<u>Summary of Key Points</u>
in Testimony of Anne E. Smith, Ph.D.
at a Hearing on
EPA's Final Clean Power Plan Rule
by the
Committee on Science, Space, and Technology
United States House of Representatives
Washington, DC

November 18, 2015

- NERA Economic Consulting has performed an analysis of the potential energy sector, energy cost, and net consumer impacts of the CPP, using an integrated energy-macroeconomic model and up-to-date input assumptions from public sources.
- Projected <u>impacts to the U.S. fossil-energy sectors</u> under alternative mass-based scenarios are extensive. For example:
  - ➢ Energy sector expenditures from 2022 through 2033 increase by $220 billion to $292 billion (present value in 2016 relative to baseline projections, 2015$).
  - ➢ The average annual increase is $29 billion to $39 billion per year (2015$).
  - ➢ Average annual U.S. retail electricity rates are higher by 11% to 14% (relative to average baseline rates over the period 2022-2033).
- Projected <u>net impacts to the U.S. economy,</u> (after netting out any energy sector costs to purchase allowances, and accounting for increases in demand outside of the fossil-energy sectors) are also extensive. For example:
  - ➢ U.S. consumer spending power is projected to fall $64 billion to $79 billion (present value in 2016 relative to baseline from 2022-2033, 2015$).
- A rate-based implementation of the CPP that NERA also analyzed projected potential impacts similar in magnitude to those for the mass-based scenarios.
- The cost estimates that EPA has reported in its CPP regulatory impact analysis (RIA) for the years 2020, 2025, and 2030 are not correct representations of the true spending projected by EPA's analysis for those years.
  - ➢ Using EPA output files, NERA has determined that EPA actually projected spending levels of $17.4 billion in 2020 and $11.4 billion in 2025 (2011$).
- An "apples-to-apples" comparison shows that NERA's impact estimates are very similar to those of EPA, once the flaws in EPA's reporting of its own cost estimates are corrected.
- None of the 3,600 deaths, 90,000 asthma attacks, and 300,000 sick days reported as CPP benefits is associated with climate changes; these "co-benefits" are based on <u>non</u>-greenhouse gas emissions that are already regulated by EPA to levels that are protective of the public health under another provision of the Clean Air Act.

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Mr. Chairman and Members of the Committee:

Thank you for your invitation to participate in today's hearing. I am Anne E. Smith, a Senior Vice President of NERA Economic Consulting, and co-head of NERA's global environmental practice with Dr. David Harrison. My testimony reflects my own opinions, and not any position of my company, NERA Economic Consulting, or its clients.

I am a specialist in environmental risk assessment and economic impact analyses to support environmental policy decisions. I have performed air quality cost and benefits analyses and risk assessments over my entire career, including as an economist in the Office of Policy, Planning, and Evaluation of the U.S. Environmental Protection Agency (EPA), as a consultant to the EPA, and in many consulting engagements since then for government and private sector clients globally. I have also served on several committees of the National Academy of Sciences focusing on risk assessment and risk-based decision making, and on advisory boards of the EPA. Specific air quality issues I have analyzed include greenhouse gases, fine particulate matter ($PM_{2.5}$), ozone, mercury, regional haze, and others. I have been extensively involved in assessment of the evidence on risks from ambient $PM_{2.5}$ and ozone for twenty years, and have performed analyses of the impacts of climate change and climate policies for even longer.

I hold a Ph.D. in Economics from Stanford University, with a Ph.D. minor in Stanford's School of Engineering, a M.A. in Economics from Stanford University and a B.A. in Economics from Duke University, *summa cum laude*.

I thank you for the opportunity to share my perspective today on EPA's final Clean Power Plan (CPP) rule, which was promulgated on October 23, 2015.[1] My written statement provides a summary and explanation of an analysis that I co-directed with my colleague, Dr. David Harrison, to assess the economic implications of the CPP on the electricity sector, energy markets, and net effects on consumers.[2] I am also entering into the record a full copy of that analysis as Attachment A to this written submission. My written and oral testimonies reflect my own opinions, and do not represent any position of my company, NERA Economic Consulting, or its clients.

Overview of the Final Clean Power Plan Rule

The CPP is a nationwide regulation under Section 111(d) of the Clean Air Act that regulates two subcategories of existing electricity generating units: fossil fuel-fired steam units and combined-cycle combustion turbines. The rule sets maximum limits on CO_2 emission rates, measured in pounds of CO_2 per megawatt-hour (lb./MWh) for

[1] U.S. Environmental Protection Agency, *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Final Rule, 80 Fed. Reg. 64661, October 23, 2015.

[2] The final CPP impact analysis is presented in NERA, *Energy and Consumer Impacts of EPA's Clean Power Plan*, prepared for American Coalition for Clean Coal Electricity, November 7, 2015 (available: http://www.nera.com/publications/archive/2015/energy-and-consumer-impacts-of-epas-clean-power-plan.html.) This analysis followed the same methodology that NERA employed for an analysis of the impacts of the *proposed* rule, which was documented in an October 16, 2014 NERA report, *Potential Energy Impacts of the EPA Proposed Clean Power Plan*, which is also available on NERA's website.

electricity systems within individual states.[3] A state's emissions rate outcome, which would be compared to its CPP limit to determine compliance, will be calculated using a specific formula that accounts for the emissions from the affected generating units divided by their generation (in MWh), but also including the generation from new renewable and nuclear capacity, plus future incremental reductions in generation due to verified end-use energy efficiency projects. The final rule also provides states with an alternative compliance structure that would impose a CO_2 cap for total emissions from the regulated generation generators in each state ("mass cap"). The rule identifies the level of the mass cap that would apply in each state, based on EPA's assessment of the emissions that would be equivalent to complying with the state's rate-based limit. The limits, whether rate- or mass-based, are phased in from 2022 through 2030. According to EPA's estimates, by 2030, total U.S. power sector CO_2 emissions will be 32% below their level in 2005. The rule also allows states to trade with other states that elect the same generic regulatory option, 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 its analysis of emission reduction opportunities in each state. EPA evaluated the opportunities in terms of three 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; and

[3] The rule 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. The rule also does not set CO_2 emission rate limits for Alaska or Hawaii because EPA lacked the information and tools to set limits on these states.

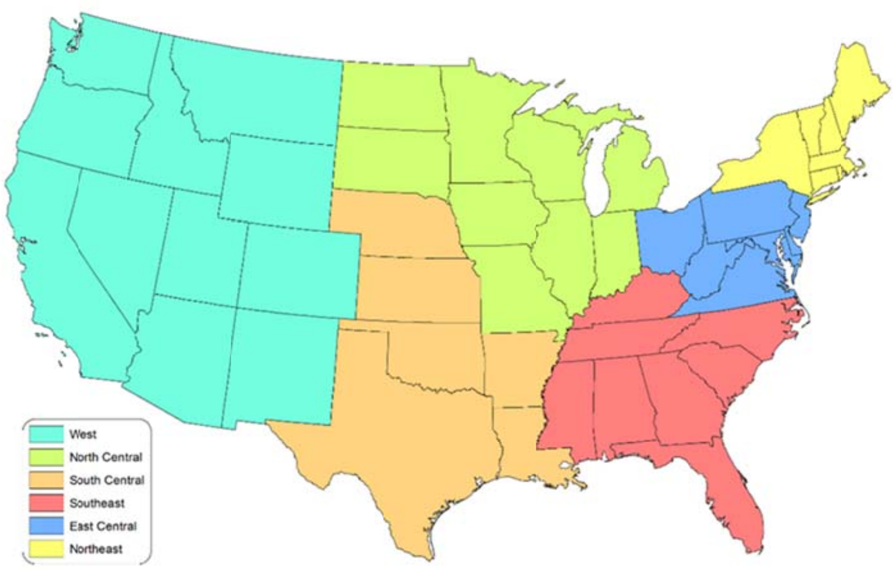
3. Building Block 3—Increases in renewables and nuclear energy.

The mass limits were then estimated based on projected compliance with the rate limits.

Objectives of NERA's Study and Scenarios Analyzed

NERA's principal objective was to evaluate the potential impacts of the CPP to the fossil-energy sector, to energy costs, and to the economy as a whole, focusing on results over the period from 2022 through 2033 (2022 marking the beginning of the ramp up of EPA's rate limits, and 2033 representing a date after the point where the most stringent rates must be achieved, *i.e.*, 2030). We developed impact estimates under two primary scenarios for compliance with mass-based caps. Both presume least-cost compliance, the first using intra-state trading, and the second allowing trading to occur across states within six multi-state regions following the same regional boundaries that EPA used to analyze regional trading in the RIA for the proposed CPP (see Exhibit 1).

Exhibit 1. Regions for Inter-State Trading in NERA's Mass-Based Scenario with Regional Trading (Based on inter-state trading regions used by EPA in its Proposed CPP RIA)



Mass-based trading schemes will require creation of emissions allowances (*i.e.*, rights to emit a ton of CO_2), the distribution of which affects the ultimate cost burdens of the regulation on different sectors and individuals. Many alternative allocation schemes have been used or proposed in past cap-and-trade programs. NERA's analysis has assumed two allocation cases for each mass-based scenario:

1. **No LDC allocation.** Allowances are auctioned to generators, with none of the proceeds distributed to local distribution companies (LDCs) for electricity.[4]
2. **50% LDC allocation**. Half of the allowances are auctioned to generators, with the other half freely distributed to LDCs and used as a credit on retail rates.

For all cases, our analysis assumes that 100% of the allowance value is returned to consumers by some route. In the case with allocation of a part of the allowances or auction proceeds to LDCs, that part of the allowance value serves to lower utility costs that otherwise would be passed through to customers—and thus to lower electricity rate impacts. The remainder of the allowance value is returned to consumers in an economically-neutral manner that economists call "lump sum." The key feature of a lump sum rebate is that the value is recycled to each individual recipient in a fixed quantity, rather than in the form of reduced income tax *rates*, or reduced electricity *rates* – which are approaches that can affect consumer behavior in ways that then have secondary effects on markets and economic outcomes. Lump sum redistributions could include per-household dividend checks, or per-person income tax rebates, among other

[4] LDCs are the entities households know of as "electric utilities." LDCs do not necessarily own any of the regulated generating units, and may only buy their power from generators. LDCs set retail electricity rates on the basis of costs, and so a free allocation to an LDC or the distribution of some of an allowance auction's proceeds to an LDC reduces electricity rates, thus reducing rate impacts of the CO_2 price.

means. The key point is that NERA's analysis returns the full value to the allocations to the economy no matter what allocation case is assumed. The only issue is by what route. After the free allocations to LDCs to mitigate electricity rate increases, we assume the remaining value is returned via economically-neutral transfers so that none of our reported impacts on consumers is inflated by the fact that states are presumed to create allowance programs as a means of encouraging cost-effective compliance strategies.

The two alternative allocation cases form a range for our reported results for each of the two mass-based scenarios. We have also analyzed a scenario in which all states follow a rate-based compliance approach. For that scenario, we considered only intra-state trading of emission reduction credits (ERCs). There are no allowances to allocate in a rate-based approach, and so for that scenario there is no range on the results.

NERA's presumption of least-cost compliance (within the specified trading boundaries) may understate the real-world impacts and costs of the CPP. Impacts also may be understated by NERA's assumptions of perfect foresight on the part of affected parties and no uncertainty or market imperfections. Additionally, our analysis does not include several types of cost that might be required to meet the electricity supply and demand changes estimated to be least-cost, such as potential needs to upgrade the existing infrastructure for electricity transmission or natural gas supply.

NERA's Analytical Methodology

NERA used its state-of-the-art, peer-reviewed energy-economic model—called N_{ew}ERA—to develop estimates of the least-cost electricity system compliance actions and their associated costs and potential macroeconomic impacts on the U.S. economy.

N_{ew}ERA is an economy-wide integrated energy and macroeconomic model that includes a bottom-up, unit-specific representation of the electric sector, as well as a representation of all other sectors of the economy and households. It assesses, on an integrated basis, the effects of major policies on individual sectors as well as the overall economy. It has substantial detail for all of the energy sources used by the economy, with separate sectors for coal production, crude oil extraction, electricity generation, refined petroleum products, and natural gas production. The model performs its analysis with regional detail. The CPP analysis used state-specific cost inputs.

More detailed documentation of the N_{ew}ERA model is available in Appendix 1 of the report provided in Attachment A of this testimony, and I will here just highlight the key assumptions of the N_{ew}ERA base case used in our CPP analysis.

The N_{ew}ERA electricity module used for our CPP analysis adopted the most recent estimates of future natural gas and oil prices, electricity demands, and new technology costs released by the U.S. Energy Information Administration (EIA) with its *Annual Energy Outlook 2015* (*AEO 2015*). The *AEO 2015* Reference Case assumptions were used. The electricity sector's base case reflects compliance with current environmental regulations (*e.g.*, the Mercury and Air Toxics Standards) and other policies. This includes two major existing programs to reduce CO_2 emissions in the electricity sector, the Regional Greenhouse Gas Initiative (RGGI) and the California AB 32 cap-and-trade program. The electricity sector base case also includes all generating unit retirements that had been publicly announced as definite by August 2015.

The parameters of the macroeconomic portions of $\mathrm{N_{ew}}$ERA (*i.e.*, projections for sectors other than the electricity sector) were estimated (*i.e.*, "calibrated") to match the *AEO 2015* Reference Case projections under the base case scenario. Thus, both the macroeconomic and electricity sector components of the model used in NERA's CPP cost analysis start from a base case reflecting the EIA's most recent projections of energy and economic activity.

The $\mathrm{N_{ew}}$ERA base case for the CPP analysis does not include the additional end-use energy efficiency potential that EPA assumes is available for CPP compliance, but it does include that potential as a compliance option, as I will discuss further below. Consistent with EPA's own analysis, NERA assumed that even highly cost-effective energy efficiency improvements would only start to be implemented once the CPP limits are in effect—an assumption that reduces the estimated costs of meeting the CPP limits.[5] It reduces estimated costs because all of the economic gains of the cost-effective energy efficiency are attributed to the CPP rule.

NERA Assumptions Related to Options for Compliance with CPP

As I have already explained, NERA assumed least-cost compliance rather than the specific mix of the building block options that EPA used to set each state's emission rate limit or mass limit. Although NERA's analysis leaves the mix of compliance options completely unconstrained, I will describe our analysis's compliance-related options for each building block category.

[5] NERA's analysis does assume, however, that California adopts the end-use energy efficiency measures as part of its compliance with the "complementary measures" under its AB 32 program, which is part of the base case.

Building Block 1 – Heat Rate Improvements for Coal Units

In its calculations of state targets, EPA assumed a range of cost and effectiveness of heat rate improvements (*i.e.*, increased efficiency in generation) that all coal units could achieve, a range that differs by region of the U.S. NERA's analysis adopts the same assumptions as EPA's. These are a 4.3% improvement in the Eastern Interconnection, 2.1% in the Western Interconnection, and 2.3% in the Texas region. EPA assumed these improvements can be achieved at a capital cost of $100/kilowatt (kW),[6] which NERA also has assumed. NERA's analysis further assumes that units undertaking a heat rate improvement will be subject to New Source Review. This would reduce such retrofits' cost-effectiveness for some units that are not maximally controlled for other types of emissions. This assumption has *de minimis* impact on our results, but it is nevertheless consistent with the legal reality.[7]

Building Block 2 – Increased Utilization of Existing NGCC

In its calculation of state targets, EPA assumed that existing NGCC units could, by some point in time prior to 2030, increase their utilization to a 75% annual capacity factor, but set early interim rate limits to allow a more gradual transition, or "glide path" to that ultimate level.[8] Increasing utilization of existing NGCC units up to each unit's assumed maximum availability (which is 89% in the N_{ew}ERA model) is an option in all

[6] RIA, p. 3-24.

[7] While this set of assumptions has *de minimis* impact on our estimates of the impacts of the proposed CPP, their accuracy 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. That legal situation would warrant a more thorough evaluation of heat rate improvement assumptions than we determined was necessary for our analysis.

[8] 80 Fed. Reg. 64661 (section V.D).

of our scenarios to the extent that it is cost-effective as either a market or CPP compliance option. 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 also are determined in N_{ew}ERA. No time constraints are placed on how rapidly NGCC units can reach their potential maximum utilization if it is cost-effective.

Building Block 3 – Increases in Renewable and Nuclear Generation

EPA's calculation of state targets includes the effects of generation from potential additions of new renewable units after 2012. Additions of new renewable and new nuclear generation also are among the CPP compliance options in NERA's analysis to the extent that they are cost-effective relative to other compliance options. Their cost-effectiveness is determined by their capital and operating costs. NERA's analysis used the capital and operating costs estimated by EIA for its *AEO 2015* forecasts. I summarize NERA's capital cost assumptions for new capacity in Exhibit 2, which also includes comparable assumptions for new natural gas capacity, as those assumptions may also affect the relative cost-effectiveness of Building Block 3-related compliance measures in a least-cost compliance outcome for CPP compliance.

Exhibit 2. NERA Analysis's Assumptions for New Renewables, Nuclear, and Natural Gas Generating Capacity (2015$; costs vary by region around these averages)

(Source: U.S. Energy Information Administration, *AEO 2015*)

Technology	Capital Cost (2020/2030) ($/kW)	Fixed O&M Cost ($/kW-yr)	Variable O&M Cost ($/MWh)	Heat Rate (MMBtu/MWh)	Maximum Capacity Factor (2)
Onshore Wind	$2,024 / $1,972	$40.92	$0.01	N/A	24% - 41%
Solar PV	$3,325 / $3,055	$25.55	$0.01	N/A	23% - 34%
Natural Gas Combined Cy	$992 / $969	$13.62	$3.73	7,050	87%
Natural Gas Combustion T	$741 / $715	$7.29	$10.74	9,750	70%
Nuclear (1)	$5,158 / $4,890	$96.52	$2.22	10,479	90%

(1) NewERA model does not allow any additions of new nuclear generating capacity until 2025.

(2) For new renewable units, the maximum capacity factor is stated as a range because it varies by model region.

Increases in End-Use Energy Efficiency

End-use energy efficiency was not treated as a building block by EPA when it calculated the CPP's state-specific limits but EPA does include it as an option for CPP compliance. Under a mass-based approach, reducing energy use is an option even if it is not specifically identified as such by the rule, because any action that reduces emissions from the capped sources is inherently an option. Under the rate-based approach, energy efficiency would need to be an allowable part of the compliance formula—which it is in the CPP. Thus, assumptions about the availability and cost of energy efficiency are important to estimates of the cost of the CPP under both approaches.

In its analysis of the proposed rule, EPA's assumed costs increased with the level of incremental energy efficiency the state added, ranging from $550/MWh for adding less than 0.5%, $660/MW for adding between 0.5% and 1.0%, and $770/MWh for adding more than 1.0% (all in 2011$). In our earlier analysis of the proposed rule, NERA reviewed the literature on the cost of energy efficiency and concluded that a cost of about $900/MWh (2011$) was an appropriate estimate of historical (*i.e.*, already-incurred) efficiency improvement cost.[9] NERA assumed that value for the first tranche of reductions, and assumed costs for the higher tranches would increase in the same proportions that EPA had assumed. For its analysis of the final CPP, EPA has revised its cost estimate for the first 0.5% of improvement upwards to $1,100/MWh (2011$),[10] which is about the same level that NERA estimated for historical costs in its earlier review. NERA therefore adopted EPA's cost of $1,100/MWh (2011$) for the first tranche of energy efficiency improvements in its final CPP analysis.

Although EPA has revised upward its cost estimate for the first tranche of efficiency gains, EPA also has reversed its prior assumption that the cost per MWh of reduction would increase for larger percentage reductions, and instead assumes now that improvements of 0.5% up to 1.0% will cost less ($880/MWh reduced, 2011$), and less still ($660/MWh reduced, 2011$) for 1.0% efficiency improvements. We have reviewed EPA's explanations for this assumption, and do not find them compelling. EPA's assumption of declining costs is not consistent with experience in which the "low-hanging fruit" for improving energy efficiencies is used up in initial programs and deeper cumulative percentage improvements become more costly. This pattern would lead to a rising $/MWh supply curve for larger percentage reductions, as EPA assumed in its analysis of the proposed rule. However, recognizing that deeper cuts will also occur later in time (due to limits that EPA assumed on the amount of improvement per year), it is

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[9] NERA developed this estimate based on information from Allcott, Hunt and Michael Greenstone. 2012. "Is There an Energy Efficiency Gap?" *Journal of Economic Perspectives*, 26(1):3-28. (Available: http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.26.1.3). See NERA's 2014 report on the proposed CPP for more discussion of these energy efficiency cost estimates. (Available: http://www.nera.com/content/dam/nera/publications/2014/NERA_ACCCE_CPP_Final_10.17.2014.pdf.)

[10] EPA, *Demand-Side Efficiency Technical Support Document*, August 2015, Table 27, p. 70. (Available: http://www3.epa.gov/airquality/cpp/tsd-cpp-demand-side-ee.pdf.)

possible that the entire efficiency supply curve could shift downwards over time. To account for these two offsetting effects, NERA's analysis assumes a flat rather than a rising $/MWh curve, while adopting the same temporal constraints on the amount of improvement per year that EPA has assumed. Thus, NERA has assumed that any quantity of end-use energy efficiency improvement can be obtained at a cost of $1,100/MWh of reduction (2011$). While this is higher than EPA's cost for the larger improvements, it still assumes a large amount of technological progress (*e.g.*, "learning by doing") to offset the natural tendency for costs to rise as more ambitious programs are implemented.

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. However, our very low cost assumptions result in our model selecting the entire potential supply of energy efficiency, consistent with EPA's assumption. As discussed in our 2014 report, 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 base case to which the CPP case is compared when deriving the cost and impacts of the CPP.

Potential Compliance Costs Not Included in NERA's Analysis

The cost and effectiveness assumptions of the above options were used in the N_{ew}ERA model to estimate the least-cost compliance paths for each trading region. There are several potential sources of compliance costs that have <u>not</u> been included in NERA's analysis. We made no attempt to assess needs for additional spending on electricity transmission infrastructure or natural gas pipeline infrastructure in order to implement any of the compliance actions selected. The analysis also does not include any costs for states to prepare their implementation plans, or to execute those plans.

Spending and Consumer Impacts of the Clean Power Plan

The NERA analysis structure that I have summarized above estimated that incremental expenditures on energy to comply with the CPP will be very substantial. For the two mass-based scenarios for CPP compliance that NERA analyzed:[11]

- Energy sector expenditures from 2022 through 2033 increase by $220 billion to $292 billion (present value in 2016 relative to base case projections).
- The average annual increase is $29 billion to $39 billion per year.
- Average annual U.S. retail electricity rates are higher by 11% to 14% (relative to average baseline rates over the period 2022-2033).

The ranges reflect the different assumptions about potential free allowance allocations to reduce electricity rates, and about the regional scale of allowance trading. Exhibit 3 provides a more detailed summary of these and other key energy sector impact measures.

[11] Unless I state otherwise, all of the dollar values in my testimony are in 2015$.

Exhibit 3. Detailed Summary of NERA's Estimates of Energy Sector Impacts over the Period 2022-2033 for Mass-Based CPP Compliance Scenarios (2015$)

	Present Value of Expenditures	Annual Average Expenditures	Retail Electricity Rate	Henry Hub Natural Gas Price	Total CO_2 Emissions
	PV billion$	Annual avg billion$	¢/kWh	$/MMBtu	Annual avg MM metric tons
Baseline	$2,143	$333	11.1	$5.7	2,038
Mass-Based	$2,384 to $2,436	$364 to $372	12.3 to 12.6	$5.7 to $5.8	1,610 to 1,613
Change	+$241 to +$292	+$32 to +$39	+1.2 to +1.6	+$0.0 to +$0.0	(428) to (425)
% Change	+11% to +14%	+10% to +12%	+11% to +14%	+0% to +1%	-21% to -21%
Mass-Based with Regional Trading	$2,364 to $2,408	$362 to $368	12.3 to 12.6	$5.7 to $5.7	1,637 to 1,641
Change	+$220 to +$264	+$29 to +$35	+1.2 to +1.5	($0.1) to ($0.0)	(400) to (396)
% Change	+10% to +12%	+9% to +11%	+11% to +14%	-1% to -1%	-20% to -19%

Source: N_{ew}ERA modeling results.
Note: Present value is from 2022 through 2033, taken in 2016 using a 5% real discount rate. Annual averages and retail electricity rates are averages over the same period. Dollars in constant 2015 dollars. The ranges on results for each alternative trading scenario reflect the proportion of allowances freely allocated to LDCs, which varies from no LDC allocation to 50% LDC allocation. By 2031, annual CO_2 emissions are 36% to 37% lower than they were in 2005.

The energy expenditure estimates include changes in spending for energy efficiency improvements that reduce electricity demand, changes in spending to meet the remaining demand, changes in costs to purchase natural gas for non-electric needs, and any necessary allowance purchases.[12] Some of that spending, such as allowance purchases, is distributional in nature, as they also imply increased revenues in other parts of the economy.

NERA's analysis was also macroeconomic in scope, meaning that it also reports the net resource cost to the entire U.S. economy of the CPP compliance expenditures net of transfer payments such as allowance purchases. NERA's macroeconomic analysis projects that the CPP also will have a substantial net effect on overall societal spending power. Even after accounting for the offsetting benefits of reduced need for consumers

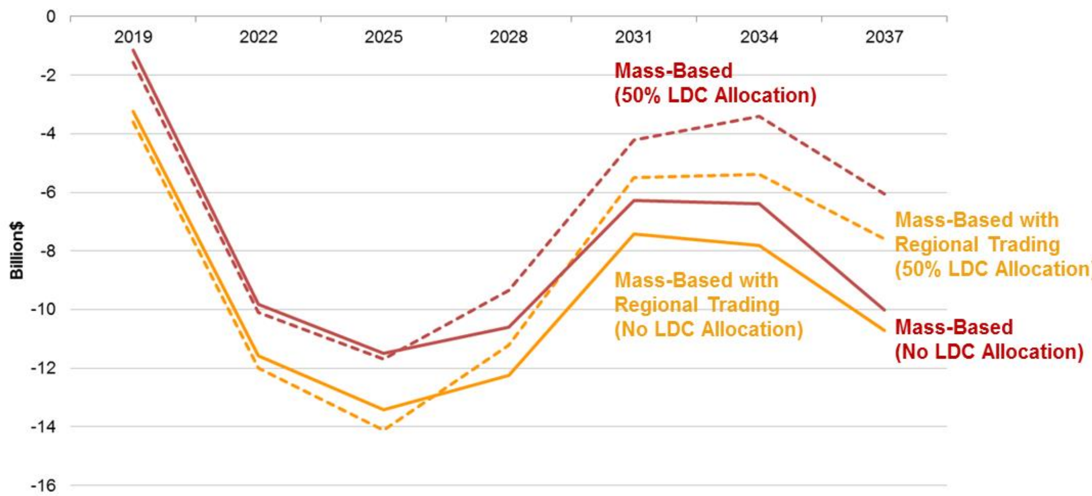
[12] Again, no costs for potential needs to upgrade electricity transmission or natural gas pipeline infrastructure have been estimated or included.

to purchase electricity, the reduced electricity rates from any free allocations to local utilities, and the financial rebates to households from the value of auctioned allowances,

- Net economic losses to U.S. consumers are projected to be $64 billion to $79 billion (present value in 2016 relative to baseline consumption from 2022-2033).

Exhibit 4 graphs the timing of the net societal costs of the CPP—as measured by reduced U.S. consumption—for the mass-based scenarios in NERA's analysis.

Exhibit 4. NERA's Estimates of Net Impacts to U.S. Consumption (Excluding All Allowance Costs) for Mass-Based CPP Compliance Scenarios
($ billions per year, relative to baseline consumption, 2015$)



Source: N$_{ew}$ERA modeling results, relative to baseline.
Notes: Net effects on U.S. spending power, including return to households of full value of allowances, either all through means other than lower electric rates (no allocation case) or half through reductions in electricity rates and half through another means (50% LDC allocation case).

The results I have described so far are for the mass-based compliance approaches that NERA modeled. Our full report (see Attachment A) also contains results for an illustrative rate-based compliance scenario in which each state achieves its limits on a least-cost basis using only within-state options. (This is consistent with trading of emission reduction credits (ERCs) on an intra-state basis.) This scenario's projected impacts are similar to those projected for NERA's mass-based compliance scenarios. Despite generally similar impacts, however, there will be many differences in implementation challenges, distributional impacts, and long-term flexibilities between the mass-based and rate-based compliance alternatives. Determining these differences and the trade-offs they present to individual states would require additional analysis.

Comparisons of NERA's Cost Estimates to EPA's Cost Estimates

I have heard commentary on NERA's analysis that suggests it projects cost impacts that are exceedingly higher than EPA's. Such statements are based on the "apples-to-oranges" comparisons, and are misleading for that reason. I would like to explain some difficulties with EPA's reporting and provide the results of an "apples to apples" comparison that shows NERA's estimates actually are in the same ballpark as EPA's.

First, I want to point out a problem in the costs that EPA has reported in its Regulatory Impact Analysis (RIA).[13] The RIA provides an estimate of compliance cost on a per-year basis, and only for three points in time (2020, 2025, and 2030).[14] For the mass-based scenario, the RIA reports costs of $1.4 billion, $3.0 billion and $5.1 billion (2011$) for each of these three years.[15] But these figures are not correct representations of the true spending projected by EPA's analysis for those years. Using EPA's own

[13] EPA's RIA is available at http://www2.epa.gov/cleanpowerplan/clean-power-plan-final-rule-regulatory-impact-analysis.

[14] Although the CPP limits do not take effect until 2022, EPA's modeling assumes that compliance starts in 2020. This appears to be because EPA did not alter its IPM model periods to match those of the final CPP, and used the same model it had used for its proposed CPP analysis.

[15] RIA, Table ES-10, p. ES-23.

output files, NERA has determined that the actual spending levels projected by EPA in those three years are $17.4 billion, $11.4 billion, and $4.1 billion, respectively (2011$).

The reason for the discrepancy is that EPA has not reported the *annual* spending on end-use energy efficiency incurred in each of those years, but instead reported an "annualized" cost, which assumes that the cost of each year's end-use efficiency spending is somehow not incurred in that year but is instead incurred over a period of 21 years into the future. This is not the way the actual spending for energy efficiency programs will be incurred. Companies pay for those projects in the year in which they occur. I understand from discussions with utility companies (and supported by analyses of rate impacts by both EIA and EPA) that those full costs are also passed through to retail rates in the same year that they are spent.[16] Thus, EPA's RIA is understating the compliance costs in those years by a very substantial amount, effectively by re-assigning a large fraction of the end-use efficiency costs to years after 2030.[17]

An additional concern with the way EPA reports costs is its reporting of just three points in time. Since costs may vary from year to year, a more appropriate way to express the full costs of a policy is to provide a present value of the policy costs, as

[16] It is evident that EPA's analysts are aware of this fact because EPA's calculations of electricity rate impacts in those years do use the full annual energy efficiency spending, and not just the much smaller levels used to report compliance costs in Table ES-10 of the RIA.

[17] These problems in EPA's cost analysis were identified by my NERA colleague, Mr. Scott Bloomberg, who is an expert in the electricity sector modeling used in N_{ew}ERA and IPM. Mr. Bloomberg used three EPA output files to replicate the costs reported in the RIA, identify the error, and then to make the correction. The files are (1) for energy efficiency costs, www3.epa.gov/airquality/cpp/df-cpp-demand-side-ee-at3.xlsx; (2) for IPM Base Case cost outputs, www2.epa.gov/sites/production/files/2015-08/base_case.zip (Base Case SSR.xlsx, Table 1-16_US worksheet, Table 15); and (3) for IPM Mass-Based scenario cost outputs, www2.epa.gov/sites/production/files/2015-08/mass-based.zip (Mass-Based SSR.xlsx, Table 1-16_US worksheet, Table 15). NERA's spreadsheet documenting the replication and then the correction based on data copied from the above three files is provided as Attachment B to this testimony.

NERA has done. Using EPA's cost output files, we have estimated that EPA's own present value for compliance spending in the period 2022-2030 is about $71 billion (2011$), or $76 billion (2015$).[18] This excludes spending on allowance purchases.[19] If companies have to purchase allowances, these costs should be reported as expenditures the electricity sector will incur to comply. However, the RIA is presenting estimates of electricity sector compliance expenditures excluding allowance spending as a "proxy" for societal costs.[20] The RIA needs to rely on a crude proxy estimate such as this because EPA has not performed a proper estimate of net societal costs using a macroeconomic model. As I have explained above, NERA has performed a proper macroeconomic analysis to assess net societal costs of the CPP. NERA's estimate of the present value of net societal costs of the CPP (excluding allowance costs) is $64 billion to $79 billion (2015$) for a mass-based approach. This is remarkably similar to EPA's $76 billion (2015$) present value "proxy" estimate. Thus, an "apples-to-apples" comparison shows that NERA's economic impact estimates are actually in the same ballpark as EPA's, once the flaws in EPA's reporting of its own cost estimates are corrected and more comparable concepts of policy cost are compared.

[18] This calculation is also documented in the spreadsheet in Attachment B of this testimony.

[19] EPA has assumed that 100% of the allowances are allocated to the electricity sector for free (RIA, p. 3-36). However, I have heard of criticism of NERA's estimates of electricity sector expenditures for including the cost of allowances; but this criticism is without merit. Although these costs are not net societal costs—and are not treated as such in NERA's analysis and reporting of social cost impacts—the costs to purchase allowances at auction do represent costs of the electricity system that do affect electricity rates. As I have discussed, NERA considered two cases with different levels of assumed allocation of free allocation that lead to different electricity rate impacts, and thus different distributional impacts.

[20] RIA, p. ES-10.

Note that NERA's estimates of changes in energy *expenditures* are outputs of the same integrated macroeconomic modeling runs that produced our estimates of net societal cost and thus are fully consistent with our societal cost estimates. The larger expenditure impacts are also relevant to an evaluation of the CPP because they reflect the potential *distributional* impacts of compliance with the CPP. Both distributional impacts and net societal costs of a policy are relevant to policy makers. In contrast to NERA's set of reported impact measures, the cost tables in EPA's RIA are unhelpful because they do not report information on properly-estimated net societal costs, nor indicate distributional impacts.

Proper Comparisons of Costs and Benefits

NERA's objective was to assess the types of energy sector shifts that are likely to be necessary to comply with the CPP limits, and their associated costs at a macroeconomic level. This objective is in the domain of economic impact analysis, which provides one of the inputs to a benefit-cost comparison. As I have explained above, EPA has understated its own cost estimates in its comparison of costs to projected benefits of the CPP in the RIA. EPA also makes misleading public statements about the benefits of the CPP. For example, in its press release for the final CPP rule, EPA stated:

> *By 2030, the plan will cut carbon pollution from the power sector by nearly a third and additional reductions will come from pollutants that can create dangerous soot and smog, translating to significant health benefits for the American people. ... Americans will avoid up to 90,000 asthma attacks and spend up to 300,000 more days in the office or the classroom, instead of sick at home. And up to 3,600 families will be spared the grief of losing a loved one too soon.*[21]

21 EPA, "Obama Administration Takes Historic Action on Climate Change/Clean Power Plan to Protect Public Health, Spur Clean Energy Investments and Strengthen U.S. Leadership." Press release, August

In fact, <u>none of those projected asthma attacks, sick days or 3,600 "premature deaths" has any relationship to climate change</u>. They are entirely based on projected changes in emissions other than greenhouse gases—emissions that are reduced coincidentally as the result of the actions to reduce CO_2 emissions. These gains are called "co-benefits." Not only do these estimates have nothing to do with avoidance or mitigation of climate change, but the health effects that may occur from these other types of emissions are already stringently regulated to non-dangerous levels under other provisions of the Clean Air Act. Indeed, if EPA considered the health risks on which its co-benefits estimates are made as manifest, EPA would be required to eliminate them as a matter of long-established law.

The public deserves both a proper assessment of the true costs of the CPP and a clear comparison of those costs to its climate-related benefits. I hope that this testimony has provided an understanding of the true nature of the potential societal costs and impacts of the CPP—important components of any valid benefit-cost analysis.

Thank you for the opportunity to testify. I am attaching and entering into the record a full copy of the NERA analysis of CPP costs and impacts that I have summarized and discussed in the above written testimony.

3, 2015. (http://yosemite.epa.gov/opa/admpress.nsf/bd4379a92ceceeac8525735900400c27/c5df9981993c6df785257e96004d4f14!OpenDocument).

ATTACHMENT A
TO NOVEMBER 18, 2015 TESTIMONY
OF DR. ANNE E. SMITH

Copy of *Energy and Consumer Impacts of EPA's Clean Power Plan,* by NERA Economic Consulting, November 7, 2015.

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Energy and Consumer Impacts of EPA's Clean Power Plan

Prepared for the American Coalition for Clean Coal Electricity

November 7, 2015

Insight in Economics™

Contents

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Executive Summary

NERA Approach to Analyzing the Final Clean Power Plan

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- NERA used a state-of-the-art energy/economy model (N_{ew}ERA) to assess the impacts of the CPP
  - Impacts are measured relative to projected baseline conditions (i.e., without CPP)
  - Baseline values for this analysis, including electricity demand and supply, capital costs, and fuel costs, are based on the *AEO 2015* reference case projections
- NERA analyzed two alternative scenarios for mass-based CPP compliance, differing in the extent of trading each assumes (state versus regional)*
  - Both scenarios identify least cost compliance from all available options within the assumed trading regions, including end-use energy efficiency
  - Results for both are presented for two cases on whether or not some of the value of allowances is used to lower electricity rate impacts

	Scenario	Trading
1	Mass-Based	Intra-State
2	Mass-Based with Regional Trading	Regional

(*) Appendix 2 provides results for a rate-based scenario

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Scenarios Include Two Assumed Cases for Allocating the Value of Allowances

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- Two mass-based modeling scenarios present a range based on two assumptions on allocation of allowance value to electric local distribution companies (LDCs), which would reduce electricity system costs and thus retail electricity rates
  - **No LDC allocation:** Allowances are auctioned to generators with none of the proceeds distributed to LDCs, and thus electricity price impacts are not reduced
  - **50% LDC allocation**: Half of allowances are auctioned to generators, with the other half freely distributed to LDCs and used as credit to retail rates
- LDCs set regulated retail electricity rates on the basis of net costs, including any allowance allocation value that is provided
  - Thus LDCs "pass on" allowance value to electricity customers in the form of lower rates
  - In cost-of-service jurisdictions, providing "free" allowances to generators would have the same effect on electricity rates
- Note that in both cases the full value of allowances is returned to state households
  - **No LDC allocation:** All value provided to all households via means other than lowering electricity rate impacts
  - **50% LDC allocation:** Half the value provided to households via means other than lowering electricity rates, and the other half of the value is provided to LDCs and thus to electricity consumers in the form of lower electricity rate impacts

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Key Findings

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- All compliance scenarios lead to large reductions in average CO_2 emissions
  - Reductions range from 19% to 21% (relative to baseline emissions)
  - By 2031, annual emissions are 36% to 37% lower than they were in 2005
- Energy sector expenditure increases range from $220 to $292 billion (spending from 2022 through 2033, brought to a present value in 2016)
  - Annual average expenditures increases between $29 and $39 billion/year
  - Expenditures include changes in electricity generation costs (including allowance costs), energy efficiency costs, and increased natural gas costs for non-electric consumers
  - Expenditures do not include potential increased costs for electricity transmission and distribution and natural gas infrastructure
- Average annual U.S. retail electricity rate increases range from 11%/year to 14%/year (relative to baseline) over the same time period
- For the overall economy, losses to U.S. consumers range from $64 billion to $79 billion on a present value basis over the same time period

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Energy Sector Impacts

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Key Energy Impacts of Compliance Scenarios (2022-2033, 2015$)

	Present Value of Expenditures	Annual Average Expenditures	Retail Electricity Rate	Henry Hub Natural Gas Price	Total CO_2 Emissions
	PV billion$	Annual avg billion$	¢/kWh	$/MMBtu	Annual avg MM metric tons
Baseline	$2,143	$333	11.1	$5.7	2,038
Mass-Based	$2,384 to $2,436	$364 to $372	12.3 to 12.6	$5.7 to $5.8	1,610 to 1,613
Change	+$241 to +$292	+$32 to +$39	+1.2 to +1.6	+$0.0 to +$0.0	(428) to (425)
% Change	+11% to +14%	+10% to +12%	+11% to +14%	+0% to +1%	-21% to -21%
Mass-Based with Regional Trading	$2,364 to $2,408	$362 to $368	12.3 to 12.6	$5.7 to $5.7	1,637 to 1,641
Change	+$220 to +$264	+$29 to +$35	+1.2 to +1.5	($0.1) to ($0.0)	(400) to (396)
% Change	+10% to +12%	+9% to +11%	+11% to +14%	-1% to -1%	-20% to -19%

Source: N_{ew}ERA modeling results.
Note: Present value is from 2022 through 2033, taken in 2016 using a 5% real discount rate. Annual averages and retail electricity rates are averages over the same period. Dollars in constant 2015 dollars. The ranges on results for each alternative trading scenario reflect the proportion of allowances freely allocated to LDCs, which varies from no LDC allocation to 50% LDC allocation. By 2031, annual CO_2 emissions are 36% to 37% lower than they were in 2005.

State Electricity Price Impacts

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- Retail electricity prices were modeled from 2022-2033 (four model years) using N_{ew}ERA output and other information that contributes to estimating cost-of-service and competitive pricing
- State-level average electricity price increases demonstrate that many states could experience significant price increases relative to the baseline
  - 40 states could have average retail electricity price increases of 10% or more
  - 17 states could have average retail electricity price increases of 20% or more
  - 10 states could have average retail electricity price increases of 30% or more
- The highest annual increase in retail rates relative to the baseline also shows that many states could experience periods of significant price increases
  - 41 states could have “peak” retail electricity price increases of 10% or more
  - 28 states could have “peak” retail electricity price increases of 20% or more
  - 7 states could have “peak” retail electricity price increases of 40% or more

State Electricity Price Impacts

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State-Level Electricity Price Increases (Relative to Baseline Prices)

	Number of States With Average Rate Increases			Number of States With "Peak" Model Year Rate Increases			
Scenario	**≥ 10%**	**≥ 20%**	**≥ 30%**	**≥ 10%**	**≥ 20%**	**≥ 30%**	**≥ 40%**
Mass-Based							
No Allocation	37	16	9	41	24	12	3
50% Allocation	30	6	1	36	14	3	0
Mass-Based with Regional Trading							
No Allocation	37	14	4	41	25	10	7
50% Allocation	31	8	0	37	15	6	2
Across Any Scenario	40	17	10	41	28	14	7

Notes: Retail electricity prices were modeled from 2022-2033 using NewERA output and other information that contributes to estimating cost-of-service and competitive pricing. The average rate increase is calculated at the state-level by comparing the price under the policy to the price in the baseline. The "peak" rate increase is calculated at the state-level by comparing, across model years, the percent increase in the price under the policy relative to the baseline price during that model year. The highest percent increase across all model years is the "peak" price increase. Results across any scenario include the four scenario/case combinations above.

The CPP could potentially generate significant average and "peak" retail electricity rate increases, with most states experiencing double-digit increases

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Impacts to U.S. Consumers

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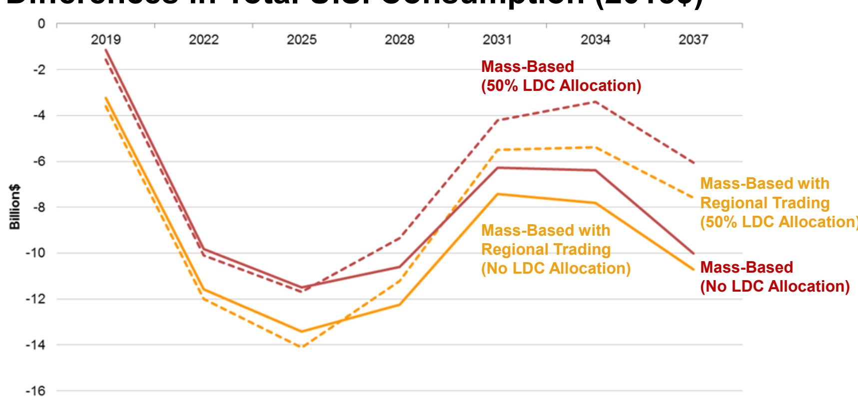
Differences in Total U.S. Consumption (2015$)



Source: N_{ew}ERA modeling results, relative to baseline.
Notes: Net effects on U.S. spending power, including return to households of full value of allowances, either all through means other than lower electric rates (no allocation case) or half through reductions in electricity rates and half through another means (50% LDC allocation case).

Present value of total consumption loss—reflecting reduced economic well-being—over the period from 2022 to 2033 ranges from $64B to $79B

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Overview of Clean Power Plan

Overview of CPP

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- The CPP aims to reduce CO_2 emissions from existing fossil-fueled power plants
- The CPP establishes interim (2022-2029) and final (2030) statewide goals in three forms:
  - Mass-based state goal measured in total short tons
  - Mass-based state goal with a new source complement measured in total short tons
  - Rate-based state goal measured in pounds per megawatt hour (lb/MWh)
- States have responsibility to implement plans to ensure that power plants in their states (individually or in combination with other measures) achieve the interim performance rates over 2022-2029 and the final goals by 2030
- States have the option to work with other states on multi-state approaches, including emissions trading

Basic Elements of the CPP

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	Final Rule
Program Timing	Starts in 2022 with "glide path" to final standards in 2030
Bases for Setting State Limits	State-specific emissions rates based on EPA's estimates of three "building block" options (increases in plant efficiency, natural gas & renewables). Emission rate limits converted to equivalent mass caps if states choose that compliance scenario.
Bases for State Compliance	Although not a "building block" for calculating state emissions limits, end-use energy efficiency can be used in state compliance plans
Trading Mechanisms	Intra-state trading and well as inter-state trading
Deadline for State Implementation Plan	September 2018, after initial submittal by September 2016
Federal Plan	EPA authorized to promulgate federal implementation plan if a state fails to submit a plan or submits a plan that does not comply.

Source: EPA (2015). *Overview of the Clean Power Plan.* http://www2.epa.gov/sites/production/files/2015-08/documents/fs-cpp-overview.pdf.

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NERA Methodology

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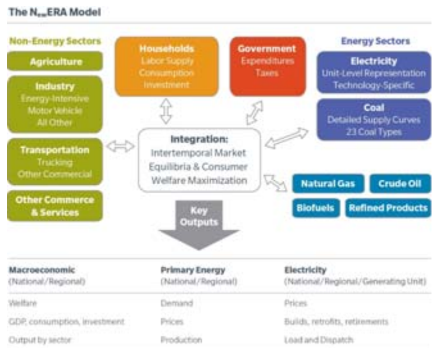
Analysis Uses NERA's N_{ew}ERA Model

- N_{ew}ERA combines a bottom-up electricity sector model with a top-down model of the full U.S. (macro)economy
  - Electricity sector model optimizes compliance with CPP and estimates electricity rate impacts and other system operational changes such as natural gas and coal usage
  - Macroeconomic model incorporates demand response to electricity price changes, and natural gas and coal price responses to changes in fuel usage
- Economic impact analysis thus offers a comprehensive understanding of not just electricity sector compliance but also overall impacts on consumer spending power
- Appendix 1 provides more details on the N_{ew}ERA model



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NERA Baseline

- N_{ew}ERA model and its baseline projections are calibrated to the Department of Energy's *AEO 2015* reference case
  - Power plant retirements were updated based on public announcements of firm closures as of August 2015
- Baseline includes effects of existing environmental regulations, including RGGI and California AB 32
  - Baseline does not reflect the possibilities of proposed or future regulations (similar to AEO methodology)
- Baseline does not include the additional end-use energy efficiency that EPA assumes is available for CPP compliance
  - Exception is that NERA assumes California adopts end-use energy efficiency as part of its compliance with the AB 32 program, and thus these costs and demand effects are assumed to be in the baseline

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NERA CPP Compliance Scenarios

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1. Mass-Based
   - State compliance with emissions targets (includes new sources)
   - Intra-state trading (least-cost compliance)
   - Range based on two assumed allowance allocations to LDCs
2. Mass-Based with Regional Trading
   - Same as Mass-Based except six trading regions
   - Regional boundaries same as EPA used in its draft Regulatory Impact Analysis (See Slide 32)
   - Range based on two assumed allowance allocations to LDCs

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NERA Assumptions Related to CPP Compliance Options

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1. **Coal Efficiency Retrofits**
   - EPA assumptions on the cost and effectiveness of coal heat rate improvements (4.3% for the Eastern Interconnection, 2.1% for the Western Interconnection, and 2.3% for the Texas Interconnection)
   - Units undertaking unit efficiency improvements are subject to New Source Review
2. **Natural Gas Generation**
   - Natural gas generation based upon least-cost generation mix using *AEO 2015* information on fuel prices and costs for alternative generation
3. **Renewable Generation**
   - Renewable generation based on least-cost generation mix using *AEO 2015* information on fuel prices and costs for alternative generation
4. **Energy Efficiency**
   - Use EPA assumption on initial cost ($1,100/MWh), which NERA applies to all energy efficiency programs (split 50/50 between utilities and consumers)
   - Use EPA assumptions on total potential for energy efficiency in each state

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Detailed Results: Mass-Based Scenario with Intra-State Trading Only

Impacts on U.S. Energy Markets: Mass-Based Scenario

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Annual Averages, 2022-2033

	Total Coal Retirements Through 2033	Coal-Fired Generation	Natural Gas-Fired Generation	Total Generation	Delivered Electricity Price
	GW	TWh	TWh	TWh	2015 ¢/kWh
Baseline	38	1,687	1,118	4,354	11.1
No LDC Allocation	85	1,254	1,121	3,919	12.6
Change	+47	(434)	+3	(435)	+1.6
% Change	+19%	-26%	+0%	-10%	+14%
50% LDC Allocation	82	1,249	1,141	3,945	12.3
Change	+45	(438)	+23	(408)	+1.2
% Change	+18%	-26%	+2%	-9%	+11%

Note: Coal retirements are cumulative from 2016-2033, with percentage change relative to baseline 2033 capacity. Other columns show annual average from 2022-2033. Natural gas-fired generation includes only existing and new combined cycle generation.

Mass-based CPP scenario leads to substantial changes in the U.S. energy system, including reductions in electricity generation and increases in electricity rates

U.S. Energy Sector Expenditure Impacts: Mass-Based Scenario

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Changes in Energy Sector Expenditures (2015$)

	No LDC Allocation	*50% LDC Allocation*
Present Value (Billion 2015$)		
Cost of Electricity, Excluding EE	($128)	($111)
Cost of Energy Efficiency	$268	$268
Cost of Non-Electricity Natural Gas	$1	$3
Cost of Allowances	$152	$80
Total Expenditures	$292	$241

Note: Present value is from 2022 through 2033, taken in 2016 using a 5% real discount rate. Note that energy efficiency costs reflect the combined costs to utilities and consumers. Costs do not include any additional transmission and distribution expenditures or any increased natural gas infrastructure costs All costs are presented relative to the baseline.

Mass-based CPP scenario leads to large increases in energy sector expenditures, reflecting substantial increases in costs for energy efficiency and allowances (particularly with no LDC allocation) that exceed savings from a smaller electricity system

Other Energy and Consumer Impacts: Mass-Based Scenario

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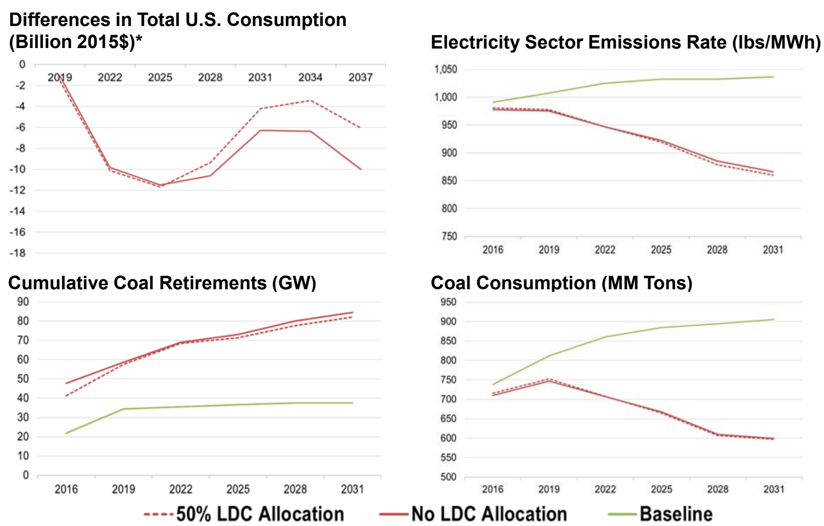

Source: N_{ew}ERA modeling results. Reported each model year (every three years).
* Consumption impacts are provided relative to Baseline scenario.

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Detailed Results: Mass-Based Scenario with Regional Trading

Impacts on U.S. Energy Markets: Mass-Based with Regional Trading Scenario

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Annual Averages, 2022-2033

	Total Coal Retirements Through 2033	Coal-Fired Generation	Natural Gas-Fired Generation	Total Generation	Delivered Electricity Price
	GW	TWh	TWh	TWh	2015 ¢/kWh
Baseline	38	1,687	1,118	4,354	11.1
No LDC Allocation	82	1,298	1,065	3,911	12.6
Change	+45	(389)	(53)	(443)	+1.5
% Change	+18%	-23%	-5%	-10%	14%
50% LDC Allocation	78	1,293	1,086	3,937	12.3
Change	+41	(394)	(32)	(416)	+1.2
% Change	+17%	-23%	-3%	-10%	+11%

Note: Coal retirements are cumulative from 2016-2033, with percentage change relative to baseline 2033 capacity. Other columns show annual average from 2022-2033. Natural gas-fired generation includes only existing and new combined cycle generation.

Mass-based with regional trading CPP scenario leads to substantial changes in the U.S. energy system, including reductions in electricity generation and increases in electricity rates

U.S. Energy Sector Expenditure Impacts: Mass-Based with Regional Trading Scenario

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Changes in Energy Sector Expenditures (2015$)

	No LDC Allocation	*50% LDC Allocation*
Present Value (Billion 2015$)		
Cost of Electricity, Excluding EE	($142)	($122)
Cost of Energy Efficiency	$268	$268
Cost of Non-Electricity Natural Gas	($4)	($2)
Cost of Allowances	$142	$76
Total Expenditures	$264	$220

Note: Present value is from 2022 through 2033, taken in 2016 using a 5% real discount rate. Note that energy efficiency costs reflect the combined costs to utilities and consumers. Costs do not include any additional transmission and distribution expenditures or any increased natural gas infrastructure costs . All costs are presented relative to the baseline.

Mass-based with regional trading CPP scenario leads to large increases in energy sector expenditures, reflecting substantial increases in costs for energy efficiency and allowances (particularly with no LDC allocation) that exceed savings from a smaller electricity system

Impacts to U.S. Consumers: Mass-Based with Regional Trading Scenario

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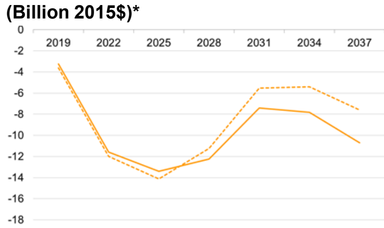
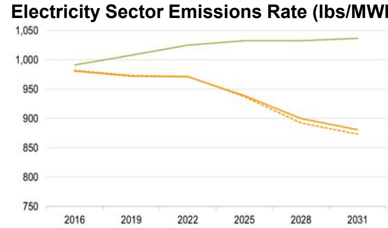
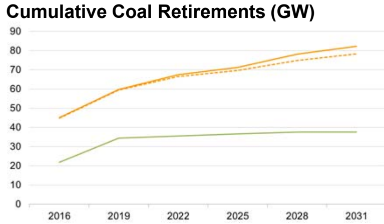
Differences in Total U.S. Consumption (Billion 2015$)*



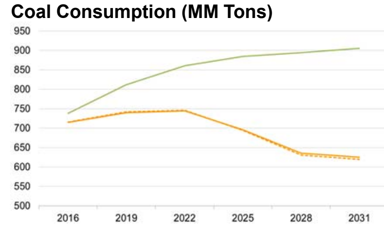
Electricity Sector Emissions Rate (lbs/MWh)



Cumulative Coal Retirements (GW)



Coal Consumption (MM Tons)



50% LDC Allocation — No LDC Allocation — Baseline

Source: N$_{ew}$ERA modeling results. Reported each model year (every three years).
* Relative to baseline consumption

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Appendix 1: Overview of N_{ew}ERA Model

N_{ew}ERA Model

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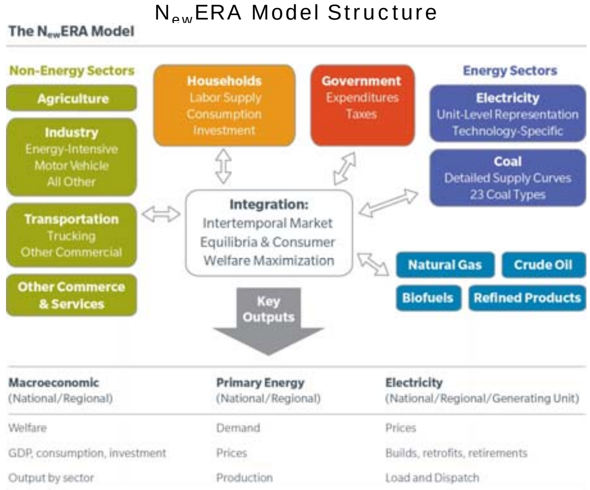
N_{ew}ERA Model Structure



Electricity Sector
- Capacity
- Generation
- Retirements
- Wholesale and Delivered Electricity Prices
- Emissions

Other Energy Sectors
- Production
- Consumption
- Energy Prices

Economic Outputs
- GDP
- Consumption
- Employment

N_{ew}ERA Electricity Sector Model: Overview

- Bottom-up dispatch and capacity planning model
  - Unit-level information on generating units in 34 U.S. regions
  - Detailed coal supply curves by coal type
  - Regional electricity demand and capacity requirements
- Least-cost projection of market activity
  - Satisfies demand and all other constraints over model time horizon
  - Projects unit-level generation and investment decisions and regional fuel and electricity prices
- Data sources
  - Model calibrated to U.S. Energy Information Administration's *AEO 2015*
  - Other electricity sector data from EIA, EPA, NERC, NREL, NETL, Ventyx Velocity Suite, and HellerWorx

N_{ew}ERA Electricity Sector Model: Unit-Level Detail

- Represents electricity capacity and generation at the unit level
  - 16 generating technologies, including renewables
  - Unit physical attributes: capacity, utilization, heat rate, outages, retrofits, emission rate
  - Unit costs: capital, fixed O&M, variable O&M, transmission and distribution, refurbishment
- Projects unit generation and investment decisions to minimize sector costs over projection period
  - Available actions include retirements, new builds, retrofits, coal type choice (for coal units), and fuel switching
  - Units will retire if they cannot remain profitable
  - Units can also be forced to take certain actions at specified times, or given a choice to act or retire

NewERA Electricity Sector Model: Fuel Supply

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- Model represents supply of five fuels: coal, natural gas, oil, biomass, and uranium
- Detailed supply curves for 23 coal types
  - At each “step” on supply curve, provides price, annual production limit, and total coal reserves available at that price
  - Transportation matrix determines coals that can be delivered to each unit and the cost of delivery
  - Coal units assigned an initial coal type, but can incur a capital costs to switch to other coal types when reasonable

NewERA Electricity Sector Model: Electricity Demand

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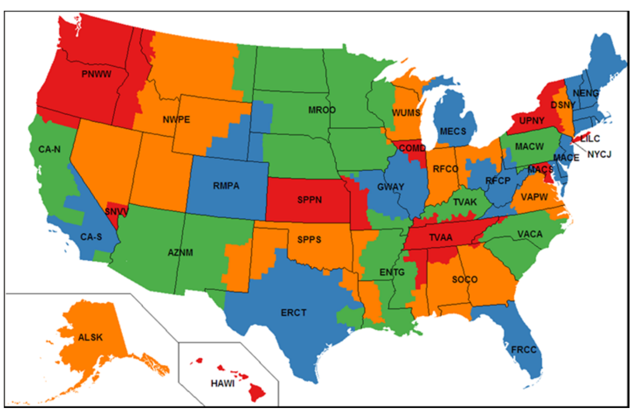

- Demand by region for 34 U.S. regions
- 25 electricity demand “load blocks”
  - Ten in summer and five each in winter, spring, and fall
  - Reflects peak vs. off-peak demand in each season
- Regional “reserve margins” based on peak demand
  - Regions required to have capacity in excess of peak demand for system reliability

N$_{ew}$ERA Electricity Sector Model: Regional Emission Trading Regions

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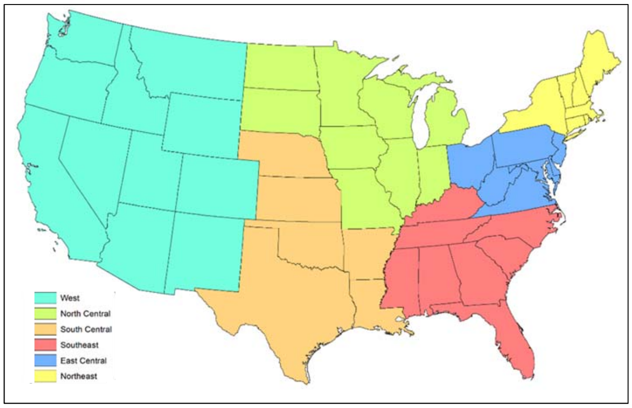

- Regions for the mass-based scenario with regional trading are based on the six regions developed by EPA in its RIA for the proposed Clean Power Plan

N$_{ew}$ERA Electricity Sector Model: Model Solution

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- Model is required to meet many electricity market and regulatory constraints
  - Regional demand, reserve capacity requirements, fuel availability, forced retrofits, RPS or emissions regulations
  - Flexible to a variety of user-specified constraints, from unit-specific actions to market-wide regulations
- Finds the least-cost way to satisfy all constraints
  - Uses perfect foresight of market conditions
  - Chooses investments and operation of units to minimize present value of costs over the entire model period

N_{ew}ERA Electricity Sector Model: Model Outputs

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- Model period 2016 – 2037 with outputs for every 3rd year (flexible to user specification)
- Unit-level and regional activity
  - Generation, investments in retrofits or capacity, retirements, operational costs, and revenues from generating and capacity services
- Regional prices
  - Minemouth and delivered coal, non-coal fuels, wholesale electricity, capacity, renewable energy credits, and emissions credit where applicable
  - Separate cost-of-service calculation reflects delivered prices in regulated jurisdictions

INPUTS
- Unit-level characteristics
- Detailed coal supply
- Regional demand
- Regulatory environment

N_{ew}ERA Model

OUTPUTS
- Load and dispatch
- Other unit actions
- Prices (fuel, electricity, capacity, tradable permits)

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The Comprehensiveness and Flexibility of the N_{ew}ERA Model is Well Suited to Modeling the CPP

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- N_{ew}ERA models CO_2 emission rates or mass-based caps at national, regional, state, or other aggregation level, accounting for changes in standards over time
- Includes an option for coal efficiency “upgrades”
  - The cost and availability can be varied by unit
- Models end-use energy efficiency as an economic decision within the model
  - Cost and availability of end-use energy efficiency are among the most significant modeling uncertainties
- Includes full suite of state options for new renewables
- Captures expected changes in natural gas prices based on changes in demand from the electricity sector
- Although this study has made simplifying alternative assumptions regarding state implementation of the CPP, N_{ew}ERA can be used to develop estimates for specific implementation plans for individual states

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Appendix 2: Detailed Results for Rate-Based Scenario

Energy Sector Impacts: Rate-Based Scenario

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Key Energy Impacts of Compliance (2022-2033, 2015$)

	Present Value of Expenditures	Annual Average Expenditures	Retail Electricity Rate	Henry Hub Natural Gas Price	Total CO_2 Emissions
	PV billion$	Annual avg billion$	¢/kWh	$/MMBtu	Annual avg MM metric tons
Baseline	$2,143	$333	11.1	$5.7	2,038
Rate-Based	$2,336	$358	12.1	$6.0	1,503
Change	+$192	+$25	+1.1	+$0.2	(535)
% Change	+9%	+7%	+10%	+4%	-26%

Source: N_{ew}ERA modeling results.
Note: Present value is from 2022 through 2033, taken in 2016 using a 5% real discount rate. Annual averages and retail electricity rates are averages over the same period. Dollars in constant 2015 dollars. By 2031, annual CO_2 emissions are 41% lower than they were in 2005.

Impacts on U.S. Energy Markets: Rate-Based Scenario

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Annual Averages, 2022-2033

	Total Coal Retirements Through 2033	Coal-Fired Generation	Natural Gas-Fired Generation	Total Generation	Delivered Electricity Price
	GW	TWh	TWh	TWh	2015 ¢/kWh
Baseline	38	1,687	1,118	4,354	11.1
Rate-Based	79	1,071	1,302	3,966	12.1
Change	+41	(616)	+184	(387)	+1.1
% Change	+17%	-37%	+16%	-9%	+10%

Note: Coal retirements are cumulative from 2016-2033, with percentage change relative to baseline 2033 capacity. Other columns show annual average from 2022-2033. Natural gas-fired generation includes only existing and new combined cycle generation.

CPP leads to major changes in the U.S. energy system under rate-based compliance scenario

U.S. Energy Sector Expenditure Impacts: Rate-Based Scenario

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Changes in Energy Sector Expenditures (2015$)

	Rate-Based
Present Value (Billion 2015$)	
Cost of Electricity, Excluding EE	($95)
Cost of Energy Efficiency	$268
Cost of Non-Electricity Natural Gas	$19
Cost of Allowances	$0
Total Expenditures	$192

Note: Present value is from 2022 through 2033, taken in 2016 using a 5% real discount rate. Note that energy efficiency costs reflect the combined costs to utilities and consumers. All costs are presented relative to the baseline.

CPP leads to large expenditures for energy efficiency that overwhelm savings from a smaller electricity system

Impacts to U.S. Consumers: Rate-Based Scenario

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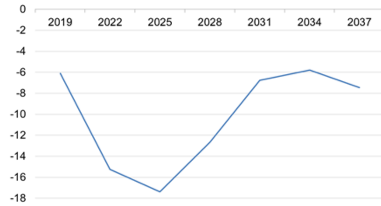
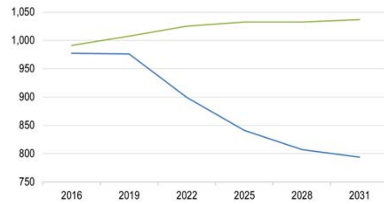
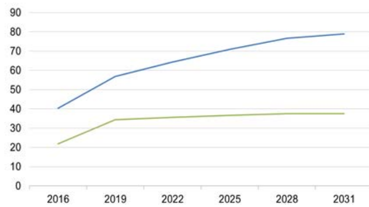
Differences in Total U.S. Consumption (Billion 2015$)*



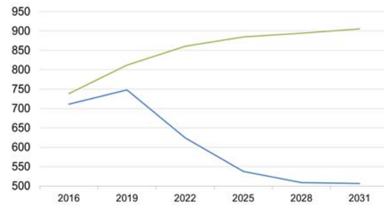
Electricity Sector Emissions Rate (lbs/MWh)



Cumulative Coal Retirements (GW)



Coal Consumption (MM Tons)



Rate-Based **Baseline**

Source: N$_{ew}$ERA modeling results. Reported each model year (every three years) relative to baseline consumption.
* Consumption impacts are provided relative to Baseline scenario.

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ATTACHMENT B
TO NOVEMBER 18, 2015 TESTIMONY
OF DR. ANNE E. SMITH

Copy of spreadsheet documenting NERA's correction to EPA's calculations of annual costs of CPP compliance in the CPP RIA, and associated present value.

Replication and Correction of EPA's Compliance Costs
Billions of 2011$

REPLICATION

	2016	**2018**	**2020**	**2025**	**2030**	**2040**	**2050**
Mass-Based Costs	$145.8	$155.6	$165.7	$164.6	$180.1	$191.8	$223.7
Base Case Costs	$146.5	$156.4	$166.5	$178.3	$201.3	$219.4	$258.8
Delta	-$0.7	-$0.8	-$0.8	-$13.7	-$21.2	-$27.6	-$35.1
Annualized EE Costs	$0.0	$0.0	$2.1	$16.7	$26.3	$31.0	$32.9
Total Policy Cost	-$0.7	-$0.8	$1.4	$3.0	$5.1	$3.3	-$2.2
Per RIA Table ES-5			***$1.4***	***$3.0***	***$5.1***		

Annual Costs w/ <u>Annualized</u> Energy Efficiency Costs

Model Year Mapping	2016	2016	2018	2020	2020	2020	2020	2025	2025	2025	2025	2025	2030	2030	2030	2030	2030	2030
Actual Year	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Mass-Based Costs	$146	$146	$156	$166	$165.7	$166	$166	$165	$165	$164.6	$165	$165	$180	$180	$180.1	$180	$180	$180
Base Case Costs	$146	$146	$156	$166	$166.5	$166	$166	$178	$178	$178.3	$178	$178	$201	$201	$201.3	$201	$201	$201
Delta	-$1	-$1	-$1	-$1	-$0.8	-$1	-$1	-$14	-$14	-$13.7	-$14	-$14	-$21	-$21	-$21.2	-$21	-$21	-$21
<u>Annualized</u> EE Costs	$0	$0	$0	$0	$2.1	$5	$8	$11	$14	$16.7	$19	$21	$24	$25	$26.3	$27	$28	$29
Total Policy Cost	-$1	-$1	-$1	-$1	**$1.4**	$4	$7	-$3	$0	**$3.0**	$6	$8	$2	$4	**$5.1**	$6	$7	$8

CORRECTION
Annual Costs w/ <u>First-Year</u> Energy Efficiency Costs

Model Year Mapping		2016	2016	2018	2020	2020	2020	2020	2025	2025	2025	2025	2025	2030	2030	2030	2030	2030	2030
Actual Year	**Present Value (2022-2033)**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Mass-Based Costs	$1,219	$146	$146	$156	$166	$165.7	$166	$166	$165	$165	$164.6	$165	$165	$180	$180	$180.1	$180	$180	$180
Base Case Costs	$1,330	$146	$146	$156	$166	$166.5	$166	$166	$178	$178	$178.3	$178	$178	$201	$201	$201.3	$201	$201	$201
Delta	-$111	-$1	-$1	-$1	-$1	-$0.8	-$1	-$1	-$14	-$14	-$13.7	-$14	-$14	-$21	-$21	-$21.2	-$21	-$21	-$21
<u>First-Year</u> EE Costs	$181	$0	$0	$0	$0	$18.1	$22	$24	$26	$27	$25.4	$25	$25	$25	$25	$25.3	$25	$26	$26
Total Policy Cost (2011$)	**$71**	-$1	-$1	-$1	-$1	**$17.4**	$21	$24	$12	$14	**$11.7**	$12	$12	$4	$4	**$4.1**	$4	$4	$4
2011$ to 2015$	*1.070*																		
Total Policy Cost (2015$)	**$76**																		

Sources:

Base Case Outputs	www2.epa.gov/sites/production/files/2015-08/base_case.zip (Base Case SSR.xlsx, Table 1-16_US worksheet, Table 15)
Mass-Based Case Outputs	www2.epa.gov/sites/production/files/2015-08/mass-based.zip (Mass-Based SSR.xlsx, Table 1-16_US worksheet, Table 15)
Energy Efficiency Costs	www3.epa.gov/airquality/cpp/df-cpp-demand-side-ee-at3.xlsx