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Low carbon standard and transmission investment analysis in the new multi-region US power sector model FACETS

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ABSTRACT

This paper presents a new US multi-region energy systems model built in the TIMES modeling system: the Framework for Analysis of Climate-Energy-Technology Systems (FACETS). The model is designed to analyze energy technology options and policy scenarios across sectors and regions, including the increasingly important interactions between state, regional, and federal policies. FACETS contains a realistic representation of key infrastructure, while retaining the flexibility to explore deep carbon emission reductions and other large changes from the baseline energy system. It is built using a unique, flexible multi-region approach so that the geographic relationships that drive the costs of energy technology transitions can be captured. Significant enhancements to the Veda-TIMES system and a GIS-results viewer permit the massive data handling needed to represent these relationships and interpret results. An analysis of a federal clean energy standard (CES) and investment in the transmission grid is presented.

1. Introduction and motivation

A variety of studies have analyzed the costs of prospective or notional federal policies to induce deep cuts in US carbon emissions over the coming half-century. In the recent Energy Modeling Forum (EMF) 22 multi-model study (Clarke and Weyant, 2009) of US cap and trade policies similar in severity to the American Clean Energy and Security Act of 2009 (ACESA or H.R.2454; US Congress, 2009), cost estimates varied widely, with annual consumption impacts ranging from tens of dollars per household to over a thousand dollars per household in the most severe and restricted scenarios. Key sensitivity factors included baseline emissions projections, the severity of the cap, policy flexibility, and especially the costs and availabilities of zero and very low carbon technologies.

A review of these studies and consideration of the US energy policy landscape suggest a clear need to assess US energy system change at a regional level, for three reasons. First, federal carbon policies will have very different cost impacts on different regions of the country. It has been suggested (Wheeler, 2008) that these disparate impacts have played a significant role in the failure to achieve consensus on a policy thus far. Second, even the *overall* costs of deep emissions reductions are driven by geographic relationships that cannot be adequately represented in a national model. Finally, states and regions are actively pursuing energy and environmental policies that can be expected to interact substantially with each other and with federal carbon policies.

In analyses that have broken the US into regions, the economic impacts of CO_2 reduction policies on households and business are found to vary substantially across regions, depending on existing electricity generation technology mix, available renewable and fossil resources, and baseline energy use patterns. Using a nine-region US CGE model coupled to a unit-level power sector model, Montgomery et al. (2009) found household consumption losses from ACESA ranging fourfold (from less than $400 per household to $1600) due to differences in industrial composition, energy intensity, and initial permit allocations. Similarly, Rausch et al. (2011) also found three- to fourfold difference in regional welfare effects, with some regions *gaining* from some versions of a federal policy in early years.

Notably the regions that experienced initial gains included states that have already enacted binding carbon emissions policies, whereas those that suffered the largest losses include regions whose representatives have strongly opposed federal climate legislation. In a county-level analysis of the incidence of a carbon tax on households, taking into account regional variation in the carbon intensity of energy consumption, Pizer et al. (2009) similarly found that the incidence in the northeast states and California, which have already enacted binding GHG emissions policies, would be about half that in the Midwest and Texas. Achieving a successful coalition to support a federal policy will require

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understanding these differences and designing mechanisms to achieve greater equity of impact.

However, even when the focus of analysis is national rather than explicitly regional, a regional analysis becomes necessary as the required carbon reductions become deeper. The cost of a transition to a very low carbon energy system will depend ultimately on the costs of zero and very low carbon energy technologies. In the EMF-22 studies, Kyle et al. (2009) found that the cost of deep carbon reductions varied threefold depending on the costs and combinations of advanced technologies available—including renewables, carbon capture and sequestration (CCS) and bioenergy. In analyses using the EPPA model, Paltsev et al. (2008, 2009) similarly found that relaxing restrictions on zero carbon electricity generation technologies had a significant impact on the cost of carbon reductions and on resulting energy system configurations.

With the exception of nuclear power, the costs of implementing zero and low carbon energy technologies in turn depend critically on geographical relationships, including those between:

- renewable resources, electricity loads, and transmission capacity;
- biomass production, transport and use; and
- CO_2 capture and sequestration sites.

Models that treat the US as a single region cannot represent these costs explicitly and must use ad hoc constraints or parametric relationships to limit the penetration of these technologies. When the required emissions reductions are severe enough to push models far along their supply curves, model results will become highly sensitive to these parameters.

Finally, environmental policy in the US is a joint federal-state responsibility. States have historically taken the lead in environmental regulation, often pioneering regulations that are later adopted at the national level. Many federal environmental regulations—particularly those that directly impact electricity generation—are implemented by the states through the state implementation plan process (Committee on Air Quality Management in the United States, National Research Council, 2004). Any new regulations on carbon emissions under the Clean Air Act are also likely to be implemented at the state level (Burtraw and Woerman, 2012).

In the absence of federal climate policy, many states have enacted climate policies and/or energy policies that can be expected to have significant emissions impacts. More than 30 states have completed climate action plans, 19 have set GHG emissions targets, and 10 have established cap and trade policies (Center for Climate and Energy Solutions, n.d.). Nearly 30 states have established renewable portfolio standards, and more than 20 have enacted binding energy efficiency standards. Burtraw and Woerman (2012) estimate that these subnational policies will by themselves lead to a 2.5% decrease in US GHG emissions below 2005 levels by 2020.

As federal climate policy is designed, the fate of these state and regional policies must be considered. Concerns have been raised that state regulations may interfere with the functioning of a federal carbon market (Burtraw and Shobe, 2009). Even if they do not, overlapping state and federal regulations may raise the overall cost of emissions reductions by driving a wedge between marginal costs in different states (Goulder and Stavins, 2011).

Thus whether the analysis focus is the state, regional, or national level, evaluation of policies to induce deep carbon reductions in the US requires a multi-region modeling framework with sufficient geographic resolution to describe the costs of implementing low carbon technologies and the relationships between national and subnational policies.

The remainder of the paper describes the design of the FACETS model—including regional structure, data, and data handling systems—and then presents an analysis of a federal clean energy standard (CES) policy, with and without investment in additional interregional transmission capacity, considering both national and regional impacts of variation in policy stringency.

2. Model design

As a result of the above considerations, FACETS has been designed with the following objectives in mind:

1. be sufficiently flexible to describe radically altered energy systems that can achieve policy goals far from business-as-usual, including deep carbon reductions,
2. describe the regional heterogeneity and key geographical relationships that drive the costs of low carbon energy, and
3. realistically analyze interactions between diverse state and federal policies and goals, including air quality regulation compliance, carbon emissions reductions, energy security, and technology transitions.

To meet these objectives, the Framework for Analysis of Climate-Energy-Technology Systems (FACETS) was built within the TIMES model generator framework (Loulou et al., 2005) using a unique, flexible multi-region approach. TIMES is a bottom-up, multi-sector, least-cost linear programming optimization system, which explicitly represents technology and energy carrier relationships as a Reference Energy System network. The TIMES modeling system, and its precursor, MARKAL, have been used for more than 30 years for analysis in more than 70 countries.[1]

The choice of a bottom-up model is driven by the need for transformative energy system change to meet deep carbon reduction goals. Under such a policy, the relationships between production, consumption, and expenditures for energy and other factors of production can be expected to shift outside of those captured by historically-derived elasticities and econometric relationships (Jean-Charles Hourcade, 2006). In addition, electricity load shapes may be transformed by further electrification of end uses. For example, it has been suggested that plug-in electric vehicles may draw charge at previously low load times of day and may even serve as novel grid-connected storage devices (National Renewable Energy Laboratory, 2012). As the value of intermittent renewables depends on the relationship between load shape and availability, it is essential to realistically represent changes in load shape and load management technologies that may be occurring simultaneously.

For these reasons, bottom-up models that explicitly represent technological relationships throughout the supply and demand sides of the energy system continue to play an essential role in setting first-best cost benchmarks for the costs of a low carbon energy transition and identifying critical technological pathways to be incentivized by policy. Indeed bottom-up models that represent individual supply options at a level of detail similar to FACETS can offer a far more realistic depiction of the costs of system transition than can top-down models using stylized supply curves. To overcome some of the limitations of the bottom-up approach in regards to microeconomic realism, FACETS can be run using the hybrid elastic-demand mode of the TIMES modeling framework, in which demands in policy scenarios respond to price changes from the Reference scenario with user-specified elasticities. However, this function was not used for the current study in order to keep the focus on electricity technology changes.

2.1. Regional structure

The US has some of the richest publicly available energy data in the world. Each sector's data are collected and reported using a different regional breakdown that reflects the key physical, economic, and institutional characteristics of that sector. So, for example, electricity generation and transmission data are collected and reported in North American Electric Reliability Corporation (NERC) regions, oil production and refining in Petroleum Administration and Defense District (PADD)

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[1] http://www.iea-etsap.org/.

regions, and end use equipment and consumption in Census Divisions. The US Department of Energy's National Energy Modeling System (NEMS) uses more than half a dozen sets of regions to describe energy supplies, demands, and flows (Energy Information Administration, 2011a).

Other existing technology rich energy system models have not been able to utilize these data in a resource-efficient, transparent way. Previous US multi-region MARKAL/TIMES models have been based on the Census Divisions (Choi et al., 2012; Shay and Loughlin, 2008), the regions which the Energy Information Administration uses to collect end use technology and consumption data, but which have little relationship to critical energy transmission infrastructure, particularly electricity transmission. Data describing all other sectors must be aggregated and disaggregated into the Census Divisions, in the process losing much of the key regional information that motivates the construction of a multi-region model. In particular, depiction of the electricity transmission infrastructure that drives the costs of decarbonizing the power sector is lost through this re-aggregation.[2]

FACETS is constructed to retain the regional characteristics of each sector, utilizing the set of regions native to the source data. Coal supply takes place within coal basins, electricity generation takes place within 32 NERC subregions that reflect key transmission bottlenecks, and demands take place within the Census Divisions, as illustrated in Fig. 1.

A set of trade matrices controls flows of energy within and between sets of regions. One trade matrix describes the flows between the 32 FACETS electricity regions, representing transmission infrastructure capacity, transmission losses, and wheeling charges. This matrix is based on existing physical transmission capacity and flows, with data derived from US EPA (2010). In the grid investment scenarios described below, additional interregional transmission capacity can be added at capital costs from EIA (2011a). A second matrix places a lower bound on the share of each Census Division's delivered electricity that must come from each electricity region. This matrix is derived from historical data representing the physical location of electricity consumers relative to utility territories, and is used in the NEMS model to apportion electricity end use loads to NEMS electricity regions (EIA, 2011a). The NEMS matrix has been modified for FACETS using historical shares of unit-level generation (EIA, 2012c) to break the 22 NEMS regions into the 32 FACETS regions.

Data structures for FACETS have been developed so that the regional breakdowns may be changed as analysis needs require. For example, power plants are tagged by state and county, and full location information for each plant is tracked and used by a Geographic Information Systems (GIS) results viewer that has been developed to visualize the results data (see Results section below). Additional state level or more detailed data can be substituted into any sector to enable analyses to drill down from national and regional to state and lower levels as needed. Finally, at the global level, FACETS is designed to be run embedded within the Times Integrated Assessment Model (TIAM) (Loulou and Labriet, 2007) global climate-energy model to enable analysis of US climate policies within consistent global resource and carbon offset supply scenarios.

2.2. Data

Data have been drawn from high quality, publicly available sources, as detailed in Table 1. Existing power plant data is drawn from the US EPA National Electric Energy Data System database (US Environmental Protection Agency, 2010), which combines data from EIA Forms 860 and 767 and EPA's E-GRID emissions data (US Environmental Protection Agency, 2013a). Hydropower plants have been aggregated by model region. Other plant types are represented at the unit level.

Additional power sector data, including regional load curves and interregional transmission constraints, as well as coal supply curves and transport costs, are drawn from EPA's Integrated Planning Model (IPM) data (US EPA, 2010 and updates). Cost and performance characteristics for new power plants and electricity load growth projections are taken from Annual Energy Outlook (AEO) 2011 data (Energy Information Administration, 2011a). Natural gas supply curves were constructed using EIA's liquefied natural gas (LNG) export study (Energy Information Administration, 2012a), which tests several shifts of the natural gas demand curve against three different shale gas resource scenarios based on AEO 2011 gas resource assumptions. The AEO 2011 Reference case shale gas assumptions have been used for the present study. Renewable resource supplies are derived from EIA NEMS and EPA IPM sources.

The effective cost of future plant investment and generation depends on several regional considerations, including resource quality and availability, fuel transport costs, regional load shape, and access to transmission capacity, as well as direct regional cost multipliers. As a result, supply cost curves are far more detailed, and the model exhibits considerably less penny switching than a model with coarser geography.

Optimization models commonly include capital cost supply step adders to represent short-term increases in costs for labor and materials when the model seeks to build new capacity of a given type faster than a specified rate. FACETS charges new nuclear, coal/gas with CCS, wind, and PV plants a 30% cost penalty to build new capacity faster than the rates shown in Table 2. These steps are based on a review of similar build rate adders in IPM (US EPA, 2010) and NEMS (EIA, 2011d), as well as recent historical maximum annual builds (EIA, 2012c) for these capacity types. All supply steps relax over time to represent the potential for development of increased national construction capacity for in-demand plants. Plant types with complex engineering requirements and limited recent builds (nuclear, coal/gas with CCS, and offshore wind) have more stringent limits that increase more slowly over time than types with simpler engineering and more rapid recent capacity additions. All plant options face the same cost of capital. No risk premiums or other inhibitory cost penalties were imposed.

The following state and federal policies are represented in the FACETS Reference case:

- The Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Rule (MATS). MATS compliance is assumed by 2017. Coal fired power plants may retrofit with any combination of wet flue gas desulfurization (FGD), selective catalytic reduction (SCR), dry sorbent injection (DSI), and activated carbon injection (ACI) in order to comply with plant level emissions limits (in the case of MATS) and state budgets and regional cap and trade (for CAIR). Cost and performance assumptions for retrofit devices are derived from EIA (2011b) and EPA (2010, 2011a, 2011b) Unit-level required upgrades specified by EPA (2011a) for fine particle control have also been imposed.
- State level renewable portfolio standards (RPS) are imposed at the regional level, as represented in AEO 2012 (Energy Information Administration, 2012b).

TIMES models are often conducted using a single optimization over the entire model horizon. A solution in this mode represents the least cost “best” that can be achieved with perfect foresight about future conditions and policy goals. Energy investment decisions in the real world are of course made with considerably less than perfect foresight. In particular, current investment decisions are being made under deep uncertainty about future carbon goals. To incorporate this uncertainty into the analysis and prevent over-optimization, all runs in the current analysis have been conducted with limited foresight in windows of 20 years, with a 10-year overlap. That is, the model solves for a least

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[2] It should be noted that using a single set of interacting regions is appropriate for many international and global bottom-up modeling endeavors, in which single countries or geographical groups of countries do actually function as independent energy systems, with only a limited set of trade flows between them. The same is not true of the US and other large energy economies in which multi-region modeling may be desirable. The US is a single energy system with different infrastructure, costs, and constraints within each sector. Thus the standard MARKAL/TIMES approach using single set of trading regions is not appropriate for modeling the US and other such systems.

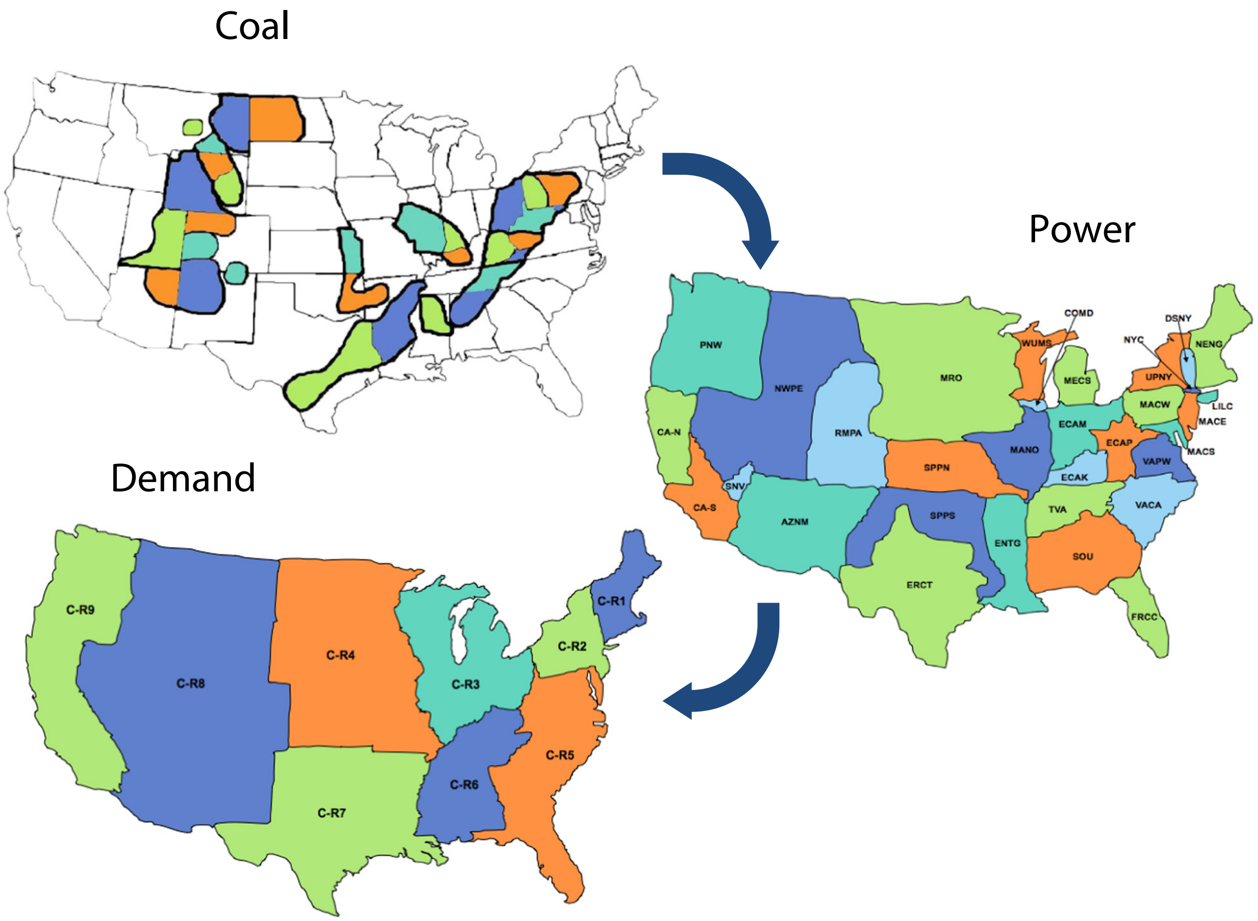

Fig. 1. FACETS regional structure.

Table 1
FACETS data sources and design details.[a]

Data type	Source	Comments
Biomass supply curves	NEMS wodsupp file	16 supply regions
Coal supply curves	EPA IPM Base Case v.4.10	31 supply sources, 3 types, 6 sulfur grades
Coal transportation costs from supply to power plants	EPA IPM Base Case v.4.10	Matrix of 85 coal types to 135 power plant groupings
Gas supply curves	Derived from EIA LNG Export Study	Based on AEO 2011 gas resource assumptions
Regional gas delivery costs	EPA IPM Base Case v.3.0	Transportation markups to power regions
Nuclear, residual, and diesel fuel costs	AEO 2011	
Existing power plants—capacity, performance, and emissions	EPA IPM NEEDS 4.10 MATS database	32 NERC subregions 11000 units, indexed by state and county
Emissions control retrofit costs and performance	EPA IPM Base Case v.4.10 and updates	FGD, DSI, SCR, and ACI retrofit options
New power plant cost and performance	AEO 2011 assumptions doc	Regional cost multipliers; New plant builds indexed by state
Wind resource and cost supply steps	AEO 2012 NEMS wesarea file	
Regional wind and solar capacity factors	AEO 2011	
Seasonal hydro capacity factors by region	EPA IPM Base Case v.3.0	
Wind contribution to reserve margins	EPA IPM Base Case v.4.10	
Geothermal potential and costs	EPA IPM Base Case v.4.10	
CO_2 transportation and storage costs for CCS	EPA IPM Base Case v.4.10	Transportation costs from ELC regions to 37 underground storage regions
Interregional transmission constraints	EPA IPM Base Case v.4.10	Among 32 NERC subregions
Capital costs for additions to interregional transmission capacity	AEO2011 ecpdat file	
Load curve	EPA IPM Base Case v.4.10	6 times of day in two seasons based on historical load
Electricity load growth	AEO 2011 results	Census divisions
Matrix for power plant regions serving load in census regions	AEO 2011 ldsmstr file	
State-level environmental regulations and renewable portfolio standards	AEO 2012 and EPA IPM Base Case v.4.10	

[a] All data used in this version of FACETS is publicly available. EPA IPM data as listed above are available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html. AEO input data may be obtained from EIA, as detailed at: http://www.eia.gov/forecasts/aeo/pdf/Information_on_Obtaining_the_NEMS_Archive.pdf. The TIMES code is maintained by IEA ETSAP, and may be obtained from ETSAP by executing a Letter of Agreement, as detailed at: http://www.iea-etsap.org/web/AcquiringETSAP_Tools.asp. Full documentation of the TIMES code is available at: http://www.iea-etsap.org/web/Documentation.asp.

Table 2
Build rate supply steps.

	Annual build limit before cost penalty incurred (GW/year)			
Plant type	2010	2020	2035	2050
Coal/gas with CCS	1.3	2.6	3.9	5
Nuclear	1.3	2.6	3.9	5
Photovoltaic	5	15	45	450
Offshore wind	0.5	1.5	10	100
Onshore wind	10	30	90	900

cost solution over the first 20 years, freezes the first 10 years of the solution, and then advances and solves the next 20 year window, repeating the procedure until the full horizon has been solved. Thus the model does not "see" the tightening carbon constraint in the slow policy scenarios described below until midway through the model horizon. The foresight approach may be adjusted at run-time.

2.3. Data handling systems

A key challenge in the construction of FACETS has been the development of tools to handle the voluminous input data. A TIMES model is built upon network topology. Each existing and potential new device in the system must be characterized along with the inputs and outputs that locate it within the network. When devices have single inputs and outputs, this is a simple, one line data specification. But one of the strengths of the TIMES modeling system is its ability to handle flexible fuel inputs, and track outputs, efficiencies, and emissions based on the input mix, so permitting a wider flexibility of input choices is desirable.

Characterizing the fuel choices for each of the more than 11,000 existing power generation units in the model requires the handling of previously unmanageable quantities of input data. For example, each of the 813 existing bituminous-fired units may draw upon a different subset of the 70 bituminous coal types that are differentiated by sulfur level and source region, depending on the plant's location, emissions control equipment, maximum permitted emissions level, and coal transportation link options. Specifying the topology by hand for every existing plant would be a time-prohibitive and error-prone process.

New capabilities were developed within the Veda-TIMES[3] data shell to produce model topology by rule, rather than enumeration. A single row in the input files creates 90,000 rows in the input data matrix, permitting, for example, all bituminous coals to be used in all bituminous-fired plants. Disallowed combinations are then controlled via flow bounds and plant level sulfur emissions constraints. The rule-based data creation approach has been extensively tested, first with comprehensive check of the output in a smaller test example that contains fewer processes and commodities but incorporates all topology cases, then by thoroughly checking the different inclusion/exclusion cases in the full model, and finally by verifying that flows in the output—in this case of coal—behave as expected. The rule-based approach also allows the direct read of source data files without significant analyst intervention, greatly reducing model build and update time and the potential for introduced errors.

3. Analysis

The analysis considered three versions of a power sector clean energy standard (CES) (Aldy and Stavins, 2012), with a number of sensitivity scenarios. A CES can be thought of as an extension of a renewable portfolio standard (RPS) that also gives credits for other zero and low carbon technologies. The CES considered here, similar to that examined by EIA (2011c), awards one CES credit per MWh of zero-carbon generation, and partial credit for some other types in rough proportion to their degree of carbon emissions reduction from coal steam generation, as shown in Table 3.

Table 3
CES credits by generation type.

Generation type	CES credits per MWh
Biomass, geothermal, hydro, nuclear, solar, wind	1.0
Gas combined cycle	0.5
Coal or gas with CCS	0.9

The CES requires an increasing percentage of CES credits as a share of total national generation, from 2010 levels of roughly 42.5% to 90% in 2050. Three CES trajectories were tested, as illustrated in Fig. 2, named C45, C65, and C85, for the share required in 2030. The C65 requirement increases linearly to 2050, while the C85 trajectory ramps up much more aggressively, reaching nearly the full level by 2030, and the C45 trajectory postpones most action until after 2030. Banking and borrowing were not permitted in this study.

The CES was evaluated with and without a policy that permits unlimited investment in inter-regional transmission grid infrastructure, wherever the model finds it to be cost effective. (Capital costs derived from AEO 2011 inputs.) Two additional sensitivity cases were evaluated: a gas price sensitivity described below, and a case in which new nuclear builds were prohibited. Including variations on the Reference case, this yields a matrix of 19 scenarios, as shown in Table 4.

The nuclear sensitivity case was chosen because exploratory runs found that the technology mix selected in policy scenarios is highly sensitive to assumptions about nuclear plant costs and short-term build rate cost penalty assumptions. At AEO 2011 capital costs, new nuclear is the dominant compliance strategy in many regions. Previous carbon cap analyses have also found a substantial difference in costs between cases in which nuclear was and was not allowed to expand (Montgomery et al., 2009). With no new nuclear builds completed in several decades, the costs, financing, and social acceptance of a major nuclear build-up are highly uncertain.

3.1. Reference case results

The Reference case is driven primarily by inputs derived from AEO 2011—including electricity load growth, gas supply curves, and power plant costs—and many results track AEO 2011 results. However, because AEO 2011 does not include MATS, some results—including coal/gas fuel mix, power plant retirements, and criteria pollutant emissions—better track later editions of the AEO. In addition, natural gas supplies in AEO 2011 are significantly smaller than current estimates, and increased used of gas-fired generation during the MATS transition period pushes near term gas prices up when using the AEO 2011-derived gas supply curves described above. A sensitivity case with gas supplies that better track AEO 2013 was run with the Reference case and the core analysis cases.

The bottom right panel of Fig. 3[4] shows the evolution of the generation mix over the model horizon for the Reference case. In the early years, moderate gas prices and the retrofit-or-retire decision forced by MATS and CAIR induce a strong shift away from coal-fired generation, towards gas. 78 GW of coal capacity ultimately retires, and 113 GW are retrofitted with some combination of emissions control devices to comply with MATS (see Table 5). Most of the retirements are smaller, older plants in the mid-Atlantic, Appalachia, and the Midwest, along with larger plants in Ohio Valley, plains, and mountain west (see Fig. 4). The retired units are significantly smaller, with an average size of 230 MW, than surviving units (average size of 325 MW), and have higher heat rates (10,880 vs. 10,370). The average ages of retired and surviving units are very similar, around 50 years.

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[3] http://www.kanors-emr.org/vedasupport.

[4] Interactive versions of all results figures are available at http://facets-model.com/ces-analysis/.

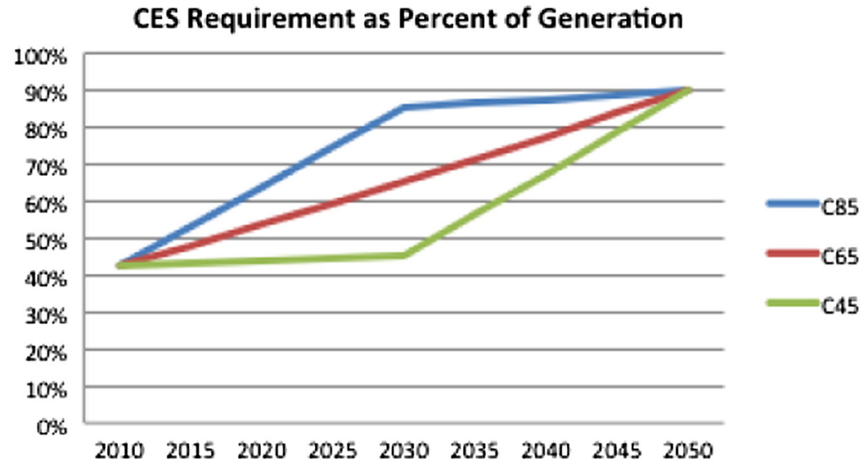

Fig. 2. Clean energy standard trajectories.

While the percentage of coal in the mix drops below 40% during the MATS transition years, by 2050 as low-cost shale gas supplies are exhausted and drilling and production costs rise, coal has rebounded to nearly 60%. Gas generation reaches a maximum 28% share in 2025, initially through increased utilization of existing capacity and then the addition of 27 GW of new gas combined cycle capacity by 2025 (see Fig. 5).

By 2035, load growth leads to the need to build significant new capacity. Unlike in recent editions of the Annual Energy Outlook (EIA, 2012b), which apply a carbon policy risk premium to new coal without CCS, in the FACETS Reference case, new capacity is predominantly new coal steam (nearly 200 GW by 2050), compliant with CAIR/MATS emissions requirements. New capacity also includes nearly 100 GW of gas, 5 GW of new nuclear, and 86 GW of new renewable capacity, most of it wind (50 GW) and biomass (30 GW). The renewable capacity additions are largely driven by state RPS requirements, after the wind production tax credit is assumed to expire in 2012. Renewable generation, including hydro, remains below 15% of the mix.

In the gas price sensitivity to the Reference case, the shift to gas is very slightly increased, with gas reaching a maximum share of 31% in 2030 (see Fig. 6). Retirements increase by about 10 GW, and retrofits decrease by a corresponding amount. But because the AEO 2011 and 2013 gas price trajectories are similar in the out years, the return of coal to dominance after 2035 is unchanged. The finding that new coal is economic after 2035, in the absence of new carbon policies, is robust to recent increases in estimates of the shale gas resource.

Reference case CO_2 emissions are roughly flat until 2030, but rise sharply with the resumed dominance of coal in the mix, reaching 30% above 2012 levels by 2050. The gas price sensitivity results in a very slight decrease (maximum 3%) in CO_2 emissions in the middle years of the projection. Emissions of mercury and sulfur dioxide fall sharply by 2020, in compliance with the toxics and acid gas provisions of MATS, while nitrogen oxide emissions decrease slowly throughout the horizon to nearly 25% below 2012 levels, as older coal plants are retired and replaced with new plants that have selective catalytic reduction (SCR) standard (see Fig. 7).

3.2. Clean energy standard analysis

3.2.1. National results

Under the most rapidly ramping CES case (C85), existing coal generation is almost entirely phased out by 2030, and the system becomes a mix of nuclear, biomass, gas and coal with CCS, new gas combined cycle, and wind (see Fig. 3). By 2050, the earliest new biomass and gas plants built in 2020 are retiring, and nuclear builds have steadily accumulated so that the system is nuclear dominated. In the slower-ramping CES 65 and 45 scenarios, coal steam generation persists into the 2040s, and nuclear and CCS build out is slower, but the overall

Table 4
Scenario matrix.

Scenario name	CES level in 2030	New nuclear allowed?	Grid investment allowed?	Gas supply
CRef.NYes.GNo[a]	None	Yes	No	AEO 2011
CRef.NYes.GNo.Gas	None	Yes	No	AEO 2013
CRef.NYes.GYes	None	Yes	Yes	AEO 2011
CRef.NYes.GYes.Gas	None	Yes	Yes	AEO 2013
C45.NNo.GNo	45%	No	No	AEO 2011
C45.NNo.GYes	45%	No	Yes	AEO 2011
C45.NYes.GNo	45%	Yes	No	AEO 2011
C45.NYes.GNo.Gas	45%	Yes	No	AEO 2013
C45.NYes.GYes	45%	Yes	Yes	AEO 2011
C65.NNo.GNo	65%	No	No	AEO 2011
C65.NNo.GYes	65%	No	Yes	AEO 2011
C65.NYes.GNo	65%	Yes	No	AEO 2011
C65.NYes.GNo.Gas	65%	Yes	No	AEO 2013
C65.NYes.GYes	65%	Yes	Yes	AEO 2011
C85.NNo.GNo	85%	No	No	AEO 2011
C85.NNo.GYes	85%	No	Yes	AEO 2011
C85.NYes.GNo	85%	Yes	No	AEO 2011
C85.NYes.GNo.Gas	85%	Yes	No	AEO 2013
C85.NYes.GYes	85%	Yes	Yes	AEO 2011

[a] Core scenarios, with reference nuclear, grid, and gas assumptions, are shown in bold.

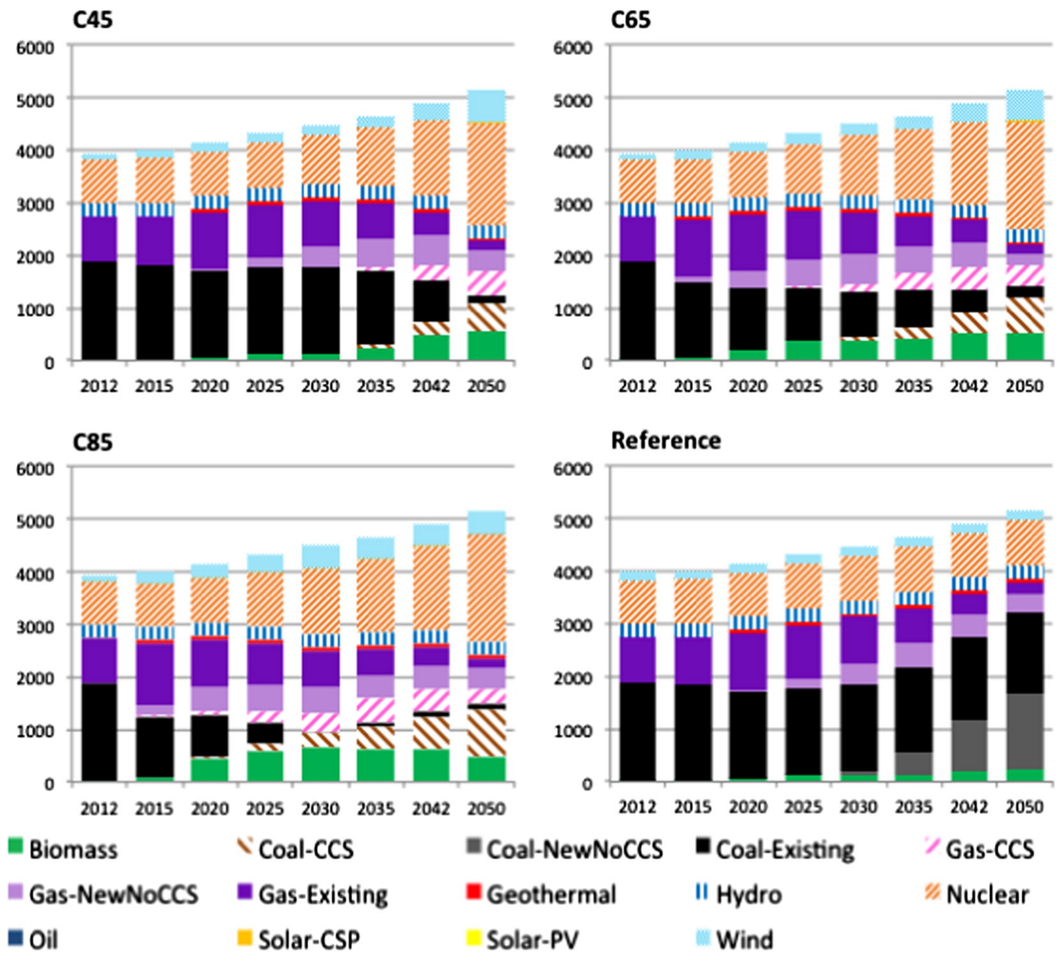

Fig. 3. Generation mix in reference and analysis cases (TWh).

system mix achieved by 2050, when all three CES standards converge at 90%, is similar. As Table 5 shows, the C45 scenario retrofits as many coal plants for CAIR/MATS compliance as the Reference scenario. Most of these plants are later idled or retired by the CES. In contrast, the faster ramping C85 and 65 cases retrofit far less capacity that will be shortly abandoned.

Fig. 8 compares the evolution of the generation mix across all sensitivity cases. Significant shifts have begun by 2025 in the C65 and C85 scenarios, with early compliance strategies including new biomass and gas combined cycle builds, along with the introduction of gas and coal with CCS and significant new nuclear in the scenarios where it is allowed. By contrast, the C45 scenarios do not begin to deviate significantly from the Reference scenarios until 2035.

By 2035, there is a clear bifurcation between the scenarios in which new nuclear is permitted and those in which it is not. When nuclear is prohibited, more wind and CCS are utilized. These substitutes are weighted more heavily toward gas CCS in the C85 scenarios, in which new capacity investments take place primarily in the middle years under moderate gas prices, and more heavily toward wind in the C45 scenarios, where new builds are postponed. By 2050, when all the CES standards have converged, there is 50% more wind in C45 than C85, because of the delay in building nuclear and CCS. (These capital-intensive, higher complexity plants are limited by the build rate supply step functions shown in Table 2, while wind is not.)

Natural gas appears as a “bridge” fuel in all the scenarios, with generation shares exceeding 30% in the scenarios that require early action. However, by 2050 the tightening of the CES requirement makes gas generation without CCS difficult to sustain, and shares have fallen to 20% or below. The increased gas supply in the gas sensitivity cases has a more dramatic impact than it did on the Reference case, expanding and extending gas's bridge role, and displacing nuclear, coal CCS, and wind. The right panel of Fig. 6 compares the evolution of coal and gas generation in the C65 cases, showing a boost to gas generation of more than 30% in the middle years of the model horizon. By 2050, however, the impact of rising prices and the tightening standard overcome the impact of greater gas supplies, and the gas share remains only a few percentage points higher than in the core scenarios.

The grid investment option makes little difference at the national scale in the nuclear-allowed scenarios, where significant nuclear capacity may readily be sited in most regions. In fact, as discussed below in Section 3.2.2, the dramatic increase in nuclear capacity results in a significant decrease in inter-regional trade from the Reference case. Grid investment makes a more significant difference in the nuclear-prohibited scenarios, particularly at the regional level, as regions must

Table 5
Coal retrofits and cumulative retirements (GW).

		Retirements		
	Retrofits	2020	2035	2050
Reference	113	68	73	78
Reference-gas	103	81	83	89
C85	5	202	306	306
C85-gas	0	233	312	312
C65	46	146	212	243
C65-gas	30	166	245	268
C45	113	69	103	180
C45-gas	102	82	121	204

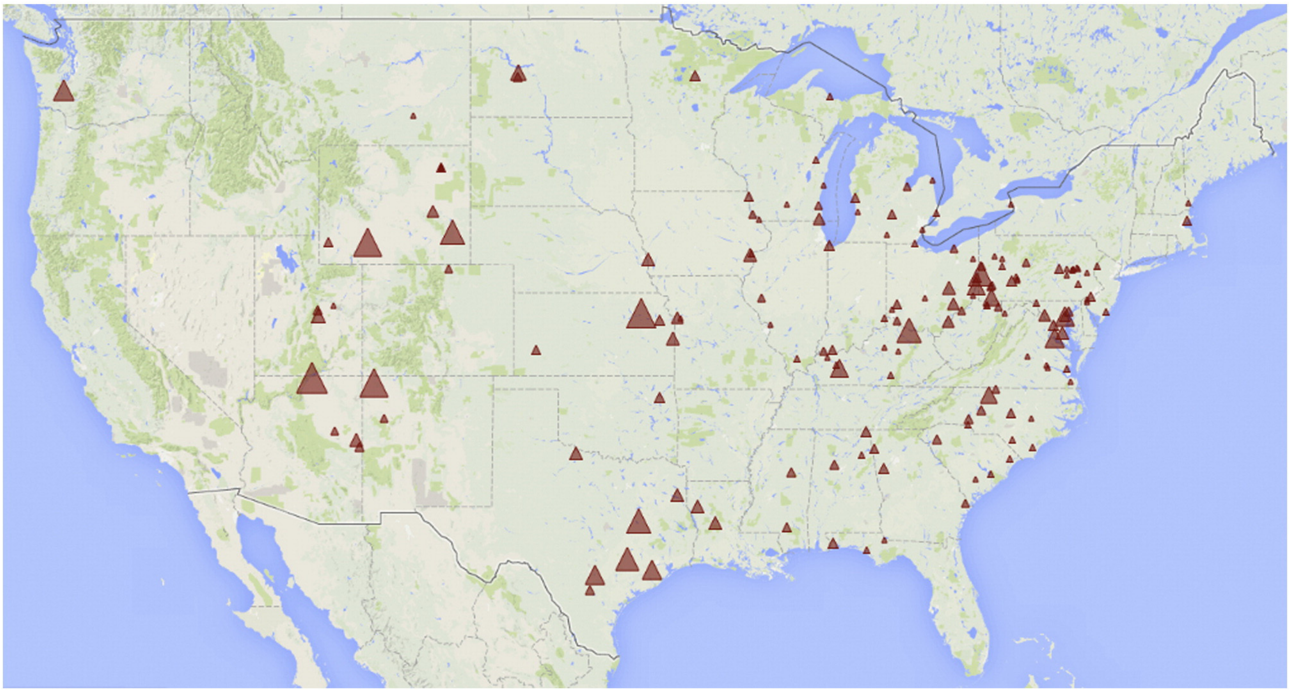

Fig. 4. Coal plants retired in the Reference case by 2020.

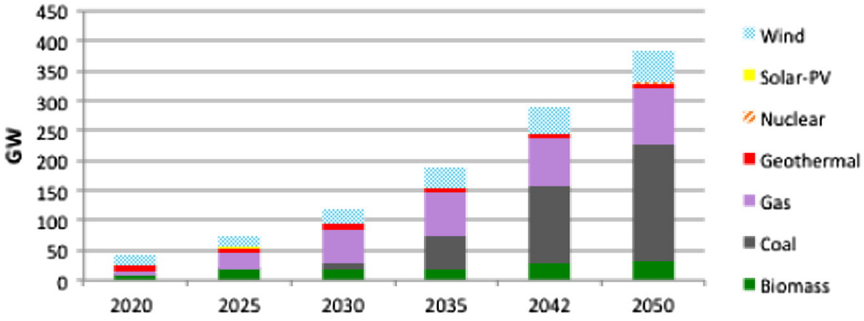

Fig. 5. Cumulative new capacity in the Reference case.

rely on more geographically heterogeneous resources to achieve CES compliance.

The C65 scenario approximately halves cumulative CO_2 emissions over the model horizon, from roughly 100 billion tons in the Reference case, to roughly 50 billion tons in C65. The C85 and C45 scenarios deliver approximately two-third and one-third reductions respectively. The CES policies also deliver significant co-benefits in criteria air pollutant reductions. The C85 scenario nearly eliminates mercury and sulfur emissions by 2030, and NOx emissions are cut almost 90% from 2012 levels by 2030. The slower CES policies deliver similar emission levels by 2050 (see Fig. 7).

All CES scenarios must build significantly more new capacity than the Reference scenario (see Fig. 9). While the Reference case builds just under 400 GW of new capacity, the CES scenarios build at least 50% more, and the No New Nuclear cases, which rely more heavily on wind generation, and up to nearly 800 GW in new investments are required.

The cost impacts of policy ramping speed are dramatic (see Table 6). The slow-ramping C45 policy adds 3.6%, or approximately $90 billion, to the total discounted cost of supplying electricity over the model horizon. The C65 approximately doubles this increase, and the fast-ramping C85 scenario more than doubles it again, to just over $400 billion.[5]

Prohibiting new nuclear builds (at AEO2011 capital costs) adds 1–2% to the cost, depending on the policy ramping speed. Extra gas supplies decrease the cost of the C85 scenario by about 1% (by alleviating near term compliance expenses) but change the cost of the other scenarios by considerably less. Transmission investment has an insignificant effect on total *national* discounted cost. However, as seen in the next section, it has a much greater impact on regions that find it economic to invest in new transmission capacity and gain from the resulting increased trade.

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[5] For a sense of scale, $400 billion is approximately the total annual value added of the electric power and associated fuel supply industries (Board of Governors of the Federal Reserve System, 2013), and is 0.1% of the net present value of cumulative GDP (at extrapolated AEO 2011 values) over the model horizon. In other words, this is neither an insignificant nor an astronomical cost. The need for earlier and much more aggressive replacement of existing capacity drives the substantial increase in costs for the C85 scenario group.

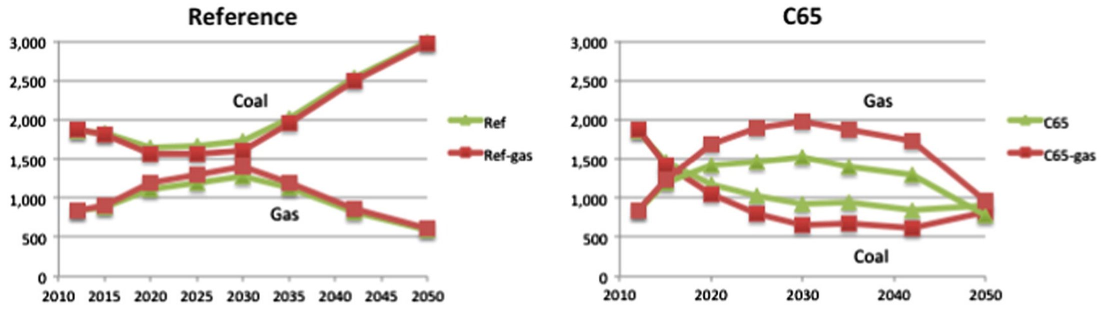

Fig. 6. Impact of gas supply sensitivities on Reference and C65 generation (TWh).

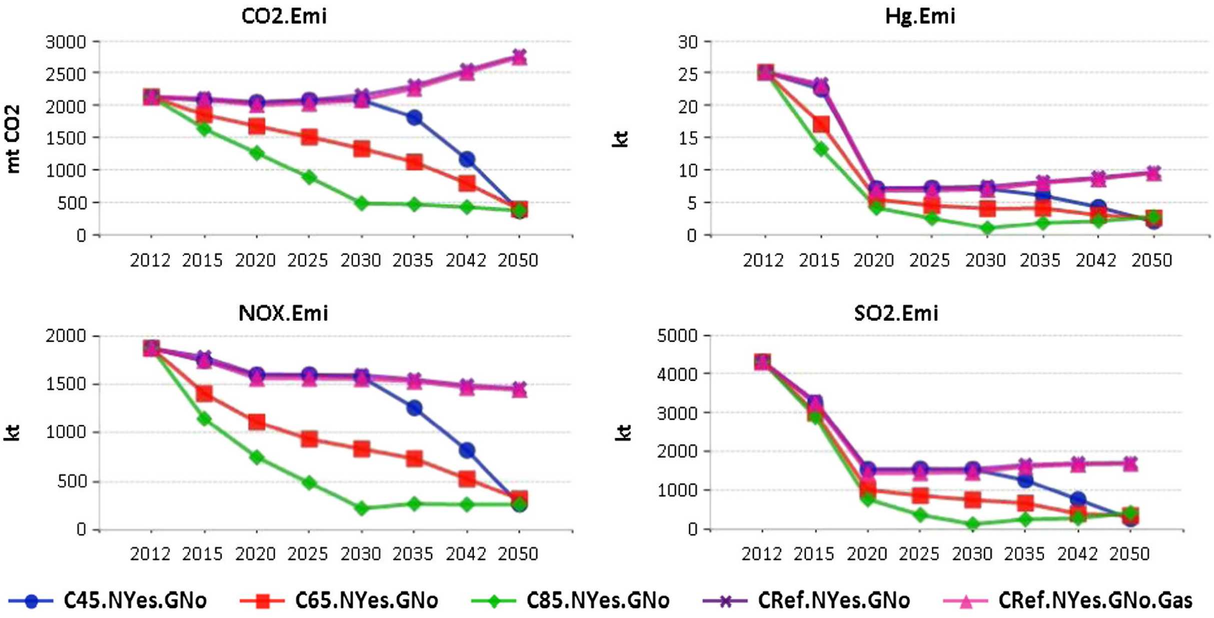

Fig. 7. Emissions across scenarios.

3.2.2. Regional results

Fig. 10 shows the generation mix and inter-regional trade flows in 2050 for the Reference, C65, and C65-NoNuc-GridYes scenarios. (Pie and wedge sizes in the figure are proportional to generation, and arrow widths are proportional to interregional flows.) The Reference case (top panel) shows the siting of new coal, and persistence of existing coal capacity in current coal-intensive regions, as well as development of wind, biomass, and geothermal in several regions to meet state RPS requirements. Reference case trade patterns are similar to current ones, with coal-generated electricity in the Ohio Valley flowing east to load centers, and significant flows into California from the Pacific Northwest and regions east.

The C65 map (middle panel) shows the range of compliance strategies in different regions. Wind, biomass, and solar resources are exploited in resource-rich areas. Coal and gas with CCS are concentrated in areas with good access to CO_2 sequestration sites (see Fig. 11 for CCS capacity and CO_2 flows to sequestration sites), and lower cost coal and gas supplies—the Ohio Valley, southwest, and south central for coal CCS, and the Ohio Valley, Great Lakes, and Gulf and West coasts for gas. Nuclear is sited first and most heavily in the southeast, where building costs are lowest, and in the mid-Atlantic, where other options are limited. When nuclear is prohibited (bottom panel), these areas substitute a mix of coal and gas with CCS and imports from more resource-rich regions.

Trade patterns in the CES cases deviate substantially from the Reference case. Trade is greatly reduced in the C65 case. By 2050, major investments in capacity have taken place in most regions, greatly reducing the need for systematic inter-regional trade. The effect is strongest in the southeast and mid-Atlantic, where nuclear builds have been the strongest. However, in the NoNuc-GridYes version of this case, regions must fall back on other resources that have very heterogeneous costs and availabilities, and the opportunities from expanded trade are substantially increased. In particular, a major increase in wind capacity in the upper Midwest is enabled by grid investment, powering expanded trade south- and eastward. The Ohio Valley regions also invest more heavily in CCS and regain some of their role as suppliers of the East coast.

Table 7 shows the net present value change in consumer plus producer surplus—measured as the change in consumer payments[6] for electricity plus the change in the difference between net producer earnings (including CES permit trades) and generation costs—in each region for the C65 scenario variants, scaled by 2012 generation in order to allow impacts on regions of different sizes to be compared.[7] Overall, impacts are negative, but some regions show a gain, including regions such as Upstate and Downstate New York, Commonwealth Edison, and Pacific Northwest that have large supplies of compliant generation in the Reference scenario, and regions with relatively cheap compliance

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[6] In a TIMES model, all fuel competition takes place on the margin, and regulated pricing structures are not represented. In the present study, regional pricing institutions would influence the split of surplus between consumers and producers, but not the overall welfare change. See Paul et al. (2011) for an excellent discussion on how consumer price impacts can be expected to vary between cost of service and marginal cost pricing regions.

[7] So the entries have the somewhat awkward units of 2004 dollars per million BTU, and should be thought of as index numbers.

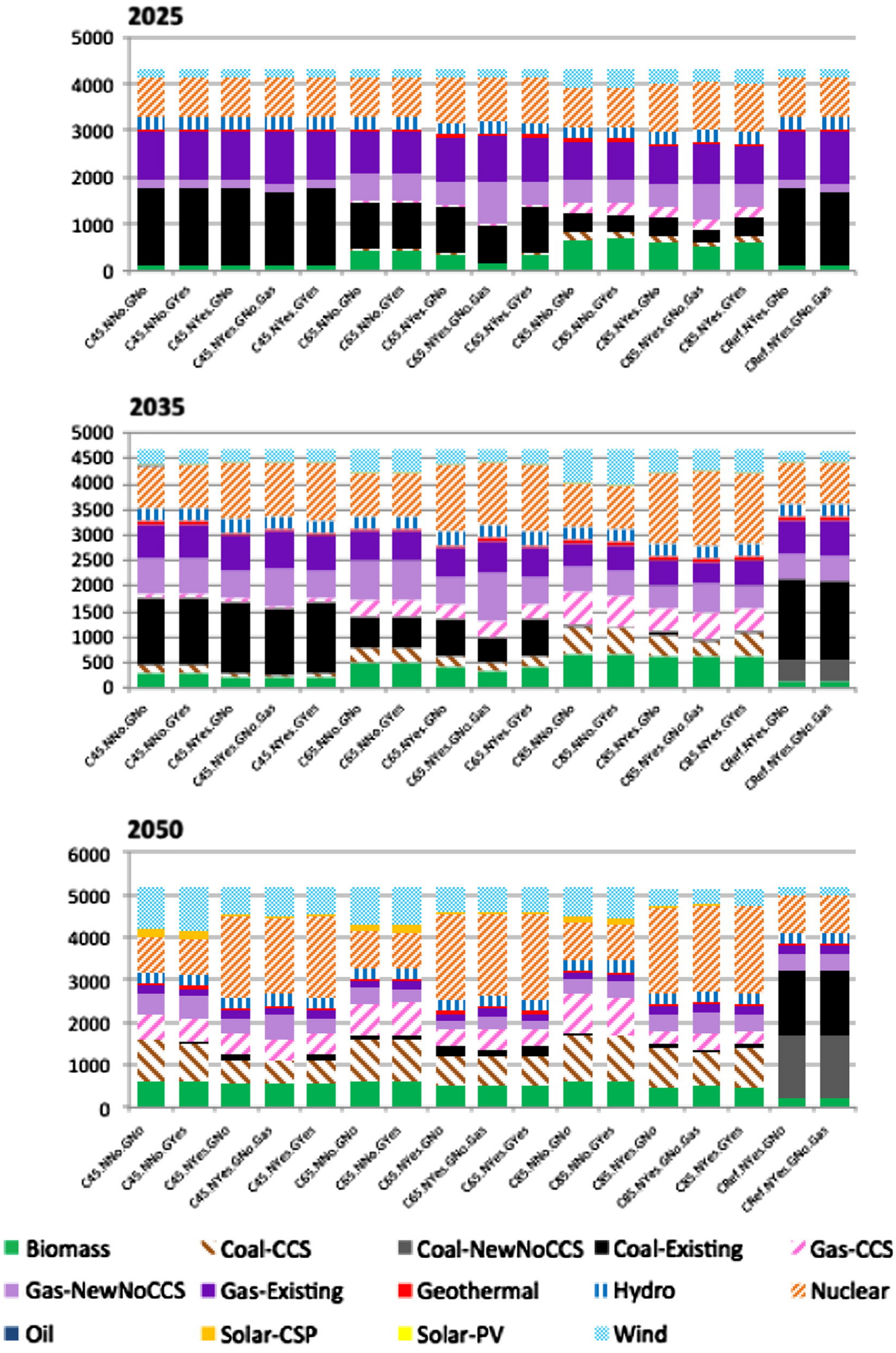

Fig. 8. Evolution of the generation mix across scenarios (TWh).

resources that become exporters of both credits and power, including Arizona–New Mexico and Southern Nevada. The worst-impacted regions are the gas-dependent New York City and Long Island, which must import the majority of their credits even in the least stringent scenarios and face higher gas prices, followed by regions that have fewer (Kentucky) and/or more expensive (Rocky Mountains) compliance options. These regions experience a nearly 25% easing in welfare losses in the gas sensitivity case, when both gas and CES credit prices are lower.

In general, the regions negatively affected are those in the middle and south of the country, while those positively are on the east and west coasts. (The exception of Commonwealth Edison is due to its

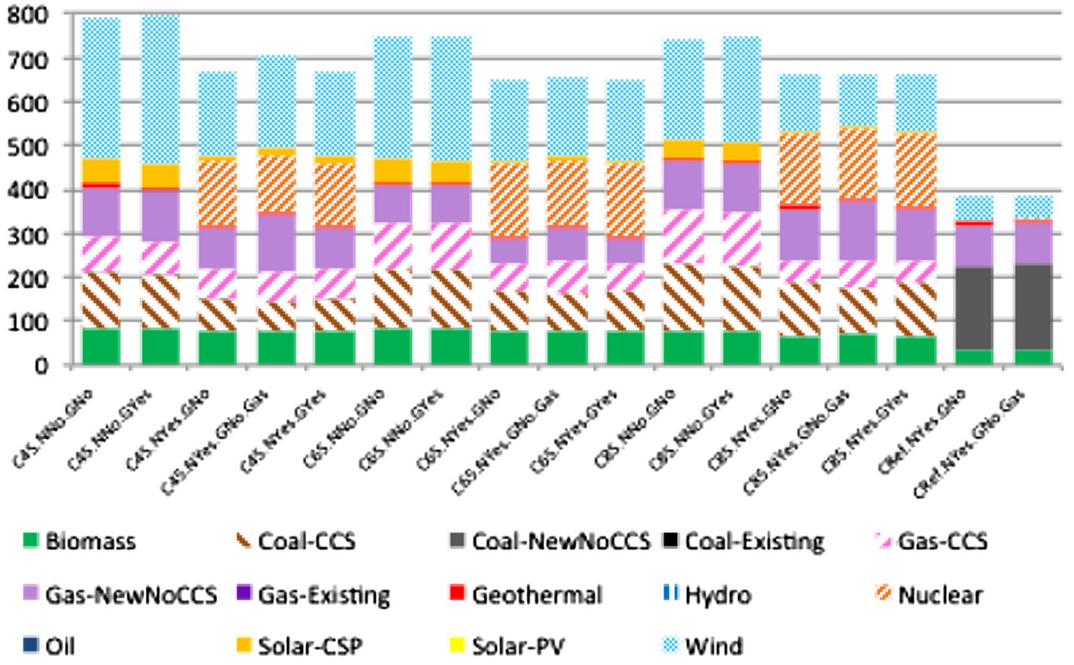

Fig. 9. Cumulative new capacity in 2050 by scenario (GW).

large existing nuclear capacity.) The results agree with previous findings (Pizer et al., 2009; Rausch et al., 2011) that national climate policy impacts are more positive in regions of the country that have already enacted climate policies and more strongly negative in regions whose representatives have so far opposed federal policy.

Fig. 12 highlights the diversity of regional experiences under different scenarios. One end of the spectrum is illustrated by the Upstate New York region, which has substantial low and zero carbon sources in its Reference case mix, allowing it to be an exporter of CES credits throughout even the most stringent scenarios with only minor changes from its Reference mix late in the model horizon. The Arizona–New Mexico region similarly has a diverse abundance of low carbon resources, but it must nearly double its output of complying generation, primarily from coal CCS, by 2050.

At the other extreme, the Kentucky region has very little low carbon generation in its Reference mix. Its compliance options are relatively costly, and it employs very different strategies in different scenarios. Outside of gas-dependent New York City and Long Island, it is the hardest hit region in terms of welfare lost. In the fast-ramping C85 scenario, it makes an early investment in coal with CCS in but postpones significant investment when the standard ramps more slowly. In the C65 scenarios, it fully exploits its biomass resources and relies on credit imports from nuclear-intensive regions when new nuclear is permitted, making up the difference in coal and gas with CCS when it is not. In the slow-ramping C45 scenario, it is one of the last regions to build new nuclear capacity. The region remains an importer of credits in even the least stringent scenarios. Its substantial welfare loss saving in the C65-gas scenario is due primarily to cheaper import credit prices.

Table 6
Percent change in total system cost.

Scenario	Percent increase in total system cost			
	Relative to reference	From excluding new nuclear	From allowing grid investment	Relative to Ref-gas
C85	16.37%			
C65	7.84%			
C45	3.60%			
C85GY	16.35%		−0.02%	
C65GY	7.84%		0.00%	
C45GY	3.59%		−0.01%	
C85NoNuc	18.51%	1.84%		
C65NoNuc	9.39%	1.43%		
C45NoNuc	4.60%	0.97%		
C85NoNuc-GY	18.47%		−0.04%	
C65NoNuc-GY	9.38%		−0.01%	
C45NoNuc-GY	4.58%		−0.02%	
C85-gas	15.26%			15.45%
C65-gas	7.03%			7.20%
C45-gas	3.56%			3.73%
Ref-gas	−0.17%			

The Texas Regional Entity and Virginia-Carolinas regions require a similar scale of increased investment over Reference case levels to comply. In Texas, which has access to low cost sequestration sites in the Gulf of Mexico, the strategy is heavily reliant on CCS in all scenarios. Virginia-Carolinas makes major investments in new nuclear capacity in the scenarios where this is permitted. When new nuclear is restricted, it falls back on more expensive coal with CCS and credit imports, more than doubling the region's welfare loss from the CES.

The Midwest Regional Organization (MRO, upper Midwest) region becomes an exporter of biomass and wind generated credits in all scenarios, but this dramatically increases in the grid expansion scenarios, as it becomes able to develop its substantial wind resources and export power south- and eastward. Thus although the overall national welfare impact of allowing investment in grid expansion is negligible, as shown in the bottom two panels of Fig. 10, it has a dramatic effect on the system configuration for trading partners MRO and Gateway (Illinois–Missouri), and it reduces their welfare loss from the CES by more than 5%.

4. Conclusions

The CES reduced cumulative carbon emissions over the model horizon by approximately half in the straight-line version, and roughly two-thirds and one-third in the aggressive and delayed versions, respectively. It also led to up to 90% cuts in emissions of criteria air emissions by the time the standard reached full stringency.

Early action was significantly more costly, roughly double for the fast-ramping policy and half for the delayed one. Early action price

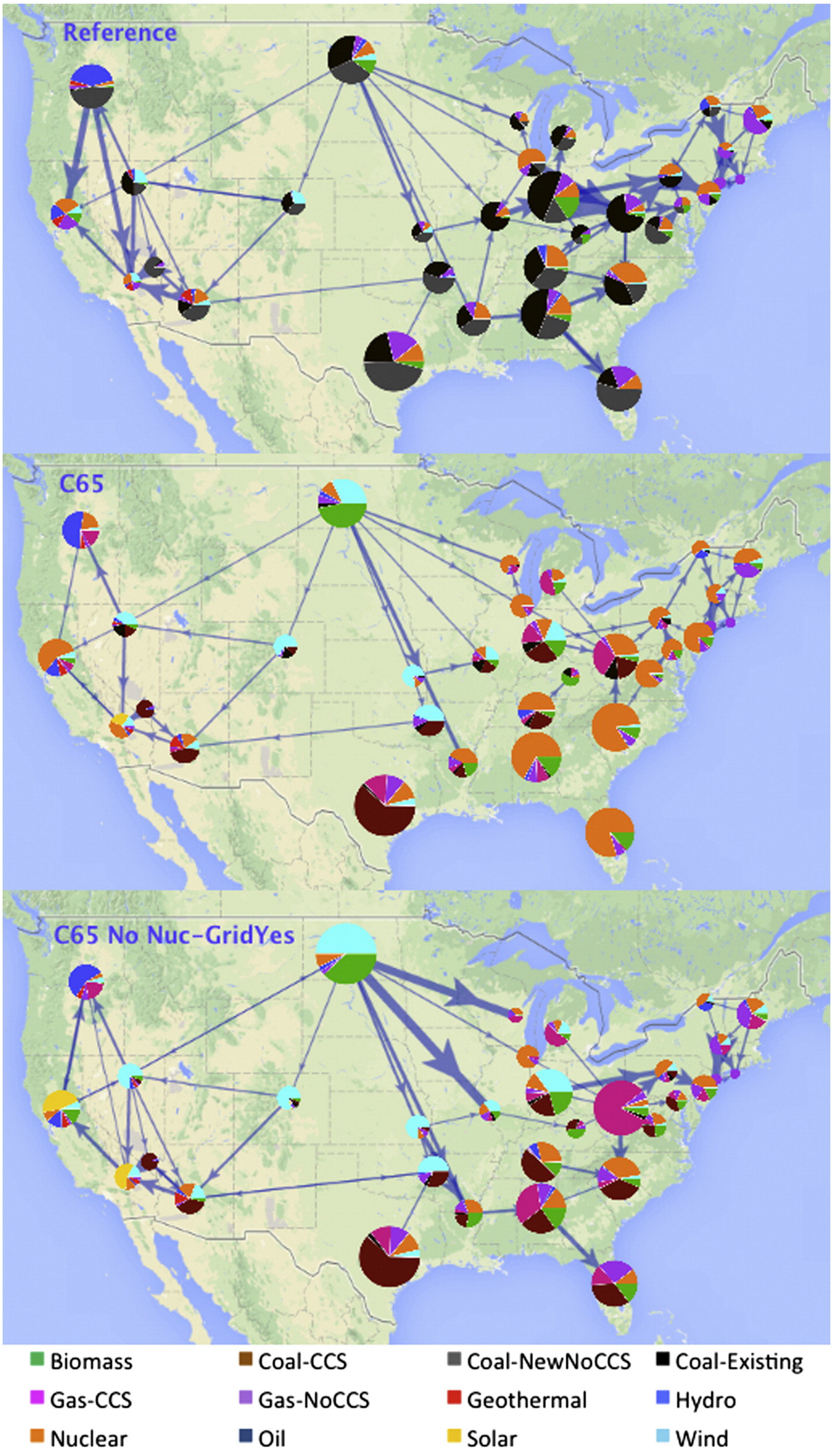

Fig. 10. 2050 generation mix and inter-regional trade in Reference, C65, and C65-NNGY scenarios.

impacts were steep, although more abundant gas supply curves moderate that impact somewhat. Delaying the initial compliance period until new capacity can be built could help to alleviate this strain on the system. CES compliance required a substantial investment in new capacity, and short-run capital cost penalties from trying to build so much new capacity fast played an important role in shaping the national generation mix.

Additional natural gas supplies made little difference to the Reference scenario, shifting the generation mix and carbon emissions by no more than 3% during the middle of the horizon, a finding consistent with the recent EMF 26 Shale Gas study (Huntington, 2013). In particular, additional gas does not change the conclusion that, in the absence of new carbon policies, new coal builds are the economic choice for new

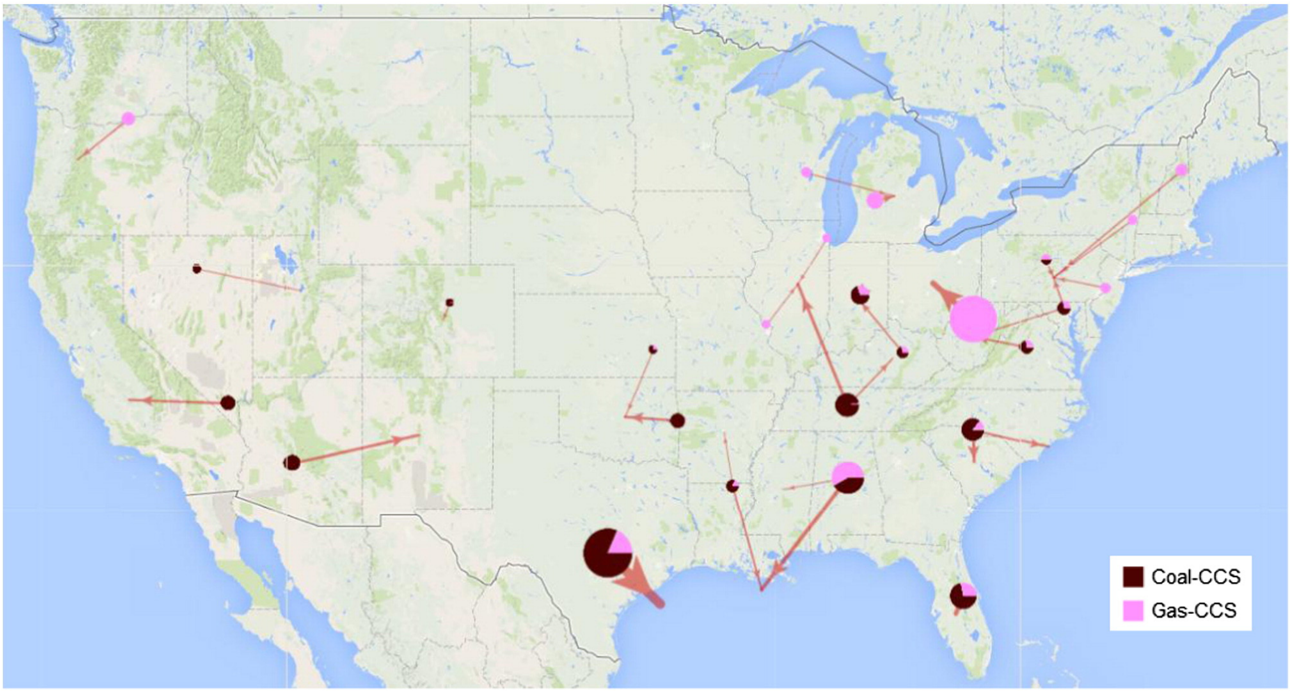

Fig. 11. 2050 CCS capacity and CO_2 flows in the C65-NNGY scenario.

capacity needed after 2035. In the CES scenarios, additional gas made a larger difference, increasing and extending gas's role as a bridge fuel, and decreasing near term compliance costs, but made little lasting impact on system configuration.

As noted in the introduction, a regional modeling framework adds important depth to an analysis of deep carbon reductions in a large and diverse energy system such as the US, for at least three reasons. First, the impacts of such a policy are expected to vary greatly across regions, complicating the process of arriving at national consensus on policy design. Second, the costs of most low carbon resources depend on geography. And third, any federal policy would be enacted against an array of existing state and regional policies.

In this CES analysis, significant regional differences were observed in compliance strategies and economic impacts, depending on initial zero- and low-carbon capacity and access to zero- and low-carbon options. When geographically neutral nuclear is available at attractive capital costs, it becomes the dominant choice in many regions, and the widespread buildup of capacity reduces interregional trade. When new nuclear is not available, regions must fall back on more geographically heterogeneous options, and the relationships between resources, load centers, and CO_2 sequestration sites become more important. In this context, expanding interregional transmission capacity becomes valuable to several regions where additional trade is enabled, particularly the wind-rich upper Midwest and its trading partners. As in previous studies, welfare impacts were found to be more moderate on regions that have already enacted carbon reduction policies and steeper in regions that have so far not supported federal carbon policies.

Since this analysis was completed, US EPA (2014) has released its draft regulations for CO_2 emissions from existing power plants under section 111d of the Clean Air Act, known as the Clean Power Plan (CPP). The CPP proposes a maximum carbon emissions rate for covered generation in each state, making it a version of a CES that covers a somewhat more limited universe of plants: existing fossil generation[8] plus

Table 7
Change from Reference scenario of net present value of consumer + producer surplus (scaled).

Region	C65	C65-gas	C65-NoNuc	C65-NoNucGY
Arizona-New Mexico	3.9	5.2	0.8	0.9
California North	8.4	9.8	1.7	1.6
California South	-26.3	-18.4	-29.8	-30.0
Commonwealth Edison	49.5	36.5	51.1	50.2
Downstate New York	67.6	67.9	69.7	71.8
Kentucky	-87.6	-53.2	-71.8	-71.9
MISO	-41.5	-34.9	-43.5	42.6
PJM	-39.2	-30.1	-35.9	-38.4
Entergy	-5.6	-2.4	-15.4	-14.5
Texas Regional Entity	-26.9	-19.5	-28.1	-28.1
Florida Reliability Coordinating Council	-23.5	-17.6	-38.2	-38.2
Long Island Lighting Company	-79.4	-60.2	-87.8	-85.4
Mid-Atlantic Area Council-East	1.5	4.7	-2.6	-4.9
Mid-Atlantic Area Council-South	-16.2	-9.8	-23.8	-22.6
Mid-Atlantic Area Council-West	1.3	-0.5	-3.6	-3.1
Gateway (Illinois-Missouri)	-45.5	-43.7	-54.0	-51.2
Michigan Electric Coordination System	-33.1	-22.0	-36.4	-35.9
Midwest Regional Organization	-30.1	-23.6	-32.9	-30.7
New England Power Pool	5.1	6.4	2.6	4.4
Northwest Power Pool East	-13.4	-16.2	-17.7	-17.5
New York City	-80.6	-62.5	-82.9	-86.3
Pacific Northwest	34.7	27.0	34.3	34.1
Rocky Mountain Power Area	-45.9	-35.4	-46.0	-45.1
Southern Nevada	16.3	15.2	29.2	28.2
Southern Company	-29.0	-21.3	-35.8	-35.6
Southwest Power Pool-North	-39.4	-27.1	-39.2	-40.3
Southwest Power Pool-South	-43.5	-32.4	-45.5	-46.0
Tennessee Valley Authority	-6.5	-6.1	-7.4	-7.8
Upstate New York	65.4	49.0	62.2	62.0
Virginia-Carolinas	-8.6	-8.1	-20.9	-20.6
Dominion Virginia Power	-17.6	-10.7	-36.9	-36.9
Wisconsin-Upper Michigan	-28.2	-23.6	-32.2	-35.1
Total	-514.1	-358.0	-616.7	-615.3

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[8] New fossil generation is covered under the separately proposed New Source Performance Standards (US EPA, 2013b). New coal plants will need to be equipped with at least partial CCS in order to comply, preventing the large build-up of new coal capacity without CCS found in our Reference case.

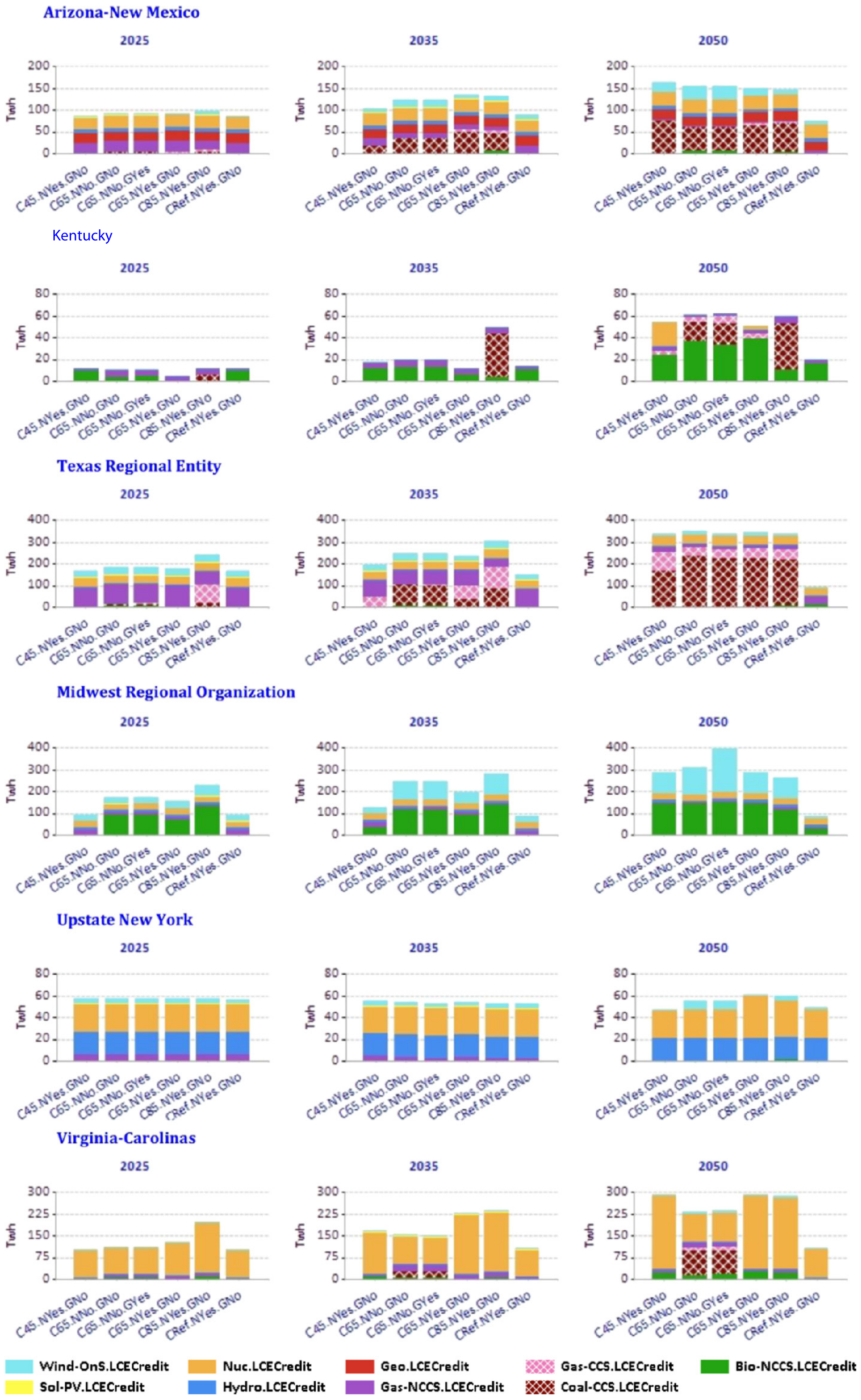

Fig. 12. CES credits by source in selected regions.

non-hydro renewables. Existing hydro and most existing nuclear are excluded, reducing or eliminating the large welfare gains found herein for regions with substantial shares of hydro and nuclear capacity in their existing mix. The CPP requirements ramp in over the period 2020–2030, reaching approximately midway in stringency between our C45 and C65 cases. No further reductions beyond 2030 are required. This gradual transition, along with continued low natural gas prices, suggests that high costs associated with early action found in our analysis will be avoided, and that overall cost impacts are likely to be quite modest.

Recognizing the very different options and compliance costs for states, EPA has built in a great deal of flexibility for states in designing approaches to meet their targets, including the option to include generation avoided through energy efficiency programs in their denominators. While the CES considered here envisioned full national trading, under the CPP, states will have the option to meet the standard on their own, or to join in multi-state compliance programs. The wide range in regional costs found in this analysis suggests that many states would benefit from joining in such trading programs, although the limited time frame for state implementation plan development may inhibit use of this approach, potentially increasing overall costs.

We hope to take up the third aspect of regional importance—interactions between state, regional, and federal policies, in future analyses with the FACETS model. These interactions will become increasingly important as states work to develop CPP compliance plans that build on their existing energy efficiency, RPS, and other policies. Additional work in FACETS will also explore the regional impacts of uncertain technology costs. While this study performed a simple technology sensitivity analysis by removing nuclear from the mix, the cost and availability of other key technologies—such as CCS—are similarly uncertain, while the costs of others, such as solar PV, are changing rapidly. Because of the wide range in regional resources, uncertainty in the costs of these technologies can be expected to impact some regions a great deal more than others, and potentially even change which regions are net credit importers and exporters.

The development of full end use sectors for FACETS is also underway, enabling evaluation of the role of energy efficiency in meeting emissions goals.

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