's preferred regulatory approach (labeled "Option 1"), the final CO_2 emission rate standards would apply in 2030, and in that year total U.S. power sector CO_2 emissions would be 30% below their level in 2005. EPA also developed and evaluated an alternative approach (labeled "Option 2") with final standards in 2025. EPA developed interim limits in addition to the final limits for each regulatory approach. The proposal would allow states to develop regional programs for collective CO_2 emission reduction, as in the Regional Greenhouse Gas Initiative (RGGI) in nine Northeastern states that began in 2009.

EPA set the state CO_2 emission rate limits based on their analysis of emission reduction opportunities in each state. EPA evaluated the opportunities in terms of four Building Blocks that can be summarized as follows:

1. Building Block 1—Heat rate improvements at coal units;
2. Building Block 2—Increased utilization of existing natural gas combined cycle (NGCC) units;
3. Building Block 3—Increases in renewables and nuclear energy; and
4. Building Block 4—Increases in end-use energy efficiency.

Chapter II of this report describes EPA's calculations for these four Building Blocks as well as the CO_2 emission rate formula and state limits that result under the CPP.

[9] The proposal does not set CO_2 emission rate limits for Vermont or Washington, D.C., because these jurisdictions do not have any affected fossil-fired power plants.

B. Objectives of This Evaluation

Our principal objective is to evaluate the potential energy market impacts and energy costs of the CPP, focusing on results over the period from 2017 through 2031 (2017 marking the beginning of the ramp up of EPA's assumed end-use energy efficiency and renewable generation, and 2031 representing the most stringent rates that are achieved by 2029). We develop impact estimates under two scenarios, both of which presume least-cost compliance by each state. (While appropriate for modeling, this least-cost presumption may lead to understating the real-world impacts and costs of the CPP.) The first scenario assumes that states are able to use all four Building Blocks and the second scenario assumes that states are constrained by the legal considerations described above but nonetheless use Building Blocks 1 and 2 to show compliance with the targets set in the CPP.[10]

1. *State Unconstrained (BB1-4)*. Each state complies with its targets, with all four Building Blocks available as compliance options.

2. *State Constrained (BB1-2)*. Each state complies with its targets; this scenario presumes that neither end-use energy efficiency (Building Block 4) nor renewables and additional nuclear energy (Building Block 3) would be available as compliance options.

We refer to the first scenario as a "state unconstrained" scenario to indicate that each state is presumed to comply using the least-cost mix across all four Building Blocks, although the specific mix of Building Blocks is limited to each state individually, and we assume there are no legal or implementation constraints to using all four Building Blocks. (Appendix B provides results for a scenario that assumes states can meet the target rates on a regional rather than state-by-state basis.[11]) We refer to the second scenario as a "state constrained" scenario to illustrate the impact of state-by-state compliance with constraints, where states would only be able to use two of the four Building Blocks to demonstrate compliance. Despite the label "constrained," even in this scenario the states could still choose their preferred compliance mix, given the constraint. For our analysis, we have assumed that each state chooses its own least-cost compliance strategy under both scenarios.

C. Organization of This Report

The remainder of this report is organized as follows.

[10] States are presumed to comply with the rate-based form of the goal, rather than with a translation of the CPP requirements to a mass-based form; EPA has not yet specified how such a translation could be accomplished.

[11] Both the state-by-state and regional results assume CPP targets are based upon the EPA compliance formula (which excludes some CO_2 emission sources) and that CPP targets would need to be met each year.

- Chapter II describes the EPA proposal, including information on the CPP CO_2 emission rate formula, the four Building Blocks, and the state emission rate targets resulting from EPA's calculations;

- Chapter III describes the modeling methodology and compliance scenarios for this study; and

- Chapter IV presents energy system modeling results for the State Unconstrained (BB1-4) and State Constrained (BB1-2) scenarios.

Appendices provide additional information on the methodology and results. Appendix A documents the key features of the N_{ew}ERA model. Appendix B provides our results for the regional compliance scenario that EPA also analyzed in its Regulatory Impact Analysis Appendix C discusses how EPA's decision to not incorporate cost-effective energy efficiency into the baseline alters the impact estimates.

II. EPA CLEAN POWER PLAN PROPOSAL

This chapter provides information on EPA's CPP proposal, including calculations for the four Building Blocks, the formula for calculating the CO_2 emission rate, and state CO_2 emission rate limits resulting from EPA's calculations. This information serves as the basis for our evaluation's methodology and inputs, as discussed below in Chapter III.

A. Building Blocks Used to Calculate State Targets

As noted above, EPA used four Building Blocks to estimate levels of CO_2 emission rate reductions in each state that it translated into state targets in the CPP. The CPP proposal does not require each state to achieve the specific measures assumed for each Building Block. Instead, each state would need to achieve the interim and final CO_2 emission rates calculated from the combination of all four Building Blocks. States might choose not to implement some of the Building Blocks at all and might develop entirely different strategies for lowering their CO_2 emission rates to the required levels. This subsection provides information related to EPA assumptions for each Building Block.

1. Building Block 1: Heat Rate Improvements at Coal Units

The first Building Block involves improving the heat rate (*i.e.*, fuel efficiency and hence CO_2 emission rate) at existing coal units. Based on engineering analyses by Sargent & Lundy and EPA, EPA estimated that existing coal units could improve their heat rate by 6% through a combination of operational measures (4% improvement) and equipment upgrades (additional 2% improvement). EPA also estimated that the heat rate improvements would require costs of $100/kW measured in 2011 dollars (EPA 2014b, Chapter 2).

2. Building Block 2: Increased Utilization of Existing NGCC Units

The second Building Block involves increasing the utilization (*i.e.*, capacity factor) of existing NGCC units. According to EPA (2014c), the average utilization of existing NGCC units across the country was 44% in 2012. The goal of this Building Block is to increase average utilization in each state to 70%.

EPA assumed that utilization of coal- and oil-fired units would decrease in order for utilization of existing NGCC units to increase. States with little generation from coal- and oil-fired units under baseline conditions (and hence little opportunity for fuel switching) would not achieve the 70% utilization target for existing NGCC units. Beyond the availability of coal- and oil-fired generation, EPA did not account for any potential regulatory, engineering, or infrastructure barriers to increasing the utilization of existing NGCC units.

3. Building Block 3: Renewables and Nuclear

The third Building Block involves renewable energy, new nuclear units under construction, and at-risk nuclear units (as described above regarding relevant MWh for the CO_2 emission rate formula). EPA estimated feasible reductions in CO_2 emission rates for each state with this Building Block based on current state renewable portfolio standards (RPS), recent historical renewable energy percentages relative to total generation, conversion to MWh, and information on under-construction and at-risk nuclear units.

Many states already have RPSs with goals in terms of MW of capacity, MWh of generation, percentage of total state generation, or other measures. EPA grouped states into regions and used current RPS targets in individual states to estimate renewable energy percentage targets (relative to total state generation) and annual growth rates for each region.[12] EPA then applied these annual growth rates to each state's 2012 renewable energy percentage to develop targets for individual years through 2029. In EPA's calculations, state target renewable energy percentages are never allowed to exceed the target for the corresponding region, and some states with low 2012 starting points do not reach the target for their region even by 2029 after many years of applying the corresponding regional growth rate.

EPA converted the state target renewable energy percentages to MWh in each year using 2012 generation in each state. EPA added MWh from under-construction and at-risk nuclear units to estimate total MWh for this building block.

4. Building Block 4: Increased End-Use Energy Efficiency

The fourth Building Block involves increases in end-use energy efficiency programs. To evaluate opportunities for increased energy efficiency in each state, EPA began by reviewing the annual incremental savings in electricity sales (measured as a percentage of the previous year's sales) from energy efficiency programs across the country. Based on this review, EPA concluded that implementation of "best practices" for energy efficiency programs would enable all states to achieve 1.5% annual incremental savings in the long term. In the calculations for this Building Block, EPA assumed that states would begin in 2017 with an initial annual incremental savings rate equal to their 2012 incremental savings. Thereafter, the incremental savings rate would increase by 0.20% until it ramped up to a final rate of 1.5% per year. This trajectory would reduce total U.S. electricity sales in 2029 by about 10% relative to the baseline total sales projection for that year (EPA 2014c).

From its review of energy efficiency program information, EPA concluded that at annual incremental savings rates less than 0.5%, the energy efficiency programs for compliance with the

[12] EPA did not account for existing RPSs in Texas and Iowa, which have RPS targets specified in terms of MW (rather than specified in MWh). On the other hand, EPA based the renewable energy target for the entire South Central region on Kansas, which also has a RPS target in terms of capacity (MW) rather than generation (MWh).

CPP would require upfront costs of $550/MWh measured in 2011 dollars, with 50% borne by utilities and 50% borne by consumers. For annual incremental savings between 0.5% and 1.0%, EPA assumed that the upfront costs would increase by 20%, to $660/MWh. For annual incremental savings above 1.0%, EPA assumed the upfront costs would increase by 40% (relative to the initial cost), to $770/MWh (EPA 2014b, p. 5-54).

B. CO_2 Emission Rate Formula

As noted above, the EPA proposal would address CO_2 emissions from power plants by setting maximum limits on the CO_2 emission rate (measured in lbs/MWh) for each relevant state. The limits would first take effect in 2020. They would tighten over time until reaching final levels in 2030 (for EPA's preferred regulatory approach labeled "Option 1") or 2025 (for the alternative regulatory approach labeled "Option 2").

The proposal uses a specific formula to calculate CO_2 emission rates that are to be compared to the proposed target emission rate for each state:

$$\frac{\text{Relevant Fossil Fuel Emissions (lbs of } CO_2\text{)}}{\begin{array}{c}\text{Relevant MWh}\\ \text{(Relevant Fossil Fuel Generation } + \text{ Renewable Generation } + \text{ Nuclear Generation } + \text{ Energy Efficency)}\end{array}}$$

This section discusses the formula's numerator (relevant CO_2 emissions) and denominator (relevant MWh) and illustrates the impact of the EPA Building Block assumptions on the CO_2 rate calculation.

1. Numerator: Relevant CO_2 Emissions

The numerator in the CO_2 emission rate formula is CO_2 emissions from relevant sources. These include existing coal units (this includes the under-construction IGCC unit with carbon capture in Mississippi), existing NGCC units, and certain combustion turbine or steam units consuming oil or natural gas. CO_2 emissions from combined heat and power (CHP) units that produce "useful thermal output" according to EPA terminology also count in the numerator.

Note that the numerator does not include CO_2 emissions from future NGCC additions. Nor does it include emissions from "peaker" units smaller than 73 MW with annual production less than 219,000 MWh (EPA 2014a, p. 34954).

2. Denominator: Relevant Megawatt-hours

The denominator in the CO_2 emission rate formula is relevant MWh. This includes generation from the fossil units listed above (and does not include generation from future NGCC additions or "peaker" units). It also includes generation from renewables (except existing hydro), new nuclear units (*i.e.*, nuclear units currently under construction as well as future nuclear

additions)[13], and "at-risk" nuclear units (*i.e.*, the 5.8% of existing nationwide nuclear capacity that are at-risk for shut down for financial reasons under baseline conditions according to EPA and EIA analysis).

In addition, the denominator includes avoided MWh from increased end-use energy efficiency based on the actual levels of incremental energy efficiency. The use of additional energy efficiency as a compliance measure raises several important impact estimation issues, however, as discussed in Appendix C.

3. Summary of CO_2 Emission Rate Impacts of EPA Building Blocks

Figure 1 illustrates the hypothetical impact of each EPA Building Block on CO_2 emission rates (calculated using the formula above) based on analysis of state information in EPA (2014b, p. 25) and EPA (2014c). In particular, state information has been weighted by relevant MWh in 2012 in each state to develop U.S. averages. The starting U.S. average emission rate of 1,474 lbs/MWh is based upon EPA's application of 2012 historical generation and emissions information; the different components of the CO_2 rate formula are then modified from the 2012 values to reflect EPA assumptions about the Building Block measures. According to EPA, full implementation of all four Building Blocks would reduce the U.S. CO_2 emission rate (again calculated using the formula above) to 1,016 lbs/MWh by 2030. As discussed below, some of the assumptions behind these calculations are not correct.

EPA information indicates that full implementation of the Building Blocks would have the following impacts on U.S. average CO_2 rates:

1. Building Block 1—heat rate improvements at coal units—would reduce the U.S. CO_2 emission rate by 67 lbs/MWh (assuming no retirements or reduced utilization of coal units). Note that if any coal units were to retire as a result of the Building Block 1 contribution to emission rate targets, this would result in more emission reductions than would be achieved if those units were to achieve a 6% heat rate reduction and continue operating. In addition, the potential for emission rate reductions due to coal heat rate improvements is diminished by the other Building Blocks, which tend to reduce coal generation.

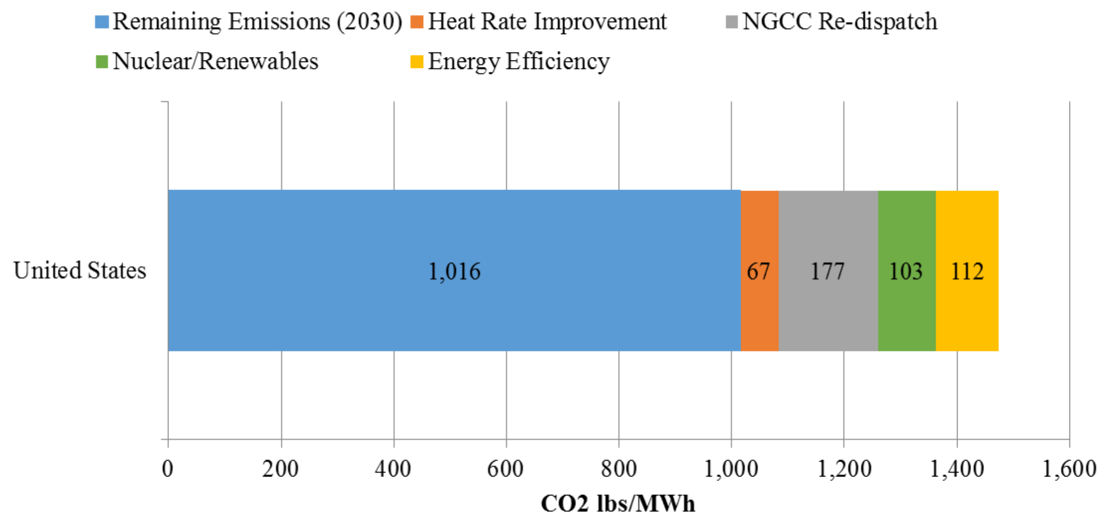
2. Building Block 2—increased utilization of existing NGCC units—would reduce the U.S. CO_2 emission rate by 177 lbs/MWh. This calculation is based upon EPA's assumptions regarding the capacity of NGCC units and their emission rates; as discussed below, these assumptions overstate the likely reductions in CO_2 rates.

[13] We interpret the CPP proposal as including generation from new nuclear units in the denominator for purposes of compliance.

3. Building Block 3—increases in renewables and nuclear energy—would reduce the U.S. CO_2 emission rate by 103 lbs/MWh.

4. Building Block 4—increases in end-use energy efficiency—would reduce the U.S. CO_2 emission rate by 112 lbs/MWh. This calculation assumes that these energy efficiency programs would not be developed in the baseline even if baseline market conditions would mean that the energy efficiency was cost-effective. The implications of this assumption for impact estimates are discussed in Appendix C.

Figure 1: Calculation of U.S. 2030 CO_2 Emission Rate Target from 2012 Rate and Building Blocks

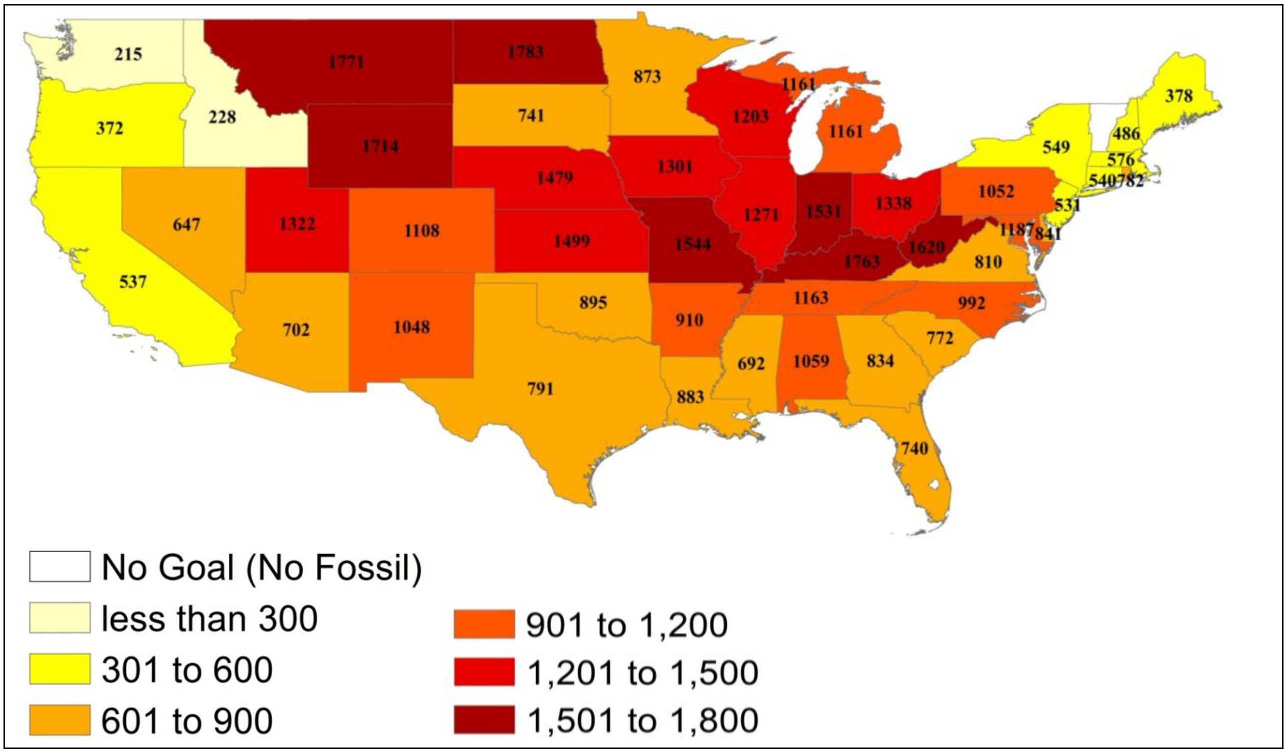


Source: NERA calculations as explained in text.

C. State CO_2 Emission Rate Targets

Figure 2 shows each state's final CO_2 emission rate target for 2030 under EPA's preferred regulatory approach ("Option 1") in lbs/MWh. These final state targets that apply for 2030 and thereafter—as well as the interim targets before 2030—are inputs to the modeling scenarios for this evaluation, as described in the following chapter.

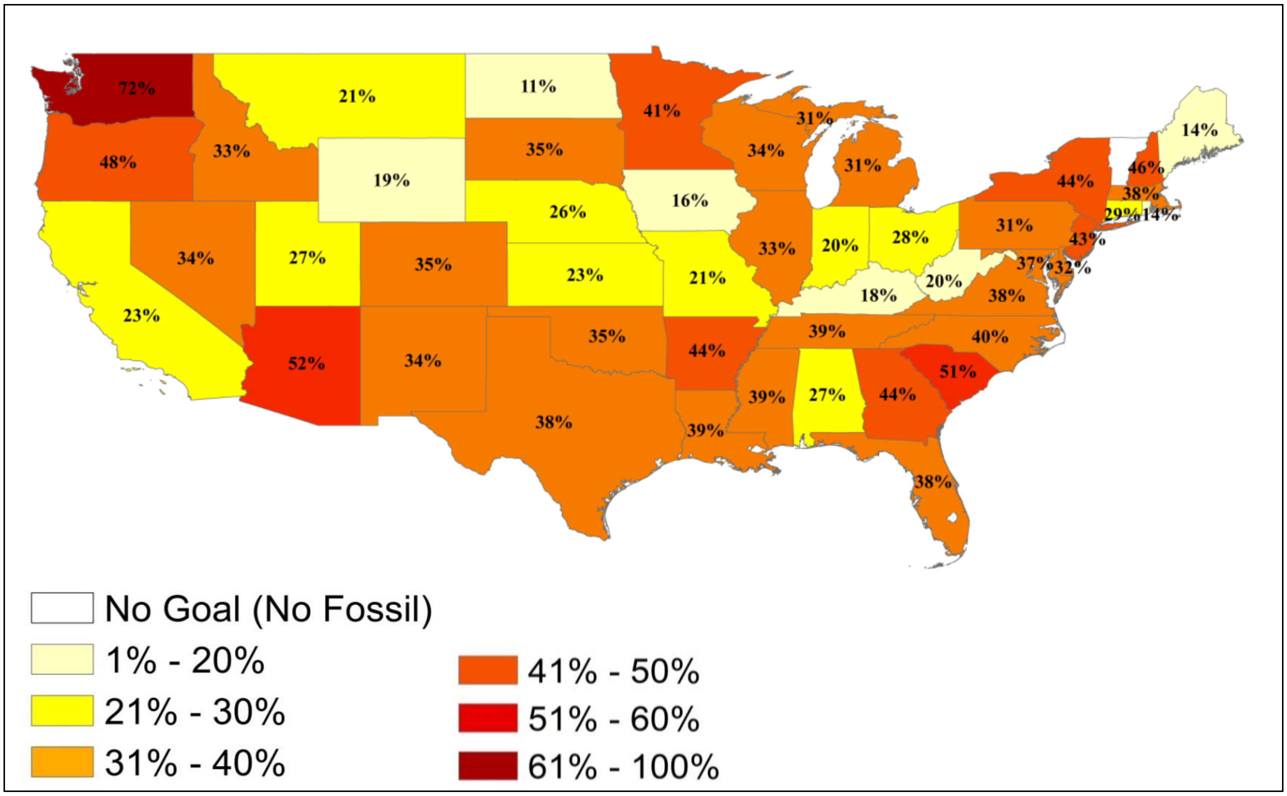
Figure 2: 2030 CO_2 Emission Rate Targets for EPA Option 1 (lbs/MWh)



Source: NERA calculations as explained in text.

Figure 3 shows each state's reduction in CO_2 emission rate by 2030 as a percentage relative to each state's CO_2 emission rate in 2012 based on EPA's emission rate formula and calculations.

Figure 3: CO_2 Emission Rate Reduction for 2030 Target Relative to 2012 Rate



Source: NERA calculations as explained in text.

III. MODELING METHODOLOGY AND STATE COMPLIANCE SCENARIOS

This chapter describes the modeling methodology and scenarios. The first two sections describe the integrated energy-and-economy model used in this evaluation (N_{ew}ERA) and the specific modeling assumptions. The third section describes the compliance scenarios evaluated in this study.

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 unit-level details that affect costs of compliance options. 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 2014 through 2038 with modeling inputs and results for every third year in that period. The model outputs include the following information.

- *Unit-level dispatch decisions in the electric sector* – changes in unit dispatch in response to different operating constraints (*e.g.*, emission rate limits).
- *Unit-level investments in the electric sector* – retrofits in response to environmental policies, new builds (full range of new generation technologies represented), and retirements based on economics.
- *Energy prices* – wholesale electricity prices for each of 34 U.S. regions, capacity prices for each U.S. region, delivered electricity prices by sector, 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), emissions prices for all regional and national programs with tradable credits, and prices for the EPA state/regional rate limits.

Appendix A provides additional information on the N_{ew}ERA modeling system.

B. Modeling and Input Assumptions

For this study, N_{ew}ERA's baseline conditions were calibrated to reflect projections developed by Federal government agencies, notably the Energy Information Administration (EIA) as defined in its *Annual Energy Outlook 2014* (*AEO 2014*) Reference case. This baseline includes the effects of environmental regulations that have already been promulgated (e.g., Mercury and Air Toxics Standards) as well as other factors that lead to changes over time in the U.S. economy and the various sectors. Key assumptions drawn from *AEO 2014* include natural gas prices, regional electricity demand, capital costs for new electric generators, GDP growth, and non-

electric sector fuel use and emissions. The baseline includes two major existing programs to reduce CO_2 emissions, the Regional Greenhouse Gas Initiative (RGGI) and the California cap-and-trade program.

The following sections provide information on other important assumptions used in the analysis.

1. Energy Efficiency Availability and Cost

For purposes of this analysis, we assumed that the quantities of end-use energy efficiency that EPA assumed in its analyses of the CPP were available to each state. We assumed the same rate of growth by state, the same quantities of annual incremental energy efficiency, and the same decay rate as EPA used.

For the costs of energy efficiency, we started with a base of EPA's energy efficiency costs, but scaled them up based on the ratio of the levelized costs of energy efficiency derived from Allcott & Greenstone (2012) to that for EPA. Allcott & Greenstone (2012) reviewed the literature and recommended a levelized utility cost of end-use energy efficiency of 5.3¢/kWh (2011$) estimated by Arimura et al (2011). Assuming equal utility and participant costs of end-use energy efficiency (as in EPA's analysis), this implies a total levelized cost per kWh of 10.6¢ (2011$) compared to EPA's levelized rate of 6.51¢ (EPA 2014b, p. 5-56). We applied this ratio of 1.63 to EPA's total cost of initial energy efficiency to obtain an upfront cost of $896/MWh.

The costs of energy efficiency programs will depend crucially on the *trajectory* of expected increases in the costs of state energy efficiency programs as increasingly ambitious standards are developed. Assessing this trajectory is complicated because of the potential diversity of the underlying energy efficiency programs (*e.g.*, residential versus commercial, light bulb replacement versus equipment retrofit), differences in the empirical techniques to assess such costs (engineering, statistical, modeling), and differences among states. We are not aware of any study that has provided a literature review on this topic equivalent to the review by Allcott & Greenstone of the historical cost information. Thus, in the absence of other information, we applied the same trajectory as used by EPA to the values for more ambitious targets. This results in energy efficiency costs of $896/MWh for states adding less than 0.5%, $1,075/MWh for states adding between 0.5% and 1.0%, and $1,254/MWh for states adding more than 1.0% incremental energy efficiency. As discussed in Appendix C, these cost assumptions, combined with the assumption that electric customers do not adopt cost-effective energy efficiency in the absence of state government programs under the proposed CPP, have important influences on the results.

2. Coal Efficiency Retrofit

In its calculations of state targets, EPA assumed that all coal units could achieve a 6% improvement in their efficiency (*i.e.*, reduction in heat rate), and in its cost modeling EPA also assumed this 6% improvement could be achieved at a capital cost of $100/kilowatt (kW). We understand that various industry experts have concluded that these assumptions are unrealistic in

light of practical engineering considerations, actual industry experience, and the incentives owners of electricity generators already have to improve plant efficiency. Our clients suggested an alternative set of assumptions, in particular, (a) for a cost of $100/kW, a maximum efficiency improvement of 1.5% would be achievable for the most inefficient existing units and a 0.75% improvement would be available for units with average efficiency, and (b) no efficiency improvements would be available to the most efficient units.[14]

We investigated the significance to our incremental energy cost estimates of these alternative sets of assumptions regarding potential heat rate improvements and found that this set of assumptions did not have a major effect on the results; using EPA's heat rate assumption rather than the alternative set resulted in less than a 1% change in our estimate of the overall energy system cost of the CPP in the unconstrained scenario. Thus, although we are not indicating that we attempted to determine the most realistic set of assumptions, we adopted the alternative industry set of assumptions regarding potential heat rate improvements. We note that while this set of assumptions has *de minimis* impact on our estimates of the impacts of the proposed CPP, this issue would be much more significant if the Section 111(d) limits for legal reasons had to be based solely on systems of emissions controls that can be achieved on the existing fossil units themselves. In that legal situation, this uncertainty would warrant a more thorough treatment of heat rate improvement assumptions than we determined was necessary for our present analysis.

3. Modeling Years

We model impacts for three-year periods beginning with 2014. We present results for 2017, 2020, 2023, 2026, and 2029 (the years from the beginning of CPP implementation through full implementation). Each model year represents an average of three years, the stated year and the next two years; for example, 2017 represents the average of 2017 through 2019. Average annual impacts and present values of impacts are based on results from 2017 through 2031.

C. Compliance Scenarios

We develop impact estimates under two state compliance scenarios, both of which presume least-cost compliance by each state.[15] The first scenario assumes that states are able to use all four Building Blocks options in their least-cost mix to demonstrate compliance with their targets

[14] In our modeling of a unit's decision whether to undertake an efficiency retrofit, we also assumed that the unit would be subject to New Source Review (NSR). That is, if a unit adopts an energy efficiency retrofit, we assume that it will also have to meet the NSR requirements, including the requirement to meet Best Available Control Technology (BACT) requirements for other regulated pollutants. If a unit does not already have these control levels, then it would have to add the missing BACT controls along with the energy efficiency improvement investment.

[15] Appendix B to this report provides results for a scenario that assumes states can meet the target rates on a regional (rather than state-by-state) basis. Both the state-by-state and regional results assume CPP targets are based upon the EPA compliance formula (which excludes some CO_2 emission sources) and that CPP interim targets would need to be met each year rather than on average over the 2020 through 2029 period as allowed for in the CPP proposal.

under the CPP. Legal analysts have questioned whether EPA has the statutory authority to require states to extend regulation under Section 111(d) to account for emissions other than those from the specific existing electricity generation units in the listed source category. This concern calls into question whether the use of Building Blocks that require these other actions—increased utilization of natural gas combined cycle units (Building Block 2), renewables and nuclear energy (Building Block 3), and end-use energy efficiency (Building Block 4)—could be included for demonstrating compliance even though the proposed state targets have been computed on the assumption they would be allowed.[16]

In addition, some states may not be able to impose measures that would be needed to implement Building Blocks 3 and 4 (such as renewable portfolio standards and energy efficiency resource standards) without legislation. Also, it is the opinion of some legal analysts that EPA could not enforce Building Blocks 3 and 4 if the Agency imposed a Federal Implementation Plan on states.[17]

For all these reasons, we developed a second scenario that addresses the impact of potential legal and other constraints on state and federal plans by assuming that states can only use Building Blocks 1 and 2 to show compliance with the CPP targets proposed by EPA.[18] The following are summaries of these two state compliance scenarios.

1. *State Unconstrained (BB1-4)*. Each state complies with its target, with all four Building Blocks available as compliance options.

2. *State Constrained (BB1-2)*. Each state complies with its target; this scenario presumes that neither end-use energy efficiency (Building Block 4) nor renewables and additional nuclear energy (Building Block 3) would be available as compliance options.

We use N_{ew}ERA to estimate the energy system impacts and energy system costs of these two scenarios, both of which assume that the same state CO_2 emission rate targets would apply. Under the State Constrained (BB1-2) scenario, states would have to rely more heavily on the permissible compliance measures (such as retirement of fossil units) because end-use energy efficiency and additional renewables and nuclear energy are not available as compliance options.

[16] EPA requests comment on a separate set of target calculations based upon only Building Blocks 1 and 2 (EPA 2014a, p. 34878); however, the targets actually proposed by EPA assume all four Building Blocks would be allowed. This analysis focuses on the proposed targets.

[17] Some legal analysts have indicated that EPA also could not enforce Building Block 2.

[18] This report does not take a position on legal and practical constraints related to the Building Blocks, including whether EPA has authority under the Clean Air Act to base Section 111(d) standards on requirements concerning how generating units are dispatched. The second scenario reflects the likelihood that if coal-fired generation is to be used less, gas-fired generation will be used more.

IV. RESULTS FOR STATE COMPLIANCE SCENARIOS

This chapter shows the potential impacts of the State Unconstrained (BB1-4) and State Constrained (BB1-2) scenarios. We discuss potential impacts on U.S. and regional energy systems, energy costs, and electricity prices.

A. Impacts on U.S. Energy System

Figure 4 summarizes the energy system impacts of the state scenarios on an annual average basis for the period from 2017 through 2031.[19] (These figures omit several factors that could add to impacts and costs.) The energy market impacts of the CPP would be substantial in the State Unconstrained (BB1-4) scenario. The annual average electricity sector CO_2 emissions would be reduced by about 22% over the period from 2017 through 2031. Coal unit retirements would increase by about 45 gigawatts (GW). Coal-fired generation would decline by about 29% on average over the period, with natural gas-fired generation increased by about 5% on average. The Henry Hub natural gas price would increase by about 2% on average. Delivered electricity prices would increase by about 12% on average over 2017 through 2031.

Figure 4: Overview of Energy System Impacts of State Compliance Scenarios (Annual Average, 2017-2031)

	Total Coal Retirements Through 2031	Coal-Fired Generation	Natural Gas-Fired Generation	Henry Hub Natural Gas Price	Delivered Electricity Price	Electricity Sector CO2 Emissions
	GW	TWh	TWh	2013$/MMBtu	2013 ¢/kWh	MM metric tons
Baseline	51	1,672	1,212	$5.25	10.8	2,080
State Unconstrained (BB1-4)	97	1,191	1,269	$5.36	12.0	1,624
Change from Baseline	+45	-481	+57	+$0.11	+1.3	-456
% Change from Baseline	+18%	-29%	+5%	+2%	+12%	-22%
State Constrained (BB1-2)	220	492	2,015	$6.78	12.6	1,255
Change from Baseline	+169	-1,180	+802	+$1.53	+1.9	-825
% Change from Baseline	+69%	-71%	+66%	+29%	+17%	-40%

Note: Coal retirements are cumulative from 2014. Percentage change in coal retirements is relative to total baseline 2031 coal capacity.

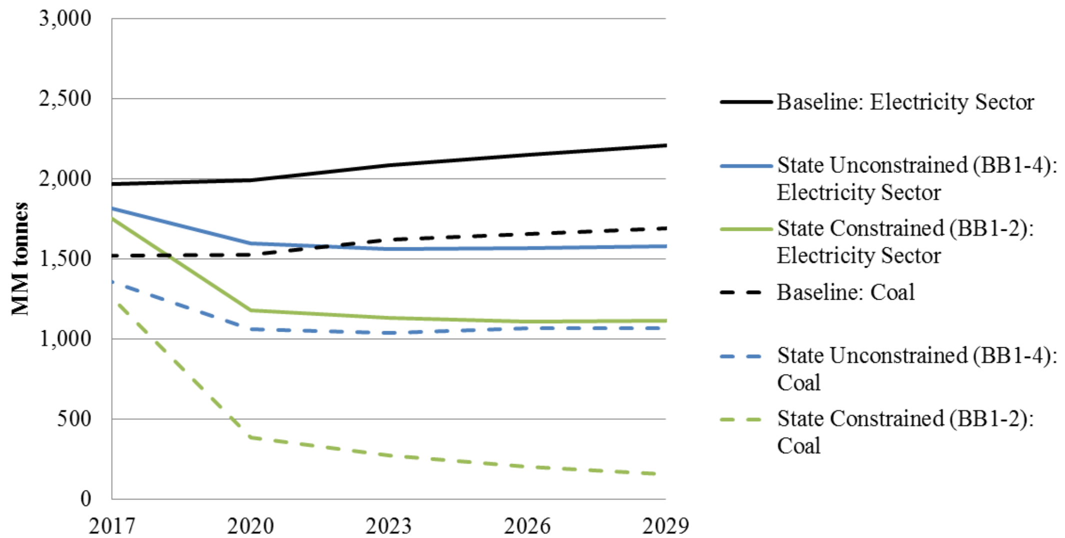
Source: NERA calculations as explained in text.

[19] Potential infrastructure costs related to natural gas pipelines, electricity transmission, and voltage support or ancillary services are not included. Low projected capacity utilization of non-retired coal units would lead to decreases in efficiency (*i.e.*, increases in heat rates), additional wear and tear costs from operating coal units in a cycling mode, and potentially additional retirements, none of which are included in our modeling. Costs related to unit ramp rate constraints, minimum load constraints, and delays in new build or retirement permitting are also not accounted for in our cost estimates.

The energy market impacts would be much greater if states had to comply with the same CPP state targets but without either end-use energy efficiency or new renewable/nuclear generation as compliance alternatives. In the State Constrained (BB1-2) scenario, reductions in average annual electricity sector CO_2 emissions over the 2017 through 2031 timeframe would be 40%, almost twice the amount under the State Unconstrained (BB1-4). Such a constrained compliance scenario would result in very large changes in the electricity system, including 169 GW of coal retirements, a 29% average increase in natural gas prices and a 17% increase in average delivered electricity prices.

Figure 5 shows the CO_2 emission impacts of the state compliance scenarios. It shows CO_2 emission impacts for the U.S. electricity sector as well as impacts for U.S. coal units in particular. These figures show the substantially greater CO_2 emission reductions under the constrained case than in the unconstrained case.

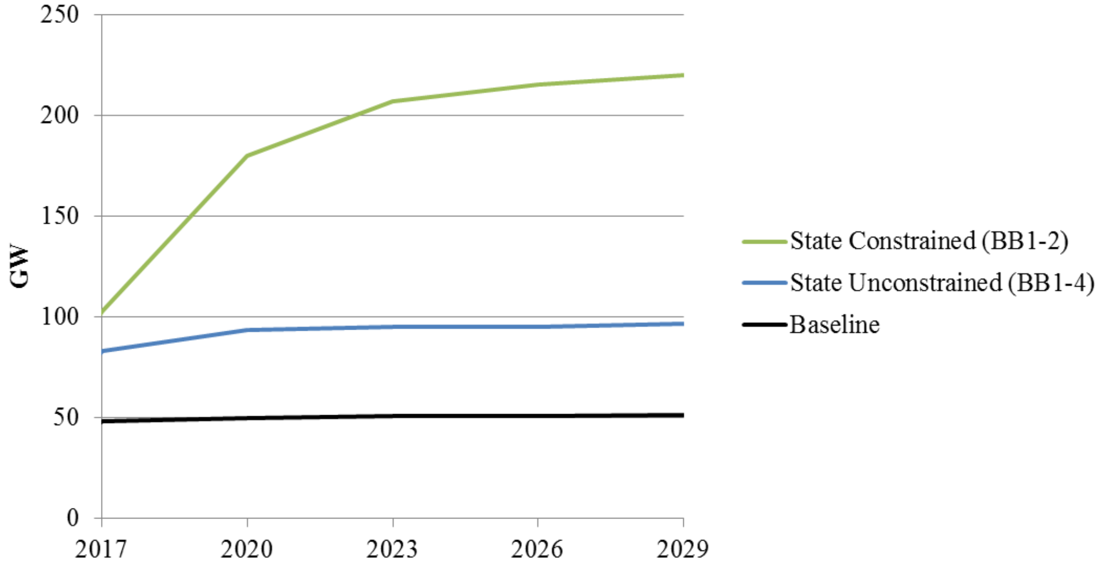
Figure 5: CO_2 Emission Impacts of State Compliance Scenarios (Million Metric Tons)



Source: NERA calculations as explained in text.

Figure 6 shows coal unit retirement impacts of the two scenarios.

Figure 6: Coal Unit Retirement Impacts of State Compliance Scenarios



Source: NERA calculations as explained in text.

Figure 7 shows the impacts of the two scenarios on electricity generation capacity by fuel type. Capacity changes reflect a shift away from coal toward generation sources with lower CO_2 emission rates (natural gas, nuclear, and renewables) in both scenarios as well as the effect of the reduction in demand due to energy efficiency programs in the unconstrained scenario.

Figure 7: Capacity Impacts of State Compliance Scenarios (GW)

	2017	2020	2023	2026	2029
Baseline	**1,019**	**1,034**	**1,053**	**1,074**	**1,095**
Coal	249	247	246	246	246
Natural Gas CC	247	251	260	272	283
Oil/Gas CT/Steam	239	244	251	259	267
Nuclear	99	103	103	103	103
Hydro	76	76	76	76	76
Non-Hydro Renewables	108	113	116	118	120
State Unconstrained (BB1-4) (Change)	**-59**	**-82**	**-98**	**-116**	**-134**
Coal	-34	-43	-43	-44	-45
Natural Gas CC	-2	-6	-15	-26	-37
Oil/Gas CT/Steam	-22	-31	-38	-46	-54
Nuclear	0	0	0	+2	+5
Hydro	0	0	0	0	0
Non-Hydro Renewables	-1	-2	-2	-2	-3
State Constrained (BB1-2) (Change)	**-65**	**-71**	**-56**	**-18**	**-3**
Coal	-54	-129	-156	-164	-168
Natural Gas CC	+9	+88	+132	+140	+156
Oil/Gas CT/Steam	-20	-29	-34	-2	-10
Nuclear	0	0	0	+2	+14
Hydro	0	0	0	0	0
Non-Hydro Renewables	-1	-1	+1	+5	+5

Source: NERA calculations as explained in text.

Figure 8 shows the generation impacts of the two scenarios, including a line for end-use energy efficiency (which is assumed to serve as an equivalent to generation to meet demand). Generation follows a similar pattern to capacity: energy efficiency reduces overall generation needs in the unconstrained scenario; the CPP CO_2 rate targets lead to fuel switching away from coal in both scenarios; and increased electricity prices have a feedback effect of reducing overall demand (beyond the effect of energy efficiency) in both scenarios. Energy efficiency is cost-effective in the State Unconstrained (BB1-4) scenario, so all of the energy efficiency assumed by EPA to be available is adopted. In our analysis (to be consistent with EPA's analysis), none of this energy efficiency is allowed to be adopted in the baseline even if it is cost-effective without a CO_2 constraint. This is an important assumption that affects the pattern of policy impacts, the implications of which are discussed in Appendix C.

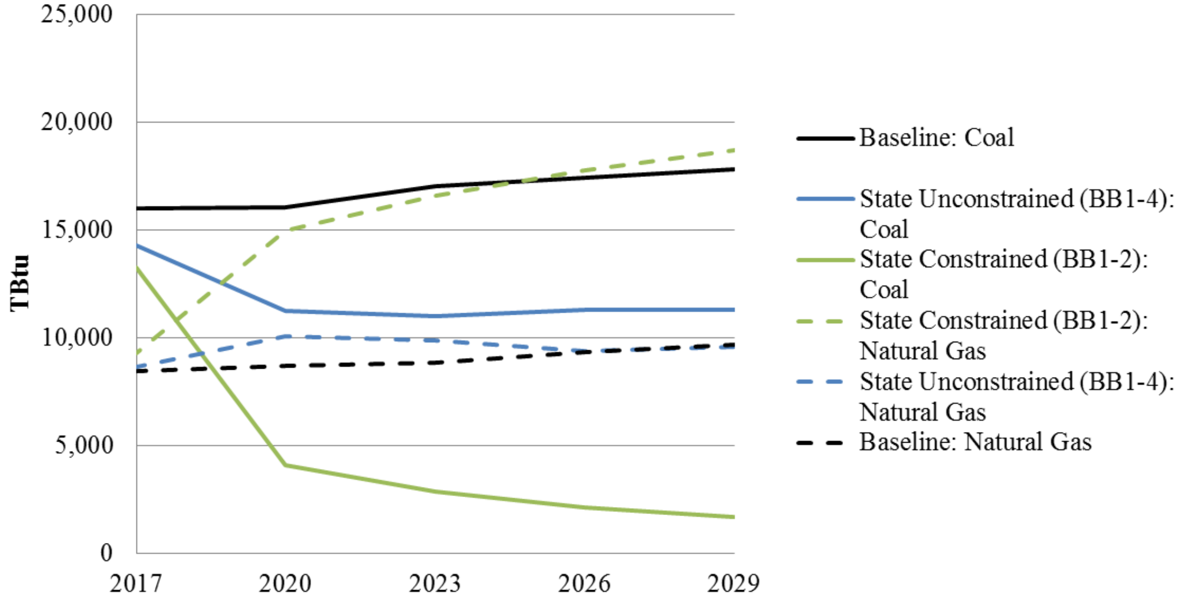
Figure 8: Generation Impacts of State Compliance Scenarios (TWh)

	2017	2020	2023	2026	2029
Baseline	**4,134**	**4,238**	**4,368**	**4,484**	**4,587**
Coal	1,587	1,593	1,688	1,726	1,767
Natural Gas CC	1,128	1,167	1,194	1,262	1,310
Oil/Gas CT/Steam	14	14	10	11	13
Nuclear	786	816	816	816	816
Hydro	253	253	253	253	253
Non-Hydro Renewables	366	395	407	414	428
Energy Efficiency	0	0	0	0	0
State Unconstrained (BB1-4) (Change)	**-113**	**-180**	**-221**	**-232**	**-199**
Coal	-157	-459	-577	-586	-627
Natural Gas CC	+28	+171	+125	-6	-32
Oil/Gas CT/Steam	-0.2	-2	-1	-2	-1
Nuclear	0	0	+0.1	+17	+37
Hydro	0	0	0	0	0
Non-Hydro Renewables	-5	-9	-11	-14	-24
Energy Efficiency	+21	+119	+243	+358	+447
State Constrained (BB1-2) (Change)	**-147**	**-351**	**-338**	**-326**	**-214**
Coal	-260	-1,166	-1,385	-1,500	-1,590
Natural Gas CC	+115	+747	+954	+1,021	+1,175
Oil/Gas CT/Steam	+2	+71	+89	+119	+75
Nuclear	0	0	+0.1	+17	+112
Hydro	0	0	0	0	0
Non-Hydro Renewables	-3	-3	+4	+17	+15
Energy Efficiency	0	0	0	0	0

Source: NERA calculations as explained in text.

Figure 9 shows the coal and electricity sector natural gas consumption impacts of the two scenarios. This graph shows the large decreases in coal consumption and the large increases in natural gas consumption in both of the state compliance scenarios, although the changes are much more pronounced in the constrained scenario.

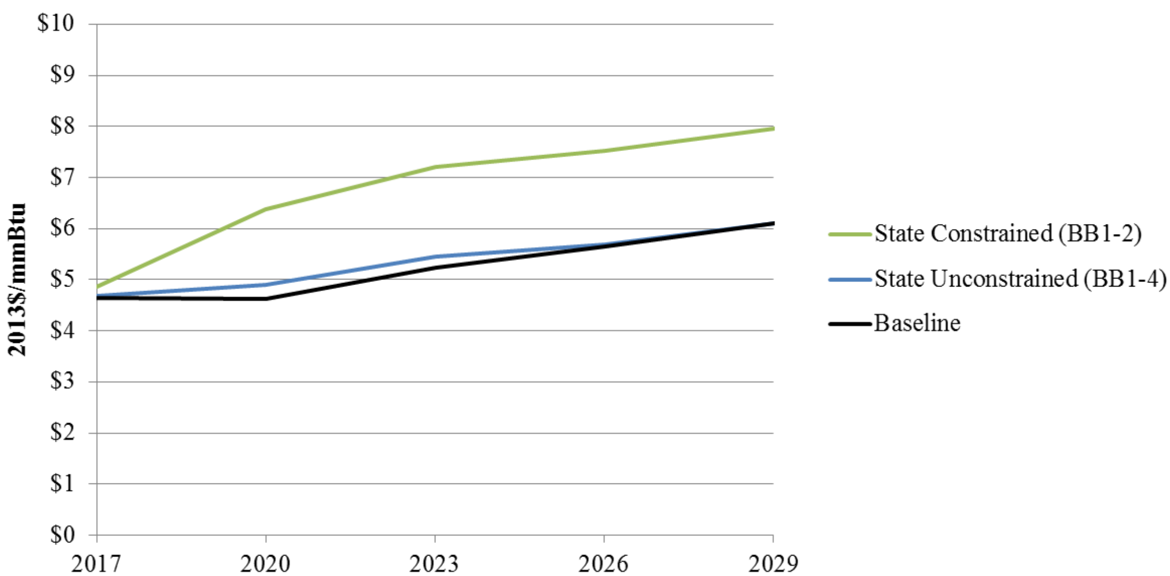
Figure 9: Coal and Natural Gas Consumption Impacts of State Compliance Scenarios



Source: NERA calculations as explained in text.

Figure 10 shows the natural gas wholesale price (Henry Hub) impacts of the two scenarios. The increases in natural gas prices are much greater in the State Constrained (BB1-2) scenario than in the State Unconstrained (BB1-4) scenario.

Figure 10: Natural Gas Wholesale Price (Henry Hub) Impacts of State Compliance Scenarios



Source: NERA calculations as explained in text.

Figure 11 shows the energy system costs of the two scenarios, both over time and expressed as present values in 2014 of spending incurred over the period from 2017 through 2031. The costs

are broken down into three categories: (1) costs to serve electricity load; (2) costs of the end-use energy efficiency programs, both to the utilities and to the participants; and (3) costs of non-electricity natural gas use. Under the State Unconstrained (BB1-4) scenario, energy system costs are dominated by the costs to the utilities and to participants of the additional state energy efficiency programs, which are estimated to cost about $560 billion (in present value) over the period from 2017 through 2031. The reduction in electricity demand over the period 2017 through 2013 results in a net decrease in production costs to meet electricity load that has a present value in 2014 of about $209 billion; this partially offsets the investment costs of the energy efficiency programs. Higher gas prices are part of the higher cost to serve load, but they also affect consumers who purchase natural gas for non-electricity energy services; the higher consumer cost for direct consumption of natural gas adds another $15 billion to the present value of the CPP over the years 2017-2031. The net result is that energy system costs would be greater by about $366 billion in present value terms over the period from 2017 through 2031 under the State Unconstrained (BB1-4) scenario.

The net cost of the State Constrained (BB1-2) scenario—excluding energy efficiency, renewables, and additional nuclear—is substantially greater than the State Unconstrained (BB1-4) scenario. There would be no costs for end-use energy efficiency (because this would not be allowed as part of demonstrating compliance), but the additional costs of providing electricity services are estimated at $335 billion. The higher natural gas prices would result in an increase in natural gas costs for non-electricity users of about $144 billion. The net result would be an increase in energy system costs by about $479 billion in present value terms over the period from 2017 through 2031.

Figure 11: Energy System Cost Impacts of State Compliance Scenarios (billion 2013 dollars)

	2017	2020	2023	2026	2029	PV (2017-2031)
State Unconstrained (BB1-4)						
Cost of Electricity, Excluding EE	-$9	-$13	-$24	-$36	-$42	-$209
Cost of Energy Efficiency	$25	$52	$71	$73	$73	$560
Cost of Non-Electricity Natural Gas	$0	$3	$3	$1	$1	$15
Total Consumer Energy Costs	$16	$42	$49	$39	$33	$366
State Constrained (BB1-2)						
Cost of Electricity, Excluding EE	-$6	$33	$46	$59	$73	$335
Cost of Energy Efficiency	$0	$0	$0	$0	$0	$0
Cost of Non-Electricity Natural Gas	$1	$19	$21	$20	$21	$144
Total Consumer Energy Costs	-$4	$51	$68	$79	$94	$479

Note: Present value is from 2017 through 2031, taken in 2014 using a 5% real discount rate.
Source: NERA calculations as explained in text.

B. Impacts on Regional Energy Systems

Figure 12 shows coal unit retirements by region for the two scenarios. (The regional aggregations shown in this figure are the EPA aggregations used for its modeling of "regional

compliance." The regional results below are from state compliance scenarios, but we also provide impact estimates by region from an actual regional compliance analysis in Appendix B.) All regions have increased coal retirements under the two state compliance scenarios. (The coal unit retirements might be greater than listed in this table because some coal units are predicted to operate at low capacity factors, a condition that may lead their owners to retire the units.) The Southeast and Central regions experience the greatest impact on coal retirements in both scenarios.

Figure 12: Coal Unit Retirement Impacts by Region Through 2031

	Baseline	State Unconstrained (BB1-4)		State Constrained (BB1-2)	
		Change	% Change	Change	% Change
U.S.	*51*	*+45*	*+18%*	*+168*	*+68%*
Northeast	2	+0.3	+16%	+2	+100%
East Central	13	+3	+9%	+30	+80%
Southeast	13	+14	+24%	+43	+73%
North Central	11	+11	+14%	+36	+47%
South Central	6	+11	+24%	+42	+94%
West	5	+5	+20%	+15	+58%
AK & HI	0	+0.01	+4%	+0.2	+99%

Note: Coal retirements are cumulative from 2014. Percentage change in coal retirements is relative to total baseline 2031 coal capacity.
Source: NERA calculations as explained in text.

Figure 13 shows the impacts of the two scenarios on NGCC generation by region. Impacts vary significantly by region. Southeast, North Central, and South Central regions (which saw the greatest increase in coal retirements) have increased NGCC generation, while other regions have reductions in the State Unconstrained (BB1-4) scenario. The State Constrained (BB1-2) scenario relies more heavily on fuel switching for compliance, so only the Northeast region reduces its NGCC generation. Generation impacts are the net effect of fuel switching, reductions in total generation needs due to end-use energy efficiency adoption, and reduced demand due to feedback from rising electricity prices.

Figure 13: Natural Gas Combined Cycle Generation Impacts by Region of State Scenarios (Annual Average, 2017-2031, TWh)

	Baseline	State Unconstrained (BB1-4)		State Constrained (BB1-2)	
		Change	% Change	Change	% Change
U.S.	*1,212*	*+57*	*+5%*	*+802*	*+66%*
Northeast	85	-21	-25%	-20	-24%
East Central	260	-43	-17%	+138	+53%
Southeast	327	+24	+7%	+218	+67%
North Central	50	+29	+58%	+245	+489%
South Central	224	+94	+42%	+141	+63%
West	258	-24	-9%	+79	+31%
AK & HI	8	-1	-14%	+1	+15%

Source: NERA calculations as explained in text.

Figure 14 shows the NGCC unit fuel consumption impacts of the two scenarios by region. Natural gas consumption follows the same regional pattern as NGCC generation, discussed above.

Figure 14: Natural Gas Combined Cycle Fuel Consumption Impacts by Region of State Scenarios (Annual Average, 2017-2031, TBtu)

	Baseline	State Unconstrained (BB1-4)		State Constrained (BB1-2)	
		Change	% Change	Change	% Change
U.S.	*8,893*	*+524*	*+6%*	*+5,719*	*+64%*
Northeast	630	-158	-25%	-172	-27%
East Central	1,912	-306	-16%	+967	+51%
Southeast	2,374	+206	+9%	+1,533	+65%
North Central	368	+231	+63%	+1,793	+487%
South Central	1,667	+737	+44%	+1,059	+64%
West	1,877	-178	-9%	+531	+28%
AK & HI	65	-8	-12%	+8	+12%

Source: NERA calculations as explained in text.

C. Impacts on Electricity Prices

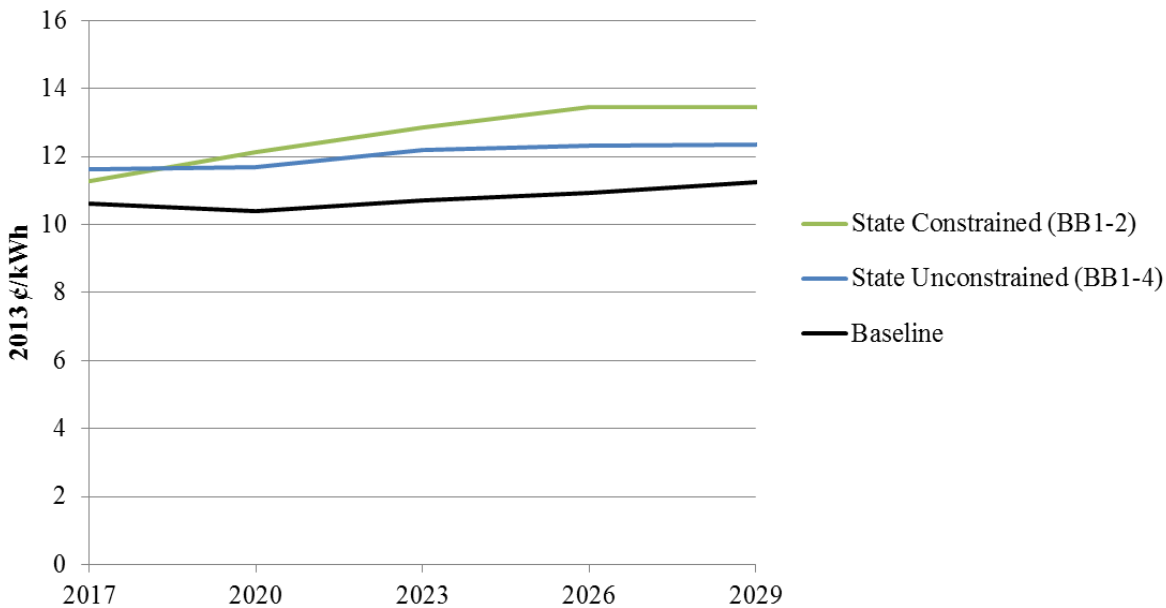
Delivered electricity prices are affected by various aspects of the CPP. One element is the upfront utility cost of end-use energy efficiency, which is assumed to be one-half of the total program cost of energy efficiency. The utility cost is treated as a utility expense and is reflected in prices in the same year in which it is incurred. The consumer's half of the energy efficiency cost is *not* reflected in delivered prices.

Energy efficiency programs tend to increase delivered prices for two reasons. First, as noted, the upfront utility costs of energy efficiency programs are recovered through delivered prices on remaining generation in the year they are incurred. Second, fixed transmission and distribution

costs are spread over fewer electricity sales (because energy efficiency reduces end-use electricity sales). These increases can be offset somewhat by decreases in wholesale and capacity prices due to reduced electricity demand.

Figure 15 shows the delivered electricity price impacts (averaged over all sectors) for the two scenarios. Delivered electricity price impacts are greater under the State Constrained (BB1-2) scenario than under the State Unconstrained (BB1-4) scenario.

Figure 15: All Sectors Delivered Electricity Price Impacts of State Scenarios



Source: NERA calculations as explained in text.

Figure 16 shows the average (2017 through 2031) delivered electricity price impacts by ratepayer class (residential, commercial, industrial, and averaged over all sectors) for the two scenarios. Total energy efficiency use and utility program costs are allocated to ratepayer classes based on state-specific sector shares of incremental energy efficiency use in EIA 2012 Form 861 data. Industrial energy efficiency use is lower than residential and commercial energy efficiency use in the 2012 data, so industrial prices in the State Unconstrained (BB1-4) scenario reflect lower energy efficiency costs (and lower avoided generation) than the other sectors. In the State Constrained (BB1-2) scenario, which does not allow end-use energy efficiency, delivered price impacts are primarily due to costs and market changes that are common to all ratepayer classes. This leads to similar cent per kWh impacts for all three sectors, but greater percentage impacts for the industrial sector (which has lower baseline price levels than the other two sectors).

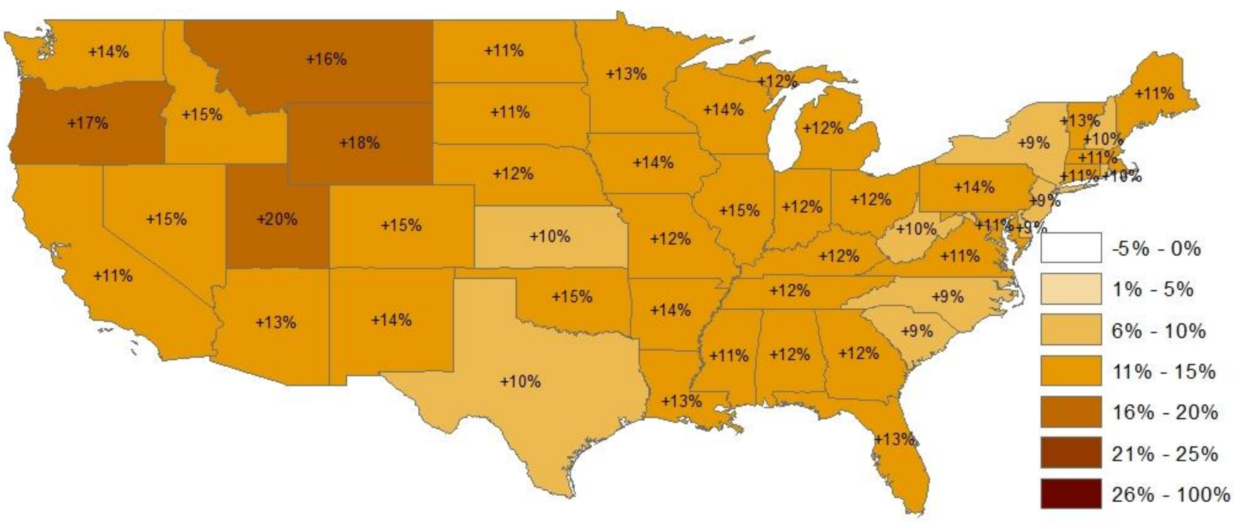
Figure 16: Ratepayer Class Delivered Electricity Price Impacts of State Scenarios (Annual Average, 2017-2031, 2013 cents per kWh)

	Residential	Commercial	Industrial	All Sectors
Baseline	12.7 ¢	11.0 ¢	7.8 ¢	10.8 ¢
State Unconstrained (BB1-4)	14.3 ¢	12.6 ¢	8.3 ¢	12.0 ¢
Change from Baseline	+1.7 ¢	+1.5 ¢	+0.5 ¢	+1.3 ¢
% Change from Baseline	+13%	+14%	+6%	+12%
State Constrained (BB1-2)	14.6 ¢	12.9 ¢	9.5 ¢	12.6 ¢
Change from Baseline	+2.0 ¢	+1.9 ¢	+1.7 ¢	+1.9 ¢
% Change from Baseline	+15%	+17%	+22%	+17%

Source: NERA calculations as explained in text.

Figure 17 shows changes in annual average (2017 through 2031) delivered electricity prices (averaged over all sectors) for the State Unconstrained (BB1-4) scenario by state. The lowest state price impacts are in the East Central and Northeast parts of the country, and the highest price increases are in the Northwest.

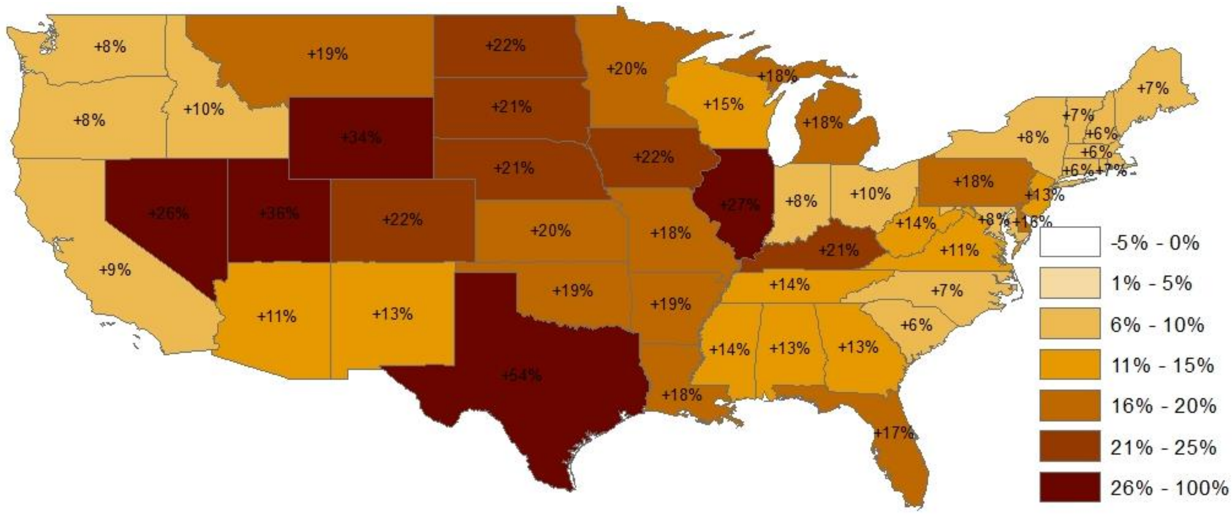
Figure 17: State All Sectors Delivered Electricity Price Impacts of State Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031)



Source: NERA calculations as explained in text.

Figure 18 shows changes in annual average (2017 through 2031) delivered electricity prices (averaged over all sectors) for the State Constrained (BB1-2) scenario by state.

Figure 18: State All Sectors Delivered Electricity Price Impacts of State Constrained (BB1-2) Scenario (Annual Average, 2017-2031)



Source: NERA calculations as explained in text.

Figure 19 shows changes in average (2017 through 2031) electricity-related consumer costs by ratepayer class (residential, commercial, industrial, and averaged over all sectors) for the two scenarios. These costs are composed of electricity bills and the consumer cost of energy efficiency. The electricity bills component is calculated from delivered electricity prices and electricity sales and includes the utility program cost of any end-use energy efficiency (passed on to end users through higher electricity rates). Bills reflect both higher prices on electricity and, in the State Unconstrained (BB1-4) scenario, lower electricity demand due to energy efficiency reducing generation needs. When the consumer share of energy efficiency costs is included, total electricity-related costs in the State Unconstrained (BB1-4) increase by an average of $34 billion per year from 2017 through 2031 across all sectors. Residential and commercial consumers have much larger increases in costs than industrial consumers in this scenario primarily due to lower energy efficiency use in the industrial sector than the other two sectors. In the State Constrained (BB1-2) scenario, which does not include any incremental end-use energy efficiency, consumer electricity costs increase an average of $48 billion per year.

Figure 19: Consumer Electricity-Related Cost Impacts of State Scenarios (Annual Average, 2017-2031, billion 2013 dollars)

	Residential	Commercial	Industrial	All Sectors
Baseline	$192	$161	$85	$439
State Unconstrained (BB1-4)				
Electricity Bills	$195	$164	$84	$443
Consumer Energy Efficiency Costs	$13	$13	$4	$29
Total Consumer Electricity-Related Costs	$207	$177	$88	$472
Change from Baseline	+$15	+$15	+$3	+$34
% Change from Baseline	+8%	+9%	+3%	+8%
State Constrained (BB1-2)				
Electricity Bills	$210	$179	$98	$487
Consumer Energy Efficiency Costs	$0	$0	$0	$0
Total Consumer Electricity-Related Costs	$210	$179	$98	$487
Change from Baseline	+$18	+$18	+$13	+$48
% Change from Baseline	+9%	+11%	+15%	+11%

Source: NERA calculations as explained in text.

V. REFERENCES

Allcott, Hunt and Michael Greenstone. 2012. "Is There an Energy Efficiency Gap?" *Journal of Economic Perspectives*, 26(1): 3-28. http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.26.1.3.

U.S. Energy Information Administration ("EIA"). 2014. Annual Energy Outlook 2014. U.S. EIA. Washington, DC. April.

U.S. Environmental Protection Agency ("EPA"). 2014a. "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule." 79 *Federal Register* 34830-34958. June 18. http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf.

U.S. Environmental Protection Agency ("EPA"). 2014b. *GHG Abatement Measures*. June 10. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

U.S. Environmental Protection Agency ("EPA"). 2014c. Goal Computation Data File. http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-state-goal-data-computation_1.xlsx.

APPENDIX A: THE N$_{EW}$ERA MODEL

A. Introduction

NERA developed the N$_{ew}$ERA model to project the impact of policy, regulatory, and economic factors on the energy sectors and the economy. When evaluating policies that have significant impacts on the entire economy, this model specification captures the effects as they ripple through all sectors of the economy and the associated feedback effects. The N$_{ew}$ERA model combines a macroeconomic model with all sectors of the economy with a detailed electric sector model that represents electricity production. This combination allows for a complete understanding of the economic impacts of different policies on all sectors of the economy.

The macroeconomic model incorporates all production sectors except electricity. Policy consequences are transmitted throughout the economy as sectors respond until the economy reaches equilibrium. The production and consumption functions employed in the model enable gradual substitution of inputs in response to relative price changes, thus avoiding all-or-nothing solutions.

The main benefit of the integrated framework is that the electric sector can be modeled in great detail yet through integration the model captures the interactions and feedbacks between all sectors of the economy. Electric technologies can be well represented according to engineering specifications. The integrated modeling approach also provides consistent price responses since all sectors of the economy are modeled. In addition, under this framework we are able to model electricity demand response.

The electric sector model is a detailed model of the electric and coal sectors. Each of the more than 17,000 electric generating units in the United States is represented in the model. The model minimizes costs while meeting all specified constraints, such as demand, peak demand, emissions limits, and transmission limits. The model determines optimal investments to undertake and units to dispatch. Because the N$_{ew}$ERA model is an integrated model of the entire U.S. economy, electricity demand can respond to changes in prices and supplies. The N$_{ew}$ERA model represents the domestic and international crude oil and refined petroleum markets.

The N$_{ew}$ERA 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, and changes in “job equivalents” based on labor wage income, as discussed below in the section on macroeconomic modeling.

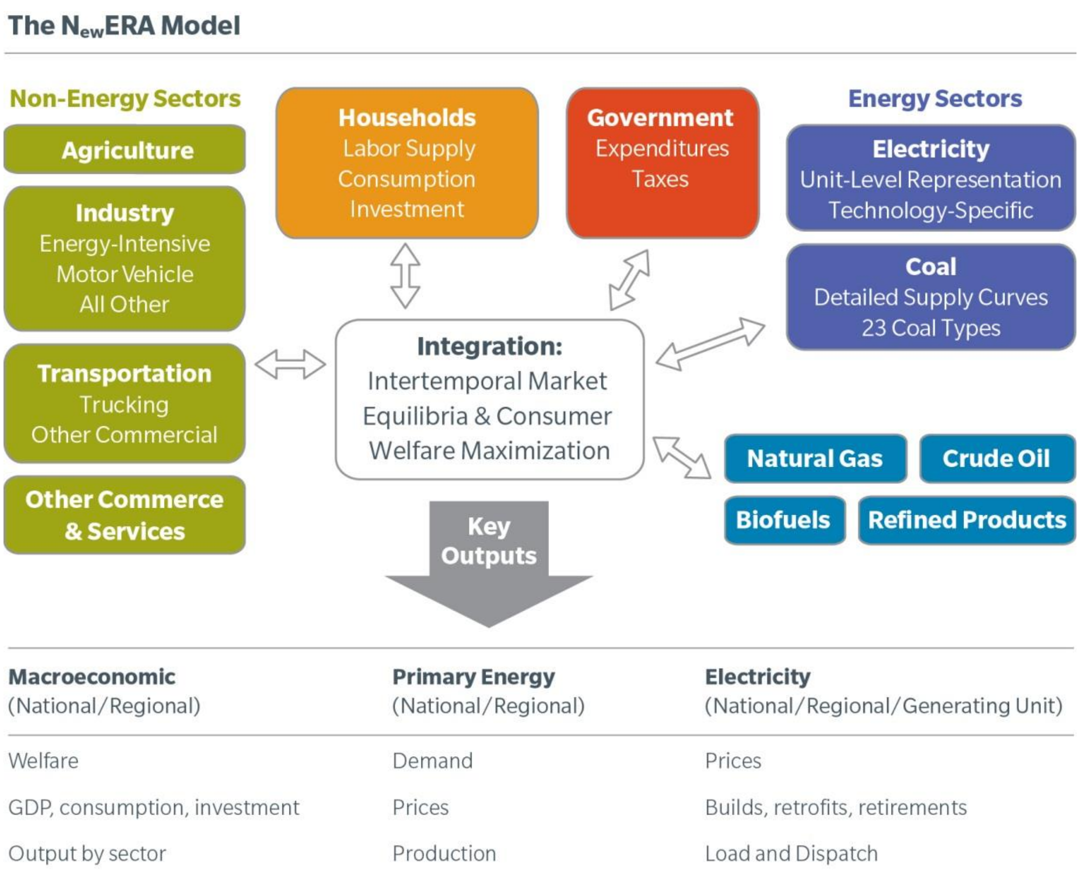
B. Overview

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 unit-level details that affect costs of

compliance. N$_{ew}$ERA integrates the electricity sector model with a macroeconomic model that includes all other sectors of the economy (except for the electricity production) using a top-down representation. The model produces integrated forecasts for future years; the modeling for this study was for the period from 2014 through 2038 with modeling inputs and results for every third year in this period.

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



C. 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. Consistent with the macroeconomic model, the electric sector 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 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.

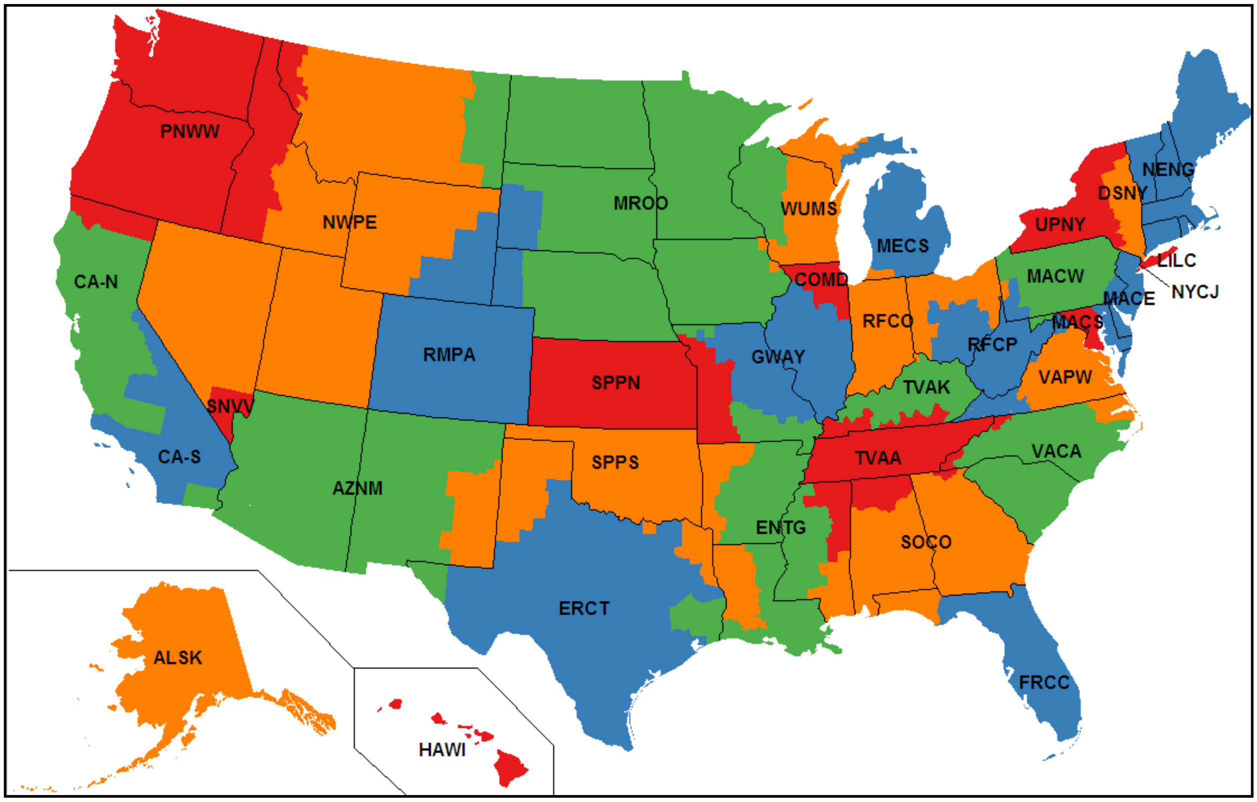
Just as with investment decisions, the operation of each unit in a given year depends on the policies in place (*e.g.*, unit-level standards), electricity demand, and operating costs, especially energy prices. The model accounts for all these conditions in deciding when and how much to operate each unit. 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 34 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. When used in an integrated manner with the macroeconomic model, and to analyze long-term effects, the model has the same time steps as in the macroeconomic model (2014 through 2038, modeling every third year).

D. 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.

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

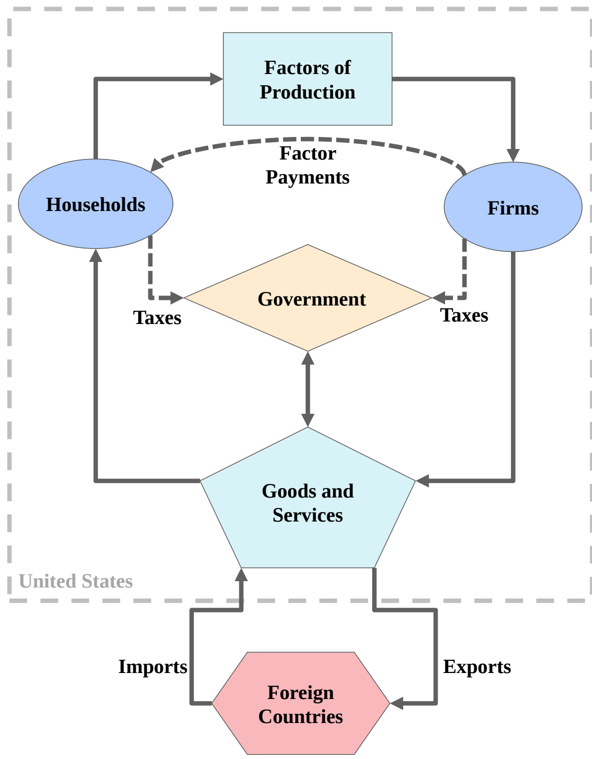
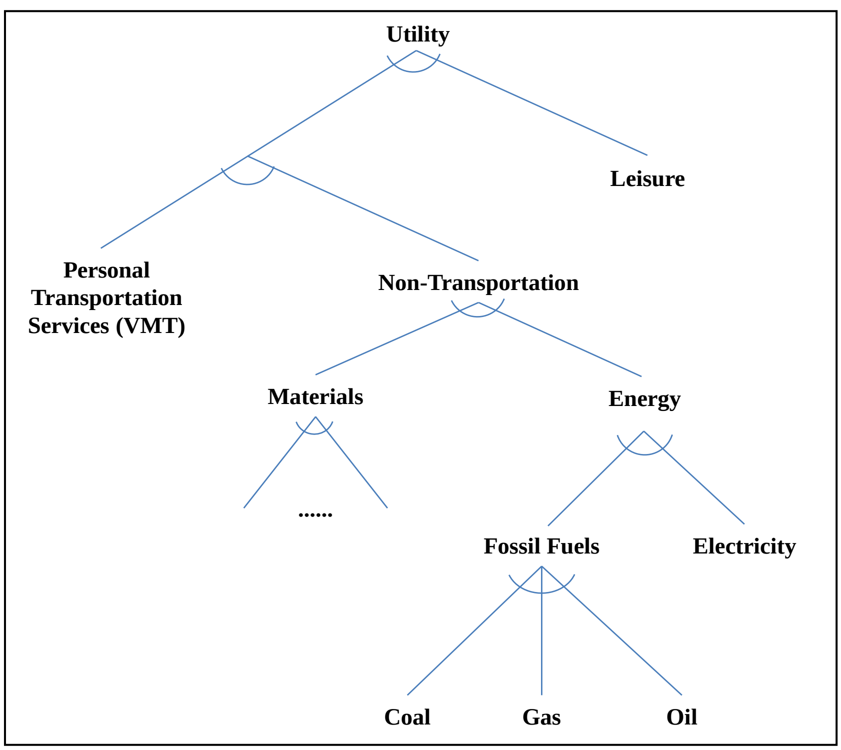


Figure A-4: Household Consumption Structure in N_{ew}ERA's Macroeconomic Model



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 (*i.e.*, materials) 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

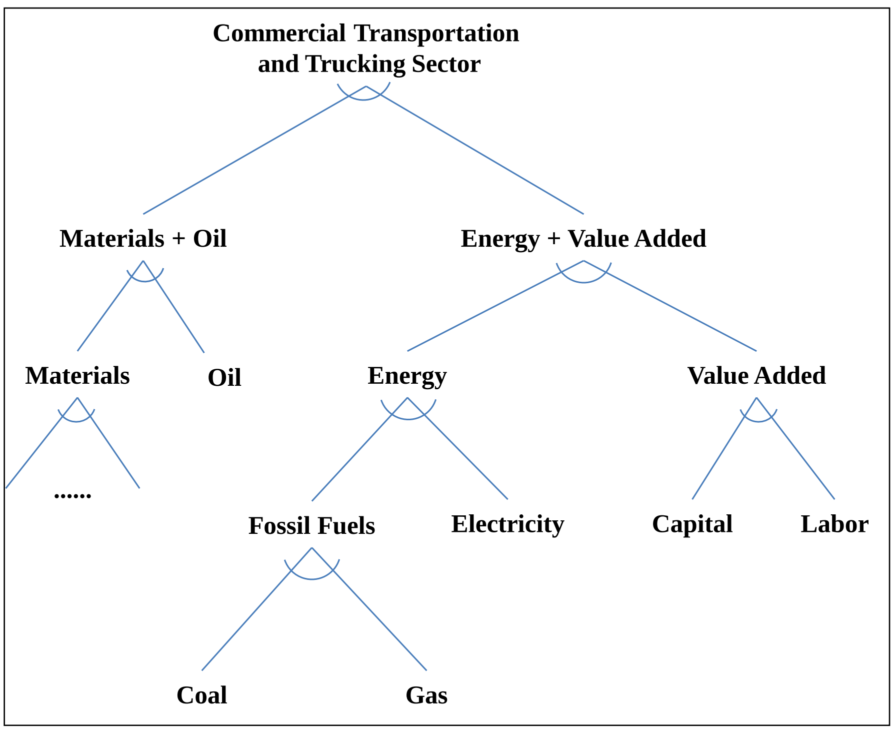
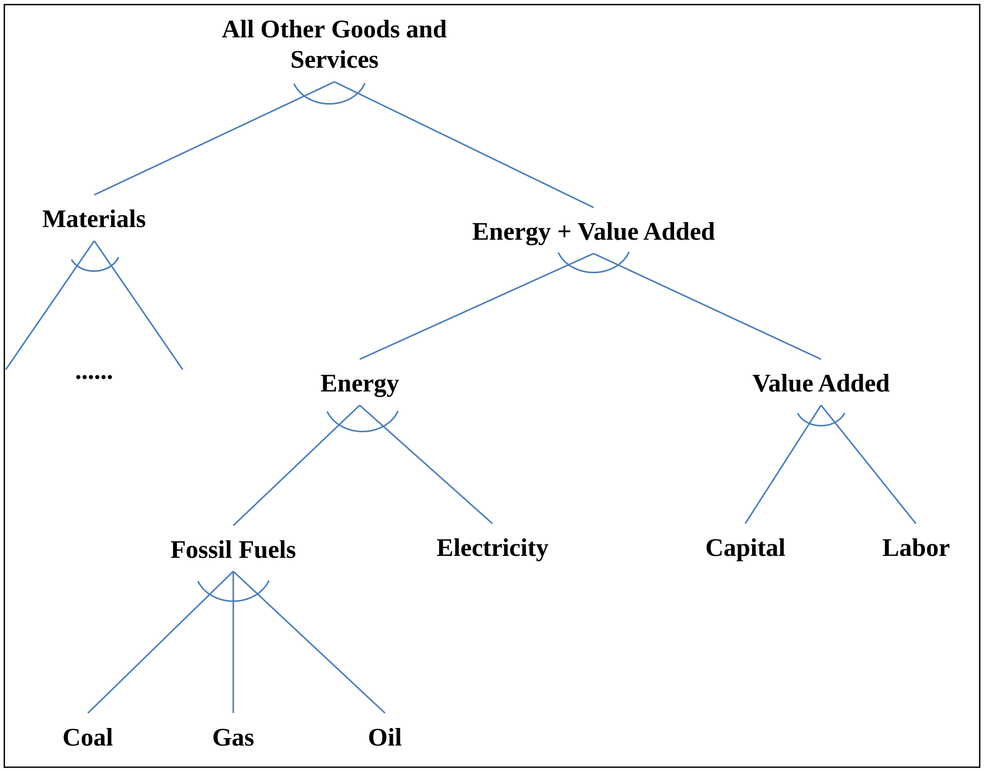


Figure A-6: Production Structure for Other Sectors in N$_{ew}$ERA's Macroeconomic Model



All goods and services, except crude oil, are treated as Armington goods, which assume 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*) *2014* Reference case.

2. Interactions between Compliance Costs, Capital Investment, and Household Expenditures

Regulations cause producers in the affected industries to make capital expenditures that they would not make otherwise. In addition, regulations change consumption patterns for households. To model the macroeconomic impacts of regulations, N$_{ew}$ERA accounts for interactions between

compliance costs, capital investments, and household expenditures based on the following three effects.

A. *Compliance costs for producers in the regulated industries*. Producers in the regulated industries have to make capital expenditures to comply with the regulation. These expenditures increase the costs of producing goods and services in the regulated industries. The higher costs lead to higher prices for the goods and services, which in turn lead to lower demand in the regulated industries. Thus, this effect reduces economic activity.

B. *Scarcity effect due to non-optimal capital allocation*. In N_{ew}ERA's modeling framework, the capital expenditures for regulatory compliance are assumed to be unproductive. The capital expenditures in the regulated industries make less capital available to produce goods and services throughout the economy. In other words, the unproductive capital expenditures in the regulated industries "crowd out" productive capital investment in the broader economy. This scarcity effect increases the opportunity cost of capital in the economy, which implies higher costs of capital. This in turn lowers investment in productive capital and slows economic growth.

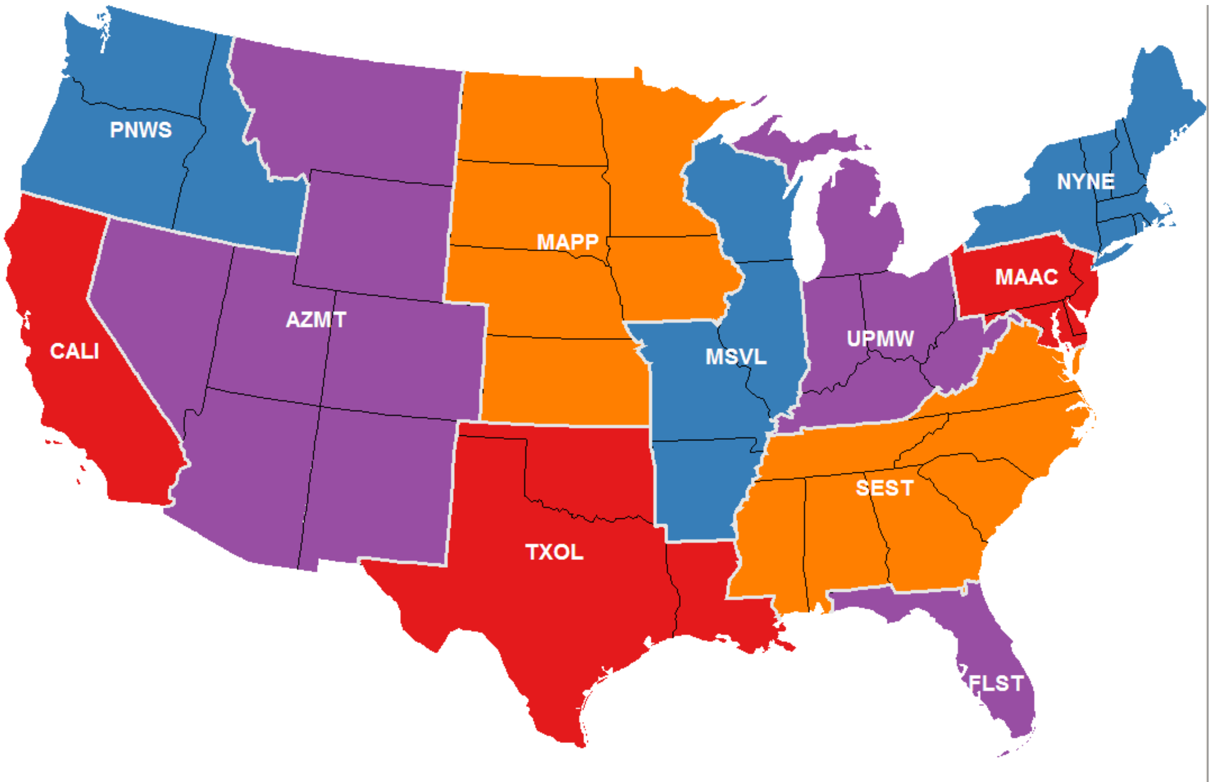
C. *Household purchases of unproductive durable goods*. Regulations also cause households to change their consumption patterns, particularly in terms of durable goods. For example, households may need to purchase new automobiles, lawn mowers, or equipment for compliance with the regulation. These additional expenditures on unproductive durable goods are non-optimal from the standpoint of households, but they represent increased demand for the manufacturing sector. Thus, these additional household purchases increase economic activity.

The net macroeconomic impacts of regulations calculated by N_{ew}ERA reflect the combination of these three effects.

3. Regional Aggregation

The N$_{ew}$ERA macroeconomic model typically includes 11 regions built up from economic data for the 50 U.S. states and the District of Columbia. The regions are shown in Figure A-7.

Figure A-7: N$_{ew}$ERA Macroeconomic Model Regions



4. Sectoral Aggregation

The N$_{ew}$ERA model includes a standard set of 10 economic sectors: five energy (coal, natural gas, crude oil, electricity, and refined petroleum products) and five non-energy sectors (services, manufacturing, agriculture, commercial transportation excluding trucking, and trucking). 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.

5. Natural Gas and Crude Oil Markets

As with most commodity markets, there are 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. To account for natural gas supply 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.

6. 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 disposable 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.

For modeling the economic impacts of changes in energy prices, we assume that 50% of the wealth impacts would accrue to local residents in each energy production region (state), and the remaining 50% of wealth impacts would accrue to energy company shareholders based on national population percentages. We are not aware of any recent studies of the geographic

distribution of potential energy sector gains, so we used an even division between state and national impacts given that some energy companies are in-state and some gains to national companies would accrue to local residents. A large fraction of energy production (particularly for natural gas shale developments that have become available through horizontal drilling techniques and hydraulic fracturing, or "fracking") is on private land and generates payments to local residents (payments, severance taxes, renegotiated leases, etc.). The remaining wealth impacts from changes in energy prices would affect shareholders in large publicly-traded energy companies, who are spread throughout the country.

E. 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 (EIA's *AEO 2014* 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 and oil); 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 $\mathrm{N_{ew}ERA}$ 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.

F. References to the Appendix

Armington, P. 1969. "A Theory of Demand for Products Distinguished by Place of Production." *International Monetary Fund Staff Papers*, XVI: 159-78.

Arrow, K.J., and G. Debreu. 1954. "Existence of an Equilibrium for a Competitive Economy." *Econometrica* 22:265-290.

Burfisher, M.E. 2011. *Introduction to Computable General Equilibrium Models*. New York: Cambridge University Press.

APPENDIX B: REGIONAL SCENARIO

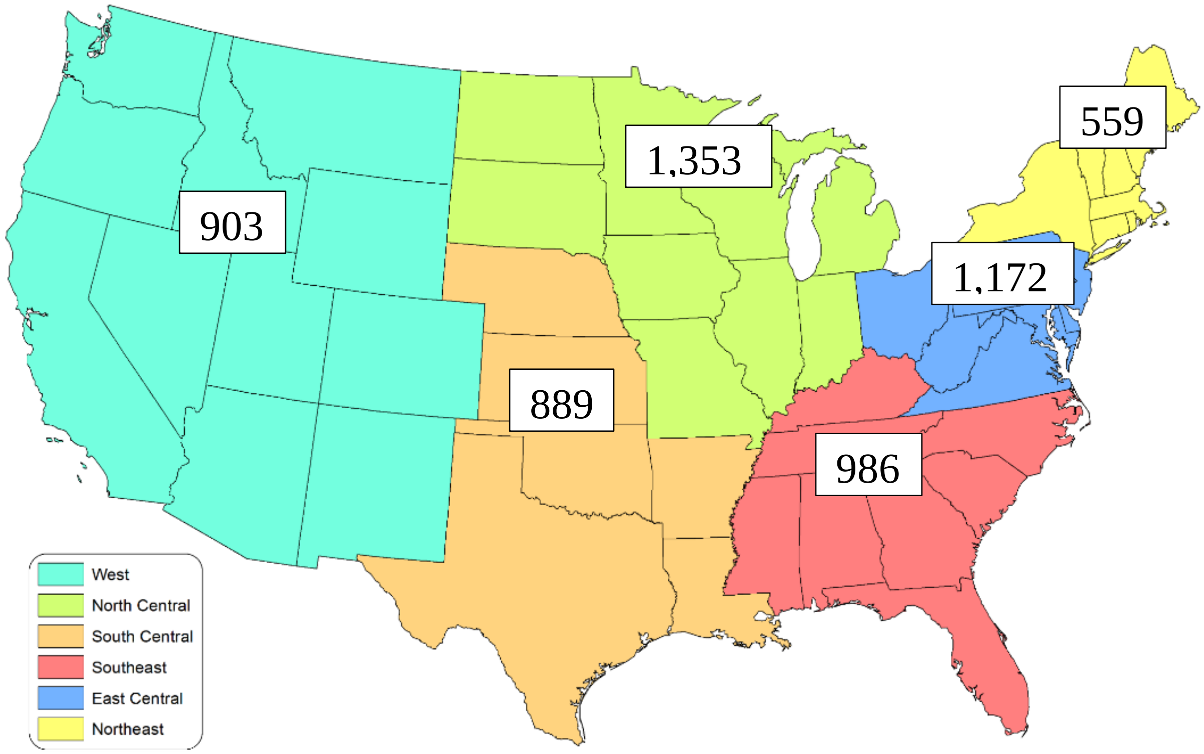
This appendix describes our modeling methodology and results for a regional scenario in which regions are presumed to comply with the EPA CPP using all four Building Blocks, a scenario we label Regional Unconstrained (BB1-4). Legal analysts have pointed out potential legal and practical challenges states would face in forming regions to comply with the CPP on a regional basis. This analysis ignores these considerations.

A. Overview of the Regional Unconstrained Scenario

The Regional Unconstrained (BB1-4) scenario assumes states can use all four building blocks as compliance measures and also assumes states would band together to develop regional programs for collective CO_2 emission rate reductions. To assign states to regions and calculate regional CO_2 emission rate targets, we followed the same procedures as EPA specified in the proposed rule (EPA 2014a, p. 34911) and as EPA used for its own modeling (EPA 2014b, p. 3-13). In particular, we aggregated states into six regions and calculated regional CO_2 emission rate targets as the weighted average of the constituent state targets, with weights based on 2012 generation from affected units in each state.

The following figure shows the 2030 regional CO_2 emission rate targets (in lbs/MWh) for the Regional Unconstrained (BB1-4) scenario. As with the State Unconstrained (BB1-4) scenario, the Regional Unconstrained (BB1-4) scenario also includes interim targets before 2030 and long-term targets after 2030.

Figure B-1: 2030 Regional CO_2 Emission Rate Targets (lbs/MWh)



Source: NERA calculations as explained in text

B. Impacts on U.S. Energy System

Figure B-2 summarizes the energy system impacts of the Regional Unconstrained (BB1-4) scenario on an annual average basis for the period from 2017 through 2031.

Figure B-2: Overview of Energy System Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031)

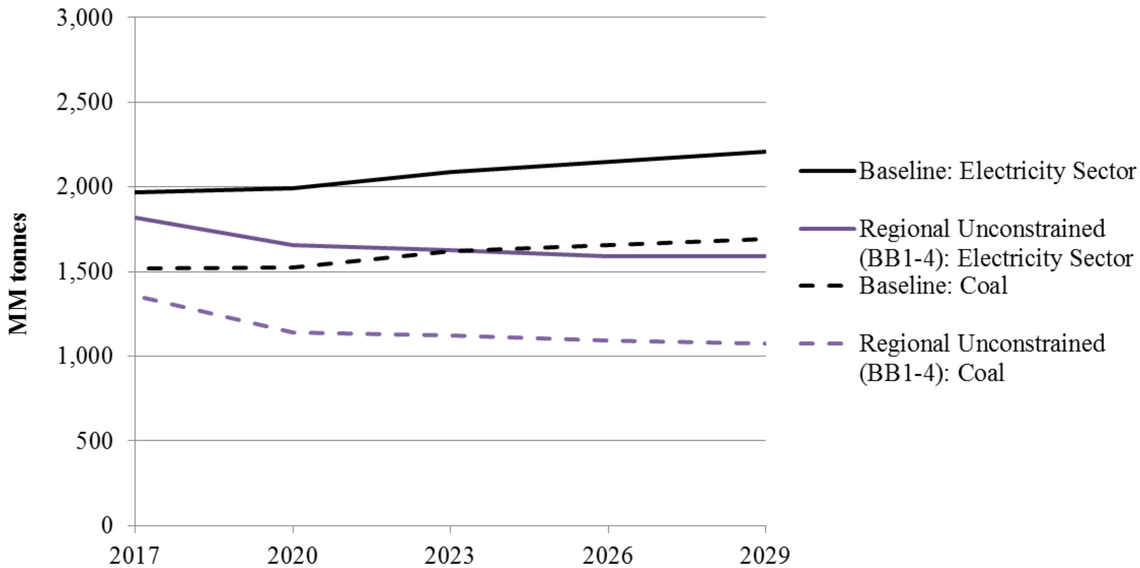
	Total Coal Retirements Through 2031	Coal-Fired Generation	Natural Gas-Fired Generation	Henry Hub Natural Gas Price	Delivered Electricity Price	Electricity Sector CO2 Emissions
	GW	TWh	TWh	2013$/MMBtu	2013 ¢/kWh	MM metric tons
Baseline	51	1,672	1,212	$5.25	10.8	2,080
Regional Unconstrained (BB1-4)	94	1,231	1,256	$5.34	12.0	1,657
Change from Baseline	+42	-441	+44	+$0.09	+1.2	-423
% Change from Baseline	+17%	-26%	+4%	+2%	+11%	-20%

Note: Coal retirements are cumulative from 2014. Percentage change in coal retirements is relative to total baseline 2031 coal capacity.

Source: NERA calculations as explained in text.

Figure B-3 shows the CO_2 emission impacts of the Regional Unconstrained (BB1-4) scenario. It shows CO_2 emission impacts for the U.S. electricity sector as well as impacts for U.S. coal units in particular.

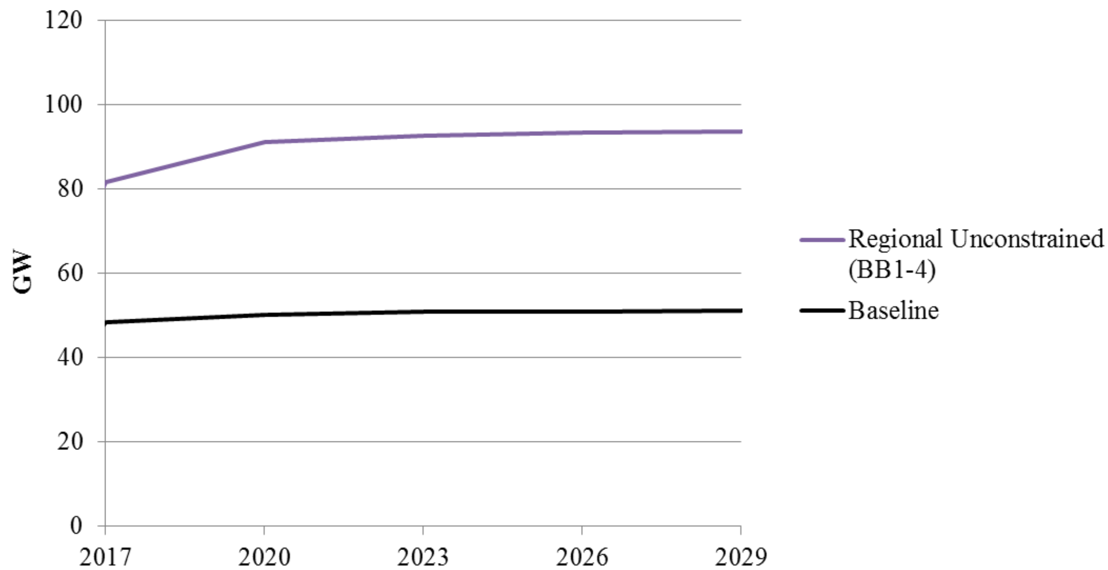
Figure B-3: CO_2 Emission Impacts of Regional Unconstrained (BB1-4) Scenario



Source: NERA calculations as explained in text.

Figure B-4 shows coal unit retirement impacts of the Regional Unconstrained scenario.

Figure B-4: Coal Unit Retirement Impacts of Regional Unconstrained (BB1-4) Scenario



Source: NERA calculations as explained in text.

Figure B-5 shows the capacity impacts of Regional Unconstrained (BB1-4) scenario.

Figure B-5: Capacity Impacts of Regional Unconstrained (BB1-4) Scenario (GW)

	2017	2020	2023	2026	2029
Baseline	**1,019**	**1,034**	**1,053**	**1,074**	**1,095**
Coal	249	247	246	246	246
Natural Gas CC	247	251	260	272	283
Oil/Gas CT/Steam	239	244	251	259	267
Nuclear	99	103	103	103	103
Hydro	76	76	76	76	76
Non-Hydro Renewables	108	113	116	118	120
Regional Unconstrained (BB1-4) (Change)	**-56**	**-77**	**-95**	**-115**	**-133**
Coal	-33	-40	-41	-42	-42
Natural Gas CC	-2	-5	-14	-26	-37
Oil/Gas CT/Steam	-21	-29	-36	-44	-52
Nuclear	0	0	0	0	0
Hydro	0	0	0	0	0
Non-Hydro Renewables	-1	-2	-3	-4	-3

Source: NERA calculations as explained in text.

Figure B-6 shows the generation impacts of the Regional Unconstrained (BB1-4) scenario, including a line for end-use energy efficiency (which serves as a generation resource to meet demand). Generation follows a similar pattern to capacity; energy efficiency reduces overall generation needs, the CPP CO_2 rate targets lead to fuel switching away from coal, and increased electricity prices have a feedback effect of reducing overall demand (even including energy efficiency).

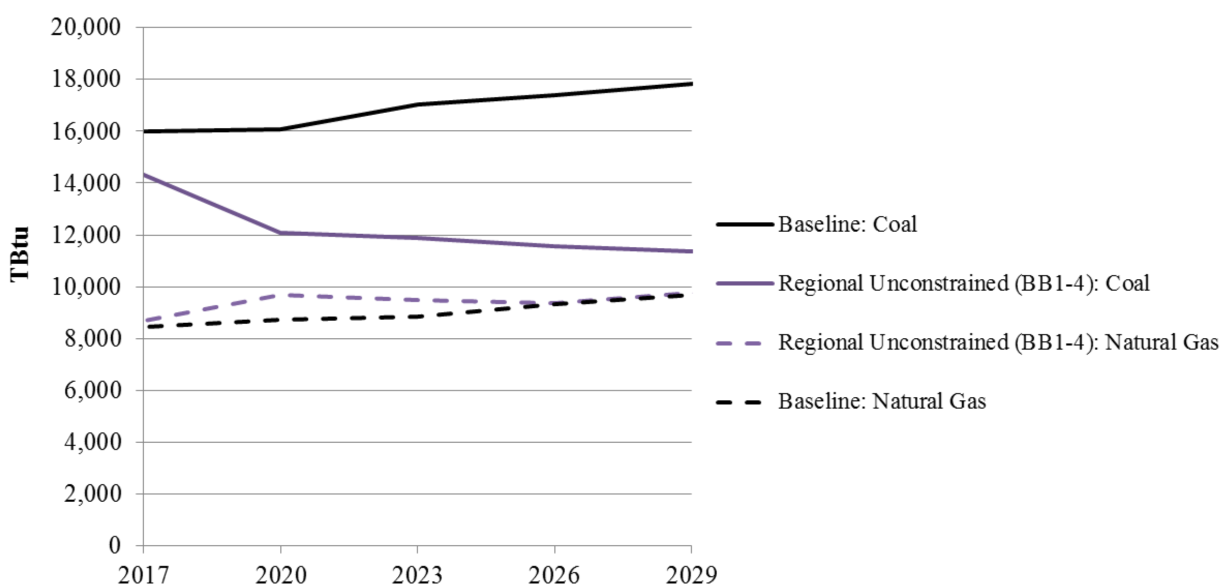
Figure B-6: Generation Impacts of Regional Unconstrained (BB1-4) Scenario (TWh)

	2017	2020	2023	2026	2029
Baseline	**4,134**	**4,238**	**4,368**	**4,484**	**4,587**
Coal	1,587	1,593	1,688	1,726	1,767
Natural Gas CC	1,128	1,167	1,194	1,262	1,310
Oil/Gas CT/Steam	14	14	10	11	13
Nuclear	786	816	816	816	816
Hydro	253	253	253	253	253
Non-Hydro Renewables	366	395	407	414	428
Energy Efficiency	0	0	0	0	0
Regional Unconstrained (BB1-4) (Change)	**-109**	**-149**	**-193**	**-230**	**-201**
Coal	-156	-376	-491	-561	-620
Natural Gas CC	+31	+122	+75	-6	-5
Oil/Gas CT/Steam	+1	-1	-2	-4	-3
Nuclear	0	0	0	0	0
Hydro	0	0	0	0	0
Non-Hydro Renewables	-6	-10	-16	-18	-20
Energy Efficiency	+21	+116	+241	+358	+447

Source: NERA calculations as explained in text.

Figure B-7 shows the coal and electricity sector natural gas consumption impacts of the Regional Unconstrained (BB1-4) scenario.

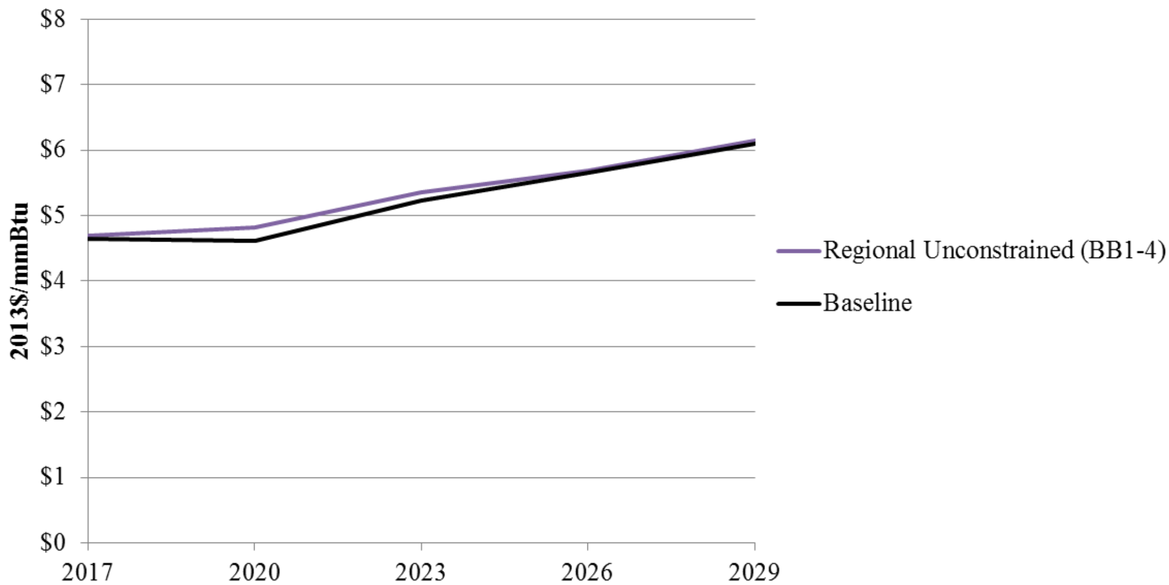
Figure B-7: Coal and Natural Gas Consumption Impacts of Regional Unconstrained (BB1-4) Scenario



Source: NERA calculations as explained in text.

Figure B-8 shows the natural gas wholesale price (Henry Hub) impacts of the Regional Unconstrained (BB1-4) scenario. The scenario leads to increased natural gas generation and thus higher natural gas prices.

Figure B-8: Natural Gas Wholesale Price (Henry Hub) Impacts of Regional Unconstrained (BB1-4) Scenario



Source: NERA calculations as explained in text.

Figure B-9 shows the regulation cost impacts as annual and present values (2017 through 2031) based on the costs of providing electricity (excluding energy efficiency), costs of energy efficiency programs (including costs to participants as well as to the utility), and costs of non-electricity-sector natural gas consumption for the Regional Unconstrained (BB1-4) scenario.

Figure B-9: Regulation Cost Impacts of Regional Unconstrained (BB1-4) Scenario (billion 2013 dollars)

	2017	2020	2023	2026	2029	PV (2017-2031)
Regional Unconstrained (BB1-4)						
Cost of Electricity, Excluding EE	-$9	-$15	-$26	-$38	-$44	-$225
Cost of Energy Efficiency	$25	$52	$71	$73	$73	$560
Cost of Non-Electricity Natural Gas	$0	$2	$2	$1	$2	$13
Total Consumer Energy Costs	$15	$39	$46	$37	$31	$348

Note: Present value is from 2017 through 2031, taken in 2014 using a 5% real discount rate
Source: NERA calculations as explained in text.

C. Impacts on Regional Energy Systems

Figure B-10 shows coal unit retirements by region for the Regional Unconstrained (BB1-4) scenario. (Regional aggregations are based on the EPA aggregations for its modeling, as shown

above.) All regions in the lower 48 states have increased coal retirements. The Southeast, North Central, and South Central regions experience the greatest impact on coal retirements in both scenarios.

Figure B-10: Coal Unit Retirement Impacts by Region of Regional Unconstrained Scenario Through 2031

	Baseline	Regional Unconstrained (BB1-4)	
		Change	% Change
U.S.	*51*	*+42*	*+17%*
Northeast	2	+0.3	+16%
East Central	13	+4	+11%
Southeast	13	+14	+24%
North Central	11	+11	+14%
South Central	6	+11	+24%
West	5	+1	+6%
AK & HI	0	+0.01	+3%

Note: Coal retirements are cumulative from 2014. Percentage change in coal retirements is relative to total baseline 2031 coal capacity.
Source: NERA calculations as explained in text.

Figure B-11 shows the natural gas combined cycle generation impacts of the Regional Unconstrained (BB1-4) scenario by region. Impacts vary significantly by region. Southeast, North Central, and South Central regions (which saw the greatest increase in coal retirements) have increased natural gas combined cycle generation, while other regions have reductions. Generation impacts are the net effect of fuel switching, reductions in total generation needs due to end-use energy efficiency adoption, and reduced demand due to feedback from rising electricity prices.

Figure B-11: Natural Gas Combined Cycle Generation Impacts by Region of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, TWh)

	Baseline	Regional Unconstrained (BB1-4)	
		Change	% Change
U.S.	*1,212*	*+44*	*+4%*
Northeast	85	-22	-25%
East Central	260	-29	-11%
Southeast	327	+20	+6%
North Central	50	+37	+73%
South Central	224	+94	+42%
West	258	-56	-22%
AK & HI	8	-1	-17%

Source: NERA calculations as explained in text.

Figure B-12 shows the natural gas combined cycle unit fuel consumption impacts of the Regional Unconstrained (BB1-4) scenario by region. Natural gas consumption follows the same regional pattern as natural gas combined cycle generation, discussed above.

Figure B-12: Natural Gas Combined Cycle Fuel Consumption Impacts by Region of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, TBtu)

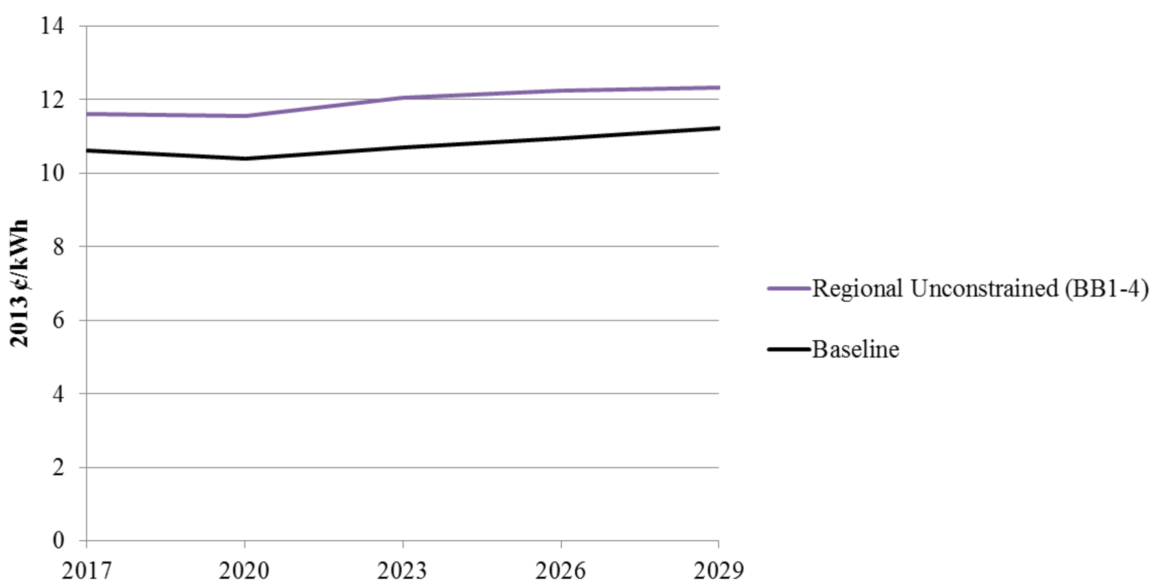
	Baseline	Regional Unconstrained (BB1-4)	
		Change	% Change
U.S.	*8,893*	*+412*	*+5%*
Northeast	630	-160	-25%
East Central	1,912	-193	-10%
Southeast	2,374	+167	+7%
North Central	368	+285	+78%
South Central	1,667	+739	+44%
West	1,877	-418	-22%
AK & HI	65	-10	-15%

Source: NERA calculations as explained in text.

D. Impacts on Electricity Prices

Figure B-13 shows the delivered electricity price impacts (averaged over all sectors) for the Regional Unconstrained (BB1-4) scenario.

Figure B-13: All Sectors Delivered Electricity Price Impacts of Regional Unconstrained (BB1-4) Scenario



Source: NERA calculations as explained in text.

Figure B-14 shows the annual average (2017 through 2031) delivered electricity price impacts by ratepayer class (residential, commercial, industrial, and averaged over all sectors) for the Regional Unconstrained (BB1-4) scenario.

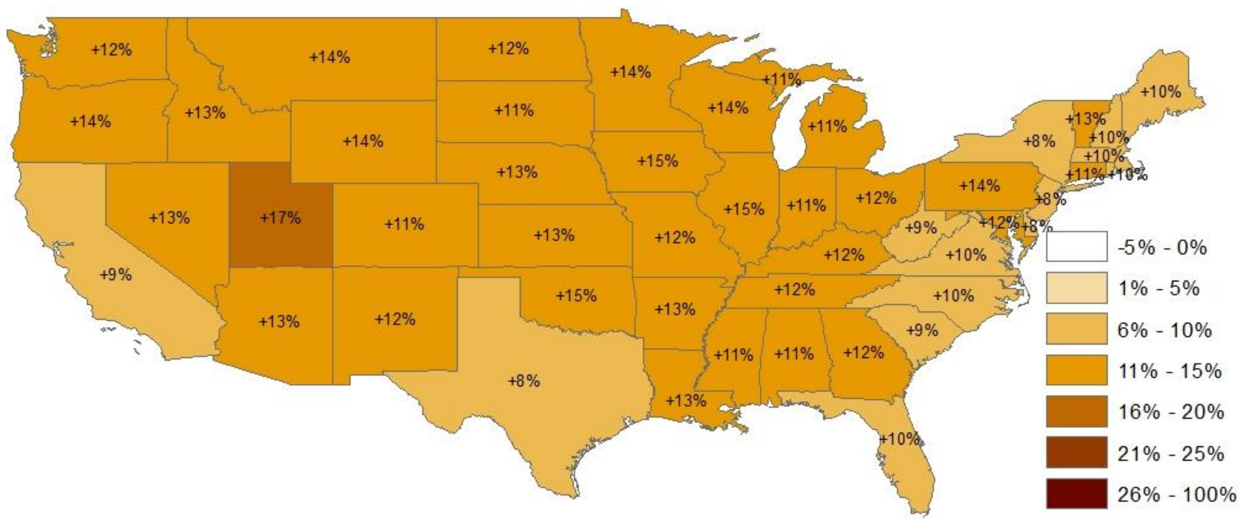
Figure B-14: Ratepayer Class Delivered Electricity Price Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, 2013 cents per kWh)

	Residential	Commercial	Industrial	All Sectors
Baseline	12.7 ¢	11.0 ¢	7.8 ¢	10.8 ¢
Regional Unconstrained (BB1-4)	14.2 ¢	12.5 ¢	8.2 ¢	12.0 ¢
Change from Baseline	1.6 ¢	1.4 ¢	0.4 ¢	1.2 ¢
% Change from Baseline	+13%	+13%	+5%	+11%

Source: NERA calculations as explained in text.

Figure B-15 shows changes in annual average (2017 through 2031) delivered electricity prices (averaged over all sectors) for the Regional Unconstrained (BB1-4) scenario by state.

Figure B-15: State All Sectors Delivered Electricity Price Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031)



Source: NERA calculations as explained in text.

Figure B-16 shows changes in annual average (2017 through 2031) electricity-related consumer costs by ratepayer class (residential, commercial, industrial, and averaged over all sectors) for the Regional Unconstrained (BB1-4) scenario.

Figure B-16: Consumer Electricity-Related Cost Impacts of Regional Unconstrained (BB1-4) Scenario (Annual Average, 2017-2031, billion 2013 dollars)

	Residential	Commercial	Industrial	All Sectors
Baseline	$192	$161	$85	$439
Regional Unconstrained (BB1-4)				
Electricity Bills	$194	$164	$84	$442
Consumer Energy Efficiency Costs	$13	$13	$4	$29
Total Consumer Electricity-Related Costs	$207	$176	$88	$471
Change from Baseline	+$15	+$15	+$3	+$32
% Change from Baseline	+8%	+9%	+3%	+7%

Source: NERA calculations as explained in text.

E. References

U.S. Environmental Protection Agency ("EPA"). 2014a. "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule." 79 *Federal Register* 34830-34958. June 18. http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf.

U.S. Environmental Protection Agency ("EPA"). 2014b. Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. June. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

APPENDIX C: COMPLICATIONS IN MODELING ENERGY EFFICIENCY

EPA's analysis of the impacts of the CPP rule assumes that (a) end-use energy efficiency improvements presumed to be available would not be adopted in the absence of the CPP (*i.e.*, in the baseline), and (b) these energy efficiency improvements would be fully adopted with the proposed CPP. In this study, to allow direct comparisons of our impact estimates to those of EPA, we have followed the EPA assumption that none of the potential supply of energy efficiency is adopted in the baseline (although our model allows for endogenous determination of how much energy efficiency would be adopted in the proposed CPP). This appendix explains why EPA's assumptions about baseline levels of energy efficiency are questionable for evaluating the likely effects of the proposed CPP, and how those assumptions affect results.

A. EPA versus NERA Modeling of Energy Efficiency

EPA analyzed the cost of the CPP using the Integrated Planning Model (IPM) developed by ICF, International. This EPA analysis did not endogenously determine how much of the assumed energy efficiency supply would be adopted as part of a least-cost response to the regulation. Instead, EPA exogenously determined that a specific quantity would be adopted in each individual model run and manually adjusted the electricity demands down by that amount before running the model to estimate the effects of attainment for the remainder of the CO_2 rate limit (EPA 2014, pp. 3-2 and 3-9).

This approach does not allow the analysis to indicate whether some or all of the potential energy efficiency programs would be cost-effective even in the absence of the CPP – *i.e.*, in the baseline scenario to which the CPP scenario is compared to derive the impacts and costs of the CPP. EPA decided to assume that none of the potential energy efficiency will be adopted in any year of the baseline scenario, and to assume that 100% of the energy efficiency potential would be adopted in the CPP policy scenarios. In contrast, N_{ew}ERA can endogenously determine when and how much of the assumed supply of potential energy efficiency to adopt. This analysis is based on whether the end user's cost per kWh of an incremental investment in energy efficiency is cheaper than the present value of the delivered cost of the kWh of purchased electricity that would thereby be avoided.[20]

When we input the energy efficiency cost per kWh that EPA has assumed, our N_{ew}ERA model finds that all of that energy efficiency would be cost-effective to adopt in the baseline scenario, even if the consumer would be given no subsidy by the utility. As discussed in the report, we

[20] In this decision, the end-user considers only the portion of cost per avoided kWh for which he/she pays. NERA, like EPA, assumes this is 50% of the total cost, with the utility paying the other 50%. (While the share paid by the utility does not appear in the consumer's decision, N_{ew}ERA does account for that part of the cost in its projected total cost of the proposed CPP.)

modified some of EPA's energy efficiency cost assumptions based upon a review of the economics literature, but even with those revised assumptions, our model finds all of the assumed energy efficiency supply to be cost-effective without any implicit carbon price signal from the CPP (*i.e.,* in the baseline scenario). These results raise an important question of whether these energy efficiency cost estimates are unrealistically low, given that EPA assumes they will not be adopted unless there is a policy such as the CPP.

B. Energy Efficiency Costs and Consumer Choices

In effect, the EPA's analysis assumes that state regulations as part of CPP compliance would release consumers from a number of non-cost related barriers that would prevent them from choosing energy efficiency, even though it is beneficial to them in the absence of the CPP. EPA also assumes that the state programs that presumably overcome those barriers do not impose any financial or other costs on consumers.

If the assumptions used in either EPA's analysis (or our analysis) are considered reasonable estimates of energy efficiency cost, it would seem sensible to include the energy efficiency improvements in the baseline scenario (since rational consumers would adopt the changes without the need for a government program). As noted, our analysis follows EPA's approach by excluding energy efficiency from the baseline scenario, and allowing it in the unconstrained policy scenario. This assumption allows greater comparability of our analysis to that by EPA, and enables other important aspects of the CPP cost determinants to be studied; however, this EPA decision to exclude cost-effective energy efficiency from the baseline has important implications for the estimates of CPP impacts.

The combination of EPA's decision to exclude energy efficiency from the analytic baseline and assumptions that might understate the cost of energy efficiency introduces potential distortions in the modeling. Note that the baseline electricity demand in our analysis adopts the projection of *AEO 2014*. There is some implicit energy efficiency in the *AEO 2014* baseline due to implementation of existing appliance efficiency standards, but we do not make any adjustment for other potential energy efficiency in the baseline used in our CPP analysis. Based on our assumptions about energy efficiency costs, the unconstrained policy scenario (State Compliance (BB1-4)) then endogenously chooses to adopt all of the energy efficiency, plus a cost-effective mix of other actions to attain the CPP's target emission rates (*i.e.*, coal-to-existing gas switching, building of new renewables and nuclear generation, coal unit efficiency retrofits, and price-induced demand reduction). The policy impact estimates reflect the net effect of energy efficiency (which, given the current cost assumptions, implies an economic savings) and the other available CO_2-reducing measures (which all have costs). By netting analytically questionable energy efficiency savings against the other costs, the potential impact to the economy is likely understated. Thus, policy impact estimates are quite different in analyses that do not adopt the EPA decision to exclude additional cost-effective energy efficiency from the baseline. The policy impact estimates are also different in analyses that use different

assumptions on the additional cost and additional availability of energy efficiency as state efficiency improvement efforts become more ambitious.

C. References

U.S. Environmental Protection Agency ("EPA"). 2014. Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants. June. http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

NERA
ECONOMIC CONSULTING

NERA Economic Consulting
200 Clarendon Street, 11th Floor
Boston, MA 02116
Tel: +1 617 927 4500
Fax: +1 617 927 4501
www.nera.com