Combining a Renewable Portfolio Standard with a Cap-and-Trade Policy: A General Equilibrium Analysis

by

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Submitted to the Engineering Systems Division
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ABSTRACT

Most economists see incentive-based measures such a cap-and-trade system or a carbon tax as cost effective policy instruments for limiting greenhouse gas emissions. In actuality, many efforts to address GHG emissions combine a cap-and-trade system with other regulatory instruments. This raises an important question: What is the effect of combining a cap-and-trade policy with policies targeting specific technologies?

To investigate this question I focus on how a renewable portfolio standard (RPS) interacts with a cap-and-trade policy. An RPS specifies a certain percentage of electricity that must come from renewable sources such as wind, solar, and biomass. I use a computable general equilibrium (CGE) model, the MIT Emissions Prediction and Policy Analysis (EPPA) model, which is able to capture the economy-wide impacts of this combination of policies. I have represented renewables in this model in two ways. At lower penetration levels renewables are an imperfect substitute for other electricity generation technologies because of the variability of resources like wind and solar. At higher levels of penetration renewables are a higher-cost prefect substitute for other generation technologies, assuming that with the extra cost the variability of the resource can be managed through backup capacity, storage, long range transmissions and strong grid connections. To represent an RPS policy, the production of every kilowatt hour of electricity from non-renewable sources requires an input of a fraction of a kilowatt hour of electricity from renewable sources. The fraction is equal to the RPS target.

I find that adding an RPS requiring 25 percent renewables by 2025 to a cap that reduces emissions by 80% below 1990 levels by 2050 increases the welfare cost of meeting such a cap by 27 percent over the life of the policy, while reducing the CO_2-equivalent price by about 8 percent each year.

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1. INTRODUCTION

There are two main categories of policy instruments to reduce emissions: economic incentive approaches and command-and-control approaches. From the first category is a cap-and-trade policy, which places a limit on the total quantity emissions. All covered entities must submit a permit or allowance for every ton of emissions produced, and the total number of allowances in existence equals the national cap. Covered entities can trade allowances, which creates a market for allowances and establishes a price on emissions, which in turn creates economic incentives for abatement.[1] Command-and-control measures are conventional regulations, for example mandating that specific technologies be used.

Most economists see incentive-based measures such as a cap-and-trade system or an emissions tax as cost effective instruments for limiting greenhouse gas (GHG) emissions. In actuality, many efforts to address GHG emissions combine a cap-and-trade system with regulatory instruments. This raises an important question: What is the effect of combining a cap-and-trade policy with policies targeting specific technologies?

To investigate this question I focus on how a renewable portfolio standard (RPS) interacts with a cap-and-trade policy. An RPS specifies a certain percentage of electricity that must come from renewable sources such as wind, solar, and biomass. RPS policies have gained increasing focus in climate policy, and have already been implemented in some places. The European Union's 20-20-20 goal includes achieving a 20% renewables energy mix by 2020, which is commonly implemented through an RPS. Many states in the U.S. have implemented state-level RPS policies. Further, the majority of U.S. cap-and-trade bills include a national RPS. With so much attention on RPS, it is important to study how such a policy interacts with a cap-and-trade policy.

To do this, I use a computable general equilibrium (CGE) model. Because I am looking at policies that impact sectors throughout the economy, it is crucial to capture all of the interaction and ripple effects. A CGE model is able to do this and is therefore a particularly appropriate tool to assess the economy-wide impacts of these policies. I use the MIT Emissions Prediction and Policy Analysis (EPPA) model, which is developed specifically to evaluate the impact of energy and environmental policies on the global economic and energy systems.

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[1] For a discussion of the history of cap-and-trade systems in the US and analysis of their application to CO_2 see Ellerman, Joskow and Harrison (2003).

I have represented renewable technologies in the EPPA model in two ways. At lower penetration levels renewables are an imperfect substitute for other electricity generation technologies because of the variability of resources like wind and solar. At higher levels of penetration renewables are a higher-cost perfect substitute for other generation technologies, assuming that with the extra cost the variability of the resource can be managed through backup capacity, storage, long range transmissions and strong grid connections. To represent an RPS policy, the production of every kilowatt hour of electricity from non-renewable sources requires an input of a fraction of a kilowatt hour of electricity from renewable sources. The fraction is equal to the RPS target.

The Chapters are organized as follows: Chapter 2 looks at the recent focus on RPS policies in other countries, states within the U.S. and proposed national legislation in the U.S. Chapter 3 reviews the issues affecting the costs of renewable generation, such as government support, intermittency, storage and backup, and long distance transmission and grid connections, which must be accounted for in a CGE model. In Chapter 4 I describe the CGE model I use, and how I modified it to better represent renewable technologies and to implement an RPS constraint. Chapter 5 explores the effect of the adding the new technologies to the model and then uses the new RPS constraint to assess the impacts of an RPS policy, both alone and combined with a cap-and-trade policy. Those results are also compared to a cap-and-trade only policy. I also explore the sensitivity of the results to different assumptions about the costs of generating technologies. In Chapter 6 I offer some conclusions.

2. RENEWABLE PORTFOLIO STANDARDS AND CLIMATE POLICY

2.1 Renewable Portfolio Standards

A renewable portfolio standard (RPS) is a policy that requires that a minimum amount of electricity come from renewable energy sources, such as wind, solar, and biomass. The standard could be expressed in a number of ways, such as the number of megawatts of installed capacity, the percentage of installed capacity, the percentage of electricity produced, or the percentage of electricity sold at retail. Most commonly the RPS is in terms of percentage of electricity sold at retail; for example by 2020 20% of electricity sold must come from renewables. The energy sources qualifying as "renewable" to meet the standard can also vary. Wind, solar (solar thermal and photovoltaic), biomass, and geothermal are generally always eligible. Hydroelectricity may or may not be eligible. A commonly proposed rule is that existing hydroelectric generation does not count, but incremental new hydroelectricity does (EIA, 2007a). Municipal solid waste and landfill gas are sometimes included. Some argue that the standard should be expanded to low-carbon technologies like nuclear, integrated coal gasification combined cycle (IGCC) plants and plants with carbon capture and sequestration (CCS), but almost none of the existing RPS policies or proposals consider these technologies eligible.

Many RPS programs utilize tradable renewable electricity certificates (RECs) to increase the flexibility and reduce the cost of meeting the target. A REC is created when a specified amount (e.g. kilowatt-hour or megawatt-hour) of renewable electricity is generated, and it can be traded separately from the underlying electricity generation. REC transactions create a second source of revenue for renewable generators, which functions like a subsidy. RECs also offer flexibility to retail suppliers by allowing them to comply by either directly purchasing renewable electricity or by purchasing RECs. Banking and borrowing of RECs may also be allowed for flexibility.

Another design option is "tiered" targets. Tiered targets establish different sets of targets and timetables for different renewable technologies (for example, one target for solar and another for wind and biomass). The purpose of tiers is to ensure that an RPS provides support to not just the least-cost renewable energy options, but also to certain "preferred" resources such as solar power (DeCarolis and Keith, 2006). However, this design option is not common as it makes compliance with the target more expensive by mandating technologies other than the least-cost renewables.

An RPS is often advanced as part of a package to address climate change. An important economic concept is that policy should correct market externalities. An array of economic work supports broad incentive-based measures, such as a cap-and-trade system, over technology specific measures for addressing environmental externalities such as climate change (for example, Baumol and Oates, 1988; Tietenberg, 1990; Stavins, 1997; Palmer and Burtraw, 2005; Dobesova et al., 2005). Fischer and Newell (2004) compared the partial equilibrium social cost of different policies using a simple economic model of electricity markets. They found that 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 (assumed equivalent to a cap-and-trade) to achieve the same emissions reductions. By shifting investment away from the least-cost emission reduction options and toward specific renewable technologies, which are not necessarily least-cost or even low-cost, an RPS adds to the economy-wide cost of the policy. Theoretical analysis also generally concludes that economic instruments are more efficient than regulatory mechanisms at promoting technical change (Jaffe et al., 1999; Jaffe and Stavins, 1995). Regulations provide no incentive for firms to make improvements beyond the standards imposed whereas taxes and permits provide continual incentive to reduce pollution control costs. Also, a technology standard like an RPS can result in technological lock-in of solutions that are not the best.

Unlike an RPS, a carbon pricing policy (a cap-and-trade or emissions tax) does not attempt to pick winning technologies. By forcing fossil fuels to internalize the cost of their emissions, a cap-and-trade system indiscriminately provides an advantage to technologies in proportion to the level of emissions they produce, and lets the market choose the least-cost options that achieve to the emissions goal. The market may choose renewables, but it may not— it may instead choose nuclear or CCS. But the winning technologies themselves are not the point, the point is that the emissions target is being met, and is being met in the least-cost way.

Another common argument in support of an RPS is that it is necessary for the development of renewable technologies. There are cases made for intervention in the market when technologies are underdeveloped. Development of new technologies requires gradual learning by doing or learning by using (Arrow, 1962; Dosi, 1988; Mann and Richels, 2004). Thus, it is not because a particular technology is efficient that it is adopted, but rather because it is adopted that it will become efficient (Arthur, 1989). An RPS policy, which forces adoption of renewable technologies, may be appropriate if there are market barriers preventing their adoption, and hence development. Such barriers may exist due to the public good nature of knowledge or learning and scale effects that may act as market barriers for new technologies. Knowledge gained from research, development and deployment can be shared by people outside of the investment and can spillover to other technologies. These positive externalities are not factored into investment decisions and as a result there is an underinvestment in RD&D compared to what is optimal from a social welfare perspective. Also, renewable technologies, like any new technology, have to compete with established technologies which have benefited for a long time from scale, mass production and learning effects, all of which lower costs. When renewables arrive on the market, they have not reached an ideal level of performance in terms of cost and reliability, and hence cannot compete and remain underdeveloped. It can then be argued that an RPS is needed to incentivize investment in and the adoption of renewable technologies.

Otto and Reilly (2007) investigated the need for policies targeting specific low-carbon technologies. They found that when technology externalities exist, adoption or R&D subsidies added to a CO_2 trading scheme can increase the cost-effectiveness of achieving an abatement target by internalizing the externalities. An RPS can be considered an adoption subsidy as it forces renewables into the market. However, they noted that depending on the target, a CO_2 trading scheme alone can be sufficient to induce adoption of low-carbon technologies, alleviating the need for technology specific policies. A cap-and-trade policy at the levels being discussed today (80% below 1990 or 2005 levels) would likely provide sufficient incentive to stimulate dynamic learning for whatever technology the market chooses.

Even if barriers do exist, they would vary by technology in such a way that a generic RPS would not address all of them. Renewable technologies have reached different stages of maturity, and the type of support given to each should therefore be adapted. This might range from R&D support for emerging technologies to information and communication support for those technologies that have already demonstrated their profitability (Christiansen, 2001). The privileged market access afforded by an RPS is likely to be of greatest value in accelerating the progress of early-stage technologies toward competitiveness with conventional fuels in a carbon pricing world, and of least value when extended to mature technologies. Since wind is by far the most mature, it has the least need for RPS support, but because it is the cheapest it would likely dominate, as has been the experience in U.S. states. Further, barriers are not unique to renewable technologies, but are also faced by technologies like CCS and nuclear. It is unclear why renewables would merit directed support while other technologies would not. In addition, most market barriers are to initial entry and should be overcome once a technology achieves a low percentage of the generation mix, well below the percentage targets in proposed and existing RPS policies. In the U.S., state RPS policies have likely already served that purpose. Thus for this study I am assuming that these barriers are already solved.

2.2 Focus on RPS in Climate Legislation

RPS policies are being implemented or proposed more and more frequently, making the study of their impacts increasingly important. A number of countries have already implemented renewable portfolio standards. In 2008 the European Union announced its 20-20-20 goal, which includes achieving a 20% renewables energy mix by 2020.[2] Member states are required to adopt national targets consistent with reaching the overall EU target. Several countries have implemented an RPS with tradable certificates to achieve their national goals, including the United Kingdom, Sweden, Belgium, Italy, and Poland. The European Union is also studying the feasibility, costs, and benefits of implementing a community-wide renewable certificate trading program (ESD 2001, Quené 2002). Outside of the EU, Australia adopted an RPS for wholesale electricity suppliers beginning in 2001. Japan also has an RPS that includes a price cap on the price of renewable credits (Keiko 2003).

In the United States there have been numerous attempts since 1997 to pass a federal RPS, but none have succeeded. However, a federal RPS is now included in a number of Congressional proposals. There is currently a federal RPS bill in the House by Representative Markey (H.R.890) and one in the Senate by Senator Tom Udall (S.433). The RPS included in the Waxman-Markey draft (The American Clean Energy and Security Act of 2009) has the same time schedule of RPS targets as these bills, which is 25% renewable electricity by 2025. The RPS proposals include REC trading, limited banking and borrowing of RECs (within 3 years), alternative compliance payments, penalties, a renewable electricity deployment fund, and sunset provisions, among other features. In addition to stand-alone federal RPS plans, a number of proposed cap-and-trade bills also include an RPS. A selection of U.S. cap-and-trade proposals is presented in **Table 1a, b, and c**. As the "Other Features" row of Table 1c shows, the majority of Congressional cap-and-trade bills incorporate command-and-control, technology-specific measures, particularly an RPS.

[2] The other components of the EU 20-20-20 target are a 20% reduction in CO_2 and a 20% increase in energy efficiency, both by 2020.

Table 1a. Congressional Cap-and-Trade Bills, Basic Features.

	Lieberman-Warner 2007	Bingaman-Specter 2007	Kerry-Snowe 2007	Sanders-Boxer 2007	Waxman-Markey Draft 2009	Feinstein August 2006
Bill Number/ Name	S.2191; America's Climate Security Act of 2007	S.1766; Low Carbon Economy Act of 2007	S.485; Global Warming Reduction Act of 2007	S.309; Global Warming Pollution Reduction Act of 2007	Draft; American Clean Energy and Security Act of 2009	
Basic Framework	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based cap on total emissions for all large emitters: cap & trade with safety valve (TAP)	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based, system to be determined by EPA, allows for cap & trade in 1 or more sectors	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade	Mandatory, market-based, cap on total emissions for all large emitters: cap & trade
Targets	Return emissions to 2005 levels by 2012, then gradually reduce to 70% below 2005 levels by 2050. (different targets for HFCs)	Return emissions to 2006 levels by 2020, 1990 levels by 2030, and at least 60% below 2006 levels by 2050 (set allowances up to 2030, then contingent on global effort)	Gradually reduce to 65% below 2000 levels by 2050: 1990 levels by 2020, then reduce by 2.5% per yr between 2020 and 2029, and 3.5% per yr between 2030 and 2050.	Achieve 1990 levels by 2020, reduce by 1/3 of 80% below 1990 levels by 2030, by 2/3 of 80% below 1990 levels by 2040, and 80% below 1990 levels by 2050.	3% below 2005 levels by 2012, 20% below 2005 levels by 2020, 42% below 2005 levels by 2030, and 83% below 2005 levels by 2050. (different targets for HFCs)	Cut emissions to 70% below 1990 levels by 2050.
Allocation of Allowances	Table of yearly percent auctioned: starts with 22.5% in 2012, ends with 70.5% 2031-2050, balance allocated free (portions earmarked)	Table of yearly percent auctioned: starts with 24% in 2012, increased to 53% in 2030, and to about 80% by 2050, balance allocated free (portions earmarked)	Undetermined percent auctioned, balance allocated free	Undetermined allocation, any allowances not allocated to covered entities should be given to non-covered entities	Undetermined auctioning and allocation	Undetermined auctioning and allocation
Additional Details	• Upstream • Covered entities include 80% of national emissions • Covered entities emit, produce or import products that emit over 10,000 metric tons of GHGs per year • Separate quantity of emission allowances (Emission Allowance Account) for each year from 2012 to 2050 • Banking • Borrowing (up to 15% per yr) • Non-compliance penalties	• Upstream • Covered entities produce over 80% of national emissions • Technology Accelerator Payment (TAP) (safety valve): instead of submitting allowances can pay TAP price: \$12/mt CO_2, escalates annually at 5% real • Banking • President can exempt entities and extend to uncovered entities • Non-compliance penalties	• Total GHGs less than 450 ppmv • Banking • Non-compliance penalties	• Less then 3.6^{o}F (2^{o}C) temperature increase, and total GHGs less than 450 ppmv • Suggests declining emissions cap with technology-indexed stop price	• Upstream & Downstream mix • Covered entities eventually include 85% of national emissions • Covered entities emit, produce or import products that emit over 25,000 metric tons of GHGs per year • Banking • Borrowing (up to 15% from 2-5 years into the future, with interest) • Non-compliance penalties	• Keep temperature increase to 1 or 2^{o}C

Table 1b. Congressional Cap-and-Trade Bills, Additional Details and Features.

	Lieberman-Warner 2007	**Bingaman-Specter 2007**	**Kerry-Snowe 2007**	**Sanders-Boxer 2007**	**Waxman-Markey Draft 2009**	**Feinstein August 2006**
Provisions Related to Foreign Reductions	• Acceptance of foreign allowances (up to 15%) •2.5% of yearly allowances for reducing tropical deforestation in other nations •Help develop and fund adaptation plans in and deploy technology to least developed nations •Review of other nations: if major emitting nations do not take comparable action within 8 yrs, President can require importers to submit allowances for emission-intensive products from such nations	• 5-yr reviews of 5 largest trading partners: if taking comparable action, President recommends emission reductions of at least 60% below 2006 by 2050, also decisions about foreign credits and international offset projects • If other nations do not take comparable action, President can require importers to submit allowances for emission-intensive products from such nations •International technology development program		• Task Force on International Clean, Low Carbon Energy Cooperation to increase clean technology use and access in developing countries	• Criteria for accepting foreign allowances • Deployment of clean technology to developing countries •Allocates 5% of allowance value to reduce international deforestation • “Rebates” to energy intensive industries to maintain competitiveness • Potential to require importers to submit allowances for emission-intensive products	• Credits for protecting rain forests in developing countries • Proposed acceptance of foreign allowances
Credit Provisions	•Credits from sequestration for facilities that do not use coal (for coal-using facilities sequestration reduces their allowance submission), emissions that are destroyed or used as feedstocks, offsets (up to 15%) from non-covered entities	• Credits from sequestration, the use of fuels as feedstocks, the export of covered fuel or other GHGs, hydrofluorocarbon destruction, and offset projects that reduce uncovered GHGs, and perhaps international offset projects	• Credits from sequestration	• Credits from sequestration • Renewable energy credit program	• Offsets limited to 2 billion tons system-wide • Need 1.25 offset credits for every ton of emissions • Offsets Integrity Advisory Board determines eligible projects	• Credits from sequestration, non-covered entities, international projects, and responsible land use

Table 1c. Congressional Cap-and-Trade Bills, Additional Details and Features (continued).

	Lieberman-Warner 2007	**Bingaman-Specter 2007**	**Kerry-Snowe 2007**	**Sanders-Boxer 2007**	**Waxman-Markey Draft 2009**	**Feinstein August 2006**
Other Features	• Carbon Market Efficiency Board: monitors economy and allowance trading market, can provide relief (more borrowing, lower loans, loosened cap for a given year, etc.) to avoid significant harm to the economy, as long as cumulative emissions reductions over the long term remain unchanged • Climate Change Credit Corporation: proceeds from allowance auctions and trading activities, deposited into multiple funds (6 new) covering technology R&D, transition assistance, wildlife and ecosystem restoration, climate adaptation and security, and firefighting •Energy efficiency standards •Incentives to produce fuel from cellulosic biomass	•Proceeds from auction go to Energy Technology Deployment Fund (which also gets all proceeds from TAP payments), Adaptation Fund, and Energy Assistance Fund •Incentives to produce fuel from cellulosic biomass	• Climate Reinvestment Fund: proceeds from auctions, civil penalties, and interest, used to further Act and for transition assistance • National Climate Change Vulnerability and Resilience Program • EPA to carry out R&D **• Renewable Portfolio Standard: 20% of electricity must be renewable by 2020** • Motor vehicle emission standard • Renewable fuel required in gasoline • E-85 fuel pump expansion • Consumer tax credits for energy efficient motor vehicles	• EPA to carry out R&D • Sense of Senate to increase federal funds for R&D 100% each year for 10 years • Transition assistance **• Renewable Portfolio Standard: 20% of electricity must be renewable by 2020** • Mandatory emissions standards for all electric generation units built after 2012 and final standards for all units, regardless of when they were built, by 2030 • Motor vehicle emission standard	• Strategic Reserve of 2.5 billion allowances for cost-containment **• Renewable Portfolio Standard: 25% of electricity must be renewable by 2025** • Low Carbon Fuel Standard • Motor vehicle emission standard • Energy efficiency standards • Incentives for CCS and electric vehicles • Use of auction revenue unspecified, but implied use for clean technology, worker transition, consumer assistance, adaptation, and international obligations	• Climate Action Fund: proceeds from allowance auctions and interest, used for technology R&D, wildlife restoration, and natural resource protection **• Renewable Portfolio Standard;** • Carmakers must improve mileage by 10 mpg by 2017 • Emission standards for power producers • Biodiesel and E-85 fuel pump expansion • Plans to extend California-style green-technology programs nationwide

2.3 U.S. State-Level RPS Policies

Within the U.S. many states are not waiting for a federal RPS. In fact, currently 28 states and the District of Colombia have enacted non-voluntary state-level PRS statutes. Five additional states have voluntary RPS programs. Initially, state RPS policies were incorporated into broader state electricity restructuring legislation. More recently, however, state RPS policies have been adopted through stand-alone legislation. **Table 2** lists the current state targets**.** Percentages refer to a portion of electricity sales and megawatts (MW) to absolute capacity requirements. The date refers to when the full requirement takes effect. As of 2007, when 21 states and the District Colombia had an RPS, these policies covered roughly 40% of total U.S. electrical load (Wiser et al., 2007). They have been implemented in both restructured electricity markets and in cost-of-service-regulated markets. Because many of these policies are new, experience remains somewhat limited, yet immensely varied.

Roughly half of the new renewable capacity additions in the U.S. from the late 1990s through 2006 have occurred in states with RPS policies, totaling nearly 5,500 MW (Wiser et al., 2007). However, state RPS policies are not the only driver of renewable energy development. Other significant motivators include federal and state tax incentives, state renewable energy funds, voluntary green power markets, and the economic competitiveness of renewable energy relative to other generation options. It is immensely challenging to isolate the impacts of the various drivers.

Compliance with the state RPS policies has shown a complete dominance of wind power, with biomass and geothermal playing a small role. Over the past 5 years 97% of all new renewable generating capacity installed in the U.S. was wind (see **Figure 1**) (Hogan, 2008). The Independent System Operator and Regional Transmission Organization (ISO/RTO) Council noted in October 2007 that 87% of all the renewable generation in interconnection queues across the country was wind generation (ISO/RTO Council, 2007). EIA (2006) projected that of the capacity stimulated by state RPS programs to 2030, more than 93 percent is estimated to result from large wind farms. Of the eligible renewable resources, terrestrial wind is clearly the most mature and as a result it generally offers the least costly and most immediately accessible option for meeting the RPS targets.

Table 2. State Renewable Portfolio Standards.

State	Amount	Year
Arizona	15%	2025
California	20%	2010
Colorado	20%	2020
Connecticut	23%	2020
District of Columbia	11%	2022
Delaware	20%	2019
Hawaii	20%	2020
Iowa	105 MW	
Illinois	25%	2025
Maine	10%	2017
Maryland	20%	2022
Massachusetts	15%	2020
Michigan	10%	2015
Minnesota	25%	2025
Missouri	15%	2021
Montana	15%	2015
Nevada	20%	2015
New Hampshire	23.8%	2025
New Jersey	22.5%	2021
New Mexico	20%	2020
New York	24%	2013
North Carolina	12.5%	2021
North Dakota*	10%	2015
Ohio	13%	2024
Oregon	25%	2025
Pennsylvania	18%	2020
Rhode Island	16%	2020
South Dakota*	10%	2015
Texas	5,880 MW	2015
Utah*	20%	2025
Vermont*	20%	2017
Virginia*	15%	2025
Washington	15%	2020
Wisconsin	10%	2015

*North Dakota, South Dakota, Utah, Vermont, and Virginia have set voluntary goals for adopting renewable energy instead of portfolio standards with binding targets. (Source: North Carolina Solar Center)

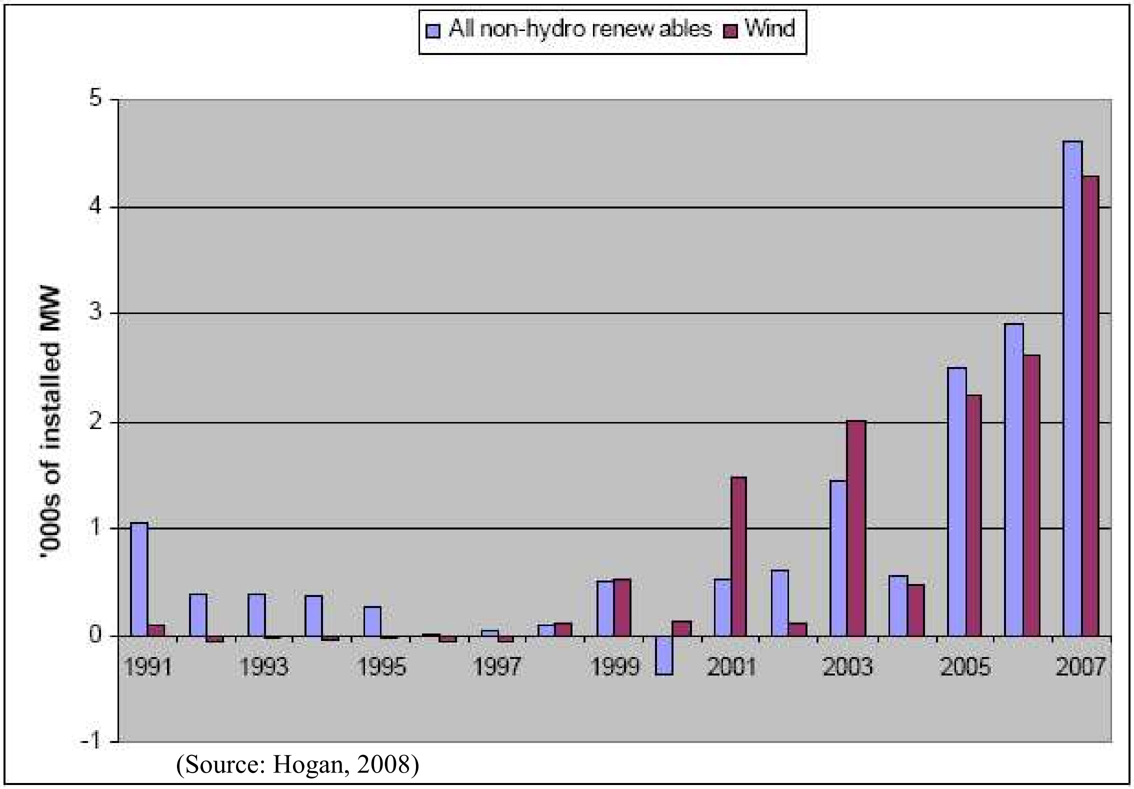

Figure 1. New Additions of Non-hydroelectric Renewable Capacity in the U.S. 1991-2007.

3. ISSUES AFFECTING THE COSTS OF RENEWABLES

There are important factors that impact the costs of renewables, including government support, the intermittency of wind and the need for storage or backup, and the construction of new transmission lines and connecting to the grid. These cost factors are frequently left out of price and cost estimates. For an accurate portrayal of the impacts of an RPS it is vital that I capture these costs in my model.

3.1 Existing Public Policies

There are a number of existing government policies that support renewable technologies. These include subsidies, tax credits and R&D funding. In the U.S. state RPS policies also act as subsidies which reduce the perceived cost of renewables.

The production tax credit (PTC) has been the main renewable electricity policy employed at the federal level in the U.S. In 1992, Congress passed the U.S. Energy Policy Act which authorized a Renewable Energy Production Credit (REPC) of 1.5 cents/kWh of electricity produced from wind and dedicated closed-loop biomass generators. The REPC applied to new generators for the first 10 years of operation. The REPC was extended in 2001, and extended again in 2004 through the end of 2005 and expanded to include geothermal, solar, landfill gas, open-loop biomass, and small hydro. It was extended again and set to expire at the end of 2008. The American Recovery and Reinvestment Act of 2009 (H.R. 1) signed by President Obama extended the PTC until 2012 for wind and until 2013 for other renewables. The PTC acts to reduce corporations' federal tax burden towards levels where only the Alternative Minimum Tax applies. In addition to this production incentive, the Federal government also offers an investment tax credit (ITC) of 10-30% of capital costs depending on the renewable technology. There are also a number of state-level tax credits and subsidies that support renewables.

It is sometimes assumed that a national RPS policy would simply replace the PTC. However, experience with state RPS policies demonstrates the recurring role of the PTC. In Figure 4 above, the impact of the PTC is notable. The PTC has expired three times during the RPS era without immediately being renewed – the end of 1999, 2001 and 2003. Each time it was belatedly reinstated about a year later. The result each time was a notable drop in the pace of renewables development (see 2000, 2002, and 2004 in Figure 4). So even with the RPS, the PTC has been playing a crucial role in renewable development. Also, policymakers in states that have implemented RPS programs have relied on the PTC and federal subsidy programs to contain the retail price impact of RPS compliance.

These financial support policies represent a cost to society that is often not included in cost and price estimates of renewable technologies. The expenditures must be paid for by raising other taxes, increasing borrowing, or cutting government programs. So while the incentives reduce producer costs and therefore retail prices, they do so at the expense of the taxpayer, and this welfare cost is typically not considered when calculating the cost of renewables. Also, by keeping electricity prices low, this subsidy leads to more consumption and generation, limiting the effectiveness of reducing carbon.

3.2 Intermittency and the Need for Storage or Backup

The majority of cost and price estimates do not include the costs of intermittency or the costs of capacity reserves or storage needed to maintain system security. These costs particularly apply to wind and solar. Here I focus on wind since it is the dominant renewable. Because of the intermittency of wind and the temporal mismatch between supply and demand (wind blows more at night when demand for electricity is low), backup capacity and/or storage systems must be put into place. These additional systems have real costs that need to be considered. A study by DeCarolis and Keith (2006) and found that these costs at all levels of wind penetration amount to 1.1 ¢/kWh. Strbac (2002) found 0.9 – 1.2 ¢/kWh for such costs in the U.K.

The intermittency of wind energy affects electricity grids on timescales of seconds to days. System operators are concerned with minute-to-minute, intrahour, and hour to day-ahead scheduling. They employ an automatic generation control (AGC) system to manage minute-to-minute load imbalances. An operating reserve of spinning and nonspinning reserves is capacity that can be dispatched within minutes to respond to forced outages or fluctuations in intrahour load. To meet forecasted demand using economic dispatch, system operators schedule units to produce a specified amount of electricity hours or days in advance. Wind intermittency complicates economic dispatch, particularly when wind serves a large fraction of demand, because the system operator must balance the risk of wind not meeting its scheduled output against the risk of committing too much slow-start capacity (Milligan, 2000). All else equal, the cost of intermittency will be less if the generation mix is dominated by gas turbines (low capital costs and fast ramp rates) or hydro (fast ramp rates) than if the mix is dominated by nuclear or coal (high capital costs and slow ramp rates) (DeCarolis and Keith, 2006).

Intermittency can be mitigated by constructing storage facilities or backup capacity integrated with large wind farms, or by adding load following capacity to the wider grid. Storage and backup add to the cost of the wind project and increase the price of electricity. This will be explored more in Chapter 4. Intermittency can also be mitigated by geographically dispersing wind turbine arrays. Geographic dispersion over sufficiently large areas can increase the reliability of wind by averaging wind power over the scale of prevailing weather patterns. Kahn (1979) quantified the reliability benefit of geographically dispersed wind turbine arrays using California data. More recently, Archer and Jacobson (2003) demonstrated the diversity benefit by comparing the average wind power output across 1 wind site in Kansas, 3 sites across Kansas, and 8 site spanning Kansas, New Mexico, Texas, and Oklahoma. However, such dispersal requires the construction on long-distance transmission lines which are very expensive and also increase the cost of renewables. Intermittency and backup or storage to mitigate it are important costs that need to be accounted for in my model.

3.3 Transmission and Grid Connections

There is also mismatch in the spatial distribution of wind resources and demand. Remote, high-quality, large-scale wind resources are in the middle of the country while electricity demand is on the coasts. This means there is a need for long distance electricity transmission, the costs of which need to be considered.

Existing wind installations are generally located at strong wind sites close to preexisting transmission infrastructure. However, such sites close to demand are not exploitable for large-scale wind. First, these resources tend to be of lower quality, which makes it more economical to import electricity from distant high quality wind sites (Decarolis and Keith, 2006). Second, the high quality wind sites that do exist near demand centers are generally in environmentally sensitive areas and/or areas where there will be significant public opposition. In the U.S., the controversy surrounding the Cape Wind project is an example of the uproar created by proposals aimed at building wind farms in an area that is both a popular recreational center and environmentally sensitive (Grant, 2002; Ziner, 2002).

For wind to serve a significant fraction U.S. electricity demand (20% or more), it will need to be located where there is cheap land, low population densities, and strong wind resources. This means the majority of wind capacity will be placed in the Great Plains and transmitted long distances to demand center. A study by Grubb and Meyer, demonstrated that under moderate land use constraints on wind farm siting, 12 Midwestern states could supply four times the current U.S. demand (Grubb and Meyer, 1993). However, connecting several hundred miles between the Great Plains wind and demand centers would be very costly, and would increase the price of electricity.

The Dobesova et al. (2005) Texas study attempted to quantify all of the additional costs of the RPS policy. **Table 3** shows their accounting of the various costs in 2002, with the total amounting to close to $76 million. When divided by the total RPS generation, this amounts to 2.7 cents/kWh. If only new renewables are counted, this cost rises to 3.1 cents/kWh. These numbers are added on to the cost of generation. This study, of course, was specific to Texas and cannot simply be extrapolated to the country as a whole. However, it is a useful demonstration of how renewable electricity cost and price estimates often leave out important cost components, thereby underestimating costs. In order for my model to accurately capture the costs of an RPS, it is essential that I account for the additional costs of existing policies, intermittency, and transmission.

Table 3. 2002 Costs of Texas RPS.

Summary of 2002 Texas RPS costs	
Production Tax Credit	$44,100,000
Curtailments	$18,000,000
Transmission	$13,000,000
RPS Administration	$663,000
Total	$75,763,000

4. ANALYSIS METHOD

4.1 A Computable General Equilibrium (CGE) Model for Energy and Climate Policy

Computable General Equilibrium (CGE) models represent the circular flow of goods and services in the economy. They represent the supply of factor inputs (labor and capital services) to the producing sectors of the economy and provide a consistent analysis of the supply of goods and services from these producing sectors to final consumers (households), who in turn control the supply of capital and labor services (Paltsev et al., 2005). Corresponding to this flow of goods and services is a reverse flow of payments. Households receive payments from the producing sectors of the economy for the labor and capital services they provide. They then use the income they receive to pay producing sectors for the goods and services consumed. CGE models tracks all of these transactions within and across sectors as well as among countries.

In this way CGE models are very powerful tools for assessing the economy-wide impacts of policies. It is a particularly appropriate tool to study the impacts of emissions reductions and electricity policies. Because these policies impact key sectors of the economy, they affect other sectors throughout the economy. If electricity prices increase, the prices of goods produced by electricity increase, or people have less money to buy other goods. Or electricity may become important to the transportation sector through plug-in electric vehicles. Or biomass may become an important source of electricity generation, thereby affecting the agriculture sector. The point is that policies, especially ones affecting key economic sectors, have ripple effects throughout the entire economy. A CGE model captures all of these ripple and feedback effects. A partial equilibrium model looking just at the electricity sector would not capture all of these interactions and therefore would not get as accurate an estimate of the true economy-wide cost of a policy.

4.2 The Emissions Prediction and Policy Analysis (EPPA) Model

The CGE model that I use is the latest version of the Emissions Prediction and Policy Analysis (EPPA) model developed by the MIT Joint Program on the Science and Policy of Globale Change. The EPPA model is a multi-region, multi-sector recursive-dynamic representation of the global economy (Paltsev *et al.*, 2005). In a recursive-dynamic solution economic actors are modeled as having "myopic" expectations.[3] This assumption means that

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[3] The EPPA model can also be solved as a forward looking model (Gurgel *et al.*, 2007). Solved in that manner the behavior is very similar in terms of abatement and CO_2-e prices compared to a recursive solution with the same model features. However, the solution requires elimination of some of the technological alternatives.

current period investment, savings, and consumption decisions are made on the basis of current period prices.

The EPPA model is built on the GTAP dataset (Hertel, 1997; Dimaranan and McDougall, 2002), which accommodates a consistent representation of energy markets in physical units as well as detailed data on regional production, consumption, and bilateral trade flows. Besides the GTAP dataset, EPPA uses additional data for greenhouse gases and air pollutant emissions based on United States Environmental Protection Agency inventory data.

The model is calibrated based upon data organized into social accounting matrices (SAM) that include quantities demanded and trade flows in a base year denominated in both physical and value terms. A SAM quantifies the inputs and outputs of each sector, which allow for the calculation of input shares, or the fraction of total sector expenditures represented by each input. Much of the sector detail in the EPPA model is focused on providing a more accurate representation of energy production and use as it may change over time or under policies that would limit greenhouse gas emissions. The base year of the EPPA model is 1997. From 2000 the model solves recursively at five-year intervals. Sectors are modeled using nested constant elasticity of substitution (CES) production functions (with Cobb-Douglass or Leontief forms). The model is solved in the Mathematical Programming System for General Equilibrium (MPSGE) language as a mixed complementarity problem (Mathiesen, 1985; Rutherford, 1995). The resulting equilibrium in each period must satisfy three inequalities: the zero profit, market clearance, and income balance conditions (for more information, see Paltsev et al., 2005).

The level of aggregation of the model is presented in **Table 4**. The model includes representation of abatement of CO_2 and non-CO_2 greenhouse gas emissions (CH_4, N_2O, HFCs, PFCs and SF_6) and the calculations consider both the emissions mitigation that occurs as a byproduct of actions directed at CO_2 and reductions resulting from gas-specific control measures. Targeted control measures include reductions in the emissions of: CO_2 from the combustion of fossil fuels; the industrial gases that replace CFCs controlled by the Montreal Protocol and produced at aluminum smelters; CH_4 from fossil energy production and use, agriculture, and waste, and N_2O from fossil fuel combustion, chemical production and improved fertilizer use. More detail on how abatement costs are represented for these substances is provided in Hyman *et al.* (2003).

Non-energy activities are aggregated to six sectors, as shown in the table. The energy sector, which emits several of the non-CO_2 gases as well as CO_2, is modeled in more detail. The synthetic coal gas industry produces a perfect substitute for natural gas. The oil shale industry produces a perfect substitute for refined oil. All electricity generation technologies produce perfectly substitutable electricity except for Solar and Wind and Biomass which is modeled as producing an imperfect substitute, reflecting intermittent output.

The regional and sectoral disaggregation is also shown in Table 4. There are 16 geographical regions represented explicitly in the model including major countries (the US, Japan, Canada, China, India, and Indonesia) and 10 regions that are an aggregations of countries. Each region includes detail on economic sectors (agriculture, services, industrial and household transportation, energy intensive industry) and a more elaborated representation of energy sector technologies. The electricity technologies in red are new additions to the model from this work.

Table 4. EPPA Model Details.

Country or Region [†]	***Sectors***	***Factors***
Developed	***Final Demand Sectors***	Capital
United States (USA)	Agriculture	Labor
Canada (CAN)	Services	Crude Oil Resources
Japan (JPN)	Energy-Intensive Products	Natural Gas Resources
European Union+ (EUR)	Other Industries Products	Coal Resources
Australia & New Zealand (ANZ)	Transportation	Shale Oil Resources
Former Soviet Union (FSU)	Household Transportation	Nuclear Resources
Eastern Europe (EET)	Other Household Demand	Hydro Resources
Developing	***Energy Supply & Conversion***	Wind/Solar Resources
India (IND)	Electric Generation	Land
China (CHN)	Conventional Fossil	
Indonesia (IDZ)	Hydro	
Higher Income East Asia (ASI)	Nuclear	
Mexico (MEX)	Wind, Solar	
Central & South America (LAM)	Biomass	
Middle East (MES)	Advanced Gas (NGCC)	
Africa (AFR)	Advanced Gas with CCS	
Rest of World (ROW)	Advanced Coal with CCS	
	Wind with NGCC Backup	
	Wind with Biomass Backup	
	Fuels	
	Coal	
	Crude Oil, Shale Oil, Refined Oil	
	Natural Gas, Gas from Coal	
	Liquids from Biomass	
	Synthetic Gas	

[†] Specific detail on regional groupings is provided in Paltsev *et al.* (2005).

When emissions constraints on certain countries, gases, or sectors are imposed in a CGE model such as EPPA, the model calculates a shadow value of the constraint which can be interpreted as a price that would be obtained under an allowance market that developed under a cap and trade system. Those prices are the marginal costs used in the construction of marginal abatement cost (MAC) curves. They are plotted against a corresponding amount of abatement, which is the difference in emissions levels between an unconstrained business-as-usual reference case and a policy-constrained case.

The solution algorithm of the EPPA model finds least-cost reductions for each gas in each sector and if emissions trading is allowed it equilibrates the prices among sectors and gases (using GWP weights). This set of conditions, often referred to as "what" and "where" flexibility, will tend to lead to least-cost abatement. Without these conditions abatement costs will vary among sources and that will affect the estimated welfare cost—abatement will be least-cost within a sector or region or for a specific gas, but will not be equilibrated among them.

The results depend on a number of aspects of model structure and particular input assumptions that greatly simplify the representation of economic structure and decision-making. For example, the difficulty of achieving any emissions path is influenced by assumptions about population and productivity growth that underlie the no-policy reference case. The simulations also embody a particular representation of the structure of the economy, including the relative ease of substitution among the inputs to production and the behavior of consumers in the face of changing prices of fuels, electricity and other goods and services. Further critical assumptions must be made about the cost and performance of new technologies and what might limit their market penetration. Alternatives to conventional technologies in the electric sector and in transportation are particularly significant. Finally, the EPPA model draws heavily on neoclassical economic theory. While this underpinning is a strength in some regards, the model fails to capture economic rigidities that could lead to unemployment or misallocation of resources nor does it capture regulatory and policy details that can be important in regulated sectors such as power generation.

4.3 Representing Renewables and Renewable Policy

To model an RPS I added new renewable electricity generation technologies into the EPPA model and added the capability to impose an RPS constraint.

4.3.1 Renewable Technologies

In this model I have distinguished between renewables at low penetration levels and large scale renewables. The cost of advanced electricity technologies, including renewables, is determined by the cost markup, which is the cost relative to electricity prices in the 1997 base year of the model. At lower penetration levels renewables (wind and solar and biomass) are an imperfect substitute for other electricity generation technologies because of the variability of resources.[4] It is assumed these are located at sites with access to the best quality resources, at locations most easily integrated into the grid, and at levels where variable resources can be accommodated without significant investment in storage or backup. The elasticity of substitution creates a gradually increasing cost of production as the share of renewables increases in the generation mix. Thus, the markup cost strictly applies only to the first installations of these sources, and further expansion as a share of overall generation of electricity comes at greater cost (due to locations far from demand and the grid and the need for transmission as well as storage or backup).

In the real world renewables, and wind particularly, have been expanding at a high rate, though from a very small base. Casual observation of the rapid growth rate might suggest these sources are now competitive with conventional generation. However, that evidence does not reveal the full cost of wind or solar at a large scale. Current investment has been spurred by significant tax incentives and subsidies. While representing the after-incentive cost in the EPPA model might produce an accurate portrayal of current market penetration, simply lowering the cost to reflect the subsidies would underestimate the hidden costs of the incentives to taxpayers and utility customers. As discussed in Chapter 3, the costs of these incentives are often ignored in cost and price assessments of renewables. To account for these costs, the model therefore uses the pre-incentive cost of renewables.

To represent large scale renewables, I created two new renewable backstop technologies: large scale wind with biomass backup and large scale wind with NGCC backup. Unlike regular wind, solar, and biomass, large scale wind with biomass or NGCC backup are modeled as perfect substitutes for other electricity because the backup makes up for intermittency. The elasticity of substitution does not create a gradually increasing cost of production as the share of these two technologies increases in the generation mix. The additional costs for large scale wind

[4] For a description of this component of the EPPA model, see Paltsev *et al*. (2005).

(transmission and storage or backup) are incorporated into the markup costs of the new technologies as is explained below.

The main drawback of renewable technologies like wind and solar is their intermittency. As wind and solar increase in scale, making up a larger portion of electricity generation, intermittency becomes even more of an issue. It becomes necessary for these large scale renewable operations to have a reliable backup source of generation.[5] I focus on wind as it the most rapidly expanding renewable and an RPS would likely favor wind, as it has in states with an RPS. It is often assumed that wind can make up a significant portion of electricity generation without threatening the reliability of electricity with its intermittence if turbines are geographically distributed across large areas with low wind correlation. However, there are times when the wind is still for hours or even days at a time over expansive regions (Joint Coordinated System Plan). Such occurrences would be devastating to an electricity system relying on wind for a significant portion of generation. While spreading out wind sites reduces the number of hours with low or zero wind, there is still an effective limit imposed by intermittency. Regardless of how much wind capacity is built, there are still periods when the wind does not blow and backup capacity must be utilized to meet the load. This may create the need for an installed capacity of backup generation of 1 KW for every KW of installed capacity of wind. Even though these backup plants would rarely operate, they would need to be capable of replacing all wind generation in the case of a wind block.

A study by Decarolis and Keith (2006) on large sca1e wind found natural gas to be crucial to a large-scale wind system. They used an optimizing model that minimizes the average cost of electricity by adjusting wind capacity at various sites, a storage system, and gas turbines to meet time varying load under a carbon tax. They found that as the level of wind increased (as the carbon tax increased), the installed gas capacity remained equal to the maximum load so as to be able to meet peak demand if there was no wind. At high levels of wind penetration, the gas turbines effectively acted as capacity reserve that ramped to complement the time-varying wind. There are options other than gas that could also serve as the reserves. The point is that large scale wind needs to be accompanied by a nearly equal capacity of a backup. A storage system is an

[5] Increasing the price responsiveness of demand is another potential method for managing intermittency. Residential customers could be provided with real-time monitors that track energy consumption and price. However, studies have shown demand response to be weak, particularly at the short timescales of economic dispatch (Matsukawa, 2004). Another more effective option is for customers to allow system operators to control appliance loads.

alternative to backup capacity. However, compressed air, pumped hydro, batteries, and other technologies are prohibitively expensive at this time, making backup capacity more likely.

To represent large scale wind with backup capacity in the EPPA model, I created two new renewable technologies: large scale wind with biomass backup and large scale wind with NGCC backup. To do so I calculated the levelized cost of electricity from pulverized coal, wind, biomass, NGCC, wind plus biomass backup and wind plus NGCC backup (see **Table 5**). Overnight capital and fixed and variable operation and maintenance (O&M) costs were taken from EIA data (2009), as were heat rates. For simplicity, all plants were assumed to have a 20 year lifetime. Capacity factors for the traditional plants and fuel costs were taken from a study conducted by Lazard Ltd. (Lazard, 2008). The capital recovery rate of 8.5% was calculated as the rate that gives the constant capital recovery necessary each year over the life of the plant in order to recover capital costs, taking into account inflation and discounting.[6]

For the wind with backup it is assumed that for every KW installed capacity of wind there is one KW installed capacity of backup (either biomass or NGCC). The backup allows the combined plant to be fully reliable because whenever the wind is not blowing demand can still be met through the backup. It is assumed that the backup is only needed 7% of the time (for the rare occurrences when there is no wind). Since the wind operates 35% of the time, this gives a combined capacity factor of 42%. Capital, O&M and fuel costs of a wind plant are combined with those of a biomass or NGCC plant in the levelized cost calculation for wind with backup.

The calculation provides a levelized cost of electricity of 4.1 cents per kWh for pulverized coal, 15.8 cents per kWh for solar thermal, 23.1 cents per kWh for solar photovoltaic (PV), 6.3 cents per kWh for wind, 7.1 cents per kWh for biomass, 4.1 cents per kWh for NGCC, 16.5 cents per kWh for wind with biomass backup, and 8.2 cents per kWh for wind with NGCC backup. As discussed in Chapter 3, we also need to account for the costs of transmission and distribution. I assume an additional \$0.02 per kWh for regular electricity sources and an additional \$0.03 per kWh for large scale wind plus biomass and large scale wind plus NGCC. The \$0.02 per kWh comes from work by McFarland (2002). The extra \$0.01 for large scale wind with backup is assumed to account for the fact that such large scale wind production will be predominately located in the middle of the country at the best wind sites, which is far away from electricity demand which is largely concentrated on the coasts. For example, Wyoming is a prime site for

[6] This capital recovery rate is consistent with Stauffer (2006).

Table 5. Cost Calculation of Electricity from Various Sources.

	Units	Pulverized Coal	Solar Thermal	Solar PV	Wind	Biomass	NGCC	Wind Plus Biomass Backup [1]	Wind Plus NGCC Backup [2]
"Overnight" Capital Cost	$/kW	2058	5021	6038	1923	3766	948	5689	2871
Capital Recovery Charge	%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%
Fixed O&M	$/kW	27.5	56.78	11.68	30	64.5	11.7	94.5	41.7
Variable O&M	$/kWh	0.0045	0	0	0	0.0067	0.002	0.0067	0.002
Project Life	years	20	20	20	20	20	20	20	20
Capacity Factor	%	85%	35%	26%	35%	80%	85%	42%	42%
(Capacity Factor Wind)	%							35%	35%
(Capacity Factor Biomass/NGCC)	%							7%	7%
Operating Hours	hours	7446	3066	2277.6	3066	7008	7446	3679.2	3679.2
Capital Recovery Required	$/kWh	0.02	0.14	0.23	0.05	0.05	0.01	0.13	0.07
Fixed O&M Recovery Required	$/kWh	0.00	0.02	0.01	0.01	0.01	0.00	0.03	0.01
Heat Rate	BTU/kWh	9200	0	0	0	9646	6752	9646	6752
Fuel Cost	$/MMBTU	1	0	0	0	1	4	1	4
(Fraction Biomass/NGCC)	%							8.8%	8.2%
Fuel Cost per kWh	$/kWh	0.0092	0	0	0	0.0096	0.0270	0.001	0.0022
Cost of Electricity	$/kWh	0.0409	0.1577	0.2305	0.0631	0.0712	0.0414	0.1646	0.0819
Transmission and Distribution [3]	$/kWh	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03
Levelized Cost of Electricity	**$/kWh**	**0.0609**	**0.1777**	**0.2505**	**0.0831**	**0.0912**	**0.0614**	**0.1946**	**0.1119**
Markup Over Coal		**1.00**	**2.92**	**4.11**	**1.36**	**1.50**	**1.01**	**3.20**	**1.84**

[1] For calculation purposes we assume a combined wind and biomass plant where there is 1 KW installed capacity of biomass for every 1 KW installed capacity of wind so that when the wind is not blowing a full kWh can be produced. We assume the wind operates 35% of the time and the biomass operates 7% of the time.

[2] For calculation purposes we assume a combined wind and NGCC plant where there is 1 KW installed capacity of NGCC for every 1 KW installed capacity of wind so that when the wind is not blowing a full kWh can be produced. We assume the wind operates 35% of the time and the NGCC operates 7% of the time.

[3] Transmission and distribution costs are assumed to be 2 cents per kWh for existing technologies and 3 cents per kWh for new large scale wind with backup (because wind the is far from demand).

large scale wind, but the closest hub it could connect to is Chicago, Illinois, which is about 1,000 miles from Cheyenne, Wyoming. Long transmission lines would need to be constructed to connect the best wind sites to demand hubs. Adding in these costs gives a levelized cost of electricity of 6.1 cents per kWh for pulverized coal, 17.8 cents per kWh for solar thermal, 25.1 cents per kWh for solar PV, 8.3 cents per kWh for wind, 9.1 cents per kWh for biomass, 6.1 cents per kWh for NGCC, 19.5 cents per kWh for wind with biomass backup, and 11.2 cents per kWh for wind with NGCC backup.

Using these levelized costs including transmission and distribution and dividing by the levelized cost of pulverized coal gives the cost markup of each technology over traditional coal generation. The markup is 1.36 for wind, 1.5 for biomass, 1.01 for NGCC, 3.2 for wind with biomass backup, and 1.84 for wind with NGCC backup.[7] These markups are then put into the EPPA model to define the cost of the advanced electricity technologies. As in the previous section, the costs for renewables do not include tax or subsidy incentives as doing so would hide the economy-wide costs of the technologies.

The EPPA model also keeps track of the cost shares of generation (for example, what share of the cost is capital, labor, fuel, etc.). The factor inputs are capital (K), labor (L), fixed factor (FFA), gas for the NGCC backup (GAS), and land for the biomass backup (LND). 62% of the transmission and distribution cost is attributed to capital and 32% to labor (McFarland, 2002). The fixed factor ensures that the entrance of a new technology is controlled. For example, in the model without the fixed factor once wind with NGCC became competitive it would suddenly take over a large share of electricity generation. This is not very realistic as the entrance of the technology is subject to, at the very least, physical construction constraints. The fixed factor accounts for this and ensures that a new technology realistically eases into the market. The share for fixed factor and land (for the wind with biomass plant) is assumed. The data in Table 5 allows for the calculation of shares of capital, labor (fixed and variable O&M) and fuel costs. The relationship between these three inputs is held constant and they are scaled down to account for the share of fixed factor and land (for the wind with biomass plant). These input cost shares (see **Table 6a** and **b**) are then put into EPPA.

[7] The solar technology in the model, which includes both solar thermal and solar PV, is prohibitively expensive and does not come in in any scenario. The traditional wind technology can be thought of as also including some small-scale solar generation that may be comparative in cost to wind.

Table 6. Cost Shares for Electricity Generating Technologies: **(a)** Existing Technologies and **(b)** New Technologies.

(a) Existing Technologies

Factors	Wind Factor Shares	Biomass Factor Shares	NGCC Factor Shares
K	0.75	0.54	0.37
L	0.20	0.22	0.18
FFA	0.05	0.05	0.01
LND		0.19	
GAS			0.44
TOTAL	*1.00*	*1.00*	*1.00*

(b) New Technologies

Factors	Wind + Biomass Factor Shares	Wind + NGCC Factor Shares
KWind	0.32	0.56
LWind	0.08	0.15
KBackup	0.41	0.16
LBackup	0.12	0.06
FFA	0.05	0.05
LND	0.02	
GAS		0.02
TOTAL	*1.00*	*1.00*

The production functions for the new technologies were then detailed. They can be viewed as a biomass plant or an NGCC plant added on to a wind plant. The elasticity of substitution between the two plants is zero (Leontief) because both are needed in fixed proportions in the production of electricity. The other elasticities are taken from each of the plants individually from prior work on the EPPA model. The production functions are given in **Figure 2 and 3**. WINDBIO represents wind with biomass backup and WINDGAS represents wind with NGCC backup. WINDBIO is considered a fully renewable source counting toward the RPS. However, WINDGAS uses some natural gas, which does not count as renewable. Because it is assumed that the NGCC portion of the plant operates 7% of the time and the total operation of the plant (wind plus NGCC) is 42%, we can say that 16.7% (7/42) of the kWh produced is from NGCC and does not qualify for the RPS. Alternatively, 83.3% of the WINDGAS output does qualify as renewable for the RPS. The gas from the WINDGAS plant is also subject to any carbon policy, and carbon permits or a carbon tax payment covering the amount of gas used must accompany its production.

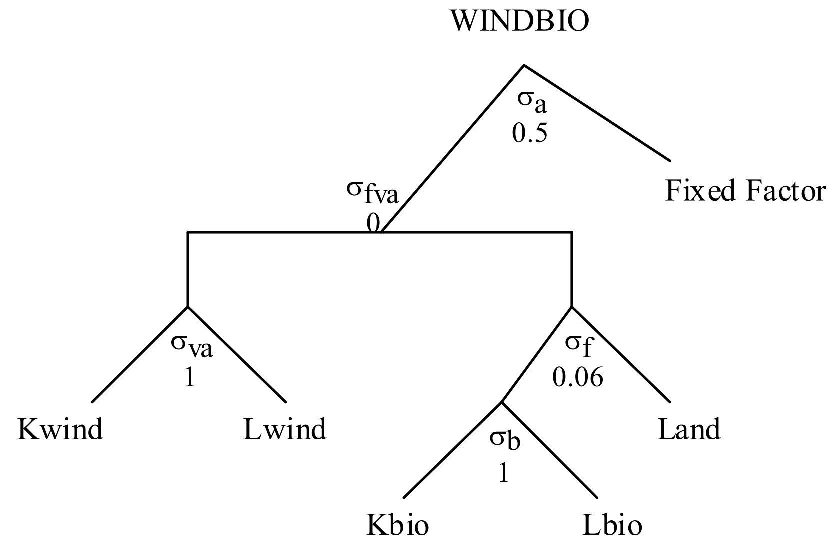

Figure 2. Production Function for Electricity from Wind with Biomass Backup.

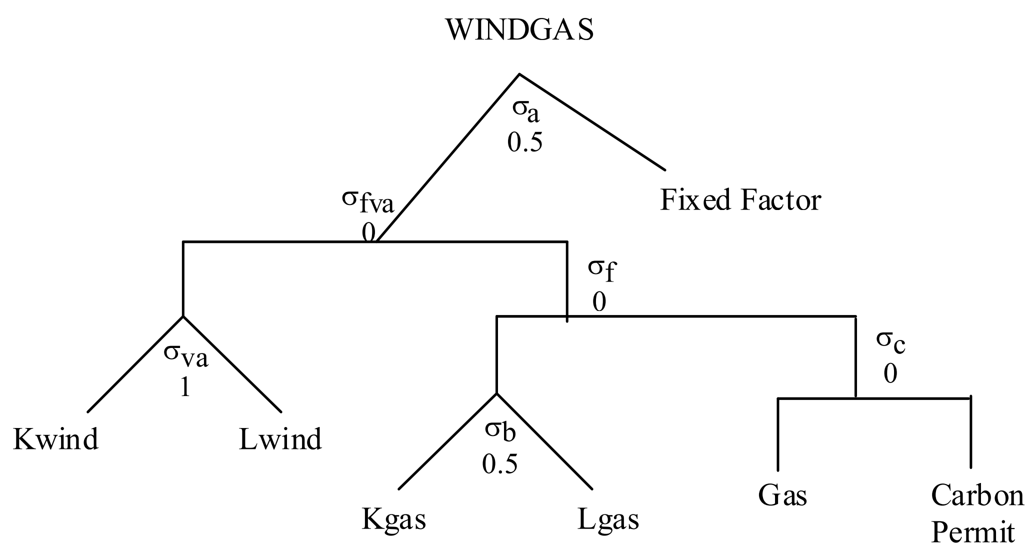

Figure 3. Production Function for Electricity from Wind with NGCC Backup.

4.3.2 RPS Constraint

Next I implemented an approach for modeling an RPS constraint. In the production functions of all non-renewable electricity generating sources, I have added an additional input of renewable electricity. Every kWh of non-renewable electricity requires as an input a certain percentage of renewable electricity (the percentage of the RPS). So if the RPS is 20%, the production of every one kWh of electricity from coal, for example, requires 0.2 kWh of renewable electricity. In the production functions of all renewable electricity generating sources, I have added an additional output of renewable electricity. This method is based on an MPSGE (Mathematical Programming System for General Equilibrium analysis) example created by Tom Rutherford (see **Appendix**).

The way to think about this is as representing renewable electricity credits (RECs), which are a part of all of the U.S. national RPS bills currently proposed. Each REC is equal to one kWh of renewable electricity. So every kWh of electricity produced from renewable sources receives one REC. Alternatively, the production of every kWh of electricity from non-renewable sources requires the input of a fraction of a REC, with the fraction being equal to the RPS requirement. So, again, if the RPS is 20% the production of one kWh of electricity from coal requires 0.2 REC. This input requirement ensures that 20% of all electricity production is from renewables. It is easy to imagine that the non-renewable plants will buy RECs from the renewable plants that receive them with their electricity generation.

5. ECONOMICS OF RENEWABLE PORTFOLIO STANDARDS

To explore the economics of renewable portfolio standards I will focus on policies in the U.S. **Figure 4** shows an approximation of the allowance paths specified in current U.S. cap-and-trade legislation. In some cases judgments were required to fill in an allowance path that is incompletely specified in the legislation. Also, some of these bills were drafts, or subject to revision, and so readers need to check their status to ensure the comparison remains appropriate. The figure also includes a core scenario (167 bmt) that will be the focus of this work. This case represents an 80% reduction below 1990 levels by 2050. For this core case, an allowance path was specified that starts in 2012 by returning to estimated 2008 levels, extrapolating 2008 emissions from the 2005 inventory by assuming growth at the recent historical rate of 1% per year as documented in U.S. EPA (2008). A linear time path of allowance allocation was then assumed between this level in 2012 and a 2050 target equal to 80% below 1990 levels. Given the stock nature of the global warming externality, cumulative emissions is of concern. The core case is therefore labeled by the cumulative number of allowances that would be made available between 2012 and 2050 in billions of metric tons (bmt), or gigatons, of carbon dioxide equivalent (CO_2-e) greenhouse gas emissions. This amount is 167 bmt.[8] Given the recent Congressional focus on cap-and-trade policies of similar stringency, as depicted in Figure 4, focus on this 167 bmt case is appropriate and relevant to current policy discussions.

Throughout the analysis the cap covers the emissions of the six categories of greenhouse gases identified in U.S. policy statements and in the Kyoto Protocol (CO_2, CH_4, N_2O, SF_6, HFCs, and PFCs), with the gases aggregated at the 100-year Global Warming Potential (GWP) rates used in US EPA (2006). All prices are thus CO2-equivalent prices (noted CO_2-e), and are in 2005 dollars. It is also assumed that the cap applies to all sectors of the economy except emissions of CO_2 from land use, and no credits for CO_2 sequestration by forests or soils are included. It is also important to note that in the core cases nuclear power is assumed to be limited by concerns for safety and siting of new plants, and thus nuclear capacity is not allowed to expand. The policy scenarios provide no possibility for crediting reductions achieved in systems

[8] A complete set of results for this scenario and two other core scenarios and for variation in system features over such dimensions as coverage, banking and borrowing, trade restrictions, revenue recycling, and agricultural markets is provided in Paltsev et al. (2008).

outside of the U.S. such as the Kyoto-sanctioned Clean Development Mechanism (CDM) or other trading systems such as the EU Emission Trading Scheme (ETS).

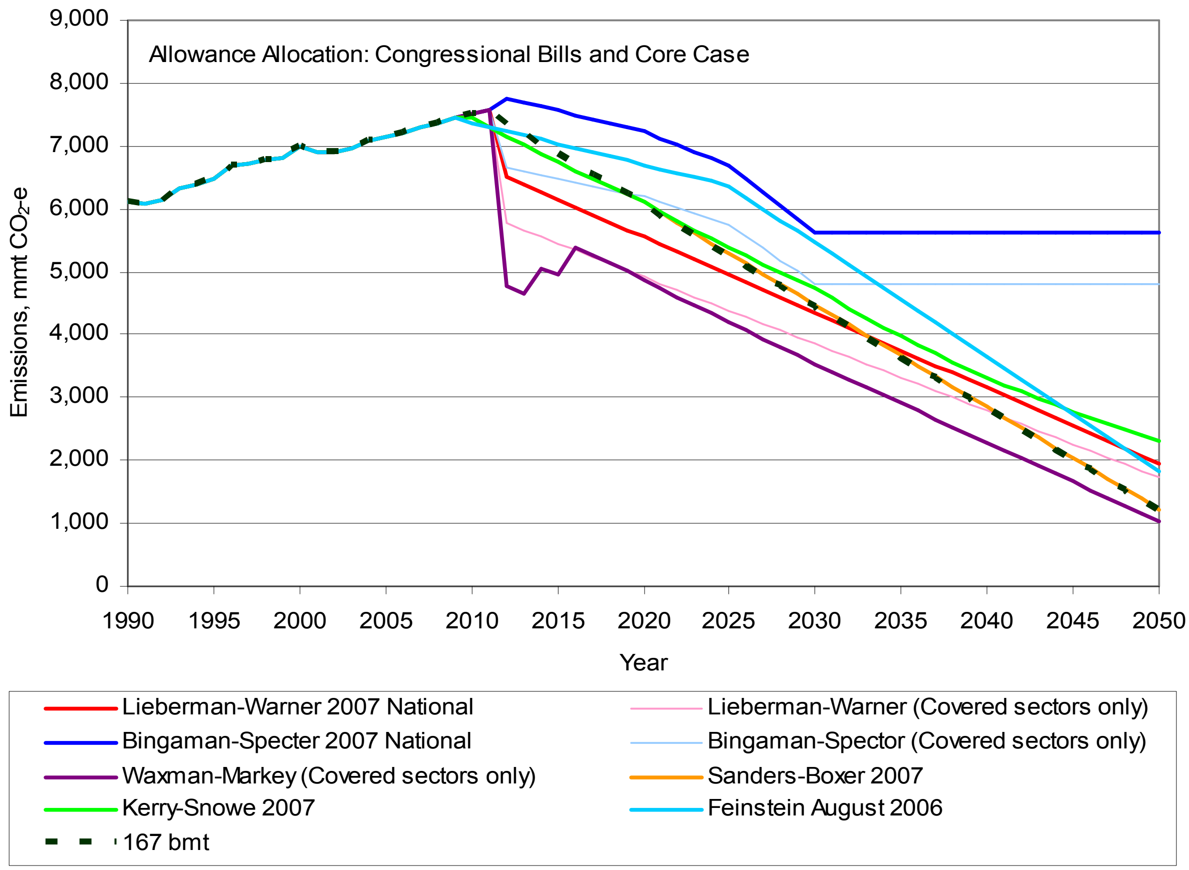

Figure 4. Scenarios of allowance allocation over time.

However, it is assumed that other regions pursue climate policies as follows: Europe, Japan, Canada, Australia, and New Zealand follow an allowance path that is falling gradually from the simulated Kyoto emissions levels in 2012 to 50% below 1990 in 2050. All other regions adopt a policy beginning in 2025 that returns emissions to their 2015 levels from 2025 to 2034, and then further reduces them to their 2000 levels by 2035 and holds emissions at that level to 2050. There is no emissions trading among regions, although implicitly a trading system operates within each of the EPPA regions/countries which include, for example, the EU as a single region (see Table 4). Emissions trading and the availability of CDM projects have a potential to reduce policy costs, however, Paltsev et al. (2007) estimate that international emissions trading does not lead to substantial economic efficiency gains unless the U.S. policy is much more stringent than that in other regions. In all cases, the policy impacts of interest are emissions, CO_2-e price, and welfare change from a reference no policy or business-as-usual scenario. I am also interested in changes to the electricity generation mix.

5.1 Effects of the Revised Model

First I explore the effects of the revised model, without the RPS constraint. To do so, I use a previous version of the model to run the 167 bmt cap-and-trade case. The differences between this previous version and my new version are the new renewable technologies and updated markups on existing technologies. In the new version, the markups on traditional wind and biomass are lower and the markup on NGCC is higher.

Figure 5 shows the GHG emissions paths for the reference and 167 bmt cases for both versions of the model, as well as the 167 bmt allowance path. The paths from model runs are almost identical. The 167 bmt cases show net banking, with GHG emissions below the allowance path in early years and exceeding it in later ones. With banking, allowance holders decide whether to bank or not by comparing the expected rate of return on abatement (and banking of allowances) to returns on other financial instruments and alter their banking behavior until these returns are equalized. The result is that projected emissions in 2050 in both 167 bmt cases are only about 50% below 1990 although the allowance path sets 2050 allowances at 80% below 1990. The bump-up in emissions in 2035 is due to assumptions about policies abroad and the resulting effects on international fuel markets, as the developing countries ramp down their emissions at that time. Their emissions reductions result in lower demand for fossil fuels, especially petroleum, reducing their prices. The U.S., with the banking provision, takes advantage of this effect by consuming relatively more petroleum products when the fuel price falls. Since the U.S. must meet its overall cap over the period to 2050, these added emissions must be made up for with greater reductions (and banking) in earlier periods. Other assumptions about policies abroad could smooth out or eliminate this effect, but the U.S. would still likely exhibit net banking over the control period.

The CO_2-e price for the 167 bmt case in the initial projection year is \$53 per ton CO_2-e using the old model and \$56 per ton CO_2-e using the new model, as graphed in **Figure 6a.** Bankable allowances are financial assets. As such, arbitrage in finance markets ensures that they will earn the same rate of return as other financial assets, here assumed constant at 4% per annum. The return on an allowance is simply the increase in price of the allowance. Thus, in the case of free banking and borrowing of allowances, permit prices must grow at an annual rate equal to the return on other financial assets (4%). The result is that by 2050 CO_2-e prices reach \$210 and \$220 per ton CO_2-e for old and new model runs of the 167 bmt case.

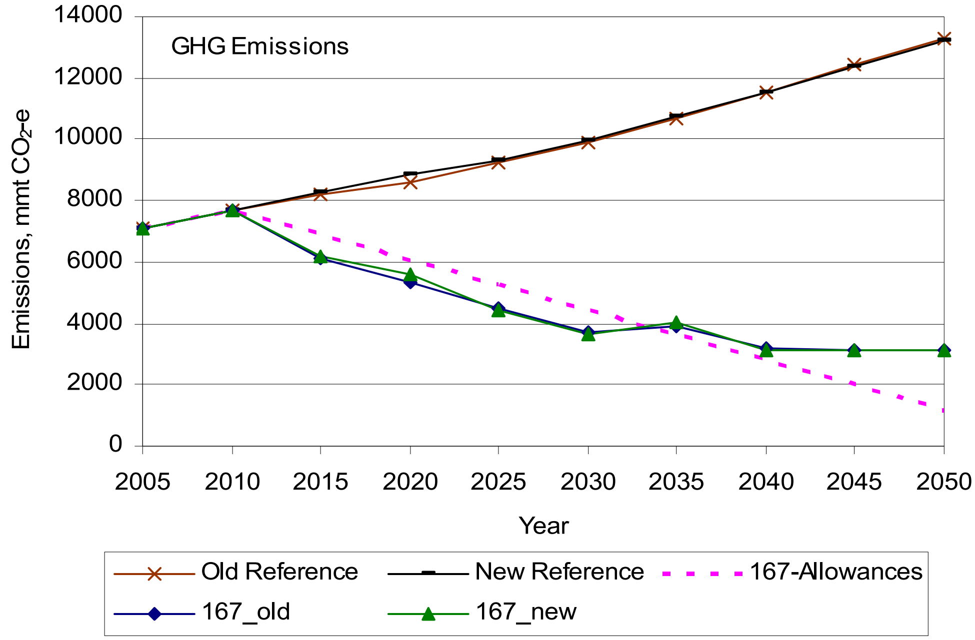

Figure 5. GHG Emissions in Old and New Model.

Following standard economic theory, the overall economic cost of the policy scenarios is calculated using a dollar-based measure of the change in welfare for the representative agent in the United States. In technical terms, welfare is measured as equivalent variation and it reflects a change in aggregate market consumption and leisure activity.[9] The results for the 167 bmt case from both versions of the model are graphed in **Figure 6b**. The initial (2015) levels of welfare effects from the 167 bmt case are small: at -0.07% in both versions of the model. They rise to -1.79% and -1.83% in 2050 in the old and new versions of the model respectively.

[9] The general equilibrium modeling convention is based on economic theory whereby workers willingly choose to work or not, and when they choose not to work they value their non-work time at the marginal wage rate. Carbon dioxide mitigation tends to increase the cost of consuming market goods and thus workers have a tendency to choose to work less, and thus have more non-work time. As a result, the percentage welfare changes in figures and tables throughout this work combine a loss of market consumption that is partly offset by a gain in leisure. Moreover, the denominator is larger by the amount of leisure accounted for in the model, which for our accounting increases the denominator by about 17%. How much non-work time to account is somewhat arbitrary and so the denominator in this calculation can be made larger or smaller depending on how much time is accounted. For the model used here we assume a reasonable number of potential labor hours rather than accounting all waking hours of people of all ages. For a discussion, see Matus et al. (2007).

Given the smooth rise in the CO_2-e price, a similarly smooth increase in the welfare cost might be expected. Instead the percentage loss increases through 2030, drops back in 2035, and then increases again. This pattern results because there are two components of the welfare change. One is the direct cost of abatement that can be calculated as the area under a marginal abatement cost curve. A second stems from general equilibrium interactions, specifically the effects of climate policy abroad. The increase in emissions mitigation by developing countries in 2035 affects domestic welfare through terms-of-trade effects, predominantly through changes in oil prices.

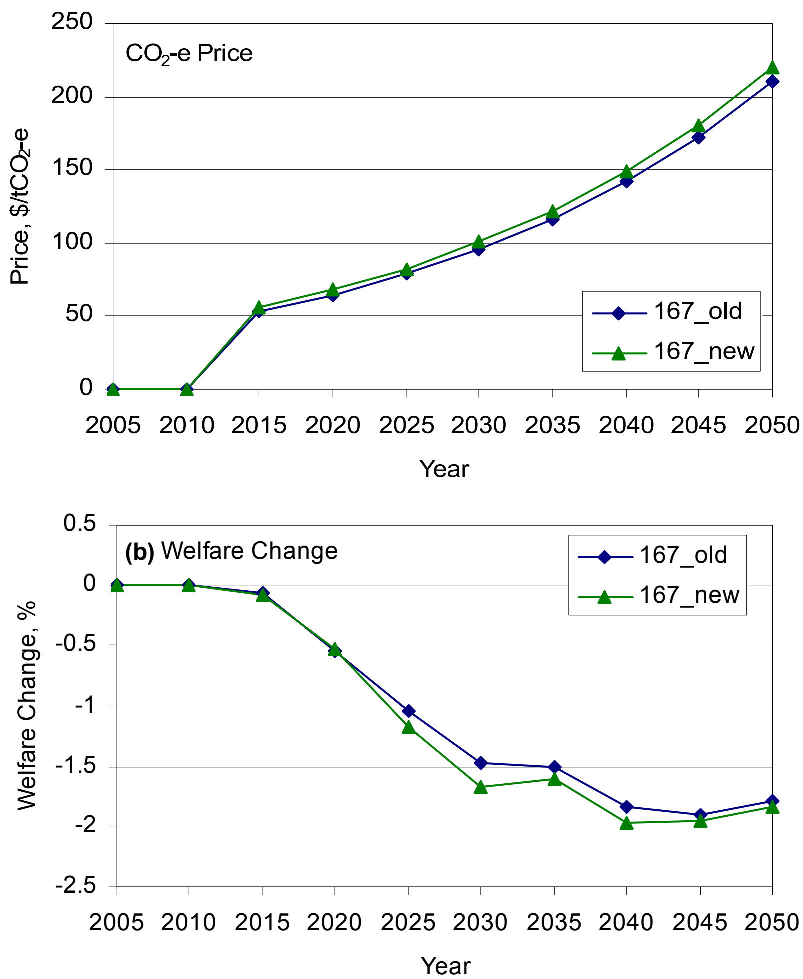

Figure 6. (a) CO_2-e Prices and **(b)** Welfare Changes in Old and New Model.

The slightly higher CO_2-e price and welfare loss that results from the new version of the model can be attributed to the fact that NGCC is more expensive compared to the older version.

NGCC plays an important role in electricity generation, especially before the policy becomes stringent enough to bring CCS technologies into the mix. So when gas is more expensive, the cost of the policy becomes more expensive. Although traditional wind and biomass are cheaper in the new version, they are still not cheap enough to cause significantly more use or to offset the increase in cost from more expensive NGCC.

As presented in **Figure 7**, while the total amount of electricity changes very little from the reference, the energy sources in the 167 bmt cases are drastically different. Whereas the majority of electricity in the reference case comes from coal without CCS, that source is completely eliminated by 2040 in 167 bmt cases. The most striking feature is the dominance of coal with CCS in the 167 bmt cases. This is driven by assumptions about costs. Paltsev et al. (2009) conducted various sensitivity tests on cost markups. Either coal with CCS or nuclear dominate depending on which technology has the cost advantage. For the results in this work, nuclear is constrained for political reasons and therefore CCS has the advantage. The pattern of natural gas is related to coal with and without CCS: natural gas increases to replace traditional coal, but as the policy becomes more stringent coal with CCS out-competes natural gas and it is reduced to a tiny fraction of electricity by the end of the period. New renewables include wind with biomass backup and wind with NGCC backup and traditional renewables are small scale wind, solar and biomass. In the reference case all renewables make up about 2% of electricity in all periods, and in both 167 bmt cases they only make up 2-3%.

Comparing the 167 bmt case results from the old and new versions of the model, they are very similar. In the new version, there is a little more coal, traditional renewables and reduced use, and a little less gas. This is due to the fact that the NGCC markup is higher and traditional renewables markup is lower in the new version. Even though the new version has the new renewable technologies (wind with biomass and NGCC backup), they are too expensive to come in on their own even with an 80% policy. Coal with CCS is a cheaper option and so it dominates.

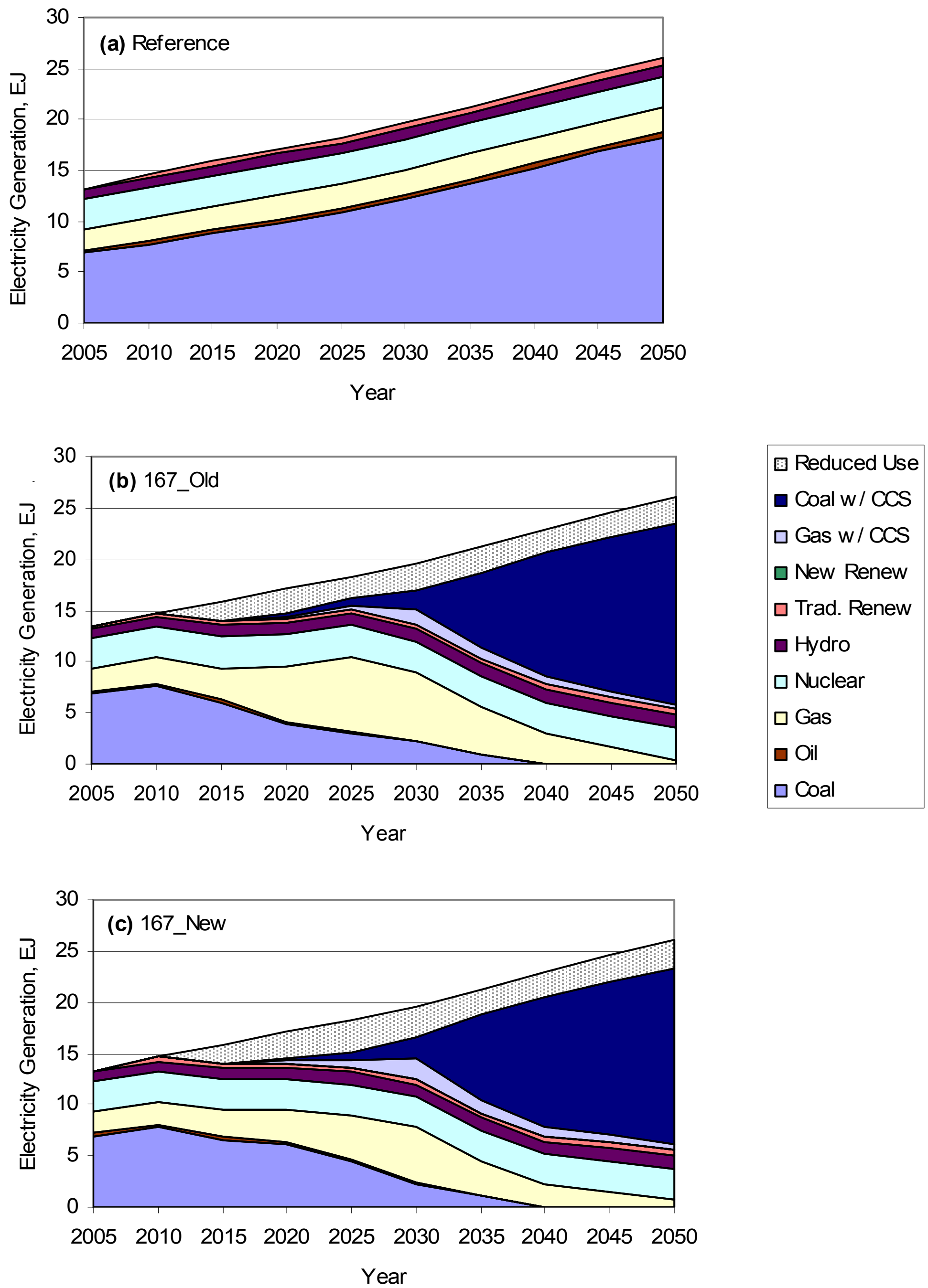

Figure 7. Electricity Generation by Source **(a)** Reference Case, **(b)** 167 bmt in Old Model, and **(c)** 167 bmt in New Model.

To explore when the new model does bring in the new renewable technologies, I have run a series of scenarios in which CCS technologies are not available at all. This could be the case if regulatory hurdles for the development of storage for captured CO_2 are not resolved. In the first scenario (167_wind_gas) the base markups for the new model, those in Table 5, are used. In a second scenario (167_wind_gas_high gas cost) the markup on NGCC is increased to the level of the wind with NGCC backup markup (1.84). In a third scenario (167_wind_low wind cost) the markup on wind with NGCC backup is decreased to the level of the NGCC markup. **Figure 8** shows the electricity generation by source under each scenario.

Using the base markups (Figure 8a), NGCC dominates when CCS is not available. The new renewable technologies remain too expensive to use and it actually proves more cost-effective to significantly reduce electricity use compared to the reference case than to develop the new technologies. When NGCC is as expensive as wind with NGCC backup (Figure 8b), the expansion of NGCC is severely limited. Wind with NGCC backup becomes competitive in the final years when the policy is most stringent and makes a significant contribution (34%) to total electricity generation in 2050. In this case there is also a significant reduction in electricity use and rather than reducing use further in later years, developing the new renewable technology is more cost-effective. Because of the lack or relatively cheap clean technology options, coal sticks around in this case. Given the amount of coal that stays in the generation mix, additional reductions in use compared to the previous case and the emergence of the new renewable technology are required to be able to meet the 167 bmt target. When wind with NGCC backup is the same cost as NGCC (Figure 8c), the new renewable technology dominates electricity generation. Wind with NGCC backup only uses 16.7% of the amount of emissions as NGCC, so if the two technologies have the same cost it is far more cost-effective to meet the emission reduction target using wind with NGCC backup. Developing this clean new wind technology allows for very little reduction in total electricity use, and in fact by 2050 total use is slightly above reference. This last scenario implies the importance of bringing down the cost of large scale renewable technologies.

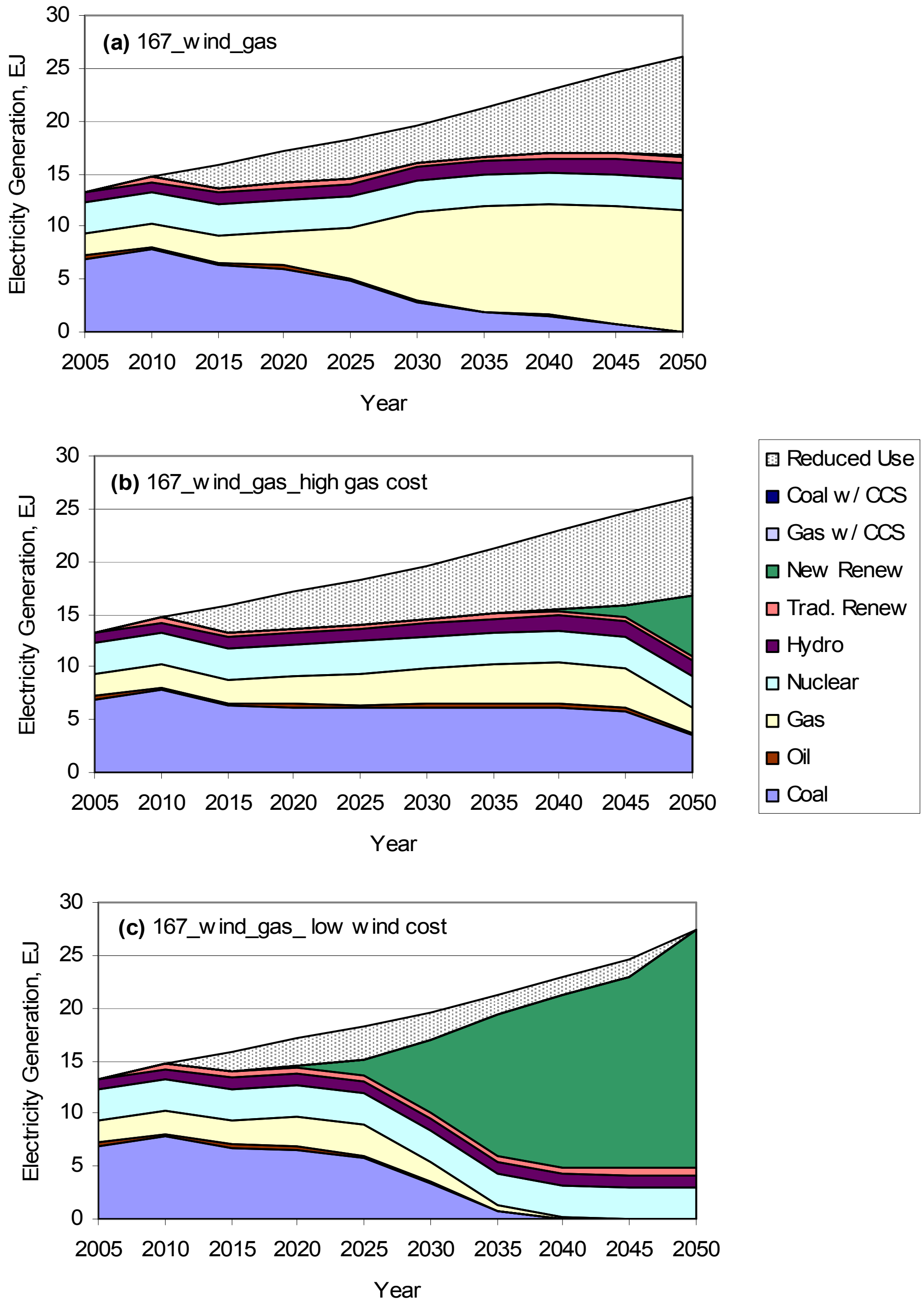

Figure 8. Electricity Generation by Source **(a)** 167 bmt with No CCS, **(b)** 167 bmt with No CCS and High Gas Cost, **(c)** 167 bmt with No CCS and Low Wind with Backup Cost.

5.2 Impact of RPS Policy

Next I utilize the new RPS constraint that I built into the model to test the impact of RPS policies. I use RPS targets from current U.S. Congressional proposals. The RPS-only bills by Representative Markey and Senator Udall (H.R. 890 and S.433) and the RPS included in the comprehensive energy and climate proposal by Representatives Markey and Waxman all include the same RPS targets and timeline (see **Table 7**). As the EPPA model runs in 5-year time steps, I use the RPS targets in years represented in the model: 8.5% in 2015, 17.5% in 2020, and 25% in 2025 and 2030. I then assume that renewables will be held at 25% for the rest of the period to 2050. For the cap-and-trade policy, I continue to use the 167 bmt case (80% below 1990 levels by 2050) as described in the previous chapter.

Table 7. RPS Targets and Timetables **(a)** in Congressional Bills, and **(b)** Used in EPPA.

(a) Targets and Timetables in Bills

Year	Target
2012	6%
2013	6%
2014	8.5%
2015	8.5%
2016	11%
2017	11%
2018	14%
2019	14%
2020	17.5%
2021	17.5%
2022	21%
2023	21%
2024	23%
2025-2039	25%

(b) Targets and Timetables in EPPA

Year	Target
2015	8.5%
2020	17.5%
2025-2050	25%

To help put these RPS targets into context, it is helpful to look at the penetration of renewables under business as usual assumptions. Today in the U.S., renewables are responsible for roughly 3% of electricity production, according to EIA data. The model used in this analysis predicts that under business as usual non-hydro renewables will represent roughly 2% of electricity throughout the period from 2015 to 2050. The share of renewables is lower than today due to a projected increase in electricity demand that is met mainly through fossil fuels. Other models and studies have similar forecasts. For example, in a study done by Palmer and Burtraw (2005) using a Haiku electricity market model, the baseline case forecasts generation by non-hydro renewables to be 3.1% of total generation by 2020. Meeting a 25% target by 2025 would require almost a 13-fold increase in non-hydro renewable generation from 2005 levels, and almost 70% new capacity added during that period would have to be renewables (EIA, 2007a).

5.2.1 RPS Only

To test the impact of an RPS policy alone, I created generic policies in addition to the RPS path expressed in Table 7b above. RPS-only policies for 2015 through 2050 that require the same percentage of renewables for the whole period were simulated for 5, 10, 15, and 20% renewables. So a 20% RPS would start in 2015 requiring 20% renewables and would have that same requirement until 2050.

Figure 9 shows the GHG emissions resulting from the RPS only policies. The 167 bmt case is also plotted to provide context for the emissions reductions achieved via an RPS alone compared to a cap-and-trade policy. It is immediately clear that RPS only policies do not significantly reduce emissions. By 2050, the RPS in the bills reduces emissions by less than 14% below the reference case. In contrast, the 167 bmt case reduces emissions by over 76% compared to the reference case. Cumulative emissions over the period from 2015 to 2050 are approximately 402 bmt for the reference case, 355 bmt for the bill RPS, 397 bmt for the 5% RPS, 385 bmt for the 10% RPS, 373 bmt for the 15% RPS, and 361 bmt for the 20% RPS.

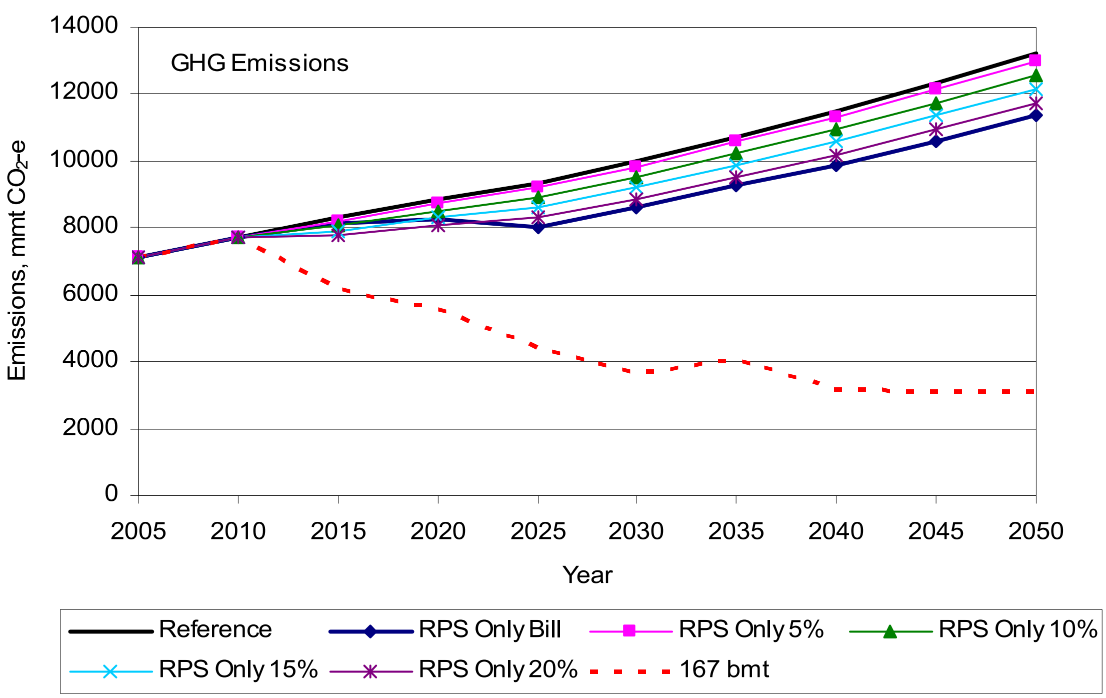

Figure 9. GHG Emissions Paths.

Figure 10 shows the welfare change from the reference no policy case that results from the RPS only policies. Of course, the more stringent the RPS, the greater the welfare cost. The policies show a pattern of more significant losses early on and then welfare gradually improves over time. This is consistent with what one would expect about the costs of a policy like this. In earlier years it is most expensive because it requires investment in new, expensive technologies, such as wind with NGCC backup. Over time, these new technologies are developed and become cheaper, making it easier to meet the RPS target. For the bill RPS, the peak of the welfare loss occurs in 2025 with the peak target of 25%. After 2025 the target stays at 25% while the costs of the new renewable technologies become cheaper because earlier long-lived investments in the technologies reduce future marginal costs. Therefore welfare costs decrease over time. **Table 8** lists the net present value (NPV) of the change in welfare from 2015 to 2050, discounted at a rate of 4% to 2005 dollars. The bill RPS has an aggregate welfare impact over the course of the policy of -0.74%.

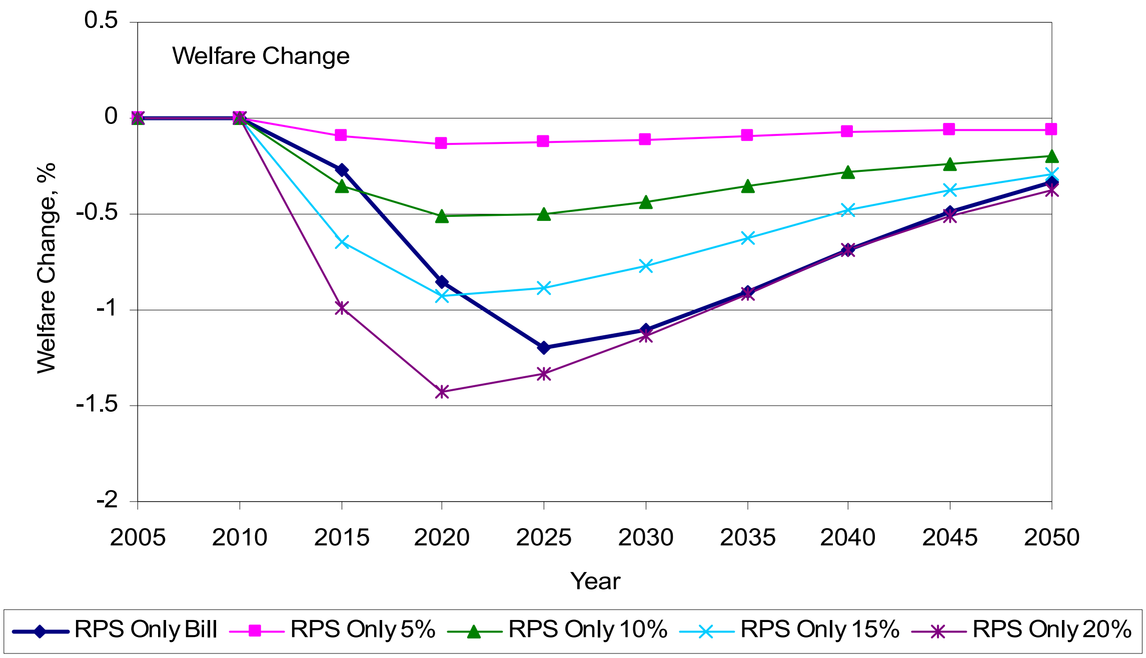

Figure 10. Welfare Change.

Table 8. Net Present Value Welfare Change 2015-2050.

Policy	NPV Welfare Change (%)
RPS Only Bill	-0.74
RPS Only 5%	-0.10
RPS Only 10%	-0.36
RPS Only 15%	-0.64
RPS Only 20%	-0.95

Figure 11 shows electricity generation by source for the reference case and the RPS policy in the Congressional Bills. New renewables and traditional renewables combined achieve the RPS target. In the RPS case, traditional renewables expand to meet the early year targets, but by 2025 with the 25% target, the new large scale renewables become more cost-effective in meeting the target. The new renewables largely replace coal, as well as some natural gas. However, coal use is still significant as an RPS policy alone is not stringent enough to further reduce coal generation, or to bring in CCS technologies. The amount of generation from new renewables also means that little reduction in total electricity use is required.

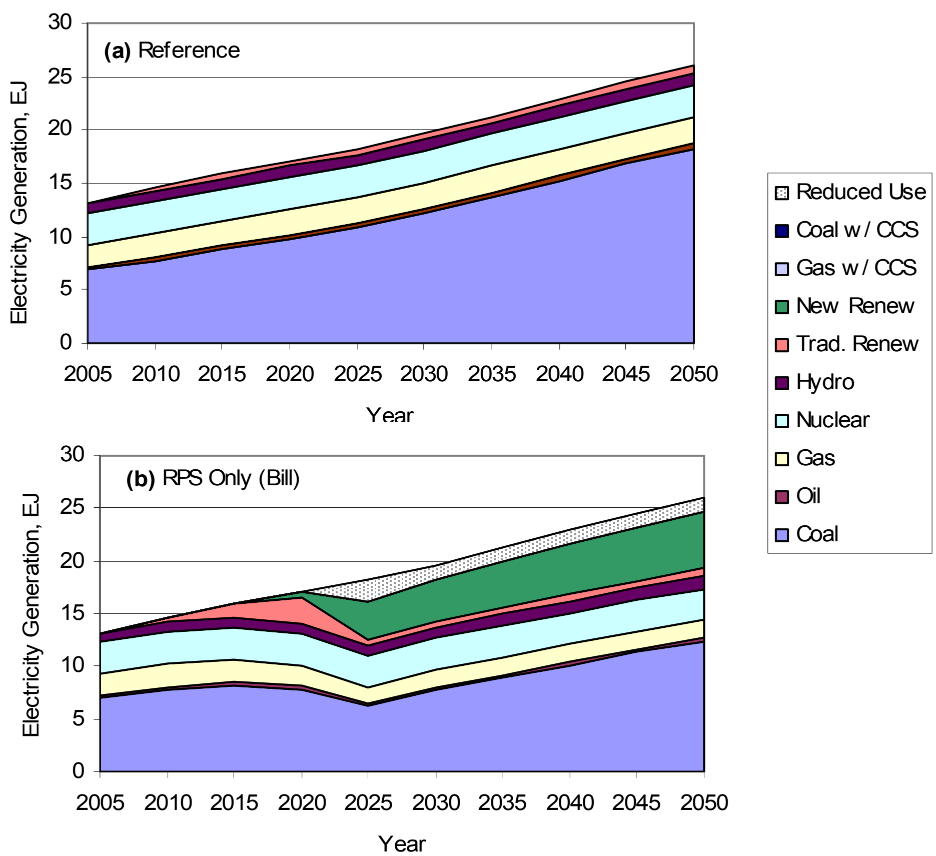

Figure 11. Electricity Generation by Source: **(a)** Reference and **(b)** RPS Only.

5.2.2 RPS with Cap-and-Trade

Next I explore the impact of combining the RPS policies described above with the 167 bmt cap-and-trade policy. **Figure 12** shows that the GHG emissions paths for the various levels of RPS added to the 167 bmt cap-and-trade are almost the same as the emissions path for the 167 bmt cap-and-trade policy alone. This is because the cap is the binding constraint which dictates the emissions path. Adding an RPS to that cap only dictates how to meet part of the cap (through renewables), but does not affect the cap itself.[10] The slight variations in the paths are due to differences in banking behavior. All paths result in cumulative emissions from 2015 to 2050 of 167 bmt.

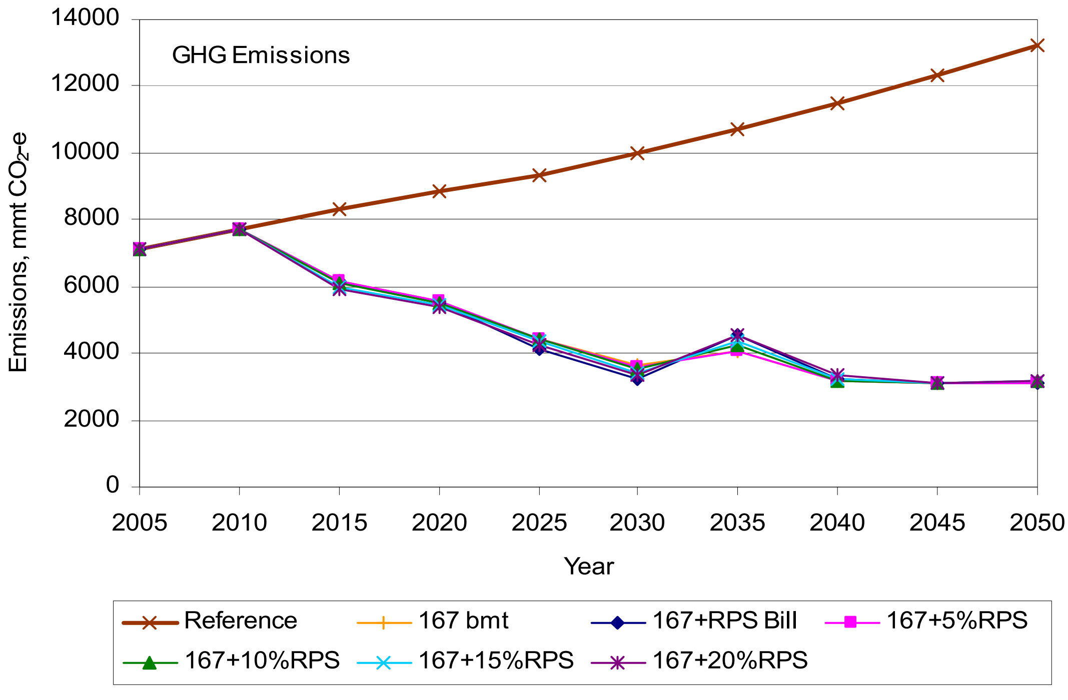

Figure 12. GHG Emissions Paths.

Figure 13 shows the welfare change from the reference case in 2030 for various levels of RPS requirements added to the 167 bmt cap-and-trade. 2030 is displayed because in that year welfare loss reaches a peak in all cases. In the figure below 0% RPS is the 167 bmt cap only. As the level of RPS added to the cap-and-trade policy increases, the welfare loss increases.

[10] If a high enough RPS was added to the cap (for example 80% renewables), then that may become the binding constraint and would determine the emissions path.

Comparing the no RPS case to the 20% RPS, welfare loss increases from less than 1.7% to 2.36%. Beyond 2030, the difference in welfare change due to the RPS level decreases because there has been significant time to adjust to the policy and make investments in renewable technologies that bring down costs in the later years. Combining this information with Figure 12, an RPS combined with a cap-and-trade policy achieves the same emissions as a cap-and-trade only policy but at a greater cost than the cap-and-trade alone. How much greater the cost is of course determined by the level of the RPS.

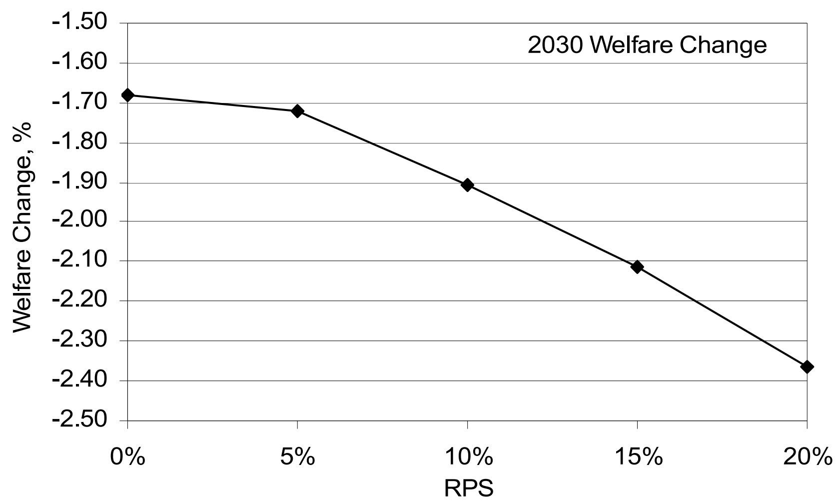

Figure 13. 2030 Welfare Change at Various Levels of RPS Targets.

Figure 14 shows the effect of the additional RPS at various levels on the CO_2-e price in 2030. As the level of RPS added to the cap increases, the CO_2-e price decreases. The price difference is not very large- the price is about \$100/tCO_2-e under the cap-and-trade alone and a little less than \$91/tCO_2-e under the cap with a 20% RPS. However, this decreased price is important. Policymakers have pointed to the lower CO_2-e price that results under a cap with an RPS to claim that adding an RPS to a cap-and-trade policy makes the policy cheaper. However, CO_2-e price is the wrong measure for the cost of the policy. Change in welfare captures the true economy-wide cost of the policy to society. As we saw in Figure 13, adding an RPS to a cap-and-trade increases the welfare loss, meaning it increases the cost of the policy.

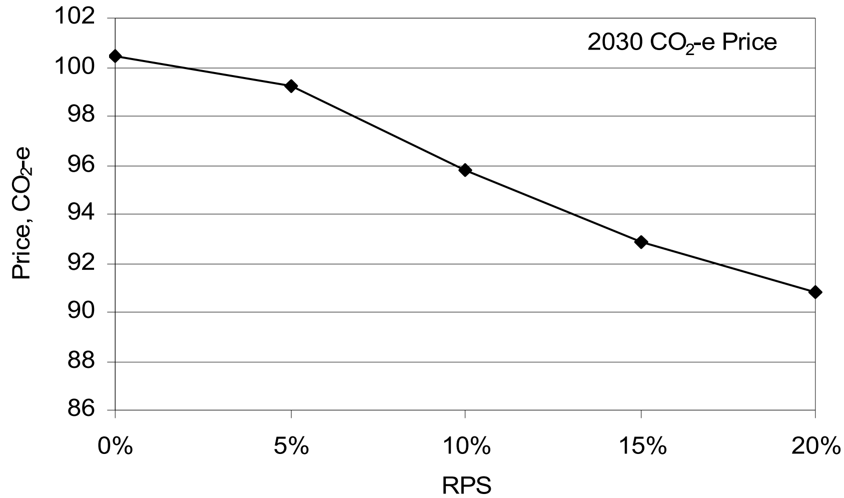

Figure 14. 2030 CO_2-e Price at Various Levels of RPS Targets.

The reason the CO_2-e price decreases with the addition of the RPS can be explained by the marginal abatement cost (MAC) curve. Marginal abatement cost refers to the cost of eliminating an additional unit of emissions. Total abatement cost is simply the sum of the marginal costs, or the area under the MAC curve. A MAC curve for emissions abatement can be constructed by plotting CO_2-e prices (or equivalent CO_2 taxes) against a corresponding reduction amount for a specific time and region (Ellerman and Decaux 1998). Construction of MACs involves multiple runs of a model to get different price-quantity pairs. MAC curves can be used to estimate the amount of emissions reductions that will occur at a given emissions price, or to estimate the emissions price that will result from a given emissions cap.[11]

The generic MAC curves in **Figure 15** can be thought of as MACs for the U.S. for a given year, and are used here as an illustration. Panel(a) represents a cap-and-trade only policy: a target (the cap) is set for a specific amount of emissions reductions. You then find where the cap meets the MAC curve and identify the CO_2-e price (P_{Cap}) that will result from that cap. Panel(b) represents a cap-and-trade policy with the addition of an RPS. The RPS mandates that a certain amount of emissions reductions must occur as a result of replacing fossil fuel electricity generation with generation from renewables. Because the RPS has to be met separate from the cap-and-trade policy, the emissions reductions that occur through the RPS are placed into the baseline emissions. The cap-and-trade then faces a world with lower emissions and therefore

[11] For a study on Marginal Abatement Cost Curves using the EPPA model see Morris et al. (2008).

fewer reductions are required by the cap-and-trade to meet the target. In this way, the RPS essentially shifts the MAC curve to the right. Where the target meets this shifted curve now results in a different, lower price ($P_{Cap+RPS}$). Panel c puts Panels a and b together. The addition of the RPS reduces the price that results from the cap-and-trade.

There is one crucial piece missing from this picture: the emissions reductions achieved through the RPS are *not* free. Although they are worked into baseline emissions because they are required regardless of the cap, they of course come at a cost. To simply say that because we have done the RPS and reduced some emissions that way it will now be easier and cheaper to obtain the cap, ignores the costs of reducing those emissions through the RPS. As discussed in previous sections, an RPS entails significant costs. Figure 13 above shows that the RPS adds significantly to the economy-wide welfare costs. So while the CO_2-e price may be lower, the actual cost of the policy is higher. In this way, adding an RPS to a cap-and-trade can help hide the cost of the policy by reducing the CO_2-e price.

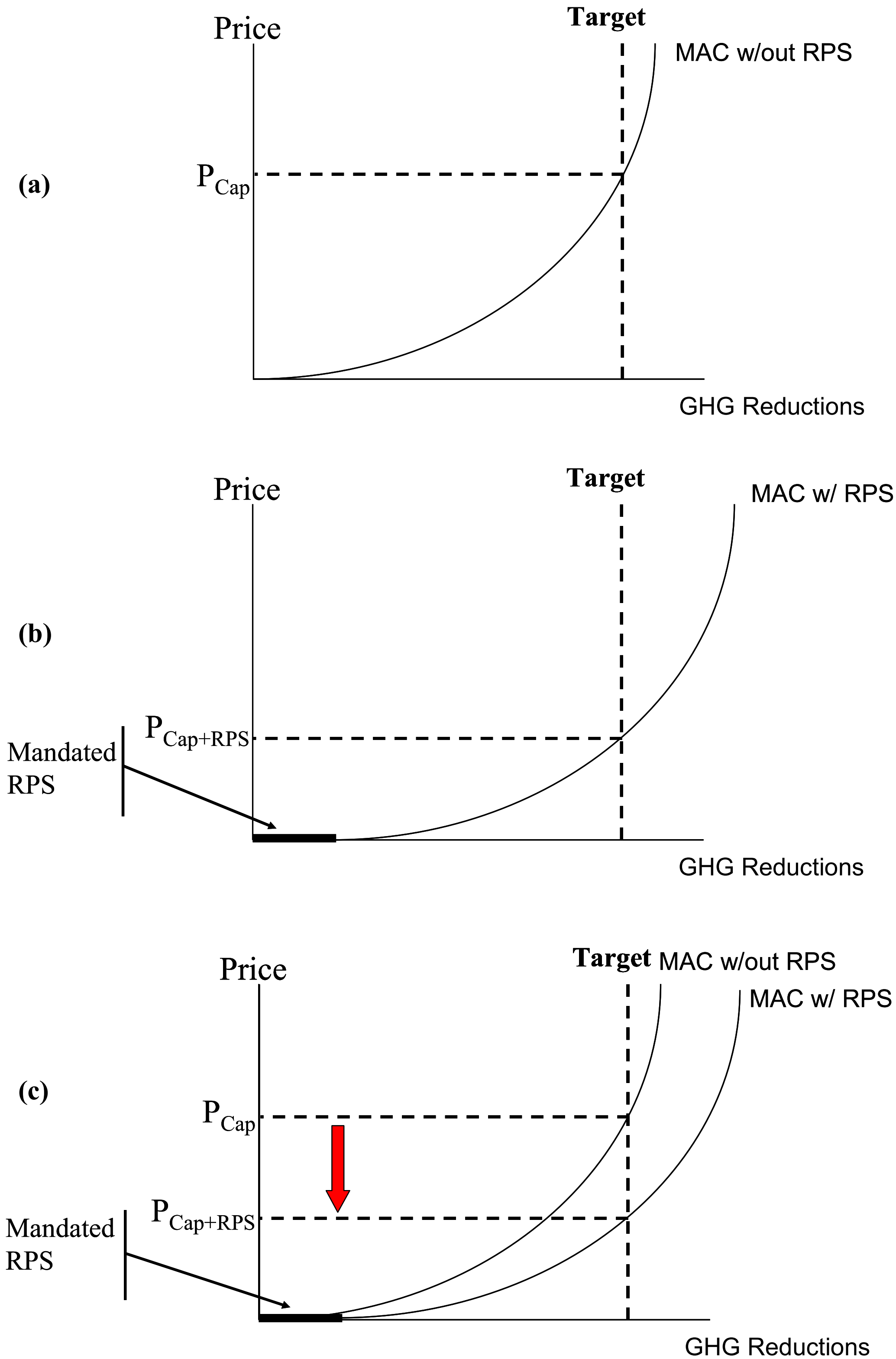

Figure 15. MAC Curves with and without an RPS.

To provide insight into the policy options being considered in the U.S., I focus on scenarios representing actual Congressional proposals: a cap-and-trade alone reaching 80% below 1990 levels by 2050, an RPS alone according to the targets and timetables in the bills (25% by 2025), and the combination of the cap and RPS. **Figure 16** shows the GHG emissions paths for these scenarios. As we have seen above, the RPS alone does not significantly reduce emissions, and results in 355 bmt cumulative emissions over the course of the policy. The cap alone and the cap with the RPS both result in 167 bmt cumulative emissions.

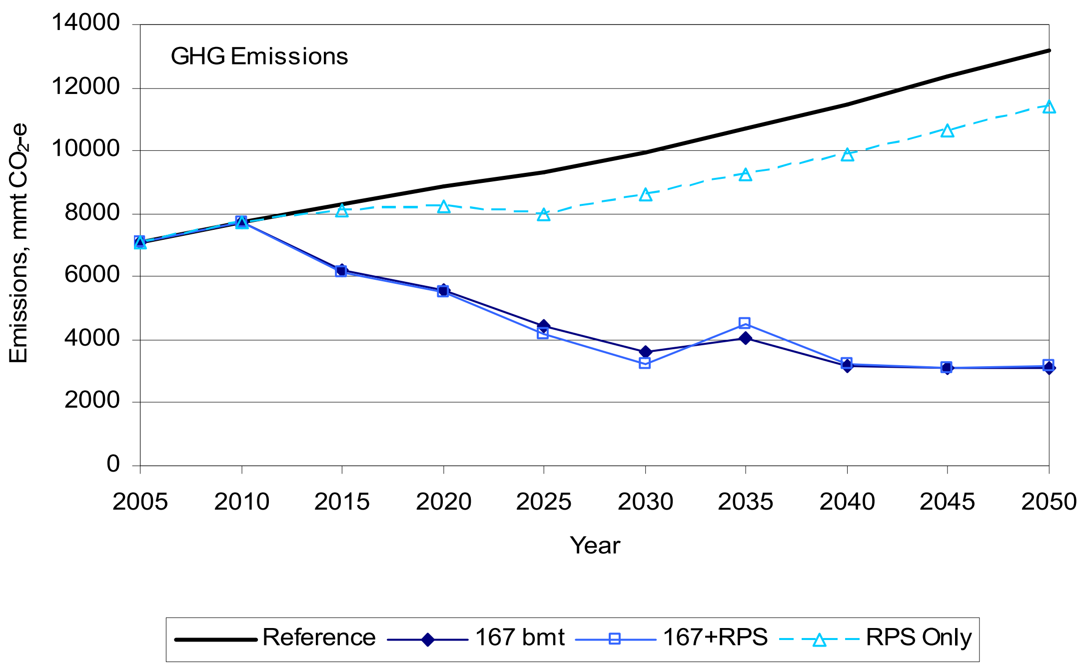

Figure 16. GHG Emissions Paths.

Combining the RPS with the cap results in higher welfare costs than the cap alone (see **Figure 17** and **Table 9**). This means that adding an RPS to a cap achieves the same amount of emissions reductions but at significantly greater costs. The net present value of welfare change over the policy period is -1.22% for the cap alone and -1.55% for the cap with the RPS. This represents a 27% cost increase as the result of adding the RPS to the cap-and-trade. The RPS alone has an NPV welfare change of -0.74%, which is costly considering how little emissions reductions it achieves. As in previous figures, the bump up in welfare change in 2035 is due to the assumption about developing countries ramping up their emission reduction efforts. The cap with the RPS has similar welfare changes as the cap alone in the last years of the policy. This is because there has been sufficient time to adjust to the RPS policy and new renewable technologies have been developed in earlier years making them cheaper in later years.

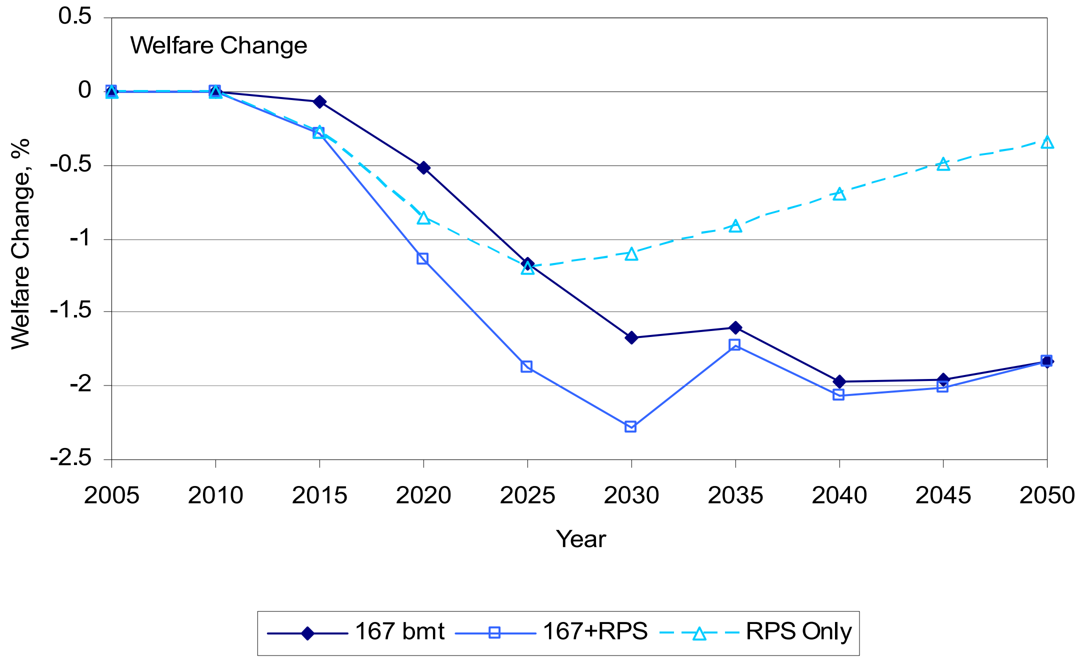

Figure 17. Welfare Change.

Although adding the RPS to the cap increases the welfare cost, it decreases the CO_2-e price (see **Figure 18** and Table 9). With the cap alone the price starts at about \$56 per ton CO_2-e in 2015 and rises to \$220 per ton CO_2-e in 2050. When the RPS is added to the cap the initial 2015 price is reduced to about \$51 per ton CO_2-e and rises to about \$202 per ton CO_2-e in 2050. Adding the RPS to the cap reduces the CO_2-e price by about 8% each year compared to the cap alone.

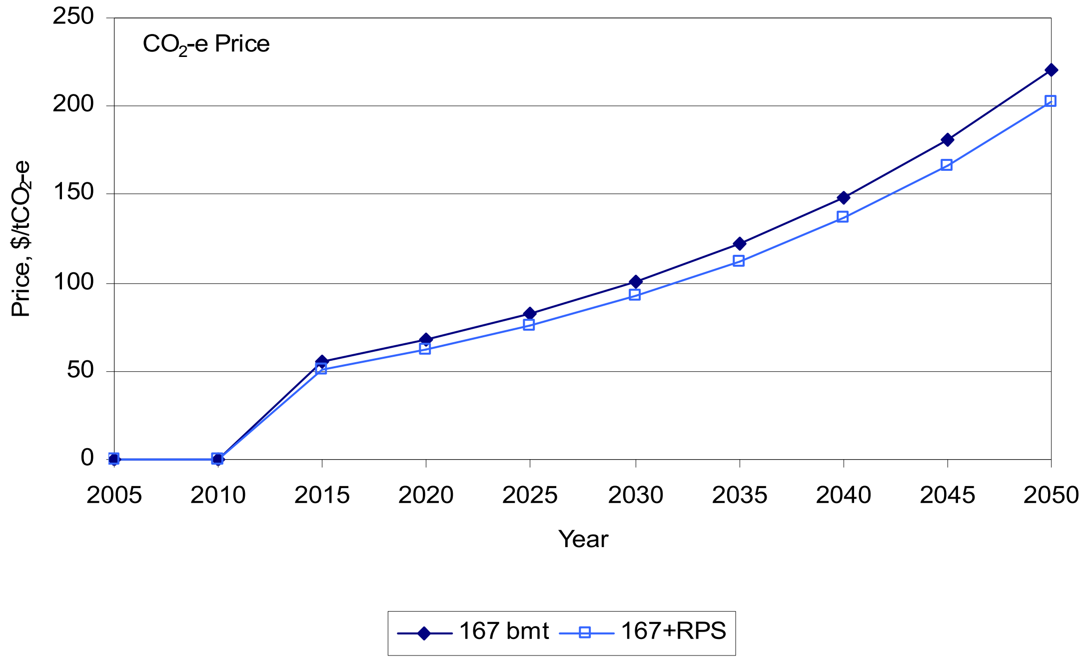

Figure 18. CO$_2$-e Price.

Table 9. Welfare Change and CO$_2$-e Price of Congressional Proposals.

	Welfare Change (%)			CO$_2$-e Price	
	167 bmt	167+RPS	RPS Only	167 bmt	167+RPS
2005	0	0	0	0	0
2010	0	0	0	0	0
2015	-0.07	-0.29	-0.27	55.78	51.24
2020	-0.52	-1.14	-0.86	67.87	62.34
2025	-1.17	-1.87	-1.20	82.57	75.84
2030	-1.68	-2.28	-1.10	100.46	92.27
2035	-1.60	-1.72	-0.91	122.22	112.27
2040	-1.96	-2.06	-0.69	148.70	136.59
2045	-1.95	-2.01	-0.49	180.92	166.18
2050	-1.83	-1.83	-0.34	220.11	202.18

Thus an RPS requiring 25% renewables by 2025 increases the welfare cost of meeting a 167 bmt cap by 27% over the life of the policy, while reducing the CO$_2$-e price by 8% percent each year.

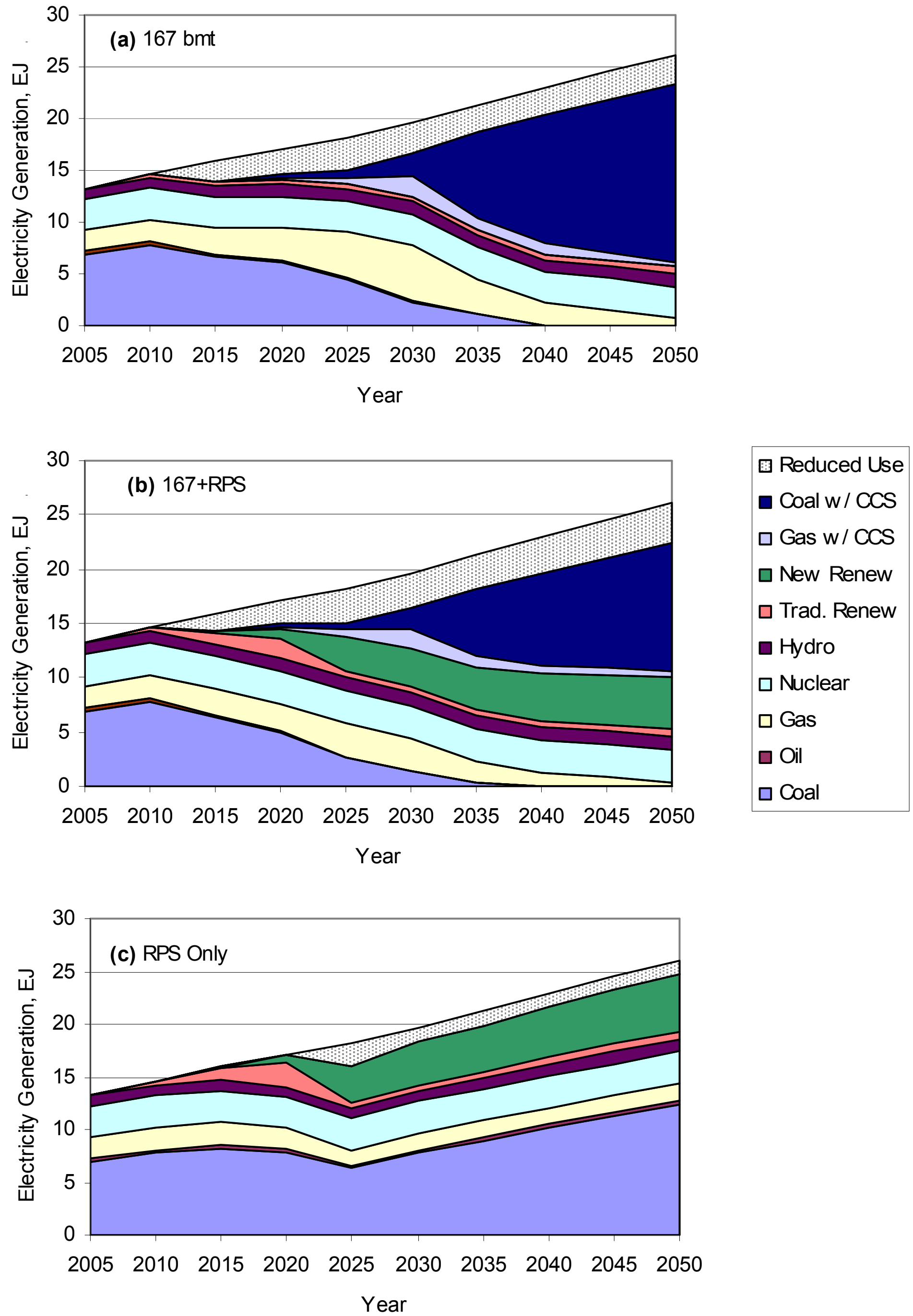

Figure 19. Electricity Generation by Source: **(a)** 167 bmt, **(b)** 167 bmt with RPS, and **(c)** RPS Only.

Figure 19 compares the electricity generation by source of the cap only, cap plus RPS, and RPS only cases. The cap only and RPS only figures have already been shown in Figures 7 and 11 respectively, but it is also useful here to compare them to each other and to the combination of the two policies. Adding the RPS to the cap reduces generation by coal, gas, and coal with CCS. The RPS requires that these cheaper generation sources be replaced by more expensive renewables. In the cap alone, renewables are only about 3% of generation in all years, as CCS is chosen as the more cost-effective low-emitting source. With the RPS, traditional renewables ramp up in early years to meet the renewables target. However, as the target becomes more stringent the new renewable technologies, specifically wind with NGCC backup, become more cost-effective than traditional renewables. This occurs because there is an increasing penalty on traditional renewables as they increase as a percentage of total generation (because of assumptions about intermittency and transmission costs discussed in section 4.3.1). There is also more reduced use with the addition of the RPS, implying it is cheaper to reduce use a little more than to add additional generation by expensive renewables.

Figure 20 displays the impact on electricity prices of the three policy options. The prices are indexed to 2005, so that 2005 equals 1.0. For a sense of the actual prices projected in these scenarios, the index values in the figure can be multiplied by an average electricity price in 2005. Price projections for any particular year are most appropriately viewed as a five-year average because the model simulates the economy in 5-year time steps. The electricity prices are inclusive of the carbon charge and emissions mitigation increases prices relative to the reference. The EPPA model includes increasing adjustment costs when technologies expand rapidly, and these policies involve a rapid transformation of electricity generation. This feature of the sector results in electricity prices overshooting the long-run level as this adjustment occurs, and then falling from that level by 2035 as advanced technologies become cheaper due to previous investment. The cap alone increases electricity prices significantly over the reference case due largely to the marginal cost of adding carbon capture and storage. Adding the RPS to the cap increases prices even more because the RPS forces the use of renewable technologies that are even more expensive than CCS. For the same reason, the RPS alone also significantly increases electricity prices, but not as much as the cap or the cap with the RPS because the RPS does not require significant emissions reductions and therefore does not require the development of other low-emitting technologies like CCS.

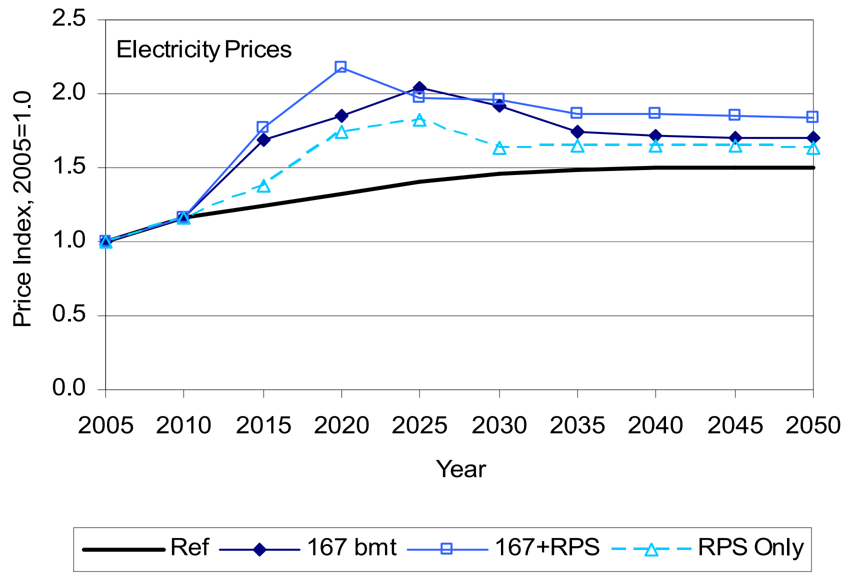

Figure 20. Electricity Price Index.

5.3 Sensitivity

To test the sensitivity of the results above to the cost assumptions made, I created two additional cases with different cost assumptions. In the first case the cost markups for CCS technologies are increased (cases denoted high ccs cost). Coal with CCS and gas with CCS markups are increased from 1.19 and 1.17 to 1.6 and 1.6 respectively. CCS could be more expensive than earlier engineering studies and analyses predicted. There has been slow progress in commercial demonstration and large uncertainties about storage remain. In the second case the cost markups for all renewable technologies (traditional and new) are increased by 25% (cases demoted high renew cost). This is to explore the situation in which renewables cost more than expected, perhaps due to unanticipated difficulties related to scale, transmission or grid connection.

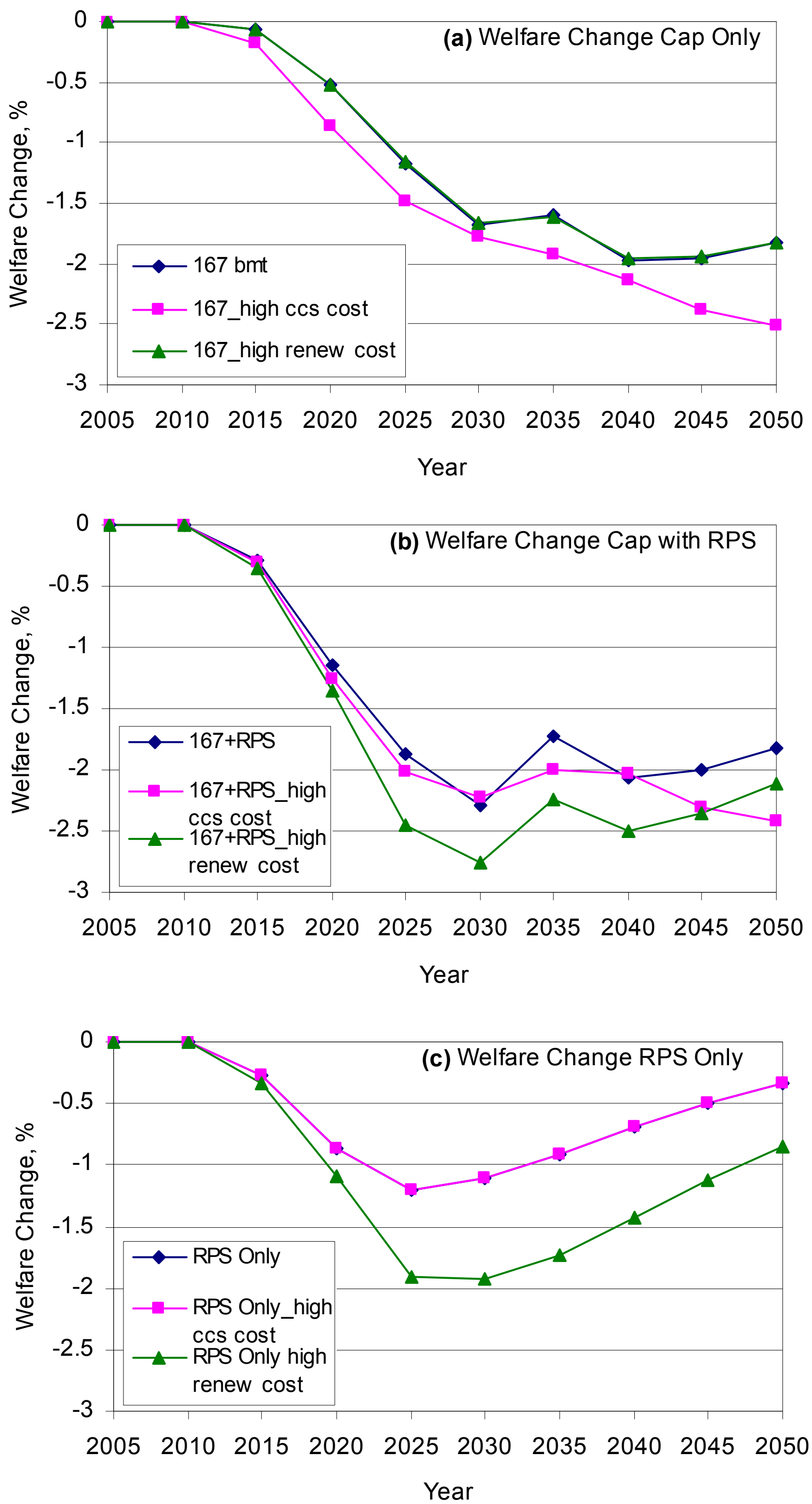

Figure 21. Welfare Change: **(a)** 167 bmt, **(b)** 167 bmt with RPS, and **(c)** RPS Only.

Figure 21 compares the welfare changes in the base case, high CCS cost case, and high renewable cost case for the three policy options: cap only, cap with RPS, and RPS only. For the cap only (Figure 21a), the high renewable cost does not affect the welfare compared to the base case. This is because the cap alone uses only small quantities of traditional renewables (about 3% of generation) so the higher renewable costs have virtually no impact on welfare. The 167 bmt cap policy relies predominately on coal with CCS to meet the cap. For this reason the high CCS cost case results in a higher welfare cost. With high CCS costs the cap must instead be met with an enormous expansion of NGCC and a significant reduction of total electricity use. These options are still more cost-effective than using the expensive renewables, but are worse for welfare than having cheaper CCS available. For the cap with RPS (Figure 21b), the RPS forces a significant percentage of renewables so the high renewable cost case significantly increases the welfare cost. The high CCS cost case does not vary as much from the base case as it did for the cap alone because both cases now require the same amount of renewable generation thereby reducing the impact of differences in the rest of generation. However, at the end of the period the welfare costs of the high CCS cost case increase and surpass those of the high renewable cost case. This happens because, as we will see below, new renewable technologies dominate in those years. For the RPS only (Figure 21c), high CCS costs do not make a difference because an RPS alone policy is not stringent enough to bring in CCS. The high renewable costs, however, drastically increase the cost of meeting an RPS policy.

Figure 22 shows the CO_2-e prices that result from the different cost assumptions for the cap alone and the cap with the RPS. For the cap alone, the high renewables cost assumption does not make a difference in the CO_2-e price because, as was explained, there is very little renewable generation under the cap alone. The high CCS cost assumption, however, results in significantly higher CO_2-e prices because using NGCC and reduced use to meet the cap is more expensive than using CCS at the lower cost. As we saw above and was explained in Figure 15, adding the RPS to the cap lowers the CO_2-e price. The RPS added to the cap makes the biggest difference in price in the high CCS cost case. The high renewables cost assumption results in very similar prices as the base assumptions for the cap with RPS. This means the RPS is doing an excellent job of hiding the cost of the policy. Even though the welfare costs are much higher with the high renewables costs the CO_2-e price is almost the same as with the base cost assumptions.

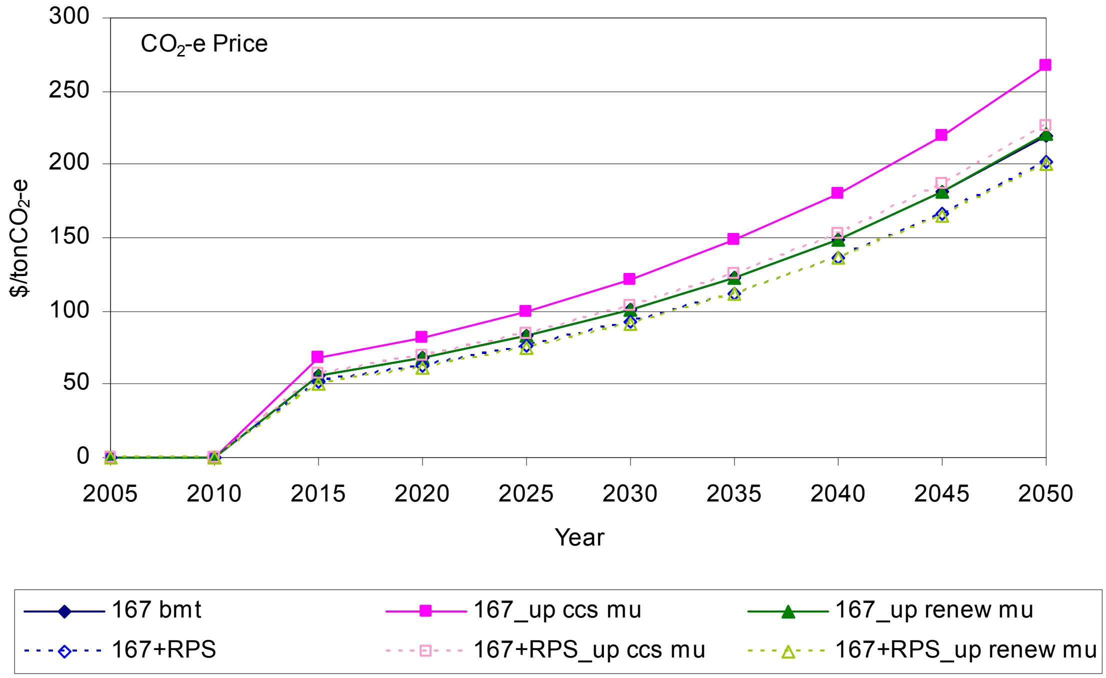

Figure 22. CO_2-e Prices.

Figure 23 shows the electricity generation by source for the cap with RPS policy for the base case, high CCS cost case, and high renewables cost case. The high renewables cost generation mix is almost the same as in the base case, but of course it achieves its RPS target at far greater a cost. For the high CCS cost case CCS is virtually eliminated from the generation mix. The most interesting aspect of this case is that in 2045 and 2050 renewables actually expand beyond the 25% required by the RPS. Renewables rise to 45% and 59% of total electricity in 2045 and 2050 even though only 25% is required. This happens because in earlier years the RPS required the development of the new renewable technologies, especially wind with NGCC backup. This development lowered the cost of these technologies to the point at which they were the most cost-effective means of meeting the stringent cap in later years. In the late years of the policy it was more cost-effective to continue to expand new renewables than to start to develop CCS or to further reduce use. This case suggests the potential value of an RPS in early years to develop and bring down the costs of new technologies, and the lack of a need for an RPS in later years once the technologies have been developed and can compete on their own.

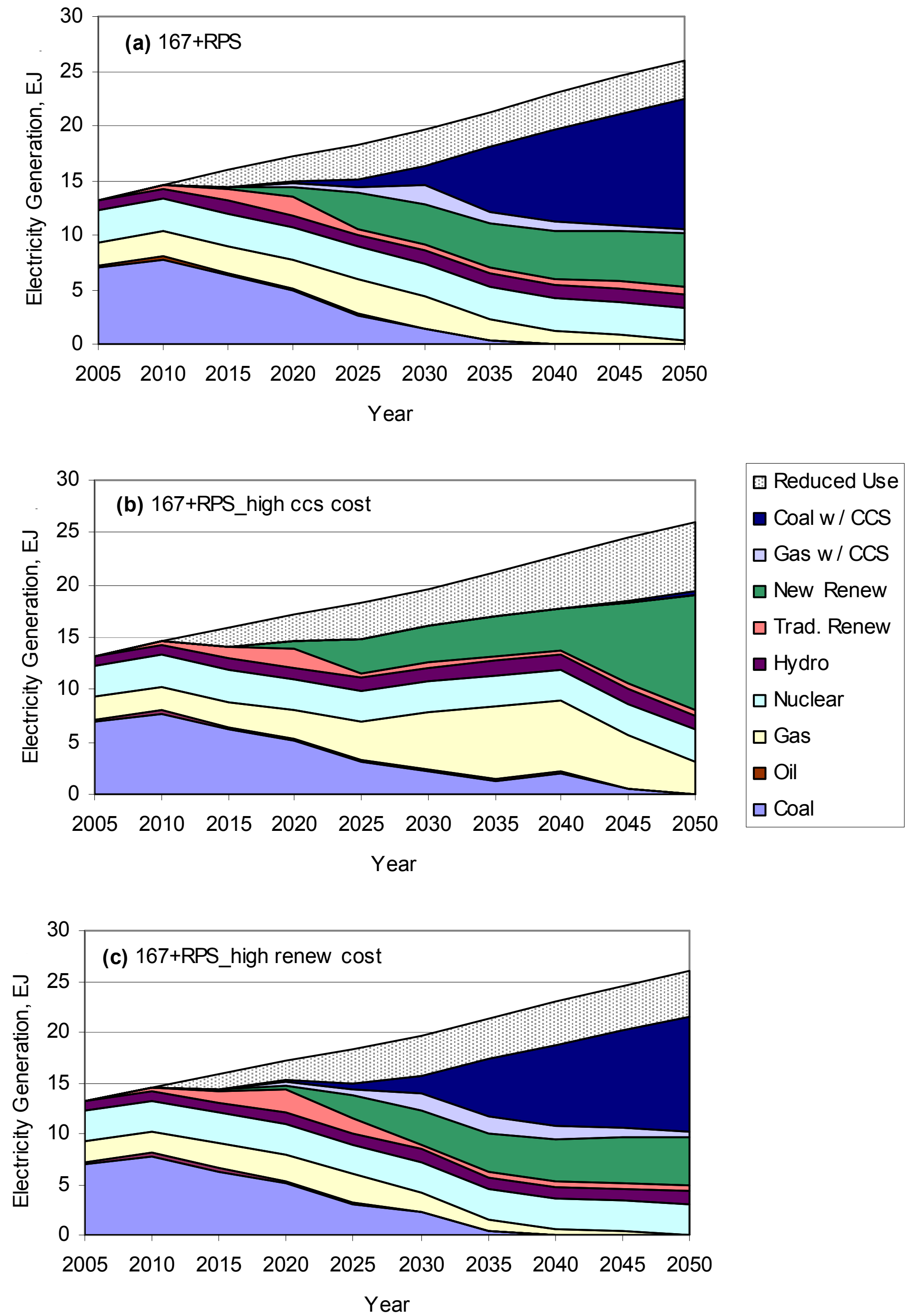

Figure 23. Electricity Generation by Source for the 167bmt with RPS Policy in: **(a)** the Base Case, **(b)** the high CCS cost case, and **(c)** the high renewables cost case.

Figure 24 shows the electricity price index for the policy of the cap combined with the RPS. The high renewables cost case of course results in higher electricity prices than the base case. The difference is greatest when the RPS reaches its peak of 25% in 2025. The high CCS cost case is similar to the base case until 2030 when the high CCS cost case requires more NGCC and reduced use to meet the cap which is more costly than when CCS is cheaper. In 2045 and 2050 the high CCS cost case is using predominately the new renewable technologies, which are the most cost effective in that case, but are more expensive than CCS in the base case.

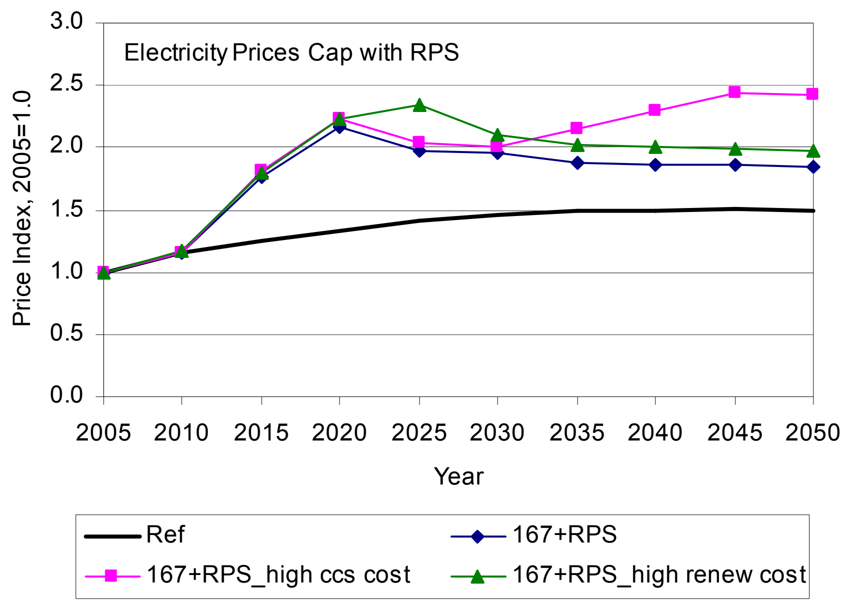

Figure 24. Electricity Price Index.

Table 10 provides a summary of the welfare costs and CO_2-e prices for the three policies (cap alone, cap with RPS, and RPS alone) under the three different cost assumption scenarios. When an RPS is added to a cap the cost of the policy significantly increases (by 27%). If CCS technologies or renewables technologies turn out to be more expensive than expected, each of the policy options becomes even more expensive. When renewables are more expensive, adding an RPS to a cap increases the cost of the policy over the whole period by 39%. This large increase in costs is a result of the RPS policy preventing the use of least-cost options and instead forcing the use of renewables even though they are very expensive. Without the RPS, the cap alone has the flexibility to meet the 167 bmt target with the most cost-effective technologies. Adding the RPS to the cap removes this flexibility, which proves immensely costly when renewables turn out to be more expensive than expected. This point highlights the problem with an RPS: it picks technology winners that may not prove to be the best or cheapest. A cap alone does not pick winners, but provides incentives to develop the technologies that can meet the cap in the most cost-effective way. If CCS proves to be more expensive, more NGCC and a greater reduction in use become the more cost-effective options. If NGCC turns out to be more expensive or renewables are less expensive, then renewables would enter as a cost-effective way to meet the cap. The advantage of the cap policy alone is that you do not have to be accurate in your predictions about the costs of technologies. The market will have the flexibility to react and choose whatever technology is most cost-effective to ensure that the cap is met in the cheapest possible way. Limiting this flexibility by adding an RPS guarantees that the policy will not be achieved in the cheapest possible way, and could in fact turn out to be much more expensive than necessary.

Table 10. Summary Results Table.

Policy	NPV Welfare Change (%)	2015 CO_2-e Price	2050 CO_2-e Price
167 bmt	-1.22	55.78	220.11
167_high ccs cost	-1.49	67.67	267.04
167_high renew cost	-1.28	55.81	220.24
167+RPS	-1.55	51.24	202.18
167+RPS_high ccs cost	-1.68	57.46	226.73
167+RPS_high renew cost	-1.97	50.91	200.91
RPS Only	-0.74	n/a	n/a
RPS Only_high ccs cost	-0.74	n/a	n/a
RPS Only_high renew cost	-1.35	n/a	n/a

6. CONCLUSIONS

Most economists see incentive-based measures such a cap-and-trade system as cost effective instruments for limiting greenhouse gas (GHG) emissions. However, many efforts to address GHG emissions combine a cap-and-trade system with regulatory instruments, particularly a renewable portfolio standard. RPS policies have gained increasing focus in climate policy. They have already been implemented in several countries and U.S. states and are receiving serious attention at the federal level in the U.S. This raises an important question: What is the effect of combining a cap-and-trade policy with an RPS. By adding new technologies and an RPS constraint to the EPPA model I was able to explore this question. The computable general equilibrium framework of this analysis allows for the capture of the full economy-wide costs and impacts of such policies.

In representing new renewable technologies it was important to account for costs stemming from existing policy incentives supporting renewables, the intermittency of wind and the need for backup or storage, and the need for long-distance transmission and grid connections. These costs are frequently left out of cost assessments, yet are important to the economy-wide costs of the technologies. In representing the RPS constraint, I simulated the use of Renewable Electricity Credits (RECs) such that renewable generation receives a REC for every kWh produced and non-renewable generation requires a fraction of a REC for every kWh produced (where the fraction equals the RPS target).

Using the updated model, I simulated three realistic policy options: a cap-and-trade alone that reaches 80% below 1990 levels by 2050, an RPS alone that reaches 25% renewables by 2025, and the cap combined with the RPS. I find that the RPS alone only makes small emissions reductions resulting in 355 bmt cumulative emissions from 2015 to 2050, whereas the cap alone and the cap with the RPS results in 167 bmt cumulative emissions. Although adding the RPS to the cap results in the same cumulative emissions, it increases the economy-wide welfare costs of policy by 27% over the life of the policy. At the same time, the addition of the RPS reduces the CO_2-e price by about 8 percent each year, thereby hiding the additional welfare costs.

Using different cost assumptions that make either CCS technologies or renewables more expensive increases the cost of all three of the policies. When renewables are more expensive, adding an RPS to a cap increases the cost of the policy over the whole period by 39%. This highlights the problem with an RPS: it picks technology winners regardless of their cost-effectiveness. An RPS shifts investment away from the least-cost emission reduction options and toward these specific renewable technologies, which are not necessarily least-cost or even low-cost. Thus, by removing the flexibility to pursue the least costly emission reduction strategy, an RPS adds to the economy-wide cost of the policy.

Unlike an RPS, a carbon pricing policy, like a cap-and-trade system, does not attempt to pick winning technologies. By forcing fossil fuels to internalize the cost of their emissions, a cap-and-trade system indiscriminately provides an advantage to technologies in proportion to the level of emissions they produce, and lets the market choose the least-cost options that achieve the emissions goal. Because the goal is emissions reductions, the winning technologies themselves are not the point, the point is that the emissions target is being met, and is being met in the least-cost way. Limiting flexibility by adding an RPS guarantees that the policy will not be achieved in the least-cost way, and could in fact turn out to be much more expensive than necessary.

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APPENDIX: An MPSGE Template for Renewable Portfolio Standards by Tom Rutherford

The following is taken directly from http://mpsge.org/rps/:

In this little model electricity generation is associated with 100 generating facilities, each of which has the same capacity. Units have different operating costs, both associated with their technology characteristics and other idosyncratic features of each plant. Units are dispatched in merit order utilizing Mathiesen's complementarity format to integrate the complementary slackness features directly into the equilibrium problem. (See this working paper and the associated GAMS files.)

A two-dimensional set (a "tuple") pt(t,f) associates generating units t with fuel characteristics f. A renewable portfolio standard is a constraint which requires that units based on a particular set of fuels supply a minimum fraction of the delivered power:

```
        sum(pt(t,rps), x(t)) =g= phi * sum(t,x(t));
```

The trick to implementing this constraint in MPSGE is to identify which of these coefficients on the $prod:x(t) block are inputs and which are outputs.

The way to think of this is to imagine a permit system which implements the RPS policy. Each time that someone generates a KWH of electricity from a renewable plant, the manager receives a RPS permit.At the same time, any time that any plant (including a renewable plant) produces 1 KWH of electricity, they must surrender phi permits, where phi is the renewable portfolio standard.

In linear programming parlance, the RPS rule introduces a "blending constraint", and it is notable that blending constraints are linearly homogeneous -- there is no RHS constant. In economic terms, this means that the RPS system redistributes funds between power plant operators, but any impact on household incomes is purely indirect, operating only through the price of the delivered electricity. In other words, there are no pure rents produced by the RPS, and perhaps this is one reason that these sorts of rules are so popular.

```
set   f   Electric power technologies /coal,gas,nucl,wind,solar,hydro/,
      rps(f)  Renewable power technologies /wind,solar,hydro/,
      t       Power plants (for simplicity equal capacity) /p1*p100/,
      pt(t,f) An association of plants to fuels (one to one);

$eolcom !

parameter        pi(f)   Fraction of plants in each type
        /coal   0.4
         gas    0.2
         nucl   0.2
         wind   0.05    !
         solar  0.05    !  Renewables are only 20% of capacity.
         hydro  0.10/;  !  Higher targets require idling of capacity.

*       Convert the fractions to a cumulative distribution:
loop(f, pi(f) = pi(f-1) + pi(f););  display pi;
```

```
*       Produce a tuple which maps plants to fuels in numbers which are
*       consistent with the plant fractions:
pt(t,f) = yes$(ord(t)/card(t) > pi(f-1) and ord(t)/card(t) <= pi(f));

parameter       nplant(f)       Number of plants by type;
nplant(f) = sum(pt(t,f),1);
display nplant;

set bug(t);
bug(t) = yes$(1-sum(pt(t,f),1));
display bug;

parameter       ac(f)   Average cost /
                        coal    10
                        gas     20
                        nucl    10
                        wind    40
                        solar   50
                        hydro   60 /;

parameter       tc(t)   Technology cost (with random differences);
loop(pt(t,f),   tc(t) = ac(f) * normal(1,0.2););  display tc;

parameter       rpsout(t)       Coefficient for RPS system,
                phi             RPS target share,
                delta(t)        Switch for introducing permit system,
                limit           Target associated with permit system;

*       Base year equilibrium has no RPS constraint nor permits:
limit = 0;
delta(t) =0;
phi = 0;
rpsout(t) = 0;

$ontext
$model:aaelec

$sectors:
        c       ! Consumption of goods and leisure
        y       ! Other production
        x(t)    ! Electricity generation

$commodities:
        pc              ! Price of consumption
        py              ! Price of output
        pe              ! Price of energy
        pl              ! Price of leisure
        pk              ! Price of capital
        pcap(t)         ! Price of electricity generating capacity
        prps$phi        ! Shadow price on renewables
        plim$limit      ! Shadow price on efficient instrument

$consumers:
        ra      ! Representative agent
```

```
*       Final consumption combines goods and leisure:
$prod:c  s:1
        o:pc    q:100
        i:pl    q:50
        i:py    q:50

*       Macro production trades off energy use with value-added:
$prod:y  s:0.5  va:1
        o:py    q:50
        i:pe    q:2
        i:pl    q:30
        i:pk    q:18

*       Electricity generation:
$prod:x(t)  s:0
        o:pe            q:2
        i:py            q:(tc(t)/100) ! Scaling here to match macro
        i:pcap(t)       q:1           ! units -- benchmark output approx. = 2

*       RPS policy instruments, including both input and output coefficients:
        o:prps          q:rpsout(t)
        i:prps          q:phi

*       Efficient policy instrument:
        i:plim          q:delta(t)

*       Final demand:
$demand:ra
        d:pc
        e:pk            q:18
        e:pl            q:80
        e:pcap(t)       q:0.05

*       When we have a permit system, rents on permits are return lump-sum:
        e:plim          q:limit

$offtext

$sysinclude mpsgeset aaelec

*       The model is not precisely calibrated.  We therefore need to solve
*       for a benchmark equilibrium and cannot use the debugging trick of
*       setting the iteration limit to zero:
$include AAELEC.GEN
solve aaelec using mcp;

parameter       results         Summary report;
results("bmk",f) = sum(pt(t,f),x.l(t)*2);
results("bmk","PE") = pe.l/pc.l;
results("bmk","pl") = pl.l/pc.l;
results("bmk","pk") = pk.l/pc.l;
results("bmk","c") = c.l;
results("bmk","e") = sum(t,x.l(t)*2);
display results;
```

```
*       Set the solvelink to 2 so that GAMS remains in memory during the
*       solution process and does not need to reload after each solution:
aaelec.solvelink = 2;


*       The shadow prices on the RPS is initially omitted from the model. We
*       need to set the level value of this price to zero so that we properly
*       report the initial price:
prps.l = 0;

*       Consider a range of RPS targets from 0% to 50%:
set     rpslvl  Level of the renewable portfolio standard (%) /0*50/;

loop(rpslvl,

*       Establish the target share here:
        phi = 0.01*(ord(rpslvl)-1);

$include AAELEC.GEN
        solve aaelec using mcp;


*       Record results for this RPS target:
        results(rpslvl,f) = sum(pt(t,f),x.l(t)*2);
        results(rpslvl,"rpssbd") = 100*prps.l/pe.l*(1-phi)/2;
        results(rpslvl,"rpstax") = 100*prps.l/pe.l*phi/2;
        results(rpslvl,"E")  = sum(t, x.l(t)*2);
        results(rpslvl,"PE") = pe.l/pc.l;
        results(rpslvl,"pl") = pl.l/pc.l;
        results(rpslvl,"pk") = pk.l/pc.l;
        results(rpslvl,"c") = c.l;

*       As part of the reporting, record the emission level from the non-RPS
*       plants.  These values will permit us to compute the excess economic
*       cost of the RPS policy, as we can compare it with a first-best permit
*       system (see below):
        results(rpslvl,"emit") = sum(pt(t,f)$(not rps(f)), X.L(t));


*       Install the RPS output coefficients for those plants which are fueled
*       with renewable inputs:
        loop(pt(t,rps), rpsout(t) = 1;);

);



*       Turn off the RPS instrument:
rpsout(t) = 0;  phi = 0;

*       Turn on the permit system which simply places an upper bound on the
*       non-renewable generation:
loop(pt(t,f)$(not rps(f)), delta(t) = 1;);
```

```
*       Go back through the same set of emission targets so that we can
*       evaluate how the excess cost is related to the renewable target:
loop(rpslvl,

        limit = results(rpslvl,"emit");

$include AAELEC.GEN
        solve aaelec using mcp;

*       Record a few characteristics of these equilibria: energy price,
*       permit price, and aggregate consumption:
        results(rpslvl,"PE*") = pe.l/pc.l;
        results(rpslvl,"plim") = 100 * plim.l/pe.l * 1/2;
        results(rpslvl,"E*")  = sum(t, x.l(t)*2);
        results(rpslvl,"c*") = c.l;
);

display results;
```

[The remainder of the code, which is omitted here, is to produce plots of the results]