Electricity, Renewables, and Climate Change: Searching for a Cost-Effective Policy

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Chapter 1. Introduction

The electricity sector is a major source of the carbon dioxide emissions that contribute to global climate change. In the United States, electricity generators fired by fossil fuels are responsible for roughly 40% of all carbon dioxide emissions resulting from human activity. Switching a substantial fraction of U.S. electricity generating capacity from fossil fuels to renewable technologies such as geothermal, biomass, or wind-powered turbines would help to reduce carbon emissions from this sector. Nonetheless, because of their relatively high cost, renewables remain a small share of existing electricity markets (McVeigh et al. 2000). Non-hydroelectric renewables account for only 2% of total electricity generation in the United States.[1]

The prospects for renewables depend in part on the future course of electricity market deregulation or restructuring. On the one hand, the move toward more competitive electricity markets has brought with it the demise of many regulatory programs that traditionally have supported use of renewables. On the other hand, the move toward competitive retail markets makes it possible for renewable generators to differentiate their product and appeal directly to consumers who prefer “green” power and are willing to pay a higher price for it. If this market turns out to be sufficiently large, it could help to get more renewable generation into the generation mix, which, in

[1] According to data from the Energy Information Administration (U.S. EIA 2003a), in 2000, roughly 8% of all electricity produced in Japan came from hydroelectric facilities and nearly 2% came from non-hydro renewables. Fossil fuel generators were the largest source, responsible for close to 61% of all electricity production; the remaining 29 percent came from nuclear generation.

turn, could help to bring down the costs of supplying renewable energy in the future. However, most observers would agree that supply-side incentive programs are likely to have a more significant effect than consumer preferences on the demand side. Consequently, supply-side incentives are the focus of this study.

In theory, one way to motivate a shift away from fossil fuels toward renewables would be to tax or cap carbon emissions from electricity generators. However, policymakers have not embraced carbon taxes as a means of controlling carbon emissions, and they are unlikely to be adopted in the United States. Moreover, research suggests that carbon taxes need to be quite high before renewables penetration starts to grow in any substantial way.[2] Even if a national carbon tax were to be adopted in the United States, it is likely to start out small and increase in size over time. Similarly, aggregate emission caps coupled with emission trading are likely to start with modest reductions. The "slow, stop, reverse" approach to carbon mitigation has become a central tenet of the U.S. policy debate. Modest emission reduction targets in the near term are expected to be met with modest substitution away from coal to expanded use of natural gas, with very small incentives for greater renewables use in the short run. This go slow approach, which has much to recommend it given the uncertainties surrounding the costs and benefits of reducing greenhouse gas emissions, nevertheless limits the possibilities for learning by doing in the near term. Political preference for the go slow approach suggests that a policy aimed directly at increasing renewables may be necessary to realize any gains from learning and to achieve substantial contributions from renewables, which will be necessary to achieve more substantial emission reduction goals in the long term.

Several approaches are currently being used or considered to promote the use of renewables for electricity generation in the United States. A number of states—including Connecticut, Maine, Nevada, Massachusetts, New Jersey, and Pennsylvania—have adopted a requirement, known as a renewables portfolio standard (RPS), that a minimum percentage of the electricity produced or sold in the state must come from renewable sources, typically excluding hydroelectric facilities. A number of bills

[2] See D. Burtraw, K. Palmer, R. Bharvirkar, and A. Paul "The Effect of Allowance Allocation on the Cost of Carbon Emissions Trading," Washington, DC: Resources for the Future, Discussion Paper 01-30 (August 2001).

proposing national renewables portfolio standards ranging from 5% to 20% by different deadlines—ranging from 2010 to 2020—have been before the U.S. Congress in recent years, but none has been passed into law. Some states, such as California, have adopted another approach known as a surcharge-funded production subsidy. Under this approach, consumers pay a surcharge on all electricity purchases, and the revenue from the surcharge is distributed to renewable generators on a per-kilowatt-hour basis for each unit of electricity produced. The recipients of these payments and the level of the payments are determined in a periodic auction where the winners are those who bid the smallest increment of subsidy required per kilowatt-hour (kWh). Tax credits for certain types of renewables are another approach that has been popular at the federal and state levels.

This research analyzes the effects of government policies designed to increase the contribution of renewables to total U.S. electricity supply on electricity generators and consumers, and on carbon emissions from the electricity sector. We focus primarily on an RPS used to achieve different shares of renewables generation and compare that policy to a Renewable Energy Production Credit (REPC), which uses tax credits to encourage generation with renewables.

We also contrast an RPS to a carbon cap-and-trade policy that uses an updating approach to allocate carbon emission allowances in order to encourage generation by low- and non-emitting technologies. We consider the effects of these policies on costs, utility investment decisions, the mix of technologies and fuels used to generate electricity, and on renewable generation by region. We also analyze the effects of these policies on electricity prices and on carbon emissions from electricity generators. Lastly, we look at the effects of different technological assumptions, the role of learning, and the role of fuel price assumptions on the effects of the RPS policy.

We find that the RPS policy is more cost-effective than the REPC, both as a means of increasing renewables and of reducing carbon emissions. The cost of the RPS is relatively low at levels up to 15% and then rises dramatically between 15% and 20%. Both the RPS and the REPC policies tend to encourage renewables largely at the expense of natural gas, and thus are less effective at reducing carbon emissions. A climate policy is the most cost-effective at reducing carbon emissions, although this finding depends importantly on how the carbon emission allowances are allocated.

Chapter 2. Review of Policies to Promote Renewables

Worldwide, within the collection of OECD countries and within the United States, non-hydro renewables account for about 2% of total electricity generation. However, most developed countries are hoping to increase renewable generation dramatically over the next 30 years, and a number of countries have implemented policies to help them to achieve these goals.[3] In this chapter we summarize some of these policies, focusing on those targeted directly at increasing electricity supply from renewable generators (as opposed to targeting research and development).

Renewables Policies in the United States

In the United States, policies to promote the use of renewable technologies to generate electricity by commercial electricity suppliers (as opposed to firms generating electricity primarily for their own consumption) can be divided primarily into federal and state level programs. At the federal level, the main policy employed has been a production tax credit. At the state level there is a wider range of policies, but we focus here on renewable generation requirements and subsidies to renewable generation.

Federal Tax Programs. In 1992, the U.S. Congress passed the Energy Policy Act. This law authorized a renewables production tax credit (known as the Renewable Energy Production Credit, or REPC) of 1.5 cents per kWh of electricity produced from wind and dedicated closed-loop biomass generators.[4] The REPC production incentive applied to new generators that came on-line after the Act took effect for the first 10 years of their operation. The original production incentive expired at the end of 2001, but was then

[3] For an overview of the status of renewable generation, with a particular focus on wind and a review of some of the policies being implemented to promote renewables around the world, see Darmstadter (2003).

[4] A closed-loop biomass system involves a source of biomass fuel dedicated to energy production. A dedicated biomass facility is one that burns biomass only. In contrast, an open-loop biomass system could use biomass waste from other economic activities either at a dedicated biomass facility or at a facility that also uses fossil fuel.

extended in March of 2002 as a part of the Job Creation and Worker Assistance Act of 2002. It was also indexed to inflation at that time and was set at 1.7 cents in 2003 when it lapsed. The credit has not been extended as of this writing.[5] Many legislators are interested in renewing this policy, but prospects for its renewal remain uncertain. In addition to this production incentive, the Energy Policy Act also authorized a tax credit for investment in geothermal and solar generators equal to 10% of the capital cost of the generating facility. This tax credit has no expiration date.

Renewables Portfolio Standards. Since the mid 1990s, 15 states in the United States have imposed renewables generation requirements on electricity retailers or generators within their borders.[6] Typically referred to as a renewables portfolio standard, or RPS, these requirements set a minimum level or percentage of electricity sales that must come from renewable generation by a particular date. Generally these programs set a number of increasingly stringent requirements over the course of several years into the future. The stringency of the standards and the types of renewables covered by the requirement differ from state to state. Most states, with the notable exception of Maine, exclude traditional hydro facilities.[7] Some states have separate minimum requirements for the various renewable technologies in an effort to specifically target increased penetration of preferred classes of renewables and, at the same time, provide some incentive for increased use of other types.

[5]For more information about this policy, see http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=US13F&Search=TableType&type=Corporate&CurrentPageID=7 (accessed January 16, 2004). In 1995, a renewable energy production credit was established for generation by new renewables owned by publicly owned electricity generators. This incentive payment is contingent on sufficient funds being available to make the payment and has not been fully funded for several years. This incentive expired in September of 2003. For more information, see http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=US33F&Search=TableType&type=Production&CurrentPageID=7 (accessed January 16, 2004).

[6] For more details on state RPS policies, see the Union of Concerned Scientists website at www.ucsusa.org/publication.cfm?publicationID=68. Since this site was last accessed, the State of Maryland adopted a policy promoting renewables.

[7] Maine actually includes small-scale combined heat and power facilities in its RPS as well. In the case of Maine, the RPS was not set much higher than the current level of renewables generation, so it didn't prove to be very constraining on generators' behavior.

In several states, including Connecticut, Nevada, New Jersey, New Mexico, Texas, and Wisconsin, the implementing law or regulation also allows for trading of renewable energy credits or certificates to meet this requirement.[8] Typically, renewable energy certificates are created whenever an eligible renewable facility generates a kilowatt-hour of electricity. These certificates can then be sold either bundled with the electricity or separately. Thus, an electricity retailer can meet its renewables obligation by generating renewable energy itself and keeping the associated credits, purchasing renewable energy bundled with credits from others or by purchasing renewable energy credits sold separately. In New Mexico and Nevada, solar generators receive more than one credit per kWh produced, providing them with an additional incentive above other renewables.

All of the existing RPS programs in the United States are fairly young, and other programs are still in the planning stages, so there has been little formal evaluation of program performance to date. The Texas RPS program completed its first year of compliance requirements at the end of 2002. This program allows banking of renewable energy credits for up to two years and limited borrowing from the future as well. The program imposes a penalty of 5 cents per kWh or 200% of the mean certificate price for noncompliance.

The Texas program has a strong credit tracking system that is expected to provide credibility to the market. An evaluation of the program finds that as of early 2002, newly installed renewables capacity was well in excess of the 2003 goal. This observation suggests that banking was likely taking place and providing an incentive for expanded investment in the near term, which could have a positive influence on learning and the future path of production costs for the entire industry. Renewable energy credits were trading for a price of about 0.5 cents per kWh in a market where the average retail price of electricity is about 6 cents per kWh. The study also finds,

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[8] Renewable energy certificates are also referred to as Green Tags, a name often used by environmental organizations seeking public support for renewables through sales of green tags, whose revenues are used to subsidize renewables generation, typically using wind power or solar power. (See www.greentagsusa.org, accessed March 19, 2004.) There are active private markets in green tags and renewable energy certificates. (See www.mainstayenergy.com, accessed March 19, 2004.) The liquidity of these markets can suffer from a lack of uniformity in definition of this commodity across different suppliers and demanders in the market.

however, that renewables credits generally trade with renewable energy, and thus trading volume for credits separate from renewable energy has so far been limited (Langniss and Wiser 2003).

Surcharge-Funded Production Incentives. An alternative approach that substitutes a price-based policy for the minimum quantity requirement of the RPS is a subsidy or production incentive for renewable generation. This approach, which has been used in California, raises revenue through a surcharge on all electricity consumption that cannot be bypassed, typically referred to in the United States as a public benefits fee or charge. The revenue from the surcharge is distributed to producers of renewable energy in periodic auctions that allow producers to bid for per-kilowatt-hour subsidies. Winning bidders receive the amount of the subsidy they bid into the auction for every kWh of electricity generated using a qualifying renewable technology. Similar bidding programs for renewables subsidies have been used in New York and Pennsylvania (Wiser et al. 2003).

Surcharge-funded production incentives have had somewhat limited success in bringing new renewables on-line; only one-third of the new capacity awarded contracts through this type of bidding process have actually started operating, and several projects that won in a competition are not expected to be completed. Wiser et al. suggest that one reason for this is project developers face a sort of chicken-and-egg problem. Developers often bid on a subsidy before obtaining the long-term power purchase agreement that will ultimately be necessary to get project financing and that will determine the price they get per kWh in the marketplace. This price in turn determines how much of a subsidy they ultimately need to cover their costs. With no penalty for failing to perform on the contract, developers often bid low in the subsidy auction in order to win, only to discover later that they cannot make money with such a small subsidy. Given the limited success of the subsidy auction, California decided to supplement this policy with an RPS, which was adopted in 2002.

Other Programs. In addition, there are a myriad of other programs to promote both research and development into renewables and actual use of renewables to generate electricity. A number of states require electricity suppliers within their boundaries to offer net metering to small renewable generators. Under net metering, a customer who generates electricity for his or her own use can sell any excess electricity back to the electricity supplier at the retail price, essentially running the meter backwards. Many states have special programs to fund R&D into renewables and the U.S. Department of Energy also has a substantial R&D budget devoted to the development of renewables technologies.

Renewables Policies in the European Union

Renewables mandates are also becoming more popular in Europe. The European Union issued a Renewables Directive in October of 2001 that requires member states to adopt national targets for renewables consistent with reaching the overall EU target that 12% of total energy and 22% of all electricity come from renewables by 2010. For the United Kingdom, the directive requires that 10% of total electricity consumption be generated using renewables by 2010.[9] The United Kingdom has decided to implement a tradable credit scheme to help in achieving this goal, moving away from a subsidy scheme that had been used earlier. In the European Union, renewables credits are referred to as certificates. Under this program, retailers must purchase renewables certificates to show compliance with their obligation; retailers must pay a penalty of 30 pounds per MWh for any shortfall. Other European countries, including the Netherlands, Belgium, and Italy, are in the process of implementing tradable credit schemes (Energy for Sustainable Development 2001, The Center for Resource Solutions 2001). The European Union is also studying the feasibility and costs and benefits of implementing a community-wide trading program for renewables certificates (ESD 2001, Quené 2002). Australia also has adopted new renewable generation targets for wholesale electricity suppliers and an associated tradable renewable energy credit program beginning in 2001.[10]

In addition to implementing a quantity-based approach, several countries in Europe and elsewhere also have used a price guarantee, often referred to as a feed-in tariff, to promote the use of renewables. Feed-in tariffs have been used in Germany,

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[9] Different targets are set for different member states based on current renewable generation and potential resources available locally.

[10] For more information, see www.orer.gov.au (accessed February 21, 2003).

France (for wind power only), Finland, and Denmark, among other places.[11] Germany's initial feed-in tariff law was in effect from 1990 until 2000.[12] Under this law, utilities were required to purchase renewable energy from independent power producers at an administratively determined price in excess of the wholesale market price of electricity. The price varied depending on the type of renewable energy, with wind and solar power receiving the highest payment and landfill gas and hydro facilities receiving the lowest payment. The total amount of the tariff payment each year was based on utility average revenues, so the payments would fluctuate by year.

The feed-in tariff approach has been successful in promoting wind energy. In 2000 a new feed-in tariff law took effect to help Germany achieve its goal of doubling renewables share from 6% to 12% by 2010. Under the new law, grid operators instead of utilities pay the feed-in tariffs and the level of the payment depends on renewable type. The size of the tariffs diminishes over time.

The third major approach to promoting renewables used in Europe is the competitive tender offer or bidding system. This approach typically takes the form of a solicitation by a governmental energy agency, regulator, or regulated utility (under regulatory or legal requirement) for bids to supply renewable energy of particular types for many years (typically 15 or 20) into the future. Bids often take the form of the minimum price of electricity (per kWh) that a renewable supplier needs to supply electricity. This approach has been used in other places, including France and Ireland.

Renewables Policies in Japan

In Japan renewables use for electricity generation is covered by broader-based policies that have been adopted to promote a large category of underdeveloped energy resources, known as New Energy, throughout the economy. New Energy sources include most renewables, natural-gas-fired cogeneration, and fuel cells, but exclude hydro and geothermal. Currently, Japan has a target of achieving 3.1% of total primary

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[11] Denmark had planned to replace the feed-in tariff system with a tradable credit approach in January of 2003, but that change has been postponed indefinitely due to concerns among renewable generators about the effectiveness of the green certificate market in promoting renewables.

[12] For more information, see http://www.renewable-energy-policy.info/relec/germany/policy/feed-in.html, accessed February 23, 2004.

energy supply (not just electricity) from New Energy sources by 2010. According to the International Energy Agency, there are also targets for increased market penetration of specific renewable technologies in 2010, including a 20-fold increase in wind capacity, a 14-fold increase in photovoltaic capacity, and a five-fold increase in biomass capacity.[13]

In 2002, Japan adopted the Special Measures Law Concerning the Use of New Energy by Electric Utilities. This law includes annual renewable penetration targets for electricity generators for the years between 2003 and 2010 and has a long-term goal of 1.35% of total electricity generation by 2010. The types of energy covered by this policy include solar, wind, biomass, small hydro, and geothermal.

The Japanese RPS policy is similar to those used in the United States and elsewhere. Electricity retailers are responsible for meeting the RPS, which will ramp up over time. Renewables suppliers must be certified by the Ministry of Economy, Trade and Industry. Certified renewables producers receive credits for "Applicable Amounts of New Energy Electricity" that they can sell bundled with electricity-to-electricity retailers or trade separately on the renewables credit market. Renewables credits are bankable for up to one year and retailers are free to borrow up to 20% of their obligation in a current year from the subsequent year. Retailers who fail to comply with the renewables requirements will face penalties. However, there is a price cap of 11 yen per kWh on the price of renewables credits and retailers who cannot purchase credits for that price are exempt from fines (Keiko 2003).

Japan also has a national program to subsidize increased use of renewables by local governments and by small business, and a substantial program to support research and development into renewable technologies.

[13] See http://library.iea.org/dbtw-wpd/pamsdbre.aspx?id=90,accessed February 18, 2004.

Chapter 3. Prior Studies of Renewables Portfolio Standards

The national policy debate over imposing a federal RPS in the United States began in the late 1990s and has continued throughout the early part of this decade. To help inform that debate, at various points in time the U.S. Energy Information Administration (EIA) has conducted several simulation studies of how the electricity sector would respond to the imposition of an RPS. Most of these studies look at specific RPS targets between 7.5% and 20%, with some differences across the studies in the design features of the policy and how the targets were phased in over time. Typically these studies find a small effect on both electricity price and carbon emissions from the electricity sector; however, for stricter targets, the effects on both electricity price and emissions tend to be higher.

EIA did its first analysis of the RPS as a sensitivity case accompanying its *Annual Energy Outlook (AEO) 2000* 20-year forecast (EIA 1999). In that analysis, EIA looked at the effects of a 7.5% minimum renewables generation requirement by the year 2010 proposed by the Clinton administration as part of its national electricity deregulation plan.[14] The analysis considered three cases: (1) the phased-in 7.5% RPS coupled with a 1.5 cents per kWh cap on the price of renewables credits and a provision to sunset the RPS requirement by the end of 2015, (2) a 7.5% RPS scenario without sunsetting but with the credit price cap and (3) a 7.5% RPS scenario with no sunset and no credit price cap. The analysis focused on 2010 and found that the price cap of 1.5 cents would cut the effectiveness of the RPS minimum roughly in half, yielding only a 4.2% penetration of renewables in 2010, and that adding the sunsetting reduced penetration in 2010 to about 3.4%.

With no price cap on renewables credits, the price of electricity is 1.4% above the baseline result for 2010 in order to achieve the 7.5% RPS, while the price of natural gas delivered to electricity generators is nearly 6% below the baseline. The lower gas price also has implications for industrial use of gas as well as home heating. This analysis

[14] EIA (1999) looks at the effect of the RPS separately from the effects of any further deregulation of the electricity sector.

suggested that the 1.5 cents per kWh credit price was substantially too low to achieve the desired level of renewables penetration by 2010.

Several subsequent RPS policy analyses by EIA focus on policies that target a specific level of renewables penetration by 2020. The main policy assumptions and some of the results of these subsequent EIA studies are summarized in Table 1. It is important to note that these studies are not directly comparable because of differing assumptions across the different *AEO* baselines regarding:

- costs and performance characteristics of renewables and other generating technologies and how they are likely to change over time,
- underlying forecasts of input fuel prices, including natural gas prices,
- the role of state-level renewables programs, and
- the pace and nature of electricity restructuring.

Table 1. Comparison of EIA RPS Studies with a 20-year Horizon

	EIA RPS Studies				
	EIA 2001	*EIA 2001*	*EIA 2002*	*EIA 2002*	*EIA 2003‡*
Characteristics of Policy					
RPS Standard in 2020	10%	20%	10%	20%	10%
RPS Credit Price Cap	None	None	3 Cents	3 Cents	1.5 Cents (nominal)
RPS Sunset Date	None	None	12/31/20	12/31/20	12/31/30
Qualifying renewables	All renewables		Only new renewables		
Basis for RPS	All generation		Total electricity sales minus generation by renewables and by small generators		
Results					
Renewables Penetration (in model)	8.2%	16.7%	8.4%	11.7%	6.1%
RPS Credit Price in 2020	2.5 cents#	5.0 cents#	3 cents*	3 cents*	.96 cents+
Electricity Price Impact	+ <0.1%	+ 4.2%	+ 1.5%	+ 3.0%	0
Natural Gas Price Impact	-8.4%	-17.7%	-3.7%	-6.7%	-0.3%
Carbon Emissions Impact (electricity only)	-7.2%	-17.6%	-6.7%	-7.3%	-2.8%

Price in 1999 $.
* Price in 2000 $.
+ Price in 2001 $.
‡ Renewable energy production credit extended through 2006 and applied to more technologies.

Despite their important differences, we compare these studies to gain some insights into what past studies have shown and to highlight some of the scenario characteristics that may have contributed importantly to these findings.

In its 2001 study of multipollutant policies and the RPS, EIA (2001) looked at the effects of imposing two RPS requirements: a 10% minimum renewables requirement phased in by 2020 and a 20% minimum renewables requirement phased in by 2020. In both cases, the RPS was implemented through a tradable credit system and credits were awarded to all non-hydro renewable generators, including cogenerators and non-grid-connected renewables for each kWh of electricity generated. Because non-grid-connected renewables are allowed to earn credits, the renewables percentages within the commercial electricity sector are slightly below the required levels.

The studies showed that a 10% RPS (resulting in 8.2% renewables penetration in the commercial electricity market) leads to a negligible increase in electricity price in the year 2020, but results in an 8.4% decline in the wellhead price of natural gas (relative to the baseline). RPS credits would trade at a price of 2.5 cents per kWh in 2020. The 10% RPS brings about a 7.2% decline in carbon emissions from the electricity sector, but only a 2.7% reduction in carbon emissions economy-wide in 2020. This result occurs because over 40% of carbon emissions are the result of burning petroleum outside the electricity sector and this activity is not affected by the RPS, except indirectly through the reduction in natural gas price that would lead to increased carbon emissions outside the electricity sector.

With a 20% RPS, renewables penetration in the commercial electricity sector is about 16.9%. Renewables credits trade at a price of 5 cents per kWh and the price of electricity is 4.2% higher than in the base case in 2020. This policy scenario leads to a dramatic drop in gas prices, with prices 17.7% below the baseline forecast for 2020. Carbon emissions from electricity generators fall by 17.6% relative to the baseline and total carbon emissions are 6.6% lower.

The EIA (2002) study, also summarized in Table 1, focuses on a specific legislative proposal for a 10% RPS by 2020, and the analysis also considers a 20% RPS by 2020.[15] The specific proposal analyzed includes an effective price cap on renewables credits of 3 cents per kWh and the analysis assumes that this price cap is set in real terms (and thus allowed to grow in nominal terms at the rate of inflation). In addition, the RPS requirement ends on December 31, 2020. Also, only new renewables that come on-line after the bill is passed are eligible to earn credits; existing renewables do not earn credits.

Due to a combination of the price cap for RPS credits, the sunsetting provision, and the adjustments to the baseline to which the RPS is applied, the actual percentage of total non-hydro renewables achieved in 2020 under the 10% RPS was 8.4%. This produced a modest 1.5% increase in electricity price and a 3.7% drop in natural gas prices. The present discounted value of total resource costs to the industry over the 2002–2020 horizon are about 1% greater with the 10% RPS than in the baseline. Carbon emissions from the electricity sector are predicted to be 6.7% lower than the baseline in 2020.[16] Under a 20% RPS with the 3-cent cap on the credit price, renewables penetration in 2020 reaches 11.7%. Despite the price cap, renewables penetration is higher in 2020 under this policy than under the 10% RPS because the tighter targets in the earlier years make renewables credits more valuable during the years before the price is bid up to the cap. Electricity price in 2020 is 3% above the baseline level. The present discounted value of total resource costs to the electricity sector is also 3% above the baseline level. Natural gas prices in 2020 are 6.7% lower than in the baseline and carbon emissions from electricity producers are 7.3% below baseline levels.

The last of the three EIA studies featured in Table 1, EIA (2003b), focuses on a 10% RPS with a 1.5 cent nominal price cap on renewables credits.[17] This policy also continues the renewable energy production credit of roughly 1.8 cents per kWh for new dedicated closed-loop biomass and wind generation brought on-line through 2006,

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[15] This analysis makes use of the AEO 2002 reference case as the base case. In that base case, EIA includes renewables that are expected to come on-line as a result of previously adopted state-level renewables policies. EIA also considers an alternative baseline and RPS scenario in which the pace of technological improvement for renewables exceeds that assumed in the reference case.

[16] Carbon emissions impacts for the entire economy are not reported.

[17] EIA also looked at the effects of indexing the cap on the RPS credit price to inflation and of eliminating state-level RPS programs and found very small effects of both on both renewables penetration and on prices.

providing an added boost to renewables that come on-line during the early years of the forecast period. The 1.5-cent price cap on RPS credits, which falls over time in real terms, leads to a 6.1% penetration for renewables in 2020. Most of the increase in renewables generation comes from wind and biomass cofiring with a very small increase in landfill gas.[18] Dedicated closed-loop biomass and geothermal generation do not increase in response to the RPS. The effect on electricity price is negligible and natural gas prices fall slightly. Carbon emissions are 2.8% lower in 2020 as a result of the policy.

A handful of other studies have looked at the effect of different RPS proposals using similar large-scale simulation models. Palmer et al. (2002) consider a 3% RPS effective in 2008 with a 1.7-cent real cap on the price of renewables credits. They find that the price cap limits renewables penetration to just over 2% of total generation and the impact of the policy on electricity price is negligible. The increased renewables tended to displace both coal and natural gas generation. Carbon emissions fall by just over 1% as a result of this modest increase in renewables.

In an earlier report, Bernow et al. (1997) study a 4% RPS phased in by 2010. They model this policy by incorporating a negative price "adder" into the utility dispatch and planning model and then increment that adder until the model solution yields the desired level of renewables. They find that average electricity price in 2010 increases by close to 0.5% and most of the new generation comes from wind and geothermal, which tends to displace coal. This study also focuses on the regional effects of the RPS policy, and it shows that 25% of the new renewable generation under the policy is found in California and Southern Nevada and in the Pacific Northwest. Substantial amounts of new renewables are also added in Texas, New England, the Rocky Mountain region, and the Mid-Atlantic.

Lastly, the Union of Concerned Scientists (Clemmer et al. 1999) looked at a number of different RPS proposals ranging from a 4% requirement in 2010 to a 20% requirement by 2020. Using somewhat more aggressive assumptions about the pace of technological improvement, Clemmer et al. find that the 20% RPS case results in

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[18] SO_2 allowance prices are substantially lower relative to the reference case due to increased cofiring at coal plants.

electricity prices that are 6.1% higher in 2020 than in the base case, but it produces the lowest natural gas prices of all the cases analyzed.

RPS policies have also been analyzed using a welfare-theoretic model. Fischer and Newell (2004) use a simple partial equilibrium model of electricity markets, which includes choice between two electricity-generating technologies and endogenous decisions about R&D investment by electricity generators, to compare several different policies to promote renewables. The policies they analyze include carbon taxes, renewable generation subsidies, fossil fuel taxes, a tradable RPS, a tradable emissions intensity standard, and subsidies for R&D investment in renewable technologies. They develop a theoretical model that involves two types of electricity generators (fossil and renewables) and they use that model to assess the types of incentives created by the different policies for reducing emissions intensity, conserving electricity, increasing renewable energy use, and increasing R&D. To analyze the effects of the different policies on economic welfare when all are set to achieve the same amount of carbon emissions reduction (5.8% below baseline emission levels from electricity producers), they select specific functional forms for the production function and parameterize the model using data from the Energy Information Administration and other sources.

Using their stylized model, Fischer and Newell find that using an RPS set to achieve a 5.8% reduction in carbon emissions is 7.5 times as costly in terms of social welfare as using an emissions tax to achieve the same amount of emissions reduction.[19] However, it costs 40% less than a direct government subsidy on renewables production targeted to achieve the same level of emission reductions.[20] Their central case allows for learning by doing. Not allowing for learning by doing increases the cost disadvantage of the RPS compared to an emission tax by about 5%, and allowing for more effective learning lowers the cost disadvantage of the RPS relative to the emission tax by just under 19%.

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[19] The 5.8% reduction in carbon emissions is what results when a tax of $25 per metric ton of carbon is imposed.

[20] The renewables subsidy modeled by Fischer and Newell (2004) is funded by general government revenues and not by a surcharge on electricity sales (like the policies in place in California and some other states). The surcharge on electricity sales would have the effect of raising the electricity price, thereby capturing emission reductions through reduction in total generation.

The role of learning by doing has become an important justification for policies to promote renewable technologies. In his seminal paper on the topic, Kenneth Arrow (1962) shows that if the productivity of capital is increasing the level of cumulative investment because of learning, then individual firms will underinvest in capital because they do not internalize the larger social gains from learning. From the cost perspective, the theory of learning by doing suggests that technology costs will fall as experience with a technology grows. Learning functions typically express the cost of a technology as a constant elasticity function of the amount of accumulated capacity (Loschel 2002), where the elasticity is often referred to as the learning index. Most renewable technologies, with the possible exception of wind power, are relatively immature and thus the potential for learning with greater market penetration is relatively high. Empirical studies of learning curves for energy technologies suggest that there is a large variation in the rate of learning across different energy technologies (McDonald and Schrattenholzer 2001, IEA 2000) with more mature technologies having substantially lower learning rates than newer technologies. The inappropriability of the gains from learning means that there may be a market failure at work that justifies policies to promote renewables, in addition to the usual environmental justification.

Chapter 4. Model Description

The study we conduct makes some important contributions to the existing literature. This is the first study to compare several different RPS policies in a common framework using common underlying assumptions. This study is also one of the first to analyze the effects of extending the recently lapsed REPC into the future and the first to compare this approach to an RPS.[21] This study also looks at a more general REPC that subsidizes all the renewables technologies that are covered by the RPS in a manner designed to achieve the same quantity of renewables generation as a 15% RPS. Unlike prior studies, this study measures the economic surplus effects of different policies. We also look at the effects of different national policies on regions. Lastly, we contrast the RPS policy to a carbon cap-and-trade program that uses carbon allowance allocation as a method of encouraging the use of low-emitting and non-carbon-emitting generating technologies to see how the two compare in terms of promoting renewables use and other measures.

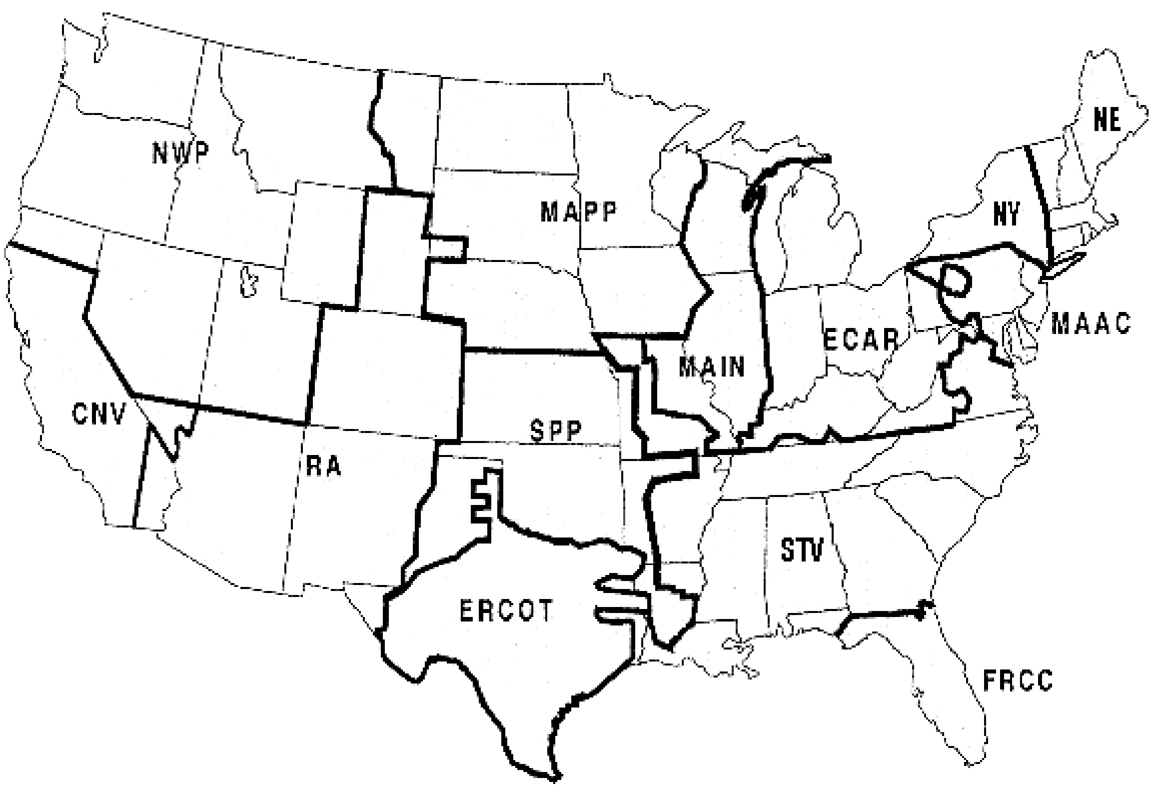
The framework for conducting this study is the Haiku electricity market model. The model simulates equilibrium in regional electricity markets in the United States and inter-regional electricity trade with an integrated algorithm for SO_2, NO_x, and mercury emissions control technology choice.[22] The model calculates electricity demand,

[21] In the most recent *Annual Energy Outlook*, the U.S. EIA (2004a) presents a policy analysis that considers three different approaches to extending the REPC. In one variation, they extend the existing credit through 2006 and expand it to include open-loop biomass and landfill gas generation. In a second variation, they expand the coverage of the credit similarly and extend it through the end of 2012. In a third variation, they cut the value of the tax credit in half and extend it through 2012. They find that all of the policies have their biggest effect on wind generation, followed by dedicated biomass, with much smaller impacts on municipal solid waste and landfill gas and on biomass cofiring. Wind generation in 2010 is more than twice as large as the reference case with the three-year extension of the REPC and over five times as large with the nine-year extension. The effect on dedicated biomass is larger during the later part of the forecast period, with a four-fold increase under the nine-year REPC extension. The policies all lead to higher electricity generation in 2010 (implying lower prices, although effects on electricity prices are not reported).

[22] Haiku was developed by RFF and has been used for a number of reports and articles that appear in the peer-reviewed literature. The model has been compared with other simulation models as part of two series of meetings of Stanford University's Energy Modeling Forum (Energy Modeling Forum 1998, 2001).

electricity prices, composition of electricity supply, inter-regional electricity trading activity, and emissions of key pollutants such as NO_x, SO_2, CO_2, and mercury from electricity generation. The model solves for the quantity and price of electricity delivered in 13 regions, for four time periods (super-peak, peak, shoulder, and baseload hours) in each of three seasons (summer, winter, and spring/fall). The 13 regions are illustrated in Figure 1. For each of these 156 segments of the electricity market, demand is aggregated from three customer classes: residential, industrial, and commercial. Supply is aggregated from the complete set of electricity plants in the United States, which for modeling purposes are aggregated into 48 representative plants in each region. Investment in new generation capacity and retirement of existing facilities are determined endogenously in a dynamic framework, based on capacity-related costs of providing service in the future. Generator dispatch in the model is based on the minimization of short-run variable costs of generation. All costs and prices are expressed in 1999 real dollars.

Figure 1. Haiku Model Regions



Inter-regional power trading is identified as the level of trading necessary to equilibrate regional electricity prices (accounting for transmission costs and power losses). These inter-regional transactions are constrained by the assumed level of available inter-regional transmission capability as reported by the North American Electric Reliability Council (NERC). Factor prices, such as the cost of capital and labor, are held constant. Fuel price forecasts are calibrated to match U.S. Energy Information Administration price forecasts from the *Annual Energy Outlook 2003* (U.S. EIA 2002a), although they are varied in sensitivity analysis. Fuel market modules for coal and natural gas calculate prices that are responsive to factor demand. Coal is differentiated along several dimensions, including fuel quality and location of supply, and both coal and natural gas prices are differentiated by point of delivery. All other fossil fuel prices are specified exogenously.

For control of SO_2, coal-fired plants are distinguished by the presence or absence of flue gas desulfurization, also called scrubbers. Unscrubbed coal plants have the option to add a retrofit SO_2 scrubber, and all plants select from a series of coal types that vary by sulfur content and price as a strategy to reduce SO_2 emissions. The model accounts for ancillary reductions in mercury associated with other post-combustion controls, including decisions to install retrofit SO_2 scrubbers and NO_x controls, and the model includes activated carbon injection (ACI) as another means of reducing mercury emissions. For control of NO_x, coal-, oil- and gas-fired steam plants solve for the least costly post-combustion investment from the options of selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR), and also reburn for coal-fired plants. The variable costs of emission controls plus the opportunity cost of emission allowances under cap-and-trade programs are added to the variable cost of generation when establishing the operation of different types of generation capacity.

The model allows new additions of four types of renewable generators: wind turbines, biomass gasification combined cycle, geothermal, and landfill gas.[23] Resource availability at particular cost levels is specified for each of the 13 regions in the model. Geothermal resources are limited to the southwestern section of the continental United States. The generating potential of the wind resource varies substantially across regions,

[23] Solar generators are currently excluded because of their high costs.

largely as a function of wind speed. The cost of tapping that wind resource to generate electricity also varies greatly due to factors such as wind speed, alternative land uses, difficulty in accessing and developing certain types of terrain, and distance to the transmission grid. Biomass generation depends importantly on the nature of the biomass fuel supply curve within a particular region. Landfill gas resources depend on methane yield from different classes of landfills and associated costs. Information for resource availability and other technical characteristics is taken from a variety of sources, but primarily from EIA.

Throughout this analysis, we make several assumptions about underlying policies, both environmental and market regulatory policies that affect the performance of electricity generators. On the environmental side, we assume that electricity generators face an annual cap on SO_2 emissions as a result of Title IV of the 1990 Clean Air Act Amendments and that there is a seasonal cap on NO_x emissions in all of the regions that include states covered by the EPA NO_x SIP Call.[24] We assume electricity generators face no requirements to reduce mercury emissions or emissions of CO_2. We include all announced New Source Review (NSR) settlements in our technical assumptions about emissions control at existing generators.[25] We do not include state-level multipollutant policies such as those passed in New York and North Carolina.[26]

In our central case, we assume that the recently lapsed renewable energy production credit (for dedicated biomass and wind generation) is extended through 2005 and is then phased out between 2005 and 2010.[27] We also include a perpetual 10%

[24] Due to the availability of the emission allowance bank built up between 1995 and 2000, actual emissions of SO_2 exceed the level of the cap until 2012. We model this drawdown of the bank exogenously using information from U.S. EPA and EIA.

[25] NSR settlements are those that electricity-generating companies have reached with the federal government to bring their plants into compliance with New Source Review requirements for emission reductions that the government claims were violated by past investments at specific facilities.

[26] Several states have passed or are considering laws limiting emissions of some combination of NO_x, SO_2, mercury, and CO_2 from electricity generators. Most of these laws or proposals, such as new regulations in Connecticut and Massachusetts that limit non-ozone season emissions of NO_x, are formulated as limits on emission rates. The largest state actions are in North Carolina and New York, which have recently placed emissions caps on their largest coal-fired plants. A similar plan has been adopted in New Hampshire for all existing fossil fuel generators.

[27] In practice, facilities that qualify receive the credit for 10 years. In our model, they receive the credit indefinitely, but only as long as the credit is active.

tax credit for investment in new geothermal resources, but we do not include any state-level RPS policies.

On the regulatory side, we assume that electricity prices are set competitively in six NERC regions—New York, New England, Mid-Atlantic (MAAC), Illinois area (MAIN), the Ohio Valley (ECAR), and Texas (ERCOT)—and that there is time-of-day pricing of electricity for industrial customers in these regions. In all other regions of the country, we assume that prices are set according to cost-of-service regulation at average cost. We simulate the model through 2020 and extrapolate our results out to 2030 for purposes of calculating returns to investment choices. We report results for the year 2020.

Chapter 5. Scenarios and Sensitivity Analysis

We focus on three types of policies to promote renewables: (1) a series of increasingly stringent renewables portfolio standards, (2) a production incentive (tax credit) for renewables, and (3) a carbon cap-and-trade program that uses an updating approach to allocation of emission allowances to reward generation from relatively clean technologies. The tax credit policy represents an extension of the recently expired national policy in the United States. That policy is likely to be extended by the Congress at some point, and there has been only limited study of the effects of doing so (U.S. EIA 2004a). This policy could be either a substitute for or a complement to an RPS, and an important question is how effective it is in promoting renewables.

Renewables Portfolio Standard Scenarios

We analyze a series of national renewables portfolio standards ranging from 5% to 20%. These standards are phased in between 2005 and 2020 as shown in Table 2. The renewable technologies covered by the standard include existing solar and municipal solid waste (MSW) generation and both new and existing dedicated biomass, biomass cofiring in coal-fired generators, geothermal, and wind.[28] For each kWh of electricity generated using one of these technologies, a renewable energy credit is created, and these credits are assumed to be tradable in a national-credit trading market. This means that there may be some geographic concentration of renewables generation in regions with greater access to abundant and low-cost renewable resources, and these regions may become exporters of renewables credits and, in some cases, depending on transmission constraints, of electricity as well. We look at the regional impacts of a national RPS.

[28] The model does not include any type of new solar generation, as the costs are so high that the model would never choose to construct a solar generator.

Table 2. Phase-in of Renewables Portfolio Standard Targets

	Minimum Renewables Requirement by Year			
RPS Target for 2020	2005	2010	2015	2020
5%	1.25%	2.5%	3.75%	5%
10%	2.5%	5.0%	7.5%	10%
15%	2.5%	6.5%	10.5%	15%
20%	2.5%	8%	14%	20%

The costs and other effects of the national RPS analysis are likely to depend on several underlying assumptions in the model. Important assumptions include the ability to cofire coal plants with biomass and whether or not those cofired kWhs are covered by the RPS program, the underlying price of natural gas, the importance of learning in determining future capital costs of all new technologies, and whether or not the RPS is coupled with a renewable energy production credit (see below). We include several sensitivities of the 15% RPS scenario measured against a relevant baseline to investigate how changing these assumptions affects the way the industry responds to a 15% RPS.

Renewable Energy Production Credit

We model two versions of a renewable energy production credit (REPC) policy. The first, REPC-E, represents an extension of a recently expired policy that grants a federal income tax credit of 1.7 cents (in real dollar terms) for every kWh of electricity generated using either wind or closed-loop biomass technology.[29] This production incentive amounts to an after-tax subsidy of 2.8 cents per kWh of electricity generated from these sources. This tax credit applies to generation from new wind and closed-loop biomass generators. When the production incentive is extended in the model, we assume it applies to all future generation across the entire forecast horizon.

[29] Note that recent proposals to extend the production tax credit move to expand the credit to include both open- and closed-loop biomass facilities and landfill gas generation (see U.S. EIA 2004b).

In addition to the recently expired REPC policy that targets only wind and closed-loop biomass, which we label REPC-E, we also model a more general production tax credit policy that we label REPC-G, and which is comparable to the RPS policies. Specifically, we identify the levels of a production tax credit applied to wind, all biomass, and geothermal—the three technologies eligible for renewables credits under an RPS—that provide an after-tax subsidy to renewables in each simulation year that is equivalent to that resulting from the phased-in 15% RPS policy. In the case of the RPS, the source of the subsidy is effectively a tax on fossil, hydro, and nuclear generation. In the case of the REPC-G, the source of the subsidy is federal tax dollars. Analyzing this scenario provides a means for directly comparing the effects of the two instruments, a tax credit and a tradable portfolio standard, set to achieve a common effective renewables subsidy.

Updating Allowance Allocation Based on Output

If a carbon tax or carbon cap-and-trade program is put into place, the program could be designed in such a way as to encourage the use of renewables and other low-emitting technologies.[30] One approach that is embodied in federal multipollutant legislation in the United States by Senator Carper (D-DE) is to allocate emission allowances on the basis of recent electricity generation to all generators, including renewables, regardless of whether they emit carbon or not. Under this approach, each generator's share of the total annual amount of allowances would depend on its share of output in a recent year. This approach essentially provides a subsidy for increasing output, and the subsidy is particularly effective for renewables since they don't need to surrender allowances to cover their emissions and thus can sell off their total allocation and keep the revenues.[31] This approach is analogous to a revenue-neutral pollution tax on NO_x that has been implemented in Sweden (Sterner and Hoglund 2000).

[30] Placing a tax on carbon emissions or imposing a carbon cap-and-trade program arguably will create an incentive to adopt renewables, which have no carbon emissions. The point here is to impose policies that go even further to create an advantage for using renewables.

[31] An important consideration in determining the effect of this implicit subsidy is the way in which prices are determined and the nature of regulation at the state level (Burtraw et al. 2001, 2002).

There are many different ways that such a policy could be implemented. Here, we consider two approaches:

- allocating carbon emission allowances to all generators, excluding existing hydro and nuclear facilities based on current year generation (an approach that is consistent with many proposals, including that of Senator Carper), and
- allocating carbon emission allowances to non-hydro renewable generators only based on current year generation.

To create some comparability across policies, we set the level of the carbon cap for these runs in each year equal to the total amount of emissions under a 15% RPS.

Chapter 6. Results

In the following chapters, the results of the simulations of the different policy cases are compared to a baseline scenario. The results of the central case baseline forecast for the year 2020 and three alternative baselines are summarized in Table 3.

In the central case baseline, total generation is expected to be 4.9 trillion kWh in 2020, with 50% from coal. Generation by non-hydro renewables is forecast to be 3.1% of total generation in the absence of an RPS, with the majority of that coming from geothermal. Natural gas accounts for roughly 93% of total new capacity brought on-line by 2020. Total carbon emissions from the electricity sector are projected to be 857.8 million tons in 2020.

The first alternative baseline reported in Table 3 is one with no capital cost learning. In this model, capital costs of new technologies do not depend on the level of accumulation of new capacity, nor do they vary over time. This change in assumptions should reduce the future cost advantages of investing in new and less developed technologies such as biomass gasification and geothermal today and thus reduce their share of both investment and generation, compared to the central case baseline.[32] This scenario produces opposite results for generation and investment in mature technologies such as fossil plants, thus increasing their share of investment and generation. In fact, this scenario does bring about a markedly lower level of generation from non-hydro renewables as a class and particularly from biomass and geothermal. This shift away from renewables results in a very slight increase in total carbon emissions from electricity generators relative to the central case baseline.

[32] Although wind is perceived as a new technology, it actually is considered to be fairly advanced along the learning curve and is mature relative to other renewables.

Table 3. Overview of Electricity Price, Generation, Capacity, and Emissions in 2020: Baseline Cases

	Baseline	Baseline with No Learning	Baseline with High Gas	Baseline with No Cofiring
Average Electricity Price (1999$/MWh)	68.99	69.96	71.27	69.22
TOTAL Generation (billion kWh)	4873	4861	4842	4872
Coal	2453	2445	2499	2459
Gas	1222	1263	1100	1219
Nuclear	734.9	730.9	739.7	733.1
Hydro	311.0	310.9	310.9	310.9
TOTAL Renewables*	150.7	110.0	204.3	144.4
Wind	9.167	9.851	11.19	9.018
Geothermal	104.0	67.85	106.7	97.16
Biomass	10.29	4.329	39.41	13.81
TOTAL New Capacity (GW)**	390.7	380.7	388.1	385.5
Coal	12.75	11.49	18.43	13.65
Gas	364.4	360.9	350.8	358.7
TOTAL Renewables*	13.47	8.254	18.73	12.63
Wind	0.398	0.841	1.249	0.300
Geothermal	11.22	6.442	11.52	10.43
Dedicated Biomass	1.074	0.095	4.948	1.518
Carbon Emissions (million tons)	857.8	860.6	856.3	858.7

* TOTAL Renewables includes wind, geothermal, biomass, and other, but does not include hydro.
** New nuclear capacity and new hydro capacity are not available options in the model. Numbers do not sum due to rounding.

The second alternative baseline, the high gas price case, assumes that the price of natural gas is roughly 15% higher than in the central case baseline. One reason this scenario may be compelling is the empirical observation that long-run gas prices that lock in through forward markets are consistently above long-run forecasts. Bolinger and Wiser (2003) conjecture this difference is due to price risk stemming from short-run volatility. This scenario yields an electricity price that is $2 per megawatt-hour (MWh) higher and total generation that is slightly lower than in the central case baseline in 2020. The higher relative price of natural gas dampens gas generation to a level 9% below the central case baseline, but results in more generation by coal and by renewables. The changing mix of generation results in no real change in total carbon emissions as the emissions reductions from substituting away from gas toward renewables are roughly cancelled out by the increased emissions associated with increased use of coal.

The third alternative is a baseline with no biomass cofiring of existing coal plants. Biomass cofiring is a somewhat experimental technology. Its true costs and the extent to which this technology will play out in the future are uncertain at this point. In the central case baseline, the contribution of cofiring helps preserve the value of existing coal plants. We see that eliminating the cofiring option leads to slightly more generation with new, dedicated biomass and new coal in 2020, in place of generation from biomass cofiring.

Renewables Portfolio Standards

Table 4 summarizes the results for 2020 for the four different RPS scenarios analyzed here: 5%, 10%, 15%, and 20%.[33] The broad spectrum of results from these scenarios appear consistent with prior expectations in several respects:

- The price of electricity and the renewables credit price are increasing in the level of the RPS.
- Generation from both coal and natural gas declines as the level of the RPS increases.
- Gas generation is more dramatically affected than coal generation, because it competes at the extensive margin for a share of new capacity.
- The level of carbon emissions from the electricity sector is decreasing in the level of the RPS.

Focusing on the results from specific scenarios provides more details regarding the magnitude of the effects of these scenarios on important variables.

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[33] Note that non-hydro renewables penetration levels that result in the different RPS runs differ slightly from the minimum portfolio standards as a result of imperfect model convergence. For example, the model produces 4.9% renewables penetration in 2020 for the 5% RPS scenario, 10.4% for the 10% RPS, 15.08% for the 15% RPS, and 19.8% for the 20% RPS scenario.

Table 4. Overview of Electricity Price, Generation, Capacity, and Emissions in 2020: RPS and REPC Cases versus Baseline

	Baseline	5% RPS	10% RPS	15% RPS	20% RPS	REPC-E	REPC-G
Average Electricity Price (1999$/MWh)	68.99	69.38	69.59	70.47	74.55	68.20	67.04
Renewables Credit Price (1999$/MWh)	N / A	3.750	14.30	22.42	35.42	N / A	N / A
TOTAL Generation (billion kWh)	4873	4865	4867	4839	4778	4901	4917
Coal	2453	2439	2318	2259	2203	2400	2266
Gas	1222	1135	993.1	812.6	692.7	897.8	878.9
Nuclear	734.9	733.0	732.5	724.8	624	725.8	730.4
Hydro	311.0	310.8	310.8	310.9	309.8	311.2	310.9
*TOTAL Renewables**	150.7	244.6	510.8	730.0	947.9	564.8	728.9
Wind	9.167	36.93	142.1	301.4	467.8	384.8	312.2
Geothermal	104.0	113.1	122.9	133.1	157.4	76.15	127.5
Biomass	10.29	66.76	219.2	270.6	298.3	79.17	264.8
TOTAL New Capacity (GW)**	390.7	387.1	416.7	456.2	504.8	483.1	462.2
Coal	12.75	13	11.18	11.33	5.173	8.765	9.088
Gas	364.4	345.4	331.4	313.6	304.5	328.6	320.0
*TOTAL Renewables**	13.47	28.64	74.08	131.4	195.1	145.7	133.1
Wind	0.398	9.232	45.32	98.83	154.9	126.6	102.2
Geothermal	11.22	12.34	13.72	15.04	18.28	7.463	14.31
Dedicated Biomass	1.074	6.22	14.36	16.88	21.52	11.28	16.21
Carbon Emissions (million tons)	857.8	846.7	805.9	768.6	738.9	804.5	778.0

* TOTAL Renewables includes wind, geothermal, biomass, and other, but does not include hydro.
**New nuclear capacity and new hydro capacity are not available options in the model. Numbers do not sum due to rounding.

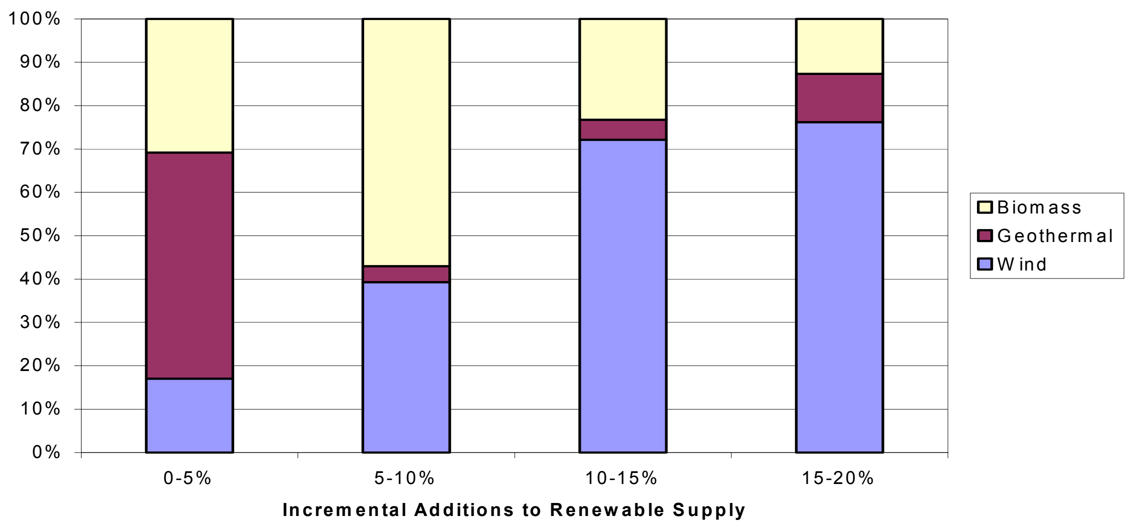
While the 5% RPS policy more than doubles the level of investment in new renewables relative to the baseline in 2020, it has very little effect on electricity price, total generation, and total carbon emissions from the electricity sector. Electricity price rises by less than 1%, and total generation drops only slightly. Generation by gas units declines by 7%, but coal generation drops by less than 1%, contributing to the small magnitude of the change in carbon emissions.

The RPS credit price for a 5% RPS is roughly an order of magnitude smaller than the RPS credit price for a 20% RPS. This is understandable because the 5% RPS represents an increase of only 2% in renewable generation over the baseline level, which is about 3.1%. For the 5% and 10% RPS policies, the electricity price impact is very small, and, even at the 15% RPS policy, electricity price increases by only 2.1%. However, with a 20% RPS electricity price in 2020 is 8.5% higher than under the baseline. The reason for this nonlinear response in price is explained below.

The relative importance of different classes of renewables in satisfying the RPS depends upon the stringency of the RPS. Figure 2 shows the composition of the renewable generation used to meet each 5% increment in the RPS in 2020. At the 5% RPS, as in the baseline, geothermal continues to provide the primary source of non-hydro renewable supply, although there is an important expansion in biomass generation between the baseline and the 5% level. Biomass is the most important renewable technology in the incremental generation required to go from a 5% RPS to a 10% RPS, followed by wind, with only a small expansion for geothermal. In the last two steps, from 10% to 15% and from 15% to 20%, wind is the most important contributor, comprising over 70% of incremental generation in each of the two steps.

With a 20% RPS, the composition of generation changes significantly as the increased use of renewables backs out generation from other sources. This has important implications for the market price of natural gas. Over the decade between 2010 and 2020, the 20% RPS produces an average decline in total gas-fired electricity generation of 30% relative to the baseline with a price of gas delivered to utilities that is 6% below baseline levels. Gas generation is 43% lower in 2020 with a 20% RPS than in the baseline scenario, while coal generation is only about 10% lower than the baseline. In relative terms, the reduction in gas generation is 210% that of coal generation. This drop in gas demand from electricity generators and the associated drop in price mean lower gas prices for residential and industrial gas consumers as well, an important political consideration.

Figure 2. Composition of Incremental Additions to Non-hydro Renewable Generation



At the 20% RPS level, renewables start to back out nuclear generation. In 2020 with a 20% RPS, nuclear generation is roughly 100 billion kWh, or 15%, less than in the baseline scenario. This is a striking finding; at lower levels of the RPS, renewables are displacing fossil generation almost exclusively, but this is no longer the case at the 20% level. In the Haiku model, nuclear capacity is divided into efficient and inefficient nuclear model plants in each of the 13 regions. Much of this reduction in the 20% RPS case is a result of the retirement of over half of the inefficient nuclear capacity nationwide by 2020 relative to the baseline. Nuclear plants are an important source of baseload generation due to their typically low variable costs. For the most part, the renewable technologies that are being brought on-line by the RPS policy are also baseload technologies because they have very low operating costs.

Once these renewable plants are constructed, they are expected to run as often as possible. At high levels of required renewables generation and the associated cost of having to purchase renewables credits, it may not be worth it for certain high-cost nuclear plants to pay the costs associated with relicensing and keeping plants on-line, especially given the possibility that they will be displaced in the dispatch order by a renewable generator. In addition, in the baseline scenario many of these nuclear plants actually make investments, known as uprates, to increase the capacity rating at existing plants. With the 20% RPS, as compared to the baseline, fewer of these investments take place, which contributes to the lower level of nuclear generation.

The backing out of baseload nuclear generation in the increment between the 15% RPS and the 20% RPS—instead of backing out as much natural gas as occurred at lower levels of the RPS policies—explains why the electricity price increase is greater between the 15% RPS and 20% RPS than at other increments. Natural gas is often at the margin in electricity generation. Since relatively more expensive gas generation will be the last to generate, the reduced need for new investment in gas-fired capacity and reduced need for gas generation leads to lower marginal costs. Furthermore, when gas generation is decreased, natural gas prices decrease, thereby lowering marginal generation costs of gas.

At levels of the RPS below 15%, the reduction in marginal generation costs from natural gas helps offset the cost of the RPS policy; but this was less likely to occur in the increment between the 15% RPS and 20% RPS policies because of backing out of nuclear. In Table 4, one can see that the renewables credit price is 58% greater in the 20% RPS than in the 15% RPS policy. However, the relative change in electricity price is nearly four times as large under the 20% RPS.

The carbon emission reductions associated with these scenarios follow from the reduction in total generation and the change in the generation mix. For the 5% and 10% RPS policies, annual carbon emissions in 2020 are lower by 10 and 50 million tons, respectively, relative to a baseline level of 857.8 million tons—a decline of 1.2% and 5.8%, respectively. (Recall that in the baseline, renewables already constitute 3.1% of total generation in 2020.) A 15% RPS results in 89 fewer million metric tons of carbon emissions in 2020, just over 10% lower than the baseline level. A 20% RPS results in carbon emissions that are 119 million tons, or 13%, lower than in the central case baseline.

The results of the RPS runs are compared to the findings of earlier EIA analyses of RPS policies in figures 3 and 5. Figure 3 shows the renewables credit price and the renewable generation share for a number of different EIA model runs and for those found in this study. This graph shows that our results predict lower renewables credit prices for achieving a given level of renewables penetration than did the earlier EIA studies. Many factors contribute to these differences. Key among them is the fact that the natural gas price trajectory found in our baseline scenario, which is based on *AEO 2003,* is higher than the gas price forecasts underlying several of the other analyses, which use a range of AEO baselines starting with *AEO 2001*.[34] Figure 4 shows how the EIA long-run natural gas wellhead price forecasts have risen over time and continue to rise with the release of *Annual Energy Outlook 2004* in December 2003. Furthermore, as noted previously, Bolinger and Wiser (2003) identify a systematic bias toward underestimating long-range gas costs, which is not reflected in our study. In addition to the influence of gas prices, our model also includes more up-to-date information about technology costs for the various renewable technologies as well as updated assumptions about technological learning, both of which would tend to lower the costs of the RPS relative to earlier studies.

One potentially offsetting factor is that the National Energy Modeling System (NEMS) model used by EIA includes data on noncommercial cogenerating units that use renewable technologies. These generating units are allowed to earn renewables credits in many of the scenarios that are analyzed and thus represent an additional resource not included in the Haiku model. In some scenarios, these noncommercial units contribute as much as 20% of the total non-hydro renewables generation.[35]

[34] We run an alternative baseline and 15% RPS scenario that substitutes the *AEO 2001* fossil fuel price assumptions, which are lower than in our central case, for those used in the central cases in this study. The lower alternative fuel prices raise the opportunity cost of generating electricity and thus the renewables credit price. The analysis shows that the renewables credit price is roughly 14% higher with the *AEO 2001* fuel prices than in the central case for a 15% RPS.

[35] Another offsetting factor is that landfill gas units are not eligible to earn renewables credits in the scenarios we run. We did a sensitivity case for the 15% RPS that included landfill gas units under the RPS. For that scenario, we find that the renewables credit price is about 10% lower in 2020 when landfill gas units are included. Generation by landfill gas generators is about 30% higher, but landfill gas still only accounts for 4.5% of total non-hydro renewable generation, versus 3.4% when landfill gas units do not receive credits.

Figure 3. Renewable Credit Price in 2020

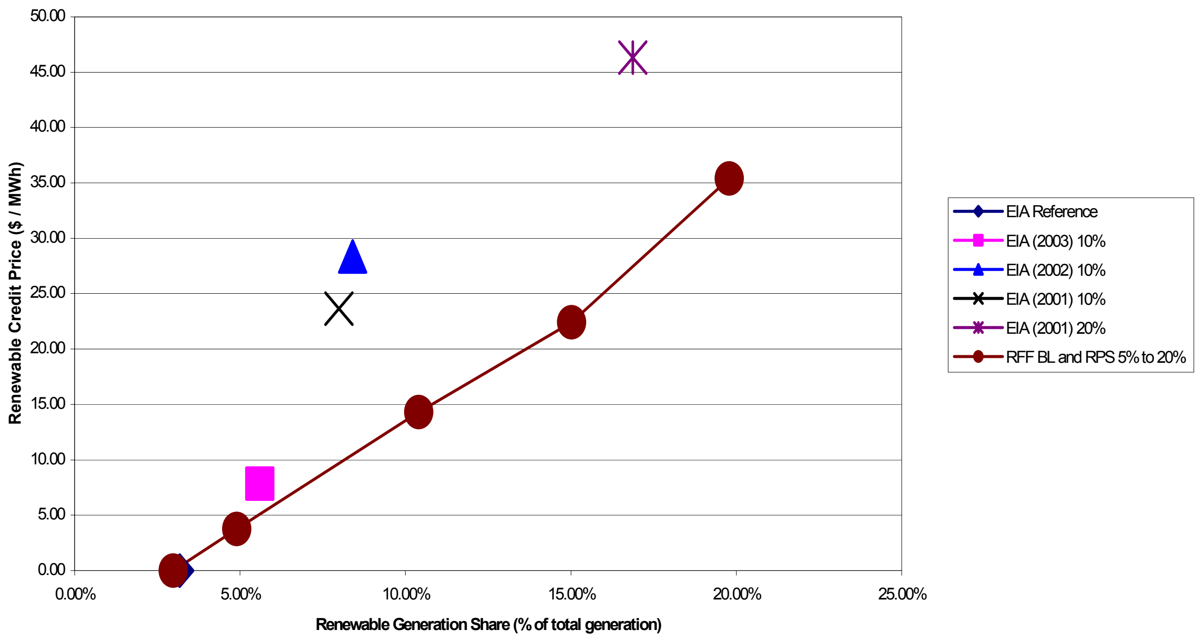


Figure 4. Average Natural Gas Source Price Forecasts, from AEO 1999-2004

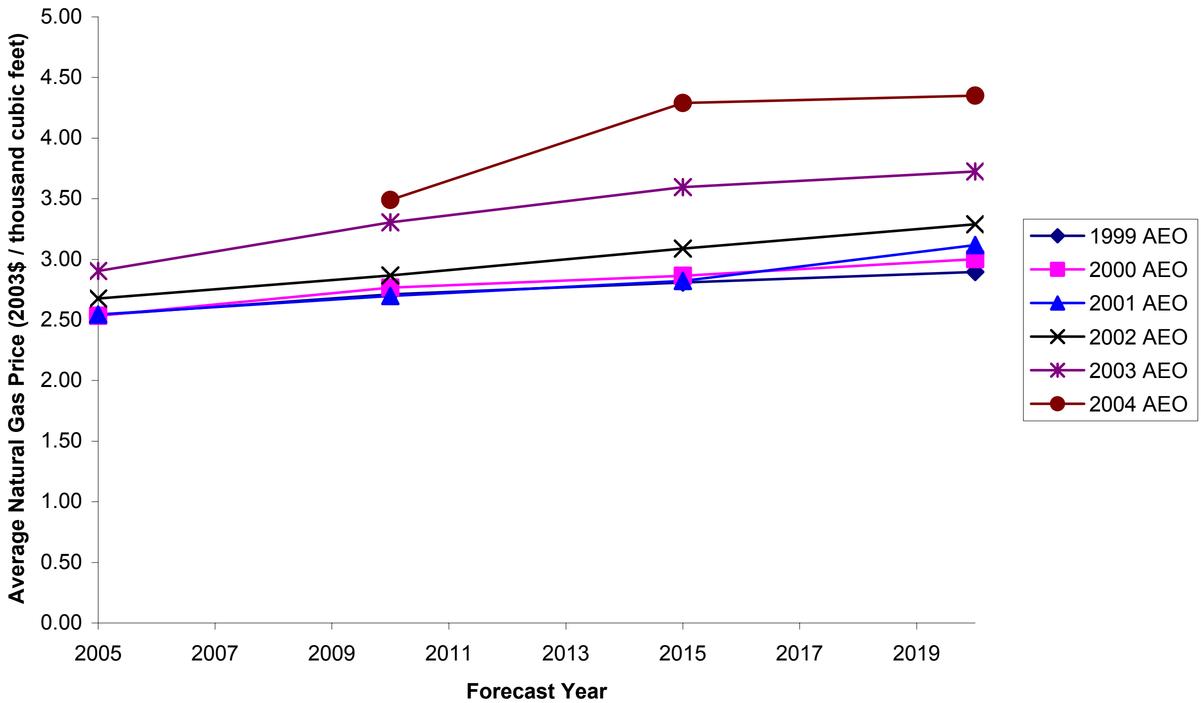


Figure 5. Carbon Intensity of Electricity Generation in 2020

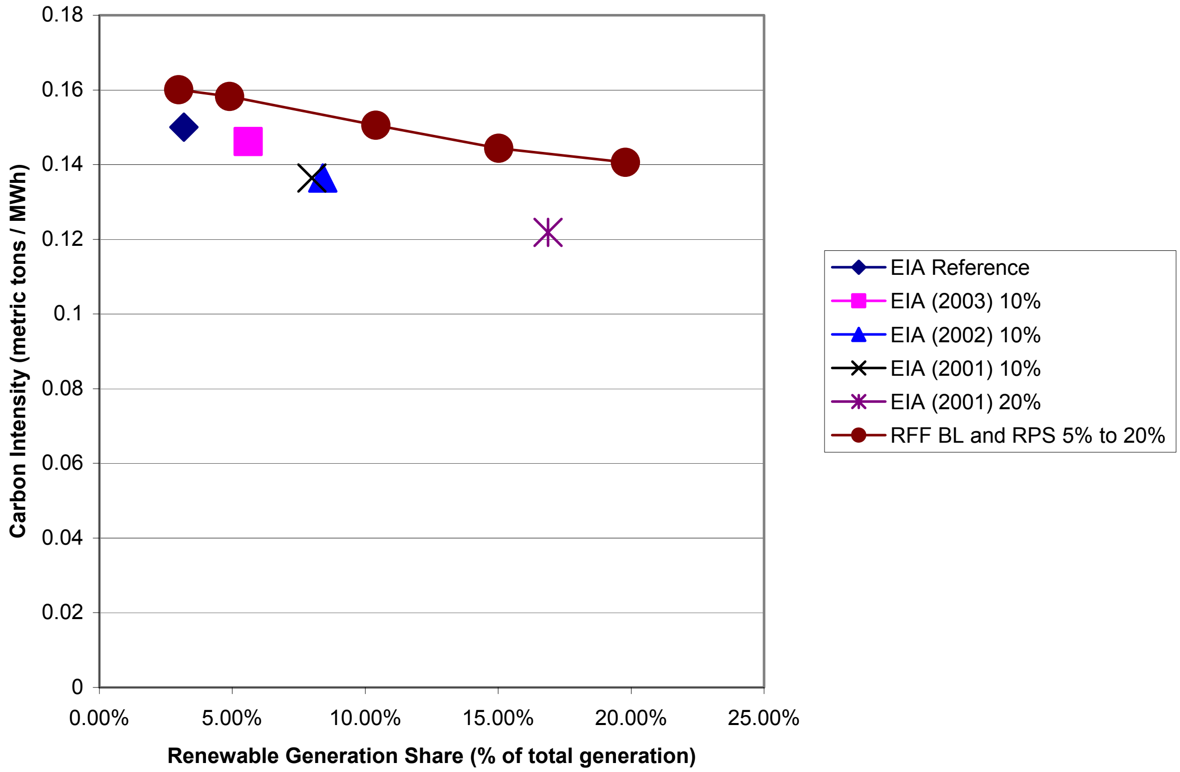


Figure 5 shows the relationship between the carbon intensity of generation and the level of renewables penetration. This figure also displays results from this study and from prior EIA studies. The results indicate that the carbon intensity of the Haiku model runs reported here is generally higher than the carbon intensity in the earlier EIA studies. This finding follows in part from the differences in relative natural gas prices and the resulting role for coal in electricity generation. Due to the higher gas prices, the Haiku model relies more heavily on coal-fired generation than does the EIA model, both with and without the RPS policies. As a result, the carbon intensity of the electricity sector is typically higher in our analysis.

The graph also shows that as the RPS stringency increases within the RFF model runs, the carbon intensity of generation falls. Coal-fired generation falls by only 0.6% of baseline levels in the 5% RPS policy, and by 0.9% of baseline levels between the 5% RPS and 10% RPS levels. However, coal-fired generation falls by 2.4% in the increment between the 10% RPS and the 15% RPS. Overall, the reduction in carbon emissions is roughly linear for increases in the RPS up to 15%. In the final increment from the 15% RPS to the 20% RPS, coal-fired generation falls by 2.3%, but renewables start to back out nuclear generation instead of fossil generation, especially instead of natural gas. This results in a smaller incremental decline in carbon emissions intensity as the standard rises above 15% RPS. This is illustrated by the flattening out of the curve connecting the 15% RPS and the 20% RPS policies.

Renewable Energy Production Credit

The Renewable Energy Production Credit (REPC) for dedicated closed-loop biomass and wind generation that recently expired in the United States was a tax credit of 1.7 cents per kWh of generation. This incentive amounts to an after-tax subsidy of 2.8 cents per kWh. In the baseline scenarios and all the RPS policy scenarios, we assume that the REPC policy continues through simulation year 2005 and is phased out between 2005 and 2010.[36] In the policy scenarios analyzed here, we extend the REPC across the full 20-year forecast horizon.[37]

In the REPC-E scenario, the tax credit is *extended* until 2020 and continues to apply only to wind and closed-loop biomass.[38] The results of this analysis are reported in the next to last column of Table 4 (page 30). The extended REPC-E results in a substantial increase in the amount and share of generation from non-hydro renewable sources relative to the baseline scenario. Renewables rise to 11.5% of total generation in 2020 from a baseline level of 3.1% in 2020. Most of the additional renewable generation is from wind and biomass, the two renewable technologies that are eligible for the production incentive. Wind generation increases by over 380 billion kWh, to four times its level in the baseline, and biomass generation grows to over 15 times its level in the

[36] Furthermore, we assume that facilities can earn the credit only as long as it is available to new qualified facilities. The actual provision makes the credit available for only 10 years. The continuation of this policy through the year 2006 is included in the energy bill recently debated in the U.S. Senate and House of Representatives.

[37] In the recently expired legislation, the renewable production tax credit was only available during the first 10 years of the unit's operation. In this analysis, we assume that the REPC is in effect throughout the operating life of the renewable facility.

[38] The production credit is set at its historic level of 1.8 cents per kWh (in real terms) throughout the forecast period.

baseline with the addition of 150 billion kWh. Generation from geothermal plants is 30 billion kWh, or 30%, lower with the REPC than in the baseline, in large part because geothermal plants do not benefit from the production incentive.

Under the REPC-E scenario, electricity price is 1% lower in 2020 than it is in the baseline. This finding results from the fact that renewables enter the operating schedule as baseload facilities because of low operating costs, displacing gas, which otherwise has higher operating costs. In competitive regions where electricity price depends directly on marginal generation cost, this effect is reflected directly in prices. The lower price results in a slightly higher quantity of total electricity generation.

As with the low and mid-level RPS policies, in the REPC-E scenario the increased generation from renewables is backing out fossil generation. As a result of the REPC-E, gas-fired generation is roughly 26% lower than in the baseline and coal generation is lower by roughly 2%. Extending the production tax credit through 2020 reduces carbon emissions in 2020 by 53 tons or 6.2% relative to the baseline. This is approximately equal to the level of carbon emissions that results with the 10% RPS in 2020.

In order to be able to compare the efficacy of a production tax credit such as the REPC with an RPS policy, we also look at a more *general* production tax credit, the REPC-G, targeted at wind, biomass, and geothermal, the three technologies that qualify for the RPS. The policy is constructed by translating the after-tax subsidy received by renewable generators, or the renewables credit price, associated with the 15% RPS into an equivalent production tax credit to be received by renewable generators. In the case of the RPS, renewables are subsidized and the funds for that subsidy effectively come from a tax on fossil, nuclear, and hydro generation. In the case of the REPC-G policy, renewables receive an identical after-tax subsidy, but the source of that subsidy is federal taxpayers.

The results for the REPC-G scenario are presented in the last column of Table 4. By design, the REPC-G policy achieves a comparable quantity of total renewables generation in 2020 (729 GWh) as the 15% RPS policy (730 GWh), although the relative shares of wind, geothermal, and biomass within that total are somewhat different. Because renewable generation is subsidized using general tax revenues, electricity price is lower and total generation is higher than in the baseline or any of the other policy scenarios, including the 15% RPS and the REPC-E. Total gas generation is 66 billion kWh, or 8 %, higher than under the 15% RPS case and gas accounts for the lion's share of the difference in total generation between the REPC-G case and the 15% RPS case. Higher total generation means that total carbon emissions in this case in 2020 are higher than in the 15% RPS case.

Welfare Effects of RPS and REPC Policies

The economic cost of the RPS and REPC policies within the electricity sector are best measured by looking at their effects on consumer and producer surplus within the sector and on the size of government revenues relative to the no-policy baseline. Consumer surplus is an economic measure of the well-being of consumers, and one can think of it as consumer profits. More technically, it is a measure of the difference between the willingness to pay by consumers for electricity and the amount they actually have to pay. Producer surplus can be thought of as producer profits. The change in government revenues is also important because the change must be made up with other revenue sources, or, alternatively, the revenue could be returned directly to consumers and would count as consumer surplus. The REPC subsidy represents a cost because the money used to subsidize renewables producers is money that is not available to the government to spend on other government programs.[39] Total economic surplus is the sum of these three measures: consumer surplus, producer surplus, and the change in government revenues. Economic efficiency is maximized when total economic surplus is maximized. Of course, this measure takes into consideration only the changes within the electricity market. It does not account for other effects, such as environmental benefits from renewable generation.[40]

Table 5 provides an annual snapshot of the economic surplus changes from the baseline associated with the different policies in the year 2020. The first four columns of this table focus on the different RPS policies. These columns show that consumers always lose with an RPS (not accounting for environmental benefits) because the RPS raises electricity price. With a 5% RPS, producers actually see an increase in producer

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[39] In this analysis, we assume that $1 of government subsidy is worth $1. If we were to account for the distortions created by typical government fundraising activities, the cost of the subsidy would be higher. Typically, the marginal cost of raising $1 in public revenue is estimated at about $1.3.

[40] For a recent analysis of the benefits of reducing atmospheric emissions from electricity generation, see Banzhaf et al. (2004).

surplus. As the RPS becomes more stringent, losses to both consumers and producers increase up to the 15% RPS policy. The total economic surplus loss under the 15% RPS is $11.27 billion in 2020, or roughly 3% of the estimated $326 billion in total electricity sector revenue under the baseline scenario in 2020. Between the 15% RPS and the 20% RPS policies, the electricity price increase is substantial, resulting in a big drop in consumer surplus. For producers, the price increase means that they actually experience a much smaller drop in producer surplus relative to the baseline under the 20% RPS than under less stringent policies.

Table 5. Economic Surplus as Difference from Baseline
(2020 snapshot, Billion 1999$)

	5% RPS	**10% RPS**	**15% RPS**	**20% RPS**	**REPC-E**	**REPC-G**
Consumer Surplus	-1.93	-2.59	-6.37	-25.46	3.91	9.42
Producer Surplus	1.66	-3.21	-4.92	-1.62	-4.84	-4.63
Cost of REPC	N/A	N/A	N/A	N/A	-11.82	-16.27
TOTAL Economic Surplus*	-0.24	-5.76	-11.27	-27.08	-12.75	-11.48

*The economic surplus measures do not include any environmental benefits resulting from the policy.

The last two columns of Table 5 summarize the costs of the two REPC policies. Because it yields a lower price of electricity, the REPC-E policy (extended until 2020 but limited to wind and dedicated closed-loop biomass) makes consumers better off than they are in the baseline scenario in 2020. The loss to producers in 2020 offsets some of the gain to consumers, but the main cost of the policy is the large size ($11.8 billion) of the subsidy to renewables associated with the cost to government in 2020. The combined effect is a $12.8 billion drop in economic surplus as a result of the policy.

The broader-based REPC-G policy, which is extended to 2020 and expanded to a general set of renewable technologies to be comparable to an RPS policy, yields the highest level of consumer surplus increases due to the low electricity price, but it also yields the highest cost to government in order to fund the subsidy. The REPC-G policy turns out to be less costly overall in terms of total economic surplus loss than the REPC-

E, which makes sense because the REPC-G allows for an expanded set of options that qualify for delivering a comparable amount of renewable energy. However, the REPC-G policy is roughly 2% more costly than the 15% RPS, which yields comparable levels of renewable generation.

The economic surplus consequences of regulations that raise electricity prices, such as an RPS for the electricity sector, are complicated by the fact that electricity is not priced efficiently and often, during peak demand periods, for example, the price paid by consumers is substantially below marginal cost. This is even more likely to be the case in regions where electricity price is set using cost-of-service regulation, as assumed for much of the country in these model runs. In cases such as this, any policy that raises the price of electricity and thereby narrows the gap between electricity price and marginal cost leads to less of an efficiency loss than occurs with a comparable REPC policy that doesn't raise the electricity price.

Comparing the tradable credit and the production subsidy approaches, we find that the REPC-E has a greater economic cost than the 15% RPS even though it yields only an 11.5% share of generation by renewables. Due to its limited focus, the REPC-E policy fails to promote use of geothermal resources, which are shown to be an important contributor of renewable generation at low-level RPS settings. In addition, this policy provides a subsidy to generation and thereby does not promote energy conservation as a way of achieving the renewables standard by reducing total electricity consumption and generation.

Comparing the tradable credit (15% RPS) and a production subsidy aimed at a general portfolio of renewable technologies (REPC-G), with both approaches yielding about 730 billion kWh of renewable electricity generation in 2020, we find the RPS is slightly less costly than the REPC-G. In addition, the REPC-G yields a slightly higher level of carbon emissions than the 15% RPS policy, because the subsidy provided by government helps to keep electricity prices low, leading to 3% more total generation. Hence, we find that the RPS approach dominates the REPC approach, both as a policy to promote renewables and a policy to reduce carbon emissions.

Regional Effects of the National RPS and REPC-E policies

Federal policies to promote renewable generation, such as the RPS or the REPC-E, will have different impacts on different regions of the country, depending on the stringency of the policy and, in the case of the REPC-E in particular, which types of renewables are targeted by the policy. With an RPS, some regions will be importers of renewables credits while others will be exporters, and which regions will fill which role will depend on the stringency of the RPS.

Table 6 shows the electricity price and the renewables share of total generation by region and for the nation as a whole for the central case baseline and three policy scenarios for the year 2020. In the baseline, the national share of total generation attributable to non-hydro renewables in 2020 was just over 3%. Four regions, New England (NE), the Northwest (NWP), the Arizona-Nevada region (RA), and California/Southern Nevada (CNV) have renewable generation shares in excess of the national average. The renewables shares in these regions that exceed the national average in the baseline are highlighted in the table.

Under an RPS, those regions with renewable generation shares that exceed the national RPS will be exporters of renewables credits in the national credit trading system, while those regions with shares below the minimum RPS will be importers. In the middle two sets of columns in Table 6, the renewable generation shares of renewables credit exporting regions are highlighted. Under the 5% RPS, five regions, the western plains (MAPP), New England, Florida (FRCC), the Northwest (NWP), and California/Southern Nevada, are all exporters of renewables credits. To a large extent, which regions specialize in renewables production can be explained by which technologies are important components of the total pool of renewables. Most of the renewables added to go from 3% non-hydro renewables (0% RPS) to the 5% requirement are either biomass or geothermal, which is consistent with the credit exporting status of regions like California/Southern Nevada and NWP, which have a large share of the geothermal resources. Interestingly, renewables credit exporters include both low price regions like NWP and MAPP and higher priced regions like California and New England.

At the 20% RPS level, six regions are renewables credit exporters, including MAPP, New England, the Northwest, RA, SPP, and California. Several of these regions actually have renewables shares that are twice the level of the national RPS, reflecting their relatively large endowment of wind and other renewable resources. Once again, both high-price and low-price regions are in the position of exporting renewables credits. Inter-regional power trading is also higher with an RPS than in the baseline, and trading increases with the stringency of the RPS.

For the REPC-E scenario extended to 2020, but which benefits only wind and closed-loop biomass, there are seven regions where the share of renewable generation exceeds the national average obtained by the policy. The renewables shares for these regions are highlighted in Table 6. This policy leads to a similar regional pattern of "overachievers" as found under the 20% RPS policy.

Table 6. Average Electricity Price and Renewables Share of Total Generation by Region in 2020. (Shaded cells indicate regions exporting renewables credits.)

	Baseline		5% RPS		20% RPS		REPC-E	
Region	**Price**	**Share**	**Price**	**Share**	**Price**	**Share**	**Price**	**Share**
ECAR	64.02	0.13%	64.88	0.58%	71.2	8.33%	64.95	2.72%
ERCOT	72.24	0.29%	72.7	2.88%	80.63	11.77%	72.32	9.84%
MAAC	87.82	1.36%	89.67	1.91%	96.21	13.82%	86.88	7.77%
MAIN	74.43	0.39%	73.45	0.87%	77.1	13.40%	68.22	5.91%
MAPP	60.83	1.26%	61.45	6.08%	58.77	48.46%	60.36	44.09%
NY	104.2	1.68%	107.4	2.89%	111.9	17.33%	102.9	13.76%
NE	97.29	4.27%	97.41	6.83%	101.2	31.75%	91.39	26.14%
FRCC	73.32	2.40%	73.7	5.73%	80.98	7.12%	71.54	5.21%
STV	61.33	0.24%	62.04	1.08%	70.08	5.29%	60.73	1.62%
SPP	59.51	0.03%	60.12	1.07%	67.19	40.27%	62.15	31.34%
NWP	40.61	17.21%	40.52	22.72%	39.12	42.51%	42.67	35.49%
RA	69.37	3.83%	69.7	4.88%	72.87	46.79%	69.24	26.68%
CNV	82.7	13.31%	80.25	18.44%	82.03	34.68%	79.09	21.57%
Total	68.99	2.98%	69.38	4.90%	74.55	19.79%	68.19	13.25%

Which regions are exporters and which are importers of renewables credits is only part of the story, however. There are also important differences in terms of how much each region contributes to total national non-hydro renewable generation. Figure 6 shows the regional shares of national non-hydro renewable generation under a 5% RPS. This graph shows that NWP and CNV combined provide just over 60% of total national renewable generation with the 5% RPS.

Figure 6. RPS 5%: Percentage of National Renewable Generation

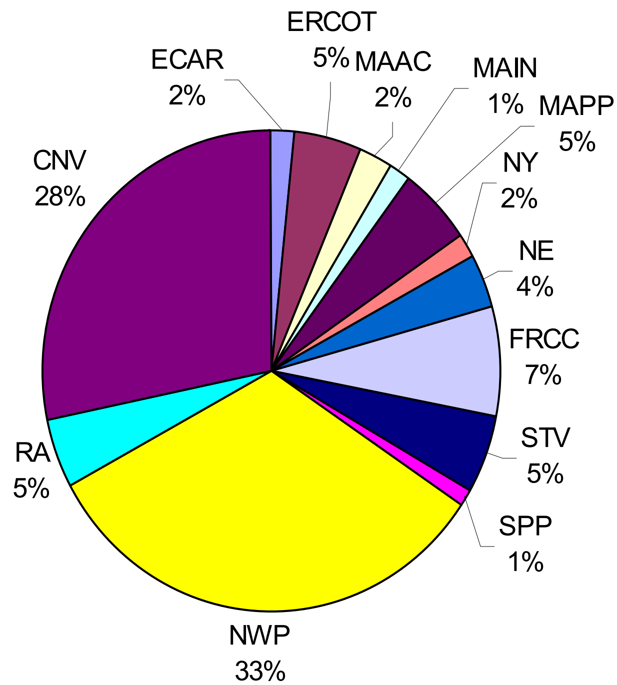


Figure 7. RPS 20%: Percentage of National Renewable Generation

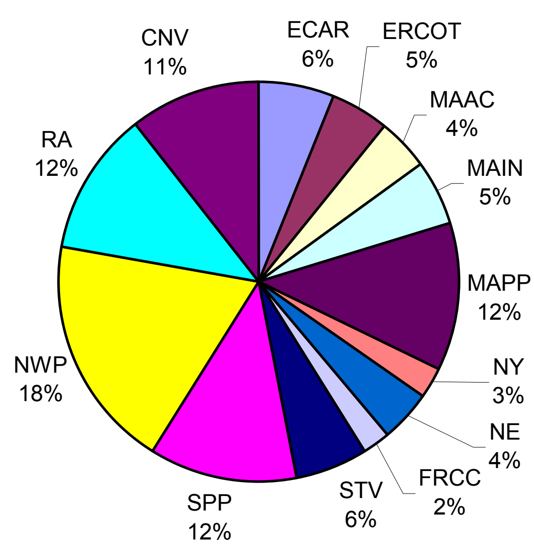
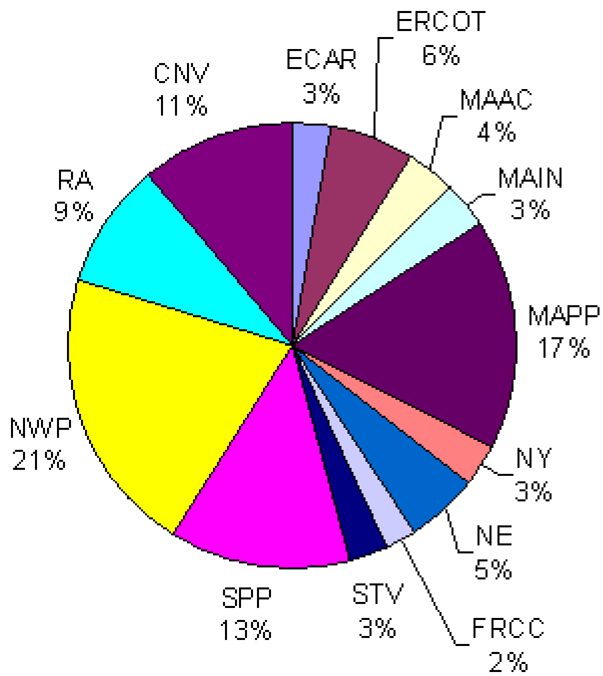


Figure 8. REPC-E: Percentage of National Renewable Generation



As the RPS standard increases, however, the relative contribution of these two regions to total renewable generation diminishes and MAPP, SPP, and RA become increasingly important sources of renewables, due in part to their large endowment with wind resources.[41] Figure 7 shows the relative contributions of different regions to national renewable generation with a 20% RPS. Figure 8 displays the relative contributions of different regions to national renewable generation under the REPC-E scenario. Because the REPC-E offers an incentive only for wind and biomass, it leads to a greater role for generation by the regions with these resources—MAPP and NWP—relative to the 20% RPS.

[41] For example, in SPP in the 20% RPS scenario, the percent growth from 2005 to 2020 in biomass is larger (20-fold, rising from 500,000 MWh to 10 million MWh), but the absolute growth of wind is far greater, rising from 18.7 million MWh to 95.5 million MWh.

An example of the effect of the 15% RPS in 2020 on the dispatch schedule of marginal generation costs is illustrated in Figure 9. This figure illustrates the dispatch curve for MAPP, which is a net exporter of renewable production credits because over 42% of its electricity generation is from renewables, far in excess of the 15% requirement. The dashed curve in the figure represents the dispatch schedule for the summer peak time block, with a sample of four model plants also highlighted to illustrate the average variable costs of those plants. The solid curve that lies below the baseline is the dispatch schedule for the 15% RPS case.

Two phenomena are apparent. First, if one compares the location of a specific nonrenewable plant across the two schedules, one sees that its costs actually rise, due to the requirement to purchase renewables credits. The costs rise slightly less for coal plants because they can cofire biomass to a limited degree, and thereby satisfy part of the renewable requirement. Secondly, there is an expansion of renewable capacity with very low dispatch costs. In fact, the dispatch costs of renewables may be negative due to revenues received from the sale of renewables credits. This pushes the schedule for other plants to the right, resulting in more capacity at each measure of marginal cost. The net effect for nonrenewable plants is a shift to the right along the dispatch curve and a shift up of their portion of the dispatch curve.

An example of a region that is a net importer of renewables credits is presented in Figure 10. Again, this corresponds to the summer peak time block for 2020, this time in MAAC, where 9.3% of total generation comes from renewables. The region imports renewables credits to make up the difference under the 15% RPS requirement. In Figure 10, the baseline and 15% RPS cases overlap somewhat. Nonetheless, the two phenomena apparent in Figure 9 are apparent in Figure 10. First, the marginal costs of nonrenewable plants rise. Second, most of the nonrenewable plants shift to the right along the dispatch schedule due to the addition of renewable capacity with relatively lower marginal cost.

However, this is not the case for the average unscrubbed coal plant. The cost for unscrubbed coal plants rises less than the costs of other nonrenewable plants because of their ability to cofire biomass at a cost that is less than that of obtaining renewables credits. In the baseline, the coal plant has costs that are very similar to those of existing nuclear plants, as illustrated by the long, relatively flat portion of the curve. In the 15% RPS case, the small difference in the additional cost of the RPS policy makes a big difference in the dispatch order. Since the nuclear plants have to obtain more renewables credits than the coal plant, they have a slightly higher cost increase due to the RPS policy, and this difference is enough to cause them to switch place with the coal plant in the dispatch curve. Hence, we see that an RPS policy can have subtle effects, not only among regions, but also among conventional technologies.

Figure 9. The schedule of marginal costs for a region (MAPP) that exports renewable credits under a 15% RPS policy, summer peak time block in 2020.

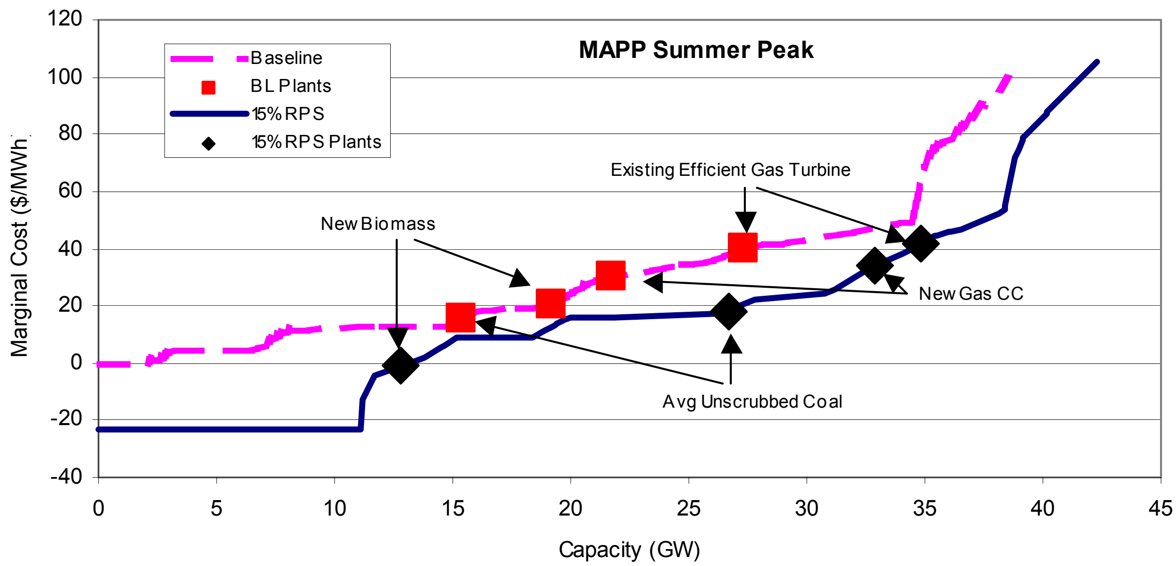
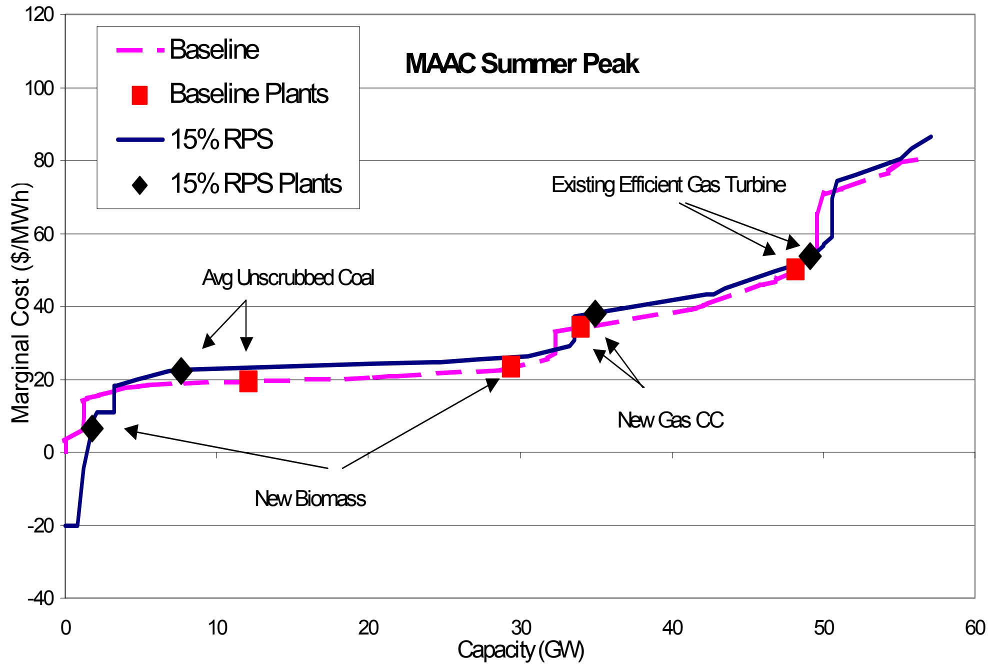


Figure 10. The schedule of marginal costs for a region (MAAC) that imports renewable credits under a 15% RPS policy, summer peak time block in 2020.



The heterogeneity in regional contributions to the total amount of non-hydro renewable generation required or brought about by these policies suggests that imposing uniformity of renewables policy goals across regions without inter-regional trading is likely to be quite costly. Regionally targeting policies in this way (to be uniform) will force regions that do not have access to low-cost resources to spend more money to reach their own regional goal and will prevent other regions from taking full advantage of the low-cost resources that they do have.

Sensitivity Analysis for the 15% RPS

The effects of an RPS on investment and generation decisions as well as on electricity price and emissions may depend on the underlying assumptions about parameters in the model. In this chapter, we consider four sensitivity cases on the 15% RPS model run: no capital cost learning for new model plants, a high gas price scenario, no cofiring of coal-fired generators with biomass, and the combination of a renewables production tax credit such as the REPC-E with a 15% RPS. A summary of the results from the central case 15% RPS scenario and the different sensitivity analyses is presented in Table 7.

Table 7. Overview of Electricity Price, Generation, Capacity, and Emissions in 2020: 15% RPS Sensitivity Cases

	15% RPS	15% RPS No Learning	15% RPS High Gas Prices	15% RPS No Cofiring	15% RPS with REPC-E
Average Electricity Price (1999$/MWh)	70.47	72.60	71.13	71.98	68.87
Renewables Credit Price (1999$/MWh)	22.42	30.72	19.98	40.05	11.19
TOTAL Generation (billion kWh)	4839	4816	4832	4827	4890
Coal	2259	2255	2277	2323	2323
Gas	812.6	781.9	769.0	750.0	815
Nuclear	724.8	718.1	728.9	704.0	698.9
Hydro	310.9	309.5	310.6	310.3	311.3
TOTAL Renewables*	730.0	748.9	743.8	738.3	740.8
Wind	301.4	391.9	304.3	417.7	441.3
Geothermal	133.1	114.5	133.0	155.6	112.5
Biomass	270.6	217.9	281.6	140.4	162.4
TOTAL New Capacity (GW)**	456.2	471.3	463.0	491.2	504.8
Coal	11.33	10.68	11.48	5.732	8.484
Gas	313.6	308.9	317.7	309.8	321.1
TOTAL Renewables*	131.4	151.4	133.72	175.4	175.2
Wind	98.83	129.4	102.6	138.2	145.8
Geothermal	15.04	12.63	18.15	18.13	12.33
Dedicated Biomass	16.88	9.242	19.58	18.81	16.72
Carbon Emissions (million tons)	768.6	765.6	768.0	768.9	777.7

* TOTAL Renewables includes wind, geothermal, biomass, and other, but does not include hydro.
**New nuclear capacity and new hydro capacity are not available options in the model. Numbers do not sum due to rounding.

Technological learning has a direct effect on the capital cost of a new generator and that effect can be large for new technologies like biomass IGCC. The construction cost of new biomass capacity in 2020 in the 15% RPS case is $82 per MW. This is about 60% lower than in the 15% RPS with capital cost learning assumed not to occur.

The change in cost due to learning is smaller for wind, which is characterized as a relatively more mature technology than biomass. The capital cost of wind in 2020 in the 15% RPS case is $229 per MW, about 21% lower than if capital cost learning is assumed not to occur. Moreover, this comparison does not solely reflect learning because wind technology has an upward sloping capacity supply function in the model, reflecting the higher capital costs associated with accessing wind resources that are of lower quality, in remote locations or on difficult terrain. Thus capital costs will increase as the lower cost wind sites are used up. When learning is turned off in the model, wind becomes more appealing relative to other renewable technologies and it takes market share away from biomass, thus causing construction costs of wind to increase even more. The role of the increasing cost curve is particularly conspicuous in 2020 in the 15% RPS case when wind construction cost is 36% higher than in the baseline. This difference reflects the fact that under the 15% RPS total wind capacity is 33 times the level it is in the baseline in 2020.

The price of a renewable energy credit in 2020 is over $8.00 per MWh higher, or nearly 36% higher, when learning is assumed not to occur. The price of electricity is also over $2.00 per MWh higher than in the central 15% RPS case, and total generation is somewhat lower. The increase in the electricity price relative to the baseline brought about the 15% RPS is also substantially larger with no learning than when learning is allowed. Under the no-learning scenario, wind plays a relatively more important role in meeting the RPS than in the central 15% RPS case. This finding is attributable largely to the assumption that wind is a mature technology with only small possibilities for future learning. The capital cost of biomass and geothermal have a much faster learning rate than does wind and thus they are relatively more appealing options when learning occurs. However, when learning is not taking place, the ultimate cost advantages of these two technologies over wind are diminished and wind is more often the technology of choice.

In the high gas price scenario, renewables credits are just under $20.00 per MWh, less expensive than in the central case. This is consistent with the increased opportunity cost of using natural gas to generate electricity, making renewables more appealing in the baseline. In the high gas price baseline, the renewables share of total generation in 2020 is 3.7%, higher than the 3.1% found in the central case baseline. Comparing the 15% RPS with high gas prices to the high gas price baseline in Table 3 shows that the average price of electricity in 2020 actually declines very slightly when the 15% RPS is imposed. In regions where electricity price is set competitively, this finding is consistent with renewables entering at the low end of the dispatch supply curve, due to their low variable cost, and effectively shifting the curve out. Such a shift can mean that the intersection between electricity demand and marginal cost of generation curve is below the baseline levels, resulting in a slightly lower market-clearing price. This lower price does not imply that the policy does not have resource costs, only that those costs are not being borne by consumers.

We also run a sensitivity case where no biomass cofiring is allowed in the baseline and co-firing does not receive credits when there is an RPS. Electricity price is about $2.5 per MWh higher than in the no-cofiring baseline with an associated 45 billion kWh drop in total generation with the RPS. In this case, we see that the renewables credit price in 2020 at $40 per MWh is almost twice as high as in the central 15% RPS case. With no cofiring allowed, the composition of renewable generation involves substantially less biomass and substantially more generation from wind and somewhat more from geothermal than in the 15% RPS central case.

The last sensitivity case that we look at is a case that combines the 15% RPS with the extension of the renewables production tax credit for wind and dedicated closed-loop biomass (REPC-E). In this case, the renewables credit price is very low, only $9.09 per MWh in 2020. This low credit price reflects the fact that the REPC-E by itself yields over 11% renewable generation in 2020, so getting to 15% doesn't require a substantial subsidy.[42] The price of electricity for this scenario is lower than the central case baseline for 2020 and only slightly higher than the REPC-E case with no RPS for 2020. Adding the subsidy to the central case 15% RPS results provides an incentive for generators to increase output, and this incentive contributes to the lower electricity price. In this scenario, wind achieves its largest share of total non-hydro renewables generation and renewables start to back out nuclear generation in addition to natural gas and coal, although coal generation is higher in this scenario than in any of the other 15% RPS runs.

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[42] Note that due to imperfect convergence in the model, this model run actually yields 15.2% renewables in 2020. The actual credit price necessary to get to 15 % renewables could in fact be lower than $9.00 per MWh.

The last row of Table 7 indicates that, with the exception of the combination 15% RPS/REPC-E policy, the various assumptions used in the sensitivity analysis have very little effect on the level of total carbon emissions from the electricity sector in 2020. In the combination case, carbon emissions are higher than in the other 15% RPS cases. This finding is consistent with the higher level of total generation and with the greater reliance on coal in this scenario.

The sensitivities do have an effect on the economic costs of the 15% RPS, as measured by changes in producer and consumer surpluses. Table 8 provides a snapshot of changes in economic surplus for the year 2020.[43] Each 15% RPS scenario except one is compared to the relevant baseline for purposes of calculating changes in economic surplus.[44] This table shows that the economic surplus losses from a 15% RPS are substantially higher when there is no capital cost learning or when biomass cofiring is not allowed than they are in the baseline. In the case of high gas prices, the 15% RPS results in a smaller economic surplus loss in 2020 than when gas prices are lower under the central case. This finding is due in part to the slight drop in electricity price that yields a small increase in consumer surplus in 2020 as a result of the RPS policy.

The last column of Table 8 compares the combination of the 15% RPS and the REPC-E with the REPC-E policy scenario and is thus not directly comparable to the other columns. When the 15% RPS is combined with an REPC-E policy, the loss in surplus is quite small and results mostly from the cost of the additional tax credits that go to incremental generation by biomass and wind generators not occurring in the REPC-E policy case. However, when the combination of the two policies are compared to the central case baseline, the loss in total economic surplus is about $18.7 billion (1999$), which is larger than the surplus loss with any of the other sensitivity cases.

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[43] Note that unlike Table 5, this table is showing sensitivity results so it is not possible to identify the lowest cost policy by selecting among the columns since the policy is the same (except for the last case), but the underlying scenario assumptions are changing.

[44] Note that the carbon emission reductions from the relevant baseline associated with each policy except the 15% RPS/REPC-E combination are very similar across the scenarios and thus each policy is buying a very similar package of emission reduction benefits.

Table 8. Sensitivities for Economic Surplus as Difference from Respective Baselines. (Results in the last column are not directly comparable to the others.) (2020 snapshot Billions 1999$)

	15 % RPS	15% RPS No Learning	15% RPS High Gas Prices	15% RPS No Cofiring	15% RPS with REPC-E
Consumers	-6.37	-11.69	1.20	-12.62	-3.05
Producers	-4.92	-6.79	-10.47	-5.78	-0.97
Cost of REPC	N/A	N/A	N/A	N/A	-1.90
TOTAL Economic Surplus*	-11.27	-18.46	-9.28	-18.37	-5.92

* The economic surplus measures do not include environmental benefits resulting from the policy.

Allocating Carbon Emission Allowances on the Basis of Generation

The third policy case that we consider involves using a cap-and-trade approach to restrict carbon emissions from electricity generators, combined with an emission allowance allocation approach that rewards generators for producing electricity. Under this approach, the total pool of carbon emission allowances for a particular year is allocated to all eligible generators based on each generator's share of output in a recent year. This approach to allowance allocation is typically referred to as "updating allocation based on output," or "updating" for short. Advocates of the updating approach say that it rewards low-emitting and nonemitting generators in two ways. First, like any cap-and-trade program, relatively clean generators will have lower costs because they have lower emissions. Second, it gives all generators an incentive to generate more electricity by providing them with a share of the total pie of emission allowances that grows with their share of total generation. Low-emitting and nonemitting generators can turn around and sell these allowances at the market price because they have fewer emissions that require allowances. Critics of the updating approach to allocation point out that by subsidizing electricity production, updating leads to lower electricity prices and creates a disincentive to conserve electricity that limits its ability to reduce carbon emissions efficiently (Bernard et al. 2001; Palmer and Burtraw 2003).

We consider two variants of updating. One allocates a share of allowances to all electricity generation, except hydro and nuclear, based on current generation, which we call "broad-based" updating. The second allocates all allowances to renewable generators only, based on their share of total renewable generation, called "updating to renewables." The former approach allows fossil generators that are carbon emitters to receive some allowances for free, while the latter approach focuses exclusively on renewables. Both approaches exclude nuclear and hydro generators.

The results of this analysis for 2020 are reported in Table 9. The two updating approaches are targeted to achieve the level of carbon emissions that result in each year from a 15% RPS.[45] The price of a carbon emission allowance is $67 per ton in the broad-based updating scenario. This scenario leads to a lower electricity price than the 15% RPS scenario and the baseline scenario. The price is lower because of the output subsidy associated with the allocation mechanism. Distributing allowances on an updated, broad-based basis results in a nearly 340 billion kWh lower level of coal generation, much of which is offset by higher renewables generation. Renewables generation increases from 3.1% of total generation in 2020 in the baseline to 9.3% of total generation under the broad-based updating scenario. This policy is almost as effective at encouraging renewables use as the 10% RPS, but it yields substantially lower carbon emissions because it also promotes substitution from coal to gas. At the same time, it leads to a lower electricity price and greater total electricity generation.

[45] Because of imperfect convergence in our model, total annual carbon emissions in 2020 under the broad-based updating scenario are 0.8% above the target carbon emission level taken from the 15% RPS analysis. The total carbon emissions under the updating scenario targeted at renewables are 2.4% lower than the target level.

Table 9. Overview of Electricity Price, Generation, Capacity, and Emissions in 2020: Baseline, 15% RPS Case and Carbon Cap with Updating Cases

	Baseline	15% RPS	Broad-Based Updating	Updating to Renewables
Average Electricity Price (1999$/MWh)	68.99	70.47	68.13	71.45
Renewables Credit Price (1999$/MWh)	N / A	22.42	N / A	N / A
TOTAL Generation (billion kWh)	4873	4839	4897	4838
Coal	2453	2259	2116	2237
Gas	1222	812.6	1276	835.4
Nuclear	734.9	724.8	731.0	731.9
Hydro	311.0	310.9	311.1	310.6
*TOTAL Renewables**	150.7	730.0	461.5	721.6
Wind	9.167	301.4	106.1	386.1
Geothermal	104.0	133.1	110.5	144.6
Biomass	10.29	270.6	217.0	165.0
TOTAL New Capacity (GW)**	390.7	456.2	425.6	490.2
Coal	12.75	11.33	6.582	7.099
Gas	364.4	313.6	360.3	316.5
*TOTAL Renewables**	13.47	131.4	58.67	166.5
Wind	0.398	98.83	33.56	127.9
Geothermal	11.22	15.04	12.06	16.62
Dedicated Biomass	1.074	16.88	12.14	21.40
Carbon Emissions (million tons)	857.8	768.6	775.0	749.8

*TOTAL Renewables includes wind, geothermal, biomass, and other, but does not include hydro.
**New nuclear capacity and new hydro capacity are not available options in the model. Numbers do not sum due to rounding.

The carbon cap with updating targeted at renewables results in renewables generation rising to almost the 15% target under the 15% RPS policy. The electricity price is higher than in the 15% RPS policy case. As a result of the higher electricity price and the higher level of generation from renewables, the carbon allowance price at $28 per ton is substantially lower than the $67 that resulted from the broad-based approach to updating. Both the level and composition of renewables change under the targeted updating approach, which tends to favor wind and geothermal over biomass.

Table 10 compares the economic surplus effects of four policies: 10% RPS, 15% RPS, broad-based updating (leading to a 9.3% renewables share of total generation), and updating to renewables (leading to a 14.9% renewables share). The numbers reported here provide a snapshot of the economic surplus effects of the different policies relative to the central case baseline in a single year, 2020. The last two rows of the table provide two measures of the average efficiency cost of the suite of policies: average efficiency cost per MWh of additional renewable generation and average efficiency cost per metric ton of carbon reduction. Comparing the different policies in terms of their overall cost-effectiveness is challenging because the policies yield different bundles of incremental renewables generation and carbon reductions.

Table 10. Economic Surplus as Difference from Baseline for Carbon Allowance Allocation Cases (2020 snapshot, Billions 1999$)

	10% RPS	**15% RPS**	**Broad-based Updating**	**Updating to Renewables**
Consumers	-2.59	-6.37	3.95	-11.48
Producers	-3.21	-4.92	-10.80	-5.18
TOTAL Economic Surplus*	-5.76	-11.27	-6.81	-16.62
Renewables Share	10%	15%	9.3%	14.9%
Average Efficiency Cost of Additional Renewables ($/MWh)	*15.9*	*19.5*	*21.9*	*29.1*
Average Efficiency Cost of Carbon Reductions ($/ton)	*111*	*126*	*82.2*	*153.9*

*The economic surplus measures do not include any environmental benefits resulting from the policy.

The 15% RPS can be compared to the carbon policy with updating to renewables because they achieve approximately the same amount of renewable generation and roughly equal carbon reductions as well. The 15% RPS is more cost-effective, both at promoting renewables and at reducing carbon emissions, than the updating to renewables carbon policy; the carbon policy incurs an economic surplus cost that is about 50% higher than that of the 15% RPS policy.

Expanding the comparison to include other scenarios becomes more complicated. The broad-based updating is proximate to the 10% RPS with respect to the economic surplus cost: the cost of the carbon policy with broad-based updating is $6.81 billion in 2020 to achieve just under 10% renewables, while the 10% RPS has a cost of $5.76 billion, about $1.05 billion (15%) less than the carbon policy with broad-based updating. However, the carbon policy with broad-based allocation leads to 30.9 million tons (3.6% of baseline) fewer emissions of carbon than does the 10% RPS policy. Thus the broad-based carbon policy costs $1.05 billion more, but yields 30.9 million tons of additional carbon reductions at an incremental cost of $34 per ton, substantially lower than the average cost of carbon emission reductions for any of the RPS policies, including the 10% RPS.

Broad-based updating is also comparable to the 15% RPS. By design, the two policies achieve nearly identical carbon emissions levels, and yet the latter policy is $4.4 billion more expensive in terms of economic surplus loss. However, as noted above, the latter policy also delivers 269 million additional MWhs of renewables generation, and the incremental cost of those additional MWhs is approximately $16 per MWh—much lower than the average cost of renewables under either the updating policy or the 15% RPS.

In summary, these comparisons suggest that the carbon cap combined with a broad-based updating allocation to all generators except nuclear and hydro is the most cost-effective way to reduce carbon emissions. We emphasize that the finding hinges on the way in which carbon emission allowances are allocated. A carbon cap with updating to renewables was much more expensive. In order to achieve the related goal of increasing renewable generation, the RPS policies are more cost-effective. However, the carbon cap combined with a broad-based updating performs fairly well with respect to this goal as well; but, again, a carbon cap with updating to renewables was much more expensive.

The results here are more illustrative than definitive as only a single level of renewables generation is considered when selecting the carbon cap and the updating approach is not compared to other allocation approaches such as an auction. Previous research indicates that an updating approach to allocating carbon emission allowances is generally not as cost-effective as other approaches in reducing carbon emissions from the electricity sector, such as an emission cap-and-trade program with allowances allocated by auction (Burtraw et al. 2001).

Chapter 7. Conclusions

This study evaluates several different approaches to supporting renewable generation in the U.S. electricity sector. A closely related goal to increasing renewable generation is the reduction in emissions of greenhouse gases. The approaches to supporting renewable generation that are considered include a renewables portfolio standard (RPS), renewable energy production credit (REPC), and a carbon policy with emission allowances allocated in different ways.

We find the cost of RPS policies is somewhat less than that suggested by previous studies, when cost is measured by the magnitude of the RPS credit. Several factors contribute to this result, including newer forecasts of higher natural gas prices into the future and updated information on technology cost and performance of renewables.

The RPS raises electricity prices, lowers total generation, reduces gas-fired generation, and lowers carbon emissions, with the size of these effects growing with the stringency of the portfolio standard. The regional effects of the RPS also depend on the stringency of the policy. At lower levels (5%–10%), the RPS is met largely by geothermal and biomass, which leads to increased generation in the west (geothermal) and in regions where biomass has an economic advantage over other renewable sources. At higher (10%–20%) RPS levels, wind generation becomes a key component of the incremental renewable generation required to meet the standard.

The RPS policy appears to be more cost-effective than either REPC policy in promoting renewables and in reducing carbon. Extending the recently expired REPC policy that benefits only wind and dedicated closed-loop biomass through 2020—the REPC-E scenario—produces a large increase in renewables generation, bringing the total share of non-hydro renewables above 11% in 2020. However, this policy also produces a lower electricity price, which limits its effectiveness in reducing carbon emissions. And, the total economic surplus cost of the REPC-E is greater than that of a 15% RPS policy, which does a better job of accomplishing these goals. Combining an REPC-E with an RPS also appears to be ill-advised, given that introducing the subsidy raises efficiency costs and total carbon emissions, the latter of which is due in part to the higher level of electricity production. The REPC policy aimed at a general portfolio of renewable technologies—the REPC-G scenario—is more cost-effective than REPC-E. When designed to achieve the same quantity of total renewable generation as the 15% RPS, however, it does so at greater social cost and with a smaller reduction in carbon emissions. On net, we find the RPS approach to be superior to the REPC approach.

We find the RPS to be less costly than indicated in prior analyses, but its costs are sensitive to underlying assumptions about technology learning, cofiring of coal technologies, and natural gas price projections. We find the RPS can produce important reductions in carbon emissions, both as a result of higher electricity prices and shifts away from fossil generation to renewables. However, these emission reductions are not as large as they would be if renewable generation were displacing coal instead of natural gas. Moreover, the emission reductions are tempered by the tendency for renewables to start to back out existing nuclear generation at higher levels of the RPS. All of these factors contribute to making the RPS less effective in absolute terms and less cost-effective as a mechanism for reducing carbon emissions from electricity generators than a policy designed specifically to limit carbon emissions.

We study two approaches to carbon policy. In both cases, the distribution of carbon emission allowances reward electricity production by distributing allowances to generators based on their (updated) share of electricity generation, either across a broad range of sources (broad-based updating) or limited only to renewables (targeted updating to renewables). This analysis shows that, in order to achieve a comparable level of carbon emissions, the broad-based updating approach to allocation leads to a different mix of generating technology, including fewer renewables, than does the RPS. Nonetheless, this carbon policy with broad-based updating is more cost-effective if the focus is exclusively on the lost economic surplus attributable to achieving carbon emission reductions. Alternatively, the targeted updating approach with allocation only to renewables achieves more renewable generation than the carbon policy with a broad-based approach to distributing emission allowances, but it is significantly more costly. Indeed, it is more costly even than an RPS approach with respect to either achieving carbon emission reductions or renewable generation.

The results suggest that the appropriate policy depends upon the goal. If one has a narrowly defined objective of trying to promote renewables, an RPS may be the most cost-effective approach, holding carbon emissions constant. If one is trying to achieve climate policy goals, a carbon-focused policy is preferred. In the latter case, if updating is the method used to allocate carbon allowances, a broad-based approach to updating is significantly more cost-effective in reducing emissions than a narrowly based approach that allocates only to renewable technologies. Finally, although not considered here, there may be benefits to combining an RPS with a carbon policy. Such a combined policy may help to promote capital cost learning and overcome any market failures associated with the inappropriability of these learning gains. Providing a jumpstart to technology learning could yield significant benefits in the more distant future. At the same time, a combined policy provides disincentives to using carbon-intensive technologies such as coal and provides an incentive to conserve electricity as a means to achieve emission reductions.

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