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Modeling low-carbon US electricity futures to explore impacts on national and regional water use

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Modeling low-carbon US electricity futures to explore impacts on national and regional water use

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Abstract

The US electricity sector is currently responsible for more than 40% of both energy-related carbon dioxide emissions and total freshwater withdrawals for power plant cooling (EIA 2012a *Annual Energy Outlook 2012* (Washington, DC: US Department of Energy), Kenny *et al* 2009 *Estimated Use of Water in the United States* 2005 (*US Geological Survey Circular* vol 1344) (Reston, VA: US Geological Survey)). Changes in the future electricity generation mix in the United States will have important implications for water use, particularly given the changing water availability arising from competing demands and climate change and variability. However, most models that are used to make long-term projections of the electricity sector do not have sufficient regional detail for analyzing water-related impacts and informing important electricity- and water-related decisions. This paper uses the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) to model a range of low-carbon electricity futures nationally that are used to calculate changes in national water use (a sample result, on water consumption, is included here). The model also produces detailed sub-regional electricity results through 2050 that can be linked with basin-level water modeling. The results will allow for sufficient geographic resolution and detail to be relevant from a water management perspective.

Keywords: electricity, water, climate, modeling

[S] Online supplementary data available from stacks.iop.org/ERL/8/015004/mmedia

1. Introduction

How the United States generates electricity matters from a range of perspectives. Different electricity mixes have different implications for costs to consumers, land and water resources, and air emissions including heat-trapping gases

such as carbon dioxide. As electricity sector decisions are made, assessing the suite of impacts to other sectors at both the national and regional level is important. For example, in 2011, nearly 90% of electricity in the United States came from thermoelectric (coal, natural gas, and nuclear) power plants (EIA 2012b). According to the US Geological Survey, power plants accounted for 41% of total freshwater withdrawals in 2005, and as much as two-thirds in certain states in the Southeastern United States (Kenny *et al* 2009). While power plants represent a much smaller portion of overall freshwater consumption (Solley *et al* 1998), they can have important

impacts in places with low water quantities or high water temperatures (Averyt *et al* 2012). Since the relative mix of fuels and cooling technologies used to generate electricity defines the total quantities of water used (Macknick *et al* 2011), increasing demands for electricity and a changing electricity generation mix can have important implications for national, regional, and local water budgets.

This paper details a component of a multi-year research project to analyze the water implications of different electricity pathways in the United States (Union of Concerned Scientists 2012). Here we describe modeling aimed at generating a robust, policy-relevant set of electricity generation futures that are likely to have appreciably different water profiles. Because of the large role of the power sector in contributing to and potentially mitigating climate change, several of our scenarios incorporate deep cuts in carbon emissions in the electricity sector.

For this work, we draw on analyses of current power plant water use (Averyt *et al* 2012, Macknick *et al* 2011). Other relevant work has projected future water use by the power sector (Roy *et al* 2012, Elcock 2008, e.g.) or explored power sector vulnerabilities based on the characteristics of particular plants and their water resources (Van Vliet *et al* 2012, Harto *et al* 2011, Elcock and Kuiper 2010, NETL 2009, e.g.).

The broader body of electricity–water pathways research whose foundation is the electricity scenarios described in this manuscript is unique in that we model a range of electricity futures for the US and link detailed sub-regional electricity results from that modeling with basin-level water modeling. This allows us to produce results with sufficient geographic resolution and detail to be relevant from a water management perspective. The electricity modeling also incorporates many recent changes in energy costs, technologies, policies, and regulations that will have important impacts on the future electricity mix in the US.

2. Methodology

The sections below describe our choice of model and key assumptions and scenarios we incorporated into the modeling

2.1. Electric sector model

We used the Regional Energy Deployment System (ReEDS) electricity model developed by the National Renewable Energy Laboratory (NREL) to generate future scenarios of the contiguous US power sector from 2010 to 2050. ReEDS is a long-term capacity-expansion and dispatch model that represents all major generation technologies, including coal (supercritical and integrated gasification combined cycle or IGCC), natural gas combined cycle (CC), natural gas combustion turbines, fossil fuels with carbon capture and storage (CCS), nuclear, hydropower, wind, solar photovoltaics (PV), concentrating solar power (CSP), geothermal, biopower, and storage. ReEDS provides a detailed representation of electricity generation and transmission systems in the US and addresses a variety of issues related to power system operations and infrastructure expansion, including

accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal load and generation profiles, variability and uncertainty of wind and solar power, and the influence of variability on electricity reliability (Short *et al* 2011). (See supplemental material available at stacks.iop.org/ERL/8/015004/mmedia for more information on transmission and integration issues.)

ReEDS is a linear program that finds the least-cost optimal solution sequentially for each two-year period from 2010 to 2050. The optimization is subject to a large number of constraints, including balancing electricity supply and demand, meeting planning and operating reserves, observing renewable resource limits, and limiting system flexibility based on fleet characteristics. Policy or other scenario-specific constraints can be added in the model (see section 2.3 for generation requirements used in this analysis). In addition, the sequential structure of the model allows for non-linear statistical calculations to be made between each optimization period to dynamically account for the variability of wind and solar resources. These statistical estimates include the capacity value, increased forecast error reserve requirements, and curtailment of wind and solar generation, and help to ensure that the system remains reliable (within the resolution of the model) for any future scenario. Electricity demand and the costs for generator, transmission, and other power sector infrastructure are exogenously defined. Key cost and performance assumptions used in this analysis are presented in section 2.2. The remaining data inputs are detailed in NREL (2012) and the full model documentation can be found at Short *et al* (2011). Since ReEDS does not directly include distributed generation sources in its capacity-expansion decision-making, we used the NREL Solar Deployment System (SolarDS) model to project future solar photovoltaic development in the residential and commercial sectors (Denholm *et al* 2009).

For purposes of our water-oriented electricity research, ReEDS offers the advantage of yielding results distributed among 134 'power control authorities' (PCAs) for most technologies and 356 'resource regions' for wind and concentrating solar power technologies (figure 1). That degree of spatial resolution is much greater than is available through, for example, the US Energy Information Administration's (EIA) National Energy Modeling System (NEMS), which only produces results for 22 electricity supply regions. Greater resolution is important for analyzing water impacts at relevant geographic scales, the subject of additional work under this project (Macknick *et al* 2012, Sattler *et al* 2012).

2.2. Key assumptions

The cost and performance assumptions for different electricity generating technologies came primarily from EIA's *Annual Energy Outlook 2011* (AEO 2011) reference case (EIA 2011). This includes EIA's assumptions for coal and natural gas prices, heat rates, capacity factors, operation and maintenance costs, and financing costs. We also adopted EIA's projections for electricity demand, which increases at 0.8% per year on average in the US between 2010 and 2035. We assumed this growth rate would continue to 2050.
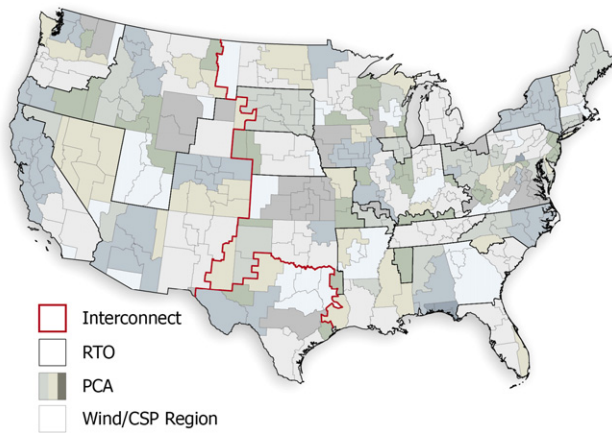
Figure 1. Regions included in the Regional Energy Deployment System (ReEDs) Model. The ReEDs model produces results for 134 PCAs (shaded areas) for all electricity generation technologies and for 356 wind and concentrating solar power (CSP) resource regions. These results can also be aggregated up to the state level, regional transmission organization (RTO) or North American Electricity Reliability Council (NERC) region level (darker black lines), or for the three major electricity interconnections (red lines).

2.2.1. Capital costs. While we used EIA's capital cost assumptions for a few technologies, our assumptions differed in four main ways. First, we did not include EIA's projected decline in commodity costs that results in capital cost reductions of approximately 20% by 2035 for all technologies because of the high level of uncertainty in projecting these costs. Second, for natural gas, coal, and biomass plants, we used EIA's initial capital costs estimates, but did not include EIA's projected cost reductions because we assumed they were mature technologies. Third, for wind and solar photovoltaics (PV), we assumed lower initial capital costs than EIA based on updated data from a large sample of recent projects (SEIA 2012, Wiser and Bolinger 2011, Musial and Ram 2010). Fourth, for advanced nuclear plants and coal and natural gas plants with CCS, we assumed higher initial capital costs than EIA based on mid-range estimates from recent studies and announced cost increases at several proposed nuclear projects in the US (Black and Veatch 2012, Penn 2012, Vukmanovic 2012, Wald 2012, EIA 2011). We also did not include EIA's projected capital cost reductions for new nuclear plants, given the historical and recent experience of cost increases in the US and other countries, but did assume EIA's projected (2035) cost reductions for CCS would be achieved by 2050. (See supplemental material available at stacks.iop.org/ERL/8/015004/mmedia for more information on capital costs and other assumptions.)

2.2.2. Renewable energy technology performance and potential. We assumed slightly higher capacity factors than EIA for onshore and offshore wind and concentrating solar power (CSP) plants based on data prepared by Black and Veatch for NREL's *Renewable Electricity Futures* study (Black and Veatch 2012). Renewable energy potential is based primarily on data from NREL that are incorporated into the ReEDs model (Short *et al* 2011). For hydropower,

NREL assumes new run of river hydro could be built, but not new large scale hydro, capacity additions at existing dams, or retirement of existing projects. The main exception is biomass, in which we used data developed for Cleetus *et al* (2009). However, we applied several exclusions to this data to help ensure that only sustainable forms of biomass were assumed to be available, resulting in an available biomass supply in the US that is 28%–38% lower than what NREL and EIA assume in their modeling. Because ReEDs only covers the electricity sector, we assume this biomass is available to generate electricity and do not account for the potential use of some of this biomass for liquid fuels in transportation.

2.2.3. Plant retirements and planned additions. We adopted EIA's convention that existing nuclear power plants will receive a 20-year license extension and retire after 60 years. We also adopted NREL's assumptions for simple lifetime-based retirements for existing plants, including 66 years for coal plants, 55 years for natural gas plants, 50 years for biopower, and 20–30 years for other renewable energy technologies based on an NREL analysis of actual plant retirements. In addition, ReEDs assumes existing coal plants are retired if the average annual capacity factor falls below 30% through 2020 and rising to 50% by 2040 (Short *et al* 2011). We also included important data that were publicly available as of September 2011 but that would not have otherwise been captured in the model: 22.2 GW (gigawatts) of announced coal plant retirements, 4.4 GW of planned nuclear capacity, and 8.2 GW of planned solar PV projects (SNL Financial 2011). Finally, we assumed that any new nuclear plants would be located in PCAs with existing nuclear capacity, which is consistent with most proposals in the United States to add new nuclear reactors to existing nuclear plants (Nuclear Regulatory Commission 2012).

2.3. Scenarios

We modeled four scenarios in ReEDs to analyze the impacts of different electricity generation futures on water withdrawals and consumption, along with carbon emissions and electricity and natural gas prices in the United States (table 1). These included a reference scenario patterned off EIA's AEO 2011 reference case. In this scenario (scenario 1), the model projects the future electricity mix in the US based on existing state and federal energy policies and the relative economics of different electricity generating technologies.

Scenario 2 assumes that the United States meets a cumulative economy-wide carbon budget (CO_{2eq}) of 170 gigatons from 2012 to 2050. The National Research Council (2010) recommended this budget as having a reasonable chance of limiting global CO_{2eq} concentrations to 450 parts per million assuming full participation by the rest of the world. The US budget, and the electricity sector's share that we adopted for this study (figure 2), are based on the average of runs from five different models completed for the Stanford Energy Modeling Forum (EMF) 22 (Fawcett *et al* 2009). As with scenario 1, we allowed the model to determine the electricity generation mix in scenario 2 based on the

Table 1. Electricity modeling scenarios.

| Scenario	Key assumptions and targets	Key sources
(1) Reference case	Existing state and federal policies	Patterned off EIA's AEO 2011 reference case, with updates to select assumptions.
(2) Carbon budget, no technology targets	Electricity sector contribution to a 170-GtC0$_{2eq}$ economy-wide US carbon (equivalent) budget through 2050	National Research Council (2010) and Fawcett *et al* (2009).
(3) Carbon budget and higher nuclear and coal with carbon capture and storage (CCS)	• 29% nuclear generation by 2035 and 36% by 2050 • 15% coal with CCS generation by 2035 and 30% by 2050	Upper end of range of estimates from Lovins (2011), National Research Council (2010), Specker (2010), Fawcett *et al* (2009), EIA (2009), and EPA (2009).
(4) Carbon budget and higher energy efficiency and renewable energy	• 20% reduction in electricity use by 2035 and 35% by 2050 50% renewable generation by 2035 and 80% by 2050	Upper end of range of estimates from NREL (2012), Laitner *et al* (2012), Lovins (2011), National Research Council (2009), Fawcett *et al* (2009), Granade *et al* (2009), and Cleetus *et al* (2009).
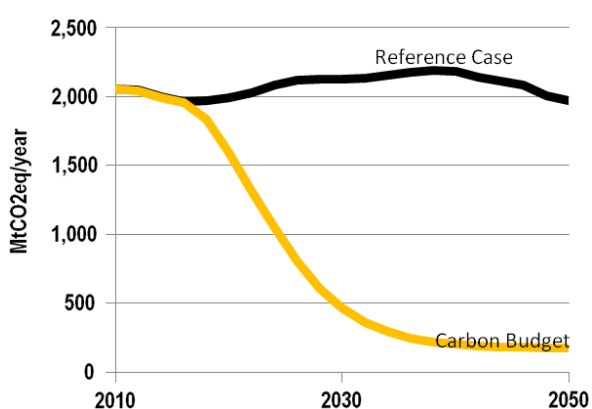
Figure 2. US electricity sector carbon budget. Fawcett *et al* suggest that to achieve an economy-wide budget of 170 GtCO$_{2eq}$, the United States would reduce emissions 83% below 2005 levels by 2050, which is similar to proposals introduced in Congress in 2009–2010 (Waxman and Markey 2009, Kerry 2010). Fawcett *et al* and the modeling for the Congressional proposals showed that near-term carbon reductions would most economically come from the electricity sector, given the technology-switching options available. Based on the average of runs from five different models from Fawcett *et al*, we assumed that the electricity sector would account for 76% of the 2010–2050 cumulative economy-wide emissions reductions.

relative economics of different technologies, subject to this emissions budget. Carbon credit banking and borrowing were not allowed in scenario 2; the annual power sector carbon emissions were determined *a priori* for all scenarios with an emissions budget.

Scenarios 3 and 4 included the same US CO$_2$ emissions budget for the electricity sector plus targets for specific low- and no-carbon technologies. The technologies and targets we chose are ones that numerous studies described below have shown could potentially achieve the greatest emission reductions in the next 40 years, and that would likely produce appreciably different modeling results with respect to water use. For each technology or group of technologies, we adopted aggressive targets to illustrate a range of possible outcomes and impacts given the uncertainty around technology costs

and innovation, fuel costs, energy policies, deployment and siting issues, and other factors that will determine which low-carbon technologies are likely to be the biggest winners. While the technology targets are specified at the national level, the model determines the geographic distribution of these technologies at the regional level based on relative economics, resource potential, electricity demand and other factors. For coal and renewable energy, the model also determines the mix and geographic distribution of different technologies included these categories (e.g. wind, solar, geothermal, or biopower).

For scenario 3, we assumed high levels of nuclear power and coal plants with CCS. We assumed nuclear generation would grow from approximately 20% of the US electricity mix today to 29% in 2035 and 36% in 2050, while coal with CCS would grow to 15% of the generation mix by 2035 and 30% by 2050. We based these levels on the upper end of a range of projections from the EMF 22 study, EIA and US Environmental Protection Agency (EPA) analyses of federal climate and energy legislation (EIA 2012c, 2009, EPA 2009), the Electric Power Research Institute (Specker 2010, Lovins 2011). We also assume that new nuclear (beyond the 4.4 GW of planned additions we included in the model) and CCS plants would not be built until after 2020, which is consistent with current proposals and the long lead time that is necessary for these plants.

For scenario 4, we assumed that the emissions reductions would be met by aggressive deployment of energy efficiency and renewable energy technologies over the next 40 years. We assumed that energy-efficient technologies and buildings would reduce US electricity demand 20% by 2035 and 35% by 2050 compared to the reference case, or about 1% per year on average starting in 2016 (Laitner *et al* 2012, Lovins 2011, National Research Council 2010, Fawcett *et al* 2009, Granade *et al* 2009). Several states are already achieving or have adopted efficiency targets of between 1% and 2.5% per year. We assumed electricity generation from renewable energy technologies, including wind, solar, geothermal, biomass, and hydropower, will grow from about 10% in 2010 to 50% in 2035 and 80% by 2050. These targets are based primarily on the 2012 NREL *Renewable Electricity Futures* study (NREL 2012), which analyzed the
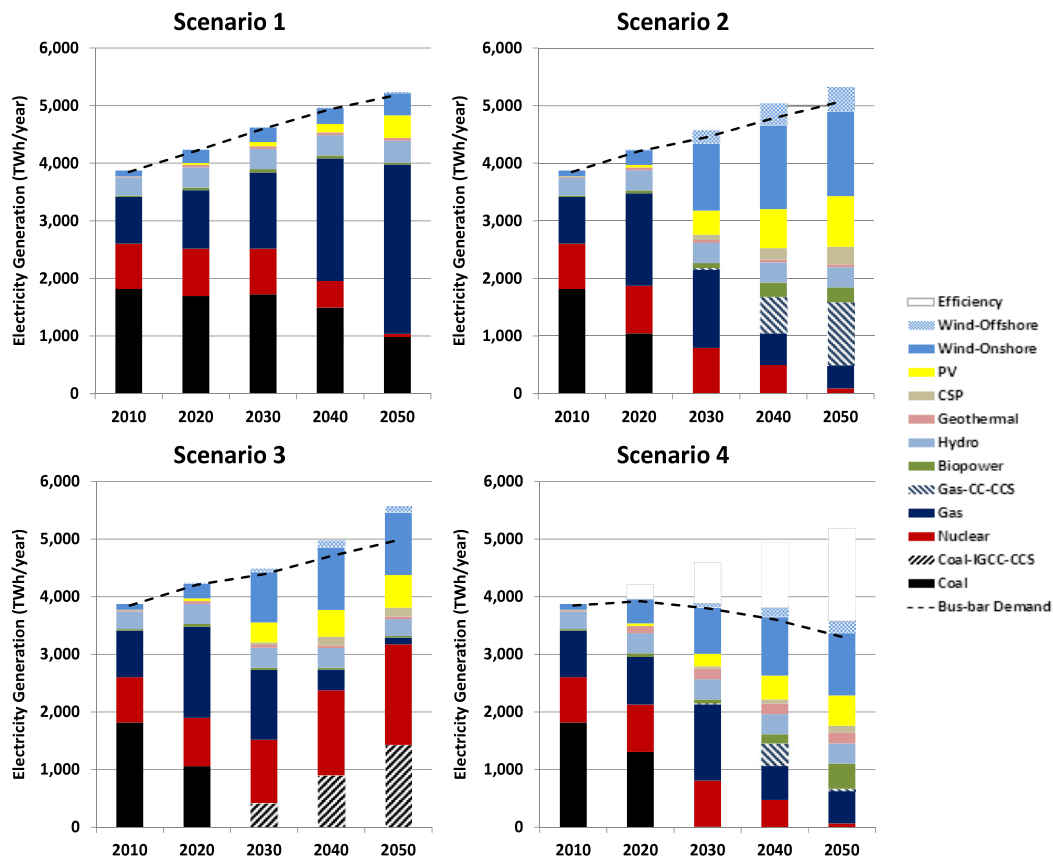
Figure 3. National electricity generation by scenario. Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets. Bus-bar demand is the amount of energy that needs to be delivered from the point of generation. Gas includes combustion turbine and combined cycle (CC) plants. Solar photovoltaics (PV) include residential, commercial, and utility scale systems.

feasibility and impacts of integrating high levels of renewable energy (30–90%) into the US electricity grid, as well as other earlier studies (Lovins 2011, National Research Council 2009, Fawcett *et al* 2009, Cleetus *et al* 2009). For this scenario, we also adopted NREL's (2012) assumption that included US Geological Survey mid-range estimates for undiscovered hydrothermal sites in the geothermal supply curve. These sites have reservoirs with sufficient naturally occurring thermal energy, water, and permeability to be able to use conventional, commercially available technology to generate electricity.

We assume that additional (beyond existing state and federal) policies and incentives would be needed to achieve the carbon budget and technology-specific targets, but we did not attempt to identify or prescribe what the policies would be and we did not include any new incentives or subsidies in the analysis. While we also did not fully evaluate the technical feasibility of achieving the technology-specific targets, some of the external studies we used to define the targets did include this information. In addition, we did not explicitly model a high natural gas case because natural gas was the dominant source of new generation in the reference case, and natural gas with CCS played a significant role in the second scenario, as shown in more detail below.

3. Results

Using the ReEDS model to explore the four scenarios, we compare the impact of each carbon budget scenario to the reference case. The ReEDS model determines the mix of electricity generation technologies at the national and regional levels to meet the carbon budget and technology targets, which we use to calculate the impacts on national water withdrawals and consumption from the electricity sector. The model also projects the impact on electricity and natural gas prices under these scenarios.

3.1. National electricity generation

Under the reference case (scenario 1), electricity generation from coal-fired power plants steadily decreases over the course of the projection, representing a 37% reduction between 2010 and 2050 (figure 3). This decline in coal generation is initially due to the announced coal plant retirements included in the model resulting primarily from low natural gas prices, implementation of EPA regulations, and state requirements for energy efficiency and renewable energy. Toward the end of the projection, coal generation declines due to existing coal plants retiring at the end of their

assumed 66-year lifetime and the higher cost of new coal plants compared with natural gas. Nuclear generation also stays near current levels through 2032, then steadily falls to near zero by 2050 due to the assumed 60-year lifetime for existing nuclear plants and the relatively high cost of building new plants.

Most of the new generation needed in the reference case to replace this reduction in coal and nuclear generation and meet the modest growth in electricity demand is projected to come from natural gas, which more than triples to provide 57% of total US electricity generation in 2050. Renewable energy generation also more than triples by 2030, due in large part to state renewable electricity standards and federal tax credits (in the early years), and increases more than six-fold by 2050, due to projected cost reductions that make some technologies economically competitive.

Under each of the carbon budget scenarios, all conventional coal generation (i.e., plants without CCS) is retired by 2030 because of its significantly higher carbon intensity compared to other technologies. Natural gas, with lower direct emissions and low fuel costs, also plays a significant intermediary role in each of these scenarios. Renewable energy generation also grows significantly under all the carbon budget scenarios. Wind and solar power experience the largest growth, contributing 37–54% of total generation by 2050, while geothermal and biopower experience more modest growth.

In scenario 2, coal generation drops to zero by 2030. Natural gas plays a larger role in the early years and, with the later addition of CCS. Renewable energy technologies make the biggest contribution in this case, providing 45% of US electricity by 2030 and 66% by 2050, as several technologies are more cost-effective alternatives for meeting the carbon budget than building new nuclear or coal with CCS plants. Wind and solar (PV and CSP) increase to 60% of total US electricity by 2050, to help meet the emission reduction targets.

For scenario 3, the nuclear and coal with CCS targets begin in 2020 and increase to provide two-thirds of total generation by 2050. Natural gas generation increases in the early years to replace some of the decline in conventional coal generation. But as the targets for nuclear and coal with CCS increase, natural gas decreases to 2% of the generation mix by the end of the projection, providing generation largely for balancing output from a variety of resources for meeting peak demands. Renewable energy generation led by wind and solar also increases under this scenario to provide approximately one-third of total generation by 2050, however, this is less than half of the growth seen in scenarios 2 and 4.

Finally, in scenario 4, energy efficiency plays a much larger role, eliminating the projected growth in electricity demand and reducing electricity use 20% by 2030 and 35% by 2050 compared to the reference case. A diverse mix of renewable energy technologies contributes to meeting the 80% by 2050 target. Wind and solar PV make the biggest contributions, providing 55% of total generation by 2050. However, some wind generation (8% of total generation in 2050) is curtailed in this scenario, primarily during periods

with strong winds and low electricity demand. Dispatchable renewable energy technologies such as geothermal, biomass, CSP with storage, and hydropower—that can generally generate electricity when needed similar to coal, nuclear and natural gas plants—also make an appreciable contribution.

3.2. Regional electricity generation

Changes in regional generation are also important to consider, as most generation and transmission decisions are made at the state and regional levels. The electricity generation mix varies greatly in different regions of the United States under our four scenarios due to regional differences in existing capacity, renewable energy resource potential, transmission capacity, electricity demand and other factors. While scenarios 2–4 specify a national carbon budget and minimum penetration levels for specific technologies, the model determines how each region will contribute to these national targets based on these factors. In this paper, we focus on the US Southwest and Southeast, where water demands of electricity production are particularly relevant and where there are significant differences in the current and projected electricity mix.

3.2.1. Southwest. The Southwest (figure 4) currently relies on natural gas (36% of total generation) and coal (33%) to meet most of its electricity needs, while the contribution from nuclear (14%) is smaller than the national average. The contribution from hydro (10%) and other renewable energy sources (7%) is higher than the national average, as this region has a wide range of high quality renewable resources and relatively strong renewable energy policies in place. Under the reference case (scenario 1), non-hydro renewable generation increases to more than 38% and natural gas generation grows to 39% of total generation by 2050, replacing retiring nuclear and coal plants.

Under the carbon budget scenarios, all conventional coal capacity in the region (as at the national level) is projected to retire and gas generation sharply declines by 2030. Renewable generation also increases appreciably under these scenarios, ranging from 66% by 2050 in scenario 3 to over 95% by 2050 in scenario 4. Under scenario 2, CSP with storage, solar PV and wind provide most of the renewable generation. Under scenario 4, geothermal generation provides a much larger share of the renewable generation (36% by 2050), as it becomes economically viable later in the forecast to develop currently undiscovered hydrothermal geothermal sites represented in the ReEDS model for this scenario. Under scenario 3, all of the existing nuclear plants are replaced with new nuclear capacity, resulting in an overall increase in nuclear generation in the region to 19% by 2050. Coal with CCS also replaces most conventional coal generation, providing 14% of the region's generation by 2050.

3.2.2. Southeast. In the Southeast (figure 5), the generation mix under each of the scenarios is much different than the Southwest. In 2010, the Southeast relied heavily on coal (47%) and nuclear (27%) to generate most of its electricity,
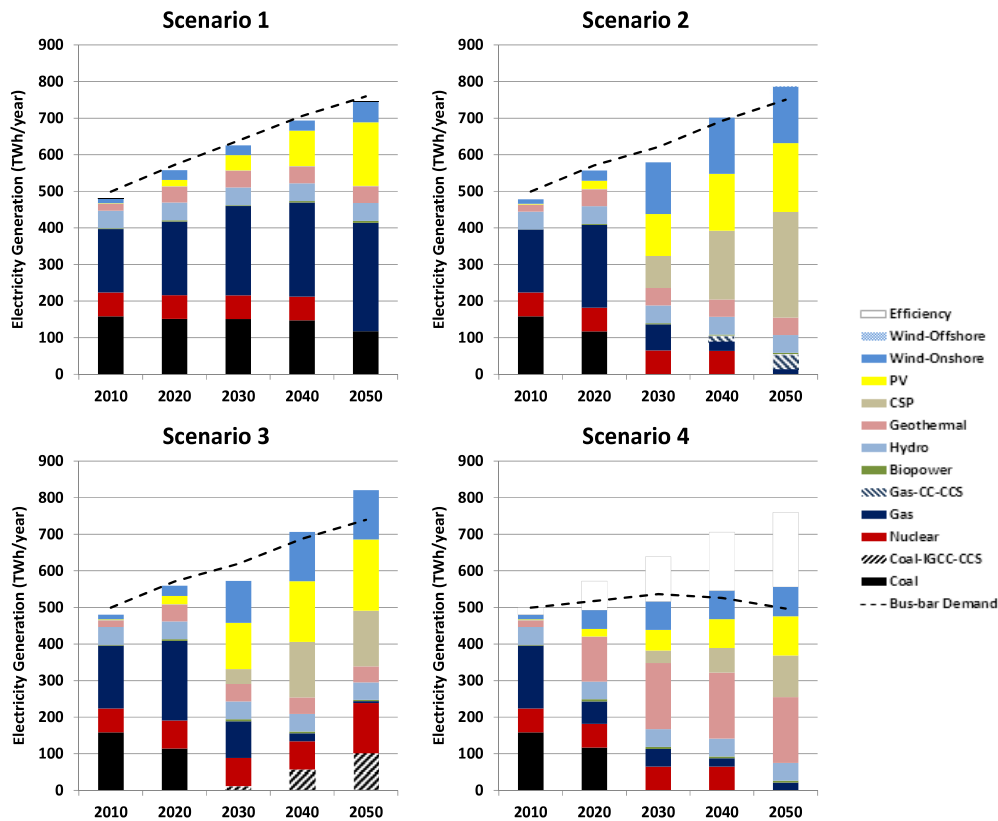
Figure 4. Electricity generation in the southwest, by scenario. Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets. For purposes of this analysis, the region includes California, Nevada, Arizona, Utah, New Mexico, Colorado, and Wyoming. Bus-bar demand is the amount of energy that needs to be delivered from the point of generation. Gas includes combustion turbine and combined cycle (CC) plants. Solar photovoltaics (PV) include residential, commercial, and utility scale systems.

while the contribution from natural gas (17%) was smaller than the national average. However, under the reference case, gas generation is projected to provide nearly three-quarters of the region's total generation by 2050, as it replaces retiring coal and nuclear plants and meets most of the projected increase in electricity demand.

Under the carbon budget scenarios, all conventional coal capacity in the Southeast is projected to be retired by 2030, which is consistent with the results at the national level and in the Southwest. The modeling also shows that the Southeast has relatively good solar PV, biomass and offshore wind resources, which results in those technologies appreciably increasing their share under scenarios 2 and 4 (27%–28% PV, 9%–26% biomass and 12%–15% offshore wind by 2050). We also see a significant amount of gas with CCS under scenario 2 (29% in 2050). With a large fraction of the nation's existing nuclear capacity located in the southeast and our assumption limiting new nuclear facilities to PCAs with existing nuclear capacity, scenario 3 sees significant growth in nuclear power in the region (to 68% of generation by 2050), along with significant growth in coal with CCS (23% by 2050).

3.3. National electricity sector water consumption

Projections for power plant cooling water use can be calculated using electricity generation figures (by fuel and cooling technology type) and average water use (withdrawals or consumption) per unit of electricity for each type, as described in Macknick *et al* (2012). For the purposes of this manuscript, we illustrate the changes in national water consumption, which captures evaporative losses from the cooling process. (Water withdrawals, another potentially important metric, can involve considerably higher volumes than water consumption, though much of the water may be returned back to the environment, at a higher temperature; consumption is the net of withdrawals and returns.) Such an approach shows wide variations by scenario (figure 6), with the scale and direction of the differences varying over the course of the projection. Under scenario 1, for example, national water consumption increases slightly (0.6%) by 2030, as increased electricity demand is met primarily with natural gas combined cycle plants, with no substantial change in coal and nuclear generation. However, by 2050, water consumption is 460 billion gallons (34.2%) lower than 2010 levels, as coal and nuclear generation is substantially reduced and replaced with natural gas and renewable generation.

Under scenario 3, national water consumption declines by 470 billion gallon (35.0%) by 2025, then increases above 2010 levels (190 billion gallons, or 21.7%) by 2050, as existing coal plants retire and new coal with CCS and nuclear facilities utilizing recirculating cooling technologies increase. Scenarios 2 and 4 follow a similar decreasing
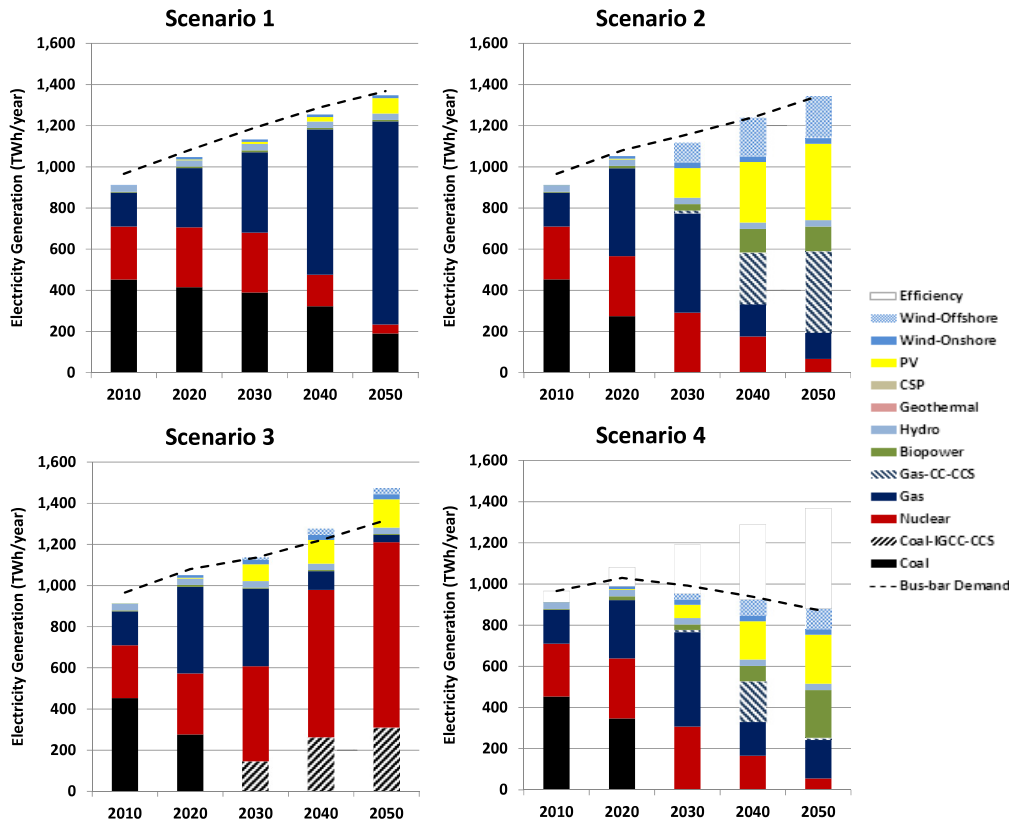
Figure 5. Electricity generation in the southeast, by scenario. For purposes of this analysis, the region includes Mississippi, Alabama, Tennessee, Georgia, South Carolina, North Carolina, and Virginia. Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets. Bus-bar demand is the amount of energy that needs to be delivered from the point of generation. Gas includes combustion turbine and combined cycle (CC) plants. Solar photovoltaics (PV) include residential, commercial, and utility scale systems.
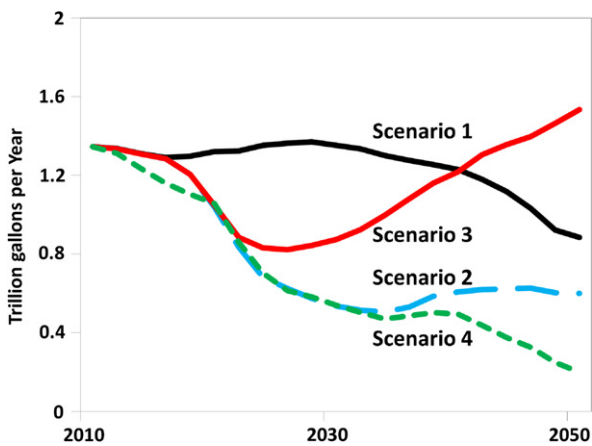

Figure 6. National electricity sector water consumption, by scenarios. Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets.

trajectory until 2030, as conventional coal plant retirements reduce consumptive uses. They then diverge, as consumption increases slightly between 2030 and 2050 under scenario 2 as a result of building new natural gas combined cycle plants with CCS and continues to steadily decline under

scenario 4 due to a reduction in electricity demand and increased penetration of renewable technologies. For scenario 4, the result is a reduction of 1.1 trillion gallons (85.2%) by 2050 from 2010 levels. For more detailed results on water withdrawals and consumption at the national and regional level, see Macknick *et al* (2012).

3.4. National electricity and natural gas costs

Because we modeled a carbon budget and specific technology targets in scenarios 2–4, showing how those scenarios impact consumer energy costs can provide policy-relevant information to decision makers. Average consumer electricity prices, for example, rise under the reference case, but rise more sharply under scenarios 2, 3, and 4, with scenario 3 producing the highest prices (figure 7). Changes in overall consumer electricity *bills* (price times usage), arguably a more important measure of the economic impact to consumers, vary more dramatically. Both scenarios 2 and 3 show increases in consumer electricity bills consistent with the respective rate increases because there is little projected change in consumer electricity use under these scenarios. In contrast, consumer electricity bills under scenario 4 drop below the reference case because of energy efficiency investments (figure 8). Because of natural gas's importance outside of the
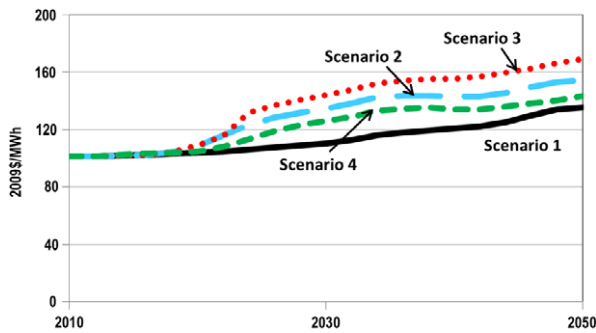
Figure 7. Average consumer electricity prices. Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets. Average consumer electricity prices represent the average of prices in the residential, commercial, and industrial sectors. Prices rise under each of the scenarios based on varying technology and generation mixes, fuel use and price, new transmission lines and new storage capacity. Under the reference case (scenario 1), electricity prices increase 34% over current levels by 2050 due to increases in natural gas and coal prices and investments in new power plants to meet the growth in electricity demand and to replace retired capacity. Scenario 3 shows the greatest increases in electricity prices compared to the reference case, 30% higher in 2030 and 25% higher in 2050. Scenario 4 shows a more modest price increases, with prices 14% higher than the reference case in 2030 and 9% higher in 2050.
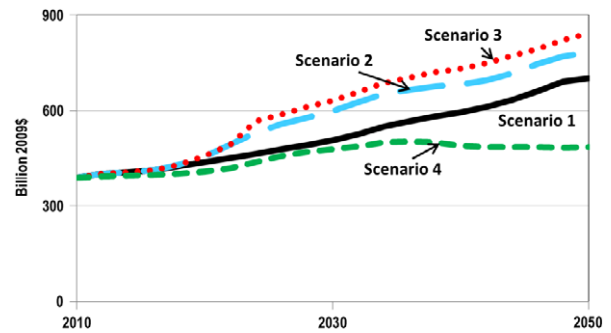
electricity sector—as a heating fuel and feedstock (plastics, chemicals, fertilizers)—changes in its pricing as a result of changes in natural use in the electricity sector can have broad implications. In scenarios 2–4, gas prices are initially higher than the reference case because of the increased near-term dependence on natural gas to help meet carbon reduction targets, but then drop below the reference case as gas generation declines, with scenario 3 having the lowest prices by 2050 (figure 9).

Importantly, these changes in electricity and natural gas prices are result of implementing a carbon budget and technology targets in the electricity sector only. They do not reflect changes in technology and fuel choices in the other sectors, and the resulting impact on energy prices and usage that would result from an economy-wide carbon budget. For example, projected changes in consumer electricity bills do not include a potential increase in electric vehicles to reduce CO_2 from the transportation sector or changes in natural gas demand in the buildings and industry sectors that would result from changes in natural gas prices.

4. Conclusions

The different electricity futures described in this paper will all have important economic and environmental implications and trade-offs at both the national and regional levels. For example, while the reference case is projected to have the lowest electricity prices, it also has the highest water consumption through 2040, highest long-term natural gas prices, and least diversified electricity mix. This scenario also has the highest carbon emissions, which would pose

Figure 8. Total consumer electricity bills. Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets. Both scenarios 2 and 3 show increases in overall residential, commercial, and industrial consumer electricity bills (calculated as the average price times total consumption) largely consistent with the price increases. There is little change in consumer electricity use in scenarios 1–3 as increases in electricity demand due to population growth, economic growth and other factors are mostly offset by efficiency improvements in energy technologies and buildings. Under scenario 4, however, significant reductions in electricity use due to more aggressive investments in energy efficiency more than offset price increases, resulting in savings on consumer electricity bills. Under that scenario, consumer electricity bills would be $63 billion or 13% lower than under the reference case by 2035 and $214 billion or 31% lower by 2050. While we did not calculate the investment or program costs that would be needed to realize those savings, a 2008 study estimated annual costs of $36 billion (in 2009$) to achieve a similar level of reduction in electricity use in 2035, increasing to $62 billion to achieve a similar reduction in 2050 (Cleetus *et al* 2009). If costs were similar or even considerably higher than these estimates, electricity consumers would still see significant net annual savings. Other studies (Laitner *et al* 2012, Lovins 2011, Granade *et al* 2009, National Research Council 2009) have also shown that electricity bill savings from energy efficiency typically more than offset investment costs.

significant risks to the climate, public health, and the economy from the projected impacts of unchecked climate change that are also not included in this analysis.

While the reference case will involve considerable changes to our energy system, achieving any of the carbon budget and high technology penetration scenarios will arguably involve more fundamental transformations. Those transformations may include significant benefits in terms of reduced climate change impacts and greater electric system diversity, but will also require major operational and infrastructure changes, as well as other economic and environmental benefits and risks not considered. Investing in new nuclear and coal with CCS facilities to significantly reduce carbon emissions is projected to result in the highest long-term water consumption and the highest electricity costs. In contrast, investing in renewable energy and energy efficiency to meet emission reduction targets is projected to result in significant water savings, lower costs, and even net savings to consumers.

Importantly, for purposes of the broader body of electricity–water work for which the electricity modeling described in this paper is the first step, different electricity mixes are also likely to have very different water profiles.
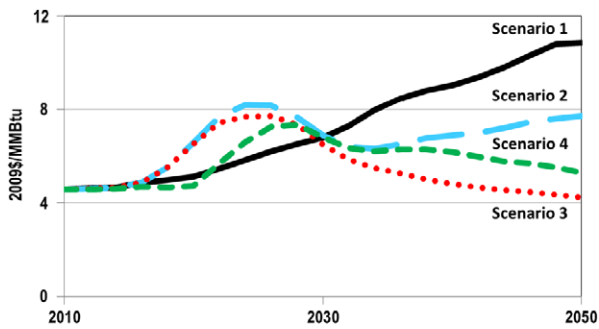
Figure 9. Natural gas prices (delivered to the electricity sector). Scenario 1, reference case; scenario 2, carbon budget, no technology targets; scenario 3, carbon budget with coal with CCS and nuclear targets; scenario 4, carbon budget with efficiency and renewable energy targets. Consumer natural gas prices and bill impacts are another important economic effect of electricity sector choices because of natural gas's role as a heating fuel and as a feedstock for the production of chemicals, plastics, fertilizers, and other products. Natural gas prices are slightly higher under scenarios 2–4 than the reference case before 2030 because of the increased near-term dependence on natural gas generation to replace coal generation and meet the early carbon reduction targets. But after 2030, natural gas prices are considerably lower than the reference case in all of the carbon budget scenarios, with scenario 3 having the lowest prices (and lowest level of natural gas generation) by 2050. These changes in natural gas prices would likely result in higher consumer natural gas bills (economy-wide) before 2030 and lower bills after 2030, even after taking into account any price-induced changes in consumer natural gas demand. Because ReEDs only models the electricity sector, we were not able to quantify the impacts on consumer natural gas bills for this study. However, other studies using economy-wide energy models have shown significant long-term consumer savings from displacing natural gas in the electricity sector (Wiser *et al* 2005, EIA 2007, UCS 2009).

Those differences stem from the wide variation in water use between most thermoelectric power plants and low- or no-water technologies such as wind and energy efficiency. We explore those differences at the large scale in the next paper resulting from this research (Macknick *et al* 2012).

The differences in the electricity mixes under the various scenarios also allow exploration of the impacts of electricity sector decisions on water resources at a much more local level. Though such exploration involves the challenge of robustly linking the electricity modeling output to the water modeling input, we do that in follow-on research focused on select basins in the US Southwest and Southeast (see, for example, Sattler *et al* 2012).

While this paper explores electricity scenarios with a wide range of potential outcomes, many other electricity futures are certainly possible. Future research could examine other scenarios such as different technology targets, technology combinations, carbon budgets, or specific energy policy proposals. Incorporating the scenario 4 energy efficiency targets in any of the other scenarios, for example, would likely result in lower costs and environmental impacts, including water use. Sensitivity analyses around specific assumptions, such as electricity demand growth, technology cost and performance, natural gas and coal prices, and other key inputs could also yield interesting results. Overall, the research

described here achieves our aim of generating electricity results that are likely to have meaningful differences from a water perspective and allow us to incorporate water results into assessments of the costs and benefits of different electricity pathways.

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