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RFF is pleased to submit answers in response to questions posed by Senators Bingaman and Murkowski. The answers are based on our research and in-house modeling (description of the model and scenarios used are contained in Appendix A to this summary). A federal Clean Energy Standard has numerous design parameters that can affect, in complex ways, its economic efficiency and distributional consequences. Our answers shed light on the complexity and interaction of these parameters. In this summary, we abstract from the complexity and focus on broad generalizations, leaving out the important caveats that remain in the texts of our answers.

Our CES modeling suggests the following:

- Cumulative CO_2 emissions reductions between 2013 and 2035 of roughly 30 percent, or 20 billion tons, relative to a baseline and the size of the annual emissions reductions will grow over time as the standard tightens.
- Under AEO 2010 assumptions about technology cost and fuel prices and supply, nuclear capacity expansion is the economically preferred approach to meeting the 2035 standard with or without existing nuclear and hydro crediting. When the model constrains the deployment of new nuclear, IGCC plants with CCS take up the slack. When nuclear and IGCC/CCS are constrained, wind is preferred.
- CES-induced electricity price effects vary by region. Considering both competitive and cost-of-service regions, a CES has an equalizing effect. Regions facing existing high electricity prices would tend to see price reductions from a CES or only small price increases. Those experiencing the largest price increases would still enjoy relatively low prices. Under a CES, western states are generally net suppliers of credits while eastern states are net purchasers.
- Interim targets are less important in a policy allowing for credit banking. Banking creates a situation where credit prices rise at the rate of interest. In the absence of banking credit, prices are relatively low in the early years (below $5MWh) and then rise rather dramatically after 2015 to above $60MWh. A low ACP will therefore bind beyond 2020.
- Qualifying existing clean facilities to receive credits represents a tradeoff between economic efficiency, electricity prices, and inter-regional equity. Whether or not existing nuclear and hydro facilities receive credits for generation has virtually no effect on dispatch or retirements and therefore virtually no direct effect on emissions, but significant effects on electricity prices.
- In most cases, the CES renders state-level renewable electricity standards nonbinding – the exception being New York and, in cases with a low natural gas price, New England as well.
- Because the technologies that receive a full credit tend to be at the low end of the dispatch order, crediting may not do much directly to affect their position in the dispatch.
- A CES policy leads to retirements of existing coal-fired and some older gas-fired capacity.
- It is presumed the point of compliance for the CES will be the local distribution companies; however, this is a policy design choice and there are benefits to be had by moving the compliance point up-stream to the generator.
- The economic efficiency and environmental efficacy of a CES could be improved if it were cast in the mold of a feebate policy that focuses on CO_2 emission rate intensity.

Question 1. What should be the threshold for inclusion in the new program?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org) / Resources for the Future

- *How should a federal mandate interact with the 30 existing state electricity standards?*

This answer speaks more to what our modeling of a CES policy says about how a federal mandate *does* interact with state standards instead of how it *should* interact.

States have adopted renewable electricity standards (also known as renewable portfolio standards) as a means of promoting the development of renewables and, in some cases, other low emitting technologies or greater energy savings through investments in energy efficiency within their states. If the federal standard allows state standards to remain in place and each megawatt hour of generation from eligible renewables is awarded a clean energy credit under both the federal program and a state program, then the states are essentially subsidizing the attainment of a federal standard. The state policy will continue to be binding if it is requiring greater adoption of renewables from in-state or proximate sources of eligible renewable generators that exceeds the level that would cost-effectively come from that state or nearby region under the federal program.

In our modeling of different variants of the CES, we find that the federal CES policy tends to make most of the state level renewable portfolio standards non-binding. The major exception is New York State where the state renewable energy credits continue to have a positive price all the way through 2035 under most of the CES policy scenarios that we consider. In the scenarios that include a low natural gas price (consistent with the assumptions for AEO 2011) the portfolio standards in New England also continue to be binding through 2035 under a CES as well. In the low gas price baseline the total value of the REC market in California, which has one of the most stringent RPS requirements of 33 percent, is substantially higher than in the baseline that uses AEO2010 natural gas price assumptions, but in both cases adding the CES makes the state RPS policy become non-binding in all years.

Question 2. What resources should qualify as "clean energy"?

Joshua Linn (linn@rff.org) / Resources for the Future

- *On what basis should qualifying "clean energy" resources be defined? Should the definition of "clean energy" account only for the greenhouse gas emissions of electric generation, or should other environmental issues be accounted for (e.g. particulate matter from biomass combustion, spent fuel from nuclear power, or land use changes for solar panels or wind, etc.)?*

  Summary: "Clean" is usually defined based on the emissions of a technology, but for reducing carbon dioxide (CO_2) emissions, the displaced emissions of the technology is what matters. These are not the same, and the displaced emissions of any given technology can vary widely.

With a clean energy standard (CES), the structure of the program implicitly defines the term clean energy. For example, under a traditional renewable portfolio standard (RPS), qualifying renewable technologies (wind, solar, etc.) are treated as "clean", in that they generate renewable energy credits (RECs), and all other technologies are "dirty", in that they do not generate RECs. With a CES, such as in the Obama proposal, each technology is assigned a level of cleanliness based loosely on its CO_2 emissions compared to a coal plant; cleanliness varies across technologies, but not for different generators of the same technology

But intermittency and regional variation in the technologies used to generate electricity create challenges to designing an effective CES. Intermittency means that the generation from wind or solar varies over time and across regions in accordance with the wind or solar resource availability. To some extent, intermittency can be forecasted accurately—for example, the sun always sets at night—but there is always some uncertainty. An implication of intermittency is that the electricity a particular generator produces varies over time and cannot be controlled in the same way that electricity from a gas or coal unit can be controlled.

In a particular region of the country, emissions reductions may vary across wind generators because of intermittency (this is probably less of an issue with solar). For a single generator, the reduced emissions associated with that generator depend on the source of emissions that it displaces. Due to differences in wind conditions, some wind generators produce more electricity at night and others during the day. Suppose that the marginal generator—the highest-cost generator in use that is needed to meet demand—is coal at night and natural gas during the day. In that case, the avoided emissions of wind generators that produce more at night will be greater because they displace more coal.

There's a second reason why the avoided emissions of generators of the same technology vary: the large differences in generator makeup across the country. For example, the Midwest relies heavily on coal and nuclear, whereas the Northwest uses a lot of hydropower. Consequently, at any point in time, the emissions of the marginal generator vary across the country. The marginal generator may be a natural gas unit in California, and a coal unit in the Midwest. So, the emissions of the displaced generator vary across the country, and the reduction in emissions for a wind or solar generator in one region of the country may be much different from the reduction in another region.

A policy that reduces CO_2 emissions at lowest costs accounts for these differences, and creates incentives for new investments that depend on emissions reductions. For example, with a CO_2 price (that is, an emissions cap or tax), the additional incentive for investment is proportional to the emissions reductions. This is true regardless of where the generating unit is located and when it produces electricity. On the other hand, an RPS or a CES that does not differentiate between existing natural gas and coal would create the same incentive for a wind generator that displaces coal as for a wind generator that displaces gas. The implication is that a CO_2 price achieves a greater emissions reduction at the same cost as a CES.

This argument was hypothetical, but how important is this concern in practice? The substantial variation in resource availability and generator composition suggest that it could be very important, but research would be needed to further investigate compare alternative policy designs.

Question 2. What resources should qualify as "clean energy"?

Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), and Matt Woerman (woerman@rff.org) / Resources for the Future

- *What is the role for energy efficiency in the standard? If energy efficiency qualifies, should it be limited to the supply side, the demand side, or both? How should measurement and verification issues be handled?*

If a clean energy standard is to be truly "technology neutral," it makes sense to include energy efficiency as well as other supply technologies. Including all options and allowing open trading of the clean energy credits created for "negawatthours" arising from energy efficiency investments and those created by using a renewable generator or other clean generator to produce megawatt hours presumably would allow for the lowest cost approach to meeting the clean energy standard. Indeed the Renewable Energy Promotion Act of 2010 sponsored by Senators Bingaman (D-WY) 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 and Senator Graham's (R-SC) bill also allows for energy efficiency credits to meet exactly 25 percent of his clean energy standard. These proposals do place a limit on the contribution from energy efficiency and in some cases they limit the tradability of credits associated with efficiency investments to be within state boundaries.

Linking policies in this way increases flexibility in how utilities can comply, and therefore presumably lowers costs and increases political acceptability. But that flexibility is also the source of additional uncertainty about the future value of clean energy credits, which are an important source of revenue for developers of renewables and other clean energy production 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 energy efficiency programs that could generate large amounts of credits and would likely insist on strict verification of those savings.

Bringing more parties to the table raises the likelihood that the energy savings attributed to a particular efficiency program are real. However, it also might complicate and delay the process of assigning net electricity savings to particular investments, which could offset some of the anticipated cost savings of a combined policy. Much will also depend on which efficiency measures are considered part of the CES policy and which are incorporated into the baseline electricity demand assumptions.

The mix of electricity savings from energy efficiency and electricity generation from renewables and other clean energy sources induced by a combined policy will depend in part on the incentives that state regulators provide for utilities to invest in energy efficiency. Typically, revenues and profits of regulated utilities selling electricity distribution services increase with electricity sales. When this is the case, utilities have a disincentive to invest in efficiency. To mitigate this disincentive, measures to decouple revenues from sales have been enacted in a number of states. Some states have gone even further to provide incentive payments for utilities that can demonstrate certain levels of energy savings attributable to efficiency programs. Measurement difficulties aside, having these types of policies in place

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should increase not only the willingness of utilities to invest in energy savings but also the relative contribution of energy efficiency to these combined standards

If the challenges associated with measurement and verification of efficiency savings suggest that excluding energy savings from efficiency investments from the CES may be the advisable course of action, that does not mean that separate policies to promote energy efficiency should not be pursued. In a world where the main policy to reduce emissions of CO_2 from the electricity sector takes the form of a clean energy standard, having a policy to address energy efficiency or energy conservation may be particularly important given that a clean energy standard does not provide the same incentive for energy conservation as a policy that places a price directly on CO_2. This will be especially true if the CES policy has a fairly restrictive alternative compliance payment. Care should be taken to try to identify the relevant market failures and create policies that are designed to correct them. More research is clearly needed to clarify the reasons for the apparent energy efficiency paradox, the extent to which market failures or behavioral failures that warrant policy interventions are part of the cause and what types of interventions would be most effective.

Question 3. How should the crediting system and timetables be designed?

Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), MatthewWoerman (woerman@rff.org) / Resources for the Future

- *Should the standard's requirements be keyed to the year 2035 or some other timeframe?*

There is nothing magic about the year 2035, other than that it is about a generation away and is the last year currently projected in the EIA's Annual Energy Outlook. One reason for picking a year far in the future is to provide both a concrete goal and sufficient time for necessary innovation and technology development to occur. Information about the nature of the climate problem will be revealed over this time path as will the range of potential solutions for reducing greenhouse gas emissions and supplying carbon-free electricity, in particular. Ultimately, the policy should be one that allows for appropriate allocation of emissions mitigation effort over time and across sectors.

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- *What interim targets and timetables should be established to meet the standard's requirements?*

If commitment to the ultimate goal is possible and the policy allows for banking of clean energy credits to be used in the future, then the precise setting of interim targets and timetables is less important. A linear time path between current levels of clean energy and the future target makes as much sense as anything and with banking, local distribution companies can buy credits when they are inexpensive, which will drive up demand for clean generation, and then use them when credit prices are higher. Allowing credit banking will tend to create a situation where credit prices rise at the rate of interest. Unforeseen technological innovations that lead to substantial reductions in the cost of particular clean energy generators could change the course of credit prices and even lead them to fall in later years.

Several of the clean energy generation options—including integrated gasification, combined cycle coal with carbon capture and storage, and renewables—are expected to decline in cost as the technology is developed and adoption increases. Consequently, waiting until the future to comply could be more cost effective. To allow electricity retailers to take advantage of this opportunity, some limited amount of credit borrowing (perhaps through the use of a three-year compliance window) could help reduce the costs of the program and the likelihood of noncompliance in any particular year.

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- *What are the tradeoffs between crediting all existing clean technologies versus only allowing new and incremental upgrades to qualify for credits? Is one methodology preferable to the other?*

The choice over whether or not to qualify existing clean facilities to receive clean energy credits involves a tradeoff between economic efficiency and equity, but it is not a simple one. The efficiency aspect hinges on whether awarding credits to existing facilities will alter their level of production, and whether higher electricity prices are efficiency enhancing or not. The equity aspect hinges on the regional and shareholder/consumer wealth transfer consequences of the choice.

To evaluate the effect of qualifying existing clean facilities on the efficiency of a CES policy at 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, which would likely occur 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. However, qualifying these existing generators does impose a cost, assuming that the level of the standard would be adjusted upward to keep constant the expected fraction of generation from non-emitting sources that the policy would induce.

The cost comes from the elevated standard level, which would require each unit of electricity consumption to acquire additional credits, thereby raising electricity prices by more than if the existing generators are excluded. Elevated electricity prices are costly to consumers and the economy and may have undesirable tax interaction effects, but may also reduce emissions by reducing consumption. Whether or not these emissions reductions are worth the cost is difficult to evaluate.

If qualifying an existing clean facility to receive credits would increase its production, then emissions will fall and therefore yield a better efficiency outcome than qualifying a facility that will not increase production. Nonetheless, it is difficult to value the overall efficiency effect including the effect of higher electricity prices, but it must be greater than the effect of 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. Biomass, natural gas, and some high-cost nuclear facilities fall into this category. Qualifying them to receive credits would be more efficiency-enhancing than qualifying those technologies that would not alter production.

The treatment of existing facilities in the CES has regional equity implications that depend on the geographic distribution of the type of facility in question. Qualifying 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 at the expense of regions of the country with fewer hydro resources. 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. However, it is precisely because of the tremendous endowment of hydro resources in that the region that it enjoys among the lowest priced electricity in the country. A wealth transfer to that region from others that face much higher electricity prices is therefore dubious on equity grounds. For other types of clean technology that are less affordable, like wind or solar, one might view existing facilities as burdensome investments with positive climate externalities. In this case, a wealth transfer to regions that have already incurred the costs of such investments, and to the benefit of everyone else, is easier to justify on equity grounds.

The shareholder/consumer dimension of the equity question hinges 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 increased prices due to the increased requirement for credits per unit of consumption that would accompany the addition of a qualifying technology. Second, the increased credit revenues taken from consumers will, to the extent that it is the lowest operating cost facilities that 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.

According to our modeling analysis of CES policies, whether or not existing nuclear and hydro facilities receive credits for generation has virtually no effect on dispatch or retirements,[1] and therefore no direct effect on emissions, but significant effects on electricity prices. The price effects are highly varied across the country and follow from the geographic resource endowment (and location of existing nuclear generators) and electricity-market regulatory structure issues described previously.

Figure 3.1 shows the retail electricity prices that are projected in 2035 in the NHCredit scenario, in which existing nuclear and hydro generators qualify for clean energy credits. The color spectrum indicates the difference in prices between this scenario and the core scenario, in which they do not qualify. Red indicates that qualifying the existing facilities raises prices; blue indicates price reductions. The locations of existing nuclear and hydro facilities and the

[1] The one exception to this is in a scenario with 2011 Annual Energy Outlook natural gas supply assumptions. In that case, there are about 5 GW of existing nuclear capacity that would not retire if it qualified for credits, but would retire by 2035 if it did qualify.

effects on electricity market structure are clearly evident. Electricity consumers in the best-endowed regions that price electricity on a cost-of-service basis are the beneficiaries. The regions are the Pacific Northwest (including 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. It is striking that the regions that benefit are generally[2] those enjoying low electricity prices, and that generally those paying the highest prices would foot the bill, the competitive regions especially. This asymmetry is not solely due to the wealth transfer, but rather the wealth transfer exacerbates the regional price differences that would exist in the absence of a CES or even under a CES that doesn't qualify existing hydro and nuclear generators (see Figure 5.2 for regional prices under that scenario). The shareholders in the competitive regions also benefit, by between $16 billion and $31 billion annually between 2020 and 2035.

The regional price effects of the policy are discussed in more detail in our answer to question 5.1.

[2] Northern California is the exception.

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Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), MatthewWoerman (woerman@rff.org) / Resources for the Future

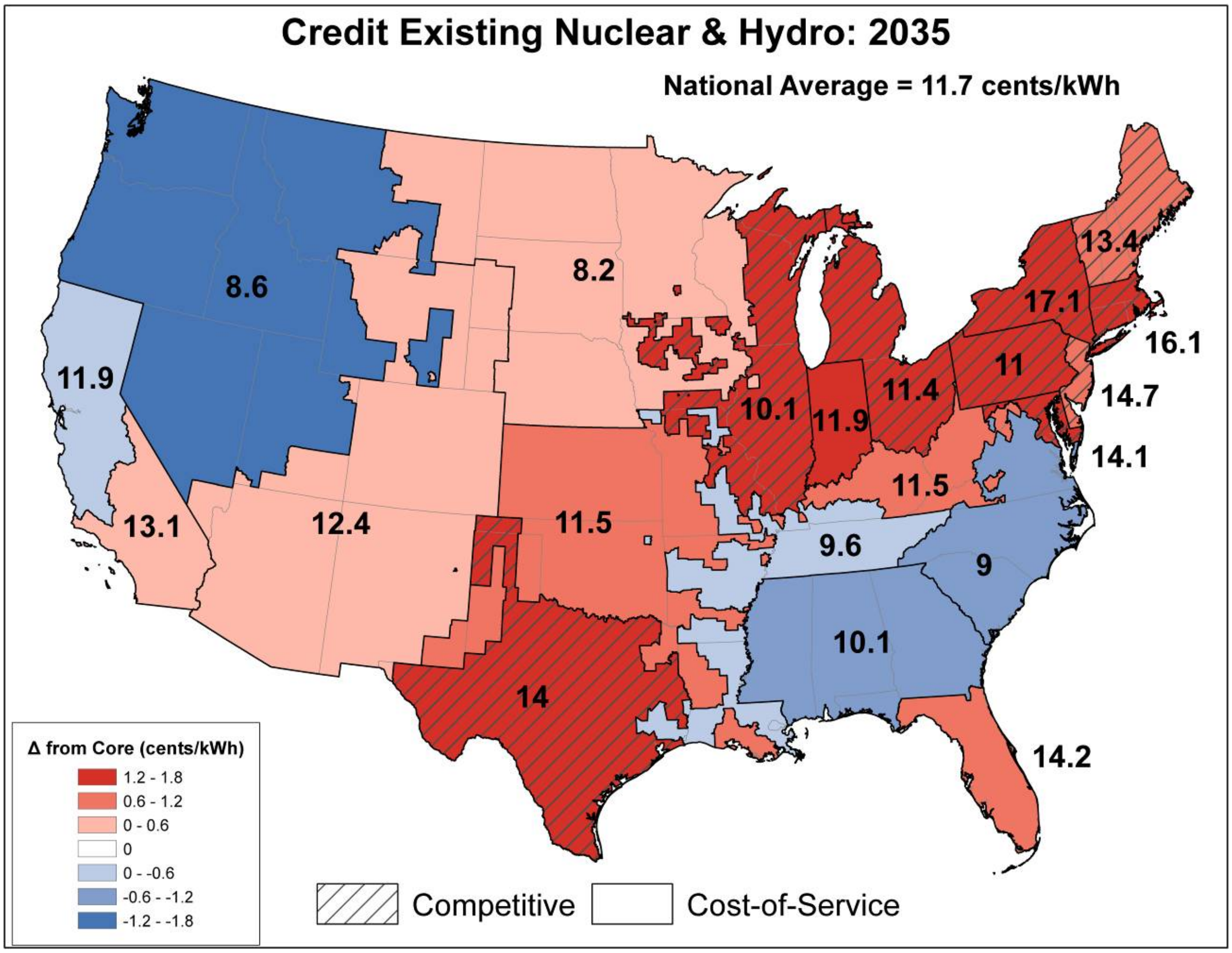

Figure 3.1. Regional Retail Electricity Prices and Changes from Core CES in 2035 (cents/kWh)

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- *Should partial credits be given for certain technologies, like efficient natural gas and clean coal, as the President has proposed? If partial credits are used, on what basis should the percentage of credit be awarded? Should this be made modifiable over the life of the program?*

If the goal of the clean energy standard is to provide incentives to reduce CO_2 emissions by rewarding generation from technologies that don't emit CO_2, then awarding partial credits to technologies that get part way toward this goal is logical. The difficulty comes in deciding how far any technology gets toward that goal. The clean energy standard is a blunt instrument that in its current incarnation does not award credits based on CO_2 emissions reductions, as policies that put a price directly on CO_2 emissions would. The logic for giving a half a credit to megawatt hours produced by a natural gas combined cycle plant is that they generate roughly half as many emissions as a coal facility. However, the MWh of additional generation from a NGCC plant may or may not be displacing coal generation and thus crediting of this sort is imprecise. One solution to this dilemma is to define the clean energy standard in terms of CO_2 emission rates and to reward generators that beat that rate and punish those that exceed it.

If on the other hand the goal of the program is to encourage the development of new technologies, in particular technologies that have further to go in terms of being competitive to market, then another possibility might be to give multiple credits to less mature technologies in order to encourage their adoption. This type of approach is a quantity-based analog to differentiating feed-in tariffs by technology as is done in many European countries. Awarding multiple credits may be superior to defining carve outs within a technology standard for particular technologies as they contribute to market liquidity and comparability of clean energy credits. However, they will complicate the task of achieving a particular emissions reduction goal as this approach goes even a step further to break the link between clean energy credits and emissions reductions.

Question 3. How should the crediting system and timetables be designed?
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- *Should there be a banking and/or borrowing system available for credits and, if so, for how long?*

Banking and borrowing are important flexibility mechanisms in any trading scheme that will help to 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 undermines 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, but allowing borrowing would require some excess generation of clean energy in the future that would help to 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 for three years) is a common practice that could put some reasonable bounds on borrowing activity and limit the possibility that the debt is never repaid.

Question 4. How will a CES affect the deployment of specific technologies?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), MatthewWoerman (woerman@rff.org) / Resources for the Future

- *How valuable would clean energy credits have to be in order to facilitate the deployment of individual qualified technologies?*

The value of credits necessary for deployment of various technologies that could be designated as qualified depends on a number of factors. In a simple example, with certainty about present and future fuel prices and electricity demand, and with a level of demand that does not vary in time (so a single technology and fuel is always on the margin), the credit price necessary for deployment of a qualified technology is the difference between the levelized cost of the marginal electricity generator in the absence of the policy and that of the qualified technology. This simple example bears little resemblance to real world electricity markets, but its lesson is applicable.

The technology at the margin varies in time and across regions of the country. The time aspect is important because solar and wind are intermittent sources that must be used when the wind is blowing and the sun is shining (although coupling solar thermal with storage may mitigate this). If wind is typically available at night but solar is typically available during the day and, if not for the policy, cheap coal is the marginal technology at night but expensive natural gas is marginal during the day, then the credit price - which cannot vary in time - required to make the renewable technologies cost competitive must be calculated as an average over time. The geographic aspect is important for similar reasons since which generators are at the margin also varies across the country. In general, the levelized cost of solar generation is 2 to 3 times (perhaps more) higher than that of wind, so solar would require a larger credit price to be cost competitive. With a national credit trading market and considering the abundance of wind, less competitive technologies like solar would not be expected to benefit much from a CES without special provisions. Such special provisions could take the form of a carve out, essentially a separate credit market with its own standard level for individual technologies, or an accelerated rate of credit acquisition, such a two credits per unit of electricity generation.

Given that in the absence of a clean energy standard, marginal generators are often fueled by natural gas, the credit price required to induce greater use of clean generators will depend importantly on the price of natural gas. In our modeling we find that lower prices for natural gas than those assumed in the AEO 2010, i.e. prices consistent with the AEO 2011, will lead to lower equilibrium clean energy credit prices in the short run, but higher prices in the long run. This is because natural gas will tend to be the technology of choice for compliance in the short run, but other technologies (nuclear, coal with CCS or wind) will be the marginal compliance technologies in the long run. If credit banking is a feature of a CES, then the short-run and long-run effects of lower natural gas prices on credit prices will not vary as they have in our modeling. Instead, lower prices for natural gas would have an ambiguous effect on credit prices, but would induce more banking in the short run.

Question 4. How will a CES affect the deployment of specific technologies?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), MatthewWoerman (woerman@rff.org) / Resources for the Future

- *How might a CES alter the current dispatch order of existing generation (such as natural gas-fired power plants), which has been driven by minimization of consumer costs, historically?*

The effect of a CES on the dispatch order of generators will depend importantly on how the policy is designed and in particular on which technologies are getting credit for being clean, how many credits each technology is getting, the equilibrium price of a credit and whether or not generation for a particular technology is excluded completely from the program by not being required to hold credits.

If the program is structured to require electricity retailers to surrender credits equal to the CES times the total number of kWh sold, this requirement effectively raises the cost of supplying electricity equally across the board. However, this cost increase will be more than offset for those kWh that receive a full credit (renewables, new nuclear, etc.) and at least partially offset for those that receive partial credit (natural gas, coal with CCS). Because the technologies that receive a full credit tend to be at the low end of the dispatch order in the first place, crediting may not do much directly to affect their position in the dispatch. However, the CES will encourage more investment in these clean technologies and once they are built, these new technologies will be dispatched first and thus will tend to push out the supply curve and displace those technologies with higher variable cost. The technologies that receive partial credit will tend to shift toward the front of the dispatch order and may, depending on the level of the credit price, dispatch before some non-qualified generators, like coal-fired generators.

Question 4. How will a CES affect the deployment of specific technologies?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), MatthewWoerman (woerman@rff.org) / Resources for the Future

- *What is the expected electricity generation mix for a target of 80 percent clean energy by 2035, under the President's proposal or an alternative construct?*

The answer to this question depends on the future prospects for nuclear power, the cost trajectories for integrated gasification combined cycle (IGCC) plants and carbon capture and storage (CCS) - as well as how certain regulatory hurdles confronting this technology 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 we discuss in the answer to parts of question 3, this feature will have an effect on electricity prices and thus on total electricity consumption.

When we model the effects of a CES with and without 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. This is even true when we raise the capital costs of new nuclear plants by 30 percent above AEO 2010 levels (bringing them more in-line with the new nuclear capital cost assumptions used in the AEO 2011, and labeled in Figure 4.1 as MoreNuke). 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 address a scenario (CoreNuke) in which the rate at which new nuclear plants can be added is constrained. These constraints limit the ultimate additions of nuclear capacity to 10 GW by 2020 and 50 GW by 2035. We also consider a case (LessNuke) where no new nuclear capacity can be added beyond the level observed in the baseline scenario. When nuclear additions are constrained, the resulting levels of generation from new nuclear plants are insufficient to meet the CES after 2020. The model finds that new coal IGCC plants with CCS take up the slack by adding up to 6 GW in 2020 and ramping up to a total of between 110 and 175 GW by 2035, depending on what is assumed about nuclear additions and the future price of natural gas. These levels of investment imply that by 2035 between 15 and 25 percent of total generation will come from coal IGCC with CCS. The generation mixes under these different assumptions about nuclear investment are shown in Figure 4.1.

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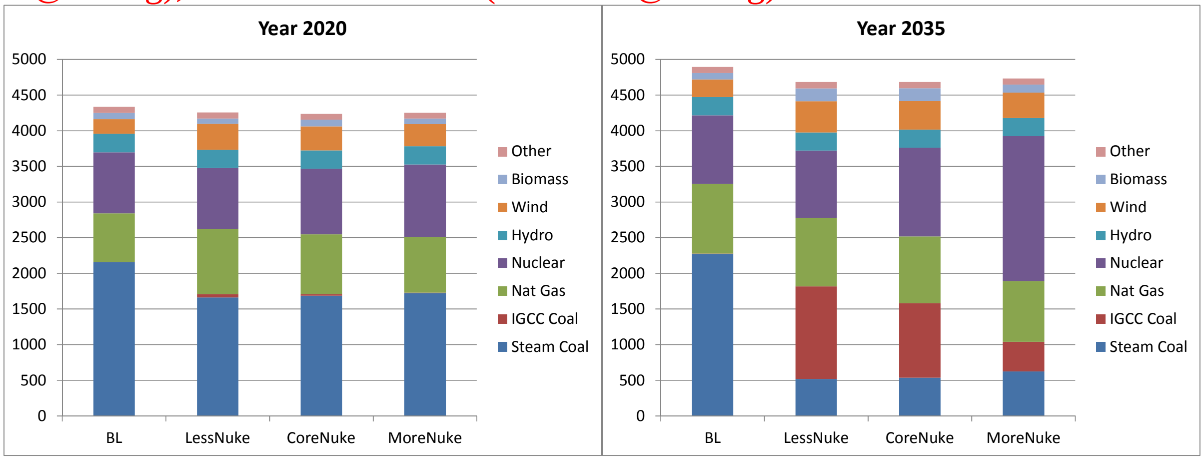

Figure 4.1. National Generation Mix (TWh) in 2020 and 2035 for Nuclear Sensitivities

Given the great uncertainty surrounding the future of both IGCC technology and CCS including costs, performance and regulatory issues related to the treatment of stored CO_2 that have yet to be resolved, the likelihood that multiple 10s of GWs of IGCC with CCS will come on-line in the next quarter century may be quite low. To account for this, we restrict the total amount of coal IGCC with CCS that can be added in any region in a given year using a similar algorithm to that used to constrain nuclear additions. This results in the addition of only 35 GW of new IGCC with CCS by 2035. Under this scenario, which is our Core scenario, we find that when both IGCC with CCS and nuclear investment is constrained, wind becomes the preferred technology, providing more than 20 percent of total electricity generation in 2035.

In all of our CES scenarios, generation from existing steam coal falls from baseline levels of roughly 45 percent of total generation in 2035 to between 8 and 13 percent in the various CES cases. By 2035, total natural gas generation ranges roughly from 100 TWh below baseline levels to 150 TWh above baseline levels, and in the Core scenario, where both nuclear and CCS additions are constrained, natural gas generation accounts for roughly 25 percent of total electricity generation in 2035. Generation from biomass is also higher with the CES but its total contribution is less than 5 percent. The generation mix in 2020 and 2035 in these scenarios is shown in Figure 4.2 below.

Question 4. How will a CES affect the deployment of specific technologies?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), MatthewWoerman (woerman@rff.org) / Resources for the Future

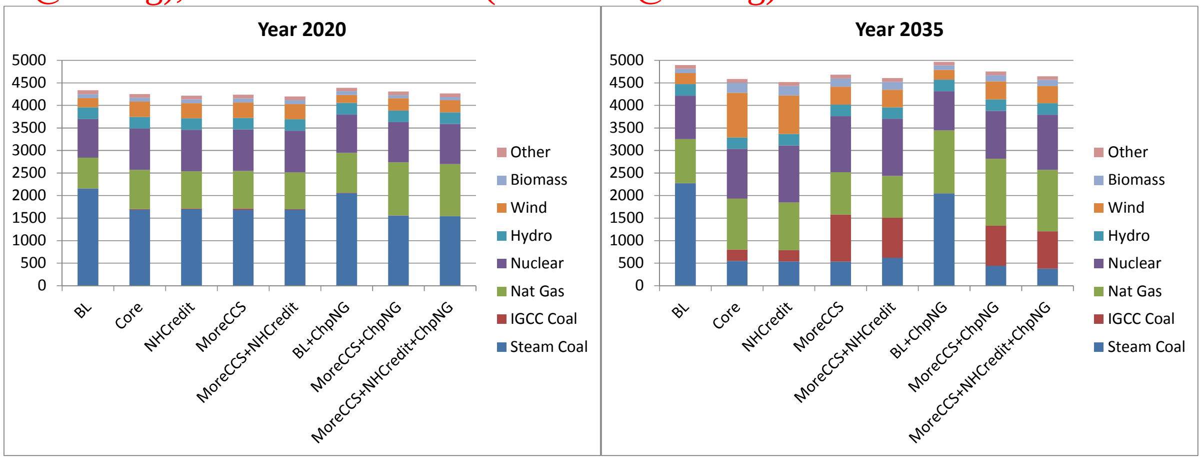

Figure 4.2. National Generation Mix (TWh) in 2020 and 2035

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Richard Morgenstern (morgenstern@rff.org) / Resources for the Future

- *What are the anticipated effects on state and regional electricity prices of a CES structured according to the President's proposal? What are the anticipated net economic effects by region?*

Depending on the expected change in electricity prices under the CES program, net economic effects by region could possibly include adverse competitiveness impacts on energy-intensive trade-exposed (EITE) industries. To date, we are not aware of specific modeling analysis that has been done on this issue for CES-type policies, although there is extensive capacity to perform such analysis at RFF and elsewhere. Unsurprisingly, an electricity-based program will impact a different set of EITE industries than an economy-wide carbon pricing scheme, as demonstrated in an early paper by Morgenstern et al. 2004.

Reference:
Morgenstern, R.D., M. Ho, J.S. Shih, and X. Zhang. 2004. "The Near-Term Impacts of Carbon Mitigation Policies on Manufacturing Industries," *Energy Policy*, 32:1825-1841.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?

Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

- *What are the anticipated effects on state and regional electricity prices of a CES structured according to the President's proposal? What are the anticipated net economic effects by region?*

Regional Electricity Prices

There are two ways that a CES can affect the cost of supplying electricity from any particular technology: all technologies[1] face an implicit tax due to the cost of clean energy credits required to cover the consumption that their generation serves, 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 (especially non-qualifying capacity will be prone to retirement). Regions that are heavily dependent on non-qualifying 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 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.

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

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?

Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

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 of the Core scenario[2] are illustrated in Figures 5.1 and 5.2 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.

[2] See the Appendix for a description of the assumptions under this scenario.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?

Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

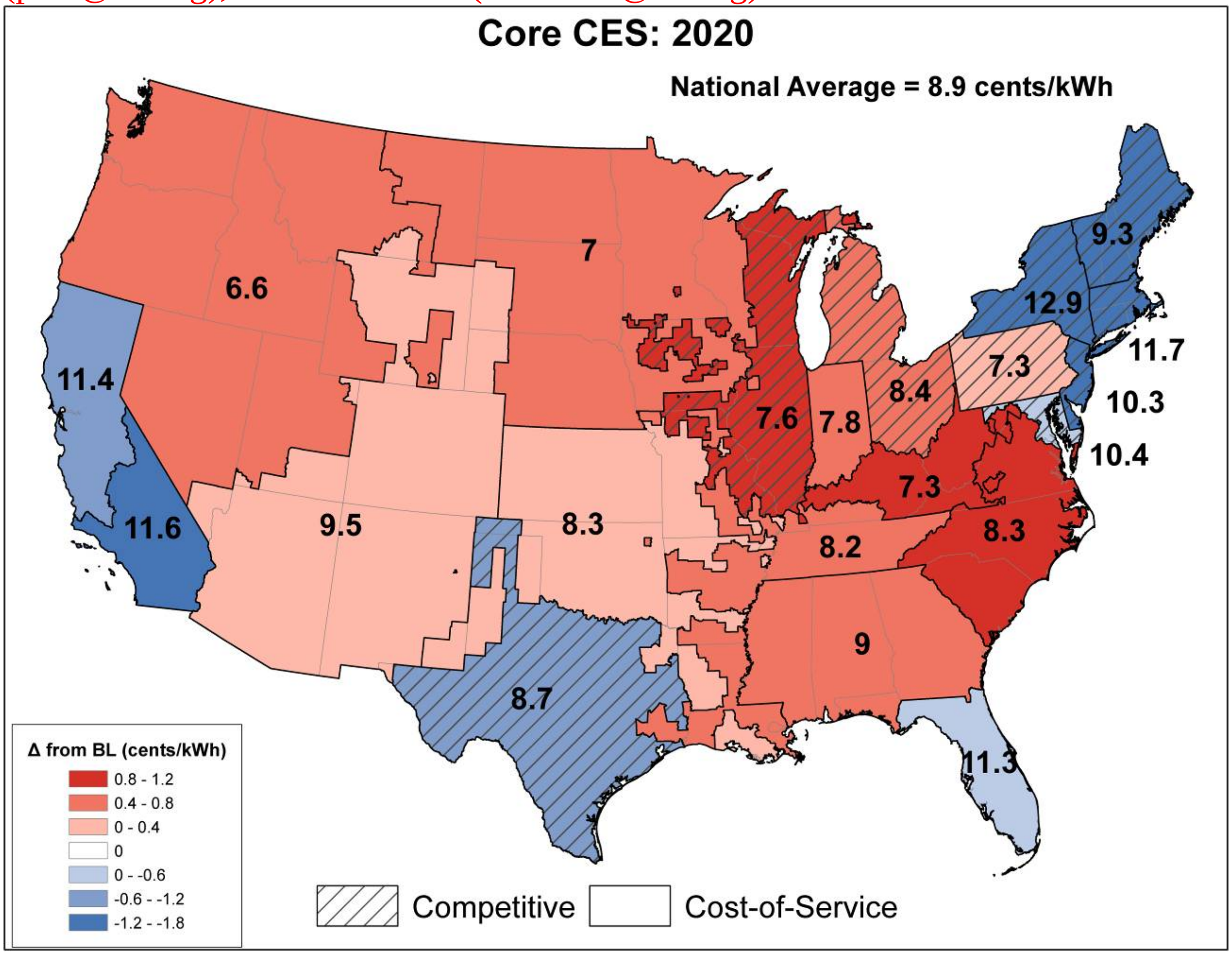

Figure 5.1. Regional Retail Electricity Prices and Changes from Baseline in 2020 (cents/kWh)

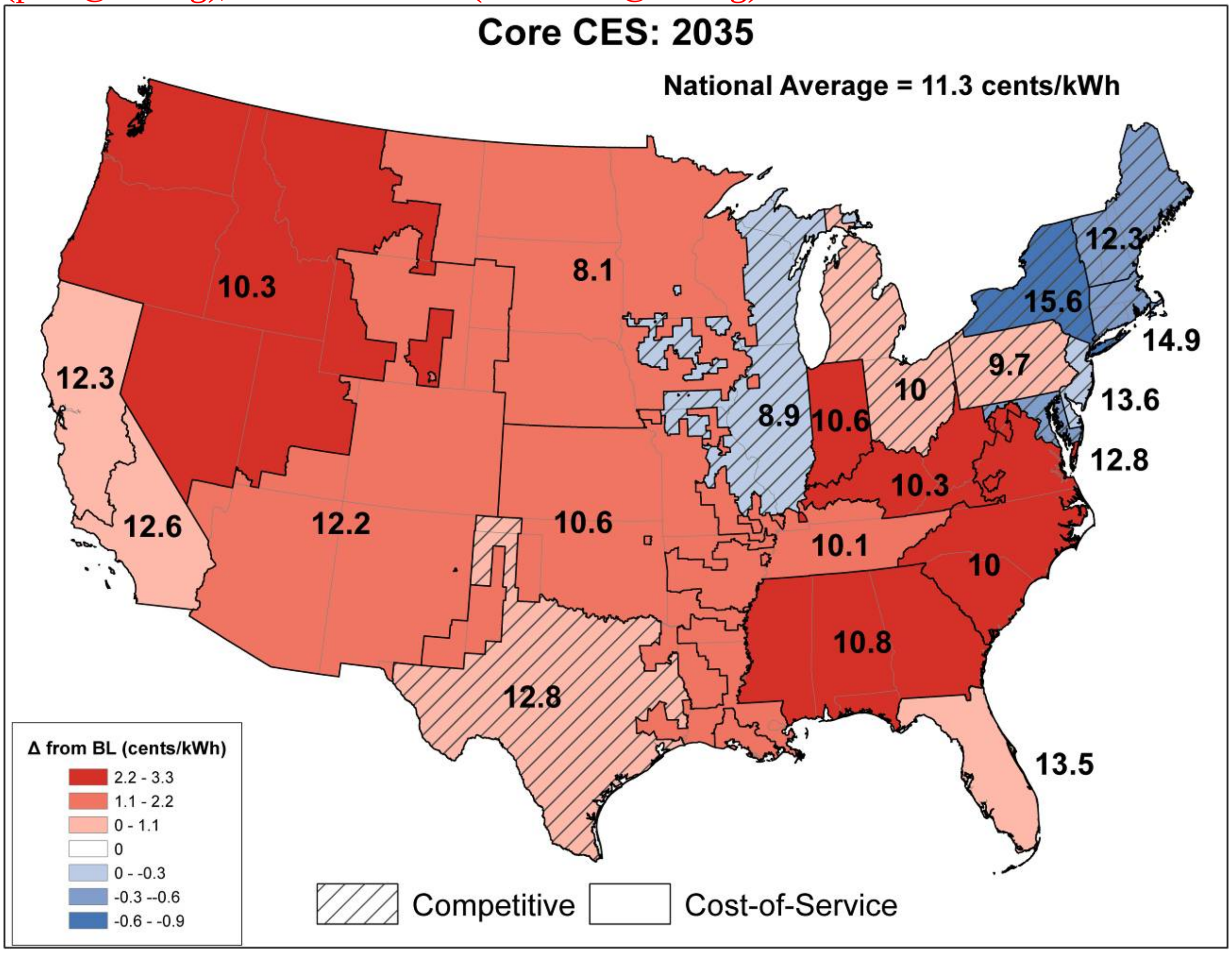

Figure 5.2. Regional Retail Electricity Prices and Changes from Baseline in 2035 (cents/kWh)

In most cases, the CES leads to lower prices in the states that participate in the Regional Greenhouse Gas Initiative, most of which have market determined electricity prices. In 2020, electricity prices fall in Texas as well under our core CES case and in 2035 prices are lower in the Illinois and Wisconsin region under the Core CES. Most 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, for those regions, their price with the CES typically remains below the national average even after the policy is implemented.

Regulated regions tend to see higher prices under the Core CES compared to the baseline, especially in 2035. The biggest price impacts tend to occur in the coal-intensive states of Kentucky, Indiana, the Virginias, and the Carolinas although the size of the impacts tends to vary by year. There are some cases where regulated regions realize lower prices under the CES policy than in the baseline. In 2020, prices fall in California, Florida and the Southwest as the revenues that those regions earn from export of clean energy credits to the rest of the country tend to more than offset the higher costs of supplying electricity under the policy. In the Pacific Northwest, prices rise with the Core CES because it treats existing hydro the same as existing coal when those facilities don't receive credits.[3]

Overall, considering both competitive and cost-of-service regions, and considering the price effects in 2020 and 2035, the 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. The national average price is shown on the figures to aid in interpreting this result.

Regional price effects of the policy will also depend on what happens with 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 impacts substantially. In addition, if retrofitting of existing coal capacity with CCS, also not considered in this preliminary modeling, 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 heavily coal dependent regions. In addition, a CES policy design that excludes existing hydro from the set of technologies subject to the requirement would curtail any price increases in the Pacific Northwest. Lower prices in that region and a commensurate increase in consumption would have a smaller impact on emissions than lower prices in other regions because of the relatively low carbon intensity of electricity production in that region.

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 receive credits or not. Figures 5.3 and 5.4 show the net credit revenue by region in 2035 under the Core CES case and the effects of giving credits to existing nuclear and hydro generation facilities on regional credit revenue in the same year. Figure 5.3 shows that credit exports tend to be concentrated in the western states with most of the eastern states importing credits in the Core CES case. The exceptions are Indiana and the Kentucky and West Virginia region where new investment in IGCC coal with CCS creates credits for export in 2035.

Figure 5.4 shows that for those regions that have plentiful amounts of hydro electric power (including New York, Northern California, Northern New England, and the Northwest Power Pool) and those regions with abundant nuclear (New Jersey and Delaware, Northern California, Wisconsin and Illinois, and Virginia and the Carolinas) granting credits to existing nuclear and hydro increases the net revenues that they receive from selling credits. For most of the other regions, the associated added burden of the increase in the target that accompanies this change in

[3] If existing hydro facilities are given credits, the policy results in lower prices in the Pacific Northwest in 2020 and 2025, but not in later years when the higher cost of the policy swamps the gains to native hydro facilities. For more details on the effects of qualifying existing nuclear and hydro generators, see our response to question 3.

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 in excess of $4 billion from sales of credits under the CES design that includes existing nuclear and hydro while both Florida and the Ohio/Michigan region are paying $2.3 and $2.6 billion, respectively, for imported credits.

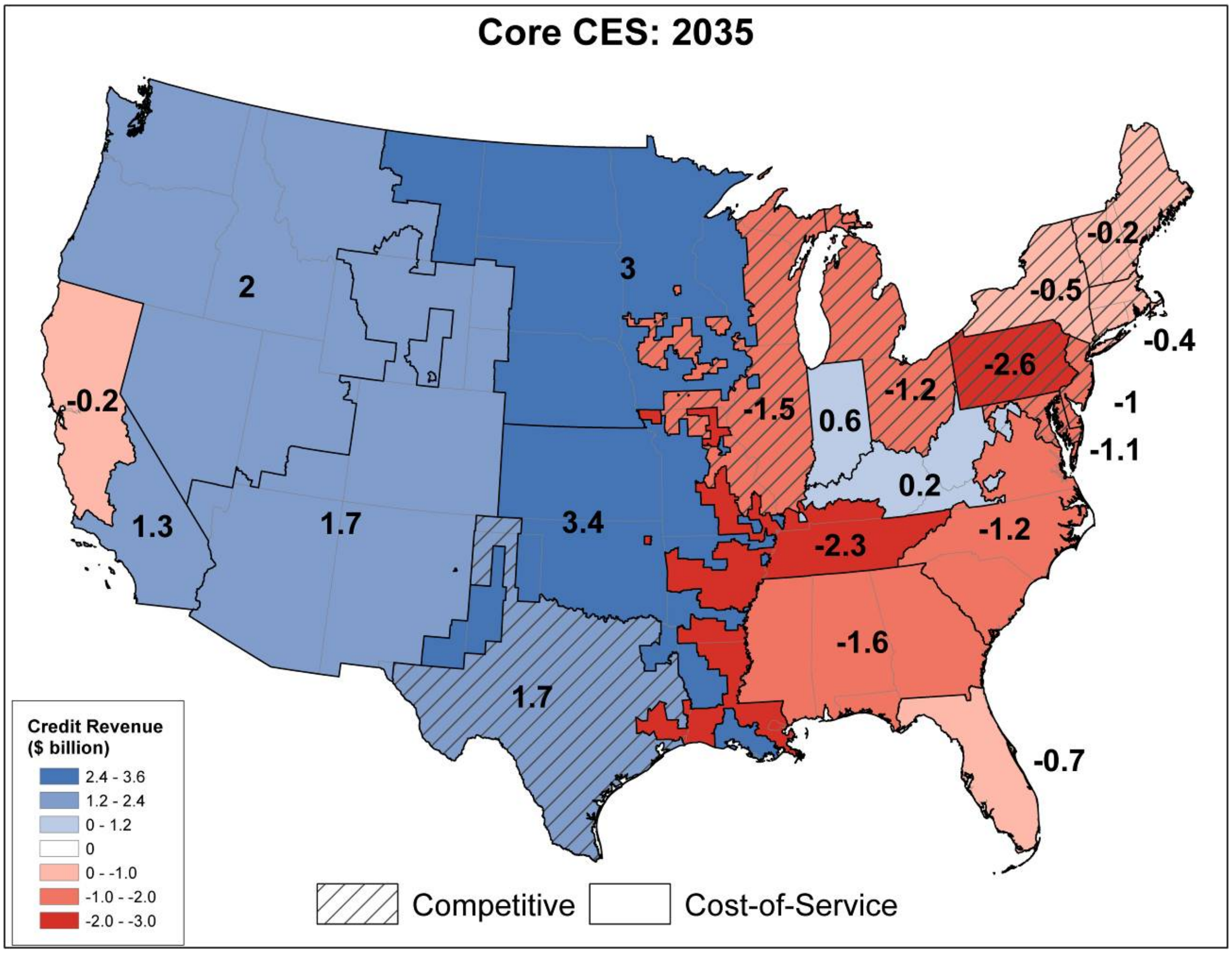

Figure 5.3. Net Federal Credit Revenues (B$) in Core Scenario

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?

Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

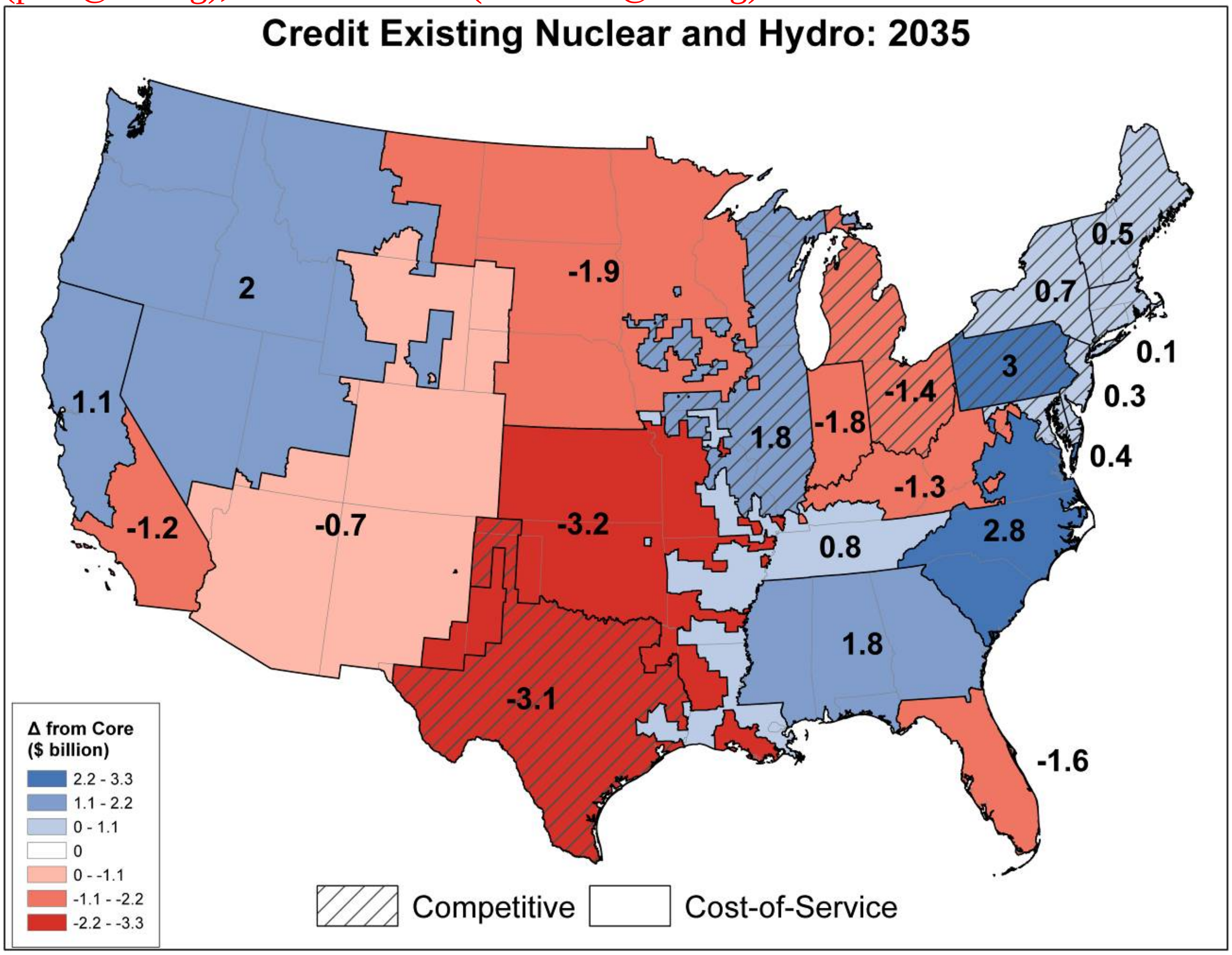

Figure 5.4. Net Federal Credit Revenues (B$) Change from Core in NHCredit Scenario

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

- *Would other CES formulations or alternative policy proposals to meet a comparable level of clean energy deployment have better regional or net economic outcomes?*

This question of how policy design could be altered to bring about more equitable impacts across regions is an important one. We note in our answer to the previous question and to question three, that the treatment of existing nuclear and hydro power in the CES policy will have important implications for overall cost and for the effects of the policy in nuclear- and hydro-intensive regions in particular. We also note that excluding generation from existing nuclear and hydro facilities from the program all together (neither getting credits nor requiring retail sales derived from nuclear or hydro power to have credits) would be one way to mitigate price impacts, in the Pacific Northwest especially, without imposing costs across the country, and doing so would be unlikely to affect the amount of generation from existing facilities. Further manipulation of design parameters to understand how they might mitigate differences in regional impacts is an important area for future research that we intend to pursue.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

- *How might various price levels for the ACP affect the deployment of clean energy technologies?*

Alternative compliance payments (ACP) have been a feature of most of the prior federal renewable portfolio standard (RPS) proposals introduced in the past few Congresses. These 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. For a CES policy with a target of 80% generation by clean sources in 2035, an ACP of $21/MWh would have two important consequences. First, it is much too low to remain non-binding through 2035 and would therefore lead to a level of clean energy production far below the target. Second, if credit banking is to be a feature of a CES, then an ACP that doesn't rise over time, 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 be more likely to bind over time. A way to work around this is simply to set an ACP price that rises at the expected rate of interest over time.

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 did not account for credit banking and therefore does not find credit prices rising at a discount rate. The left-hand panel of Figure 5.5 shows projected credit prices for the Core CES scenario, which assumes less extensive deployment of IGCC with CCS, the NHCredit scenario, which treats existing nuclear and hydro generators as qualified to earn credits, and the corresponding pair of MoreCCS scenarios. The right-hand panel of the figure shows credit prices under three scenarios that are identical, but for the assumption about nuclear capacity deployment.

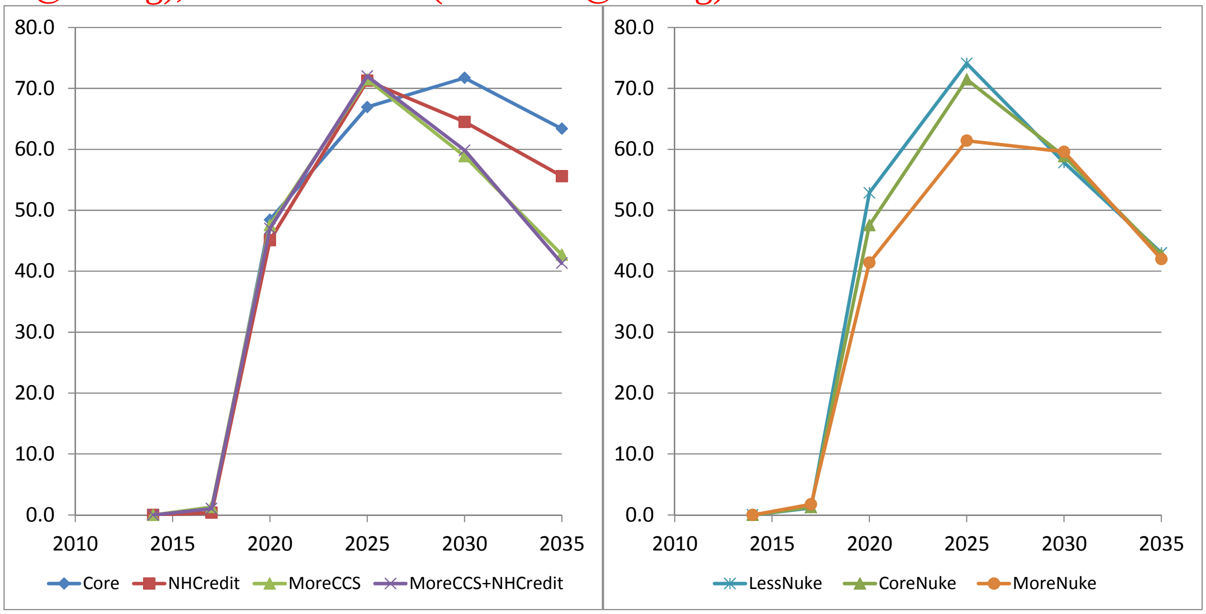

Figure 5.5. Clean Energy Credit Prices ($/MWh)

Three observations about the figure are relevant. First, these linear trajectories for the level of the standard would yield highly non-linear 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, the inclusion of existing nuclear and hydro generators (left-hand panel) along with a commensurate adjustment to the standard level (the NHCredit scenarios), 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 12% in these scenarios, suggesting that the ACP level that binds depends on the details of the features of a CES policy.

The third observation relates to the right-hand panel of the figure, which shows credit prices for different assumptions about nuclear capacity penetration. The prices in the long run are quite similar across the three scenarios, partly because IGCC with CCS is treated optimistically in these cases and therefore it takes up the slack left if nuclear capacity cannot expand further. In the medium run, however, quick and extensive nuclear capacity expansion could substantially reduce credit prices relative to the LessNuke case, by as much at 22% in 2020 in the MoreNuke scenario. This shows that the effect of an ACP level depends upon technological progress in bringing down the costs of nuclear generators, and on the political acceptability of extensive nuclear capacity expansion.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Andrew Stevenson (stevenson@rff.org) / Resources for the Future

- *What are the possible uses for potential ACP revenues? Should such revenues be used to support compliance with the standard's requirements? Should all or a portion of the collected ACP revenues go back to the state from which they were collected? Should ACP revenues be used to mitigate any increased electricity costs to the consumer that may be associated with the CES?*

In order to maintain the emissions reduction benefits of a Clean Energy Standard (CES) even when the Alternative Compliance Payment (ACP) is triggered, legislation could stipulate that ACP funding be directed towards the most cost-effective domestic and international opportunities to reduce greenhouse gas emissions. This could include supporting compliance with the standard's requirements – such as clean energy research and development or infrastructure – energy efficiency programs, or financing reductions in emissions from land use change.

One of the primary benefits of a CES would be reducing greenhouse gas emissions from electricity generation – one of the largest emissions sources in the United States. The overall emissions reduction benefits of a CES would depend on the level of the target as a percentage of overall generation, the rate of crediting for different generation types and the use of cost containment measures such as an ACP that allow regulated entities to comply without deploying clean energy

The primary purpose of an ACP is to help contain the costs of a CES by essentially putting a price cap on compliance. However, while an ACP may help contain costs, it would also limit the environmental benefits a CES achieves.

ACP revenues could be used either to provide additional cost containment benefits – such as direct rebates to consumers – or to ensure the intended benefits of a CES are achieved even when the ACP is triggered. If the ACP is set appropriately, however, at a level that would limit the costs of a CES for consumers to desired levels, there does not seem to be a strong case for using revenues to provide additional cost containment benefits.

There is a stronger case for using ACP revenues to support the achievement of CES objectives, including emissions reduction objectives. Those objectives could be met either by encouraging compliance with the CES by supporting additional clean energy deployment, or by financing potentially more cost-effective emissions reductions through domestic or international land use change. Discretion for allocating ACP funding could be given to an interagency body that targets the achievement of the most cost-effective emissions reductions.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

- *What level of asset retirements from within the existing generation fleet are anticipated as a result of a CES?*

The CES policy leads to additional retirements of existing capacity of up to 85 GW as early as 2020 with total national capacity retirements of roughly 200 GW in excess of those experienced under a business-as-usual scenario by 2035. Most of those 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 5.4 below.

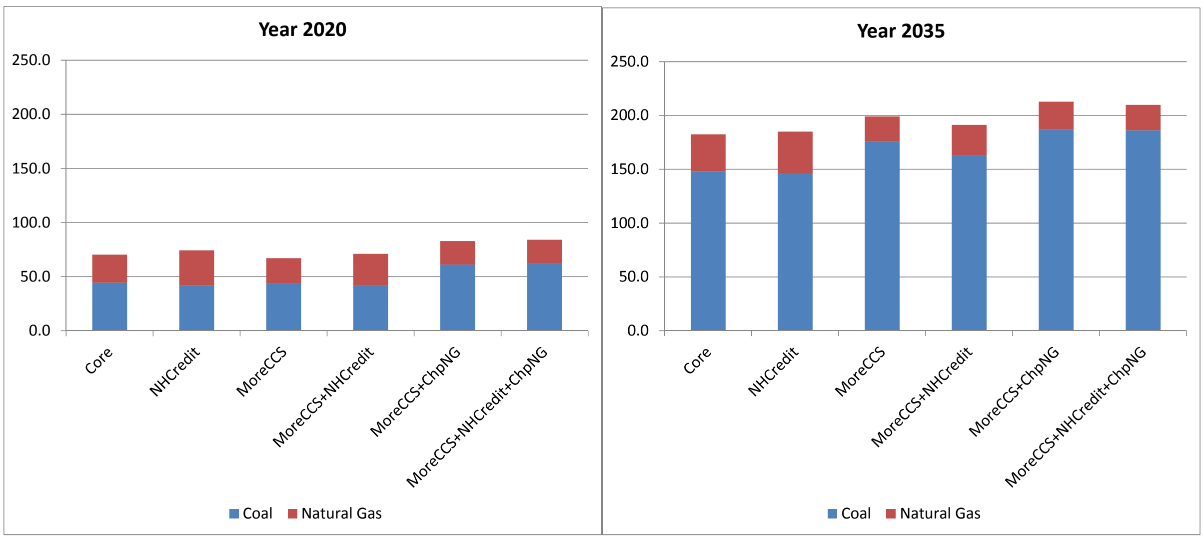

Figure 5.4. Retirement (GW) Change from Baseline in 2020 and 2035

As would be expected, most of the retirements take place in the coal-rich regions of the upper Midwest and Appalachian states and the Southeastern states, which retire 55-80 GW and 50-65 GW of total capacity by 2035, respectively, depending on the scenario. The smallest amount of capacity retirement happens in the RGGI region where just under 20 GW of additional capacity retirement occurs by 2035. The regional distribution of retirements in the Core scenario is shown in Figure 5.5.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

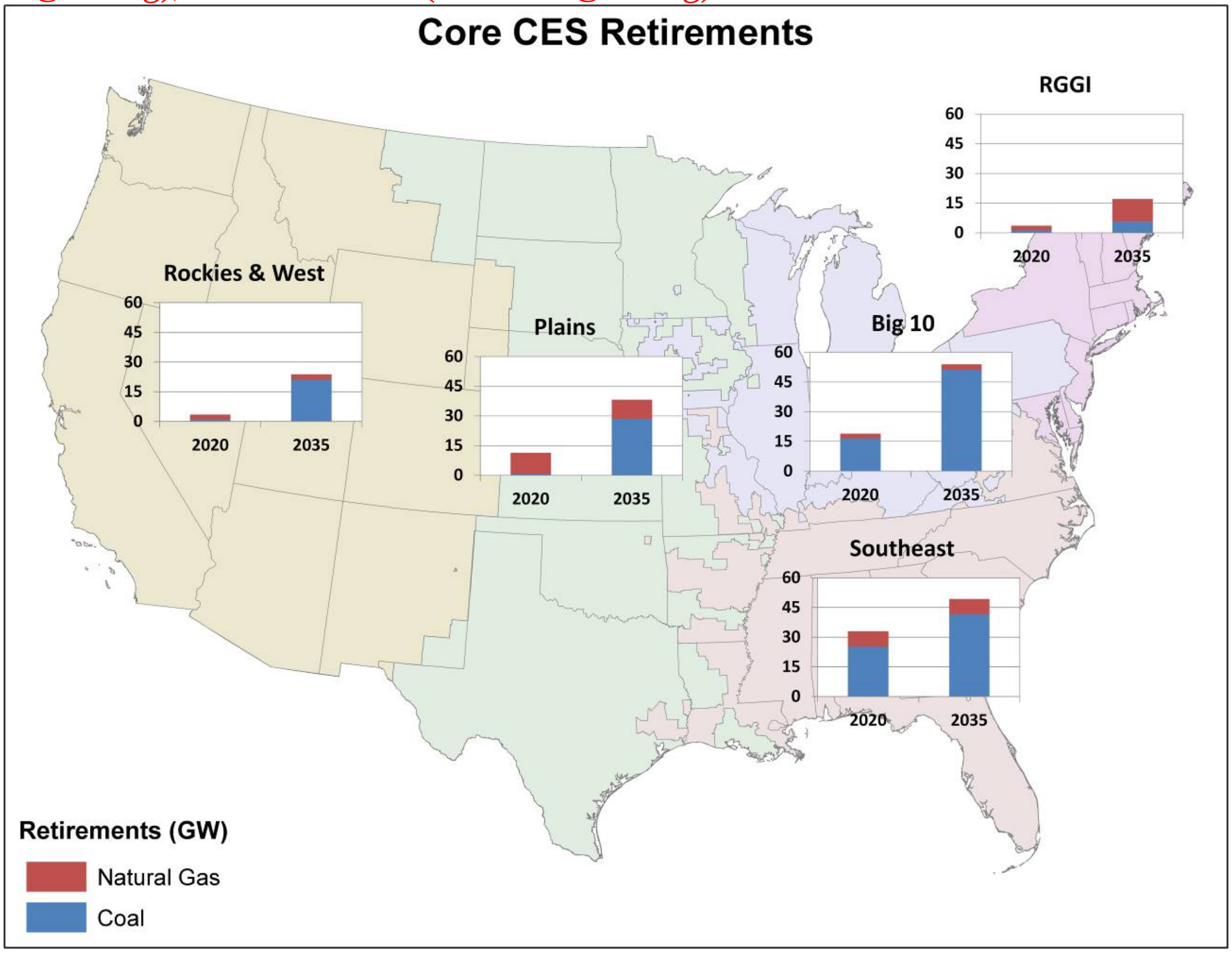

Figure 5.5. Regional Retirement (GW) Change from Baseline in Core Scenario

The amount of retirement of existing coal varies with the assumptions about potential rates of growth for nuclear and IGCC with CCS, as shown in Figure 5.4. In our Core scenario, which assumes limits on both nuclear and CCS additions, we find that an additional 150 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). In the low gas price sensitivity cases (MoreCCS+NHCredit+ChpNG) 185 additional GW of coal-fired capacity retires by 2035 as a result of the CES policy. Allowing existing hydro and nuclear generation to earn credits tends to reduce the amount of coal retirement slightly. 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.

In addition to encouraging retirement of existing facilities, the policy also promotes substantial investment in clean energy capacity to meet the standard. The technological composition and regional distribution of that investment varies with policy design and other assumptions. By 2035, between 175 and 315 GW of additional capacity relative to baseline

Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org), Anthony Paul (paul@rff.org), Matt Woerman (woerman@rff.org) / Resources for the Future

levels will be added nationwide under the policy. In our Core CES scenario, we add 315 GW of capacity, roughly three quarters of which is wind, by 2035. In scenarios where CCS is less constrained, most of the additional new capacity added by 2035 is IGCC with CCS and much less additional capacity is needed because this technology has a much higher expected capacity factor than wind.

The regional distribution of the new investment also depends importantly on assumptions about the prospects for adding IGCC with CCS. The Southeast sees more investment if IGCC with CCS is less constrained while the Plains and Western states see substantial amounts of investment in incremental wind if IGCC with CCS is substantially constrained. The Midwest sees substantial increases in investment under both approaches, building large amounts of coal with CCS when that is feasible, and large amounts of wind when it is not.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?

Submitter's Name/Affiliation: Joshua Linn (linn@rff.org) / Resources for the Future

- *Should cost containment measures and other consumer price protections be included in a CES?*

Summary: The purpose of an ACP is to reduce the costs of the standard, but an ACP also reduces the benefits. An ACP could cause the benefits-to-costs ratio to go up or down.

An Alternative Compliance Payment (ACP) has been included in many RPS or CES proposals, and it is used in many state RPS programs. For example, the ACP in Waxman-Markey was $25/MWh.

The purpose of an ACP is to contain costs, but an ACP may also have undesirable effects on emissions. As an illustration of this possibility, consider two hypothetical national RPS programs. The first has a 20 percent renewable requirement and no ACP. Suppose that the equilibrium REC price would be $30/MWh, which means that each qualifying renewable generator receives $30 for each MWh of electricity generated. The REC price provides additional incentive to invest in renewable technologies, above the revenue that would be earned from selling the energy itself. By providing additional revenue, the REC implicitly subsidizes investment in renewable generators. The subsidy is implicit, because it is not paid by the government.

The second policy is exactly the same, except that the REC price is capped at $25/ton. This means that investors will make renewable investments that are profitable with the $25/MWh subsidy. But projects that would need a greater subsidy won't occur. Instead, the utility will pay the ACP to comply with the renewable requirement of the RPS. The result is lower renewable penetration than if there were no ACP, but the total cost to the utility is also lower.

What happens to cost effectiveness, defined as the ratio of costs to emissions reduction? Actually, the ratio could go up or down. Costs obviously go down, and so do the emissions reductions, but the relative amount of the reductions matters. The projects between $25 and $30/MWh, which are developed in the first policy but not in the policy with the ACP, are relatively expensive, but they may also reduce emissions by a large amount. For example, they may be wind generators located at a site with good, but not great, wind resources so that their cost is high, but their generation may have displaced a lot of coal generation. Therefore, imposing the ACP may reduce costs, but it could reduce emissions by even more, and cost effectiveness gets worse.

Question 5. How should Alternative Compliance Payments, regional costs, and consumer protection be addressed?
Submitter's Name/Affiliation: Joshua Linn (linn@rff.org) / Resources for the Future

- *How much new transmission will be needed to meet a CES along the lines of the President's proposal and how should those transmission costs be allocated?*

  Summary: A CES affects not just how much transmission is needed, but also where it is needed. Transmission policy should be integrated with CES policy.

This question raises the broader issue of the interdependence of transmission and climate policy. The particular policy chosen, whether it is a cap-and-trade, a CES, or traditional RPS, affects not just the amount of transmission needed, but also were the transmission is needed. For example, consider an RPS with a solar "carve-out" that causes a lot of investment in solar generation capacity in the Southwest. Because solar is currently more expensive than wind, an alternative RPS, without the carve-out, might lead to a greater amount of wind investment in the center of the country. The transmission investments needed in the first case, where there is a lot of solar in the Southwest, would be different from the transmission needed to support wind in the middle of the country. Furthermore, in the case of solar, the questions is not just about the need for high-voltage transmission lines, but also whether distribution network investments are needed if solar is installed on residential or commercial rooftops.

Texas provides a good example of the tight connection between transmission and energy policy. The state has aggressively promoted wind investment, but it has also experienced a great deal of congestion because of insufficient transmission capacity. Most of the wind investment has been in western Texas, where electricity demand is relatively low. Demand is highest in eastern Texas, but very little wind has been constructed there. Because of transmission constraints between the two regions, much of the wind generation in the west could not be used—the system could not handle all of the wind that was available to the grid. With sufficient transmission capacity the extra wind generation could have been used to meet electricity demand in the east. But instead, fossil units in eastern Texas had to generate more electricity than if there had been no transmission congestion. Therefore, actual emissions reductions probably would have been much greater in the absence of the congestion.

Regulators responded to this situation and there is a lot of transmission investment underway. The situation illustrates the problems that arise when generation and transmission investment are not perfectly in sync. The problems may be resolved over time, but there could be a long period in which the system is operated in a very inefficient manner because of insufficient transmission. The question is not just how much transmission will be needed, but of where the transmission will be needed.

Question 6. Are there policies that should be considered to complement a CES?
Submitter's Name/Affiliation: Karen Palmer (palmer@rff.org) / Resources for the Future

- *To what extent does a CES contribute to the overall climate change policy of the United States, and would enactment of a CES warrant changes to other, relevant statutes?*

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%, or 20 billion tons, relative to a baseline with no 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 only reduces electricity emissions by about 5% compared to BL, but by 2035 annual CO_2 emissions from the electricity sector are roughly 60%, or 1.7 billion tons, below the BL level. The CO_2 emissions trajectory of the BL and Core scenarios are shown in Figure 6.1.

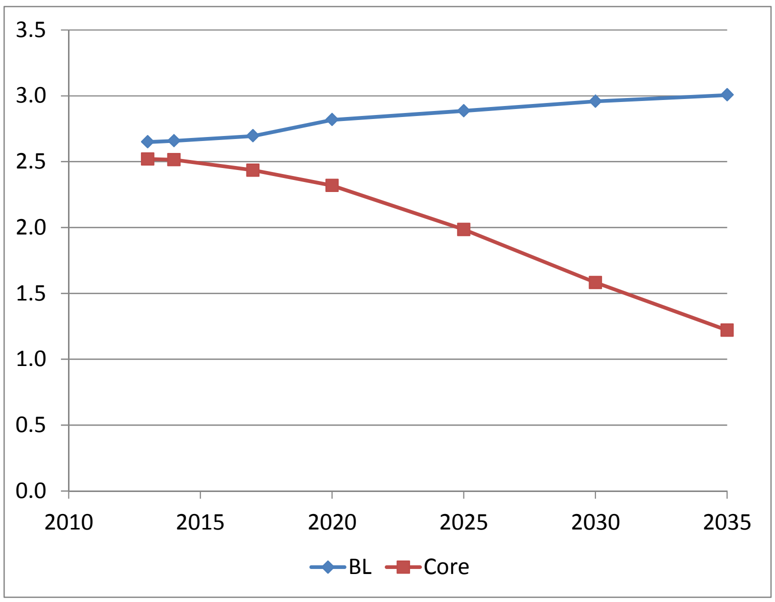

Figure 6.1. CO_2 Emissions (billion tons)

The 2011 Economic Report of the President indicates 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% below 2005 levels by 2020 and to 83% 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% 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 approximately 41% 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.

Question 6. Are there policies that should be considered to complement a CES?
Submitter's Name/Affiliation: Joshua Linn (linn@rff.org) / Resources for the Future

- *What is the current status of clean energy technology manufacturing, and is it reasonable to expect domestic economic growth in that sector as a result of a CES?*

Summary: While there is a large number of studies on the employment effects of a CES or other energy policies, it is important that these studies include the employment effects throughout the economy, and be as transparent as possible about the underlying assumptions—which can often be quite strong.

A CES or any other clean energy policy affects employment at multiple levels. First, the policy induces investment in new generation capacity, which creates jobs for construction, operation, and maintenance workers at the location of the project. Second, the components in the new generators, such as the wind turbines or the photovoltaic modules, must be manufactured. Third, the new generation capacity may reduce the utilization and fuel consumption of existing plants, which could reduce employment at those plants or upstream, such as at coal mines.

Studies have proliferated over the last several years that attempt to estimate the employment effects of different policies. There are three general problems with the majority of these studies. The first is that they tend to rely on very strong assumptions about the amount of employment caused by a given amount of investment. These assumptions are typically made based on "input-output" relationships, which essentially describe the average amount of employment per unit of output for each industry in the economy.

In this approach, the level of aggregation is key. Many studies use highly aggregated data, so that, for example, PV modules are in the same industry as semiconductors. If the actual employment in PV module manufacturing is much different from semiconductors, this analysis would lead to the incorrect conclusion. Moreover, the direction of the bias is unknown—these estimates could be too high or too low.

There is a second, more nuanced, problem with the input-output approach that would exist even if highly detailed industry data were used. Consider manufacturing employment estimates, which rely on the number of employees per unit of output—say, employees per PV module. The employment estimate in an input-output analysis is based on the average employment per module over the year, but what is really needed is the marginal amount of employment per module. That is, how much does employment change when the number of PV modules increases? This amount is different from the average number of employees per module, particularly if the manufacturing plant is operating at less than full capacity throughout the year. In that case, the manufacturer may be able to increase module production a lot without hiring many more workers or asking its existing workers to work longer hours. Focusing on the average rather than on the margin may therefore lead to an over-estimate of the induced manufacturing employment.

Question 6. Are there policies that should be considered to complement a CES?
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The second major issue with most studies is that they do not distinguish between net and gross job creation. That is, the contractor who installs the solar panels may have been employed elsewhere in the absence of the subsidy. Most studies would count this contractor as an increase in employment even though that is not the case. Furthermore, job changes in other sectors should be counted. If a CES reduces the amount of coal used to generate electricity, the analysis should include the reduction in coal mining employment.

In summary, the point is not that previous employment estimates are wildly overstated. Rather: 1) these estimates should be made as transparent as possible and with as few assumptions as possible; 2) careful attention should be paid to whether studies report gross or net changes in employment; and 3) employment throughout the economy should be included in the analysis, not just specific sectors.

Appendix: Model and Scenarios

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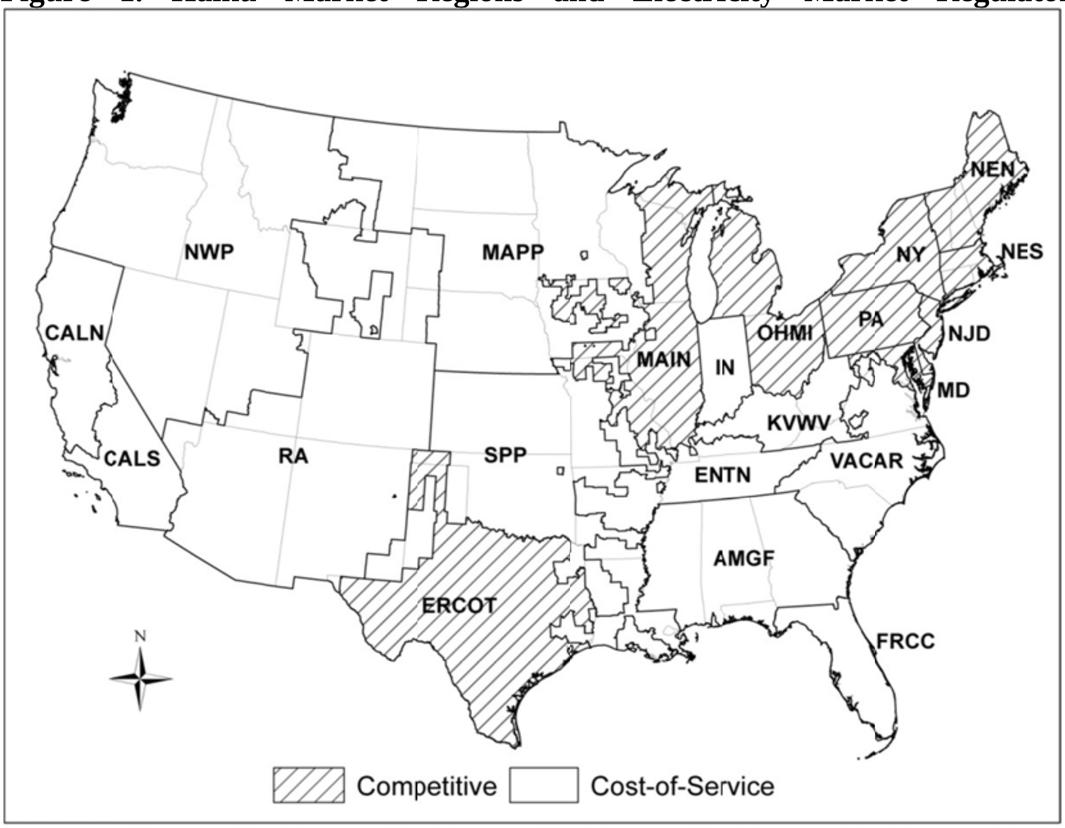
Haiku Electricity Market Model

The Haiku electricity market model is used for some of the analysis in this document. Complete documentation of the model is here: http://www.rff.org/RFF/Documents/RFF-Rpt-Haiku.v2.0.pdf.[1] 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 the EIA and the Integrated Planning Model developed by ICF Consulting and used by the U.S. Environmental Protection Agency (EPA).

Figure 1. Haiku Market Regions and Electricity Market Regulatory Structure



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

[1] Paul et al. 2009

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 1 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.[2] 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.

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 1. 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% by 2035, to $4270 per kW, even in the absence of any new capacity additions.

[2] 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.

Table 1. 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; NERC 2003b).[3] Factor prices, such as the cost of capital and labor, are held constant. Fuel prices are benchmarked to the forecasts of the 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.

[3] 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.

- *Scenarios Description*

The scenarios referenced in this document are described here. All of them are compared to a baseline scenario that represents business-as-usual in the absence of any CES policy. The characteristics of the baseline are retained in all of the CES scenarios, except as specifically mentioned in the descriptions that follow. The scenario defined below as Core is a representation of a CES policy that can be evaluated in comparison to the baseline, or in comparison to 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.

Baseline (BL)

The baseline scenario represents business-as-usual and is very similar in both assumptions and results to the Reference case of the AEO 2010 (EIA 2010a). Included in the scenario is a representation of the state-level RPS policies that currently exist 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 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.[4]

The BL scenario incorporates several existing environmental policies, including the SO_2 cap-and-trade program under Title IV of the Clean Air Act Amendments of 1990, the Clean Air Interstate Rule[5] restrictions on emissions of SO_2 in the eastern part of the country as well as the annual and ozone season restrictions on NO_x emissions, the cap on CO_2 emissions in the RGGI states (the Northeast), and the state-level mercury MACT programs.

Core CES (Core)

[4] 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.

[5] The rule was vacated and remanded to EPA in July 2008 by the federal appeals court, but after a request for rehearing, the court remanded the rule to EPA without vacating, in December 2008. 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.

The Core CES policy analyzed here is assumed to begin in 2014 at a level of 12.3% and become increasingly more stringent (on a linear path) to a level of 57.1% at the end of the modeling horizon in 2035. Banking of CES credits is not modeled, so a kWh 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 and hydroelectric power is awarded a whole credit for electricity generated by new investments, but not for generation at existing facilities.[6] Power generated by natural gas-fired combined cycle units, both existing capacity and new investments, is awarded half of a credit per unit of generation. Generation from coal-fired plants that employ a carbon capture and sequestration (CCS) system is awarded 90% of a credit per unit of power.

There are two technologies that could play an enormous role in meeting a CES, but for which there is great uncertainty about investment costs: nuclear and integrated gasification combined cycle (IGCC) with CCS. In the case of nuclear, there are also potential political obstacles to extensive deployment and the regulatory and physical infrastructure necessary to support widespread transport and storage of captured carbon is yet to be developed. In the Core CES scenario, a constraint is implemented on the quantity of new capacity of these technology types that can be constructed per year. The constraint is implemented separately for the two technologies and for each of the 21 model regions, and set to 0.25% 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, nuclear investments would amount to 56.2 GW by 2035 and investments in IGCC with CCS would amount to 61.6 GW by 2035. The aggregate constraint is different for the two technologies because of the assumption that an IGCC with CCS generator can be constructed in 4 years, 2 years less than the construction time for a nuclear generator.

Credit Existing Nuclear and Hydro (NHCredit)

The NHCredit 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% in 2014 and 80% in 2035, increasingly linearly in the intervening years.

Cheap Natural Gas (ChpNG)

The ChpNG scenarios assume supply curves for natural gas that correspond to the AEO 2011. These curves are substantially cheaper than those that corresponded to the AEO 2010.

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

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

The MoreNuke and MoreCCS scenarios raise the annual construction constraint of 0.25% of 2008 installed capacity to 1% of 2008 capacity. The More Nuke scenario also adjusts the assumed capital costs for nuclear investment upward by 30%. This brings the capital cost for nuclear closer in line to the assumptions of the AEO 2011.

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.

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Additional Topics

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Is a Clean Energy Standard a Good Way to Move U.S. Climate Policy Forward?

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Following the failure in 2010 to pass a comprehensive cap-and-trade bill to reduce carbon dioxide (CO_2) and other greenhouse gas emissions, the Obama Administration and some in Congress are now focused, in particular, on a *clean energy standard* (CES). Under this approach, electricity producers would be required to meet a rising fraction of their generation using zero carbon sources or sources with lower carbon intensity (CO_2 emissions per kilowatt-hour [kWh]) than that of coal generation.[1]

Although a CES would lower the carbon intensity of the power sector, it is typically viewed as a second-best approach relative to a well-designed, economy-wide cap-and-trade policy, as the latter promotes a broader range of behavioral responses to reduce CO_2 emissions across all sectors of the economy.

We argue in this article, however, that in some important economic and practical regards a CES may be a better first step than the cap-and-trade proposals floated in Congress. In particular, it can be significantly more cost-effective and it avoids, at least initially, large increases in energy prices, which are a major political hurdle for emissions pricing policies. But getting policy details right is critical. In fact, policymakers should also be open to a pricing alternative to the CES, known as a *feebate*, which involves fees for generators with above average emissions intensity and subsidies or rebates for those with below average emissions intensity. The feebate appears to represent a more transparent and cost-effective approach. Moreover, in principle it would be straightforward to progressively transition from this policy towards the simplest and most cost-effective policy of all—a tax on carbon with revenues used to offset other more distortionary taxes (like taxes on labor and capital income)—whenever the latter policy becomes politically viable.

Comparing Policy Costs: A First Look

Carbon taxes or cap-and-trade systems, where fuel suppliers are either taxed or required to hold permits in proportion to the carbon content of their fuels, are usually thought to be cost-effective policies for reducing energy-related CO_2 emissions. As taxes or allowance prices are passed forward into higher prices for fuels, electricity, energy-intensively produced goods, and

[1] At the same time, the U.S. Environmental Protection Agency is also initiating regulations to reduce CO_2 emissions under the Clean Air Act. The most well-developed part of the program has been new passenger vehicle fuel economy standards which are set to rise from about 25 to 35 miles per gallon over the next few years and which will ultimately reduce economy-wide CO_2 emissions by around 5 percent.

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so on, all potential options for reducing CO_2 throughout the economy are exploited. This includes fuel switching in the power sector, reductions in electricity demand, purchase of more fuel efficient vehicles, and reduced use of fuels in the residential and commercial sectors. And because the price of emissions is uniform across the economy under either policy, the incremental cost of emissions reduction activities tend to be equated across sectors, firms, and households, which means that emissions reductions are allocated across the economy in the least-cost way.

A CES policy requires switching away from coal in power generation, and promotes cost-effectiveness by offering full credits for clean fuels (nuclear and renewables) and partial credits for fuels with lower emissions intensity than coal (natural gas or coal with carbon capture and storage). But it does not discourage direct fuel consumption in other sectors. Moreover, a CES has a weaker impact on electricity prices, and hence is less effective at reducing electricity demand. Under a CES, electricity prices rise to reflect the costs of producing with cleaner, but more expensive, generation fuels. However, under carbon taxes and cap and trade, energy prices also rise to reflect the price on CO_2, providing a greater incentive to reduce electricity demand and seek gains in energy efficiency. In fact, the pass-through of carbon tax revenues, or the value of emissions allowances, has a much bigger impact on electricity prices than the costs of fuel switching.[2] In short, for a given total emissions reduction, a CES would appear to be more costly than cap-and-trade as it places too much burden on emissions reductions from fuel switching, too little burden on electricity conservation, and no burden at all on other sectors.

One cautionary note here is that most of the (relatively) low cost options for reducing CO_2 in the U.S. economy are, in fact, from fuel switching in the power sector. According to policy simulations reported in Krupnick et al. (2010, 73), using a variant of the U.S. Energy Information Agency's National Energy Modeling System (NEMS-RFF), under an economy-wide CO_2 pricing policy around two-thirds of the emissions reductions over the next 20 years would come from fuel switching in the power sector, about another 20 percent from reductions in electricity demand, but less than 10 percent from reductions in the transportation sector. An appropriately designed CES could therefore still exploit a large portion of emissions reductions that would be forthcoming under cap and trade.[3]

[2] These conceptual results are borne out in policy simulations of CES, cap and trade and a carbon tax in Palmer et al. (2010, figure 12, pg. 44). They find that, for policies achieving the same economy-wide CO_2 reductions, CES-related electricity price increases are minimal in 2020 compared to those of pricing policies, while leading to price increases of about 70 percent of those of the pricing policies by 2030.

[3] Reductions from the transportation sector are modest for three main reasons. Most important, emissions pricing has only a modest impact on the retail price of motor fuels, whereas it dramatically increases the price of coal (given its high carbon content). In addition, in contrast to the power sector, options for replacing carbon-intensive fuels with other fuels are presently very limited in the transportation sector. Furthermore, higher fuel prices have only modest effects at best on promoting the adoption of fuel-saving technologies for automobiles, given that many new technologies are already being incorporated to meet rapidly rising fuel economy standards.

Additional Topics

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A Closer Look: Cost Assessment in Real (Distorted) Economies

But in the above discussion we are comparing policy costs in a hypothetical economy in which there are no sources of pre-existing distortions of economic activity. In reality, the economy is full of distortions (from taxes, market power, other externalities, and so on) and public finance economists have long warned us that such distortions can affect the economic costs of new policies in important ways.

Here we focus on an important and under-appreciated source of pre-existing distortion for climate policy, namely distortions created by broader fiscal policies. Personal income and payroll taxes reduce the overall level of work effort below levels that would maximize economic efficiency, by lowering the returns to labor force participation, effort on the job, accumulation of skills, and so on. Similarly, personal taxes paid on dividend and capital gains income, and taxes at the corporate level on the return to investment, cause distortions by reducing capital accumulation. And generous tax preferences in the fiscal system, such as tax exemptions and deductions for employer medical insurance and home ownership, cause further distortions by creating a bias towards tax-favored spending and away from ordinary (non-tax-favored) spending.

Emissions pricing policies potentially interact with these sources of pre-existing distortion in two important, but offsetting, ways (e.g., Bovenberg and Goulder 2002). First, if carbon tax (or permit auction) revenues are used to reduce taxes on labor and capital income, there is a relatively large source of economic efficiency gain from slightly alleviating distortions from the broader fiscal system. On the other hand, the overall level of economic activity will contract in response to higher energy prices, leading to a (slight) reduction in work effort and capital accumulation, which exacerbates the costs of pre-existing taxes on labor and capital income.

These linkages with the broader fiscal system have two key implications for the ranking of different policies on cost grounds.

First, there is a large cost saving from emissions pricing policies that exploit the revenues to reduce tax distortions (what we term revenue recycling) versus pricing policies that do not exploit this effect, say by returning the revenues in lump sum transfers to households. The second (and more surprising) implication is that emissions pricing policies without the revenue-recycling benefit may no longer be superior to the CES on cost-effectiveness grounds. This is because emissions pricing policies have a bigger impact on energy prices, and hence cause more exacerbation of pre-existing tax distortions.[4]

These implications are borne out in a recent study by Parry and Williams (2011). They looked at several policies to reduce domestic, energy-related CO_2 emissions by 8.5 percent (about 0.5 billion tons) in 2020 below levels otherwise projected to occur for that year.[5] Under

[4] In practice, price impacts might be somewhat reduced under cap-and-trade systems, depending on how allowances are allocated. For example, one proposal involves allocating some free allowances to local distribution companies in the expectation that they would not pass through the value of these allowances into higher end-use prices for electricity.

[5] These reductions are approximately consistent with those projected under the Waxman-Markey bill (H.R. 2454). Although target reductions in greenhouse gases under this bill were 17 percent below 2005 levels by 2020, much of

cap-and-trade policies with free allowance allocation (or a carbon tax with revenues returned in lump-sum transfers) the estimated average cost per ton reduced is $91 (in current dollars). In contrast, under a carbon tax or cap and trade with full allowance auctions, where revenues are used to cut distortionary income taxes, average costs are actually slightly negative (as a result of large gains from cutting other taxes when they distort both factor markets and create distortionary tax preferences). Parry and Williams also examined a CO_2 intensity standard for the power sector, which is similar to a CES in that it promotes fuel switching without a large increase in electricity prices. This policy represents an intermediate case, with average costs of $29 per ton reduced.

In short, the revenues created by carbon taxes, or rents created under cap-and-trade, are potentially problematic. They need to be used to cut distortionary taxes (or used in other ways that yield comparable economic efficiency benefits) for these instruments to be unambiguously better on cost-effectiveness grounds than CES and similar policies. If not, then well-designed policies to lower the emissions intensity of the power sector could be the better way forward, at least for the scale of energy-related CO_2 reductions envisioned for the medium term.

There are caveats here. One is that a CES may not be well designed in practice (for instance, it could be designed with limitations on credit-trading provisions—see below), with a resulting loss of cost-effectiveness. Another is that the relative differences in the average costs per ton of different instruments, caused by their interactions with the tax system, become less pronounced as the goal for CO_2 reductions becomes more ambitious. A third, related point, is that there are limits to the reductions in CO_2 that a CES can deliver compared to a cap-and-trade or carbon tax policy because the CES offers less of an incentive for energy conservation and would only apply to the electricity sector. So, pushing the CES hard could, beyond some point, result in a rapid escalation of costs compared to a cap-and-trade policy.

Further (Practical) Considerations

Nevertheless, important practical obstacles are associated with higher energy prices that are holding up emissions pricing policies and that would seem to favor a CES-type approach for the time being.

One is competitiveness and the related issue of emissions leakage. As energy prices rise in response to climate policy, firms trading in global markets with energy-intensive production processes (e.g., steel, aluminum, and cement) suffer a loss of competitiveness and may relocate some of their activities to countries without emissions pricing policies. However, policies to address capital flight, like taxes, or permit requirements, imposed on embodied carbon in imported products (with symmetrical rebates for exported products), are contentious, because of problems in measuring carbon content and possible conflicts with international trade obligations.

Similar issues arise in the context of distributional impacts. CO_2 emissions-pricing policies are regressive (i.e., the burden of higher energy prices, relative to income, is greater for poor households than for wealthy households) because lower income households tend to spend a

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the reduction was projected to occur through emission offset provisions (e.g., domestic firms paying for forest carbon projects in other countries in lieu of reducing their own emissions).

relatively larger portion of their income on energy. Under emissions pricing policies, complicated compensation schemes could be designed to address some of these regressive effects (e.g., using revenues to fund tax cuts that disproportionately benefit the poor), though these schemes typically lower the economic efficiency benefits from revenue recycling.

In short, to the extent that competitiveness and emissions leakage is a concern for the near term (until emissions pricing becomes more prevalent in other countries), a CES may be favored over a cap-and-trade or carbon tax policy because the former results in less of an energy price increase. And until carbon taxes can be implemented as part of a broader fiscal package that has some progressive elements (like scaling back tax preferences favoring the wealthy), distributional concerns might be better addressed through a CES or other policy that avoids large increases in energy prices.

A Feebate as an Alternative to a CES

Although we have discussed some potential merits of the CES, there are also some potential pitfalls in design details (rather than the general thrust) of the policy. In fact, a feebate policy shares the advantages of the CES noted above, and can have some further advantages of its own.[6]

A feebate—a term taken from the literature on applying rebates to vehicles more than meeting a fuel economy standard and a fee applied to vehicles with fuel economy worse than the standard—in the electricity context would have two elements. First is a price on CO_2 emissions. Second is a *pivot point* level of CO_2 per kWh. Firms with emissions intensity (averaged across their portfolio of generation plants) in excess of the pivot point would pay a fee equal to the CO_2 price times the difference between their CO_2 per kWh and the pivot point, times their electricity generation (in kWh). Conversely, firms with CO_2 per kWh below the pivot point would receive a rebate or subsidy equal to the CO_2 price times the difference between the pivot point and their CO_2 per kWh, times their electricity generation. The policy can be made revenue-neutral (approximately) by setting the pivot point in one year equal to the average observed CO_2 per kWh in the previous year. The feebate approach has several potential advantages over the CES.

One is that the incremental costs of reducing CO_2 are automatically equated across different generators, which promotes a cost-effective allocation of emissions reductions within the power sector at a given point in time. This is because all generators receive identical benefits (either reduced fees or increased rebates) per ton of CO_2 reduced. In principle, the CES approach could also be cost-effective in this regard, though this would require extensive credit trading provisions, allowing coal-intensive generators to exceed the standard by purchasing credits (converted into CO_2 equivalents) from other generators that are well below the standard.

Another attraction of the feebate is that it automatically handles changes in the future costs of different generation technologies or fuel prices. If, for example, the future expansion of nuclear power is temporarily held up, firms would be permitted a higher emissions intensity (at the expense of paying more fees or receiving fewer rebates), whereas under a strict CES they would be required to meet a given emissions intensity standard, regardless of costs. Conversely,

[6] Here we compare the pros and cons of the CES and feebate. There are additional design issues, such as whether the policies cover both existing and new generation sources, but these issues apply equally to either instrument.

if the competitiveness of wind power improves, firms are rewarded for exploiting this opportunity and further cutting their emissions under a feebate, whereas under the CES, they have no incentive to do better than the emissions intensity standard. Under a CES, these problems could in part be mitigated if firms were able to offset shortfalls in meeting the standard one year by being credited for exceeding the standard in other years. And a CES could include an alternative compliance payment, which would enable firms to pay fees instead of meeting the standard, if credit prices reach a certain limit. These provisions complicate the design of the CES program, however.

Furthermore, a CES where credits are defined by fuel is a "blunt" instrument, as it does not encourage efficiency upgrades at plants that reduce required fuel inputs for a given amount of generation. Several categories of credits would be created: a full credit (1) for nuclear and hydro plants, perhaps a 0.9 credit for coal with carbon capture and storage, perhaps a 0.5 credit for natural gas plants, and so on. However no credits, for example, would be created for coal plants that are more efficient than other coal plants. In fact, CO_2 intensities may vary by a factor of two or more in coal plants and vary for gas plants as well. The savings from recognizing these differences in trading clean energy credits are forfeit unless this heterogeneity is recognized and plants can trade energy credits at rates reflecting their carbon intensities.[7]

Finally, by establishing a fixed price on CO_2 emissions, a feebate facilitates comparison of policy stringency across countries. This price could be set in line with estimates of the (global) environmental damages from CO_2 (currently about $21 per ton, according to a recent review across US agencies and subsequent use in U.S. regulatory impact analyses [US Interagency Working Group on Social Cost of Carbon 2010]) or prices prevailing in the European Union's Emissions Trading Scheme (currently about $22 per ton).[8] And designing a transitory compensation scheme (to help coal-intensive generators) should be straightforward under a feebate, where the future emissions price is known, rather than being revealed later on during credit trading.

Looking Ahead

A revenue-neutral carbon tax (or auctioned cap-and-trade system) is where we should be headed over the longer term, perhaps in coordination with other large emitting countries, or as part of a package of reforms that will be needed, sooner or later, to address the federal budget deficit. But in the meantime, a serious and reasonably comprehensive effort on behalf of the United States to begin scaling back CO_2 emissions is urgent, not only for its own sake, but also to undermine excuses for delaying emissions-reduction programs in other countries.

We have argued that a CES could, under certain conditions, be more cost-effective and less contentious than a tax or cap-and-trade program. In addition, we suggested that a feebate applied to power sector emissions could strike a better balance between cost-effectiveness and practical realities faced by policymakers than the CES. Moreover, once emissions are priced in

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[7] In this regard, a simple CO_2 emissions standard per kWh would be more cost-effective than a CES (Burtraw et al. 2001).

[8] Alternatively, under a CES approach, if an alternative compliance payment is included this could be scaled to CO_2 prices in other countries.

the power sector through a feebate, it would be relatively easy to progressively transition to emissions pricing in other sectors and gradually convert the fee to a carbon tax for the power sector by scaling back the pivot point.

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Additional Topics

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Most discussions of a clean energy standard (CES) program start with the presumption that the **point of compliance** will be the local distribution companies (LDCs). However, this is not the only way to design a CES. The point of compliance should be considered carefully. There are costs as well as potential benefits of placing compliance obligation with the LDC compared to the natural alternative, which would place the compliance obligation on generators who provide power through the grid to LDCs.

The second central feature of the design of the CES is the **metric for compliance**. Most discussions presume a portfolio approach will be implemented, with compliance obligation defined by the fuel that is used for electricity generation. This approach does not distinguish the operating efficiency of power plants.

At the center of the question about both the point and metric of compliance is the articulation of the goal of the CES program. Is the program first and foremost aimed at promoting new, clean technology or improving performance of the system and reducing emissions? If it is primarily a technology policy, then placing the obligation on consumers through their LDCs to support the transition toward new technology has logic, but it does not necessarily imply that the focus on LDCs is the preferable one. If the goal is to improve the performance and reduce emissions from the electricity system, then a different design would be preferable.

The portfolio approach to the program introduces ambiguity and inefficiency in its ability to promote lower emissions and improved energy efficiency from the existing fleet of electricity generators because large categories of existing facilities are treated in a homogenous manner even though they have very different operating characteristics and emissions. Under the portfolio approach, the burden that falls on facilities is determined by their fuel type, even though there is substantial variation in the operating efficiency and heat rates. The compliance obligation of two plants would be the same even if their operating efficiency (and associated fuel use and emissions) vary by 20 percent. This is plausible, even after adjusting for many plant-specific characteristics such as vintage, size, boiler type, and utilization. Although it is already the case that generators face cost-based incentives to improve efficiency where robust wholesale power markets exist, many regions of the country do not have robust wholesale competition. Because the LDC approach does not differentiate among the facilities within a given fuel category, it does not provide a direct incentive to improve the efficiency of existing facilities. In other words, with LDCs as the point of compliance and with a portfolio approach as the metric of compliance, one size fits all within a fuel category.

The literature discussing point of compliance in programs to promote clean energy and energy efficiency emphasizes the unique long-term relationship between the LDCs and their customers as a primary justification for centering the program on LDCs. Many argue that as a consequence of this relationship LDCs are best positioned to promote efficiency in end use of electricity, although others argue that the LDC's incentives are typically aligned to accomplish just the opposite and to promote higher sales and greater electricity consumption. In either case, in many states through a variety of emerging regulatory policies, the incentives for LDCs are beginning to change. Nonetheless, advocates of the LDC as the point of compliance argue that the program can have an impact on the *corporate culture* of the LDC. The LDC and its regulators will directly see "on budget" the cost of acquiring and surrendering clean energy credits. Managers at the LDC who can reduce these costs are likely to attract visible rewards. This, some argue, is likely to attract bright minds within the company to energy efficiency programs. Placing compliance responsibility with the LDC could diminish the incentive of retail distribution companies to expand sales, and conversely to increase their incentive to improve efficiency in end use of electricity.

A second aspect of LDC compliance is its unique position with respect to improvements in the local distribution network and to some degree in the transmission network. One way to reduce the compliance obligation is to reduce inefficiencies in transmission and distribution. Some observers argue that there exist inadequate incentives to make the transmission and distribution network more efficient because the benefits of doing so are diffuse. According to this reasoning, it follows that placing the LDC as the point of compliance for the CES program provides a visible incentive to reduce network inefficiencies.

Third, since most retail distribution companies are regulated, administrative proceedings provide an explicit forum for advocates of conservation measures to monitor the efficiency investments that are made. The assignment of responsibility for compliance to the LDC may make the logic for efficiency investments more transparent.

The value of improving end-use efficiency or the distribution network is related to the stringency of the program. We imagine the program would require clean energy sources (R) to be a specific share (X) of total consumption (D), leading to an equilibrium price (P) in the market for clean energy credits such that the supply for credits equals the demand: $P\ R = P\ X\ D$. The compliance obligation for an individual LDC (i) is equal to $P\ X\ D_i$. The greater the share X, the closer investment in end-use efficiency or transmission system upgrades comes to parity with incentives for clean energy sources.

However, as opposed to the effect on corporate culture, it is not clear that the LDC has a greater *economic incentive* to reduce sales than if the point of compliance were instead placed on the generator. If the generator company has compliance responsibility, the effect on the distribution company will hinge on the degree to which costs are passed through the fuel cycle, which depends in turn on the fuel used by the marginal generation unit, not the infra-marginal unit. If the marginal MWh is generated with coal, as is the case in many regions of the country for some parts of the year, then under a system placing the compliance obligation on generators the impact on wholesale power prices will be greater than if the marginal MWh is generated with natural gas. Moreover, the impact on retail power prices would be greater than if the point of compliance were the LDC in this case. Hence, one cannot state that one approach or the other will uniformly have a greater effect on retail power prices or on price-driven incentives for the LDC.

Hence, the only argument favoring the currently envisioned design of the program that seems potentially robust is that if the distribution company has compliance responsibility then it will develop an internal corporate culture that rewards efficiency. Furthermore the company may become an advocate for regulatory reform such as for decoupling revenues from sales. On the other hand, a similar argument could be made on behalf of implementing a corporate culture that rewards efficiency improvements at existing generating facilities by placing compliance responsibility on generators, but that is less likely to happen with the point of compliance at the LDC.

In summary, there are two key features in the design of a CES. One is the point of compliance obligation, and most narratives argue for the LDC as the point of compliance. The second is the metric of compliance. Most narratives argue for a portfolio-based approach treating all sources using a specific fuel in a similar manner, as opposed to an approach that would measure the operating performance of individual facilities. To accomplish the latter would require the point of compliance obligation be placed on the generator rather than the LDC because of the difficulty of accounting for the performance of generators as power flows through the network from generators to the LDCs.

The attributes of each approach are summarized in the table below. From this summary, it is apparent that the two key features discussed here deserve further consideration. It may be that a performance based CES program with the point of compliance on generators would be more efficient and efficacious than the design currently contemplated.

Key Design Features for the Clean Energy Standard

Point of compliance:	***LDCs***		***Generators***
Metric for compliance:	***(Fuel) Portfolio***		***Performance***
Incentives for energy efficiency:			
Maximal impact on corporate culture of LDCs	**X**		
Greater economic incentives for end-use energy efficiency		**?**	
Maximal impact on corporate culture of generators			**X**
Greater economic incentives for supply-side energy efficiency and emissions			**X**