



EPA's Clean Power Plan

Summary of IPM Modeling Results

JANUARY 13, 2016

Last updated: March 4, 2016 9:10 AM

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Acknowledgments

The following analysis of EPA's final Clean Power Plan (CPP) is based on Integrated Planning Model (IPM®) runs conducted by ICF International, and assumptions developed by M.J. Bradley & Associates (MJB&A). IPM® is a detailed model of the electric power system that is used routinely by industry and regulators to assess the effects of environmental regulations and policy. It integrates extensive information on power generation, fuel mix, transmission, energy demand, prices of electricity and fuel, environmental policies, and other factors.

These model runs are illustrative and not intended to be a prediction of the future; rather, the modelling is intended to assist stakeholders in understanding the implications of key policy decisions and assumptions, such as the form of the standards, the level of energy efficiency, and the degree of compliance flexibility (i.e., trading).

This report and the assumptions and scenarios for this analysis were developed by M.J. Bradley & Associates (MJB&A).

We would also like to acknowledge the valuable insights and constructive feedback of the following individuals in preparing this analysis: Derek Murrow, Starla Yeh, and Kevin Steinberger (Natural Resources Defense Council); Derek Furstenwerth (Calpine Corporation); Kathleen Robertson (Exelon Corporation); Ray Williams, Jeff Brown, and Xantha Bruso (PG&E Corporation); Michael Goggin (American Wind Energy Association); Jennifer Macedonia (Bipartisan Policy Center); Nicholas Bianco (Environmental Defense Fund); Rick Umoff (Solar Energy Industries Association); and Noah Kaufman and Kevin Kennedy (World Resources Institute).

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Executive Summary

The following report summarizes the results of 16 IPM model runs, evaluating two Reference Cases (business-as-usual scenarios) and 14 alternative Clean Power Plan (CPP) regulatory scenarios. For example, several of the cases assume that states adopt EPA's mass-based emissions goals. The cases also assume varying levels of demand-side energy efficiency. Based on the model runs completed to date, we offer the following observations and insights:

- Across a wide range of scenarios and assumptions, the results show that CPP targets are very achievable.
- The ability for power producers to trade leads to significant cost savings and flexibility for power producers.
- Increasing investment in energy efficiency programs reduces overall compliance costs because plants purchase less fuel and fewer new plants need to be built.
- States can meet the Clean Power Plan's emissions goals while relying on a diverse mix of supply- and demand-side resources, including energy efficiency, renewables, nuclear, natural gas and coal.
- EPA requires that mass-based state plans address the potential for "emissions leakage." Leakage results from the incentives under a mass-based plan to shift generation and emissions to new fossil-fired power plants outside the program. Our analysis shows that CO_2 emissions would increase with an "existing only" mass-based program versus an "existing plus new" source program. The most straightforward approach to address this issue is to adopt the "existing plus new" source mass limits, which is an option available to the states under the CPP. In addition, in the proposed model rule and federal plan, EPA has proposed a method for allocating allowances within an existing-only program to mitigate leakage. Although our modeling indicates the particular method proposed would have a minor impact on emissions leakage, EPA is taking comment on other approaches that could be more effective.
- There are additional sensitivity runs that were not evaluated as part of this study, which we hope to continue evaluating over the coming months, including: potential retirement of existing nuclear units; low gas prices; California's participation in trading systems with other states; additional "patchwork" policy and trading scenarios.
- This analysis was designed prior to Congressional approval of the phase-down of the Production Tax Credit (PTC) for wind energy and the extension of the Investment Tax Credit (ITC) for solar energy. We will plan to include these tax extensions in future model runs.

Methodology

Assumptions

- This analysis was based on IPM runs conducted by ICF International. M.J. Bradley & Associates relied on the assumptions from EPA's Base Case 5.15 implementation of IPM® as the starting the point for the assumptions that were used for this analysis. These assumptions are detailed here: http://www2.epa.gov/airmarkets/power-sector-modeling-platform-v515.
- EPA's Base Case (5.15) relies on AEO 2015 Demand Growth assumptions, updated cost and performance assumptions for renewable technologies, updated gas supply assumptions, and existing regulatory requirements (e.g., CSAPR and MATS). The PTC and ITC were assumed to expire as previously required by law.
- Consistent with EPA's modeling of the Clean Power Plan, this analysis does not assume banking of allowances and ERCs.
- In addition, M.J. Bradley & Associates made several modifications to EPA's assumptions, as detailed below.

- Some additional firm fossil unit retirements (17 units; 5.6 GW) were added, based on public announcements.
- Energy efficiency adoption was modeled in the policy cases based on a simplified "supply curve" of program costs developed from a comprehensive Lawrence Berkeley National Laboratory (LBNL) cost study.
- AB 32 CO_2 Allowance Prices were based on the California Energy Commission (CEC) IEPR "High Energy Consumption Case" through 2020; prices were held constant at 2020 levels (in real terms) post-2020. This is higher than the allowance prices that EPA had used in its CPP modeling.
- California's SB 350 RPS policy was implemented in the model.
- The carbon emissions charge on electricity imports to California was removed in 2022 and beyond in the CPP policy cases based on the logic that the country has transitioned to a national CO_2 program for the power sector.
- RGGI was assumed to remain at its 2020 goal in the Reference Case and Policy Cases.

Scenarios Evaluated

- The modeling included two Reference Case scenarios (no CPP) and 14 Policy Case scenarios:
  - Two Reference Case scenarios: (1) “RCa” assumes no additional energy efficiency savings beyond what is reflected in EIA’s AEO 2015 demand forecast; and (2) “RCb” assumes our “business-as-usual” level of energy efficiency savings described below (what we call the “current EE” savings levels)
  - Seven mass-based scenarios (both “Existing Only” and “Existing plus New”)
  - Three blended rate scenarios (these are the state-specific fossil rates in the final rule)
  - Two dual rate scenarios (steam and NGCC)
  - One patchwork scenario that combined mass-based and rate-based standards
- The Policy Case scenarios are based on EPA’s final rule published in the Federal Register on October 23, 2015.
- The modeling varied the extent of allowance/ERC trading across the Policy Cases to reflect the choices that states have in implementing the rule (see slide 12).
- The modeling varied the amount of energy efficiency available in our “supply curve” across the cases (see appendix for more detail):
  - **Current EE (CEE):** States can achieve savings up to their current (2013) annual savings rates between 2018 and 2030. This results in the lowest total energy efficiency savings among the three approaches.
  - **Modest EE (EE1):** States achieve up to a 1% annual savings rate (the same levels assumed by EPA in its RIA modelling). Nineteen states either have achieved, or have established requirements that will lead them to achieve, this rate of incremental electricity demand reduction on an annual basis.
  - **Significant EE (EE2):** States achieve up to a 2% annual savings rate.
- Most of the mass-based scenarios assumed that allowances would be auctioned; one of the scenarios modeled EPA’s proposed Federal Plan allocation methodology.

Mass-Based Scenarios

Case No.	Assumptions Key for Charts	Sources	Allocation	EE Levels	Trading Zones
MB01	e+n state ee1	Existing + New	Auction	Modest (1%)	State-by-state compliance (except RGGI)
MB02	e+n national cee	Existing + New	Auction	Current (Historic Savings Rates)	Nationwide (except California)
MB03	e+n national ee1	Existing + New	Auction	Modest (1%)	Nationwide (except California)
MB04	e+n national ee2	Existing + New	Auction	Significant (2%)	Nationwide (except California)
MB05	e national cee	Existing Only	Auction	Current (Historic Savings Rates)	Nationwide (except California)
MB06	e national ee1	Existing Only	Auction	Modest (1%)	Nationwide (except California)
MB07	e national ee1 oba	Existing Only	Federal Plan	Modest (1%)	Nationwide (except California)

Note: In all cases, we assume CEC-projected carbon prices in California—not the CPP mass goals for the state—and the RGGI states are assumed to comply with a region-wide, mass-based target equal to the 2020 RGGI cap, except in MB02, MB03 and MB04, where RGGI states trade these allowances nationally. These assumptions result in compliance with the CPP mass goals for California and the RGGI states under all cases except for MB03.

Key: MB = mass based, e+n = existing + new, e = existing only, state = no trading, national = nationwide trading (except Cal.), cee = current EE, ee1 = modest EE levels, ee2 = significant EE levels, oba = output based allocation (federal plan proposed allocation methodology)

Rate-Based Goal Scenarios

State-Specific Blended Rate Scenarios

Case No.	Assumptions Key for Charts	Rate Approach	EE Levels	Trading Zones
BR01	br ee1	Blended Rate	Modest (1%)	Two zones: East (plus Texas) and WECC (RE ERCs are traded within the zone; EE generates ERCs in-state)
BR02	br ee1	Blended Rate	Modest (1%)	Two zones: East (plus Texas) and WECC (RE/EE ERCs are traded within the zone)
BR03	br ee1	Blended Rate	Modest (1%)	Constrained EE and ERC trading
BR04	br ee2	Blended Rate	Significant (2%)	Constrained EE and ERC trading

Subcategory-Specific Dual Rate Scenarios

Case No.	Code	Rate Approach	EE Levels	Trading Zones
DR01	dr ee1	Dual Rate	Modest (1%)	Two zones: East (plus Texas) and WECC (RE/EE ERCs and GS-ERCs; Nuclear ERCs available in the state where generated)
DR02	dr ee2	Dual Rate	Significant (2%)	Two zones: East (plus Texas) and WECC (RE/EE ERCs and GS-ERCs; Nuclear ERCs available in the state where generated)

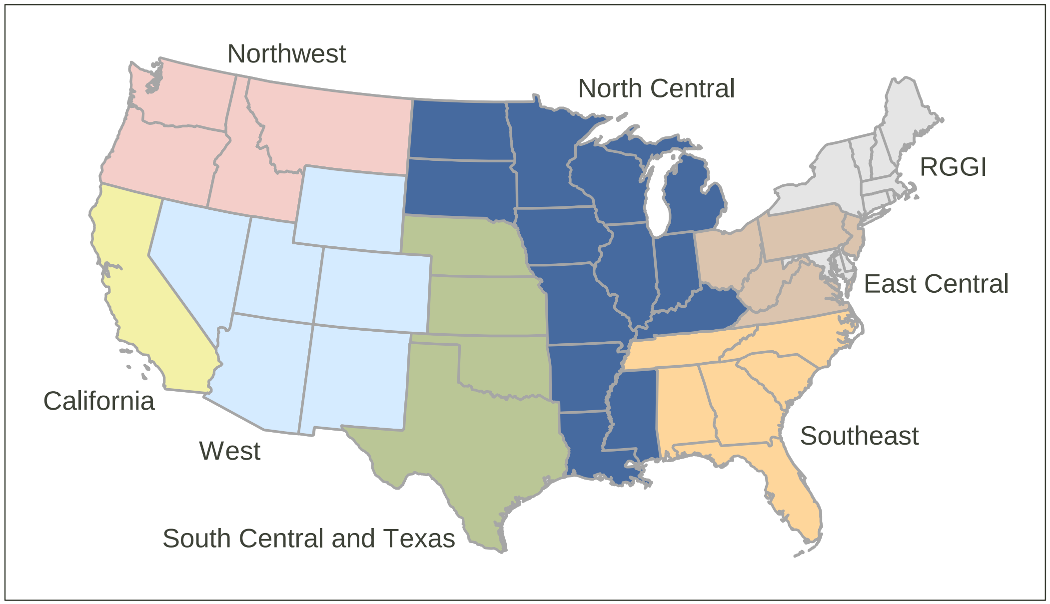
Note: In all cases, we assume CEC-projected carbon prices in California—not the CPP mass goals for the state—and the RGGI states are assumed to comply with a region-wide, mass-based target equal to the 2020 RGGI cap, except in MB02, MB03 and MB04, where RGGI states trade these allowances nationally. These assumptions result in compliance with the CPP mass goals for California and the RGGI states under all cases except for MB03.

These ERC trading scenarios are more constrained than what EPA allows under the final rule, but states may choose to limit trading and/or the geographic scope of ERC eligibility.

Patchwork Scenario

Case No.	Code	Regulatory Approach	EE Levels	Trading Zones
PW01	MB/EN/DR ee1	Mix of rate and mass	Modest (1%)	See map

Key: PW = Patchwork, MB/EN/DR = Combination of Mass Based (Existing plus New) and Dual Rate, ee1 = modest EE



Assumes multiple mass-based trading zones with the exception of the Southeast and Florida, which is assumed to adopt a dual rate approach. Mass-based states are assumed to regulate both existing and new sources. There is no trading of allowances across zones. Also, mass-based states do not generate ERC credits for use in the Southeast region.

Note: In all cases, we assume CEC-projected carbon prices in California—not the CPP mass goals for the state—and the RGGI states are assumed to comply with a region-wide, mass-based target equal to the 2020 RGGI cap, except in MB02, MB03 and MB04, where RGGI states trade these allowances nationally. These assumptions result in compliance with the CPP mass goals for California and the RGGI states under all cases except for MB03.

ERC Modeling

Blended Rate Scenarios

- Under the Blended Rate scenarios, the geographic scope of ERC crediting and trading varied across the cases:
  - Option1. EE and RE projects can apply for ERCs in any other rate-based state (within each trading zone) – BR02
    - This option represents the flexibility inherent in the final rule
  - Option 2. Only RE projects can apply for ERCs in any other rate-based state; EE ERCs are only available for compliance in the state where they are generated – BR01
  - Option 3. EE and RE projects can apply for ERCs within each market region, to mimic deliverability (i.e., PPA) requirements – BR03 and BR04
    - This scenario may be more likely to occur in practice
- Additionally, existing NGCCs are credited at the difference between the plant emissions rate and the state blended rate; these ERCs are only available in the state where they are generated

Dual Rate Scenarios

- Under the Dual Rate scenarios, ERCs were credited and traded within two zones to reduce the computational burden on the model: East (plus Texas) and WECC.
- The model credits incremental renewable generation, energy efficiency, and under construction nuclear generation. The model also credits existing NGCC with GS-ERCs. As required by the rule, GS-ERCs can only be used by steam generating units; however, there are always sufficient steam MWhs within each of the trading zones to consume all of the GS-ERCs.
- Nuclear ERCs were only available for compliance in the state where they were generated.

Results

The Clean Power Plan is Projected to Achieve a 16%-22% Reduction in Electric Sector CO_2 Emissions by 2030 (from 2012 levels) Across a Range of Scenarios

The Clean Power Plan is projected to achieve a significant reduction in electric sector CO_2 emissions across a range of different policy cases (i.e., mass-based targets, rate-based targets, and a patchwork scenario).

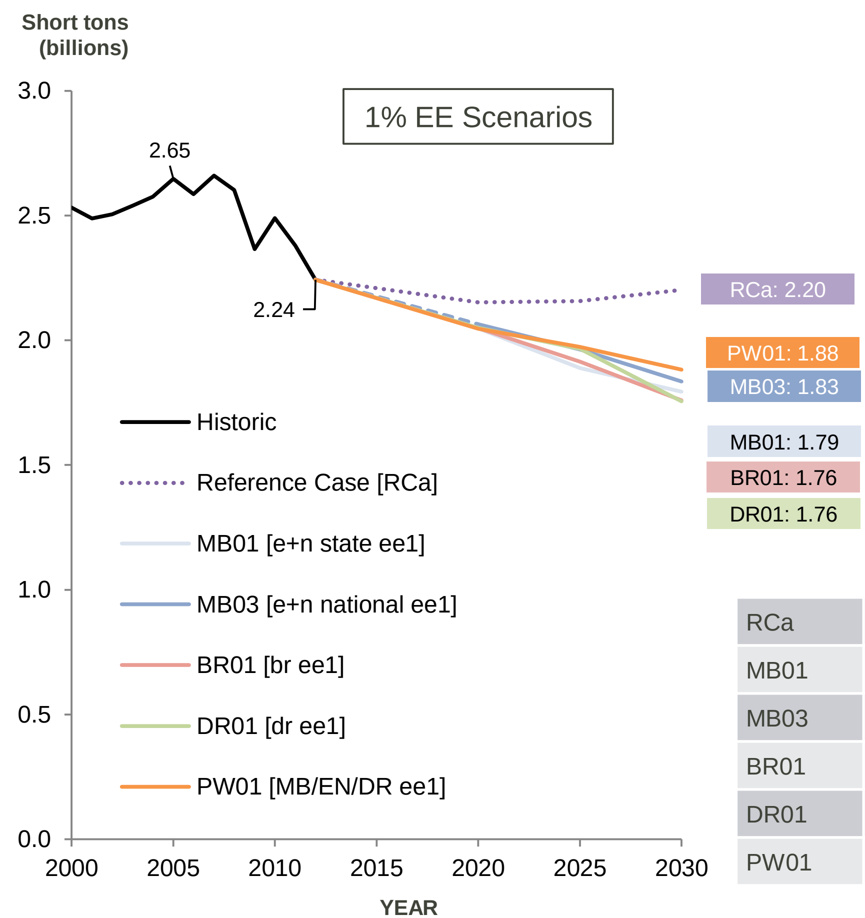
Across the "1% EE" scenarios, emissions are projected to decline between 16% and 22% below 2012 levels. See chart.

This translates to an emissions reduction of between 362 million and 490 million tons of CO_2 per year.

The emission outcomes under the rate-based scenarios, unlike the mass-based approach, are not fixed, and may vary if economic conditions (e.g. natural gas prices, renewable technology prices) differ from the assumptions used in this report.

Note: the electric sector reduced its CO_2 emissions by roughly 15 percent between 2005 and 2012. Across these model runs, emissions would be reduced between 29 and 34 percent from 2005 levels.

Historic and Projected CO_2 Emissions – 2000-2030

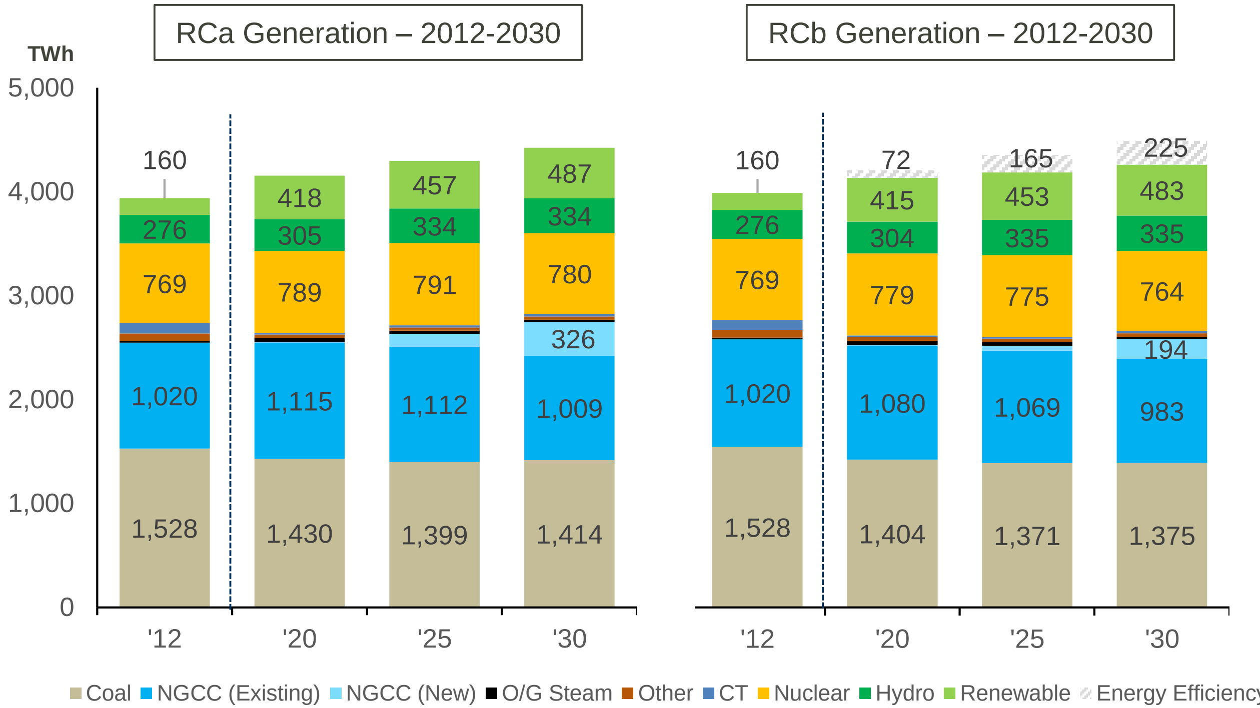


	% Change (2012-2030)
RCa	-2%
MB01	-20%
MB03	-18%
BR01	-22%
DR01	-22%
PW01	-16%

The Reference Case Projects an Increase in Total Electricity Generation (from 2012 to 2030) with Increases in Renewable and Natural Gas-Fired Generation

Reference Case Highlights

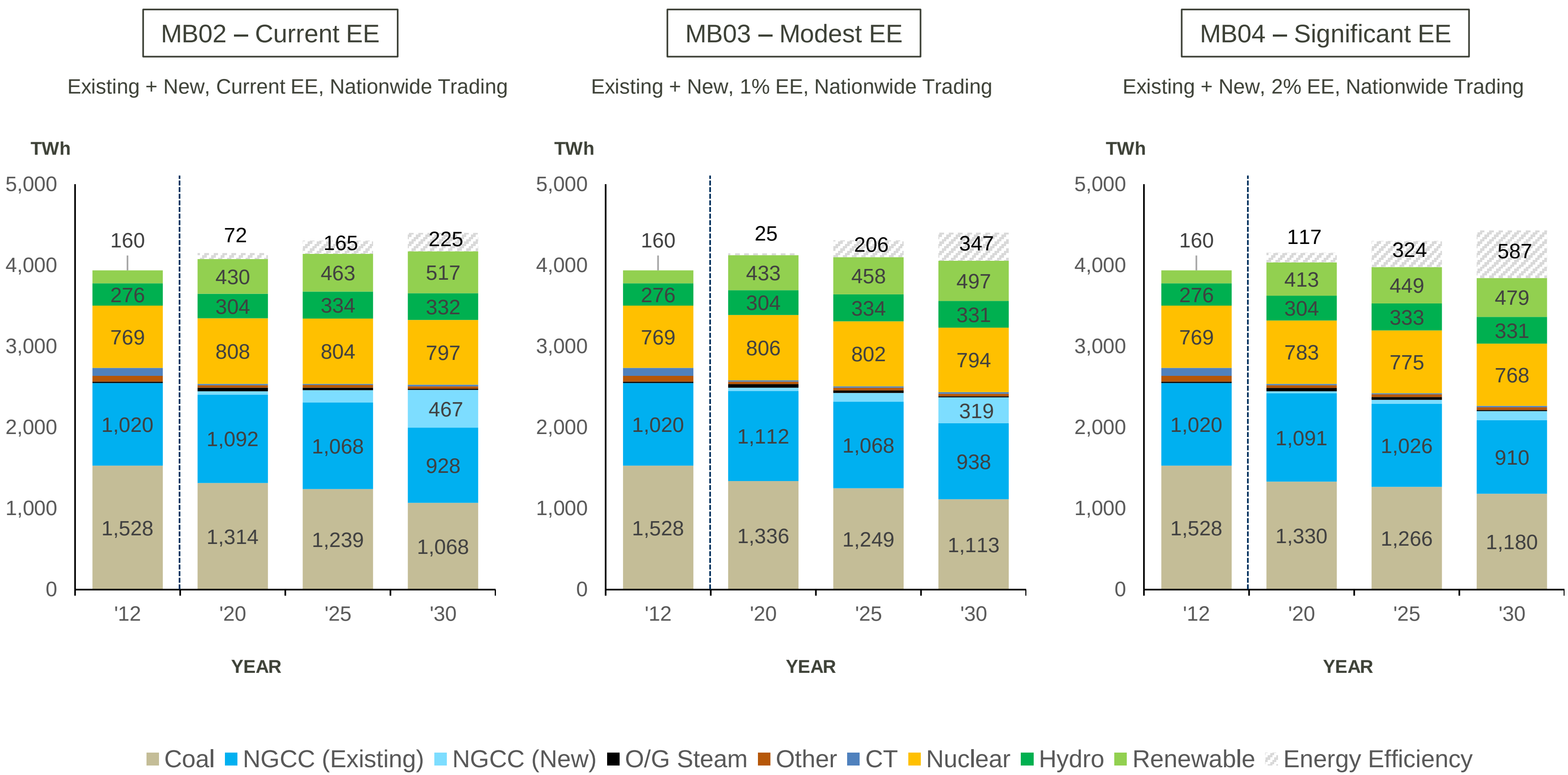
- Assumes existing power sector regulations (MATS, CSAPR, 316(b), AB 32, RGGI, state RPS)
- No Clean Power Plan
- AEO 2015 demand growth
- Henry Hub Gas price = $5.14 to $6.00 ($/mmBtu)*
- PTC and ITC were assumed to expire
- 80 GW of coal retirements by 2030, including 17 GW of firm (announced) retirements after 2016.
- 5.5 GW of nuclear retirements by 2030, including 3 GW of firm (announced) retirements after 2016.



Note: RCb assumes additional energy efficiency savings beyond what is reflected in the AEO 2015 demand growth forecast. States are assumed to achieve their current (2013) annual savings rates between 2018 and 2030.

*Natural gas prices were projected based on ICF's Integrated Gas Module, a component of the IPM model that models the natural gas market in the U.S. based on resource cost curves, pipeline data, and storage facilities consistent with EPA IPM v5.15 assumptions.

Total Generation and the Generation Mix Varies Across the Policy Cases Depending on the Level of Energy Efficiency Deployed (Current, Modest, Significant)



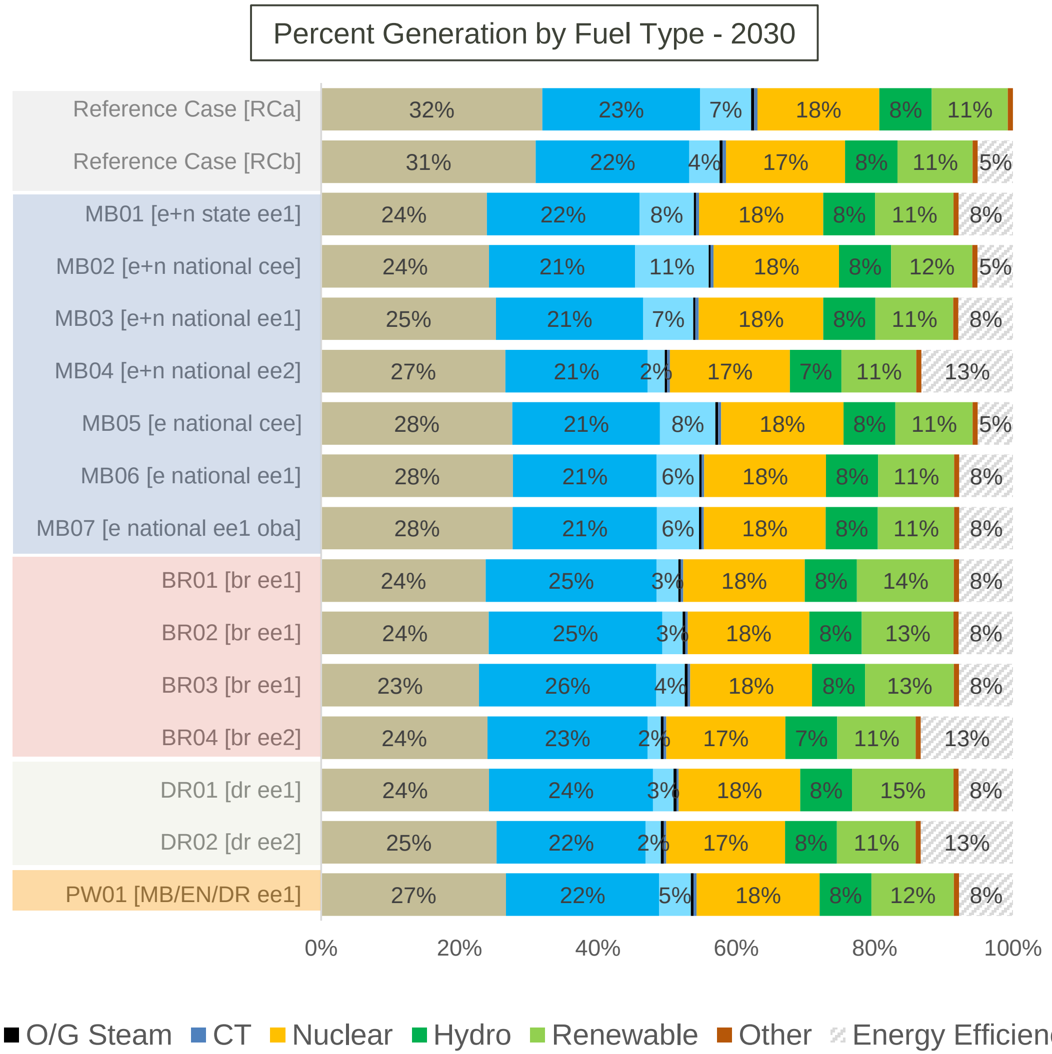
The Clean Power Plan's Emissions Goals Are Achievable While Relying on a Diverse Mix of Resources

Across all of the model runs, there is variability in the projected generation mix.

Relative to the Reference Case, coal generation declines, on average, by 21% in 2030 (averaging across all of the scenarios), but continues to supply between 23% and 28% of electricity, across all of the cases evaluated.

Natural gas (NGCC) is projected to supply between 25% and 32% of electricity in 2030, across all of the cases evaluated.

Renewable energy is projected to supply between 11% and 15% of electricity in 2030, across all of the cases evaluated.



The Mass-Based Policy Runs Project Modest Allowance Prices in the Early Years of the Program; Increasing the Level of EE Moderates the Prices Even Further.

Five model runs assumed mass-based, nationwide trading (except California), producing national allowance prices. The allowance prices are relatively modest across the scenarios, particularly in the early years of the program.

As the level of energy efficiency increases, the model forecasts a reduction in allowance prices (see cases MB02, MB03, and MB04 in the table below).

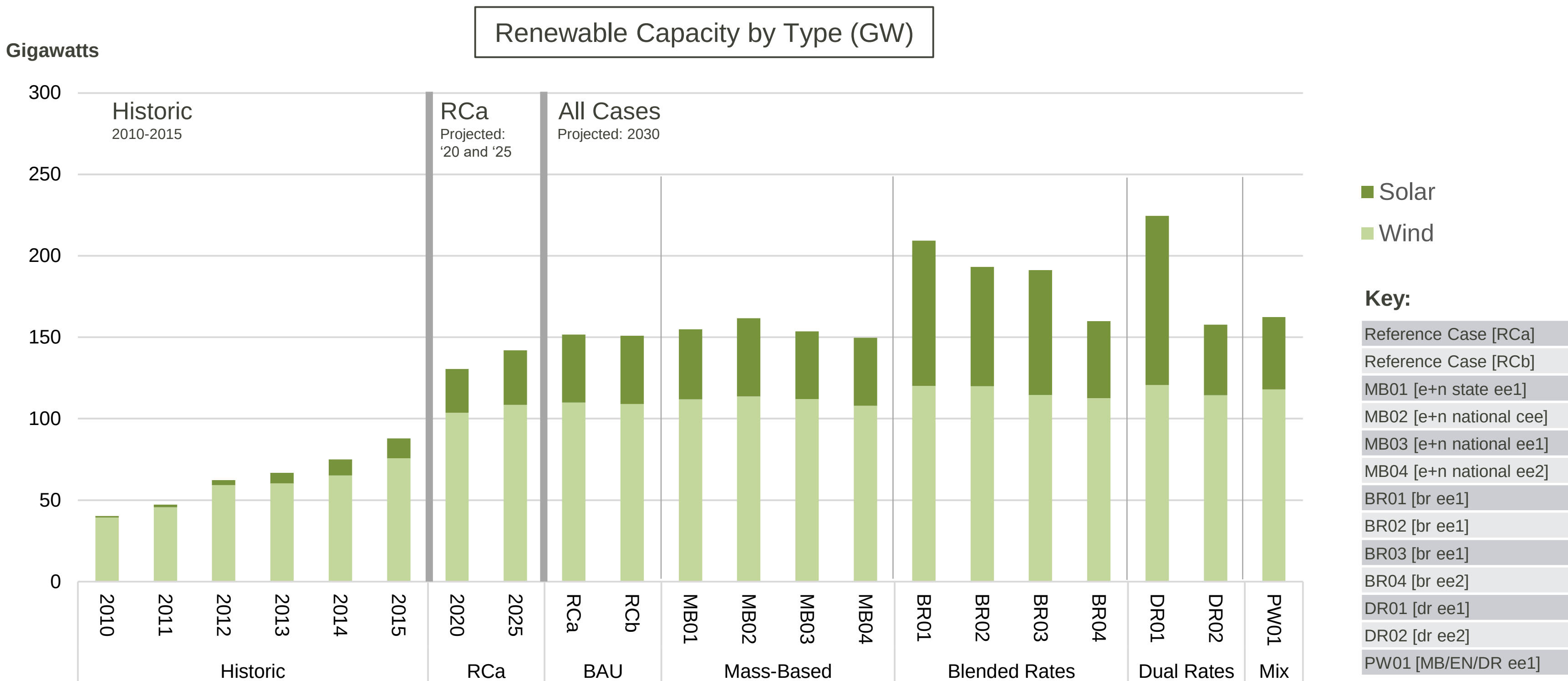
Scenario	Assumptions	2025 (2012$)	2030 (2012$)
MB02	Existing + New, Current EE, Nationwide	$0.76	$19.55
MB03	Existing + New, 1% EE, Nationwide	$0	$16.37
MB04	Existing + New, 2.0% EE, Nationwide	$0	$7.10
MB06	Existing Only, 1% EE, Nationwide, auction	$0.69	$9.05
MB07	Existing Only, 1% EE, Nationwide, federal plan allocation	$1.00	$8.80

Note: this analysis does not assume banking of allowances and the CPP goals are assumed to remain constant post-2030.

Renewable Energy is Projected to Continue to Expand in All Cases

The Reference Case and CPP Policy Cases project continued growth in solar and wind energy capacity.

Under the Clean Power Plan, incremental renewable energy capacity (post-2012) is eligible to generate "Emission Rate Credits" (ERCs) under a rate-based trading program, and under a mass-based program renewables help to meet the mass-based targets by providing a zero-emission source of energy.



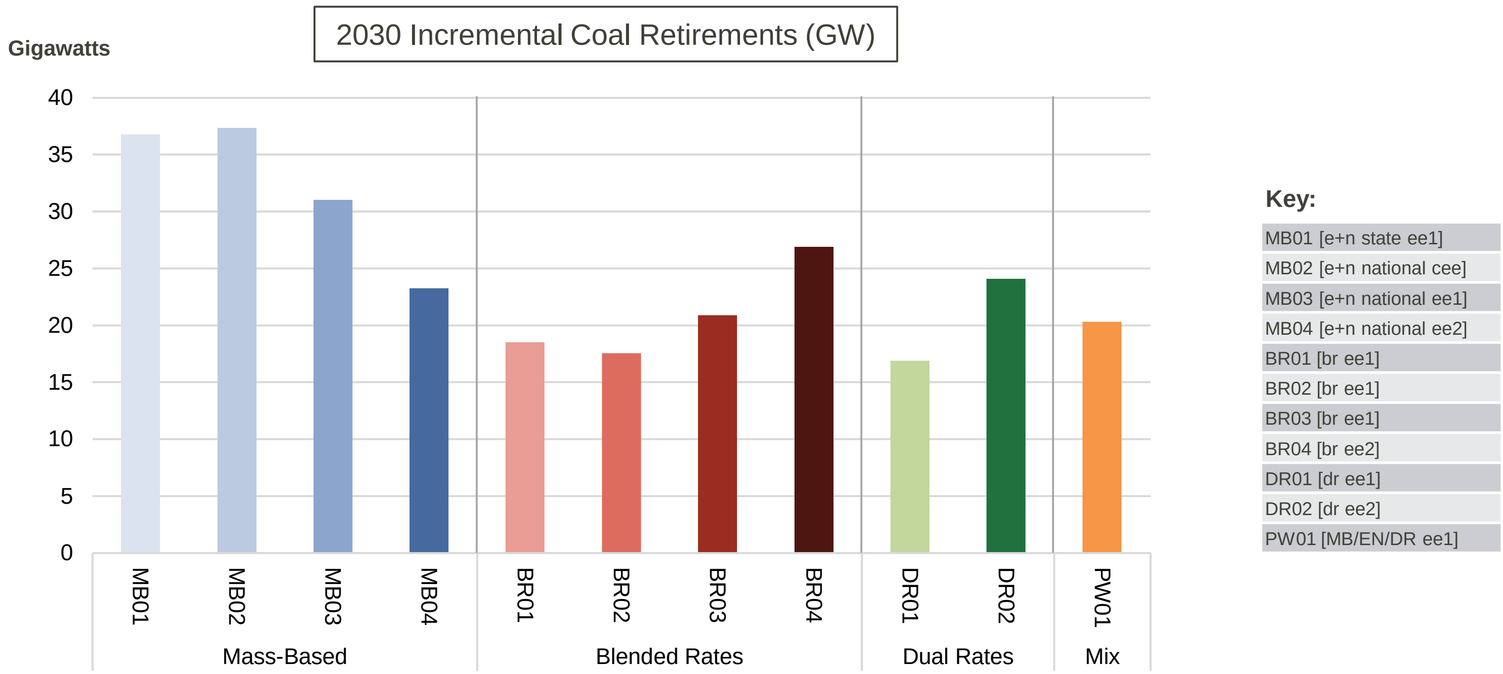
Note: The PTC and ITC are assumed to expire as previously required under federal law. Solar capacity is utility-scale only. Historic data is from EIA's AEO 2015 and AEO 2013.

Compliance Flexibility Reduces the Level of Projected Coal Retirements

Trading and increasing the level of energy efficiency reduces incremental coal retirements:

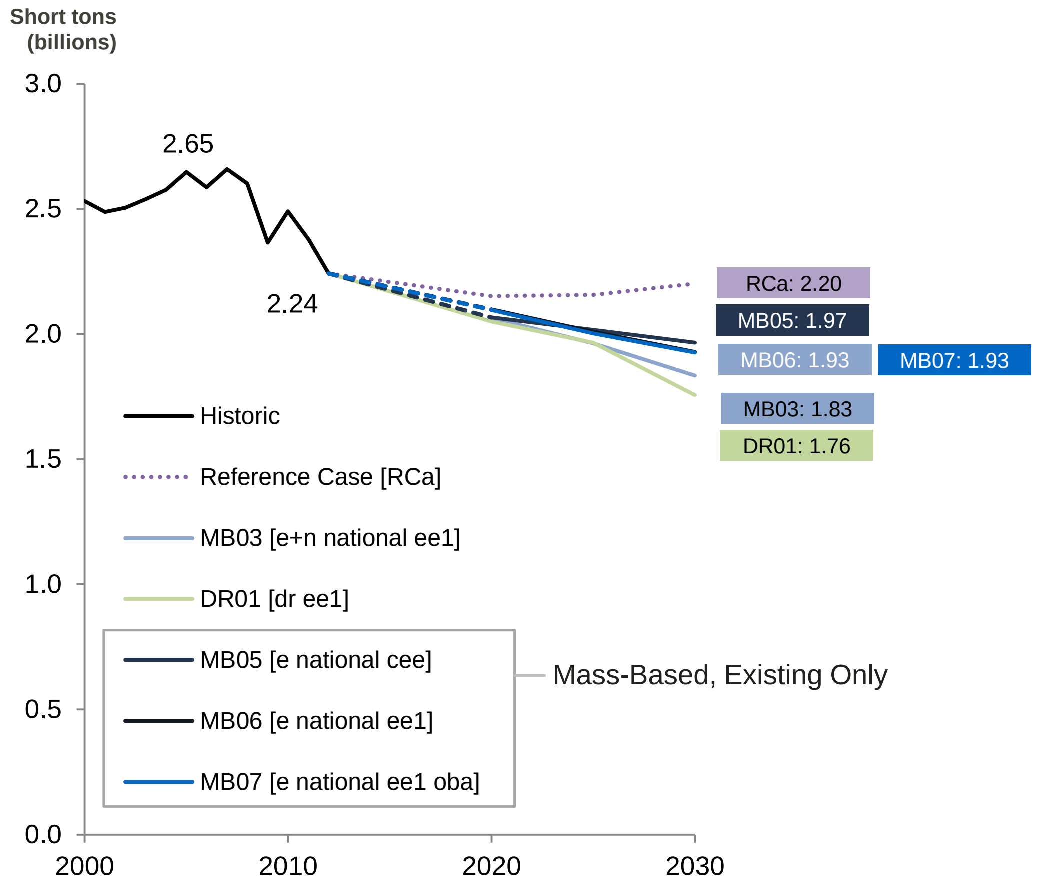
- Coal retirements are reduced by 6 GW (-16%) between MB01 [e+n state ee1] and MB03 [e+n national ee1], which assumes nationwide allowance trading (except California).
- Coal retirements are reduced by 14 GW (-38%) between MB02 [e+n national cee] and MB04 [e+n national ee2] .

The chart below summarizes the incremental coal retirements (above Reference Case levels) through 2030.



EPA Requires Mass-Based Plans to Address the Potential for "Emissions Leakage" under an Existing Only Cap; EPA's Current Proposal Has a Very Modest Impact on Emissions.

Historic and Projected CO_2 Emissions – 2000-2030



The modeling shows that CO_2 emissions would increase with an "Existing Only" mass target versus an "Existing plus New" mass target or "Dual Rate" program, both of which would be presumptively approvable to address "leakage."

Projected emissions in 2030 are 94 million tons higher (annual) under an "Existing Only" approach versus an "Existing plus New" scenario.

The modeling also suggests that EPA's proposed output-based allocation to certain existing NGCC units and a 5% set aside of allowances for renewables had a negligible impact on projected emissions (MB06 vs. MB07). EPA is taking comment on the issue, and stakeholders are currently working to offer EPA alternative allocation approaches that could be more effective.

	% Change (2012-2030)
RCa	-2%
MB03	-18%
DR01	-22%
MB05	-12%
MB06	-14%
MB07 [oba]	-14%

Mass-Based, Existing Only

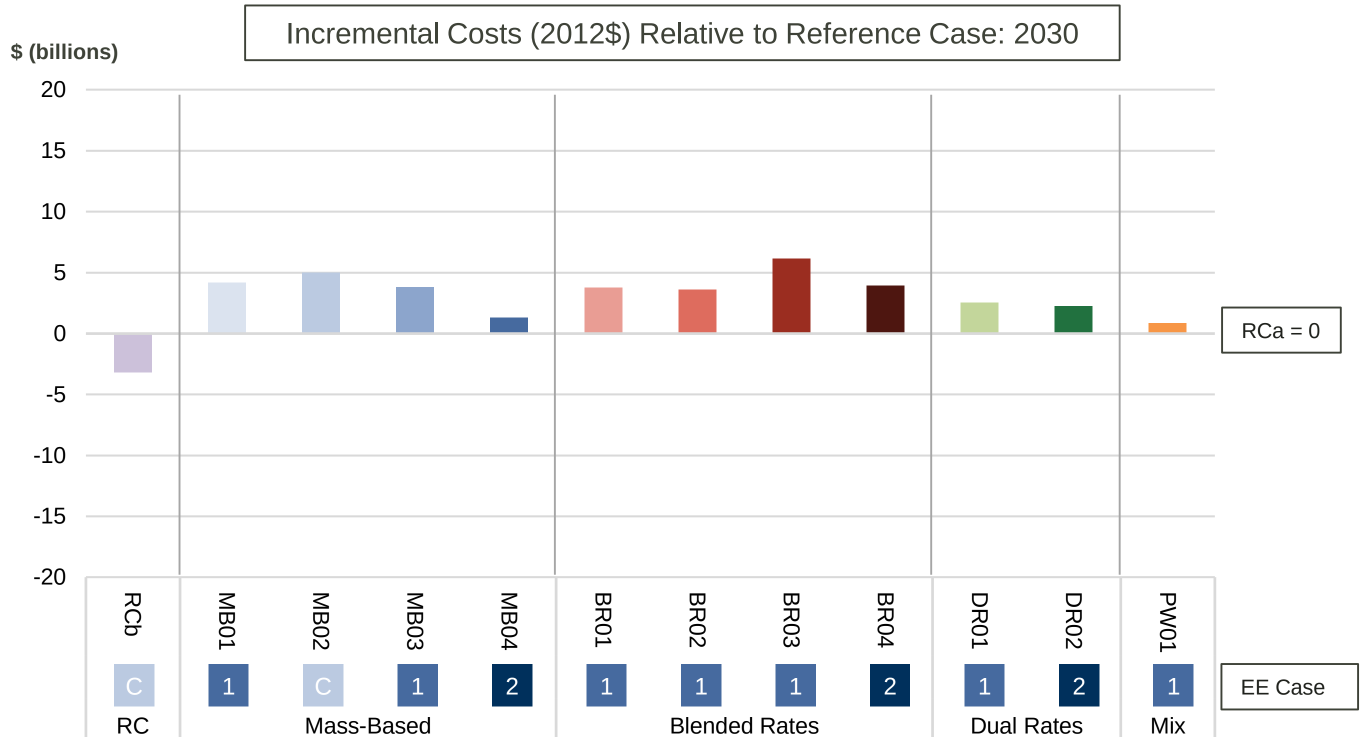
The Analysis Projects Modest Impacts on Electric System Costs under the Clean Power Plan Across a Wide Range of Scenarios

Electric system costs include: fuel, capital, O&M, and energy efficiency program costs (both utility and participant costs).

IPM projects modest increases in electric system costs under the Clean Power Plan based on the scenarios evaluated. For example, projected costs are 1.9% higher in 2030 under scenario MB03.

Based on the methodology used by EPA in the final CPP Regulatory Impact Analysis, we estimate that the benefits of reducing CO_2 and other pollutants (SO_2 and NOx) exceed the costs by $33 billion to $86 billion (2012$) in 2030.

Note: The existing only scenarios, MB05 and MB06, do not address leakage, so are not included here.



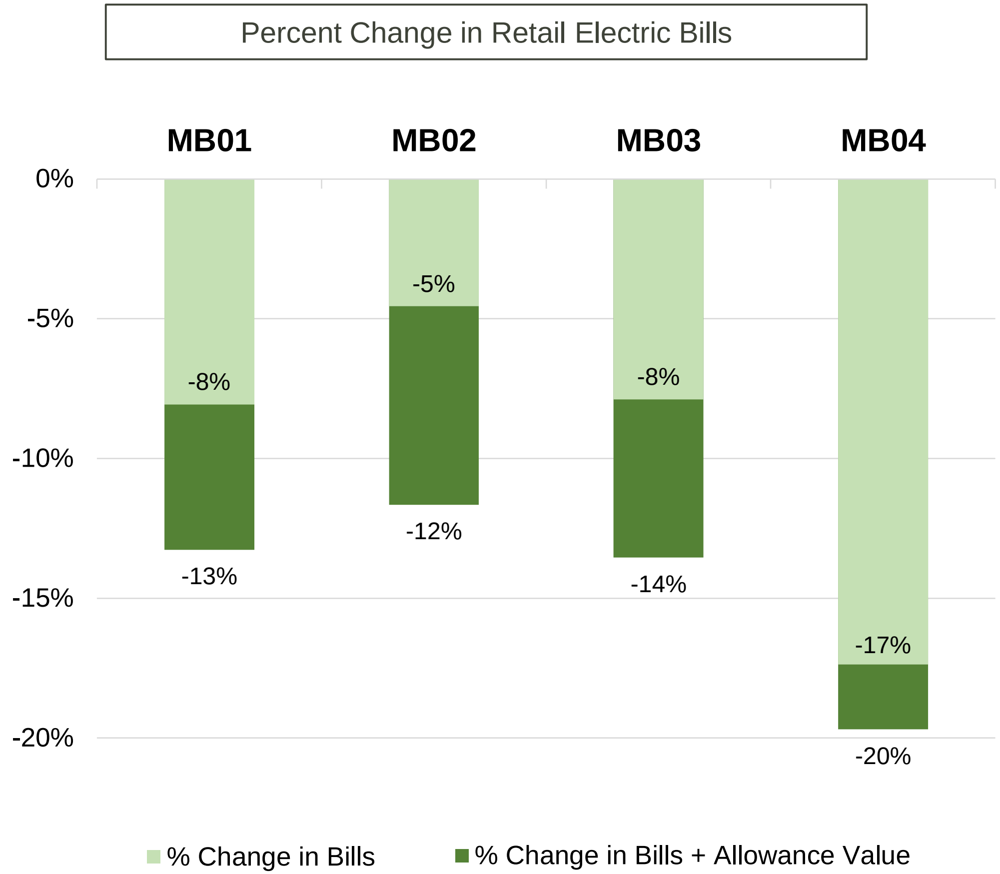
Scenario	% Change (from Reference Case, RCa)
MB01 [e+n state ee1]	2.1%
MB02 [e+n national cee]	2.5%
MB03 [e+n national ee1]	1.9%
MB04 [e+n national ee2]	0.7%
BR01 [br ee1]	1.9%
BR02 [br ee1]	1.8%
BR03 [br ee1]	3.1%
BR04 [br ee2]	2.0%
DR01 [dr ee1]	1.3%
DR02 [dr ee2]	1.1%
PW01 [MB/EN/DR ee1]	0.4%

The Analysis Projects Reductions in Monthly Household Electric Bills

Based on the methodology developed by EPA using projected changes in electric system costs, ICF International estimated the resulting impact on sales-weighted average retail bills for the continental U.S.

U.S. households would save between 5% and 20% on their monthly electricity bills in 2030. The high range estimates assume that revenue from auctioning allowances is invested in bill assistance programs and/or clean energy services that benefit electricity customers. Conversely, the low estimates assume auction revenue is utilized for other purposes.

Increased investment in energy efficiency also results in greater bill savings for households; for example, savings (without rebates) more than double between MB03 and MB04.



Note: Average retail bills are compared to Reference Case (RCa). The participant costs of energy efficiency programs are excluded from these retail bill estimates. Instead, those costs are included in the calculation of incremental compliance costs, as shown on slide 20. Including participant costs would have a minimal impact on the magnitude of these bill estimates.

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Appendix

Run Year Structure

Model Year:	Representative of:
2020	2019-2022
2025	2023-2027
2030	2028-2033

Note: throughout this summary report, when we refer to results in 2020, 2025, and 2030, we are referring to the model years above.

Demand-Side Energy Efficiency Assumptions

- Historic rates of energy efficiency savings differ for each state and were drawn from the data reported by utilities in Energy Information Administration (EIA) Form 861, 2013, available at http://www.eia.gov/electricity/data/eia861/.
- In the “Current EE” scenario, the available supply of EE is calculated based on an extension of each state’s 2013 annual savings rate. The annual savings rate is held constant between 2018 and 2030 to derive incremental annual savings and cumulative savings estimates for each state.
- In the “Modest EE” scenario, the available supply of EE is calculated based on the methodology in EPA’s Regulatory Impact Analysis (RIA) for the Clean Power Plan. Cumulative efficiency savings are projected for each state for each year by ramping up from historic savings levels to a target annual incremental demand reduction rate of 1.0 percent of electricity demand over a period of years starting in 2020, and maintaining that rate throughout the modeling horizon.
  - Consistent with EPA’s approach, the pace of improvement from the state’s historical incremental demand reduction rate is set at 0.2 percentage points per year, beginning in 2020, until the target rate of 1.0 percent is achieved.
  - States already at or above the 1.0 percent target rate are assumed to achieve a 1.0 percent rate beginning in 2020 and sustain that rate thereafter.
- In the “Significant EE” scenario, the available supply of EE is calculated based on the same methodology as the “Modest EE” scenario, but each state ramps up to a target annual incremental demand reduction rate of 2.0 percent of electricity demand.
- In the “Modest EE” and “Significant EE” scenarios, adoption of efficiency was modeled endogenously using a supply curve of program costs. In this simplified supply curve approach, the highest amount of savings assumed to be available to states in the supply curve varies by scenario, as described in the methodology above. The costs are based on LBNL’s comprehensive 2015 cost study, available at: https://emp.lbl.gov/sites/all/files/total-cost-of-saved-energy.pdf.
- Participant costs are accounted for in the calculation of total system costs.

ERC Background

Under the dual-rate structure in the proposed state model rule for rate-based trading, ERCs can be created by three categories of activities:

1 Incremental Zero-Emitting Energy and Energy Efficiency

- Renewable & nuclear capacity installed post-2012
- Energy efficiency projects begun post-2012
- Each MWh generated / saved creates one ERC

2 Affected EGUs

- Any affected EGU that emits at a rate below its compliance target
- Number of ERCs generated per MWh based on difference between EGU rate and compliance rate

3 Existing NGCC

- All NGCCs earn partial "Gas Shift ERCs" for every MWh
- Provide credit for increases in NGCC generation projected to displace coal-fired generation
- GS-ERCs can only be used by fossil steam sources for compliance

Note: The proposed Federal Plan would not credit energy efficiency. The GS-ERC crediting formula is up for comment.

ERC Background, continued

Location of Generation/Savings	Location of ERC Credit Award	ERC Eligibility Under Clean Power Plan
Dual Rate or Blended Rate	Dual Rate	**Project can apply for ERCs in any dual rate-based state.** The ERCs can then be sold to affected sources in any state with the same rate-based plan type. The project cannot earn ERCs in both states.
Dual Rate or Blended Rate	Blended Rate	**Project can apply for ERCs in any blended rate-based state.** The ERCs can then be sold to affected sources in that state (or region, if states agree to a common blended rate). The project cannot earn ERCs in both states.
Mass	Dual Rate	**Project can apply for allowances or ERCs in either state or another rate-based state (as long as the application to a rate-based state is accompanied by a PPA showing delivery to a rate-based state).** The allowances or ERCs can be used for compliance by affected sources covered by the same plan type. In all cases, a project that applies for ERCs cannot also apply for allowances from a set-aside in a mass-based state.

Retail Bill Calculation

The projected monthly average electricity bills (residential) reflect the combined effects of changes to average retail rates and average household electricity demand under the various modeling scenarios, and by region. Monthly bill impacts would change if the allowance value under a mass-based trading system was returned to customers.

The Retail Price Model accounts for variations in regulated and deregulated markets by calculating cost-of-service and competitive retail prices for each region and then weighing and allocating both to individual IPM regions according to the market structure that best represents each region:

$$\textbf{Regional Average Price (mills/kWh)} = \text{Competitive Retail Power Price} * \text{Deregulation Share (\%)} + \text{Cost-Of-Service Retail Power Price} * \text{Cost-Of-Service Share (\%)}$$

Competitive retail power price is comprised of competitive generation cost and transmission and distribution charges. Cost-Of-Service retail power price includes the cost of generation and the recovery of costs associated with transmission and distribution facilities and services.

Average retail bills are calculated based on retail rates and household demand, after energy efficiency savings.

Natural Gas Prices: All Scenarios