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Distributional and efficiency impacts of clean and renewable energy standards for electricity

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ABSTRACT

We examine the efficiency and distributional impacts of greenhouse gas policies directed toward the electricity sector in a model that links a "top-down" general equilibrium representation of the U.S. economy with a "bottom-up" electricity-sector dispatch and capacity expansion model. Our modeling framework features a high spatial and temporal resolution of electricity supply and demand, including renewable energy resources and generating technologies, while representing CO_2 abatement options in non-electric sectors as well as economy-wide interactions. We find that clean and renewable energy standards entail substantial efficiency costs compared to a carbon pricing policy such as a cap-and-trade program or a carbon tax, and that these policies are regressive across the income distribution. The geographical distribution of cost is characterized by high burdens for regions that depend on non-qualifying generation fuels, primarily coal. Regions with abundant hydro power and wind resources, and a relatively clean generation mix in the absence of policy, are among the least impacted. An important shortcoming of energy standards vis-à-vis a carbon pricing policy is that no revenue is generated that can be used to alter unintended distributional consequences.

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1. Introduction

Following the failure in 2010 to pass a comprehensive cap-and-trade bill in the United States, analysts and policymakers have called for new or more stringent policies to curb GHG emissions in the electric power sector. In his 2011 State of the Union address, President Obama announced the goal of producing 80% of electricity from "clean" energy sources by 2035, and the 2011 Economic Report of the President indicates that a Clean Energy Standard (CES) is an important component of meeting the United States' pledge, as part of the United Nations climate conferences in Copenhagen and Cancun, to reduce total CO_2 emissions. The idea of a federal CES has been garnering bi-partisan support in Washington, DC, and at latest count, 36 states (plus the District of Columbia) already employ renewable energy standards (RES) or CES programs, most of them mandating that 15–25% of total electricity production by 2020 has to come from renewable or "clean" sources (DSIRE, 2011). Energy standards in existing and proposed regulation differ with regard to the list of fuel sources included. Unlike a RES program, most CES proposals would credit not only renewable sources, like wind, solar, bio-power, hydropower and geothermal, but would also credit non-emitting non-renewable sources like nuclear energy, and would give partial crediting to certain other technologies, such as gas and coal technologies with carbon capture and storage (CCS), and natural gas combined cycle plants.

This paper examines the efficiency and distributional implications of RES and CES regulation in the U.S. electric power sector employing a numerical simulation model that is uniquely well-suited to assessing both economy-wide and electric sector impacts. We investigate the impacts of introducing a federal energy standard, formulated with and without a particular emphasis on incentivizing renewable energy, on economy-wide costs and emissions reductions, relating these impacts to changes in regional electricity generation and capacity (shifts to low carbon fuels and renewable sources), and changes in general equilibrium products and factor prices. We explore how the costs are distributed across households that differ by region and income. We compare the cost effectiveness and the distribution of impacts of such policies vis-à-vis a emissions permit market equilibrium (or a carbon tax) where marginal abatement costs across all sectors in the economy are equalized (see, e.g., Metcalf, 2009).[1] To gauge the performance of CES regulation, we also consider a cap-and-trade policy that is exclusively focused on the the electricity sector and that achieves the same emissions reductions as the CES policy.

Several studies have examined how the U.S. electric sector responds to the imposition of a RES or CES. Besides assessments that evaluate performance of state-level RES program based on past experiences (Langnissa and Wise, 2003; Wiser et al., 2007), some prior studies have employed simulation models to estimate impacts of federal RES/CES policies. A series of studies by the Energy Information Administration (Energy Information Administration, 2007, 2009a) uses the National Energy Modeling System (NEMS) (Energy Information Administration, 2009b) to examine a federal RES as specified under the American Clean Energy and Security Act and, more recently, a CES proposal that is closely related to the proposal by the Obama Administration (Energy Information Administration, 2011). Also based on the NEMS model, Palmer et al. (2010) and ? analyze a range of renewable and clean electricity standards aimed at promoting renewable and low-carbon sources of electricity. Palmer and Burtraw (2005) and Paul et al. (2013) use the Haiku model, a partial equilibrium model of the U.S. electricity sector, to compare the cost effectiveness of a federal RPS and Renewable Energy Production Tax Credit and to study the impacts of a federal CES on electricity prices and CO_2 emissions. The National Energy

[1] This paper does not aim at comparing CES regulation with a theoretical first-best, cost-effective climate policy. The reason is simply that in a practical policy setting it is not clear what would constitute a first-best policy and whether and how it could be achieved in a second-best setting. At least two important aspects suggest that the comparisons carried out in this paper would make the CES policies look more attractive relative to conceivable policy designs that maximize cost-effectiveness. A first and well-known aspect is that cost-effectiveness depends importantly on how policies interact with distortions in the economy created by the broader fiscal system (see, for example, Harberger, 1964; Bovenberg and Goulder, 1996; Goulder et al., 1999). The costs of market-based policies that do not offset the tax-interaction effect with the revenue-recycling benefit can be dramatically higher, particularly for the scale of CO_2 reductions considered here (Parry and Williams, 2012). A second aspect relates to "when-flexbility" implying that a first-best carbon policy should focus on a cumulative rather than annual CO_2 caps. Estimates of the efficiency cost of CES regulation versus a carbon pricing policy presented in this paper should thus be viewed as a lower bound.

Renewable Laboratory (NREL) analyzed the potential impacts of proposed national renewable electricity standard (RES) legislation using the ReEDS model, a linear programming generation, capacity expansion, and transmission model (Sullivan et al., 2009). Morris et al. (2010) employ a general equilibrium model with a top-down formulation of electricity to analyze impacts from combining a RES with a cap-and-trade policy.

The present study differs from earlier work in several ways. First, in contrast with all prior work,[2] this analysis combines a general equilibrium (GE) model with a detailed bottom-up representation of the electric sector based on a decomposition algorithm (Böhringer and Rutherford, 2009) that exploits the block-diagonal structure of the Jacobian matrix of the problem. We fully integrate two existing large-scale simulation models, the MIT USREP (U.S. Regional Energy Policy) model (Rausch et al., 2010, 2011b), a recursive-dynamic multi-region GE model of the U.S. economy, and NREL's ReEDS (Renewable Energy Deployment System) model (Short et al., 2011), a recursive-dynamic linear programming model that simulates the least-cost expansion of electricity generation capacity and transmission, with detailed treatment of renewable electric options.

The key innovation of our approach is that electric-sector optimization is fully consistent with the equilibrium response of the economy including endogenously determined electricity demand, fuel prices, and goods and factor prices. Our integrated assessment allows us to provide theoretically sound welfare estimates, and enables us to assess the cost effectiveness of electricity standards vis-à-vis market-based carbon pricing policies by considering abatement opportunities in all sectors of the economy within a single consistent framework.

Our analysis is also germane to the literature on integrating "top-down" and "bottom-up" models for carbon policy assessment (see, for example, Hourcade et al. (2006), for an overview). Economy-wide "top-down" models represent sectoral economic activities and electric generation technologies through smooth, aggregate production functions. While the strength of these models is to include economy-wide interactions in an internally consistent framework, they typically lack detail along a number of important dimensions critical for analyzing electric sector impacts and, in particular, the potential of renewable energy sources. These include, among others, an exhaustive representation of all major renewable generation technologies, the characterization of renewable resources and electricity demand at sufficiently resolved spatial and temporal scales, capacity investment decisions including back-up for intermittent generation and storage, and access to and the cost of transmission using a spatially resolved representation of the grid. Our analysis is the first to embed a detailed electric sector model that includes all of these aspects in a numerical general equilibrium framework.[3] By doing so, we also overcome limitations inherent to partial equilibrium "bottom-up" electric sector models that typically rely on a simplistic Marshallian formulation of electricity demand (Lanz and Rausch, 2011) and fail to include interactions with the broader economic system.

A second major difference from earlier work is the model's ability to capture distributional effects. First, the economy-wide model distinguishes larger states and U.S. regions capturing inter-regional differences in carbon intensity of energy production, consumption, and trade. Second, within each region the model considers nine households differentiated by income levels. Households across income classes differ in terms of how income is derived from different sources and how income is spent across different commodities. This enables us to capture consumer impacts both on the uses and sources side of income.[4] Sources side effects have been shown to be critical for assessing the incidence

[2] Sugandha et al. (2009) also employ a hybrid top-down bottom-up modeling approach but their modeling framework has considerably less detail with respect to modeling important features of renewable electricity generation. Furthermore, their analysis does not consider the impacts of CES or RES policies in the electric sector.

[3] In addition, a top-down representation of electricity markets implies that the price of electricity reflects the total carbon content of generation. This contrasts with real markets (and the bottom-up approach), where the carbon price is reflected in the electricity price through the carbon content of the marginal producer at a given point in time (Stavins, 2008).

[4] Environmental policies aimed at reducing carbon dioxide emissions will raise the price of carbon intensive commodities and disproportionately impact those households who spend larger than average shares of their income on these commodities. In a general equilibrium setting, environmental regulation also impacts factor prices. Households which rely heavily on income from factors whose factor prices fall relative to other factor prices will be adversely impacted. In the public finance literature on tax incidence, the first impact is referred to as a uses of income impact while the latter a sources of income impact (see, for example, Atkinson and Stiglitz (1980), for a discussion of tax incidence).

of environmental policies (Fullerton and Heutel, 2007; Rausch et al., 2011a), but the scope of a partial equilibrium electric-sector analysis implies that that those effects cannot be captured. Our integrated general equilibrium approach thus enables us to trace distributional impacts in several important dimensions.

The rest of the paper is organized as follows. Section 2 provides some background on CES and RES policies, with emphasis on the US. Section 3 outlines the model's data sources and structure. Section 4 presents and interprets results from policy simulations. Section 5 offers conclusions.

2. Background on clean and renewable energy standards for electricity

Under the typical design of an RES or CES, generators earn tradable certificates or credits for each unit of renewable or clean energy they produce. At the end of the accounting period, each firm must surrender RES/CES certificates equivalent to its required level of renewable/clean energy production, defined as a specified share of its total production.[5]

An electricity standard with trading is closely related to the cap-and-trade approach to pollution control. Many state RES programs are intended as climate policies, and these can be thought of as CO_2 cap-and-trade systems for the electric sector where the difference in carbon intensity among fuels is ignored. The disregard for differences in carbon content limits the cost effectiveness of the instrument. Cost effectiveness is also compromised because a RES/CES does not directly put a price on the externalities associated with fossil-based electricity generation; it instead focuses on the ratio of renewable/clean- to fossil-based/"dirty" generation. Because of its focus on a ratio or input intensity, the RES/CES is equivalent to the combination of a subsidy to electricity production and tax on emissions. As shown by Holland et al. (2009), the subsidy component impedes cost effectiveness. In addition, a RES/CES program fails to exploit a broader range of behavioral responses to reduce CO_2 emissions across all sectors of the economy. It may also not provide the same certainty for achieving a given emissions reductions target as an economy-wide cap-and-trade system due to potential leakage effects to non-electricity sectors.

RES programs have—since the late 1990s—proliferated at the state level in the United States. Until 2003, 14 states had enacted RES policies; at latest count, RES policies currently exist in 29 states and the District of Columbia; seven more states have non-binding goals. Existing RES programs apply to 47% of U.S. load in 2010. Most of the existing RES programs mandate that 15–25% of total electricity production by 2020 has to come from renewable sources. In general, the enactment of new RES policies is waning, but states continue to hone existing policies, with a general trend toward increased stringency of RES targets.[6]

Importantly, a federal CES or RES program would allow for tradability of credits within the entire U.S., whereas most state policies contain significant statewide or regional limitations on renewable credit sources. A federal program would therefore be at least as cost-effective as (a combination of) state-level programs.

At the federal level, a number of RES and CES proposals have been considered, but to date no proposal has been implemented. In the 111th Congress, several electricity portfolio standards have been proposed including the House-passed H.R. 2454 American Clean Energy and Security Act of 2009 and three Senate bills: the American Clean Energy Leadership Act of 2009 (ACELA); the Practical Energy and Climate Plan Act (PECPA); and the Clean Energy Standard Act of 2012 (CESA). Both ACES and ACELA have a RES which would have required that, by 2020, 20% and 30% of electricity generation come from renewable sources, respectively. The PECPA and CESA proposals include CES programs that provide credit for both renewable and lower-emitting, non-renewable energy sources comprising coal-CCS and new nuclear. For example, the most recent CESA proposal would start in 2015 and mandate that 84%

[5] Note that in most proposed federal policies or current state policies it is actually not producers who are typically required to comply with an RES or CES. Rather, local distribution companies (LDCs) must purchase credits from clean/renewable generators in order to cover a specified amount of their sales. As we do not identify separately LDCs in our modeling framework, it appropriate in the given context to conceive of generators as directly surrendering certificates.

[6] See DSIRE (2011), for an overview of existing RPS policies. Wiser et al. (2007) provides an introduction to the history, concept, and design of the RPS, and reviews early experience with the policy as applied at the state level.

of electricity generation come from clean qualifying sources by 2035. Clean sources would comprise renewable energy (including solar, wind, ocean, current, wave, tidal, geothermal, hydropower, and qualified renewable biomass), natural gas, nuclear power, qualified waste, and coal that uses carbon capture and storage technology.[7]

The CESA bill is similar to, but more stringent than, other energy standards that have been proposed before. It also aligns with the national energy policy proposed by President Obama in his 2011 State of the Union address supporting a CES that would require 80% of electricity generation to come from clean sources by 2035. At the time of writing, it is unclear whether a federal CES or RPS will come forward and how the exact parameters of such a policy would look.

3. An integrated economy-energy-electricity modeling framework

We formulate a recursive-dynamic general equilibrium (GE) model of the U.S. economy with a detailed bottom-up representation of electricity demand, generation, capacity expansion, and transmission. We embed NREL's ReEDS (Renewable Energy Deployment System) model (Short et al., 2011), a recursive-dynamic linear programming model that simulates the least-cost expansion of electricity generation capacity and transmission, with detailed treatment of renewable electric options, within the MIT USREP (U.S. Regional Energy Policy) model (Rausch et al., 2010, 2011b), a multi-region multi-commodity economy-energy GE model of the U.S. economy. We now turn to an overview of both sub-models and describe our approach to integrate them.

3.1. General equilibrium model

3.1.1. Data

This study makes use of a comprehensive energy-economy dataset that features a consistent representation of energy markets in physical units as well as detailed accounts of regional production and bilateral trade for the year 2004. The datset merges detailed state-level data for the US with national economic and energy data for regions in the rest of the world and is outlined in detail by Caron and Rausch (2011). Social accounting matrices (SAM) in our hybrid dataset are based on data from the Global Trade Analysis Project (Gtap, 1964), the IMPLAN (IMpact analysis for PLANning) data (IMPLAN, 2008), and US state-level accounts on energy balances and prices from the Energy Information Administration (2009c). Table 1 provides an overview of data sources.

The GTAP provides consistent global accounts of production, consumption, and bilateral trade as well as consistent accounts of physical energy flows and energy prices. Version 7 of the database, which is benchmarked to 2004, identifies 113 countries and regions and 57 commodities. The IMPLAN data specifies benchmark economic accounts for the 50 US states (and the District of Columbia). The dataset includes input–output tables for each state that identify 509 commodities and existing taxes. The base year for the IMPLAN accounts in the version we use here is 2006. To improve the characterization of energy markets in the IMPLAN data, we use least-square optimization techniques to merge IMPLAN data with data on physical energy quantities and energy prices from the Department of Energy's State Energy Data System (SEDS) for 2006 (Energy Information Administration, 2009c).[8]

Data for trade flows between regions outside of the US are taken from Gtap (1964) and reflect UN-COMTRADE bilateral flows. Bilateral state-to-state trade data in the IMPLAN database are derived using a gravity approach Lindall et al. (2006). Bilateral US state-to-country trade flows are based on the US Census Bureau Foreign Trade Statistics State Data Series (U.S. Census Bureau, 2010). Bilateral exports and imports are taken from, respectively, the Origin of Movement (OM) and State of Destination (SD) data series. The OM and SD data sets are available at the detailed 6-digit HS classification level, which permits aggregation to GTAP commodity categories.

[7] Covered utilities that do not generate electricity from clean sources or purchase credits from other clean sources may also comply by paying a fee under the CESA proposal with a compliance payment that starts at 3 cents/kWh in 2015, and annually increases by 5% plus the rate of inflation.

[8] Aggregation and reconciliation of IMPLAN state-level economic accounts to generate a micro-consistent benchmark dataset which can be used for model calibration is accomplished using ancillary tools documented in Rausch and Rutherford (2009).

Table 1
Data sources for USREP model.

Data and parameters	Source
Social accounting matrices bilateral trade international regions US states	Global Trade Analysis Project (Gtap, 1964), Version 7 IMPLAN (2008) and gravity analysis (Lindall et al., 2006)
US state-to-country bilateral trade flows	Origin of Movement and State of Destination data series (U.S. Census Bureau, 2010)
Physical energy flows and energy prices international regions US states	Gtap (1964) State Energy Data System (Energy Information Administration, 2009c)
Fossil fuel reserves and biomass supply	US Geological Service (US Geological Survey, 2009), US Department of Energy (2009), Dyni (2006), and Oakridge National Laboratories (2009)
Population projections international regions	United Nations (2000, 2001)
US states	U.S. Census Bureau (2010)
Marginal personal income tax rates	NBER's TAXSIM model (Feenberg and Coutts, 1993)
Trade elasticities	Global Trade Analysis Project (Gtap, 1964) and own calibration
Energy demand and supply elasticities	Paltsev et al. (2005)

We integrate GTAP, IMPLAN/SEDS, and US Census trade data by using least-square optimization techniques. Our data reconciliation strategy is to hold fixed US trade totals (by commodity) from GTAP and to minimize the distance between estimated and observed US Census state-to-country bilateral trade flows and estimated and observed SAM data from IMPLAN subject to equilibrium constraints.

For this study, we aggregate the dataset to 12 US regions, 2 regions in the rest of the world (Europe and the "Rest of the World"), 10 commodity groups, and 9 households grouped by annual income classes (see Table 2). States identified in the model include California, Texas, Florida, and New York, and several other multi-state regional composites. Mapping of states to aggregated regions is shown in Fig. 1. Our commodity aggregation identifies five energy sectors and five non-energy composites. Energy commodities identified in our study include coal (COL), natural gas (GAS), crude oil (CRU), refined oil (OIL), and electricity (ELE), which allows to distinguish energy goods and specify substitutability between fuels in energy demand. Elsewhere, we distinguish energy-intensive products (EIS),

Table 2
USREP model details.

Sectors	Regions	Primary production factors
Non-Energy	Pacific (PACIF)	Capital
Agriculture (AGR)	California (CA)	Labor
Services (SRV)	Alaska (AK)	Coal resources
Energy-intensive products (EIS)	Mountain (MOUNT)	Natural gas resources
Other industries products (OTH)	North Central (NCENT)	Crude oil resources
Commercial transportation (TRN)	Texas (TX)	Hydro resources
Passenger vehicle transportation (TRN)	South Central (SCENT)	Nuclear resources
Final demand sectors	North East (NEAS)	Land
Household demand	South East (SEAST)	
Government demand	Florida (FL)	Household income classes
Investment demand	New York (NY)	($1000 of annual income)
Energy supply and conversion	New England (NENGL)	<10
Fuels production		10–15
Coal (COL)	Europe (EUR)	15–25
Natural gas (GAS)	Rest of the World (ROW)	25–30
Crude oil (CRU)		30–50
Refined oil (OIL)		50–75
Electricity generation and transmission		75–100
As represented by ReEDS model (see Section 3.2)		100–150
		>150

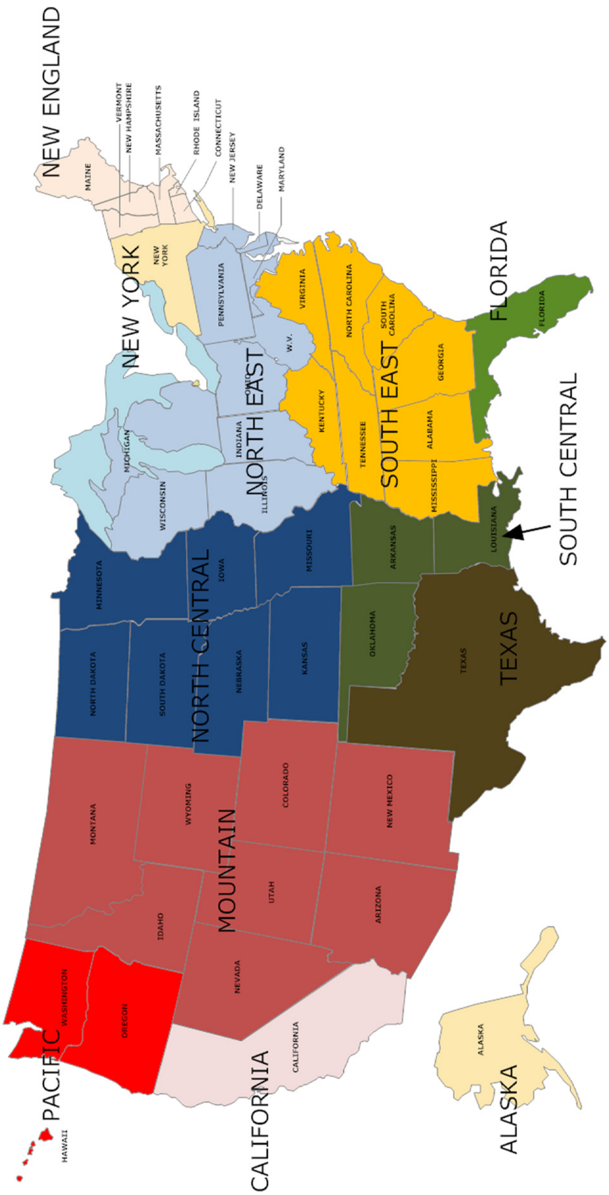

Fig. 1. U.S. regions in USREP model.

other manufacturing (OTH), agriculture (AGR), transportation (TRN), and services (SRV). Primary factors in the dataset include labor, capital, land, and fossil-fuel resources.

Energy supply is regionalized by incorporating data for regional crude oil and natural gas reserves (US Department of Energy, 2009), coal reserves U.S. Geological Service (US Geological Survey, 2009), and shale oil (Dyni, 2006). We derive regional supply curves for biomass from data from Oakridge National Laboratories (2009) that describes quantity and price pairs for biomass supply for each state.

Our dataset permits calculation of existing tax rates comprising sector- and region-specific ad valorem output taxes, payroll taxes and capital income taxes. IMPLAN data has been augmented by incorporating regional tax data from the NBER TAXSIM model (Feenberg and Coutts, 1993) to represent marginal personal income tax rates by region and income class.

3.1.2. Model structure

Production and transformation technologies. In each industry ($i = 1, \ldots, J$) and region ($r = 1, \ldots, R$) gross output Y_{ir} is produced using inputs of labor (L_{ir}), capital (K_{ir}), natural resources including coal, natural gas, crude oil, and land (R_{ir}), and produced intermediate inputs X_{jir}, $j = i$[9]:

$$Y_{ir} = F_{ir}(L_{ir}, K_{ir}, R_{ir};\ X_{1ir}, \ldots, X_{Iir}). \tag{1}$$

We employ constant-elasticity-of-substitution (CES) functions to characterize the production systems and distinguish four types of production activities in the model: fossil fuels (indexed by f={CRU, COL, GAS}), refined oil (OIL), agriculture (AGR), and non-energy industries (indexed by n={TRN, EIS, SRV, OTH}). All industries are characterized by constant returns to scale (except for fossil fuels and AGR which are produced subject to decreasing returns to scale) and are traded in perfectly competitive markets. Nesting structure for each type of production system are depicted in Paltsev et al. (2005).

We adopt a putty-clay approach where a fraction ϕ of previously-installed capital becomes non-malleable and frozen into the prevailing techniques of production. The fraction $1-\phi$ can be thought of as that proportion of previously-installed malleable capital that is able to have its input proportions adjust to new input prices. Vintaged production in industry i that uses non-malleable capital is subject to a fixed-coefficient transformation process in which the quantity shares of capital, labor, intermediate inputs and energy by fuel type are set to be identical to those in the base year:

$$Y_{ir}^{v} = \min(L_{ir}^{v}, K_{ir}^{v}, R_{ir}^{v};\ X_{1ir}^{v}, \ldots, X_{Iir}^{v}). \tag{2}$$

In each region, a single government entity approximates government activities at all levels—federal, state, and local. Aggregate government consumption is represented by a Leontief composite: $G_r = \min(G_{1r}, \ldots, G_{ir}, \ldots, G_{Ir})$.

Consumer preferences. In each region r, preferences of the representative consumers for income class h are represented by a CES utility function of consumption goods (C_i), investment (I), and leisure (N):

$$U_{r,h} = \left[\mu_{cr}^{h} \min\left[g^{h}(C_{1rh}, \ldots, C_{Irh}), \min(I_{1rh}, \ldots, I_{Irh})\right]^{1/\rho_{cr}} + \gamma_{cr}^{h} N_{rh}^{1/\rho_{cr}}\right]^{1/\rho_{cr}} \tag{3}$$

where μ and γ are CES share coefficients, and the elasticity of substitution between leisure and the consumption-investment composite is given by $\sigma_{l,r} = 1/(1-\rho_{cr})$. $g(\cdot)$ is a CES composite of energy and non-energy goods whose nesting structure is depicted in Paltsev et al. (2005) Thus, our framework captures heterogeneity in private consumption with respect to region and income. Households differ by expenditure patterns and income sources.

Supplies of final goods and intra-US and international trade. With the exception of crude oil, which is a homogeneous good, intermediate and final consumption goods are differentiated following the Armington (1969) assumption. For each demand class, the total supply of good i is a CES composite of

[9] For ease of exposition, we abstract from the various tax rates that are used in the model.

a domestically produced (i.e., locally produced and imported from domestic markets) variety and an imported (from foreign markets) one:

$$X_{ir} = \left[\psi^z\, ZD_{ir}^{\rho_i^D} + \xi^z\, ZM_{ir}^{\rho_i^D} \right]^{1/\rho^D{}_i} \tag{4}$$

$$C_{irh} = \left[\psi^c\, CD_{irh}^{\rho_i^D} + \xi^c\, CM_{irh}^{\rho_i^D} \right]^{1/\rho^D{}_i} \tag{5}$$

$$I_{irh} = \left[\psi^i\, ID_{irh}^{\rho_i^D} + \xi^i\, IM_{irh}^{\rho_i^D} \right]^{1/\rho^D{}_i} \tag{6}$$

$$G_{ir} = \left[\psi^g\, GD_{ir}^{\rho_i^D} + \xi^g\, GM_{ir}^{\rho_i^D} \right]^{1/\rho^D{}_i} \tag{7}$$

where Z, C, I, and G are inter-industry demand, consumer demand, investment demand, and government demand of good i, respectively, and where ZD, CD, ID, GD, are domestic and imported components of each demand class, respectively. The ψ's and ξ's are the CES share coefficients and the Armington substitution elasticity between the domestic and the imported foreign variety in these composites is $\sigma_i^D = 1/(1-\rho_i^D)$.

The domestic imported varieties are represented by nested CES functions, and we differentiate the following structure for US regions (indexed by $s = 1, \ldots, S$) and international regions (indexed by $t = 1, \ldots, T$). The imported variety of good i is represented by the CES aggregate:

$$M_{ir} = \begin{cases} \left[\left(\sum_s \pi_{ist}\, y_{isr}^{\rho_i^{RU}} \right)^{\rho_i^M/\rho_i^{RU}} + \sum_{t \neq r} \varphi_{itr}\, y_{itr}^{\rho_i^M} \right]^{1/\rho_i^M} & \text{if} \quad r = t \\ \left[\sum_t \varphi_{itr}\, y_{itr}^{\rho_i^M} \right]^{1/\rho_i^M} & \text{if} \quad r = s \end{cases} \tag{8}$$

where y_{itr} (y_{isr}) are imports of commodity i from region t (s) to r. π and φ are the CES share coefficients, and $\sigma_i^M = 1/(1-\rho_i^M)$ and $\sigma_i^{RU} = 1/(1-\rho_i^{RU})$ are the implied substitution elasticity across foreign and intra-US origins, respectively. The domestic variety of good i for US region s is represented by the CES aggregate:

$$D_{ir} = \begin{cases} \left[\left(\sum_{s \neq r} \pi_{isr}\, y_{isr}^{\rho_i^{SU}} \right)^{\rho^{DU}{}_i/\rho_i^{SU}} + \eta_{ir}\, y_i^{\rho_{ir}^{DU}} \right]^{1/\rho_i^{DU}} & \text{if} \quad r = s \\ y_{ir} & \text{if} \quad r = t \end{cases} \tag{9}$$

where η is a CES share coefficient, and $\sigma_i^{DU} = 1/(1-\rho_i^{DU})$ is the implied substitution elasticities between the local variety and a CES composite of intra-US varieties. $\sigma_i^{SU} = 1/(1-\rho_i^{SU})$ is the elasticity of substitution across US origins.

Intra-period equilibrium and model closure. Consumption, labor supply, and savings result from the decisions of the representative household in each region maximizing its utility subject to a budget constraint that full consumption equals income:

$$\max_{\{C_{irh}, I_{rh}, N_{rh}\}} U_{rh} \quad \text{s.t.} \quad p_r^i I_{rh} + p_r^l N_{rh} + \sum_i p_{ir}^c C_{irh} = p_r^k \overline{K}_{rh} + p_r^{Vk} \overline{VK}_{rh} + p_{fr}^R \overline{R}_{frh} + p_r^l \overline{L}_{rh} + T_{rh} \tag{10}$$

where p^i, p^c, p^k, p^{Vk}, p^R, and p^l, are price indices for investment, labor services, household consumption (gross of taxes), capital services, rents on vintaged capital, and rents of fossil fuel resources, respectively. $\overline{K}$, $\overline{VK}$, $\overline{R}$, $\overline{L}$, and T are the benchmark stocks of capital, vintaged capital, fossil fuel resources, labor, and the benchmark transfer income, respectively. Lacking specific data on capital ownership, households are assumed to own a pool of US capital—that is they do not disproportionately own capital assets within the region in which they reside.

Fossil fuel resources and vintaged capital are treated as sector-specific, whereas capital for international regions and labor for international and US regions are treated as perfectly mobile across sectors within a given region but immobile across regions. Capital in the US is assumed to be perfectly mobile across US regions but immobile across international regions. Except for labor, all factors are inelastically supplied.

Given input prices gross of taxes, firms maximize profits subject to the technology constraints in Eqs. (1) and (2). Minimizing input costs for a unit value of output yields a unit cost indexes (marginal cost), p_{ir}^{Y} and p_{ir}^{Yv}. Firms operate in perfectly competitive markets and maximize their profit by selling their products at a price equal to these marginal costs.

The main activities of the government sector in each region are purchasing goods and services, transferring incomes, and raising revenues through taxes. Government income is given by: $GOV_r = TAX_r - \sum_h T_{r,h} - B_r$, where TAX, $T_{r,h}$, and B are tax revenue, transfer payments to households and the initial balance of payments (deficit), respectively. Aggregate demand by the government is given by: $GD_r = GOV_r / p_r^G$ where p_r^G is the price for aggregate government consumption.

Market clearance equations for factors that are supplied inelastically are trivial. The other market clearance equations are as follow:

1. Supplies to the domestic market must meet demands by industry, household, investment, and government: $D_{ir} = ZD_{ir} + \sum_h (CD_{irh} + ID_{irh}) + GD_{ir}$.
2. Import supply of good i satisfies domestic demands by industry, household, investment, and government for the imported variety: $M_{ir} = ZM_{ir} + \sum_h (CM_{irh} + IM_{irh}) + GM_{ir}$.
3. Trade between all regions in each commodity has to balance: $\sum_s \sum_r y_{isr} + \sum_t \sum_r y_{itr} = \sum_s \sum_r y_{irs} + \sum_t \sum_r y_{irt}$.
4. Labor supply has to equal labor demand.

Intertemporal dynamics. We adopt a recursive-dynamic approach in which economic agents have myopic expectations and base their decisions on contemporaneous variables. Solving the dynamic model therefore involves computing a sequence of equilibria from the intra-period model.

The evolution of capital over time is governed by the following set of dynamic equations. Malleable capital (K^m) in period t is made up of investment (I_t), plus the stock of capital remaining after depreciation that also remains malleable:

$$K_{t+1}^{m} = I_t + (1-\phi)(1-\delta)K_t^m \tag{11}$$

where δ and ϕ denote the depreciate rate and the fraction of previously-installed malleable capital that become non-malleable, respectively. Malleable capital is indistinguishable from new investment, in that there is flexibility defined by the nested CES production function to adjust the input proportions given prevailing relative prices. As the model steps forward in time it preserves $v = 1, \ldots, 12$ vintages of rigid capital (K^r), each retaining the coefficients of factor demand fixed at the levels that prevailed when it was installed.[10] Each of the sector specific vintages is tracked through time as a separate capital stock. In period $t+1$, the first vintage of non-malleable capital is given by:

$$K_{i,t+1,v}^{r} = \phi(1-\delta)K_{i,t}^{m} \qquad \text{for } v = 1. \tag{12}$$

We assume that rigid capital cannot be reallocated among different sectors. In each sector, the quantity of capital in each of the remaining vintages is thus simply the amount of each vintage that remains after depreciation:

$$K_{i,t+1,v+1}^{r} = (1-\delta)K_{i,t,v}^{r} \qquad \text{for } v = 2, \ldots, 10. \tag{13}$$

[10] Because there are 12 vintages and the model's time step is two years, vintaged capital has a maximum life of 24 years.

Table 3
National welfare impacts.

	CES	CAT_CES	RES	CAT_RES	CAT_ELE
Annual impacts (equivalent variation in %)[a]					
Year 2020	−0.10 (3.9)	−0.03	−0.05 (7.3)	−0.01	−0.09 (0.9)
Year 2030	−0.48 (2.0)	−0.24	−0.26 (3.6)	−0.07	−0.42 (0.9)
Year 2050	−0.62 (1.3)	−0.47	−0.40 (2.1)	−0.19	−0.54 (0.9)
Net present value impacts (discounted at 4% p.a.)[a]					
Percentage change	−0.37 (1.9)	−0.20	−0.17 (4.0)	−0.04	−0.33 (0.9)
Billion 2006$	−1974.3	−1043.0	−907.2	−227.8	−1768.9
Annual average per household in 2006$	−392	−204	−180	−44	−350

Note: Welfare impacts refer to population-weighted national averages.

[a] Numbers in parentheses for CES, RES, and CAT_ELE denote relative efficiency (i.e., ratio of welfare impacts) with respect to CAT_CES, CAT_RES, and CES, respectively.

This formulation means that the model exhibits a short-run and long-run response to changes in relative prices. The substitution response in a single period to a change in prices in that periods is a combination of the long-run substitution possibilities, weighted by output produced by malleable capital, and no substitution, weighted by output produced with vintaged capital.

Over time, energy resources R in sector i are subject to depletion based on physical production of fuel (F) in the previous period:

$$R_{r,i,t+1} = R_{r,i,t} - F_{r,i,t}\,. \tag{14}$$

Elasticities, calibration, and model solution. As customary in applied general equilibrium analysis, we use prices and quantities of the integrated economic-energy dataset for the base year to calibrate the value share and level parameters in the model. Exogenous elasticities determine the free parameters of the functional forms that capture production technologies and consumer preferences. Reference values for elasticity parameters in production and consumption are taken from Paltsev et al. (2005) and values for Armington trade elasticities are based on econometric estimates from Gtap (1964). The values for each model parameter are listed in Table 3 in Rausch and Mowers (2012).

All fossil energy resources are modeled as graded resources whose cost of production rises continuously as they are depleted. The resource grade structure is reflected by the elasticity of substitution between resources and the capital-labor-materials bundle in the production function. The elasticity of substitution between the resource and the other inputs in the top nest determines the price elasticity of supply (ζ_f) at the reference point according to: $\zeta_f = \sigma^R_{fr}((1-\alpha_{fr})/\alpha_{fr})$. Resource estimates about natural gas reflect the current surge in recoverable resources attributable to advances in technology that enable shale gas extraction. Natural gas resource estimates are based on the MIT Future of Natural Gas Study (Moniz et al., 2011).[11]

Population and labor productivity growth over time are exogenous. Labor in efficiency units ($L_{r,t}$) is scaled from its base-year value ($\bar{L}_r$) according to: $L_{r,t+1} = \bar{L}_r(1+\gamma_{r,t})$ where the exogenous augmentation rate $\gamma_{r,t} = \gamma^L_{r,t} + \gamma^P_{r,t}$ comprises the growth of population ($\gamma^L_{r,t}$) and the growth of productivity ($\gamma^P_{r,t}$). $\gamma^L_{r,t}$ is specified using population projections from United Nations (2001) and U.S. Census Bureau (2010) for international and U.S. regions, respectively. Labor productivity growth over time is described by a logistic function: $\gamma^P_{r,t} = (\gamma^P_{r,0} - \gamma^P_{r,T})(1+\alpha)/(1+\alpha^{\beta t}) + \gamma^P_{r,T}$. The value of the logistic parameters α and β are set such that productivity adjusts from the initial rate to the final rate in year 2100 in an S-shaped fashion. Growth for historical years is overridden by specifying an augmentation factor so that simulated GDP growth matches observed historical rates.

The labor supply response within a given period is determined by the household choice between leisure and labor. We calibrate compensated and uncompensated labor supply elasticities following

[11] Natural gas resources estimates are as specified in chapter 3 of the MIT study and in Paltsev et al. (2011) which both draw partially from a similar version of the USREP model to the one used in the present analysis.

the approach described in Ballard (2000), and assume that the uncompensated (compensated) labor supply elasticity is 0.05 (0.3).

Non-price induced efficiency improvements in energy demand that scale production and consumption sectors' use of energy per unit of output are modeled following the concept of autonomous energy efficiency improvements (AEEI) (see, e.g., Paltsev et al., 2005). We assume for all regions that AEEI occur at a rate of 1% per year.

Numerically, the equilibrium is formulated as a mixed complementarity problem (Mathiesen, 1985; Rutherford, 1995). Our complementarity-based solution approach comprises two classes of equilibrium conditions: zero profit and market clearance conditions. The former condition determines a vector of activity levels and the latter determines a vector of prices. We formulate the problem in GAMS and use the mathematical programming system MPSGE (Rutherford, 1999) and the PATH solver (Dirkse and Ferris, 1995) to solve for non-negative prices and quantities.

3.2. A model of electricity generation and transmission capacity expansion

The electric sector sub-model is based on the Regional Energy Deployment System (ReEDS) model (Short et al., 2011), a linear programming model developed by the U.S. Department of Energy's National Renewable Energy Laboratory (NREL) that simulates the least-cost expansion of electricity generation capacity and transmission in the contiguous US. ReEDS provides a means of estimating the type and location of conventional and renewable resource development, the transmission infrastructure expansion requirements of those installations, the composition and location of generation, storage, and demand-side technologies needed to maintain system reliability. ReEDS provides a detailed treatment of electricity-generating and electrical storage technologies, and specifically addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal generation profiles, variability and non-dispatchability of wind and solar power, and the influence of variability on curtailment of those resources. ReEDS addresses these issues through a highly discretized regional structure, temporal resolution, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

ReEDS includes all major generator types and has additional detail for renewable generators as these generators come with concerns that many conventional dispatchable power plants do not have, including variations in regional resource quality, variability and non-dispatchability, and additional transmission needs.[12] Time in ReEDS is subdivided within each two-year period, with each year divided into four seasons with a representative day for each season, which is further divided into four diurnal time-slices. Also, there is one additional summer-peak time-slice. These 17 annual time-slices enable ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year-with both dispatchable and non-dispatchable generators.

The major constraints in the optimization include meeting electricity demand and reserve requirements within specific regions, regional resource supply limitations, and transmission constraints. The capacity expansion and dispatch decision-making of ReEDS considers the net present value cost of adding new generation capacity and operating it (considering transmission and operational integration) over an assumed financial lifetime (20 years for the present study). This cost minimization routine is applied for each two-year investment period between 2006 and 2050.

A comprehensive documentation including data and model structure is available online (Short et al., 2011). Here, we focus on highlighting the model features relevant for characterizing renewable energy supplies.

3.2.1. Renewable energy supplies

ReEDS uses 356 different resource regions in the continental United States to characterize wind and concentrated solar power (CSP) resource. Data inputs are derived from a detailed geographic

[12] A complete list of generation and storage technologies considered in the ReEDS model can be found in the working paper version of this article (Rausch and Mowers, 2012).

information system (GIS) model/database of the wind and CSP resource and transmission grid. This database is used to calculate supply curves of wind and CSP, which capture sub-regional resource quality variations and transmission costs, among other factors. Regional resource quality variations are also considered for other renewable generator types, including hydropower, biopower, and geothermal. ReEDS provides supply curves for these resources in each of the 134 BAs. To illustrate the underlying resource data for selected renewables, Fig. 2 show the resource resolution for wind, CSP, biomass, PV, hydropower, and geothermal. Resource maps for existing hydro power, new hydropower supply curves, and geothermal resources and details about the exact specification of the respective supply curves can be found in Rausch and Mowers (2012).

Variable resource renewable energy (VRRE) technologies, which include wind, CSP without storage, utility-scale PV, and distributed PV, produce power that is both variable, uncertain, and non-dispatchable. Generally, greater penetrations of these technologies lead to greater levels of curtailment, required operating reserves, as well as diminished contribution to planning reserve requirements per unit of VRRE capacity. ReEDS uses statistical calculations that rely on simulated hourly output data for wind, PV, and CSP to characterize the variance and co-variance of power output for each VRRE technology during each time slice. The calculations rely on the aggregate variability for each reserve-sharing group (for the present study, the reserve-sharing groups are assumed to be the 21 Regional Transmission Organization (RTO) regions). In general, greater geographical distance between two sites of the same resource leads to a lower degree of correlation between power outputs, thereby decreasing the variability of the combined generation. Because of these correlations, all else being equal, ReEDS will choose to spatially spread generators of the same resource to reduce aggregate variability in a reserve-sharing group.

3.3. Model integration

In principle, a bottom-up representation of the electricity sector can be integrated directly within a GE framework by solving Kuhn–Tucker equilibrium conditions that arise from the bottom-up cost-minimization problem, along with general equilibrium conditions describing the top-down model (Böhringer and Rutherford, 2008). In applied work, this approach may be infeasible due to the large dimensionality of the bottom-up problem. Moreover, the bottom-up model involves a large number of bounds on decision variables, and the explicit representation of associated income effects becomes intractable if directly solved within a GE framework (Böhringer and Rutherford, 2009).

Our computational strategy is to use a block decomposition algorithm put forward by Böhringer and Rutherford (2009) that involves an iterative procedure between both sub-models solving for a consistent general equilibrium response in both models. The first step for implementing the decomposition procedure in an applied large-scale setting is the calibration of the two sub-models to a consistent benchmark point. Initial agreement in the base year is achieved if bottom-up electricity sector outputs and inputs for all regions and generators are consistent with the aggregate representation of the electric sector in the Social Accounting Matrix (SAM) data.[13] To produce a *micro-consistent* SAM, a benchmarking routine was developed for the year 2006, the first modeled year, wherein ReEDS was solved with historical (fixed) prices for capital, labor, and fuel as well as fixed regional electricity demands.[14] Given ReEDS electricity supplies and inputs demands, we use least-square optimization techniques to estimate a new SAM holding fixed the (simulated) electric sector data. Our benchmarking routine implies that, in absence of a policy shock, the integrated model is fully converged in the base year.

Each iteration in the solution algorithm comprises two steps. Step 1 solves a version of the USREP model with exogenous electricity production where electricity sector outputs and input demands

[13] This step is necessary to ensure that in the absence of a policy shock iterating between both sub-models always returns the no-policy benchmark equilibrium. Violation of this initial condition means that any simulated policy effects would be confounded with adjustments due to initial data inconsistencies between the two sub-models.

[14] Wholesale electricity is an output of the ReEDS model, and remained so for the benchmarking routine. Electricity price distribution markups were estimated for each USREP region based on the difference between the historical 2006 retail electricity price and the wholesale electricity price from the first solve of the ReEDS model.

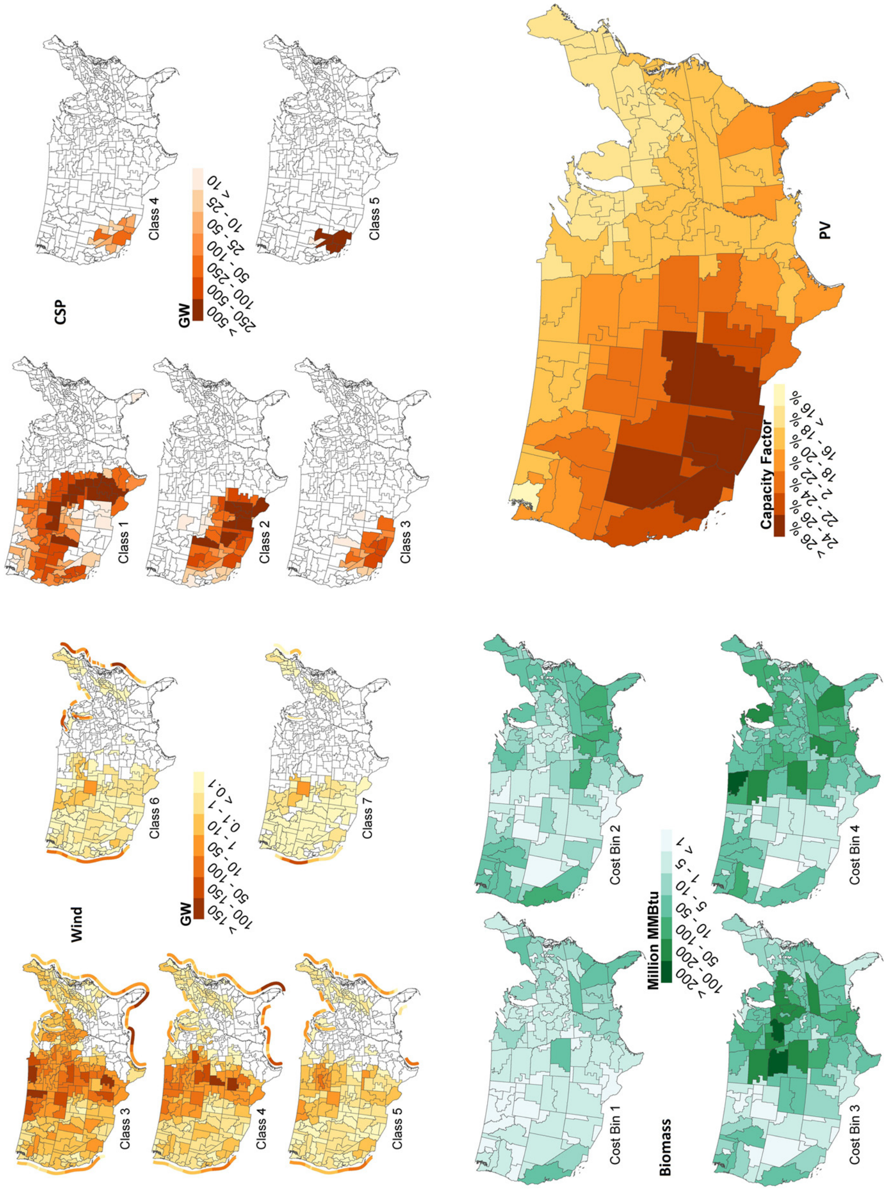

Fig. 2. Regional resource resolution for wind, CSP, biomass, and PV.

for fuels, capital, labor, and other materials, are parameterized based on the last available solution of the ReEDS model. The subsequent solution of the ReEDS model in Step 2 is based on a locally calibrated set of regional demand functions for electricity and a vector of candidate equilibrium prices for fuels, capital, labor, and materials. The key insight from Böhringer and Rutherford (2009) is that a Marshallian demand approximation in the electricity sector provides a good local representation of general equilibrium demand, and that rapid convergence is observed as the electricity sector is small relative to the rest of the economy.[15]

As this study represents the first application of the decomposition technique in a large-scale applied setting, there are a number of issues and extensions of the original method that warrant further discussion. First, incorporating a demand response in ReEDS requires modifying the objective function. Instead of minimizing total system costs, as is the case for the native version of the ReEDS model, the integrated model chooses generation, transmission, and capacity decisions for each two-year period in the electric sector that maximize the sum of regional consumer and producer surpluses. Second, commodity prices and demands are transferred between the economic and electric sector model at the regional level. To incorporate regional commodity price variation on technology and fuel costs, ReEDS maps its 134 power control areas and 356 resource regions to the 12 USREP regions. Third, a consistent integration of both models needs to capture all profits earned by sub-marginal generators in the electric sector. Profits or rents arise because of capacity, transmission and resource constraints. In ReEDS the producer surplus represents the sub-marginal profits of technologies/generators that produce electricity at a cost that is smaller than the cost of the marginal generator and sell it at the market price which in equilibrium is equal to the marginal cost. For each region, we can calculate total sub-marginal profits as the difference between the value of electricity output and the value of inputs used to produce electricity. Fourth, implementing an economy-wide carbon policy in the integrated model requires iterating on the price of carbon and the demand for CO_2 emissions permits. We thus pass a candidate carbon price from USREP to ReEDS, and the subsequent solution of USREP then calculates a new estimate for the equilibrium carbon price based on demands for emissions permits by the electricity and non-electricity sectors.

4. Simulation results

4.1. Policy scenarios

Our analysis focuses on the following five counterfactual scenarios whose specifications are outlined in the text below:

- BAU: "Business-as-usual" case without a federal CES or RES policy but existing state RES policies in the baseline.[16]
- CES: Federal Clean Energy Standard.
- RES: Federal Renewable Energy Standard.
- CAT_CES: Federal cap-and-trade policy covering all sectors of the economy and achieving equivalent year-on-year CO_2 emissions reductions as CES scenario.
- CAT_RES: Federal cap-and-trade policy covering all sectors of the economy and achieving equivalent year-on-year CO_2 emissions reductions as RES scenario.
- CAT_ELE: Federal cap-and-trade policy covering only the electricity sector and achieving equivalent year-on-year CO_2 emissions reductions as CES scenario.

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[15] In our simulations, rapid convergence is observed—usually 6–9 iterations are needed—as the electricity sector is small relative to the rest of the economy. The U.S. electric sector represents less than 4% of GDP.

[16] The exact specifications for the state RES policies are given in Short et al. (2011), Table 15, and are based on DSIRE (2011). In addition, our baseline includes federal- and state-level production and investment tax credits for wind, utility-PV, and CSP. The detailed assumptions are outlined in Short et al. (2011), Tables 13 and 14. The baseline also imposes national caps for SO_2 from electricity generation as specified by Short et al., 2011, p. 45. NO_x emissions are assumed to be unconstrained.

The CES scenario is constrained to achieve a certain clean electricity fraction target in each modeled year, defined as the ratio of total clean energy electricity generation to total electricity sales. The amount of generation from each technology that is considered clean depends on the technology. Specifically, all renewable technologies (wind, solar, hydropower, biopower, and geothermal) and nuclear are considered 100% clean, natural gas with carbon capture and storage (CCS) is considered 95% clean, coal with CCS is considered 90% clean, and gas combined cycle is considered 50% clean. Both existing installations and new investments in these technology types earn a credit.[17] The CES targets are assumed to increase linearly from 42% in 2012 to 80% by 2035. Then targets increase linearly from 2035 to 2050, achieving a final value of 95% in 2050. Our specification of the CES is therefore broadly consistent with the policy outlined by the Obama administration based on the 2011 State of the Union address and a white paper issued by the staff of the Senate Energy and Natural Committee on March 21, 2011.

Under the RES scenario all renewable technologies, including hydropower, are considered 100% clean. No credits are given for any other technology. The RES targets are assumed to increase linearly from 20% in 2012 to 70% in 2050.

For each of the federal CES and RES policies, we implement a corresponding CAT scenario that achieves the same level of economy-wide annual CO_2 emissions in each modeled year. This enables us to focus on the cost-effectiveness of the policies while holding fixed the environmental impact. In our model, these two scenarios can also be equivalently thought of as a federal carbon tax policy where tax rates over time equal the trajectory of equilibrium permit prices.

While comparing an electricity-focused policy to an economy-wide cap-and-trade policy that achieves the same emissions reductions does highlight opportunities for emissions reductions outside the electricity sector that are not exploited by a CES, there are likely to be additional policies other than a CES in place to address those other sectors. For example, tighter Corporate Average Fuel Economy standards and renewable fuel standards have been suggested as ways to reduce CO_2 emissions from transport. Without endorsing those approaches, another relevant comparison is therefore between a CES policy and a focused cap-and-trade policy that achieves the same level of emissions from the electricity sector as the CES. This scenario is labeled CAT_ELE.

In addition, the following assumptions apply to our analysis. First, trading in CES credits is national in scope and trades across state borders are not limited. As a consequence, some states or regions will be net sellers of CES credits and others will be net buyers with ensuing regional transfers of wealth. Second, banking of CES credits is not modeled, so a MWh of clean electricity generated in a particular year must be used for compliance in the same year. We also do not consider borrowing of CES credits. For consistency across policy scenarios, we assume that emissions permits also cannot be banked or borrowed. Third, we require that each policy has to be revenue-neutral which is implemented by requiring the same level of government expenditure (in real terms) as in the BAU. Balance of the government budget is achieved through an endogenous non-distortionary lump-sum tax. Fourth, for the CAT policy we assume that the revenue from emissions permits (net of what is withheld to maintain revenue-neutrality for the government budget) is distributed lump-sum to households on a per-capita basis.[18] Fifth, existing state RES policies are included in our baseline. We assume that these programs continue to exist in our counterfactual scenarios but that credits from a federal CES are not tradable with state/regional RES programs, i.e. generators receive two types of credits, one that can be used for federal compliance and the other for state compliance.[19] Sixth, our analysis does not

[17] Some CES proposals differ with respect to whether existing nuclear and hydro are treated. If they do not earn credits, existing hydro and nuclear would be treated no differently than coal facilities under a CES, which might seem perverse considering that an objective of the policy is to reduce emissions. A recent analysis by Paul et al. (2013) using the Haiku electricity model suggests that this feature of the policy may lead to a different outcome in terms of regional electricity price impacts.

[18] We therefore implicitly assume that emission permits are fully auctioned. Alternatively, our scenario can also be viewed as one that freely allocates allowances ensuring that consumers fully perceive the carbon price signal. For example, this rules out cases where the value of freely allocated allowances is passed on to consumers in the form of a subsidy to electricity prices either because the CAT regulation explicitly aims at sheltering some electricity consumers or because the intent of the legislation to have electricity prices reflect the full CO_2 costs is frustrated by Public Utility Commission's rate setting (Burtraw et al., 2001).

[19] Several state RES programs do allow for some (sometime limited) use of imported RES credits from other states and thus renewable generators can pick among markets into which to sell their renewable energy credits even for state programs.

consider alternative compliance payments (ACP) for CES credits where regulated entities could make such payments in lieu of purchasing credits. ACPs would limit the costs to the economy of imposing a CES by essentially establishing a cap on the price of CES credits—albeit at the expense of failing short of meeting environmental targets.[20]

Seven, our analysis does not consider existing (or possible future) policies outside of the electricity sector, like CAFE or renewable fuel standards. For example, although the model implicitly considers increases in the fuel economy of private passenger vehicles over time—induced by endogenous substitution toward power train capital—the simulated increases in fuel economy fall short of the targets currently specified under existing federal CAFE policy. Including such policies in the baseline would reduce the carbon price under an economy-wide cap and therefore result in less emissions reductions coming from electricity.[21]

Lastly, the CES policy modeled in this paper is a very basic one that assigns credits based solely on technology. Some recent proposals (for example, the Clean Energy Standard Act of 2012) includes unit-specific crediting where each generator gets credits depending on its emissions rate relative to a benchmark rate. This method of crediting eliminates some of the inefficiencies with the technology-specific method used in this analysis. Other policy parameters, such as different crediting for new and existing sources or banking of credits, can also be used to improve the efficiency of the CES, and thus reduce the cost differential between the CES and its corresponding cap-and-trade policy.

4.2. National impacts

4.2.1. CO_2 emissions

A CES (RES) policy as specified above will reduce cumulative CO_2 emissions in the U.S. electricity sector between 2012 and 2050 by roughly 51 (33)%, or 48.5 (31.4) billions tons, relative to a baseline with no CES/RES policy. These reductions correspond to a cut of 17 (11)% in terms of economy-wide cumulative emissions for the CES and RES scenario, respectively.[22]

The size of annual emissions reductions will grow over time as the standards tighten (Fig. 3). The CES policy is significantly more aggressive reducing emissions from electricity to 39% and 155% below the respective RES levels in 2030 and 2050. Up until 2038, the rate of emissions reductions is much bigger for the CES policy and then becomes more similar during the last 10 years of the policy.

The CAT_CES and CAT_RES scenarios will lead to 34 and 22% cumulative emissions reductions from electricity relative to the baseline, respectively, implying that both energy standards will lead to roughly 1.5 times higher cumulative emissions reductions in the electricity sector as compared to the respective cap-and-trade scenario. This suggests that a policy focused only on the electric sector will forgo low-cost abatement opportunities in other sectors of the economy that would be realized if marginal cost of abatement were equalized across all CO_2 emitting activities—as would be the case under a comprehensive federal cap-and-trade regulation.

4.2.2. Cost-effectiveness

Table 3 compares national welfare impacts across scenarios. Change in welfare is measured in equivalent variation (EV) as a percentage of full income, where full income includes material con-

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Allowing for inter-regional trading of RES credits under these programs may affect the baseline and the comparisons to baseline under the CES but would not significantly change the total amount of clean energy produced in the baseline. It would, however, decrease the national cost and electricity price slightly. Our expectation is that an aggressive nationwide CES should overwhelm those small differences.

[20] Palmer et al. (2011) provide an analysis of the effects of ACP on the performance of a federal RES policy.

[21] As CAFE and renewable fuel standard policies tend to push in high-cost abatement options that are not exploited under a CAT or CES/RPS policy (Rausch and Karplus, 2013), the *share* of emissions reductions coming from the electricity sector would not be significantly affected. We would thus expect that our main conclusions with respect to the cost-effectiveness of the CES and RPS policies are unchanged as compared to a model that explicitly represents existing CAFE and renewable fuel standard policies in the baseline.

[22] As the CAT_ELE scenario is designed to produce the same emissions reductions in the electricity sector as the CES policy, it is not discussed separately in this section. Due to inter-sectoral leakage effects, total economy-wide emissions reductions are higher under CAT_ELE relative to CES, but by a negligible amount.

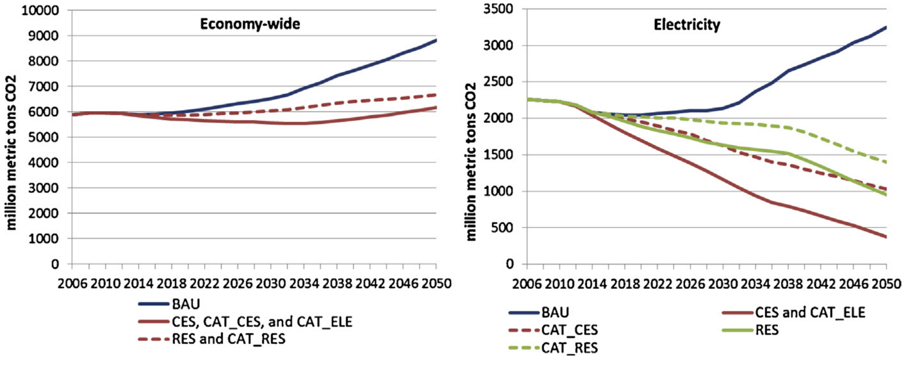


Fig. 3. National economy-wide and electric sector CO_2 emissions.

sumption and leisure. Table 3 reports a population-weighted average of EV across households by income and by region. Holding fixed year-on-year emissions across each pair of policies enables us to assess the cost-effectiveness of CES/RES policies relative to the respective cap-and-trade policy.

Both regulatory standards for the electricity sector are highly cost-ineffective. Taking a net present value (NPV) perspective, the CES (RES) is 1.9 (4) times more costly than a cap-and-trade policy that would achieve the same CO_2 emissions reductions. Surprisingly, the cap-and-trade policy that focuses exclusively on the electricity sector (CAT_ELE) is only slightly less cost-effective relative to the CES policy. While the crediting scheme under the CES policy only partially reflects the carbon intensity of electricity generation technologies, this suggests that the economic efficiency cost of such an “approximative” policy design are small in practice.

Because the set of credited technologies is larger under the CES, in particular allowing full crediting of nuclear and partial crediting of “clean” natural gas and coal, the CES is more cost-effective relative to the RES which achieves compliance by mainly deploying high-cost wind and solar power. Note that this holds true even though the RES is significantly less aggressive in terms of observed emissions reductions than the CES. This suggests that a technology mandate in the electricity sector targeted at deploying a substantial amount of renewables without allowing “clean” fossil-based generating technologies to play a role will entail significant economic costs and will not be cost-effective.

Comparing the cost-effectiveness for different sub-periods of the policy horizon shows that the relative inefficiency of regulatory policies appears to be particularly large for the first 10-20 years, but that it decreases substantially over time. This suggests that cheaper abatement options in other sectors of the economy are available in the years following the introduction of the policy, but that these are limited. Consequently, any cost-effective climate policy set out to achieve sizable economy-wide CO_2 emissions reductions over the next decades, will have to eventually involve substantial abatement from the electricity sector.

4.2.3. Distributional impacts by income

Table 4 shows NPV welfare changes by income class across scenarios. The CES, CAT_ELE, and RES policies are regressive, i.e. low-income household bear a disproportionately large burden of the economic cost. There are two key drivers for this result. First, the increase in electricity prices under a CES/RES disproportionately affects low-income households who spend a larger fraction of their budget on electricity (regressive uses-side effect). Second, capital owners benefit from returns on new investments in clean generating capacity. High-income households disproportionately benefit as they exhibit higher capital income shares relative to low-income households (progressive sources-side effect). As electricity price increases are slightly higher under the CAT_ELE as compared to the CES, the uses-side effects, and hence overall welfare impacts, are slightly more regressive in the CAT_ELE. Thus, while a CES policy is almost as cost-effective as an electricity-sector cap, the distributional implications differ with low- (high-) income households being relatively better (worse) off under the CES policy.

Table 4
National welfare impacts by income.

Income group[a]	CES		CAT_CES		RES		CAT_RES		CAT_ELE	
	%	$	%	$	%	$	%	$	%	$
<10	−0.54	−264	1.50	753	−0.31	−147	1.09	533	−0.65	−318
10–15	−0.50	−265	0.52	287	−0.27	−142	0.44	235	−0.60	−318
15–25	−0.49	−289	0.29	184	−0.25	−147	0.29	177	−0.52	−307
25–30	−0.46	−346	−0.07	−46	−0.23	−171	0.05	42	−0.48	−361
30–50	−0.40	−402	−0.28	−274	−0.19	−191	−0.09	−88	−0.42	−422
50–75	−0.38	−438	−0.46	−536	−0.17	−194	−0.21	−245	−0.39	−450
75–100	−0.35	−473	−0.33	−437	−0.16	−208	−0.13	−173	−0.35	−473
100–150	−0.33	−456	−0.33	−455	−0.14	−191	−0.13	−183	−0.28	−387
>150	−0.31	−499	−0.47	−770	−0.12	−198	−0.23	−369	−0.25	−402
Average	−0.37	−392	−0.2	−204	−0.17	−180	−0.04	−44	−0.33	−350

Notes: Welfare impacts are population-weighted averages of net present value (NPV) of equivalent variation by household. "$" refer to annual averages of NPV welfare impacts expressed in 2006$.
[a] $1,000 annual income.

The pattern of distributional impacts across income groups can be quite different under an economy-wide, federal cap-and-trade program. Assuming that the carbon revenue is returned lump-sum on a per-capita basis, both the CAT_CES and the CAT_RES are progressive. Note that this is not a general result as distributional effects depend crucially on how the carbon revenue from a cap-and-trade policy is distributed (or how freely allocated emissions permits are distributed). In fact, our per-capita allocation rule adds to the progressivity of the policy because $1 dollar of revenue allocated to a low-income household represents a larger share of income than $1 dollar allocated to a high-income household.

One important implication that follows from Table 4 is that a market-based policy such as a cap-and-trade program or a carbon tax generate revenue that can be used to alter unintended distributional consequences of the policy. On the other hand, a CES or RES program is essentially a revenue-neutral credit trading system that induces offsetting payments between "clean" and "dirty" electricity generators. Thus, besides being cost-ineffective, a CES or RES policy does not generate revenue that could be used to address concerns over distributional outcomes.[23]

4.2.4. Electricity price impacts

Table 5 shows the evolution of the US average retail electricity price across different scenarios and reports equilibrium CES/RES credit prices as well as carbon price for both CAT cases. While for all policy cases price impacts are similar by 2050, showing increases on the order of 15% relative to BAU, the equilibrium price trajectories leading up to 2050 for the CES/RES are below the one for the respective CAT case. Price impacts under CAT_ELE are higher than under CAT_CES as a higher carbon price is required to achieve the same emissions from just abating in the electricity sector. Differences in price impacts across scenarios are the largest for the initial years after the introduction of the policy and the price gap between CES/RES and CAT policies narrows over time converging in all cases to a price level of around 16.5 cents per kWh in 2050.

Differences in price impacts are due to the nature of policy instruments. First, under the CES/RES dirty, fossil-based generators are taxed and the credit revenue is used to effectively subsidize electricity production from clean energy sources.[24] In contrast, under a CAT policy the revenue from imposing a carbon charge on fossil-based generators is passed forward to consumers in the form of lump-sum

[23] Of course, additional policy measures to address distributional issues are conceivable, but one should be clear that those would go beyond what is intended under a purely technology-focused CES or RES policy.
[24] One caveat to the incidence results in this paper is that for CES or RES regulations where LDCs—and not dirty generators—are the point of compliance and must purchase credits from clean/renewable generators, consumers are actually subsidizing clean/renewable generators. This subsidy leads to a reduction of the average (and sometime marginal) cost of generating electricity, so consumers see a smaller price effect. Thus the incidence of the tax that funds the subsidy is split between consumers and fossil generators.

Table 5
US average retail electricity prices over time.

Year	BAU	CES		RES		CAT_CES		CAT_RES		CAT_ELE	
2012	10.9	10.9	(–)	10.9	(–)	10.9	(–)	10.9	(–)	10.9	(–)
2020	12.4	12.3	(−0.6)	12.4	(0.3)	13.1	(5.2)	12.7	(2.5)	13.2	(6.7)
2030	13.4	14.1	(5.2)	13.2	(−2.0)	15.1	(12.2)	14.4	(7.4)	15.6	(16.2)
2050	14.6	16.5	(13.5)	16.5	(13.3)	16.9	(15.7)	16.7	(14.2)	17.4	(19.0)

Notes: Cents/kWh. Percentage change relative to baseline in parentheses.

payments instead of subsidizing electricity prices. Second, by directly incentivizing the deployment of electricity from renewable energy sources, the CES/RES policies push in low-cost generation options that enter the dispatch order at the front end thus pushing out the existing supply curve and lowering marginal costs. Over time, as low marginal-cost options for renewable electricity are gradually used up and as CES/RES targets become more stringent, price impacts across policies converge.

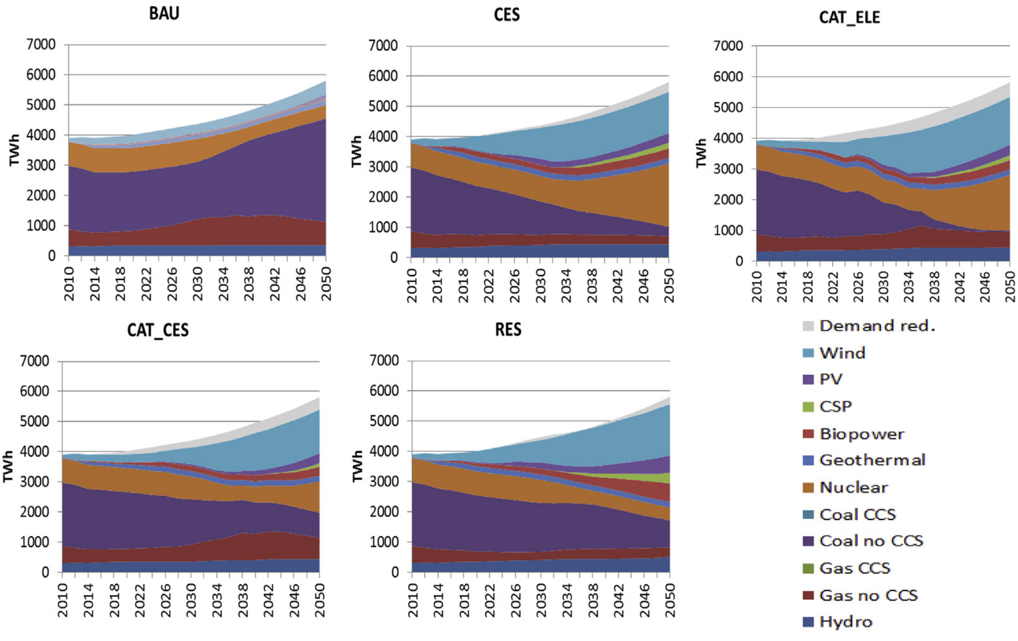
4.2.5. Electricity generation and installed generation capacity

Fig. 4 shows electricity generation and installed capacity by technology type in each scenario over time through 2050. In the BAU, the model shows an increasing dependence on fossil fuels, with 72% of total electricity generation coming from coal or gas by 2050, compared to 68% in 2010. Renewables technologies, including hydropower, provide 20% of total generation by 2050. The CES, on the other hand, reduces conventional gas and coal generation to 11% of total generation by 2050, while renewable technologies provide 51% of total generation and nuclear provides 38%. The CAT_ELE brings about an identical generation and capacity mix as under CES as the credit scheme closely mimics CO_2 penalties under a carbon pricing policy. As the scope of the CAT_CES scenario is economy-wide, transformation of the electric sector is not as large as in the CES. Coal and gas generation reduces to 28% of total generation by 2050, and renewable generation increases to 52% of total generation by 2050, while the share of generation from nuclear power remains very near 20%, similar to its share in 2012. While the RES mandates that 70% of total generation has to come from renewable energy by 2050, it brings about a significantly smaller reduction in coal and gas generation which contributes around 33% of total generation by 2050.

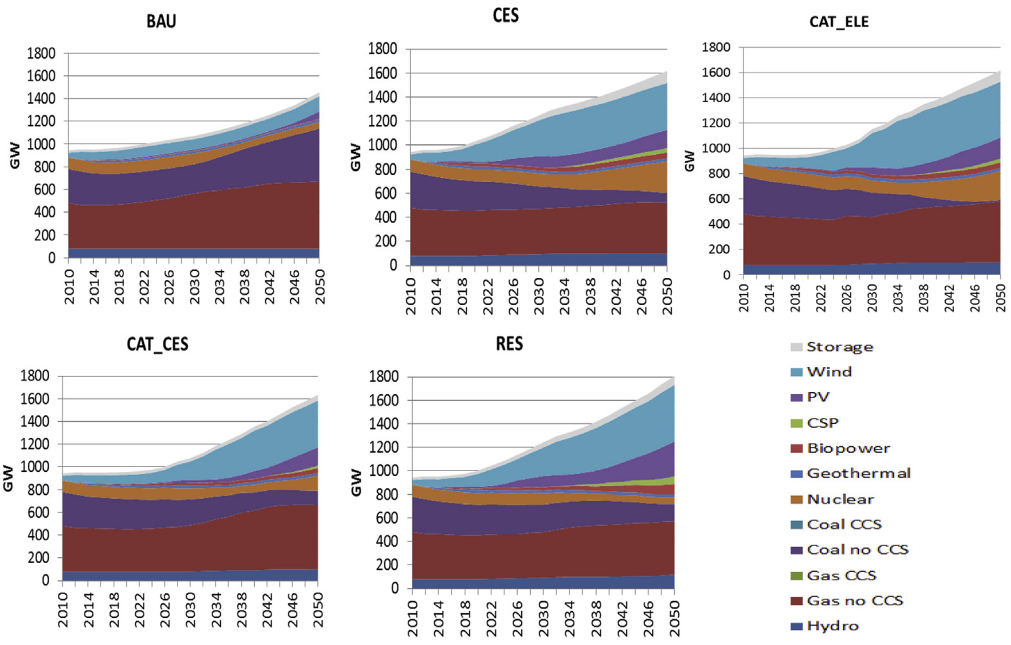
Fig. 5 enables a better comparison of US installed capacity and generation by technology, focusing on 2030 and 2050. Of the renewable generators, wind power in particular sees substantial growth in all policy scenarios, achieving near 26% of generation by 2050 in both the CES and CAT_CES scenarios. In these policy scenarios, onshore wind contributes 19% of total generation by 2050 but offshore wind installations also play a non-negligible role contributing to around 7%. The share of hydropower only slightly increases from 6% under BAU to 8% in CES and CAT_CES in 2050. The second largest growth in terms of generation shares among renewable technologies is observed for biomass electricity (including co-fired biomass) which contributes 6% under CES and CAT_CES and 12% under RES by 2050 compared to BAU levels of around 1% in 2050. Biopower is closely followed by solar which provides 6% under CES and CAT_CES and 11% under RES by 2050. The generation share of geothermal is about 3% in 2050 under the BAU case and is largely unaffected by the policies.

Fig. 6 shows annual wind capacity installations and cumulative wind capacity over time for the US. Wind growth experiences a period of rapid expansion until it reaches 350–370 GW of installed wind capacity, and then the growth rate slows substantially. This slowing of growth is due to a number of factors captured in the ReEDS model. For one, in its optimization ReEDS first chooses wind sites that are the most cost-effective in that they have the best combination of high capacity factors, nearness to transmission lines or population centers and therefore low transmission costs, and ability to fit well with temporal demand of electricity and the types of generation technologies serving a region. As these sites are used up, incremental wind generation must move to lower quality sites. Furthermore, the increase in wind penetration reduces dispatchability of the system as a whole and increases variability, increasing the need for reserve capacity and increasing curtailments.

In the RES, cumulative installed wind capacity until 2036 is slightly lower than in the CES but the patterns of annual installations under both scenarios are similar. After 2036, annual wind capacity



(a) Generation.



(b) Capacity.

Fig. 4. US electricity generation and installed generation capacity by scenario over time.

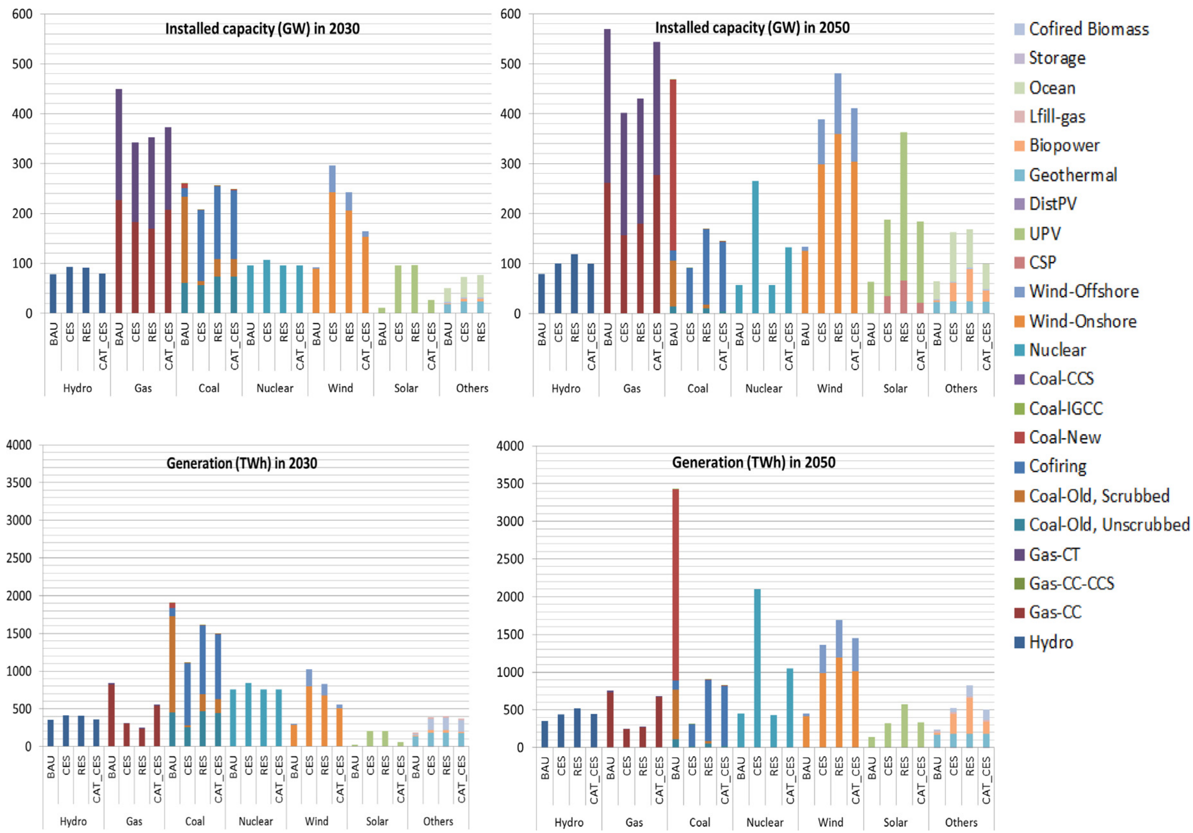


Fig. 5. US installed capacity and generation by technology in 2030 and 2050.

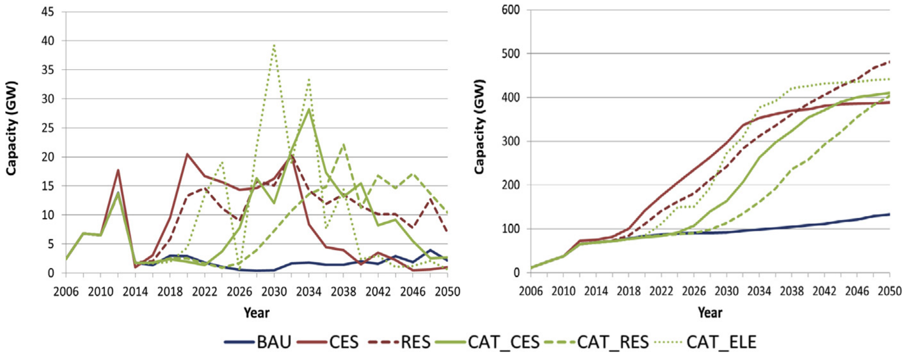


Fig. 6. US annual wind capacity installations (left) and cumulative installed wind capacity (right).

installations in the CES fall below 5 GW whereas remain at about the 2-fold level in the RES through 2050. In the CES, the sharp decline in new wind capacity additions reflects the increased role of nuclear after 2034. In the RES, the nuclear option is not available and significant growth in wind is still required to meet the more stringent targets—together with significant growth in PV, CSP, and biopower after annual wind capacity installations peak in 2032. The growth in wind capacity before around 2023 is much slower in the CAT_CES and CAT_RES cases as most of the adjustment in the electricity sector is achieved through reducing the reliance on coal. As carbon prices continue to rise reaching levels of more than \$70 per metric ton of CO_2 in the CAT_CES by 2034 (not reported here), annual wind capacity installations exceed those under the CES and RES. By 2050, the level of cumulative installed wind capacity across the different policy scenarios is relatively similar.

4.3. Regional impacts

Table 6 shows NPV welfare impacts by region expressed as a percentage change and as a per-household annual average dollar impact relative to the BAU. Regions are ordered from the top to the bottom by their percentage welfare impacts for the CES. Both a federal CES and RES policy lead to an unequal distribution of economic costs with a maximum difference of 0.88 and 0.71% points (or \$745 and \$636 annual costs per household) across regions, respectively. The CAT scenarios result in even larger regional disparities with a maximum difference of 1.99 (\$1533) under CAT_CES. There are two possible explanations for this. First, regional heterogeneity with respect to carbon intensity is

Table 6
Regional welfare impacts.

Region	CES		CAT_CES		RES		CAT_RES		CAT_ELE	
	%	\$	%	\$	%	\$	%	\$	%	\$
South Central	−1.00	−908	−1.40	−1272	−0.70	−628	−0.77	−700	−0.8	−771
Mountain	−0.57	−530	−0.78	−734	−0.25	−232	−0.42	−394	−0.5	−445
South East	−0.52	−499	−0.25	−228	−0.28	−260	−0.08	−71	−0.2	−138
Texas	−0.52	−538	−1.53	−1614	−0.36	−386	−0.84	−876	−0.9	−978
North East	−0.37	−420	−0.06	−61	−0.13	−146	0.04	46	0.0	−37
North Central	−0.30	−288	−0.20	−194	−0.02	−22	−0.03	−32	−0.1	−118
Florida	−0.29	−247	0.20	169	−0.25	−206	0.18	147	0.1	102
Pacific	−0.24	−236	−0.02	−9	−0.05	−50	0.06	64	0.0	−5
New York	−0.22	−282	0.54	694	−0.11	−140	0.42	538	0.3	421
New England	−0.16	−188	0.54	616	−0.06	−66	0.41	468	0.3	373
California	−0.12	−163	0.24	324	0.01	8	0.23	301	0.1	196
US	−0.37	−392	−0.20	−204	−0.17	−180	−0.04	−44	−0.33	−350

Notes: Welfare impacts are population-weighted averages of net present value (NPV) of equivalent variation by household. "\$" refer to annual average of NPV welfare change per household expressed in 2006\$.

Table 7
Regional electricity price impacts and inter-regional credit flows (CES scenario).

Region	Average retail price			Inter-regional credit trading (billion $)		
	Cents (kWh)	Δ% from BAU		Revenues	Purchases	Net revenue
	2006	2030	2050	2030	2030	2030
North Central	6.6	4.2	22.6	9.9	8.6	1.3
South Central	7.6	10.3	21.0	3.2	4.9	−1.7
South East	7.1	7.8	16.2	12.4	20.4	−8.0
Mountain	7.0	1.3	15.7	9.6	5.3	4.4
North East	8.6	5.3	15.5	16.7	24.5	−7.8
Texas	10.4	5.1	14.6	6.7	10.7	−4.0
Pacific	11.2	4.2	12.4	5.3	0.9	4.4
California	12.9	5.8	10.7	8.3	1.1	7.1
New England	13.6	4.9	7.2	3.3	1.6	1.7
New York	15.3	4.0	5.3	2.7	1.3	1.4
Florida	10.5	3.2	4.1	4.7	3.5	1.2
US	10.1	5.2	13.5	82.7	82.7	0

larger if all sectors of the economy, not just electricity are considered. Second, a significant amount of heterogeneity in regional impacts is due to recycling the carbon revenue under the CAT scenarios on a per-capita basis.

The CES and RES generate negative welfare impacts for all regions, while there are some regions in the CAT cases that experience welfare gains. The fact that some regions benefit from a cap-and-trade policy is not to say that carbon pricing itself is beneficial but that these regions receive transfer payments due to the allocation of the carbon revenue that overcompensate their abatement costs. Regions benefiting from a federal CAT policy are coastal regions—California, New England, New York, and Florida—that have already de-carbonized their economies to a large extent and that are relatively populous, thus benefiting from a per-capita allocation scheme.

Regional welfare impacts under the CES and RES can be traced back to electricity price impacts by region (Table 7) which in turn can be related to the generation mix in the baseline and the policy cases (Figs. 7 and 8).[25] In general, the net effect on the electricity price at the state or regional level will depend on the following two effects.[26] First, the cost of supplying electricity from any particular technology is affected by an implicit tax due to the cost of CES credits and, for qualifying technologies, an implicit subsidy from sales of CES credits. Second, the impact on electricity prices will depend on changes to the electricity supply curve. On the one hand, marginal generation costs will increase in regions that are heavily dependent on non-qualifying capacity as these will tend to experience significant capacity retirements shifting the supply curve to the left. On the other hand, regions that are endowed with rich, low-cost renewable resources will tend to experience significant investments driving down marginal cost to the extent that such technologies will enter the dispatch order at the front end; for high levels of renewable penetration, the CES will force deployment of renewable electricity generation at sites with relatively low capacity factors as the best site have already been used up, thus driving up marginal cost.

Regions that are more dependent on generation fuels that are not eligible under the CES, primarily coal, in general experience relatively large price increases. For example, North Central, South Central, South East, and the Mountain region experience significant reductions in the use of coal over the policy horizon and see the highest electricity price increases by 2050. However, the regional ranking in terms of price increases varies over time with some regions experiencing modest price impacts before 2030 while showing substantial price increases by 2050. For example, below-average price impacts in 2030 for NCENT and MOUNT reflect high-quality, low-cost wind resources in these regions implying—together with relatively small retirements in coal—only a small shift of the supply curve to

[25] The remainder of this section focuses on comparing the BAU and CES scenarios. Supplemental figures showing regional electricity generation and capacity installations for alternative scenarios are available from authors upon request.
[26] This is partly based on the discussion in Paul et al. (2013).

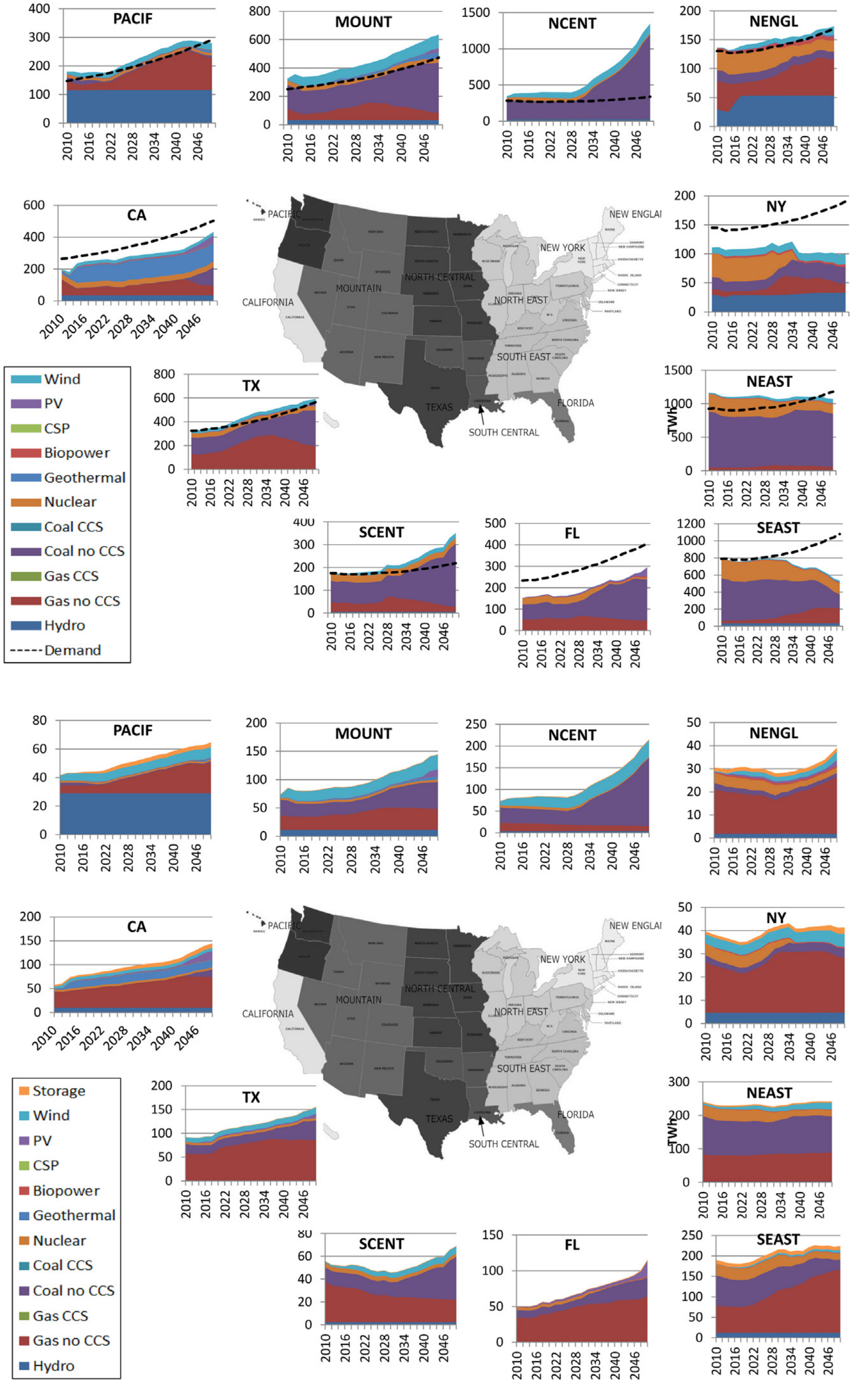


Fig. 7. Regional electricity generation and demand in TWh (top) and installed capacity in GW (bottom) for BAU.

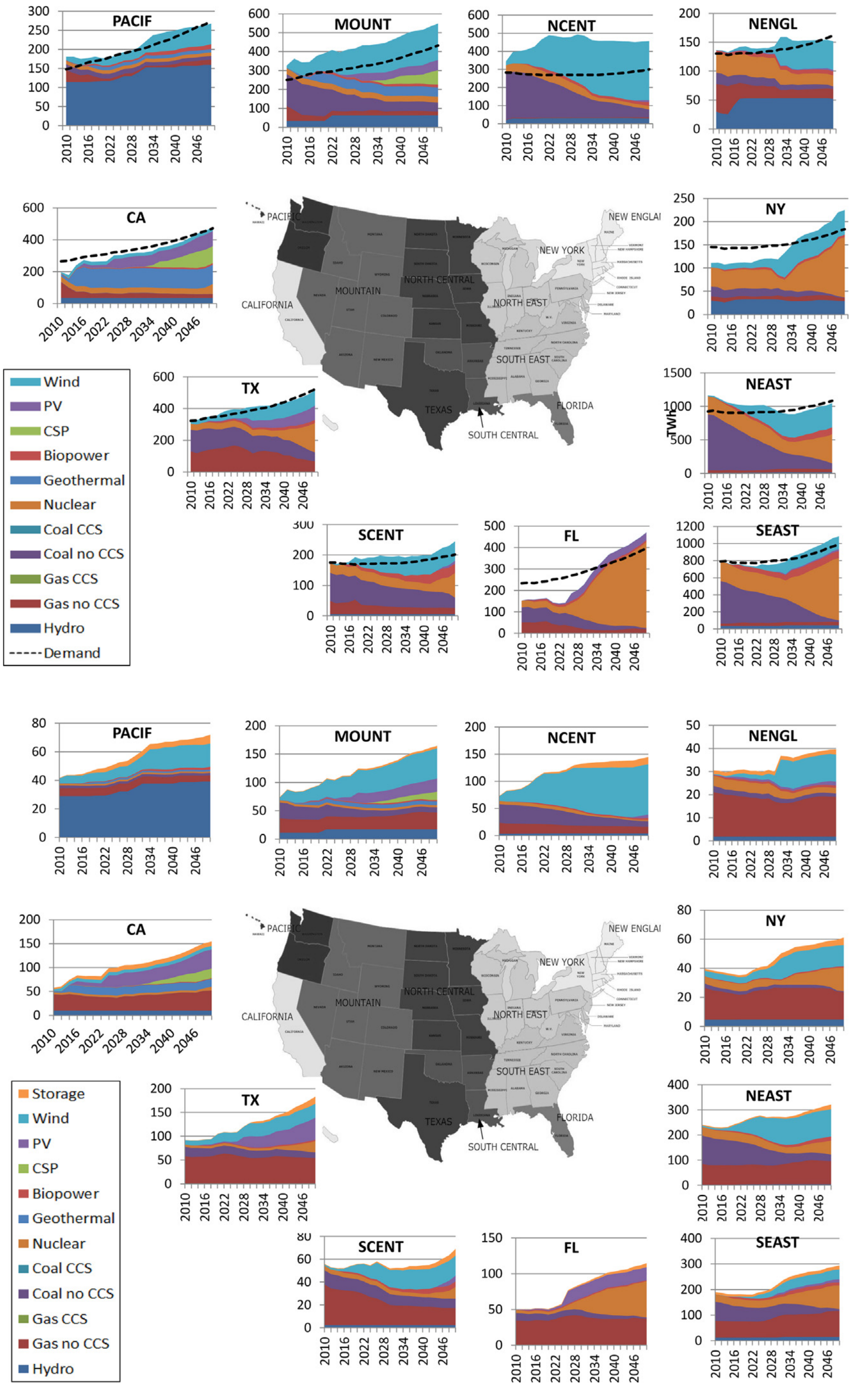


Fig. 8. Regional electricity generation and demand in TWh (top) and installed capacity in GW (bottom) for CES.

the left and ensuing moderate marginal-cost increases. The relative moderate price increases for North Central for most years explains why this region suffers only from a modest NPV welfare loss although it experiences substantial reductions in the use of coal and large deployment of wind power. Regions with a relatively clean generation mix in the baseline and abundant hydro power and wind resources (Pacific), good offshore wind resources (New England), and large resource potentials for geothermal and solar power (California) show the smallest price increases in 2050 and bear the smallest economic burdens.

The regional distribution of generation does change somewhat but there are no big reversals in terms of regions changing their net trade position from being an net electricity exporter in the BAU to a net importer in the CES. In fact, the general pattern that emerges is one where regions that are net importers in the BAU—such as California, New York, Florida, and South East—increase local generation in the CES and have to rely less on imports. This is to a large extent facilitated by the possibility to substantially increase local nuclear generation.[27]

Table 7 shows that a federal CES policy induces sizable inter-regional capital transfers that occur in the market for CES credits. Given a CES target of around 71% by 2030 and an ensuing equilibrium credit price of 6.5 cents/kWh, the volume of traded credits in 2030 totals to \$82.7 billions. Regions with high capacity factors for renewables such as California, Mountain, and Pacific receive the largest net capital inflows from credit trading among all regions ranging from \$4 to 7 billions in 2030. By 2030, the South East and North East regions, currently heavily dependent on coal and nuclear, and Texas, currently dependent on coal and natural gas, are net importers of credits financing net capital gains in other regions.

5. Conclusions

This paper considered the distributional and efficiency impacts of clean and renewable energy standards for electricity. While our analysis focused on the United States, some of the conclusions may be applicable in the context of other countries. Our analysis employed an integrated modeling framework linking a global model of economic activity and energy systems with an electricity generation dispatch and capacity expansion model for the contiguous U.S.

We find that a CES policy, broadly consistent with the proposal by the Obama administration, and a RES policy, mandating that 70% of electricity generated in 2050 has to come from renewable energy sources, would have significant effects on electricity sector CO_2 emissions. Cumulative CO_2 emissions in the electricity sector between 2012 and 2050 will be reduced by roughly 51 in the CES and by 33% in the RES case relative to a no-policy baseline. These reductions correspond to a cut of 17 and 11% in terms of economy-wide cumulative emissions for the CES and RES scenario, respectively. The CES and RES lead to extensive retirements of coal-fired capacity and substantial deployment of wind power. Besides significant additions in wind power, some regions show substantial investments in PV capacity (California, Texas, and Mountain region), CSP (California and Mountain region), and geothermal (California). In regions without abundant renewable energy resources that are subject to increasing costs with the expansion of electricity generation from renewable sources, nuclear power is the economically preferred approach to meeting the standard (Florida, South East, and New York).

We estimate that the CES policy modeled here is about twice as costly than a comprehensive market-based carbon pricing policy—such as a federal cap-and-trade regulation or a carbon tax—that achieves the same year-on-year emissions reductions. The RES policy considered here is four times more costly as it focuses on a smaller set of technologies, in particular it does not allow for “clean” gas and nuclear power to play a role in meeting the standard’s target. These estimates are best viewed as providing a lower bound on the efficiency costs of CES and RES policies. If banking and borrowing of emissions permits under a cap-and-trade program were allowed, if emissions reductions could be achieved from non-CO_2 greenhouse gases, or if the carbon revenue was used to lower distor-

[27] In our simulations we do not place any bounds on investments in new nuclear power thereby representing a world in which nuclear expansion is solely driven by economic conditions and is not constrained by siting and licensing issues or other political considerations.

tionary taxes, the CES and RES policies would compare even less favorably in terms of efficiency costs.

Clean and energy standards in the electricity sector are regressive, i.e. they place a disproportionably large burden on low-income households who spend a larger fraction of the income on electricity relative to high-income households. Regional differences in welfare impacts are driven by the variation in regional electricity price impacts. The general pattern is one where regions with low cost electricity because they rely extensively on low cost coal generation see the largest electricity price increases. However, even with larger percentage increases electricity prices generally remain considerable lower in these regions than in others with higher current electricity prices. Regions with abundant hydro power and wind resources (Northwestern and New England states), with large potentials for geothermal and solar power (California) and a relatively clean generation mix in the baseline experience the smallest price increases and bear the smallest burden of economic costs.

The sizable distributional effects under clean and renewable energy standards in terms of household impacts by region and income can be problematic as these policies do not generate any revenue that could be used to alter unintended distributional outcomes of the policy. The revenue-neutral nature of credit trading means that the revenue from selling clean energy credits to dirty electricity generators is used to subsidize electricity production at clean generators. In contrast, electricity prices under a cap-and-trade[28] or carbon tax policy fully reflect the carbon price signal, and generate carbon revenue that is available to address distributional issues of greenhouse gas policy. Assuming that the carbon revenue is recycled using equal per-capita lump-sum transfer payments, we find that such carbon pricing policies would be progressive.[29]

The results are derived in a model where the electricity sector is represented as if all regions operated under a competitive market structure. While average cost pricing for regions with cost-of-service regulation will not change the efficiency results of our analysis—assuming a federal cap-and-trade policy is designed such that consumers of regulated utilities fully perceive the carbon price signal—it may alter the distributional outcome of both technology mandates and carbon pricing policies considered here. Further sensitivity analyses would also need to explore the implications of varying technology cost assumptions, in particular with respect to renewable technologies and carbon capture and sequestration options, as well as limiting the future availability of nuclear power.

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[28] Assuming emissions permits are fully auctioned or the opportunity costs of free permits allocated to price-regulated utilities are fully passed through to consumers.

[29] This is not a novel result and is in line with other studies. See, for example, Bento et al. (2009) and Rausch et al. (2010).

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