DISCUSSION PAPER

July 2011 ■ RFF DP 11-35

Clean Energy Standards for Electricity

Policy Design Implications for Emissions, Supply, Prices, and Regions

Anthony Paul, Karen Palmer, and Matt Woerman

1616 P St. NW
Washington, DC 20036
202-328-5000 www.rff.org

RESOURCES FOR THE FUTURE

Modeling a Clean Energy Standard for Electricity: Policy Design Implications for Emissions, Supply, Prices, and Regions

Anthony Paul, Karen Palmer, and Matt Woerman

Abstract

The electricity sector is responsible for roughly 40 percent of U.S. carbon dioxide (CO_2) emissions, and a shift away from conventional coal-fired generation is an important component of the U.S. strategy to reduce greenhouse gas emissions. Toward that goal, several proposals for a clean energy standard (CES) have been put forth, including one espoused by the Obama administration that calls for 80 percent clean electricty by 2035 phased in from current levels of roughly 40 percent. This paper looks at the effects of such a policy on CO_2 emissions from the electricity sector, the mix of technologies used to supply electricity, electricity prices, and regional flows of clean energy credits. The CES leads to a 30 percent reduction in cumulative CO_2 emissions between 2013 and 2035 and results in dramatic reductions in generation from conventional coal. The policy also results in fairly modest increases on national electricity prices, but this masks a wide variety of effects across regions.

Key Words: renewables, climate, clean energy standard

JEL Classification Numbers: Q42, Q48, Q54, Q58

Contents

Modeling a Clean Energy Standard for Electricity: Policy Design Implications for Emissions, Supply, Prices, and Regions

Anthony Paul, Karen Palmer, and Matt Woerman*

1. Introduction

When the U.S. Senate failed to adopt any of the many legislative proposals for an economy-wide cap-and-trade program for carbon dioxide (CO_2) emissions during the 111th Congress, the Obama administration and other policy innovators started to develop a collection of strategies to help reduce emissions of greenhouse gases. These policy chunks, as President Obama referred to them in a September 2010 interview with *Rolling Stone* magazine, include stricter CAFE standards for vehicles, Clean Air Act rules to reduce CO_2 emissions from coal-fired utility boilers and other point sources, policies to promote energy efficiency in buildings, and clean energy standards for the electricity sector.

A clean energy standard (CES) is similar to a renewable portfolio standard (RPS), but it includes a broader range of non-CO_2-emitting and even low-CO_2-emitting technologies. Under an RPS, electric utilities are required to supply a certain percentage of the electricity that they deliver to customers using qualified renewables. Typically, the percentage goes up over time, and in some cases there are carve-outs for particular types of renewables, such as solar photovoltaics or hydrokinetic. Twenty-nine states and the District of Columbia have some form of RPS in place; the targets and timetables, set of qualified renewables, and other features of these state policies differ widely.[1] Under a CES the set of technologies that can be used to meet the standard is expanded to include other non-CO_2-emitting technologies, such as nuclear and hydro. The standard may also give partial credit to generation from coal (or natural gas) with

* Anthony Paul is a Center Fellow in the Center for Climate and Electricity Policy at Resources for the Future, Karen Palmer is a Senior Fellow, and Matt Woerman is a Research Assistant. The authors wish to thank David McLaughlin for research assistance and Dallas Burtraw and Ray Kopp for helpful comments. All remaining errors are our own.

[1] For more information on state RPS policies see the Database of State Incentives for Renewables and Efficiency at http://www.dsireusa.org/ (accessed May 25, 2011).

[2] Aldy (2011) proposes a standard based on CO_2 emissions intensity and granting of credits to generators who meet the standard; these credits can be sold to generators who fail to meet the standard.

[3] Parry and Williams (2011) show that if the allowance revenue from cap-and-trade isn't used to reduce distortionary taxes or if emissions allowances are allocated for free, a cap-and-trade policy would be substantially

[1] For more information on state RPS policies see the Database of State Incentives for Renewables and Efficiency at http://www.dsireusa.org/ (accessed May 25, 2011).

carbon capture and storage or to natural gas combined-cycle units. Some forms of a clean energy standard also give credit to electricity savings from energy efficiency programs.

In his 2011 State of the Union address, President Obama announced a goal of producing 80 percent of electricity using clean energy sources by 2035. This announcement was followed by the release of a brief summary of a clean energy standard that would achieve this goal. The policy would give full clean energy credits to technologies that emit no CO_2, such as nuclear and renewables, and partial credit to coal with CCS and efficient natural gas. The exact parameters of the administration policy have yet to be specified. On March 21, 2011, the staff of the Senate Energy and Natural Resources Committee issued a white paper that sought comment on several design elements of a CES that would be consistent with the goals that the president had laid out. This paper analyzes a CES that is broadly consistent with the policy outlined by the Obama administration and considers the effects of different design parameters and different contexts on the performance of the standard. The paper begins by comparing a CES with a cap-and-trade policy and then considers different CES design parameters. Section 2 looks at the conceptual relationship between a CES and electricity prices. Section 3 discusses the design parameters of a CES. The rest of the paper is devoted to our simulation analysis of the CES policy using RFF's Haiku electricity market model, which is described in the Appendix. Section 4 describes the scenarios that we model. Section 5 describes the results and section 6 concludes.

2. Comparison of a CES with carbon pricing

A CES is less efficient at reducing CO_2 emissions than a cap-and-trade policy or other approach that imposes a price on CO_2. There are two reasons for this.

First, by categorizing generators by broad technological and fuel categories, a CES fails to capture heterogeneity in CO_2 emissions rates within categories, and it will not impose the efficient relative incentive levels within or across categories. A price on CO_2, in contrast, causes each individual generator to bear a cost that is proportional to its CO_2 emissions rate, and it therefore provides the incentive for generators to lower their heat rates or take other steps to reduce CO_2 emissions intensity to reduce emissions-related costs. A CES could be adapted to be more efficient by setting the standard based on heat input or emissions rates and placing the point of compliance on generators instead of distribution companies.[2]

[2] Aldy (2011) proposes a standard based on CO_2 emissions intensity and granting of credits to generators who meet the standard; these credits can be sold to generators who fail to meet the standard.

Second, a CES does not yield electricity prices for consumers that reflect the full social cost, including the CO_2 emissions cost, of the electricity they consume. A policy that prices CO_2 emissions directly will yield electricity prices that reflect these costs if the emissions allowances are distributed using an allowance auction.[3] If the cost of CO_2 emissions is not reflected in electricity prices, then consumers will consume more electricity than is economically efficient, and emissions reductions will be excessively expensive. An allowance auction is used in the Regional Greenhouse Gas Initiative (RGGI) cap-and-trade program for CO_2 emissions from electricity generators in the northeast, but most other proposed or adopted cap-and-trade programs initially allocate some of the allowances for free to local distribution companies to moderate the electricity price effect of imposing the cap. However, most programs, including the AB32 program in California, recent federal cap-and-trade proposals, and the European Union's Emission Trading Scheme, envision ultimately auctioning most of the allowances, which would serve to pass the CO_2 price signal on to electricity consumers.[4]

3. CES design parameters

The design parameters of a CES can affect the effectiveness and cost of the policy in several ways.

3.1. Eligible technologies and crediting

The most restrictive form of a clean energy standard is a renewable portfolio standard (RPS), limited to renewable technologies. Under an RPS, the only technologies that qualify for credits are those that use renewable sources of energy; most RPS policies exclude existing hydro but include new hydro and both existing and new nonhydro renewables. Because of the large differences in cost across renewables technologies, an RPS that treats all renewables the same

[3] Parry and Williams (2011) show that if the allowance revenue from cap-and-trade isn't used to reduce distortionary taxes or if emissions allowances are allocated for free, a cap-and-trade policy would be substantially more costly than a CO_2 emissions rate standard for the power sector. This higher cost is attributable to the confounding effect of higher energy prices on lowering the returns to labor effort resulting from the income tax system. Parry and Krupnick (2011) argue that this tax interaction effect means that a CES that is implemented as a CO_2 emissions rate standard with a "feebate" will likely be more efficient that a cap-and-trade policy that doesn't auction allowances and doesn't use the revenue to offset existing distortionary taxes.

[4] Note that if allowances were allocated for free to electricity generators, the ultimate effect on electricity price would depend on whether electricity prices were set by regulation at average cost or in markets at marginal cost. Under this approach to allocation, prices would rise by more in competitive regions than in regulated ones (Paul et al. 2010).

would tend to favor the low-cost renewables, such as biomass and wind, and do little to encourage higher-cost renewables, such as solar. To help boost the more expensive renewables and promote cost reductions through scale economies and learning, some states have carve-outs or tiers in their RPS policies that create subcategories of technologies, each with its own standard, to ensure that these technologies also benefit from the policy. Another way to favor particular technologies is to grant them multiple credits per MWh of generation. These types of carve-outs raise the cost of the RPS policy in the short run or reduce total generation from renewables, but arguably, assuming there are opportunities for learning by doing, help reduce the costs of these less mature technologies, making them lower cost in the future.

A broader CES can include other non-CO_2-emitting technologies as well as lower-CO_2-emitting technologies, as mentioned above. Typically, a technology that does not emit any CO_2, such as nuclear, is treated the same as a renewable in that each MWh of generation receives one credit. For other technologies, such as coal or natural gas with carbon capture and storage, where most but not all of the CO_2 emissions are eliminated, each MWh generated receives partial credit based on its emissions rate relative to the emissions rate of a typical coal-fired generator, which is on the order of 90–95 percent. Similar logic applies to the determination of credits given to natural gas generation; for example, efficient natural gas plants have a CO_2 emissions rate of roughly 50 percent that of a coal-fired boiler.[5]

Treatment of energy efficiency

A truly "technology-neutral" CES would also include credits for electricity savings resulting from investment in energy efficiency. The added flexibility from including electricity savings from energy efficiency investments presumably would promote the lowest-cost approach to meeting the clean energy standard and raise the political acceptability of a CES proposal. Indeed, the Renewable Energy Promotion Act of 2010, sponsored by Sens. Bingaman (D-NM) and Brownback (R-KS), incorporates energy efficiency into the RPS by allowing just over 25 percent of the renewables standard to be met by savings from energy efficiency programs. A bill put forward by Sen. Graham (R-SC) also allows for energy efficiency credits to meet exactly 25 percent of the clean energy standard. In addition to placing a limit on the contribution of energy

[5] Palmer et al. (2010) analyze a clean energy policy standard that looks very similar to the Core policy analyzed here using the NEMS-RFF model.

efficiency to the CES, some of these proposals limit the tradability of credits associated with efficiency investments to within-state boundaries.

However, incorporating energy efficiency into a CES raises uncertainty about the future value of clean energy credits, which can be an important source of revenue for developers of renewables and other clean electricity technologies. Including energy efficiency in the CES means that the energy savings associated with efficiency programs, which are difficult to quantify, will have a direct effect on the market price of clean energy credits. Under a linked policy, renewables developers will be wary of competing with an energy efficiency program that could generate large amounts of credits; they would likely insist on strict verification of those savings.

Emissions rate-based CES

One way to avoid the categorical decisions about which generation technologies qualify would be to make credit determinations based on a more continuous metric, such as a CO_2 emissions rate. This method would develop a threshold CO_2 emissions rate per MWh and then give credits, based on differences between actual emissions rate and the standard, to all generators that outperform the standard and require generators that exceed the standard to hold credits to make up the difference. This approach would reward investments at existing units to improve heat rates and would differentiate performance in CO_2 emissions rates across generators in a particular technology class, including natural gas combined-cycle generators and coal-fired generators.[6]

3.2. Treatment of existing generators

Whether to qualify existing clean energy facilities for receipt of clean energy credits is a decision that involves a trade-off between economic efficiency and equity—not a simple decision. The efficiency aspect hinges on whether awarding credits to existing facilities will alter their level of production and thus have an effect on CO_2 emissions, and whether the higher electricity prices resulting from qualifying existing facilities are efficiency enhancing. The equity aspect hinges on the regional and shareholder-consumer wealth transfer consequences of the choice.

---

[6] Aldy (2011) discusses such an approach.

To evaluate the effect of qualifying existing clean facilities on the CES policy's efficiency in reducing CO_2 emissions, one must consider both the emissions impact and the costs. If qualifying an existing facility would not alter its level of production, likely the case for generators with low operating costs, then there is no direct emissions reduction benefit. Technologies in this category include existing hydroelectric, wind, solar, geothermal, municipal solid waste, and landfill gas–powered generators. If qualifying an existing clean facility to receive credits would increase its production, then emissions will fall and yield an improvement in efficiency relative to qualifying a facility that will not increase production. Biomass, natural gas, and some high-cost nuclear facilities fall into this category.

Qualifying existing generators does impose a cost on consumers, assuming that the level of the standard would be adjusted upward to keep constant the expected fraction of generation from nonemitting sources under the policy. The cost comes from the elevated standard level, which would require each unit of electricity consumption to acquire additional credits, thereby raising electricity prices in many regions by more than if the existing generators are excluded. Elevated electricity prices have undesirable tax interaction effects (Parry and Williams 2011) but also reduce emissions by reducing consumption. On net, the CO_2 reduction efficiency effects of higher electricity prices remain an open question in the literature.

The overall efficiency effect of qualifying existing generators, including the effect of higher electricity prices, is difficult to value ex ante. However, qualifying existing facilities that will increase production must have a greater efficiency effect than qualifying existing facilities that will not alter production. Generators with the highest operating costs are the most likely to alter production levels when awarded credits and therefore provide the biggest efficiency gain (or smallest efficiency loss) via reduced emissions.

The treatment of existing facilities in a CES also has regional implications that depend on the geographic distribution of the type of facility in question. This is discussed in detail in Section 5.6.

3.3. Coverage

A CES policy must specify which utilities and which MWhs are covered. Several RPS policies proposed in the 111th Session of Congress exclude utilities with sales below a threshold value, which ranges from 1 million to 4 million MWh annually across the different proposals. In the latter case, this would exclude approximately 23 percent of electricity sales, which could make the 80 percent clean energy goal articulated by the Obama administration impossible to achieve. It also might create perverse incentives for keeping local distribution companies small so that they avoid having to comply with the standard.

Many recent federal RPS and CES policy proposals exempt generation from existing hydro and nuclear facilities from compliance. Generation from these facilities accounts for roughly 27 percent of total generation in 2010 and roughly 23 percent of baseline generation in 2035, so excluding these units from the denominator of the CES means that the percentage of credited generation required by the policy would have to be raised to achieve a particular level of clean generation, relative to a policy in which these existing sources are not excluded and are not counted as qualifying for credits.

3.4. Targets and timetables

A CES policy needs to specify targets and deadlines by which these targets are to be met. As suggested above, the stated targets—or more accurately, the relationship between the standards specified in the policy and the stated goals of the policy—will depend importantly on what technologies are eligible to receive credits, the awarding of partial credits, and which MWhs are covered by the policy. In general, the percentage requirement of the policy will increase as more technologies, such as existing hydro and nuclear facilities, are either excluded from the policy or included in the policy and qualified for full crediting.

The timetables for these policies can vary in length and aggressiveness in terms of the speed with which targets are ramped up. The timetables matter less if the policy allows banking and borrowing of credits, which are described in Section 0.

3.5. Credit trading

A CES policy will be substantially more efficient if it allows trading in clean energy credits than if it does not. For maximum efficiency, trading should be national in scope and trades across state borders should not be limited. A consequence of open credit trading is that, as shown in Section 5.6, some states or regions will be net sellers of clean energy credits and others will be net buyers. Regional transfers of wealth are thus inevitable, although there may be ways to design the policy to limit the extent of those transfers at the cost of national efficiency. Exploring these trade-offs is beyond the scope of the current modeling analysis but is an important topic for future research.

3.6. Banking and borrowing

Banking and borrowing are important flexibility mechanisms in any trading scheme: they help smooth out price or cost fluctuations over time associated with compliance with the requirement. There are no reasons to place restrictions on banking in this policy. On the other hand, unlimited borrowing could be problematic, as it tends to undermine the incentives for electricity retailers to be committed to the continued existence of the program.

Some amount of borrowing is probably a good idea to deal with unforeseen circumstances or delays in bringing new generators on-line that could compromise compliance. This type of contingency could be handled by having an alternative compliance payment that kicks in if sufficient credits are not available at a stated price, but allowing borrowing would require some excess generation of clean energy in the future that would help maintain the environmental integrity of the policy as well as its goals for total clean energy generation. Allowing for a three-year compliance period (and thus borrowing within the compliance window) is a common practice that could put some reasonable bounds on borrowing activity and limit the possibility that the debt is never repaid.

3.7. Point of compliance

Most CES and RPS policies set the point of compliance at the local distribution company or electricity retailer. An alternative approach would place the point of compliance on electricity generators; this would be particularly attractive if the policy were sufficiently disaggregated to provide incentives for improvements in heat rates at fossil fuel generators. For example, if the standard were specified in terms of an average CO_2 emissions rate per MWh instead of percentage of MWh from a particular category of generators, then shifting the point of compliance to the generator would provide incentives for improvements in heat rates to reduce the credit requirements at an existing fossil-fueled generator, as discussed in Section 0. Placing the point of compliance at generators' heat input would also induce heat rate improvements.

3.8. Alternative compliance payment and revenue allocation

To limit the costs to the economy of imposing a CES, most policy proposals include an alternative compliance payment (ACP) for clean energy credits.[7] The regulated entities could

---

[7] For an analysis of the effects of an ACP on the performance of a federal RPS policy, see Palmer et al. (2011).

make such payments in lieu of purchasing clean energy credits, and thus the ACP essentially imposes a cap on the price of those credits.[8] ACPs have been a feature of most prior federal RPS and CES proposals introduced in the past few sessions of Congress. The RPS proposals would replace the renewable production tax credit, which has lapsed and been reinstated several times since it was first initiated. The tax credit is currently set at $21/MWh, and this value was adopted as the ACP for some of the recent RPS proposals. Other proposals include ACP levels as high as $50/MWh.

For a CES policy with a target of 80 percent generation by clean sources in 2035, an ACP of $21/MWh would have two important consequences. First, it is much too low to remain nonbinding through 2035 and would therefore lead to a level of clean energy production far below the target. Second, if credit banking will be a feature of a CES, then an ACP that doesn't rise or rises only at the rate of inflation will become increasingly more likely to bind over time. With banking, credit prices are expected to rise at the rate of interest (along a Hotelling path) as long as there are credits in the bank. Thus any ACP price that does not rise accordingly will become more likely to bind. One solution is simply to set an ACP price that rises at the expected rate of interest over time.[9]

When the ACP is binding, it will create a pool of revenues for the government that could be used for a variety of purposes: research and development into renewable technologies, refunds to electricity consumers to help offset consumers' cost of the CES policy, investment in energy efficiency, reductions in other taxes, or deficit reduction. In past proposals, the revenue was to be returned to the state from which it came, and the state would be required to use the funds for these kinds of investments or refunds.

[8] In the debate over cap-and-trade policies for CO_2, discussions of a cap on the price of CO_2 allowances transformed into conversations about a price collar on CO_2 allowances that includes both a ceiling and a floor (Burtraw et al. 2010). The floor could be enforced through the use of tax credits that would take effect only if the price of clean energy credits falls below a certain level or a standing offer from the government to purchase clean energy credits at the price floor. The price floor creates some price certainty in the clean energy credit market, and this would help promote the development of clean technologies.

[9] Aldy (2011) sets an ACP that equals $15 per ton of CO_2 per MWh and then rises at 7 percent real per year to reach $30 by 2025. This price is expected to be binding, essentially transforming the CES into a CO_2 fee.

4. Scenarios description

To explore the effects of different CES policy designs and different assumptions about electricity technologies and fuel prices on environmental and electricity market outcomes, we model several policy scenarios. We use the Haiku electricity market model, which is described in the appendix, to analyze these scenarios.

All the scenarios that we model are compared with a baseline scenario that represents business-as-usual in the absence of any CES policy. The characteristics of the baseline are retained in all the CES scenarios, except as specifically mentioned in the descriptions that follow. The scenario defined below as Core represents a CES policy that can be evaluated in comparison with the baseline, or in comparison with other versions of a CES policy. These other versions are defined by a set of deviations from the Core scenario, and they are shown in the tables, figures, and text of this document as combinations of abbreviations corresponding to deviations from the Core scenario. This section describes the baseline, the Core CES scenario, and the deviations from the Core scenario. The abbreviation for each is given parenthetically in the section headings. The modeling timeframe is 2013 to 2035.

4.1. Baseline (BL)

The baseline scenario represents business-as-usual and is very similar in both assumptions and results to the Reference case of the Annual Energy Outlook (AEO) 2010 (EIA 2010a). Included in the scenario is a representation of the existing state-level RPS policies in 29 states plus the District of Columbia, aggregated to the 21 Haiku market regions. These policies are characterized by the schedule with which the renewable goals are phased in, the basis of the RPS (sales, generation, capacity, etc.), the utilities that are required to comply, the types of qualifying renewable technologies, the extent of interstate trading of renewable energy credits (RECs) that is allowed, and the level of any alternative compliance payment (ACP). Also included is a representation of tax credits for renewables that are in place in 6 states (Florida, Iowa, Maryland, New Mexico, Oklahoma, and Utah) and those included in the federal American Recovery and Reinvestment Act (ARRA). ARRA extended the production tax credit available to existing wind generators through 2012 and for other technologies through 2013. It also allowed generators to choose between a production tax credit and an investment tax credit, depending on which provides more benefit.[10]

The BL scenario incorporates several existing environmental policies administered by the U.S. Environmental Protection Agency (EPA), including the SO_2 cap-and-trade program under Title IV of the Clean Air Act Amendments of 1990, the Clean Air Interstate Rule[11] restrictions on emissions of SO_2 in the eastern part of the country, and the annual and ozone season restrictions on NO_x emissions, as well as the cap on CO_2 emissions in the RGGI states (the Northeast) and the state-level mercury maximum achievable control technology (MACT) programs.

4.2. Core CES (Core)

The Core CES policy analyzed here is assumed to begin in 2014 at a level of 12.3 percent and become increasingly more stringent (on a linear path) to a level of 57.1 percent at the end of the modeling horizon, in 2035.[12] Banking of CES credits is not modeled, so a MWh of clean electricity generated in a particular year must be used for compliance in the same year. This means that the resulting price path may not follow a Hotelling rule that we would expect to prevail if banking were allowed. A whole clean energy credit is awarded per unit of electricity generated by wind, biomass, geothermal, solar, municipal solid waste, and landfill gas. Both existing installations and new investments in these technology types earn a credit. Nuclear facilities and hydroelectric power are awarded a whole credit for electricity generated by new investments but not for generation at existing facilities.[13] Power generated by natural gas–fired combined-cycle units, both existing capacity and new investments, is awarded half a credit per

[10] The ARRA policy also allows for renewable generators to opt for a cash grant instead of the tax credit. In the Haiku model, a cash grant is indistinguishable from an investment tax credit because capital is treated as perfectly mobile.

[11] The rule was vacated and remanded to EPA in July 2008 by the federal appeals court, but after a request for rehearing, in December 2008 the court remanded the rule to EPA without vacating. Thus the rule remains in effect while EPA develops a replacement rule that satisfies the concerns raised in the appeals court decision. This new final rule is pending.

[12] These levels would yield 40 percent clean energy in 2014 and 80 percent in 2035, assuming that generation from existing nuclear and hydroelectric facilities (which do not qualify for credits) persist at historical levels because of the low variable cost nature of these technologies.

[13] Haiku does not model new investments in hydroelectric generation capacity, so the investment aspect of this sentence applies only to nuclear investments.

unit of generation. Generation from coal-fired plants that employ a carbon capture and storage (CCS) system is awarded 90 percent of a credit per unit of power.

Great uncertainty about investment costs surrounds two technologies that could play an enormous role in meeting a CES: nuclear and integrated gasification combined-cycle (IGCC) with CCS. There are also potential political obstacles to extensive deployment of nuclear power, and the regulatory and physical infrastructure necessary to support widespread transport and storage of captured carbon is yet to be developed. The Core CES scenario places a constraint on the quantity of new capacity of these technology types that can be constructed per year. The constraint, implemented separately for the two technologies and for each of the 21 model regions, is set to 0.25 percent of total installed capacity of all types in the region in 2008. If these constraints were binding in every region in every year for both technologies, by 2035, nuclear investments would amount to 56.2 GW and investments in IGCC with CCS would amount to 61.6 GW. The aggregate constraint is different for the two technologies because of the assumption that an IGCC with CCS generator can be constructed in four years, two years less than the construction time assumed for a nuclear generator.

4.3. Credit Existing Nuclear and Hydro (CreditNH)

The CreditNH scenarios award a whole clean energy credit to existing nuclear and hydroelectric capacity per unit of generation. The levels of the standard are adjusted from the Core scenario accordingly, to 41 percent in 2014 and 80 percent in 2035, increasing linearly in the intervening years.

4.4. Exclude Existing Nuclear and Hydro (ExcludeNH)

The ExcludeNH scenario excludes generation by existing nuclear and hydroelectric facilities from the total amount of electricity sales required to hold clean energy credits under the policy. If the point of compliance for the CES is the local distribution company, as assumed here, then determining how many MWh of ultimate sales are generated by existing nuclear and hydro poses a challenge, as it is impossible to assign MWh sold at retail to particular types of generators. However, separating the excludability characteristic of a MWh generated by an existing nuclear or hydro plant from its electricity content would facilitate this type of exclusion. This separation can be accomplished by creating an exclusion credit that is awarded for every MWh produced by existing nuclear and hydro facilities. These credits give the local distribution companies an additional option for compliance with the CES: the company can purchase exclusion credits to lower its compliance obligation or purchase clean energy credits to count toward its compliance obligation. Because each exclusion credit reduces its compliance obligation by the level of the CES, the price of an exclusion credit in equilibrium will be equal to the price of a CES credit times the level of the CES. This equality implies that for modeling purposes, the combination of a clean energy credit market and an exclusion credit market can be collapsed into a single clean energy credit market in which existing hydro and nuclear units get a fraction of a credit (equal to the CES compliance percentage) for every MWh of electricity that they generate.

To achieve 80 percent clean energy by 2035, the goal for this scenario with the denominator exclusion needs to be adjusted from the 57 percent target with the numerator exclusion to 74 percent with the denominator exclusion with similar adjustments to the targets for the years leading up to 2035.

4.5. Cheap Natural Gas (ChpNG)

The ChpNG scenarios assume supply curves for natural gas that correspond to AEO 2011. These curves are substantially cheaper than those that corresponded to AEO 2010, as illustrated by the fact that Henry Hub prices for AEO 2011 are typically $2 per MMBTU below those forecasted in AEO 2010. The more abundant gas supplies that produce these lower prices are the result of more optimistic estimates of the amount of shale gas that will be entering the market at relatively low prices.

4.6. Optimism for Nuclear and IGCC with CCS (MoreNuke/MoreCCS)

The MoreNuke and MoreCCS scenarios raise the annual construction constraint of 0.25 percent of 2008 installed capacity to 1 percent of 2008 capacity.

4.7. Pessimism for Nuclear (LessNuke)

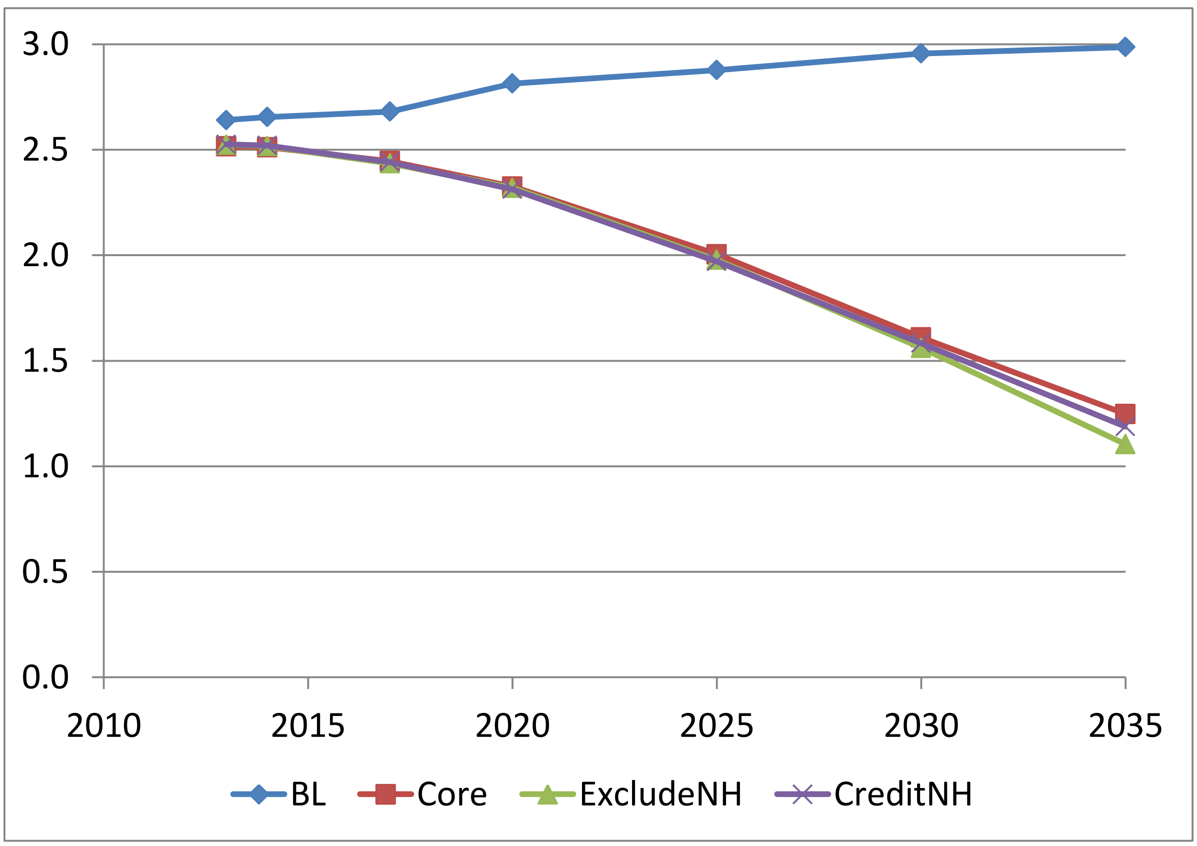
The LessNuke scenario imposes a constraint on new nuclear investments such that they cannot exceed the level of the BL scenario. However, this scenario also allows for the level of coal with CCS in the MoreCCS scenario.

5. Results

5.1. CO_2 emissions

A CES such as the Core scenario will lead to cumulative CO_2 emissions reductions in the electricity sector between 2013 and 2035 of roughly 30 percent, or 20 billion tons, relative to a baseline with no CES policy (BL). The size of the annual emissions reductions will grow over time as the standard tightens. In the early years of the policy, Core reduces electricity emissions by only a few percentage points compared with BL, but by 2035 annual CO_2 emissions from the electricity sector are almost 60 percent, or 1.7 billion tons, below the BL level. Cumulative emissions reductions are slightly higher with the ExcludeNH scenario, as that scenario precludes retirement of some existing nuclear capacity that retires in the Core scenario. Although the CreditNH scenario also precludes this nuclear capacity retirement, it also lowers credit prices as discussed below, which increases generation from coal-fired plants and yields CO_2 emissions approximately equal to those in the Core scenario. The CO_2 emissions trajectories of the BL and Core scenarios, along with the CreditNH and ExcludeNH scenarios, are shown in Figure 1.

Figure 1. CO_2 emissions (billion tons)

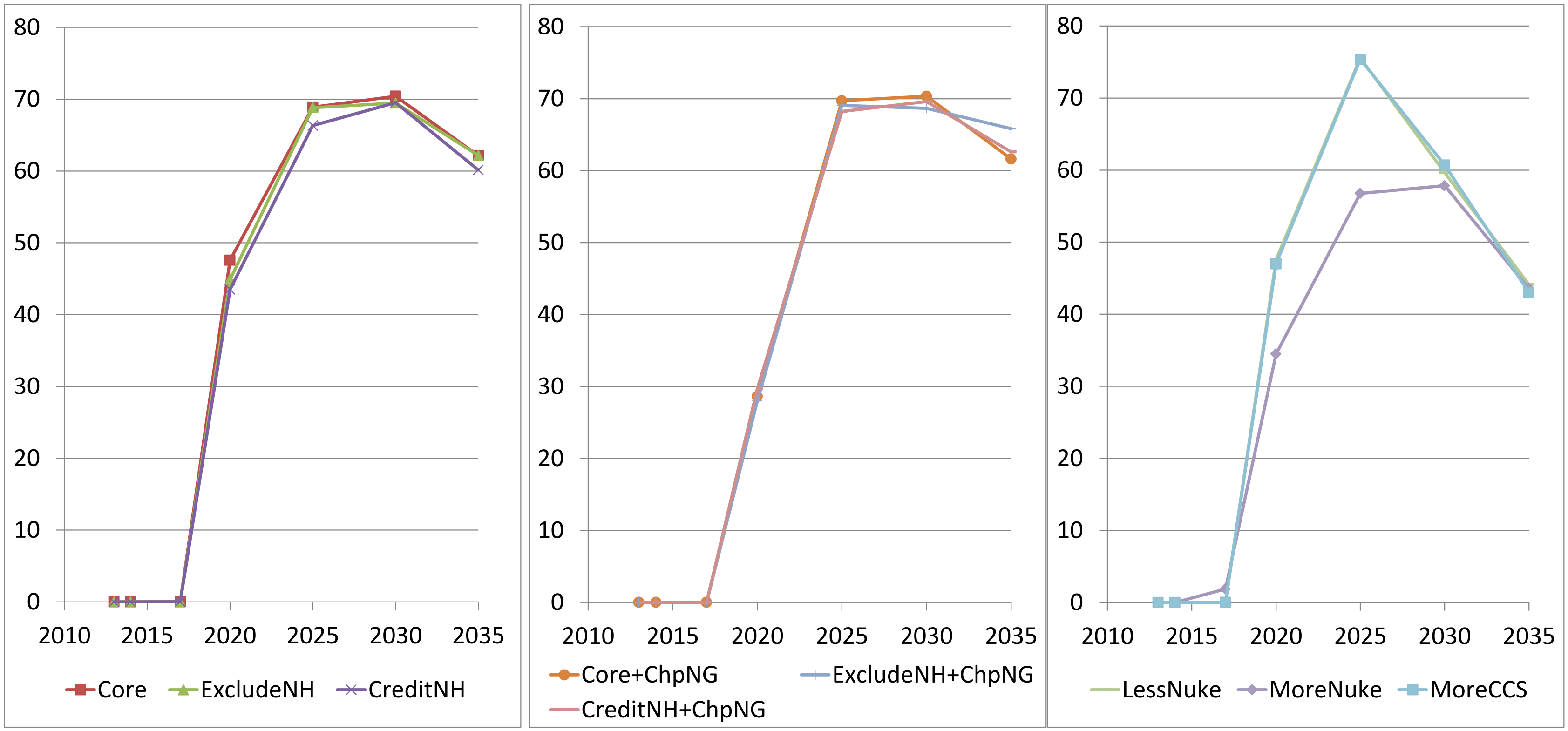


The 2011 Economic Report of the President indicates that a CES is an important component of meeting the United States' pledge, as part of the United Nations climate change conferences in Copenhagen and Cancun, to reduce total CO_2 emissions to 17 percent below 2005 levels by 2020 and to 83 percent below 2005 levels by 2050. Total economy-wide CO_2 emissions in 2005 were roughly 7.9 billion tons. Assuming a linear path of reductions, emissions will need to be reduced by 52.3 percent in 2035, which corresponds to a reduction of about 4.1 billion tons of CO_2 economy-wide. This CES policy reduces emissions by 1.7 billion tons in the electricity sector only, or 41 percent of the total emissions reductions required economy-wide by the United States' pledge. Therefore, additional policies will be required to reduce CO_2 emissions in 2035 by the remaining 2.4 billion tons and to reduce emissions in other sectors.

5.2. Clean energy credit prices

The modeling performed for this analysis provides insight into the effect of the price levels of an ACP on clean energy deployment. It is important to note that the modeling does not account for credit banking and therefore does not find credit prices rising at a discount rate. The left-hand panel of Figure 2 shows projected credit prices for the Core CES, ExcludeNH, and CreditNH scenarios. The middle panel of the figure shows credit prices under the three scenarios but with the ChpNG assumptions about the supply of natural gas. The right-hand panel of the figure shows credit prices for the sensitivity cases on nuclear and coal with CCS capacity.

Figure 2. Clean energy credit prices ($/MWh)



Four observations about the figure are relevant. First, linear trajectories for the level of the standard would yield highly nonlinear credit price trajectories in the absence of credit banking. In particular, these CES scenarios would be barely binding until 2020 and then result in credit prices substantially above the historically focal ACP level of $21/MWh. If an ACP were set at that level, the target levels would fail to be met by a wide margin.

Second, under the default assumptions on natural gas supply (left-hand panel), the inclusion of existing nuclear and hydro generators along with a commensurate adjustment to the standard level (the CreditNH scenario) would tend to reduce credit prices, since it would tend to raise electricity prices, reduce electricity demand, and therefore reduce demand for clean energy credits. The magnitude of the credit price reduction is as great as 9 percent (in 2020), suggesting that the ACP level that binds depends on the details of the features of a CES policy. Excluding existing nuclear and hydro from compliance with the policy produces credit prices that tend to fall in between those in the Core and the CreditNH scenarios. This finding reflects the fact that electricity prices in the ExcludeNH scenario tend to be intermediate as well.

The third observation relates to the middle panel of the figure, which shows credit prices for assumptions about natural gas supply that yield lower natural gas prices. The effect of lower natural gas prices on the price of clean energy credits will depend importantly on whether natural gas is the marginal technology for complying with the standard. In the early years of the CES (up until 2025), natural gas is the predominate method for complying, and thus the scenarios with lower natural gas prices tend to have lower credit prices. In later years, when other technologies are required to comply with the standard, credit prices in the Core+ChpNG scenario are more in line with those of the Core scenario.[14]

The fourth assumption relates to the right-hand panel of the figure. The prices in the long run are quite similar across the three scenarios because either IGCC with CCS or nuclear is treated optimistically in each case, and so the CES can be met at a lower cost than in the Core scenario. In the medium run, however, quick and extensive nuclear capacity expansion could substantially reduce credit prices relative to the LessNuke case, by as much as 28 percent (in 2020) in the MoreNuke scenario. This shows that the effect of an ACP level depends on

[14] In 2035, credit prices are highest in ExcludeNH+ChpNG because this scenario has the fastest demand growth in the later years, due to regional differences in electricity prices and demand eleasticities. With faster demand growth, additional clean energy sources are required to comply with the CES policy, increasing credit prices relative to the other scenarios.

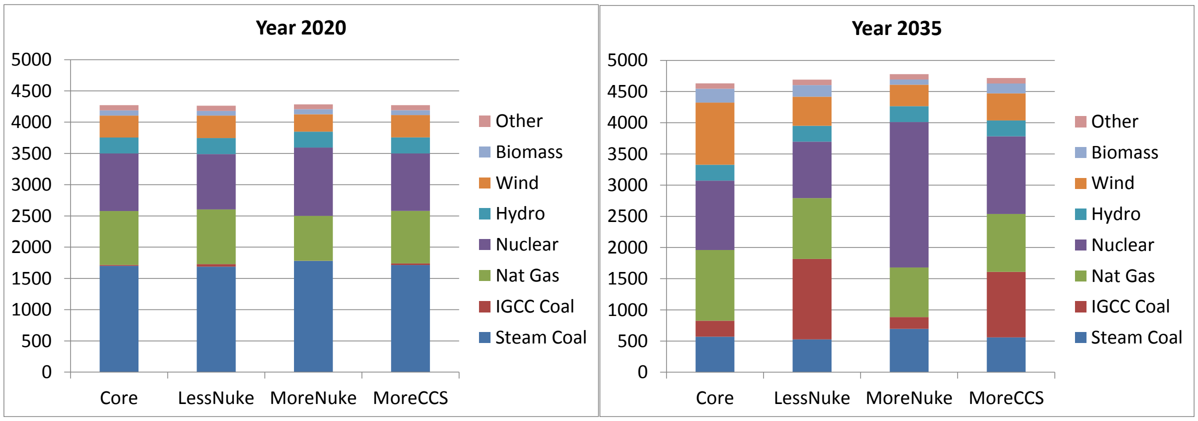
technological progress in bringing down the costs of nuclear generators, and on the political acceptability of extensive nuclear capacity expansion.

5.3. Generation

The effect of a CES on the mix of technologies and fuels used to generate electricity depends on the future prospects for nuclear power and the cost trajectories for integrated gasification combined-cycle plants and carbon capture and storage, as well as how certain regulatory hurdles confronting these technologies are resolved and what happens to natural gas prices. It does not depend importantly on whether existing nuclear and hydro facilities receive clean energy credits under the standard, although as discussed in Section 5.5, this feature will affect electricity prices and thus total electricity consumption.

When we model the effects of a CES with and without crediting existing nuclear and hydro, we find that under AEO 2010 assumptions about technology cost and fuel prices and supply, nuclear capacity expansion would be the economically preferred approach to meeting the 2035 standard. The generation mix resulting from not crediting these existing facilities with less stringent (and generally nonbinding) constraints on annual nuclear additions is shown as MoreNuke in Figure 3 (the other scenarios mentioned in this paragraph are also shown in the figure). However, the model fails to capture the public acceptance challenges faced by new nuclear plants, which have been brought to the fore and heightened by recent events in Japan, and so the extensive nuclear expansion that the model projects may not be politically feasible. We therefore constrain nuclear capacity in the Core scenario, as described in Section 4.2. We also consider a case (LessNuke) where no new nuclear capacity can be added beyond the level observed in the baseline scenario, which yields generation from new nuclear plants that would be insufficient to meet the CES after 2020. The model finds that new coal IGCC plants with CCS take up the slack, adding about 140 GW by 2035 (as shown in the MoreCCS scenario). However, CCS technology also has several sources of uncertainty, including the cost of the technology and the regulatory and physical infrastructure necessary to support widespread transport and storage of captured carbon. We therefore also constrain coal with CCS capacity in the Core scenario, as described in Section 4.2. We find that when both IGCC with CCS and nuclear investment are constrained, as in the Core scenario, wind becomes the preferred technology, providing more than 20 percent of total electricity generation in 2035.

Figure 3. National generation mix (TWh) in 2020 and 2035 for technology sensitivities



The effects of the CES on generation mix in 2020 and 2035 for both the AEO 2010 natural gas price scenarios and the lower AEO 2011 natural gas price scenarios are displayed in Figures 4 and 5. Each of these graphs displays baseline generation mixes for each natural gas price scenario and three CES scenarios. In 2020 the Core CES causes coal generation to fall from 50 percent to 40 percent of total generation and results in increases of generation from natural gas, nuclear, and wind. The treatment of existing nuclear and hydro has little effect on the generation mix, although it does affect the total amount of generation. In the ChpNG scenarios, natural gas is more important than in the baseline and Core CES scenarios, but it tends to crowd out wind and nuclear in addition to coal.

Figure 4. National generation mix (TWh) in 2020

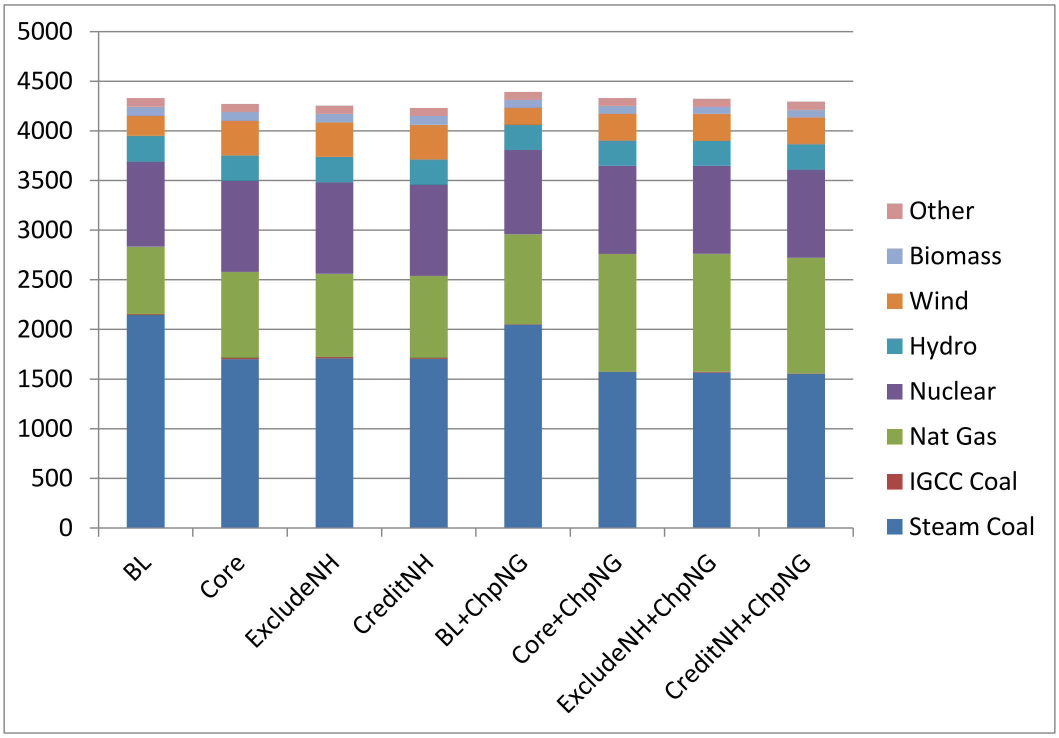
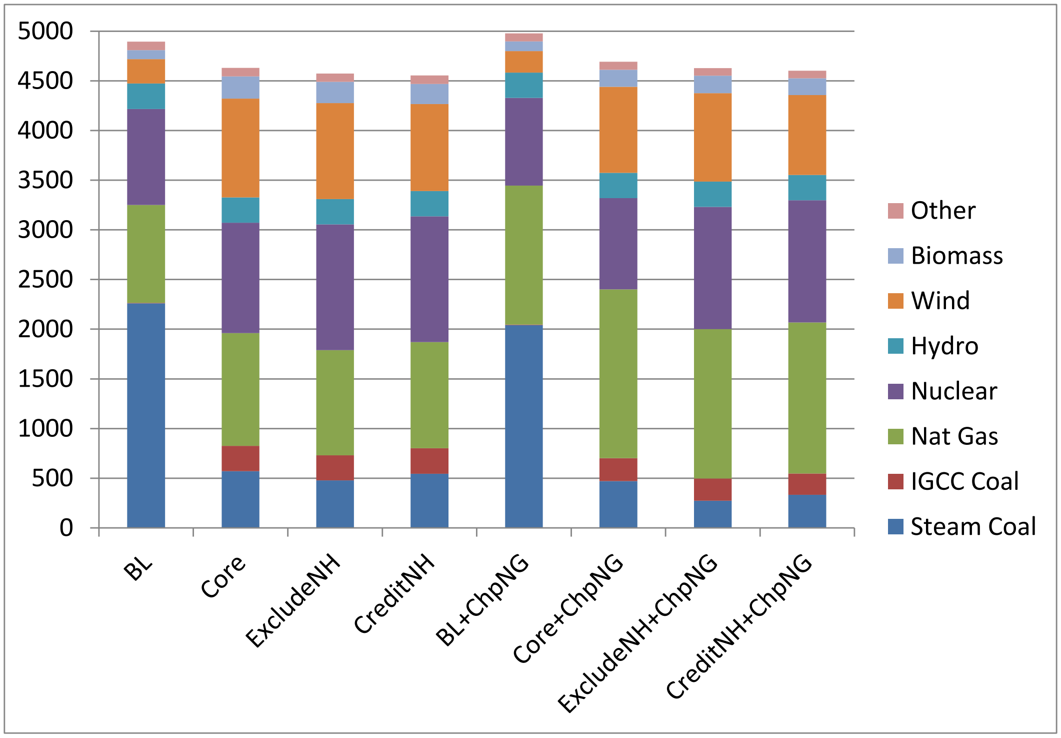


Figure 5. National generation mix (TWh) in 2035

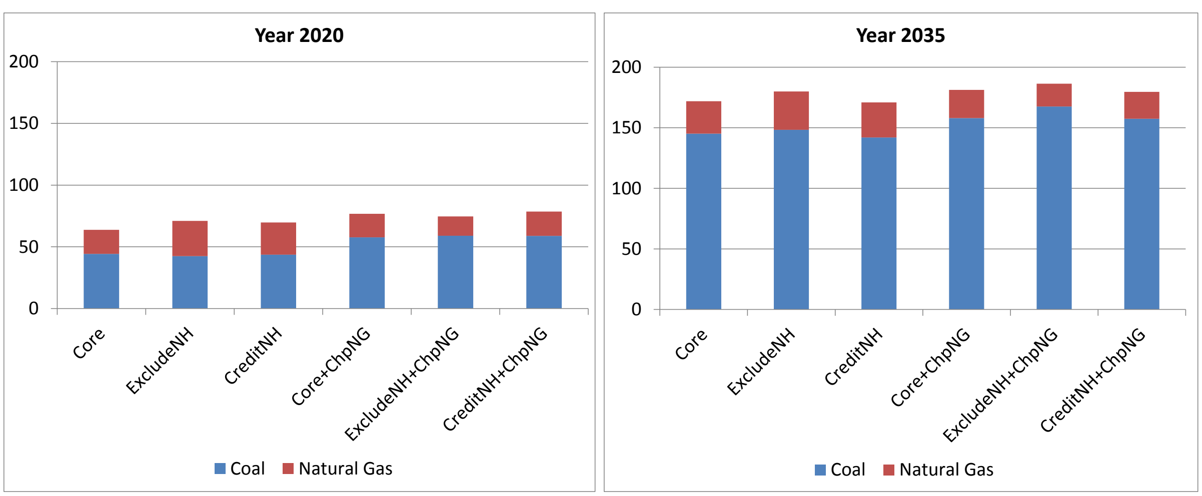


By 2035, the Core policy and its variants lead generation from coal-fired steam boilers to fall from baseline levels of roughly 46 percent of total generation to between 10–13 percent. The share of generation from these facilities is even lower when the policies are combined with cheap natural gas. In the ChpNG scenarios, the treatment of existing nuclear and hydro facilities under the CES policy influences how the policy affects coal-fired boilers, with generation being lower under the ExcludeNH and CreditNH scenarios. This is because the Core+ChpNG scenario causes retirement of some existing nuclear capacity, but excluding or crediting this existing capacity precludes the retirement and causes some coal capacity to retire instead. By 2035, wind generation accounts for more than 20 percent of total electricity supply under the Core scenarios and roughly 18 percent in the ChpNG scenarios. Natural gas accounts for just under 25 percent of generation in the Core scenarios and closer to one-third of total generation in 2035 in the ChpNG scenarios. Generation from biomass is also higher with the CES, but its total contribution is less than 5 percent.

5.4. Retirement

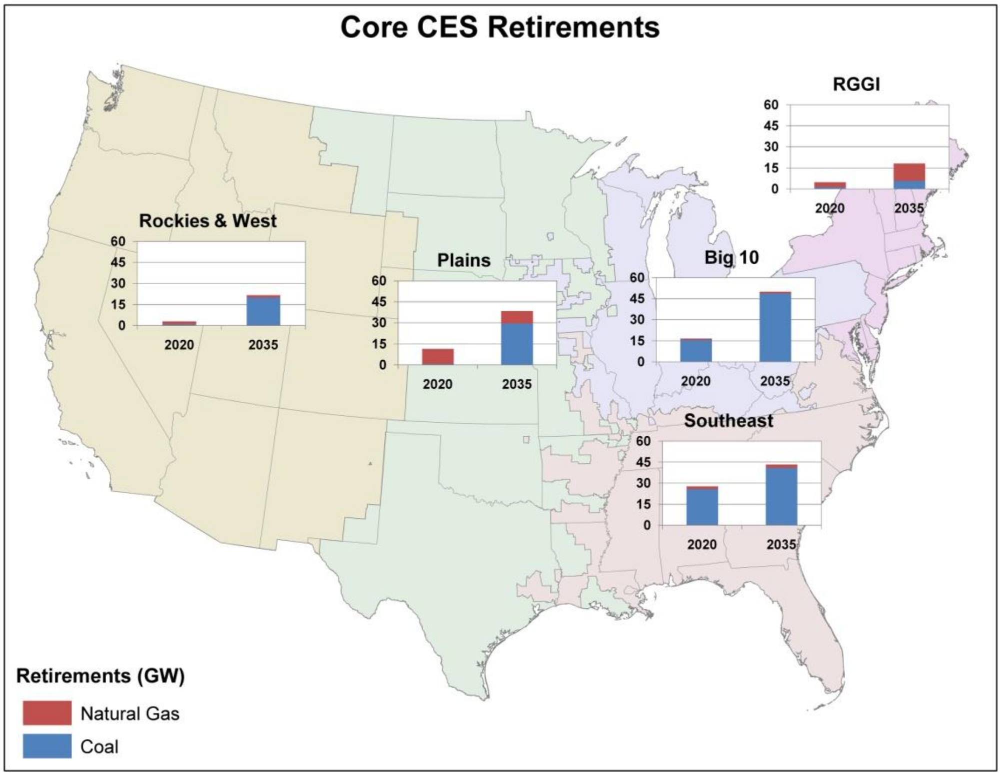
The CES policy leads to retirements of existing capacity in excess of those experienced under the baseline scenario of up to 77 GW by 2020 and between 172 and 194 GW in 2035. Most of the retirements are of coal-fired boilers, but the policy also leads to a small amount of additional retirements of older gas-fired capacity including steam units, combustion turbines, and older combined-cycle units. These retirements of coal and natural gas-fired plants are shown in Figure 6.

Figure 6. Retirement (GW) change from baseline in 2020 and 2035



As would be expected, most of the retirements in excess of baseline levels take place in the coal-rich regions of the upper Midwest and Appalachian states and the Southeastern states, which by 2035 retire 51–63 GW and 43–52 GW of total capacity in excess of the baseline, respectively, depending on the scenario. The smallest differential between baseline and CES policy retirement happens in the RGGI region, where 15–25 GW of additional capacity retirement occurs by 2035, depending on the CES scenario. The regional distribution of retirements of coal and natural gas–fired generators in the Core scenario in excess of baseline retirements is shown in Figure 7.

Figure 7. Regional retirement (GW) change from baseline in Core scenario



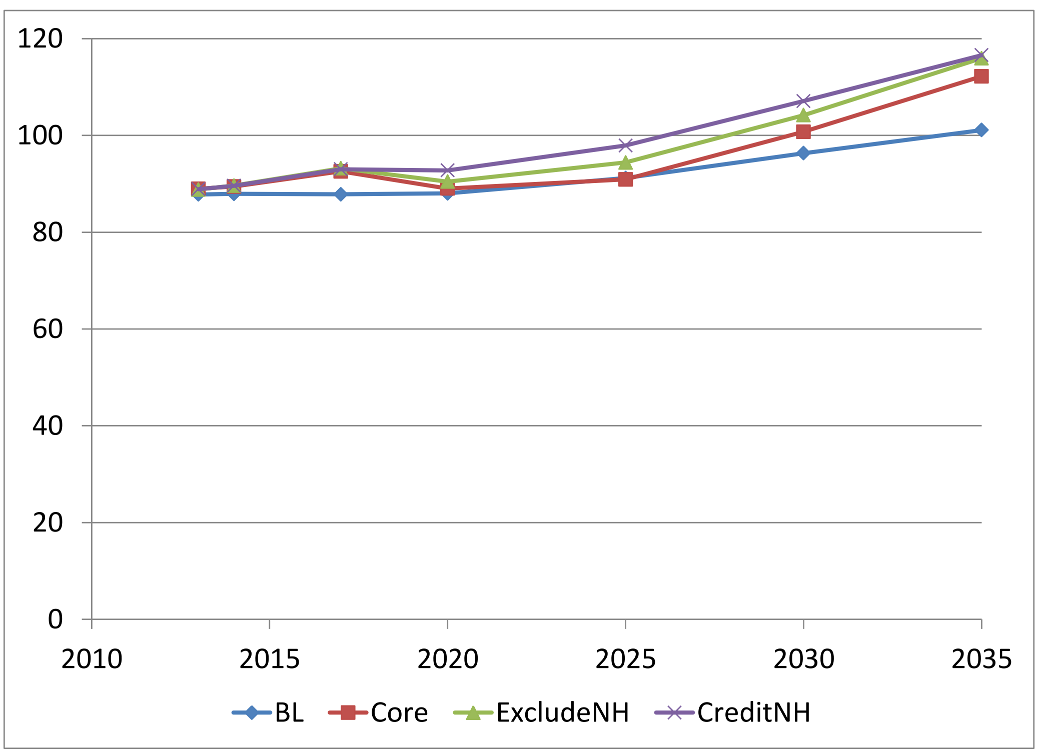
The amount of retirement of existing coal varies with the assumptions about potential rates of growth for nuclear and IGCC with CCS. In our Core scenario, which assumes limits on both nuclear and CCS additions, we find that an additional 145 GW of coal steam generation retires nationwide, but we see even greater steam coal retirement under the CES when CCS and nuclear are less constrained (not pictured here). An important caveat to these results is that we do not consider the possibility of retrofitting existing coal-fired generation with CCS. Depending on costs, allowing for this option could substantially reduce the amount of retirement of existing coal under the policy.

5.5. Electricity prices

National electricity prices

The effect of the Core CES policy on the national average electricity price is relatively modest, especially in the early years, compared with the price effects that would occur under a cap-and-trade program that achieved similar emissions outcomes and passed allowance costs on to consumers via retail electricity prices. In 2020, the national average retail price of electricity is 1 percent higher under the Core CES than under the BL scenario. By 2035 the policy leads to an 11 percent price increase relative to BL levels. Excluding existing nuclear and hydro facilities from the policy (ExcludeNH) results in larger price increases, 3 percent higher in 2020 and 15 percent higher in 2035. Granting credits to existing nuclear and hydro (CreditNH) and raising the standard commensurately also increase the costs of the policy because of the higher credit burden on electricity retailers. Under this scenario, the national average electricity price is 5 percent above baseline levels in 2020 and 15 percent higher in 2035. These prices are shown in Figure 8.

Figure 8. National average retail electricity prices ($/MWh)



Those national price differences mask large differences across regions; in some regions the policy actually leads to lower prices of electricity than in the baseline. These regional price effects, which vary depending on the treatment of existing nuclear and hydro facilities under the policy, are important to understanding the distributional consequences of the policy.

Regional electricity prices

There are two ways that a CES can affect the cost of supplying electricity from any particular technology: assuming no exemptions from compliance, all technologies face an implicit tax due to the cost of clean energy credits required to cover the consumption that their generation serves,[15] and all qualifying technologies earn additional revenues from sales of clean energy credits. The relationship between the policy's effects on costs and on electricity prices depends on whether electricity prices are set by cost-of-service regulation or by competitive markets. The ultimate effect on electricity prices at the state or regional level will also depend on the design of the policy, regional resource endowments, and the existing generation mix of the state or region.

The clean energy credit requirement raises the cost of every megawatt hour (MWh) of electricity sold by the price of a credit times the level of the clean energy standard. This cost applies uniformly to all MWhs sold in the market when all MWhs are subject to the standard. For those technologies that receive credits, there is an offsetting reduction in the variable cost of supplying electricity that is equal to the price of the credit times the number of credits earned per MWh. Because the crediting system leads to investment in generation technologies such as wind or nuclear that tend to enter the dispatch order at the front end, this policy will push out the existing supply curve and could actually lower the marginal cost of supplying electricity relative to a business-as-usual scenario with no policy.

In regions where electricity prices are set in a market, the price effects will be determined by changes to the electricity supply curve and the cost of purchasing clean energy credits to cover consumption. The price effect of changes to the supply curve will follow from the marginal-cost effect of increased investment in qualifying technologies and retirement of existing capacity (nonqualifying capacity will be especially prone to retirement). Regions that are heavily dependent on nonqualifying capacity will tend to experience significant capacity retirement, which shifts the supply curve to the left and thus will tend to drive up marginal costs

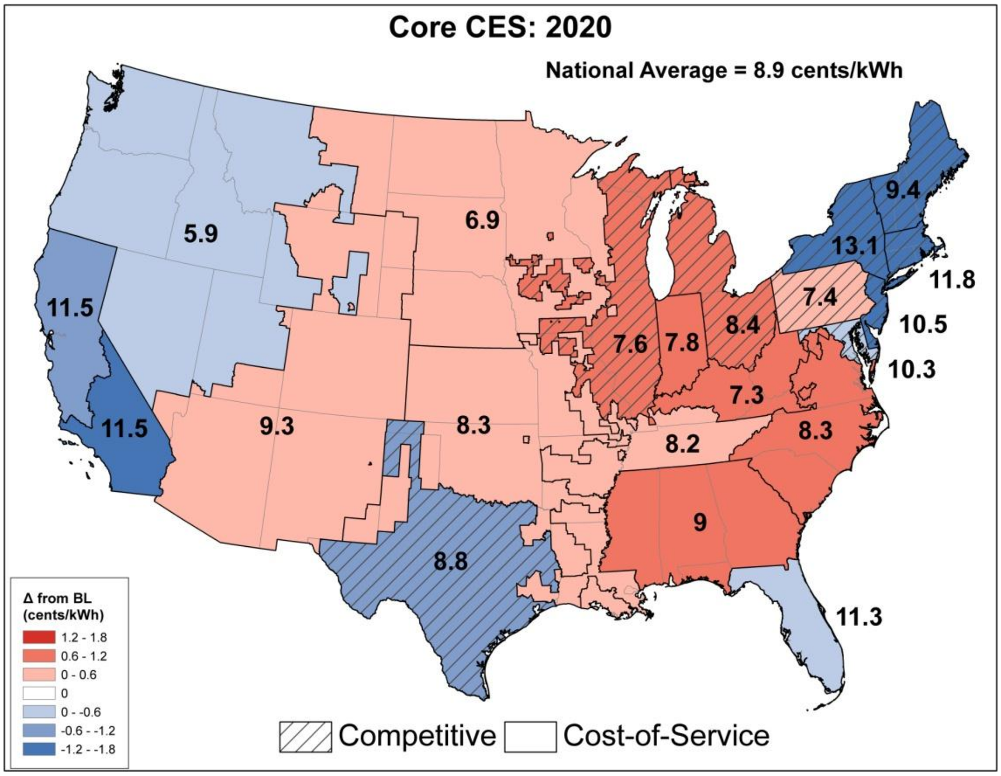
[15] If some technologies are exempt from the clean energy standard, then they would not face an implicit tax.

and electricity prices. Regions that are richly endowed with renewable resources will tend to experience significant new investments, which will tend to drive down marginal costs and electricity prices. A CES policy would induce some investment and some retirement in all regions, generating offsetting marginal-cost effects. If the net marginal-cost effect of new investments and existing retirements reduces marginal cost by more than the cost of credits required to cover consumption, then electricity prices will fall. This outcome is not unlikely in some regions of the country, especially the Northeast.

In cost-of-service regulated regions, resource costs for electricity production will rise to the extent that new investments in qualifying technologies are induced by a CES policy. If the entire country were cost-of-service regulated, then national average electricity prices would necessarily rise as consumers bear the burden of these increased costs. Regional prices in the cost-of-service regulated regions under our bifurcated system of electricity market regulation could fall to the extent that new investments generate credits beyond the volume required to cover the demand for credits from local electricity consumption. Excess credits will generate revenues from sales to other regions and these revenues will accrue to consumers, offsetting increased resource costs. On average, it is expected that electricity prices in cost-of-service regulated regions will rise by more than in competitive pricing regions, but any individual cost-of-service state could benefit from a price reduction under a CES.

The projected net electricity price effects in 2020 are illustrated in Figures 9–11. The price effects for the year 2035 are shown next, beginning at Figure 12. The value shown for each region is the projected price under the Core scenario. The color of each region represents the change in average electricity price relative to the baseline scenario (no CES policy). All of these prices are reported in cents/kWh in constant 2008 dollars.

Figure 9. Regional retail electricity prices and changes from baseline in 2020



The CES policy leads to lower prices of electricity in 2020 in the states that participate in the Regional Greenhouse Gas Initiative, all of which have market-determined prices in the model. The policy also results in lower prices in California and the Northwestern states, which have an abundance of hydro power and wind resources. Texas and Florida also see lower electricity prices with the Core CES policy than under the baseline. The regions of the country that rely more heavily on coal tend to see higher prices under the policy; however, for most of those regions, prices with the CES policy still remain below the national average.

Regional price effects depend on the fleet of existing generators, and so changing the treatment of existing nuclear and hydro under the policy will have important implications for regional prices. Figures 10 and 11 show the regional prices in 2020 under the ExcludeNH and CreditNH scenarios, respectively. For each of these two maps, the shading indicates the difference in regional prices from the Core CES scenario. Excluding existing nuclear and hydro from the CES has a very small effect on national average electricity price in 2020 and tends to dampen both the price declines in the RGGI states, Florida, and Texas and the price increases in the Southeast. However, it results in even lower prices in the Northwest and even higher prices in the Midwest, Plains, and Southwest.

Figure 10. Regional prices and changes from Core for ExcludeNH scenario in 2020

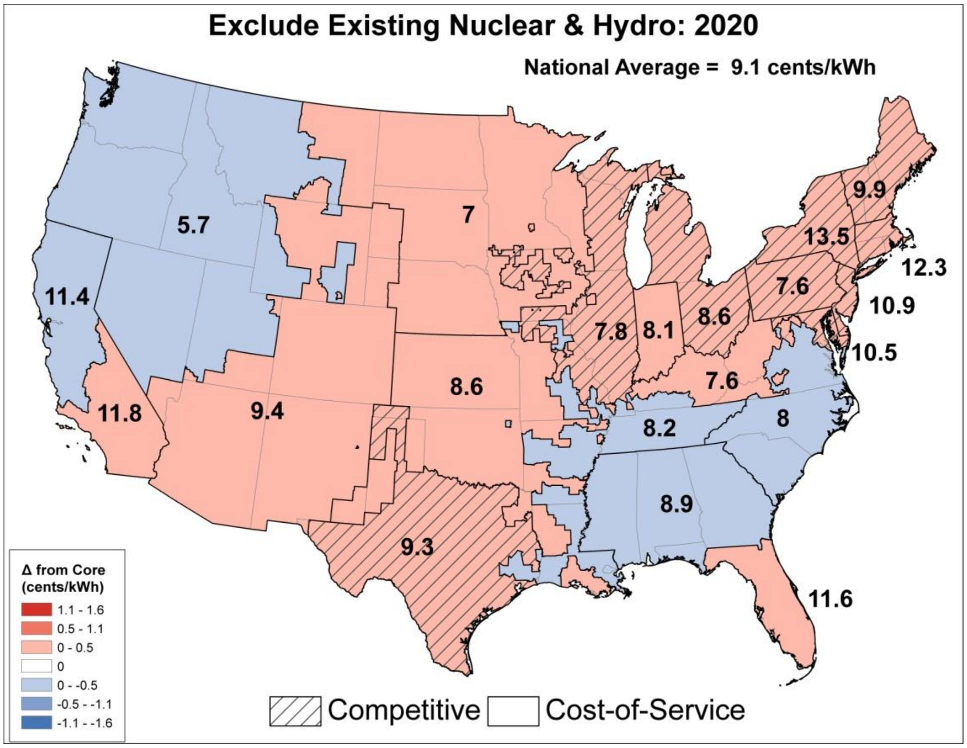
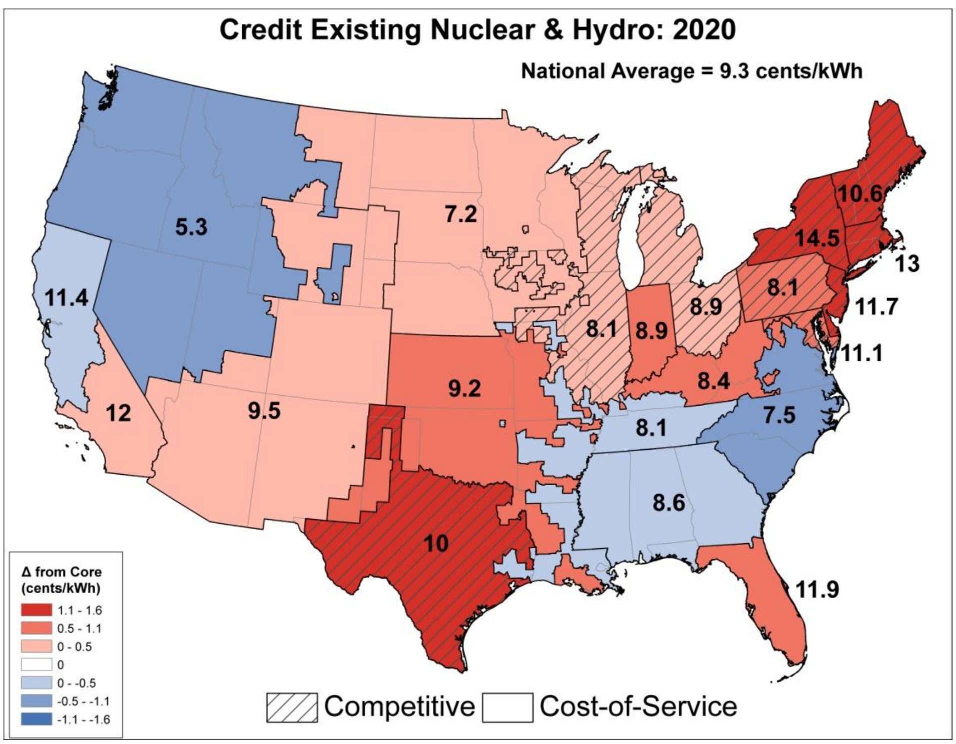


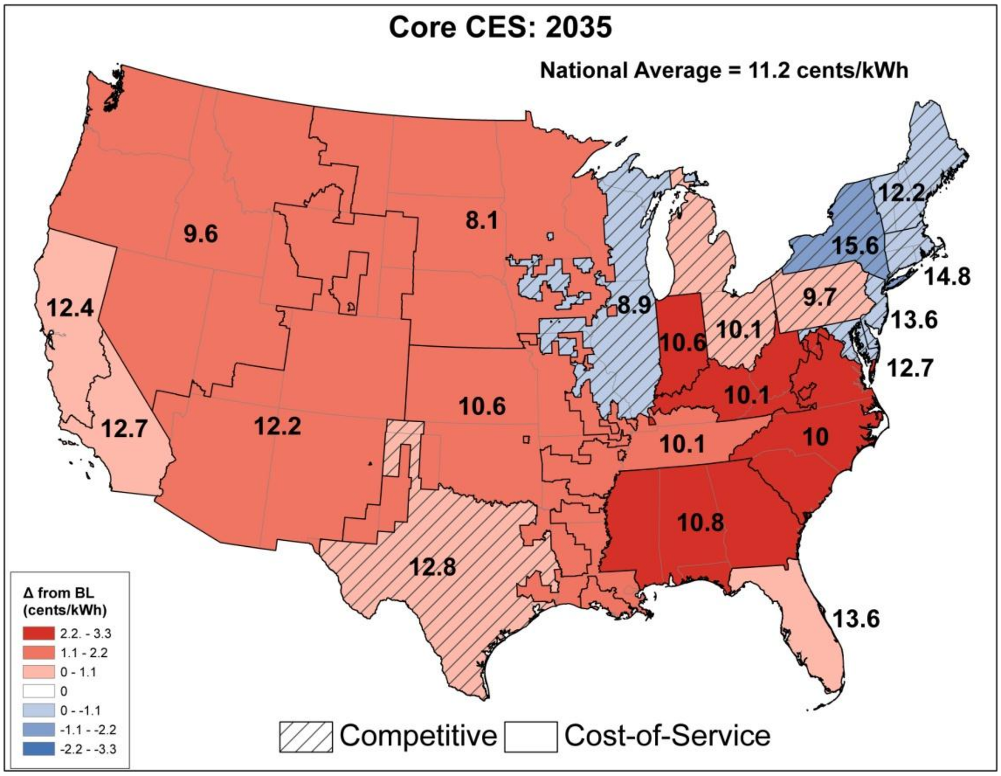
Figure 11. Regional prices and changes from Core for CreditNH scenario in 2020



Giving credit to generation from existing nuclear and hydro plants tends to exacerbate the price changes in the ExcludeNH scenario, relative to the Core CES. Prices are even higher in the Northeast than in the ExcludeNH scenario, although typically, prices in these regions are still below baseline levels. Prices also increase in Florida, the Midwest, Plains, and Southwest relative to ExcludeNH. The Southeast and Northwest, however, see even greater price declines than in ExcludeNH. The price effects of the ExcludeNH scenario are exacerbated in the CreditNH scenario because the CreditNH scenario has the higher credit requirement, which results in an increase in credit production and more credit trading across states (exports and imports).

In 2035, as in 2020, the CES leads to lower prices in the RGGI states. Prices are also lower in the Illinois-Wisconsin region under the Core CES. All of the other competitive regions experience higher prices with a CES than without, particularly those that are heavily reliant on coal, such as Pennsylvania and Ohio. However, even for those regions where electricity price rises because of the CES, it typically remains below the national average price even after the policy is implemented. All of the regulated regions see higher prices under the Core CES in 2035 compared with the baseline. The electricity price effects of the Core scenario in 2035 are shown in Figure 12. As in Figure 9, the value in each region is the retail electricity price, and the colored shading indicates the change in electricity price from the baseline.

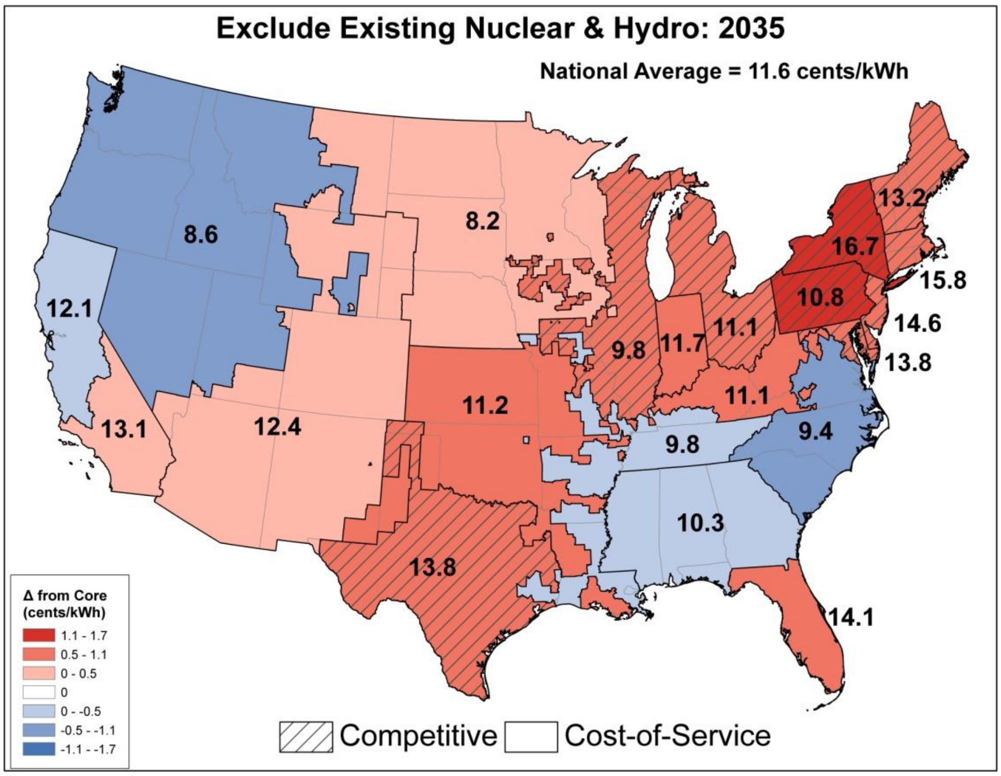
Figure 12. Regional retail electricity prices and changes from baseline in 2035



Overall, considering both competitive and cost-of-service regions, and considering the price effects in 2020 and 2035, the Core CES policy has an equalizing effect in terms of the geographic incidence of electricity price effects. The regions of the country that would face the highest electricity prices under CES tend to see price reductions from CES or only small price increases. Those that would experience the largest price increases would still enjoy relatively low prices.

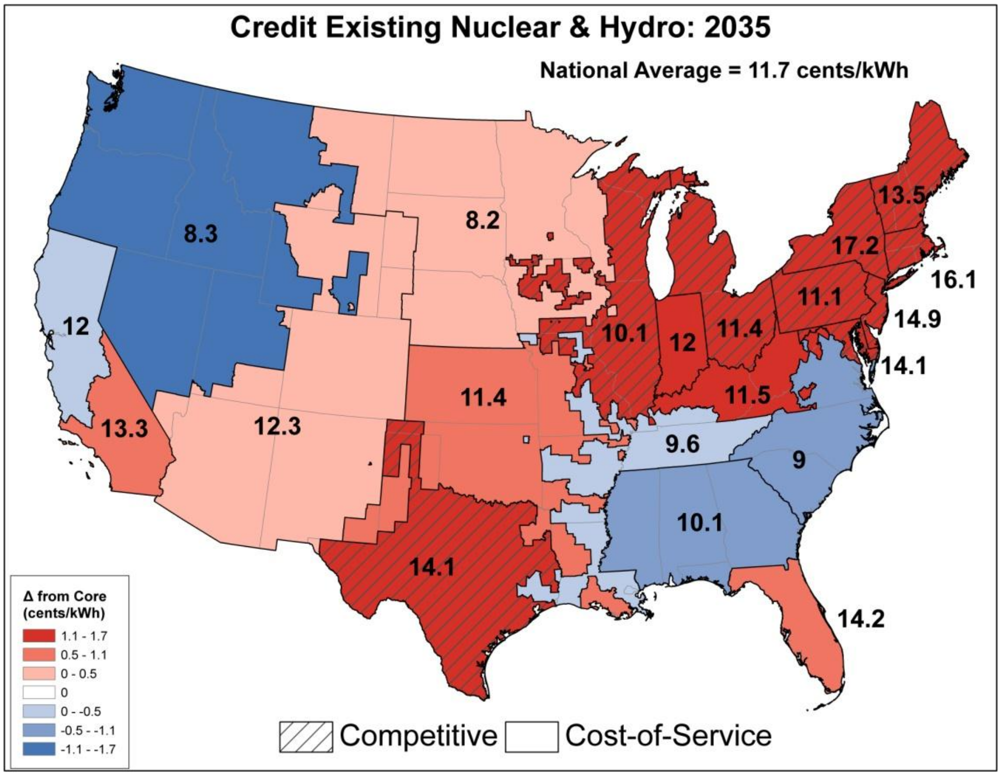
Figures 13 and 14 show the retail electricity prices that are projected in 2035 in the ExcludeNH and CreditNH scenarios. As in the comparison for 2020, the locations of existing nuclear and hydro facilities and the effects on electricity market structure are clearly evident. Electricity consumers in the regions with abundant nuclear and hydro facilities that price electricity on a cost-of-service basis are the beneficiaries. These regions are the Pacific Northwest, Northern California, and the Southeast except for Florida, where there is abundant nuclear, and hydro in TVA. Gains for these consumers come at the expense of consumers in the rest of the nation, especially those in the competitive electricity pricing regions. Note that by 2035, the difference in price effects between the ExludeNH scenario and the CreditNH scenario is very small. It is striking that the regions that benefit are generally[16] those enjoying low electricity prices, and that those paying the highest prices will generally pay even higher prices to help finance the gains for the Northwest and Southeast. Shareholders in the competitive regions also benefit under the CreditNH scenario relative to Core, by $15 billion to $30 billion annually between 2020 and 2035.

Figure 13. Regional prices and changes from Core CES in 2035 for ExcludeNH



[16] Northern California is the exception.

Figure 14. Regional prices and changes from Core CES for CreditNH in 2035



Regional price effects of the policy could also depend on the development of certain technologies not included in our modeling. For example, if natural gas with CCS becomes the technology of choice, then that will affect the location of investment in new clean generators and could alter the regional effects substantially. In addition, if retrofitting of existing coal capacity with CCS, also not considered in this analysis, becomes a preferred approach to producing clean energy credits, that could reduce the amount of retirement of existing coal capacity, which would likely reduce the price effects of the policy in regions heavily dependent on coal.

5.6. Regional net credit revenue

Under a CES policy, some regions of the country will be net suppliers of credits while others will be net purchasers. For some regions, which position they are in will depend on whether existing nuclear or hydro generators are included in the policy and whether they receive credits. Qualifying existing hydro facilities, for example, would cause a wealth transfer to the regions of the country with more hydro facilities from those with fewer without inducing additional emissions reductions. The Pacific Northwest would stand to gain the most from qualifying existing hydro. If it does not earn credits, existing hydro would be treated no differently than coal facilities under a CES, which might seem perverse considering that an objective of the policy is to reduce emissions.[17] However, it is precisely because of the region's tremendous endowment of hydro resources that the Pacific Northwest enjoys electricity prices that are among the lowest in the country. A policy that would transfer wealth to that region from others that face much higher electricity prices is therefore dubious on equity grounds. Other types of clean technology that are less affordable and have come on-line more recently, like wind or solar, might be viewed as investments with positive climate externalities that were driven by environmental concerns. A wealth transfer to regions that have already incurred the costs of such investments may be easier to justify on equity grounds.

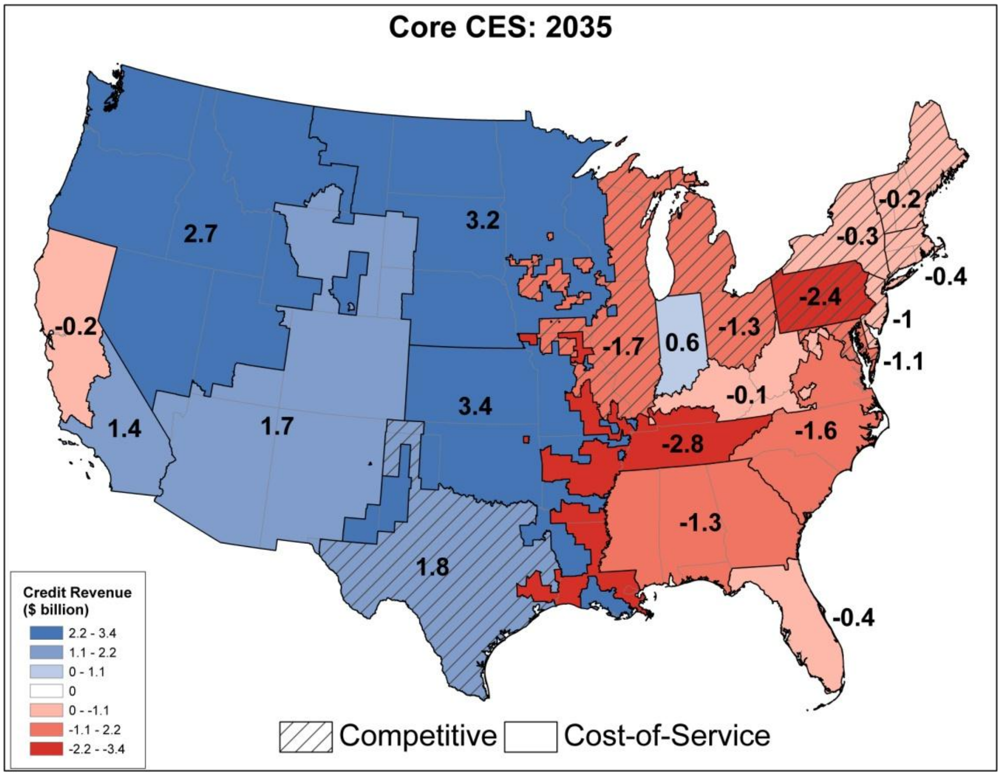
The implications of the credit trading and associated electricity price effects of different CES policy designs for utility shareholders versus electricity consumers hinge on the form of electricity market regulation in each region. In cost-of-service regulated regions, the regional benefits (or costs) of qualifying an existing facility will accrue to (or be borne by) electricity consumers. In competitively priced regions, the effects could be shared between shareholders and consumers, but mostly, shareholders will gain at the expense of consumers. There are two components to this wealth transfer to shareholders. First, consumers will bear the burden of higher prices because of the increased requirement for credits per unit of consumption that would accompany the addition of a qualifying technology. Second, the additional credit revenues taken from consumers will, to the extent that the facilities with the lowest operating costs are qualified, accrue entirely to shareholders. This is because qualifying facilities with the lowest operating costs will not affect the marginal cost of electricity production. Therefore the only effect on electricity prices will be the increase from the higher level of the standard. Conversely, if facilities with higher operating costs are qualified, then the transfer from consumers to shareholders will be mitigated to the extent that the qualified facilities produce more electricity, thereby reducing marginal production costs and lowering prices.

Figure 15 shows net credit revenue by region in 2035 under the Core CES case. Regions that are shaded red are net credit importers, and those that are shaded blue are net credit exporters. The intensity of the color reflects the level of net revenues or costs. Credit exports tend to be concentrated in the western states, with most of the eastern states importing credits. The exceptions are Indiana, where new investment in IGCC coal with CCS creates credits for export

[17] One way around this is to exclude generation from existing hydro from the MWh that must comply with the policy.

in 2035, and northern California, which imports a small number of credits.

Figure 15. Net federal credit revenues (B$) in Core scenario



Figures 16 and 17 show the effects of excluding existing nuclear and hydro and crediting existing nuclear and hydro, respectively, on the amount of net revenue from clean energy credit trading. Each region is labeled with the total net credit revenue, and the color of each region represents the change in regional credit revenues when compared to the Core CES scenario. As described in Section 4.4, under the ExcludeNH scenario, each MWh generated by an existing nuclear or hydro facility will be granted an exclusion credit, and in equilibrium each of these credits is worth the price of a clean energy credit times the level of the CES requirement in each year. This additional crediting mechanism provides a new source of revenue for those regions with plentiful amounts of hydroelectric power (including New York, Northern California, Northern New England, and the Northwest Power Pool) and those regions with abundant nuclear (the Mid-Atlantic states, Northern California, Wisconsin-Illinois, and the Southeast) and thus enhances the net credit value in those regions, as show in Figure 16. Crediting existing nuclear and hydro (and the associated increase in the CES standard) creates even greater net revenues from credit sales in these regions of abundant nuclear and hydro power, as shown in Figure 17.

For most of the other regions, the associated added burden of the increases in the target that accompanies either of these changes in policy design raises their costs of credit acquisition and requires that they import a greater number of credits from other regions, especially throughout Texas and the Plains states. In 2035, the Northwest region is earning roughly $5 billion from sales of credits under the CES design that credits existing nuclear and hydro, while both Florida and Ohio-Michigan are paying more than $2 billion for imported credits. All other regions experience smaller effects.

Figure 16. Net federal credit revenues (B$) and changes from Core CES in ExcludeNH scenario

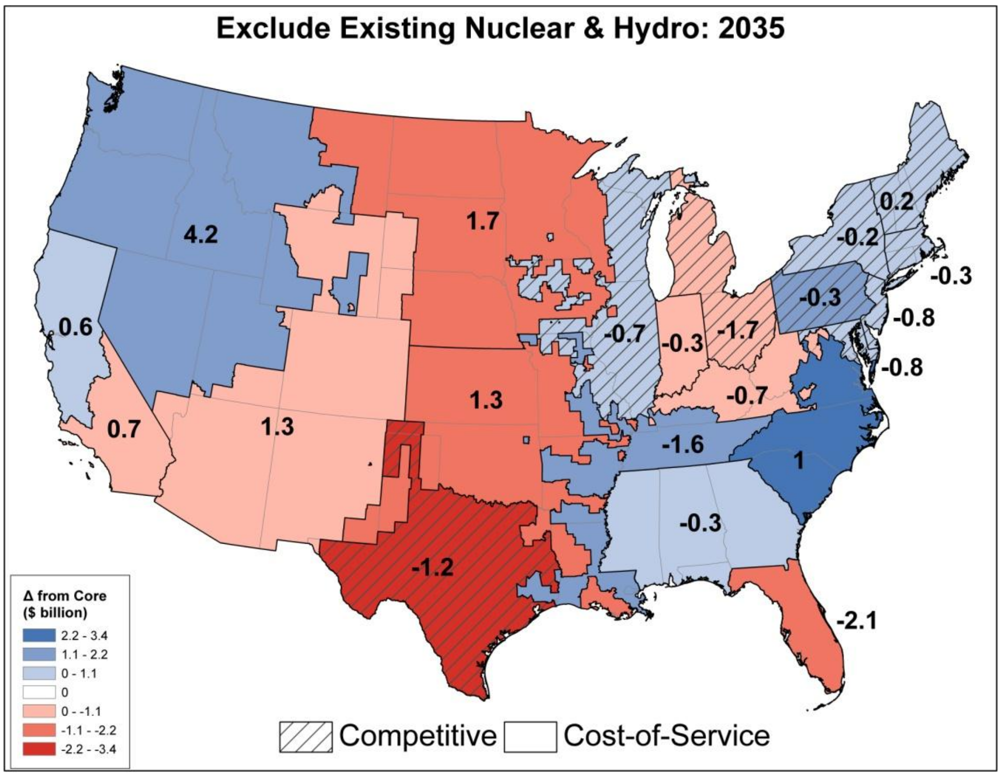
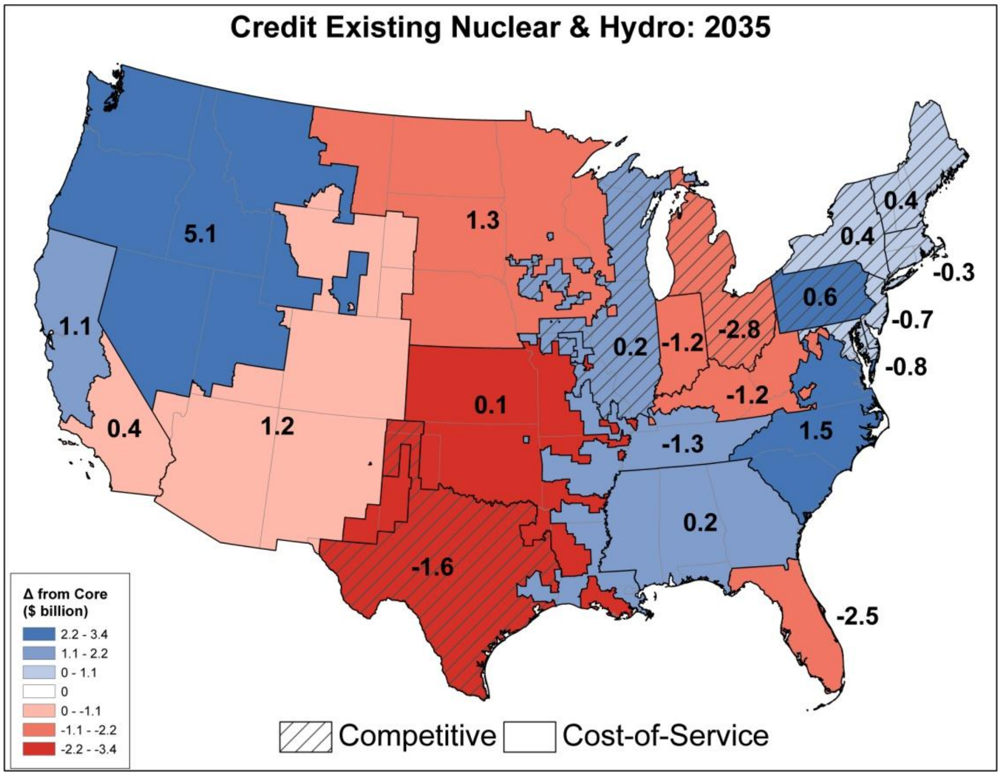


Figure 17. Net federal credit revenues (B$) and changes from Core CES in CreditNH scenario



6. Conclusions

In the absence of a direct cap on CO_2 emissions, the next legislative attempt to reduce CO_2 in the electricity sector is likely to be a clean energy standard to promote energy sources with low or no emissions. This analysis examines CES policies, similar to the proposal by the Obama administration, including different crediting schemes for existing nuclear and hydroelectric facilities. We find that the CES policies modeled would have a significant effect on electricity sector CO_2 emissions. Between 2013 and 2035, the Core CES policy would achieve cumulative CO_2 emissions reductions of roughly 30 percent, or 20 billion tons, relative to the baseline. This is 41 percent of the needed CO_2 reductions to meet the U.S. pledge arising from the United Nations climate change conferences in Copenhagen and Cancun.

A national CES would achieve emissions reductions from a change in the composition of electricity supply and would also produce large regional transfers of clean energy credits for dollars. These changes would drive regionally differentiated retail electricity price effects. The treatment of existing nuclear and hydro facilities—either excluding them from the program altogether or qualifying them to receive credits—can also change the outcomes of the policy, particularly at the regional level.

Under all of the CES variants modeled, a CES policy leads to extensive retirements of existing coal-fired (and some older gas-fired) capacity. Much of this retirement occurs in the coal-rich regions in the Midwest and Appalachian states and the Southeastern states. Nuclear capacity expansion could be the economically preferred approach to meeting the 2035 standard. If new nuclear deployment is constrained, coal gasification plants with carbon capture and sequestration could take up the slack. If both of these are constrained, wind would become the preferred approach to comply with the standard, accounting for roughly 20 percent of generation in 2035.

Capacity and generation changes are driven by the price for clean energy credits. In each of the CES variants, the credit price remains below $1/MWh in the early years of the program but reaches roughly $70/MWh in 2025 and 2030. This suggests that a low alternative compliance payment, such as $21/MWh, as in some recent RPS proposals, would bind after 2020 and reduce the deployment of clean energy sources. This analysis does not include credit banking, which would cause the credit price to increase over time at the interest rate and would also make interim targets less important.

The effect of a CES on national average electricity prices is small in 2020 but would be greater in 2035, amounting to roughly a 10–15 percent increase from baseline prices, depending on the specifics of the CES policy. The regional differences in price effects would be substantial. The Core CES scenario has an equalizing effect on regional prices, in which regions with existing high electricity prices would tend to see price reductions or only small price increases, while those experiencing the largest price increases would still enjoy relatively low prices. This effect is partly undone when existing nuclear and hydro facilities are excluded or given credits. Under these scenarios, regions with competitive electricity pricing see electricity price increases, relative to the Core CES case, as do cost-of-service pricing regions that do not have large endowments of existing nuclear and hydro capacity. Cost-of-service regions with existing nuclear or hydro capacity, primarily in the Northwest and Southeast, experience lower prices when these facilities are excluded or credited. These changes tend to be slightly larger when nuclear and hydro are credited than when these technologies are excluded from the policy altogether.

The treatment of existing nuclear and hydro facilities also has important implications for regional costs or revenues from the transfer of clean energy credits. Under the Core CES policy in 2035, a disproportionate fraction of clean energy generation occurs west of the Mississippi River, so most of the regions in the West receive net revenues from credit sales and most of the Eastern regions experience net costs from purchasing credits. When existing nuclear and hydro facilities are excluded from the program or qualified for credit generation, all regions experience increased costs because of the increase in the CES percentage, but regions with existing nuclear and hydro capacity also receive additional revenues from generating more clean energy credits. The Northwest, Northeast, Southeast (excluding Florida), and western Midwest tend to see increased revenues in these scenarios, relative to the Core CES. The Southwest, Plains, Florida, and eastern Midwest experience net costs in these scenarios. Excluding nuclear and hydro leads to smaller changes in transfers than when they are granted credits.

This analysis provides some useful insights into the consequences of different forms of a CES policy for electricity consumers, electricity producers, and the environment. Many important questions remain about how other features of the CES policy design will affect its performance. Aspects that have yet to be explored include the implications of credit banking and borrowing, partial crediting of generation from existing nuclear and hydro, the role of alternative compliance payments, the relationship between a CES and policies to promote energy efficiency, and policy interactions between the CES and EPA regulations under the Clean Air Act to reduce emissions of CO_2 from existing sources. Proposals to base a CES crediting on emissions rates instead of broad categories of technologies may create additional incentives to reduce emissions and could provide a bridge between EPA regulations of existing sources and the policy used to promote investment in cleaner generating technologies. Identification of the consequences of these design feature and alternative approaches requires additional modeling analysis. Stay tuned.

References

Aldy, J.E. 2011. Promoting Clean Energy in the American Power Sector. Hamilton Project Discussion Paper 2011-04. Washington, DC: Brookings Institution.

Bipartisan Policy Center. 2010. The Administration's Clean Energy Standard Proposal: An Initial Analysis. Bipartisan Policy Staff Paper prepared by Meghan McGuiness. April.

Brown, P. 2011. Clean Energy Standard: Design Elements, State Baseline Compliance and Policy Considerations. Congressional Research Service. March 25.

Burtraw, D., K. Palmer, and D. Kahn. 2010. A Symmetric Safety Valve. *Energy Policy* 38(9): 4921-4932.

Center for Integrative Environmental Research (CIER). 2007. Economic and Energy Impacts from Maryland's Potential Participation in the Regional Greenhouse Gas Initiative. January. Available at http://www.cier.umd.edu/RGGI/documents/UMD_RGGI_STUDY_FINAL.pdf.

Energy Information Administration (EIA). 2010a. Annual Energy Outlook 2010 with Projections to 2035. DOE/EIA-0383(2010). April.

———. 2010b. Assumptions to the Annual Energy Outlook 2010. DOE/EIA-0554(2010). April.

North American Electric Reliability Council (NERC). 2003a. 2003 Summer Assessment: Reliability of the Bulk Electricity Supply in North America. May.

———. 2003b. 2003/2004 Winter Assessment: Reliability of the Bulk Electricity Supply in North America. November.

Palmer, K., R. Sweeney, and M. Allaire. 2010. Modeling Policies to Promote Renewables and Low Carbon Sources of Electricity. Backgrounder, Washington, DC: Resources for the Future. June.

Palmer, K., A. Paul, M. Woerman, and D. Steinberg. 2011. Federal Policies for Renewable Electricity. *Energy Policy*, forthcoming.

Parry, I.W.H., and Alan Krupnick. 2011. Is a Clean Energy Standard a Good Way to Move US Energy Policy Forward? Issue Brief 11-04. Washington, DC: Resources for the Future. April.

Parry, I.W.H., and R.C. Williams. 2011. Moving U.S. Climate Policy Forward: Are Carbon Tax Shifts the Only Good Alternative? In R. Hahn and A. Ulph (eds.), *Climate Change and Common Sense: Essays in Honor of Tom Schelling*. Oxford, UK: Oxford University Press, forthcoming.

Paul, A., D. Burtraw, and K. Palmer. 2009. Haiku Documentation: RFF's Electricity Market Model version 2.0. Report. Washington, DC: Resources for the Future.

Paul, A., D. Burtraw, and K. Palmer. 2010. Compensation for Electricity Consumers under a US CO_2 Emissions Cap. In V. Ghosal (ed.), *Reforming Rules and Regulations: Laws, Institutions and Implementation.* Cambridge, MA: MIT Press.

U.S. Environmental Protection Agency (EPA). 2005. Standalone Documentation for EPA Base

Case 2004 (V.2.1.9) Using the Integrated Planning Model. September.

Appendix: Haiku Electricity Market Model Description

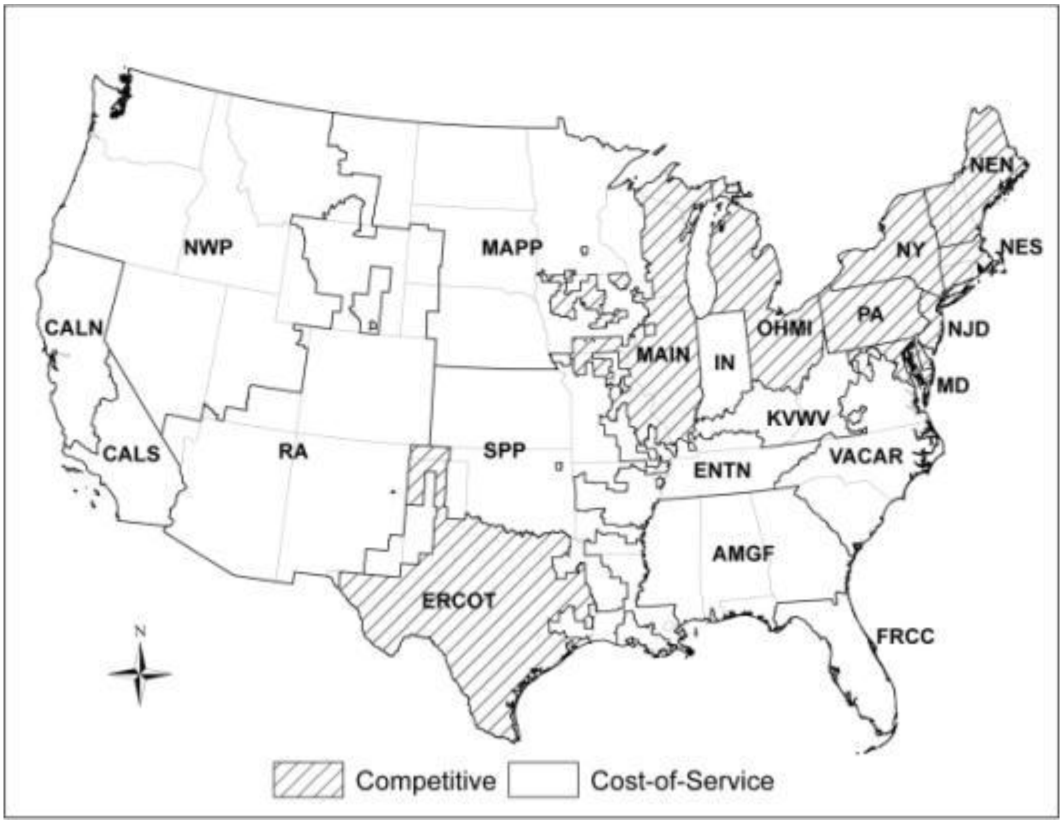
The Haiku electricity market model is used for some of the analysis in this document.[18] Haiku is a deterministic, highly parameterized simulation model of the U.S. electricity sector that calculates information similar to the Electricity Market Module of the National Energy Modeling System (NEMS) used by EIA and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (EPA).

Haiku simulates equilibria in regional electricity markets and interregional electricity trade with an integrated algorithm for emissions control technology choices for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury. Emissions of CO_2 are also tracked but without any endogenous choice for emissions abatement technology retrofit. The model does capture the potential for investment in new integrated gasification combined cycle facilities that include carbon capture and storage capability. The composition of electricity supply is calculated for an intertemporally consistent capacity planning equilibrium that is coupled with a systems operation equilibrium over geographically linked electricity markets; the model solves for 21 regional markets covering the 48 contiguous U.S. states. Each region is classified by its method for determining the prices of electricity generation and reserve services as either market-based competition or cost-of-service regulation. Figure A1 shows the regions and pricing regimes. Electricity markets are assumed to maintain their current regulatory status throughout the modeling horizon; that is, regions that have already moved to competitive pricing continue that practice, and those that have not made that move remain regulated.[19] The retail price of electricity does not vary by time of day in any region, though all customers in competitive regions face prices that vary from season to season.

[18] Complete documentation of the model is available at Paul et al. (2009). http://www.rff.org/RFF/Documents/RFF-Rpt-Haiku.v2.0.pdf.

[19] There is currently little momentum in any part of the country for electricity market regulatory restructuring. Some of the regions that have already implemented competitive markets are considering reregulating, and those that never instituted these markets are no longer considering doing so.

Figure A1. Haiku market regions and electricity market regulatory structure



Each year is subdivided into three seasons (summer, winter, and spring-fall) and each season into four time blocks (superpeak, peak, shoulder, and base). For each time block, demand is modeled for three customer classes (residential, industrial, and commercial) in a partial adjustment framework that captures the dynamics of the long-run demand responses to short-run price changes. Supply is represented using model plants that are aggregated according to their technology and fuel source from the complete set of commercial electricity generation plants in the country. Operation of the electricity system (generator dispatch) in the model is based on the minimization of short-run variable costs of generation and a reserve margin is enforced based on those obtained by EIA in the AEO 2010. Investment in new generation capacity and the retirement of existing facilities are determined endogenously for an intertemporally consistent equilibrium, based on the capacity-related costs of providing service in the present and into the future (going-forward costs) and the discounted value of going-forward revenue streams. Discounting for new capacity investments is based on an assumed real cost of capital of 8 percent. Generator availability, even for highly variable renewable resources, is captured in only a deterministic sense, i.e. no capacity penalty is assigned to account for the probability that a generator may be unavailable when called upon by the system operator.

The assumed costs and operational characteristics of new technologies are reported in Table A1. The capital costs change over time and in response to capacity additions (learning-by-doing) based on the learning functions implemented in the NEMS model and described in the documentation of the AEO 2010 (EIA 2010b). Capital costs for technologies that are relatively immature fall faster than those for mature technologies. For example, capital costs for solar thermal generators are projected to fall by 46 percent by 2035, to $4,270 per kW, even in the absence of any new capacity additions.

Table A1. Technology cost and performance assumptions

	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW)	Variable O&M (mills/kWh)	Heat Rate (Btu/kWh)	Average Capacity Factor (%)
Coal without CCS	2,223	28.15	4.69	9,200	--
Coal with CCS	3,776	47.15	4.54	10,781	--
Conventional Natural Gas Combined Cycle	984	12.76	2.11	7,196	--
Advanced Natural Gas Combined Cycle	968	11.96	2.04	6,752	--
Conventional Natural Gas Combustion Turbine	685	12.38	3.65	10,788	--
Advanced Natural Gas Combustion Turbine	648	10.77	3.24	9,289	--
Advanced Nuclear	3,820	92.04	0.51	10,488	--
Onshore Wind	1,966*	30.98	0.00	--	32-47**
Offshore Wind	3,937*	86.92	0.00	--	34-50**
Biomass	3,849	65.89	6.86	9,451	--
Landfill Gas	2,599	116.80	0.01	13,648	--
Solar Thermal	7,948	58.05	0.00	--	45
Geothermal	1,749	168.33	0.00	32,969	--

* These are the minimum overnight capital costs for wind plants. They are adjusted by multipliers that account for terrain and population density.

** Average capacity factors for wind plants vary by wind class with the minimum and maximum values shown here.

Equilibrium in interregional power trading is identified as the level of trading necessary to equilibrate regional marginal generation costs net of transmission costs and power losses. These interregional transactions are constrained by the level of the available interregional transmission capability, as reported by the North American Electric Reliability Council (NERC 2003a, 2003b).[20] Factor prices, such as the cost of capital and labor, are held constant. Fuel prices are benchmarked to the forecasts of AEO 2010 (EIA 2010a) for both level and elasticity. Coal is differentiated along several dimensions, including fuel quality and content and location of supply, and both coal and natural gas prices are differentiated by point of delivery. The price of biomass fuel also varies by region depending on the mix of biomass types available and delivery costs. All of these fuels are modeled with price-responsive supply curves. Prices for nuclear fuel and oil are specified exogenously without any price responsiveness.

Emissions caps in the Haiku model, such as the Title IV cap on national SO_2 emissions, EPA's Clean Air Interstate Rule caps on emissions of SO_2 and NO_x, and the RGGI cap on CO_2 emissions, are imposed as constraints on the sum of emissions across all covered generation sources in the relevant regions. Emissions of these pollutants from individual sources depend on emission rates, which vary by type of fuel, technology, and total fuel use at the facility. The sum of these emissions across all sources must be no greater than the total number of allowances available, including those issued for the current year and any unused allowances from previous years when banking is permitted.

[20] Some of the Haiku market regions are not coterminous with North American Electric Reliability Council (NERC) regions, and therefore NERC data cannot be used to parameterize transmission constraints. Haiku assumes no transmission constraints among regions OHMI, KVWV, and IN. NEN and NES are also assumed to trade power without constraints. The transmission constraints among the regions ENTN, VACAR, and AMGF, as well as those among NJD, MD, and PA, are derived from version 2.1.9 of the Integrated Planning Model (U.S. EPA 2005). Additionally, starting in 2014, we include the incremental transfer capability associated with two new 500-KV transmission lines into and, in one case, through Maryland, which are modeled after a line proposed by Allegheny Electric Power and one proposed by PEPCO Holdings (CIER 2007). We also include the transmission capability between Long Island and PJM made possible by the Neptune line, which began operation in 2007.