



EPA's Clean Power Plan

Summary of IPM Modeling Results With ITC/PTC Extension

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M.J. Bradley & Associates, LLC
(978) 369 5533 / www.mjbradley.com

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 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); Brian Megali and Kathleen Robertson (Exelon Corporation); Jeff Brown, Xantha Bruso, and Ray Williams (PG&E Corporation); Michael Goggin (American Wind Energy Association); Jennifer Macedonia (Bipartisan Policy Center); Nicholas Bianco (Environmental Defense Fund); and Rick Umoff and Justin Baca (Solar Energy Industries Association).

For questions or comments about this report, please contact:

Christopher Van Atten
M.J. Bradley & Associates, LLC
E-mail: vanatten@mjbradley.com
Phone: 978-369-5533

Executive Summary

The following report summarizes the results of 10 IPM model runs, evaluating two Reference Cases (business-as-usual scenarios) and eight 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:

- This analysis is an update to our prior January 2016 report and now reflects, in addition to several data updates, 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.
- Results continue to show that CPP targets are achievable under a range of scenarios and assumptions.
- States can meet the Clean Power Plan's emissions goals while relying on a diverse mix of generating resources and energy efficiency, including 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 updated analysis continues to find that CO_2 emissions would increase with an "existing only" mass-based program (with no leakage protection) versus an "existing plus new" or "dual rate" approach. 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. Our prior analysis found that the proposed method would have a minor impact on emissions leakage; however, EPA has requested 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 "patchwork" scenarios and other sensitivity cases.

Methodology

Major Changes from Prior Model Runs

- **Natural Gas Prices:** Gas prices are lower than prior round of analysis (see appendix). The gas supply curve that we used is derived from the average of the AEO 2015 Reference Case and the AEO 2015 High Gas Resource Case (Henry Hub Gas Price). Basis differentials were derived from ICF's Integrated Gas Module.
- **ITC/PTC Extension:** On December 18, 2015, Congress passed extensions to the investment tax credit (ITC) and production tax credit (PTC) for renewable energy projects. With the addition of these extensions, total U.S. Wind capacity in the Reference Case increases by about 40 GW from 2015 to a total of 118.6 GW in 2020, vs. the prior Reference Case of 103.6 GW by 2020. Utility-scale solar capacity more than triples from 2015 levels to a total of 37.2 GW in the updated runs vs. 26.9 GW in the prior Reference Case.
- **Energy Efficiency Assumptions:** We continue to model a range of energy efficiency levels (current, modest, and significant), but we modified our approach to "modest" case for some states. In the revised "modest" approach, states that are already achieving annual savings levels greater than 1% (of prior-year sales) maintain their historic (2013) savings levels.
- **Trading:** We continue to assume that California does not trade compliance instruments with other states; rather we assume updated California Energy Commission (CEC)-projected AB 32 carbon prices in California.
- **New Builds:**
  - Solar cost forecasts from National Renewable Energy Laboratory (NREL) continue to decline
  - No economic hydro builds allowed in the U.S.
  - Renewable builds limited as discussed in appendix and additional firm builds added (NGCC and renewables)

Scenarios Evaluated: Integrated Planning Model (IPM®)

Mass-Based Scenarios

Code	Abbreviated Assumptions	Regulatory Approach	Level of Energy Efficiency	Trading Zones
MB01	E+N, State, CEE	Mass-Based (Existing + New)	Current EE	**State-by-state compliance** (except RGGI)
MB02	E+N, State, EE1	Mass-Based (Existing + New)	Modest EE (1%)	**State-by-state compliance** (except RGGI)
MB03	E+N, National, CEE	Mass-Based (Existing + New)	Current EE	**Nationwide trading** (except California; RGGI trades with other states)
MB04	E+N, National, EE1	Mass-Based (Existing + New)	Modest EE (1%)	**Nationwide trading** (except California; RGGI trades with other states)
MB05	E+N, National, EE2	Mass-Based (Existing + New)	Significant EE (2%)	**Nationwide trading** (except California; RGGI trades with other states)
MB06	E, State, CEE	Mass-Based (Existing Only)	Current EE	**State-by-state compliance** (except RGGI)
MB07	E, National, CEE	Mass-Based (Existing Only)	Current EE	**Nationwide trading** (except California; RGGI trades with other states)

Subcategory-Specific Dual Rate Scenario

Code	Abbreviated Assumptions	Regulatory Approach	Level of Energy Efficiency	Trading Zones
DR01	DR, EE1	Rate-Based (Dual Rate)	Modest EE (1%)	Nationwide trading of RE, EE, Nuclear, and GS-ERCs (except California and RGGI)

Note: In all cases, we assume CEC-projected (mid-case, 2015 IEPR) carbon prices in California – not the CPP 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 and RGGI states trade these allowances nationally.

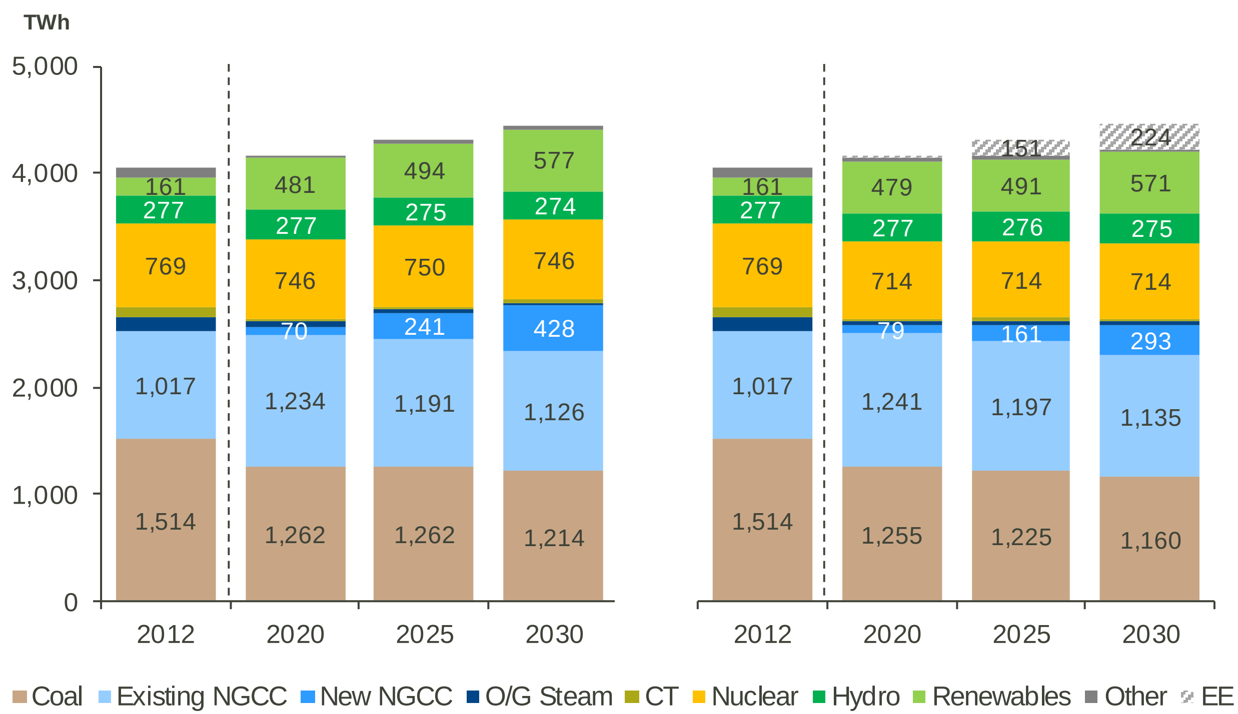
Generation Fuel Mix: Reference Cases

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
- National Henry Hub Gas price = $4.22 (2020) to $4.69 (2030) $/MMBtu. See appendix for more detail.
- ITC and PTC extension included
- 81 GW of coal retirements by 2030, including 17 GW of firm (announced) retirements after 2016.
- 10 GW of nuclear retirements by 2030, including 3 GW of firm (announced) retirements after 2016.

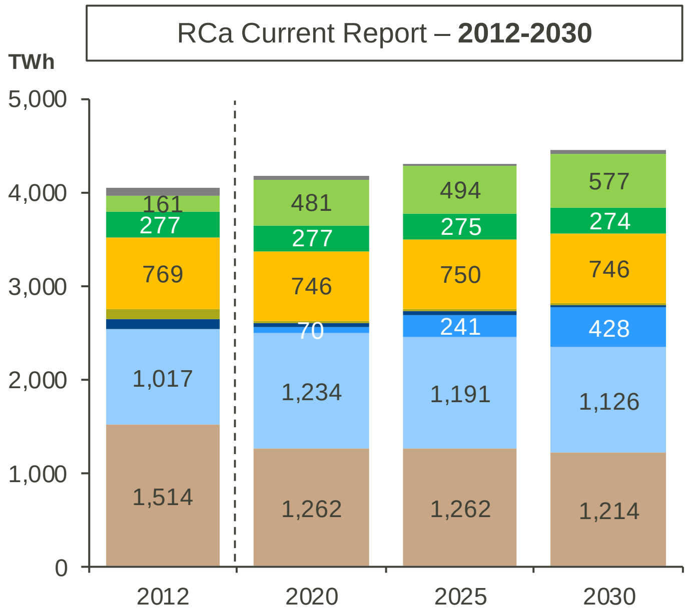
RCa, no incremental EE – **2012-2030**

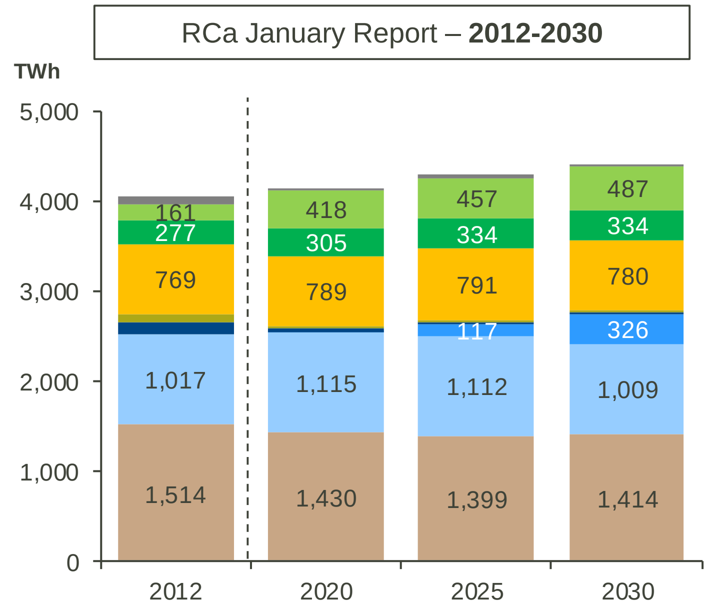
RCb, Current EE – **2012-2030**



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.

Generation Fuel Mix: Reference Case Comparison





Coal Existing NGCC New NGCC O/G Steam CT Nuclear Hydro Renewables Other

Assumptions	RCa Current Report	RCa January Report
Existing Power Sector Regulations	MATS, CSAPR, 316(b), AB 32, RGGI, state RPS	
Clean Power Plan	Does not assume CPP	
Demand Growth	AEO 2015	
ITC/PTC Extension	Extension included	Extension not included
Henry Hub Natural Gas Price	\$4.22 (2020) to \$4.69 (2030) \$/MMBtu	\$5.14 (2020) to \$6.00 (2030) \$/MMBtu
Coal Capacity in 2030	187.3 GW	201.4 GW
Nuclear Capacity in 2030	93.4 GW	98.1 GW

Results

The Clean Power Plan is projected to achieve a 16% to 18% reduction in Electric Sector CO_2 emissions by 2030 (from 2015) levels across a range of scenarios

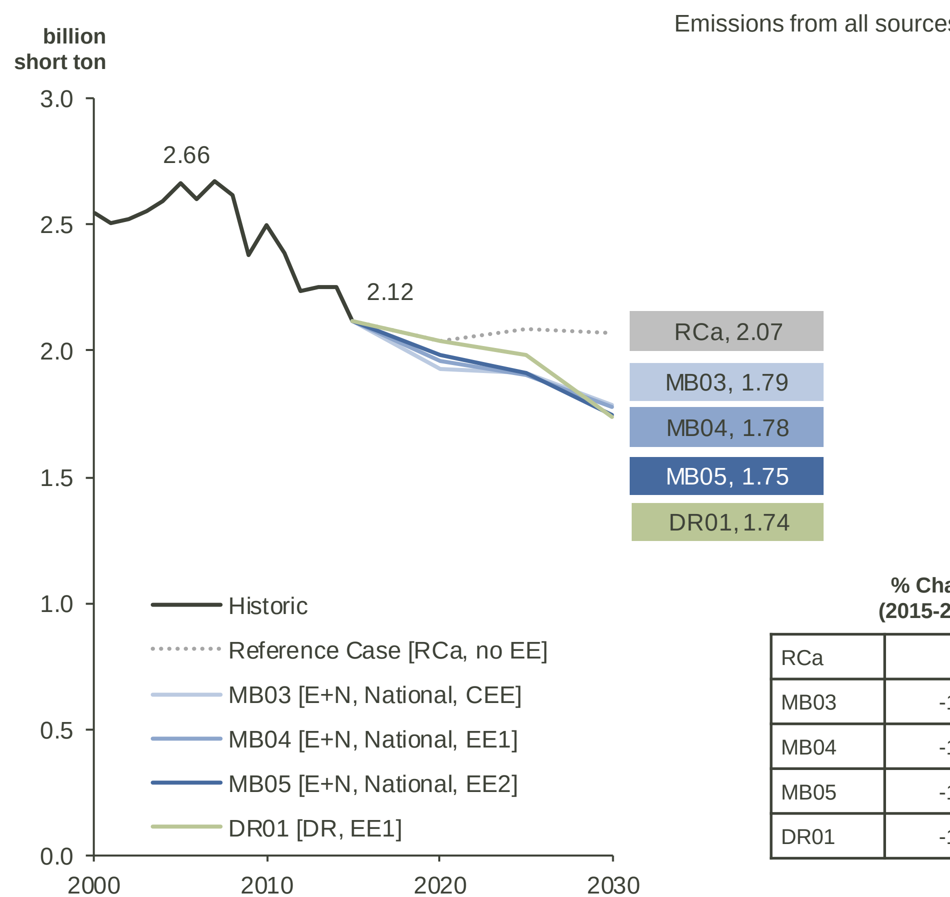
The Clean Power Plan is projected to achieve a significant reduction in electric sector CO_2 emissions across a range of different policy cases (i.e., mass-based and rate-based targets).

Across the "Existing + New" policy scenarios, emissions are projected to decline between 16% and 18% below 2015 levels. See chart.

The emission outcomes under the rate-based scenario, 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.

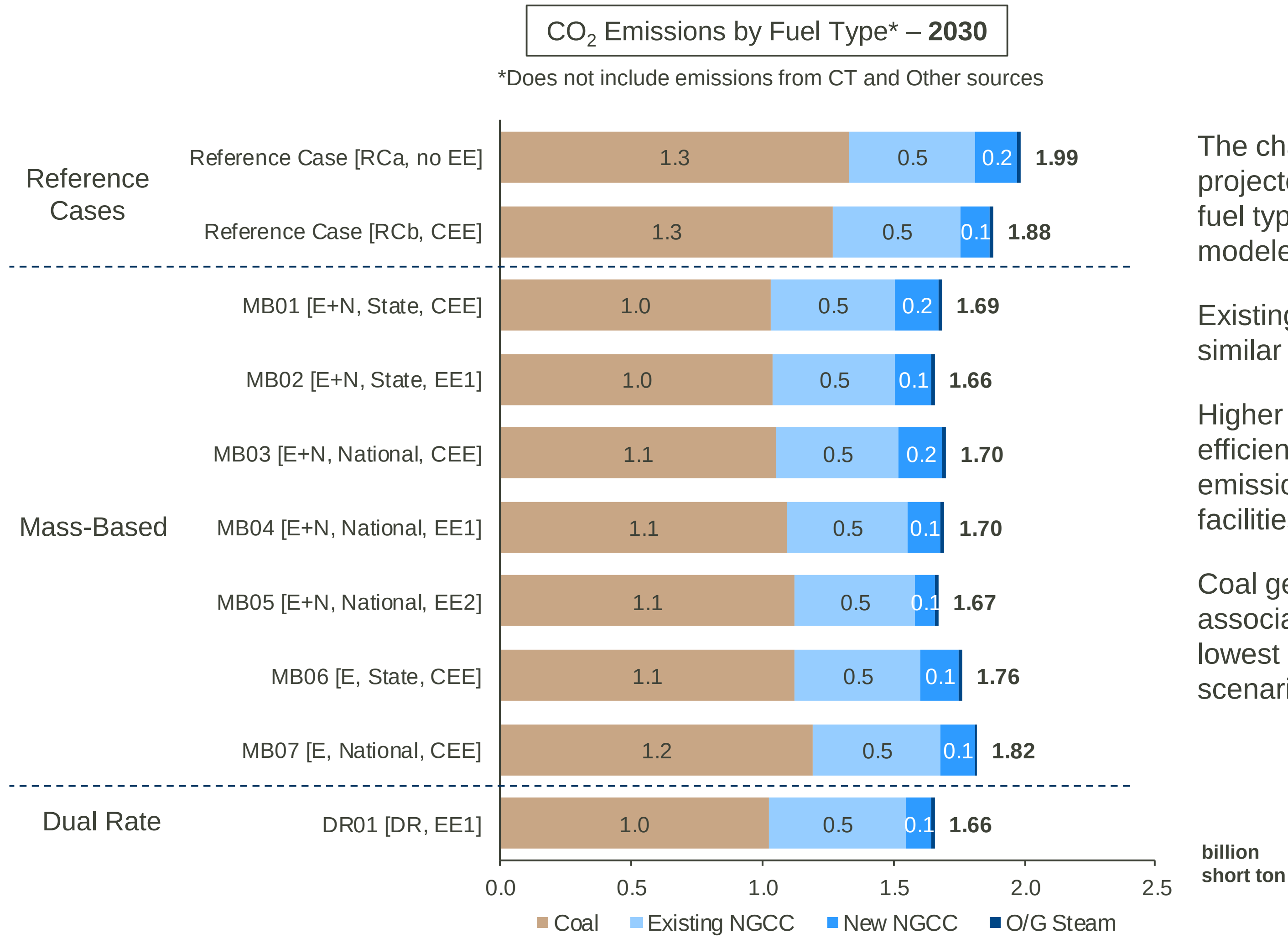
Note: the electric sector reduced its CO_2 emissions by roughly 20% between 2005 and 2015. Across these model runs, emissions would be reduced between 33% and 34% from 2005 levels.

Historic and Projected CO_2 Emissions – **2000-2030**



	% Change (2015-2030)
RCa	-3%
MB03	-16%
MB04	-16%
MB05	-18%
DR01	-18%

Electric Sector CO_2 Emissions by Fuel Type: 2030



The chart to the left highlights projected CO_2 emissions by fuel type for each of the cases modeled in 2030.

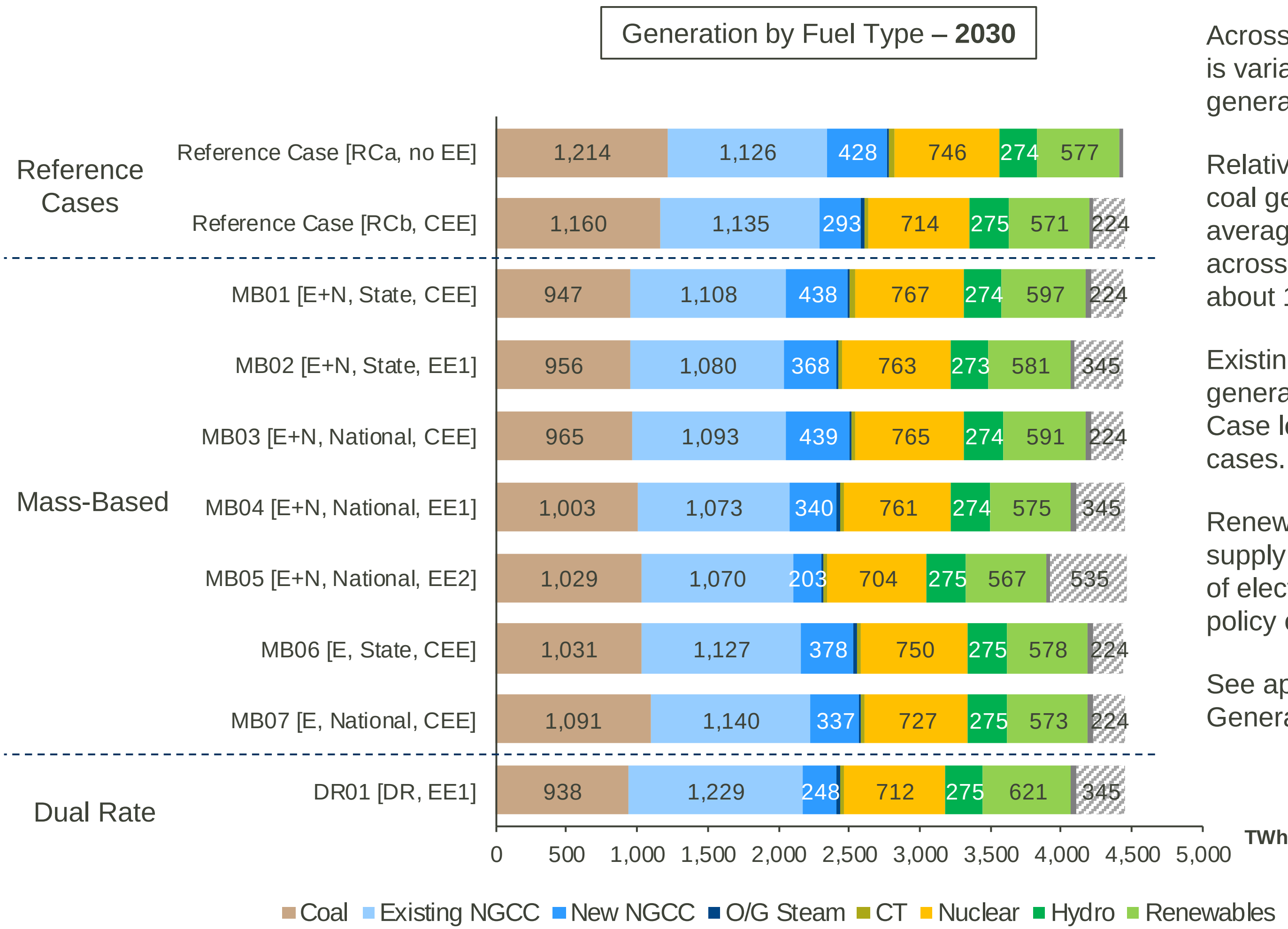
Existing NGCC emissions are similar across all of the cases.

Higher levels of energy efficiency reduces CO_2 emissions from new NGCC facilities.

Coal generation and associated emissions are lowest under the dual rate scenario.

Note: "Existing Only" cases MB06 and MB07 do not include leakage mitigation measures.

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 an average of 18% in 2030 (averaging across all of the scenarios) to about 1,000 TWh.

Existing natural gas (NGCC) generation is similar to Reference Case levels across all of the policy cases.

Renewable energy is projected to supply between 567 and 621 TWh of electricity in 2030, across the policy cases evaluated.

See appendix for Percent Generation by Fuel Type.

Note: "Existing Only" cases MB06 and MB07 do not include leakage mitigation measures.

The mass-based policy runs with national trading project modest allowance prices throughout the program; increasing the level of EE moderates the prices even further.

Four 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 MB03, MB04, and MB05 in the table below).

For MB07, the "Existing Only" case, allowance prices illustrate the overall fleet-wide reduction in stringency, which can be seen when compared to MB03 "Existing + New" case, as both scenarios assume the same level of current energy efficiency. However, MB07 does not assume any type of leakage mitigation and is therefore not presumed approvable, whereas the "Existing + New" cases would be approvable.

Allowance Prices **(2012$/ton)**

Code	Assumptions	2025	2030
MB03	Existing + New, National, Current EE	$0.00	$6.05
MB04	Existing + New, National, 1% EE	$0.00	$2.97
MB05	Existing + New, National, 2% EE	$0.00	$0.00
MB07	Existing Only, National, Current EE	$0.00	$4.14

Current EE Scenarios

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

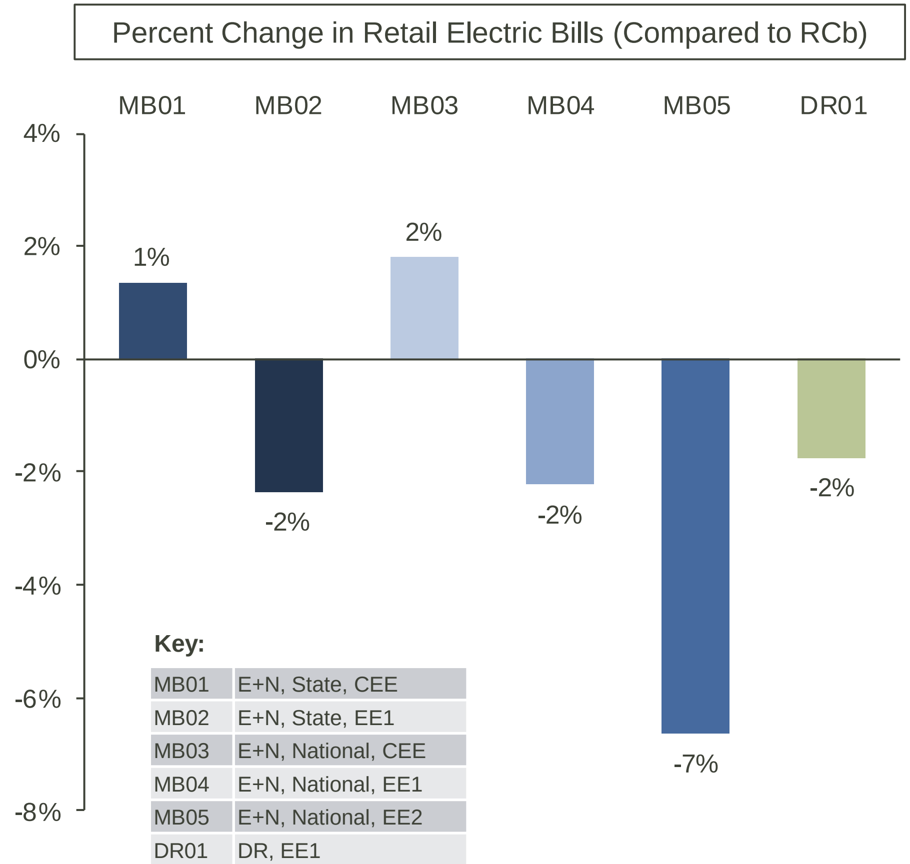
2030 U.S. Avg. Monthly Bills: Relative to RCb, Current EE

ICF International estimated average retail bills for the continental U.S. using a sales-weighted methodology developed by EPA. The estimates reflect changes in electric system costs.

On average, U.S. household bills are estimated to be slightly above reference case (RCb) levels (1%-2%) or below reference case levels (2%-7%) depending on the level of energy efficiency and policy option. The mass-based scenarios do not assume that the allowance value is returned to consumers in the form of bill assistance programs or clean energy services that could benefit electricity customers. This could further mitigate potential bill impacts.

Increased investment in energy efficiency also results in greater bill savings for households; for example, savings roughly triple between MB04 and MB05.

See appendix for comparison with Reference Case with no additional Energy Efficiency (RCa).

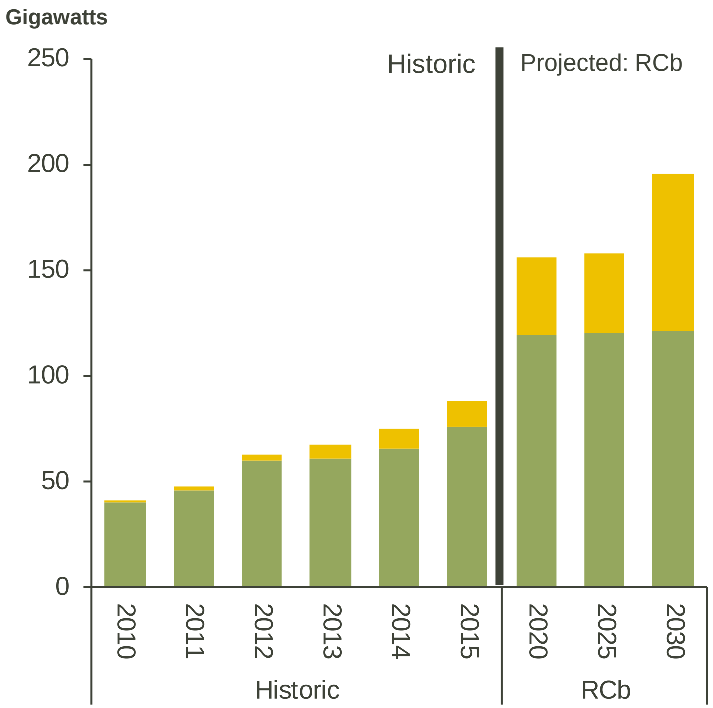


Note: Average retail bills are compared to Reference Case (RCb). MB01 and MB03 do not include any additional energy efficiency above RCb levels. The participant costs of energy efficiency programs are excluded from these retail bill estimates. Including participant costs would have a minimal impact on the magnitude of these bill estimates.

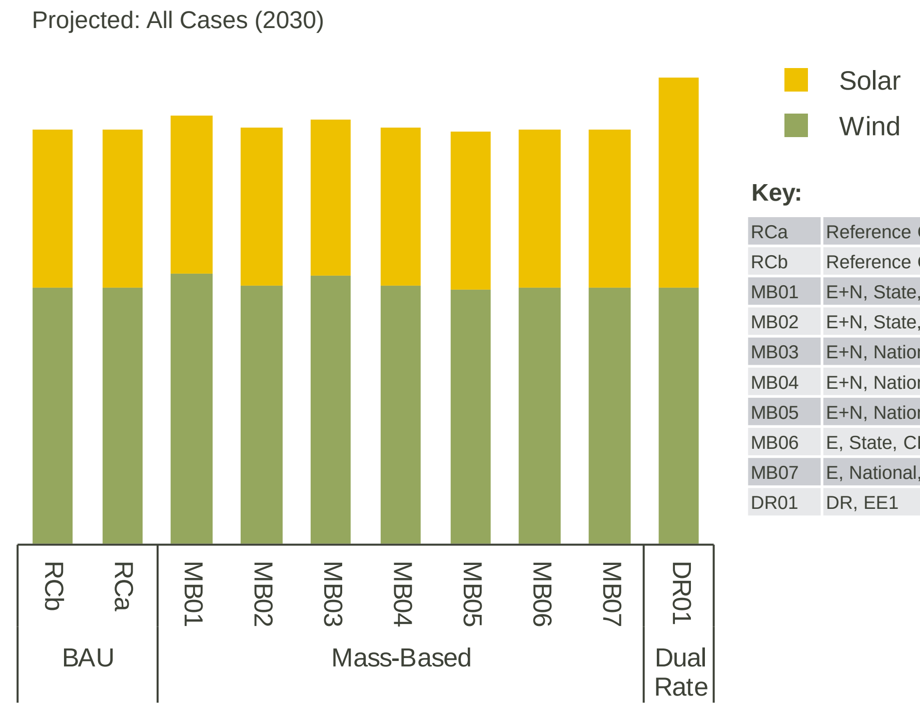
With the extension of the ITC/PTC, renewable energy is projected to continue to expand in all scenarios

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

Renewable Capacity by Type – **2010-2030**



Renewable Capacity by Type – **2030**



Key:

RCa	Reference Case, no EE
RCb	Reference Case, CEE
MB01	E+N, State, CEE
MB02	E+N, State, EE1
MB03	E+N, National, CEE
MB04	E+N, National, EE1
MB05	E+N, National, EE2
MB06	E, State, CEE
MB07	E, National, CEE
DR01	DR, EE1

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

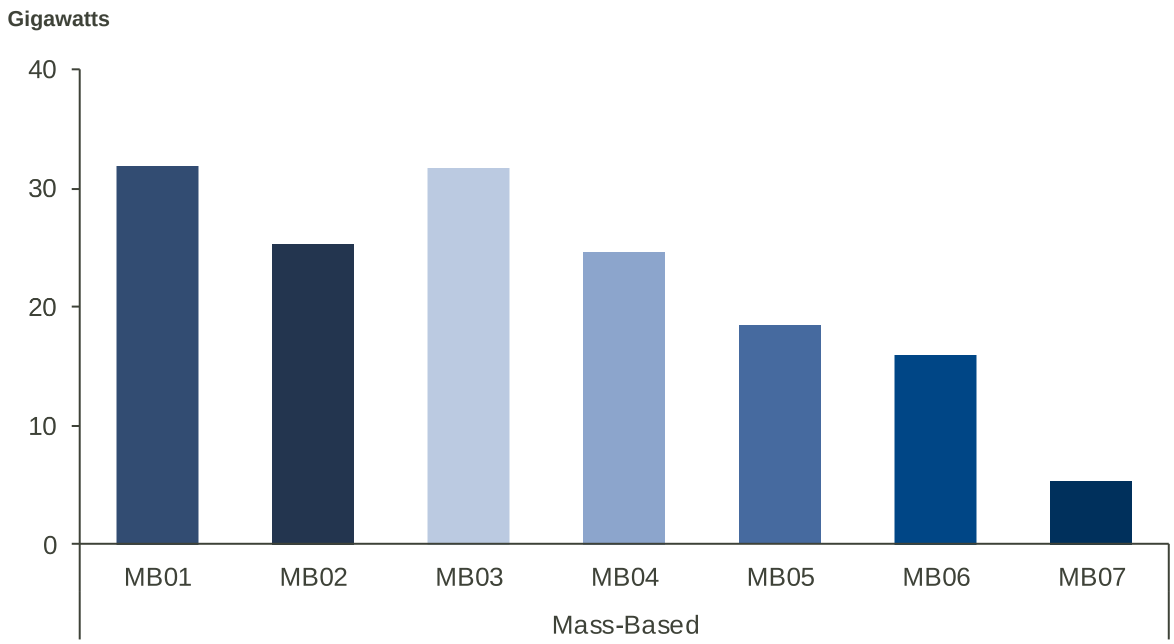
Compliance flexibility reduces the amount of coal retirements

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

- Coal retirements are reduced by 600 MW (-2%) between MB02 [E+N, State, EE1] and MB04 [E+N, National, EE1], which assumes nationwide allowance trading (except California).
- Coal retirements are reduced by 13 GW (-42%) between MB03 [E+N, National, CEE] and MB05 [E+N, National, EE2] .

The chart below summarizes the incremental coal retirements (above Reference Case levels) for Mass-Based policy scenarios through 2030.

Incremental Coal Retirements (Compared to RCb) – **2030**



Key:

MB01	E+N, State, CEE
MB02	E+N, State, EE1
MB03	E+N, National, CEE
MB04	E+N, National, EE1
MB05	E+N, National, EE2
MB06	E, State, CEE
MB07	E, National, CEE
DR01	DR, EE1

Emissions leakage resulting from an "Existing Only" compliance approach remains an issue in these model results after updated assumptions

An "Existing Only" approach, without addressing leakage, results in higher emissions compared to a "Dual Rate" or "Existing + New" approach, both of which would be presumptively approvable to address leakage.

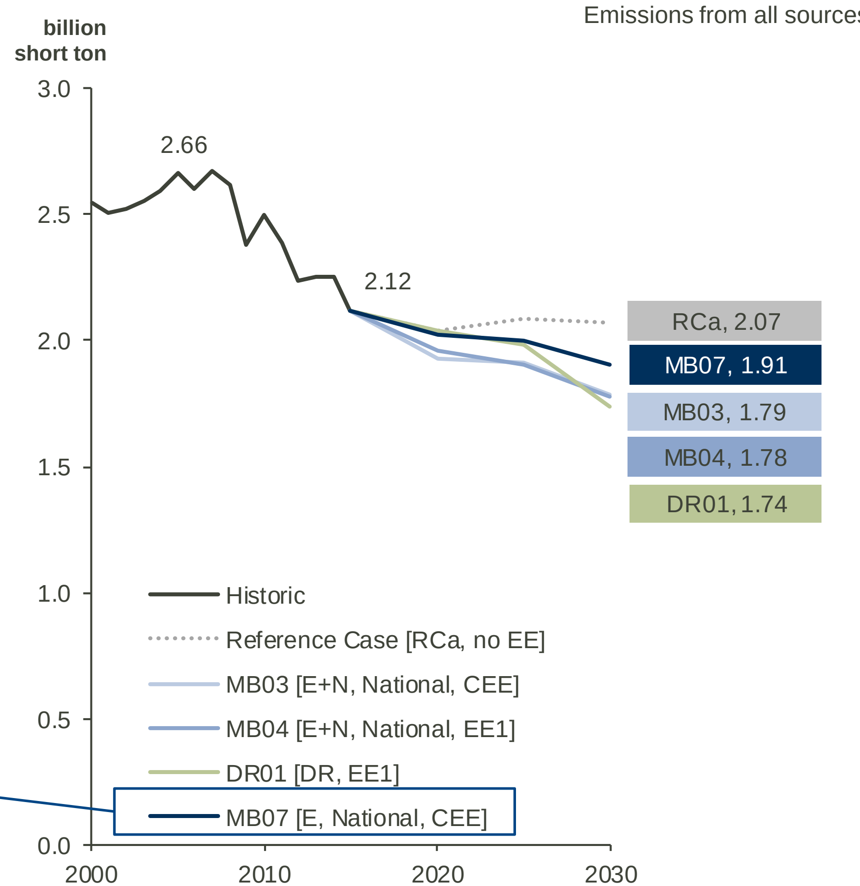
This results in an emissions gap at the national level where emissions under the "Existing Only" approach (MB07) are 117 million tons higher in 2030 when compared to the equivalent "Existing + New" scenario (MB03). Both cases assume equivalent levels of energy efficiency (CEE).

The "Existing Only" model run (MB07) does not include any protections to address leakage, which EPA has indicated will be required for any state that adopts a cap that only covers existing sources.

	% Change (2015-2030)
RCa	-3%
MB03	-16%
MB04	-16%
DR01	-18%
MB07	-10%

Mass-Based, Existing Only case

Historic and Projected CO_2 Emissions – **2000-2030**



Concord, MA

Headquarters

47 Junction Square Drive
Concord, Massachusetts
United States

Tel: 978 369 5533

Fax: 978 369 7712

www.mjbradley.com

Washington, DC

1225 Eye Street, NW, Suite 200
Washington, DC
United States

Tel: 202 525 5770

Run Year Structure

Model Year:	Representative of Average for Years:
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" (CEE) 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 2020 and 2030 to derive incremental annual savings and cumulative savings estimates for each state.
- In the "Modest EE" (EE1) scenario, the available supply of EE is first 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.
  - Our updated approach differs from EPA in that states already at or above the 1.0 percent target rate are assumed to remain at their historic savings rate beginning in 2020 and sustain that rate thereafter.
- In the "Significant EE" (EE2) 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.

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:

Regional Average Price (mills/kWh)	=	Competitive Retail Power Price	*	Deregulation Share (%)	+	Cost-Of-Service Retail Power Price	*	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.

Retail Rate Calculations – Methodology[1]

For regulated markets, ICF utilizes a Cost-Of-Service (COS) Model to develop retail costs. The COS Model estimates prices based on average cost to generate power and includes regulated returns to utilities, taxes, and transmission and distribution costs:

Cost-of-Service Retail Power Price = (Final Cost of Power Generation + Transmission Charge + Distribution Charge)

In the above calculation of retail prices, "Final Cost of Power Generation" is calculated as:

Final Cost of Power Generation (mills/kWh) = (Average Cost of Power Sales + Utility Depreciation Costs + Return to Equity and Debt + Non-Utility Generation Adder) × (1+Tax Rate)

[1]This slide is derived from EPA's documentation of the Retail Price Model, *available at:* https://www.epa.gov/airmarkets/documentation-retail-price-model

Renewables Capital Costs and Build Assumptions

- Renewables cost assumptions are presented on the following slide.
- These model runs assume that renewable resources are limited to 20 percent of net energy for load by technology type and 30 percent of net energy for load in total at each of IPM's U.S. sub-regions, on the assumption that grid integration impacts are relatively minor below these levels. EPA considers this assumption to be a conservative approach that provides a high degree of assurance that the renewable capacity deployment pattern projected by the model would not incur significant grid integration costs. See Final Clean Power Plan Rule, page 64808.
- Short-term capital cost adders are also assumed for wind and solar consistent with EPA's Base Case v.5.15. Capital costs increase when capacity additions exceed specified thresholds.
- Also, 2018 solar builds are limited to a 7.5 GW per calendar year and 2018-2019 wind builds are limited to a 15 GW per calendar year.
- Virginia wind builds limited to 500 MW based on feedback from state dialogues.

Current Renewable Cost Assumptions

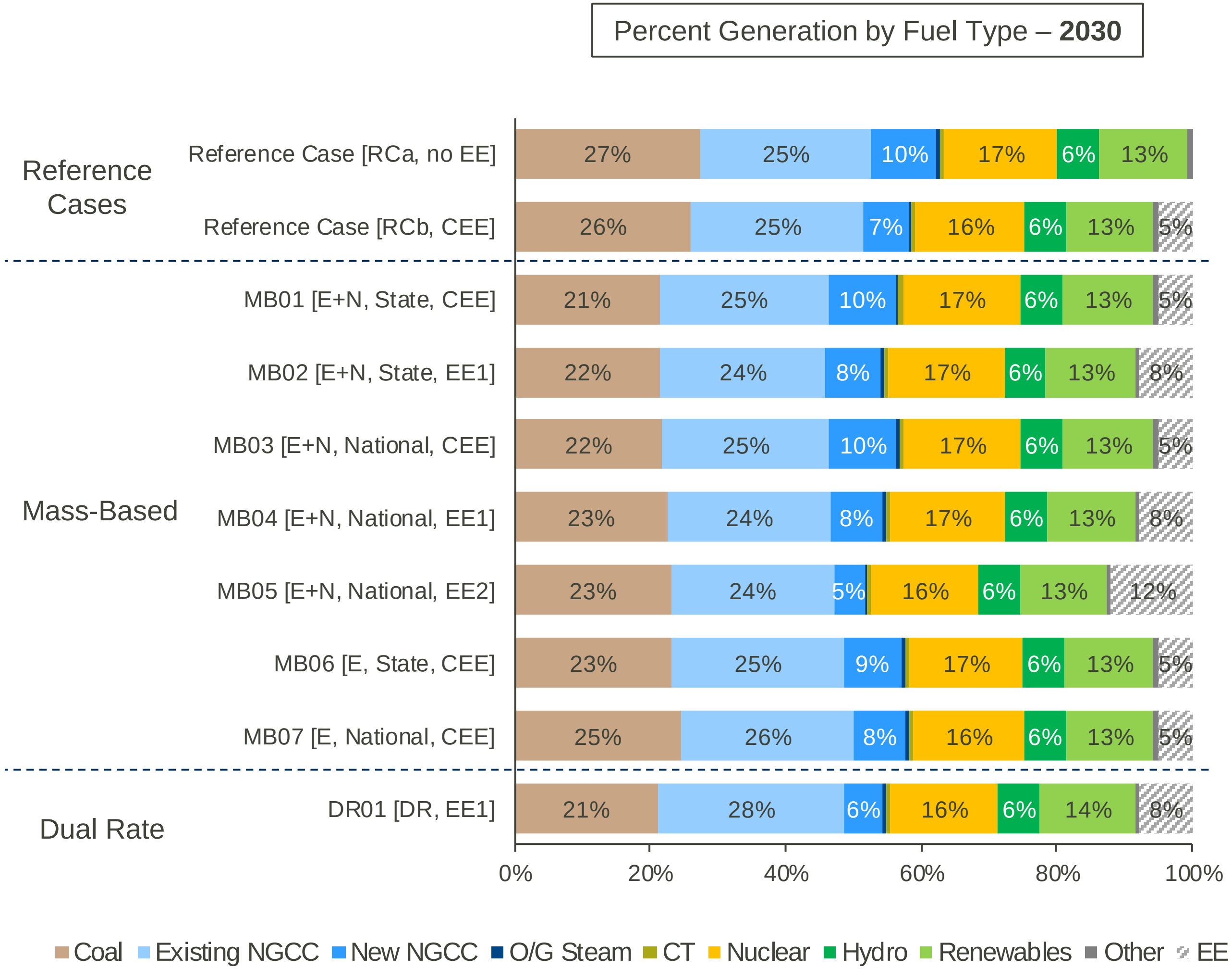
	RE Potential Build Cost and Performance - EPA v5.15					
Renewable Technologies	First Year	Vintage	Overnight Capital Costs in 2016-2054 (2012$/kW)	Heat Rate in 2016-2054 (Btu/kWh)	VOM (2012$/MWh)	FOM (2012/kW)
Biomass BFB	2018	2018-2040	4,111	13,500	5.2	103.8
Landfill Gas*	2016	2016-2040	8,554	13,648	8.5	381.7
Solar PV	2016	2016	2,182	-	-	7.4
		2018	1,880	-	-	7.4
		2020	1,579	-	-	7.4
		2025	1,448	-	-	7.4
		2030	1,053	-	-	7.4
		2040	1,053	-	-	7.4
Solar Thermal	2016	2016	5,015	-	-	42.2
		2018	4,935	-	-	42.2
		2020	4,857	-	-	42.2
		2025	4,660	-	-	42.2
		2030	4,463	-	-	42.2
		2040	4,059	-	-	42.2
Onshore Wind	2016	2016	1,724	-	-	46.5
		2018	1,717	-	-	46.5
		2020	1,711	-	-	46.5
		2025	1,701	-	-	46.5
		2030	1,697	-	-	46.5
		2040	1,696	-	-	46.5
Offshore Wind	2016	2016	5,243	-	-	101.4
		2018	4,970	-	-	101.4
		2020	4,697	-	-	101.4
		2025	4,141	-	-	101.4
		2030	4,032	-	-	101.4
		2040	3,929	-	-	101.4

For the purpose of this analysis, the Solar PV costs in 2030 were reduced to $1,053/kW based on updated data from the National Renewable Energy Laboratory (NREL).

Otherwise the renewable cost assumptions are consistent with EPA's Base Case version 5.15.

Note: Capital cost multipliers are used to adjust region specific capital cost assumptions.
*EPA's analysis includes three different landfill gas build options with varying capital costs (LGLo, LGvLO, LGHi).   The costs shown above are for the mid range LGLo.

Generation Fuel Mix



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

Relative to the Reference Case, coal generation declines an average of 18% in 2030 (averaging across all of the scenarios), but continues to supply between 21% and 25% of electricity, across all of the cases evaluated.

Natural gas (NGCC) is projected to supply between 24% and 28% of electricity in 2030, across all of the cases evaluated.

Renewable energy is projected to supply between 13% and 14% of electricity in 2030, across all of the cases evaluated.

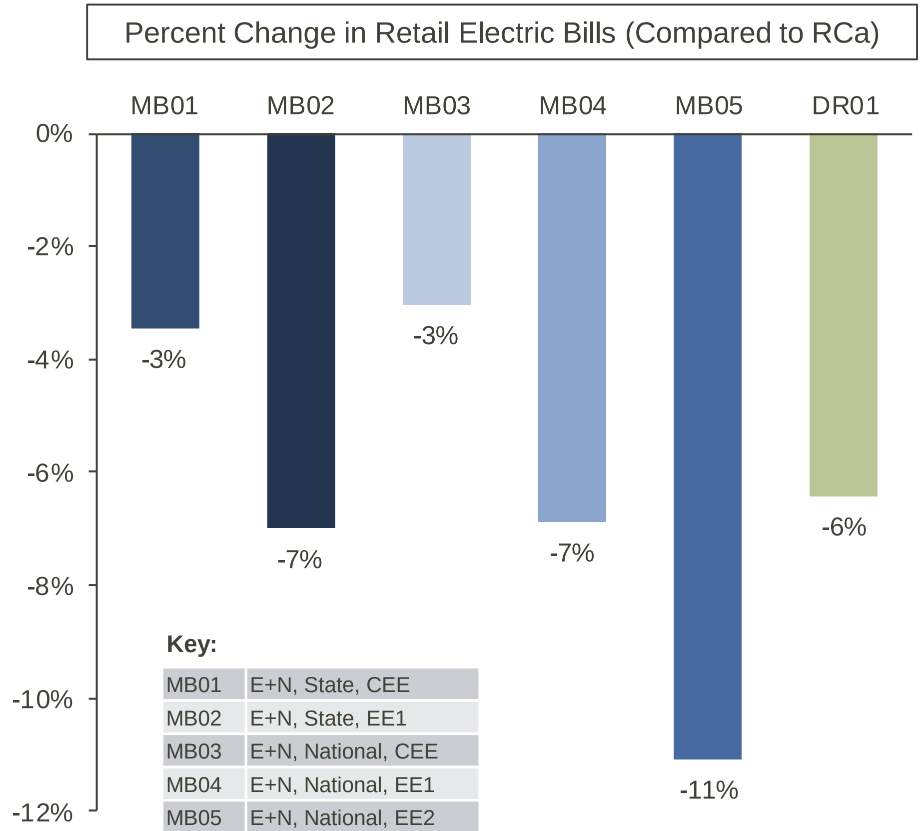
Note: "Existing Only" cases MB06 and MB07 do not include leakage mitigation measures.

2030 U.S. Avg. Monthly Bills: Relative to RCa, no EE

ICF International estimated average retail bills for the continental U.S. using a sales-weighted methodology developed by EPA. The estimates reflect changes in electric system costs.

On average, U.S. household bills are estimated to be below reference case (RCa) levels (3%-11%) depending on the level of energy efficiency and policy option. The mass-based scenarios do not assume that the allowance value is returned to consumers in the form of bill assistance programs or clean energy services that could benefit electricity customers.

Increased investment in energy efficiency also results in greater bill savings for households; for example, savings roughly triple between MB04 and MB05.



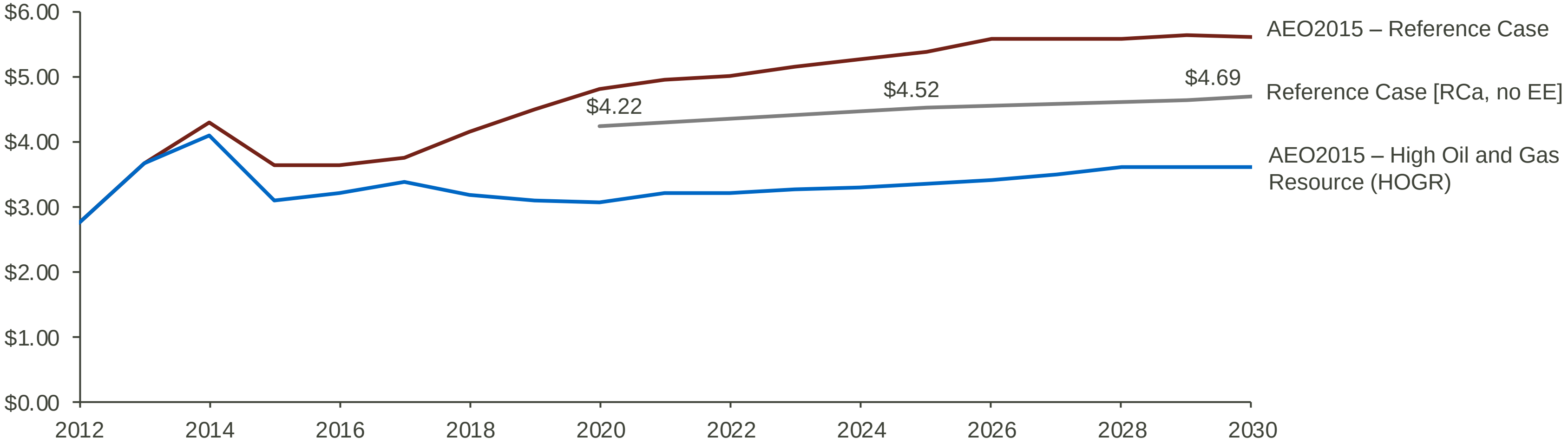
Key:

MB01	E+N, State, CEE
MB02	E+N, State, EE1
MB03	E+N, National, CEE
MB04	E+N, National, EE1
MB05	E+N, National, EE2
DR01	DR, EE1

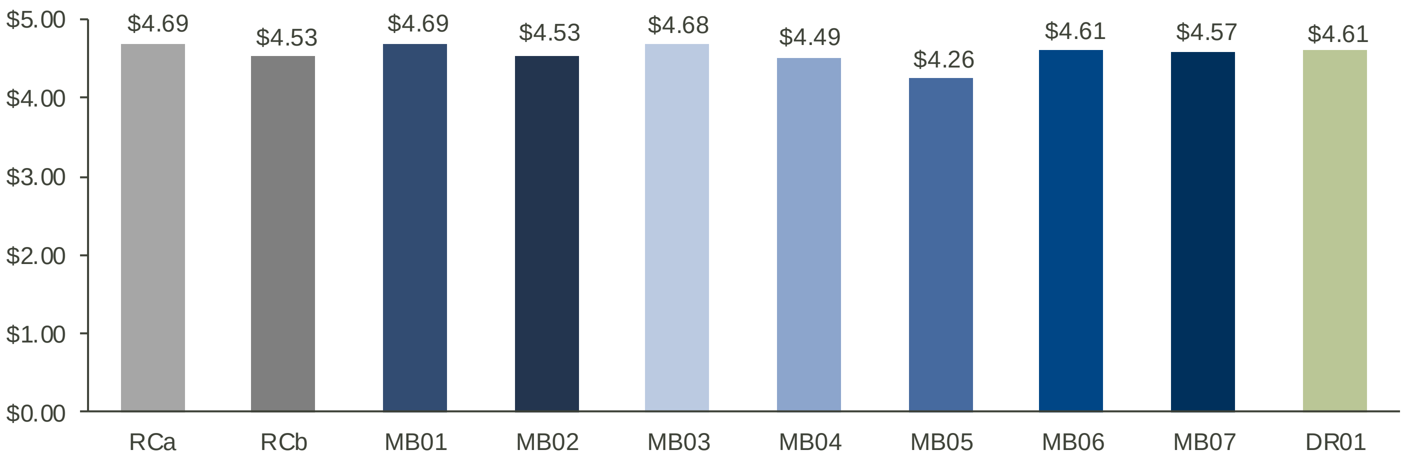
Note: Average retail bills are compared to Reference Case (RCa).
The participant costs of energy efficiency programs are excluded from these retail bill estimates. Including participant costs would have a minimal impact on the magnitude of these bill estimates.

Natural Gas Prices (2012$/MMBtu)

Reference Case A Projected Henry Hub Natural Gas Price – **2012-2030**



All Scenario Projected Henry Hub Natural Gas Price – **2030**



Key:

RCa	Reference Case, no EE
RCb	Reference Case, CEE
MB01	E+N, State, CEE
MB02	E+N, State, EE1
MB03	E+N, National, CEE
MB04	E+N, National, EE1
MB05	E+N, National, EE2
MB06	E, State, CEE
MB07	E, National, CEE
DR01	DR, EE1

Henry Hub Gas (2012$/MMBtu): Total U.S.

Code	Assumptions	2020	2025	2030
RCa	Reference Case, no EE	$4.22	$4.52	$4.69
RCb	Reference Case, CEE	$4.27	$4.44	$4.53
MB01	E+N, State, CEE	$4.32	$4.52	$4.69
MB02	E+N, State, EE1	$4.33	$4.47	$4.53
MB03	E+N, National, CEE	$4.29	$4.45	$4.68
MB04	E+N, National, EE1	$4.32	$4.40	$4.49
MB05	E+N, National, EE2	$4.36	$4.37	$4.26
MB06	E, State, CEE	$4.25	$4.48	$4.61
MB07	E, National, CEE	$4.25	$4.41	$4.57
DR01	DR, EE1	$4.25	$4.37	$4.61

Note: As of the week ending May 18, 2016, near-month natural gas futures prices were trading around $2.00/MMBtu, according to Nymex. For more information and updates see EIA's Natural Gas Weekly Update at http://www.eia.gov/naturalgas/weekly/#tabs-prices-3.