The potential impacts of climate-change policy on freshwater use in thermoelectric power generation

Munish K. Chandel [a,*], Lincoln F. Pratson [b], Robert B. Jackson [a,b,c]

[a] Climate Change Policy Partnership, Duke University, Durham, NC 27708, USA
[b] Nicholas School of the Environment, Duke University, Durham, NC 27708, USA
[c] Center on Global Change, Duke University, Durham, NC 27708, USA

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ABSTRACT

Climate change policy involving a price on carbon would change the mix of power plants and the amount of water they withdraw and consume to generate electricity. We analyze what these changes could entail for electricity generation in the United States under four climate policy scenarios that involve different costs for emitting CO_2 and different technology options for reducing emissions out to the year 2030. The potential impacts of the scenarios on the U.S. electric system are modeled using a modified version of the U.S. National Energy Modeling System and water-use factors for thermoelectric power plants derived from electric utility data compiled by the U.S. Energy Information Administration. Under all the climate-policy scenarios, freshwater withdrawals decline 2–14% relative to a business-as-usual (BAU) scenario of no U.S. climate policy. Furthermore, water use decreases as the price on CO_2 under the climate policies increases. At relatively high carbon prices (> \$50/tonne CO_2), however, retrofitting coal plants to capture CO_2 increases freshwater consumption compared to BAU in 2030. Our analysis suggests that climate policies and a carbon price will reduce both electricity generation and freshwater withdrawals compared to BAU unless a substantial number of coal plants are retrofitted to capture CO_2.

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1. Introduction

The greatest use of water withdrawals in the United States is for thermoelectric power plants. The U.S. Geological Survey (USGS) estimates that 41% of total U.S. freshwater withdrawals were for electricity generation in 2005, roughly 143 billion gallons per day or 6270 m^3 s^{-1} (Kenny et al., 2009). The demand for electricity in the U.S. is projected to rise 1.1%/yr over the next few decades (Annual Energy Outlook, 2009). In addition, future climate change may bring hotter temperatures and, in places, more droughts (Karl et al., 2009). Both greater electricity demand and potential climate change may increase water use, potentially leading to restrictions on water availability that limit the construction of new power plants. This risk could be diminished or even enhanced by climate policies that price CO_2 emissions. While a climate policy might promote the adoption of low-carbon, low-water-use power generation technologies, such as wind turbines and solar photovoltaic sources, it may also promote the retrofitting of coal-fired power plants with carbon capture systems that increase water use.

The main use of water in a thermoelectric power plant is for the cooling system that condenses steam and carries away the waste heat as part of a Rankine steam cycle. The total water requirements of such a plant depend on a number of factors, including the generation technology, generating capacity, the surrounding environmental and climatic conditions, and the plant's cooling system, which is the most important factor governing efficient water use (Carney et al., 2008). The main types of cooling systems today are dry systems, which use air for cooling, and wet systems, which use water. The latter are the dominant type of cooling system and are the focus of this paper. Wet systems include once-through systems and recirculating systems, both of which draw cooling water from outside the plant at a pace known as the water *withdrawal* rate. Once-through systems move the water through a steam condenser once before discharging it back to the source. In recirculating systems, the water is cycled through the condenser multiple times by using a cooling tower or cooling pond to facilitate heat transfer from the water to the atmosphere via evaporation (Feeley et al., 2008). Total evaporation, the plant's water *consumption*, not only diminishes the amount of cooling water remaining but also increases its salt concentration, which can hamper cooling system performance. Consequently, new water needs to be continuously introduced into recirculating systems, giving them much higher consumption rates than once-through systems. However withdrawal rates, which exceed consumption rates by more than an order of magnitude, are still significantly lower in recirculating systems.

* Corresponding author. Current address: Environmental Engineering Group, Civil Engineering Department, Indian Institute of Technology Roorkee, Roorkee 247 667, India. Tel.: +91 1332 285691.
E-mail addresses: munish.chandel@duke.edu, munish.chandel@gmail.com, munisfce@iitr.ernet.in (M.K. Chandel).

The water use for thermoelectric power generation increases competition among different domestic and commercial water users and influences the environment. In the case of the latter, cooling-water systems can entrap fish and other aquatic organisms. The chemicals used for cleaning cooling systems and the hot water they return to rivers and lakes can also harm local ecosystems (U.S. Environment Protection Agency, 2011). Because water withdrawals for once-through systems are at least an order higher than in recirculating cooling systems, the former typically have a greater environmental impact. Once-through cooling systems also dissipate heat directly into the water and hence have higher thermal pollution than recirculating cooling systems.

Retrofits of coal-fired power plants with carbon capture and storage (CCS) technologies increase water use in at least two ways. One is through extra water use at the plant for the scrubbers that remove CO_2. The other is through added water use at supplementary power-generation needed to compensate for the increased parasitic load at the retrofitted plant caused by the carbon-capture system. This parasitic load is estimated to reduce or derate a plant's capacity by up to 20–30% (Rochelle, 2009).

In its 2009 report, NETL (National Energy Technology Laboratory, 2009a) estimated that a comprehensive implementation of CCS in 2030 could raise freshwater withdrawals by 2–3% and consumption by as much as 52–55%. This assumes that all coal plants in the U.S. will be retrofitted with CCS by 2030 and that the associated derating of the plants will be compensated by any of three plant types: nuclear, integrated gasification combined cycle (IGCC) plants with CCS, and pulverized coal (PC) plants with CCS. Proposed climate policies, however, are likely to affect electricity generation and associated water use in a more complex fashion. How many coal plants retrofit with CCS and what types of new plants are built to compensate for derated capacity will depend upon the specific climate-policy regulations and the price of CO_2 under that policy.

In this paper, we explore the potential impacts that climate policies could have on water use in thermoelectric power generation. We begin by characterizing current water use in the power industry, building on recent NETL studies (National Energy Technology Laboratory, 2006, 2008a, 2009a) to establish a baseline for water withdrawals and consumption down to the level of individual generator of power plants. We then project how this water use will change in the future as electricity demand and the number and types of power plants used to meet this demand evolve in response to the climate policy scenarios. These responses are modeled using an adaptation of the U.S. Energy Information Administration (EIA) National Energy Modeling System (NEMS) modified by the Nicholas Institute for Environmental Policy Solutions. We hereafter refer to this adaptation as 'NI-NEMS' so as to distinguish it from the original NEMS and differentiate our analyses from past EIA Annual Energy Outlooks (AEO) produced with NEMS, The modeling results for all the climate policy scenarios are first examined nationally relative to a business-as-usual (BAU) projection of no climate policy out to 2030. We then assess how carbon pricing under the different climate policy scenarios might affect water withdrawals and consumption within the 13 North American Electric Reliability Corporation (NERC) regions.

2. Methodology

2.1. Electricity generation scenarios

Our approach to projecting future water use in electricity generation under possible climate-change policy scenarios builds on methodology developed by NETL (National Energy Technology Laboratory, 2006, 2008a, 2009a). Previous NETL projections for water use in thermoelectric power generation are based on annual energy forecasts by the EIA that use NEMS to predict the

number and types of power plants that will be needed to meet future U.S. demand for electricity. NEMS is a comprehensive energy-economic model that optimizes energy supply to meet demand by iteratively solving a series of equations within modules of the model that represent the activities of the resource, electrical, industrial, commercial, residential and transportation energy sectors (Gabriel et al., 2001). Energy demand in NEMS is based primarily on economic development and population growth. Electricity production to meet demand is forecasted for a mix of power plant types. Annual electricity production at each existing power plant is estimated by minimizing operation and maintenance costs, environmental costs and fuel consumption. Forecasts of new power plants are based on the same criteria plus minimization of capital costs (U.S. Energy Information Administration, 2011). The output of the NEMS electricity module includes detailed information on individual power plants, including the plant technology, the year the plant started operating, its capacity, the amount of electricity it generated in a year, and the fuel it used.

Our version of NEMS, NI-NEMS, is similar to the original except that it also includes an added module for carbon capture and storage (CCS). This module was developed by NETL to determine which conventional coal plants would retrofit for CCS under different carbon price scenarios. The module estimates retrofit costs on the basis of NETL's experimental study of amine based capture technology at American Electric Power's Conseville, Ohio Plant (National Energy Technology Laboratory, 2008b).

We used NI-NEMS to explore four climate-policy scenarios relative to a business-as-usual (BAU) scenario. The BAU policy scenario is based on the EIA's Annual Energy Outlook Reference Case that reflects the guidelines in America's Recovery and Reinvestment Act of 2009 (U.S. Department of Energy, 2009), a similar forecast used by NETL (2009a) for its water-use projections. Note that the BAU scenario assumes no climate policy and thus imposes no cost on CO_2 emissions.

The four climate policy (CAP) scenarios impose a price on carbon emissions that reflects climate bills introduced previously in the U.S. Congress. These scenarios model different CCS implementation alternatives, including special incentives for early deployment, along with other low-carbon electricity generation options. One pair of scenarios, referred to as the Low Carbon Allowance Price (LCAP) scenarios, is based on pricing of carbon emissions that the U.S. Environment Protection Agency (2009b) assessed would occur under the climate policies proposed in the American Clean Energy and Security Act (H.R. 2454, a.k.a. the former Waxman–Markey bill), and the Clean Energy Jobs and American Power Act (S. 1733, a.k.a. the former Kerry–Boxer bill). The CO_2 allowance price starts at \$15/tonne in 2012 and then increases 5% annually out to 2030. The LCAP scenarios also incorporate special incentives in the bills to spur early development of CCS. These include bonus allowances to the operators of up to 6 GW of CCS generation capacity (new or retrofits) in the first phase of the scenario starting in 2015, and an auction of bonus allowances for up to 66 GW of CCS capacity in the second phase.

The second pair of scenarios is referred to as the High Carbon Allowance Price (HCAP) scenarios. These are identical to the LCAP scenarios, except that they start with a higher initial CO_2 allowance price of \$25/tonne and do not include the special early adoption incentives for CCS.

Both the LCAP and HCAP scenarios have two versions. In one (LCAP_NR and HCAP_NR), no CCS retrofits are allowed, so existing coal power plants have to either pay the CO_2 allowance price or be retired. This is done to assess how many low-carbon power plants and new CCS-equipped fossil-fuel plants would be built under different carbon prices in the absence of retrofits. In the

other version (LCAP_R and HCAP_R), CCS retrofits are modeled representing the more likely case that existing plants will be retired or retrofitted for CCS depending on the cost of emitting CO_2. For these, we assume that a post-combustion CCS retrofit uses amine-based CO_2 capture technology and removes 90% of a plant's CO_2 emissions. We also assume that the CCS allowances under the LCAP_R scenario are divided equally between new IGCC plants with CO_2 capture and conventional coal plants retrofitted with the amine-based post-combustion capture systems.

2.2. Power plant water use

The NETL methodology (National Energy Technology Laboratory, 2006, 2009a) for projecting future water use in electricity production also includes using average rates of water withdrawal and consumption per megawatt hour of electricity generated by each *type* of power plant in the U.S. based on data from three sources: EIA-767 (U.S. Energy Information Administration, 2009a), EIA-860 (U.S. Energy Information Administration, 2009b), and the NETL Coal Plant Database (National Energy Technology Laboratory, 2009b). The adequacy of assigning average water factors to power plants based on technology type is an important assumption behind the NETL projections. Where possible, we take a more detailed approach and estimate water use by each *individual* power plant in the U.S.

Our approach is summarized in Fig. 1. We begin by using the EIA-767 database to calculate the 10-year (1996–2005) average water-use (withdrawal and consumption) factors ($m^3 MWh^{-1}$) for the cooling systems in each U.S. power plant (see Appendix A, Supplementary materials for a detailed description of the calculation). These 10-year averages provide a more robust measure of the water use at a plant than the factors recorded in any given year. Note, however, that for reasons of national security water-use factors for nuclear power plants have not been included in the EIA-767 database since the year 2000. Consequently, our average water-use factors for nuclear plants are based only on the 1996–2000 data.

We take the 10-year average water-use factors for each generator of each power plant that was operating in the year 2005 (according to the US EPA e-GRID database (U.S. Environment Protection Agency, 2009a)) and use it as the plant's water-use factor. We also use these factors to calculate a weighted average water-use factor for each plant type, which as shown in Table 1 is categorized on the basis of fuel type, cooling system type, and turbine type (e.g. steam turbine, combined cycle). These weighted averages are used as the water-use factors for power plants of these types that do not yet exist but which NI-NEMS models as coming online between 2005 and 2030 (Fig. 1).

The weighted average water-use factors for plant type are also used for a minority of existing plants that lack water-use factors in the EIA-767 database. This minority makes up 11% of total the coal power generation and 2% of the total nuclear power generation in 2010. Furthermore, we assume that power plants without recorded water-use data have wet-cooling systems with recirculating cooling towers. The one possible exception to this is natural gas combined cycle (NGCC) plants, 59% of which use dry cooling (National Energy Technology Laboratory, 2008a). Unfortunately, the EIA database did not contain enough information to identify which plants these were, so we assumed that all NGCC plants lacking recorded water-use factors drew 59% less cooling water than NGCC plants with wet cooling systems.

Similarly, renewable energy plants that use a steam cycle in electricity generation (e.g. solar thermal, biomass, municipal solid waste), but lack recorded water-use factors were also assigned values for these factors. For solar thermal plants, we used the water-use factors reported by U.S. Department of Energy (2008a) and by Baum et al. (2003) for a parabolic trough design (Table S1,

Appendix C). Water-use factors for biomass power plants are similar to those of coal plants, so we assumed them to be equal (Table S1, Appendix C). As most municipal solid waste (MSW) plants are fueled by biogas, we assigned them the same water-use factors as a natural gas steam turbine plant (Table 1). Geothermal and hydroelectric power plants also use water. However, the water use in geothermal plants is relatively negligible (Veil, 2007; DiPippo, 2008), while hydroelectric plants do not have direct water consumption, but could increase water evaporation from the water reservoir developed for the hydroelectric generation. This evaporation would depend upon reservoir surface area and the residence time of water in the reservoir and would be site specific. Due to these reasons, water use from these sources was excluded from our analysis.

All new power plants modeled to come online after 2005 were assumed to use freshwater and recirculating cooling towers (NETL, 2006, 2008a, 2009a). New plant types that do not currently exist were assigned the appropriate factors listed in Table S1 (see Appendix C). Note that the latter types include not only renewable energy plants, but also new and/or retrofitted fossil fuel plants, including IGCC, NGCC and pulverized coal (PC) plants with and without CCS systems. For plants with CCS, we used the estimates of National Energy Technology Laboratory (2007) that adding CO_2 scrubbers will increase water use by 93–96% in PC plants, and 37% in IGCC plants. We also assumed that existing plants that retrofit for CCS maintain their current type of cooling system. We emphasize the impact of CO_2 capture on water; transport and storage could have additional water-use impacts that are not included here.

Beyond cooling-water needs, power plants also use water for replenishing boiler water loss, flue gas desulfurization (FGD) and ash handling systems. We applied the water-use factors established by National Energy Technology Laboratory (2007) for these purposes, which are listed in Table S1 (Appendix C). A considerable amount of water may be required for ash disposal if the power plants use a wet ash disposal system. However, water use for ash disposal is not considered in the present study. Finally, we account for water use from the point of withdrawal to the point of discharge. We do not attempt to estimate any evaporative losses that may occur after the warmed water has been released back to its source, such as a lake or river.

3. Results

In 2010, 89% of total electricity generation in the U.S. (3978.6 billion kWh) required cooling. Based on our results, 47% of this generation used recirculating cooling towers, 25% used once-through freshwater systems, 13% used cooling ponds, and 6% used saline water (Fig. S1, Appendix B). Coal-fired generation was the dominant user in this regard, accounting for 61% of total freshwater withdrawals and 66% of freshwater consumption nationally. Nuclear generation was second at 25% of total freshwater withdrawals and 22% of freshwater consumption (Fig. S2a, b, Appendix B). Renewable generators with wet-cooling systems constituted < 1% of current electricity generation, having negligible water withdrawals but accounting for 2% of total freshwater consumption.

3.1. National changes in electricity generation by plant type

From 2010–2030 in the BAU scenario, total generation capacity and electricity production increase by 13% and 18.5%, respectively (Fig. 2a and b). The across-the-board increases are driven in large part by a projected 20% rise in the U.S. population. Electricity production also increases in all four carbon-allowance

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│        Select a thermoelectric generator from NEMS output for year i (2010-2030) │
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                                      │
                                      ▼
                              ◇ Is plant older than 2005? ◇
                    Yes ◄───────                      ───────► No
                        │                                      │
                        ▼                                      │
            ◇ Does it have water use factor ◇                  │
      Yes ◄── from 10-year average ──► No                      │
          │        database?                                   │
          │                                                    │
          │                            ◇ Does it correspond to plant ◇
          │                  Yes ◄──────  groups in Table 1  ──────► No
          │                      │                                  │
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│ Assign actual    │  │ Assign national      │  │ Assign water use     │
│ water use factor │  │ average water use    │  │ factor from Table S1 │
│ from 10-year     │  │ factor corresponding │  │ by matching plant    │
│ average database │  │ to plant group type  │  │ group type           │
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          │           │ recirculating cooling│              │
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          ▼                      ▼                          │
          ◇ Does it retrofit with CCS? ◇                    │
    Yes ◄─────                      ─────► No                │
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│ Multiply water   │                       │                 │
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│    Cooling water use factors for generator of a plant (m³ kWh⁻¹)          │
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        │   │ Add miscellaneous water use factors (i.e. FGD,     │
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│    Total water use factors of a generator (m³ kWh⁻¹)                      │
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        │   │ Multiply total water use factors by annual         │
        │   │ generation for year i                              │
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│    Total water use by plant subgroup (m³ s⁻¹) in year i                   │
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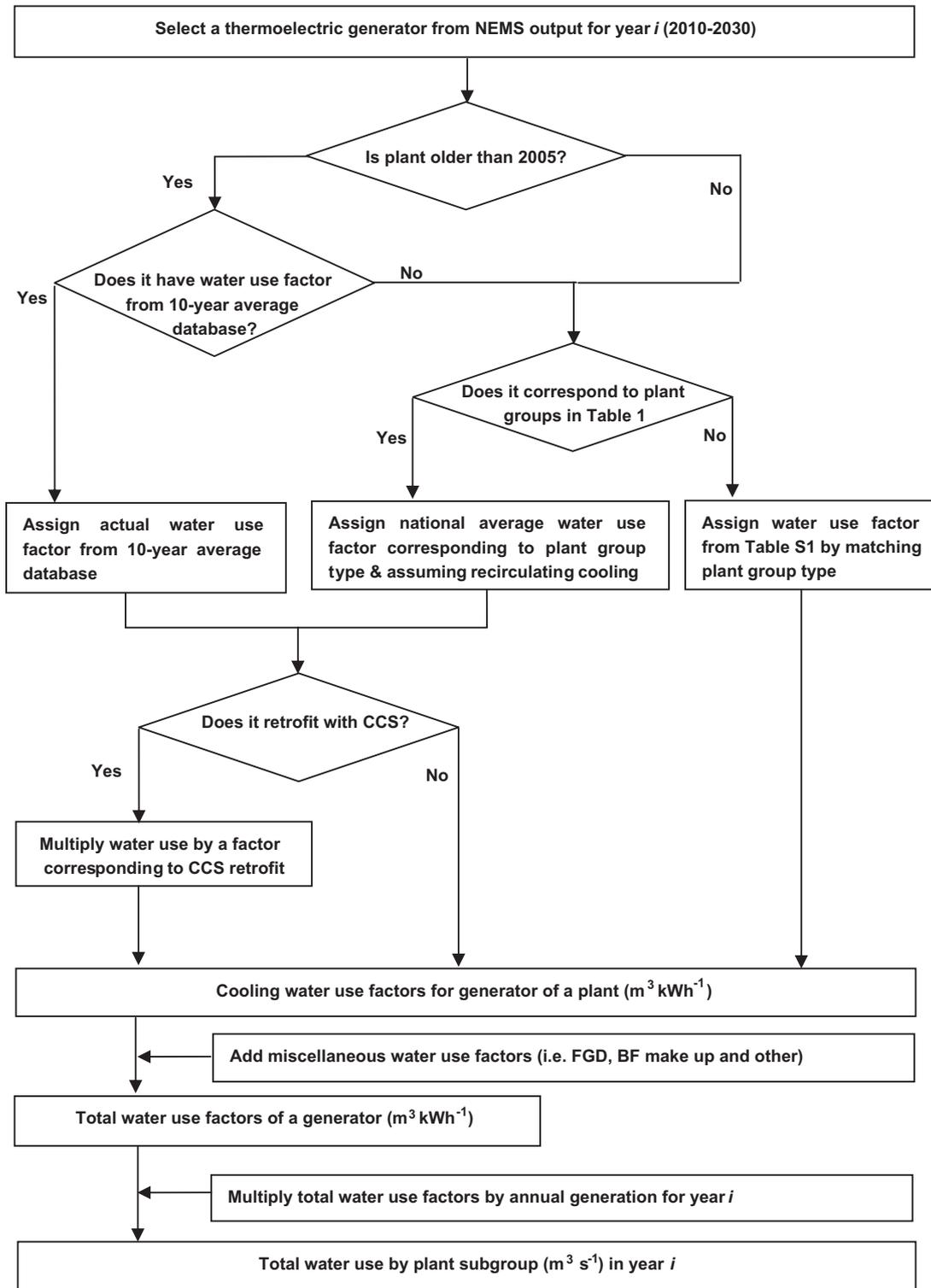
Fig. 1. Schematic of the methodology for water-usage allocation to a power plant.

price (CAP) scenarios, though less so under the CAP scenarios that lead to higher electricity prices (Fig. 2b). Under BAU, electricity prices rise 21% by 2030, whereas under the CAP scenarios, prices rise 37% (LCAP_NR and LCAP_R) to as much as 50–61% (HCAP_NR and HCAP_R, respectively). Depending upon the scenario and year, 52–56% of total capacity and 74–77% of the total electricity production requires fresh water for cooling. Only 5–6% of this generation uses saline water, a fraction that remains relatively constant for all our scenarios.

Climate-change policy scenarios alter the mix of electricity generation and reduce greenhouse gas emissions. The BAU scenario projects that electricity generation from freshwater-cooled coal plants will increase by 16.4% from 2010 to 2030. Over this same period, electricity generation from freshwater-cooled coal plants in the climate policy scenarios increases by 9.5% in LCAP_NR and 5.2% in LCAP_R, and decreases by 25.8% in HCAP_NR and 23.5% in HCAP_R (Fig. 2b). These declines in coal-fired generation in the climate-policy scenarios are partially offset
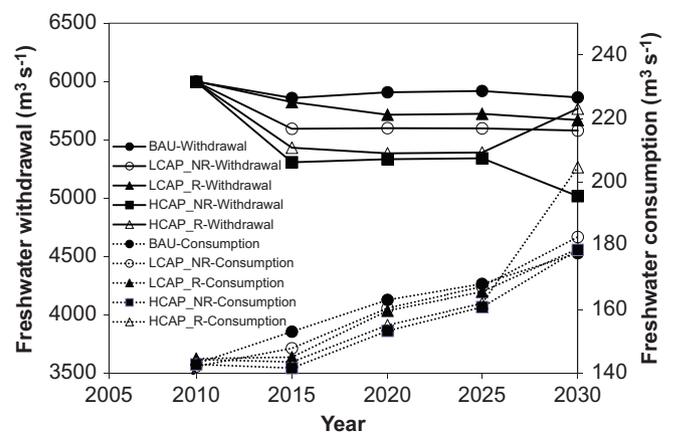
Table 1
National average cooling water-use factors for different power plant groups. The water-use factors are based on ten years (1996–2005 EIA-767) of actual water-use data.

Fuel	Prime mover type	Cooling type	Withdrawal factor (m³ MWh⁻¹)	Consumption factor (m³ MWh⁻¹)
Biomass	Steam turbine	Once-fresh	32.94	0.00
		Once-saline	129.08	0.00
Coal	Combined cycle	Once-fresh	20.15	0.00
	Steam turbine	Once-cooling pond/canal	92.02	0.00
		Once-fresh	97.73	0.00
		Once-saline	122.27	0.00
		Recirculating-cooling pond/canal	54.06	2.54
		Recirculating-cooling tower	2.78	2.14
Nuclear	Steam turbine	Once-cooling pond/canal	155.15	0.23
		Once-fresh	123.62	0.57
		Once-saline	137.37	0.00
		Recirculating-cooling pond/canal	75.81	1.12
		Recirculating-cooling tower	5.40	2.39
Natural gas	Combined cycle	Once-cooling pond/canal	36.77	0.05
		Once-fresh	31.51	0.00
		Once-saline	5.16	0.00
		Recirculating-cooling pond/canal	6.40	0.27
		Recirculating-cooling tower	1.56	1.16
Oil/gas	Steam turbine	Once-cooling pond/canal	65.02	0.17
		Once-fresh	64.07	0.00
		Once-saline	80.53	0.00
		Recirculating-cooling pond/canal	152.40	0.49
		Recirculating-cooling tower	4.66	2.99
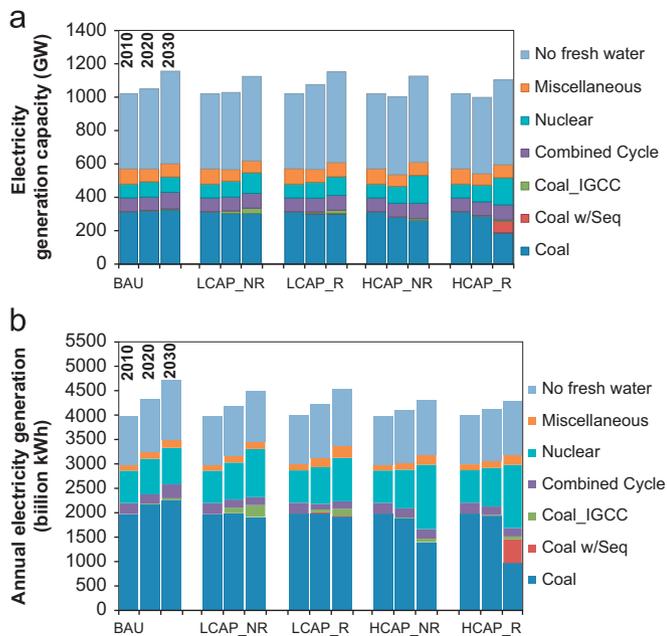
Fig. 2. Annual electricity projections under business-as-usual (BAU) and climate-policy scenarios: (a) electricity generation capacity (GW), (b) annual electricity generation (billion KWh). 'No freshwater' corresponds to either non-thermo-electric generation including renewable, or thermoelectric generation using saline water.

Fig. 3. National freshwater withdrawals and consumption under business-as-usual (BAU) and climate-policy scenarios. In all climate policy scenarios, freshwater withdrawals decrease as compared to the BAU scenario. Freshwater consumption may increase considerably under climate-policy scenarios if existing coal plants are retrofitted for CO_2 capture.

by shifts to new technologies. In 2030, for instance, CCS retrofits and IGCC plants, respectively, make up 1.2% and 6.9% of the coal generation in the LCAP_R scenario and 32.1% and 4% of the generation in HCAP_R. Due to a change in electricity-generation mix, greenhouse gas emissions in the LCAP scenarios decrease by 13% in 2030 from 2343 million metric tonne CO_2 equivalents in 2010. Similarly, for the HCAP_NR and HCAP_R scenarios, greenhouse gas emissions decrease by 35% and 49%, respectively, whereas emissions increase by 13% for the BAU scenario.

Electricity generation from nuclear plants increases for all scenarios out to 2030, with the increases being the greatest in the climate-policy scenarios due to the addition of new nuclear electricity generation, which is assumed to produce no CO_2 emissions. In the BAU scenario, nuclear generation rises 13% by 2030, whereas it increases 34–49% in the LCAP scenarios and 95–98% in the HCAP scenarios. Renewable electricity generation that uses freshwater cooling (i.e., solar thermal, biomass and MSW) also increases 63–128% in all scenarios, but remains less than 4% of total generation, with the greatest increase occurring in the LCAP_R scenario.

3.2. National changes in freshwater use by plant type

Our results indicate that a climate policy that prices carbon emissions would have a significant impact on future freshwater

use for electricity generation in the U.S. (Fig. 3). Under the BAU scenario, freshwater withdrawals are projected to decrease by 2% with respect to current levels despite a projected increase in electricity generation. In all of the CAP scenarios, withdrawals decline even more. By 2030, for instance, freshwater withdrawals are 2–14% lower in the CAP scenarios than in the BAU scenario.

Freshwater consumption, on the other hand, increases 24–42% in all scenarios between 2010 and 2030 (Fig. 3). Nonetheless, climate change policy still keeps freshwater consumption near projected BAU levels unless carbon prices reach those modeled in HCAP_R. The latter scenario drives consumption 14% above BAU due to the significant number of CCS retrofits that occur. LCAP_R is the only other climate policy scenario we considered that allows CCS retrofits, but in this case carbon prices are not sufficiently high to promote many retrofits beyond those incentivized by the bonus allowances in the former Waxman–Markey and Kerry–Boxer bills. Consequently, twenty times less capacity is retrofitted for CCS under LCAP_R than in HCAP_R.

In addition to changes in the mix of electricity generation and total generation, the change in water use is attributable to shifts in cooling systems from once-through to recirculating. These shifts are higher for the climate-policy scenarios, as power generation using recirculating cooling towers increases from 47% of electricity generation in 2010 to 51% (BAU), 55% (LCAP) or 59% (HCAP) by 2030 (Fig. S1, Appendix B). The shift in cooling systems from once-through to recirculating decreases freshwater withdrawal but increases freshwater consumption. Reduction in freshwater withdrawal and shifts from once-through to recirculating water use for climate policy scenarios reduces water withdrawals and would decrease thermal pollution and other negative impacts on aquatic ecosystems.

Our findings for freshwater cooling in power generation on a national scale differ from those in the NETL reports (2008a, 2009a). As pointed out previously, NETL (2009a) estimated that complete implementation of CCS and replacement of derated capacity due to CCS by any of three types of power plants, IGCC with CCS, pulverized coal with CCS, or nuclear, would raise withdrawals by 2–3% and consumption by 52–55%. Our results instead suggest that withdrawals will decline by 2% and that consumption increases will be only 15% even for the HCAP_R scenario in which water-dependent CCS retrofits become economical for many existing coal plants.

Comparing water use among plant types in the scenarios, nuclear and coal plants continue to be the two largest users of freshwater, as they are today. By 2030, freshwater withdrawals by nuclear plants rise 2% in BAU, 2–3% in LCAP, and 6–7% in HCAP (Fig. S2a, Appendix B). More significantly, freshwater consumption by these plants increases 24% in BAU, and jumps 60% in LCAP_R and 159% in HCAP_R (Fig. S2b, Appendix B).

The projections for coal are different. In BAU, freshwater withdrawals decrease by 2% in spite of increased generation capacity because of increased water-use efficiencies due to use of recirculating cooling towers in new coal plants. In contrast, freshwater consumption increases by 24%. In the CAP scenarios, freshwater withdrawals and consumption by coal plants are lower, in some cases substantially so. By 2030 in the LCAP_R scenario, coal plant withdrawals decrease by 4.5% while consumption decreases by 11.4%. Similarly in the HCAP_R scenario, coal plant withdrawals decrease by 3% but consumption actually increases by 8.2%.

Finally, freshwater withdrawals for renewable generation continue to be < 0.5% of total withdrawals in 2030. On the other hand, freshwater consumption for renewable power generation becomes more significant, rising to 4–7% of total freshwater consumption, with the maximum being under the LCAP_R scenario.

3.3. Regional changes in electricity generation and freshwater use

We next examine how simulated water use varies in response to climate-change policies for the North American Electric Reliability Corporation (NERC) regions. We limit our analysis to the LCAP_R and HCAP_R results relative to BAU since any climate-change policy will most likely allow existing power plants to retrofit for CCS.

At present, the regions that produce the most electricity using freshwater also have the greatest overall freshwater use (Fig. 4). These regions are located in the South and East of the United States, with the top two (in descending order) being SERC and ECAR. The Midwest MAIN region is third in generation and fourth in withdrawal. Regions with the lowest withdrawals are in the west (WECC/NWPP, WECC/RM and WECC/CA). Also, the Northwest (WECC/NWPP), California (WECC/CA), Great Plains (MAPP) and Florida (FRCC/FL) regions, and regions in northeast, New England (NPCC/NE) and New York (NPCC/NY), have the lowest freshwater consumption.
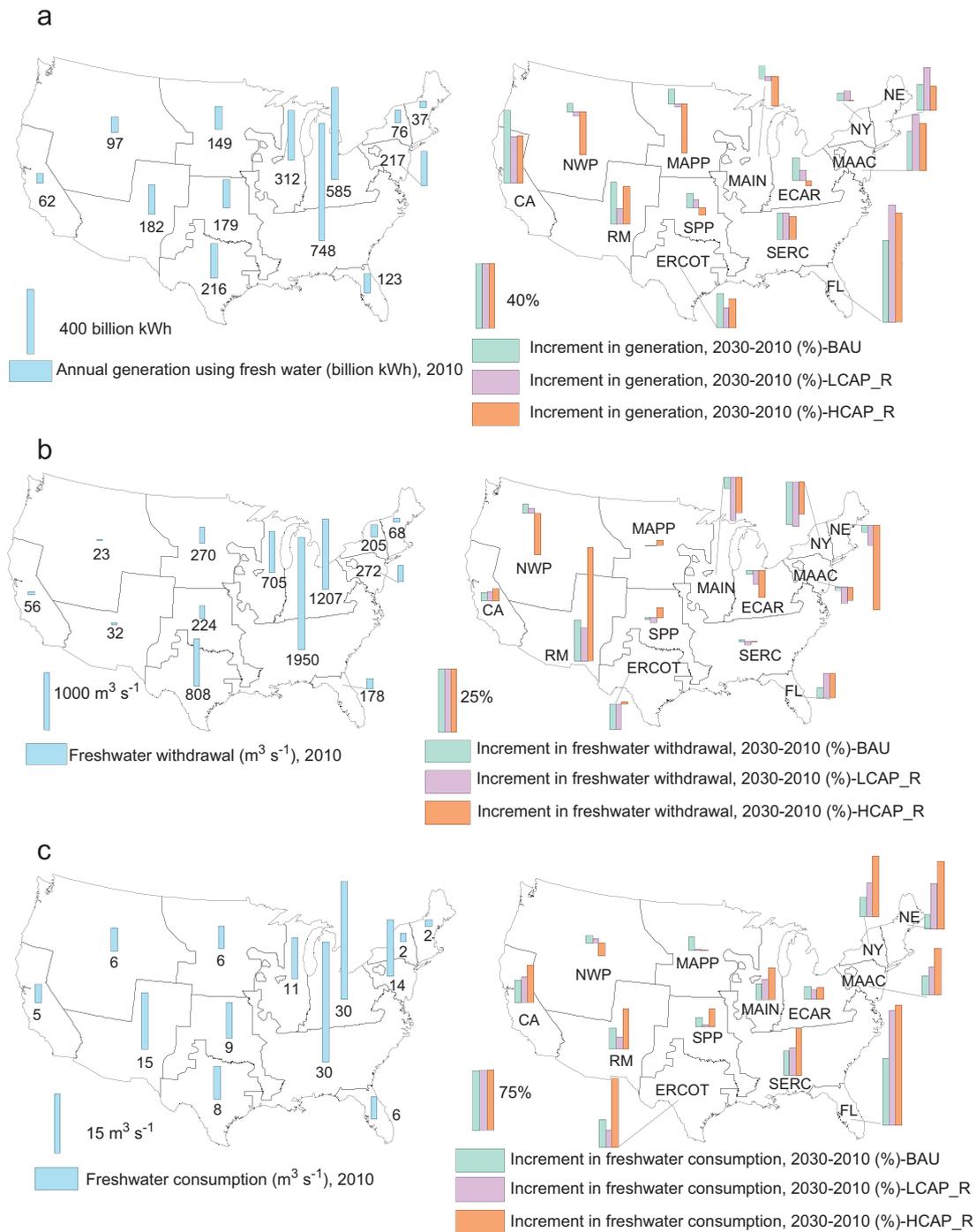
Under BAU, electricity generation using freshwater increases by 2030 in all regions (Fig. 4). The biggest projected jump in generation occurs in Florida (FRCC/FL) and in the western regions (WECC/CA and WECC/RM), but significant increases also occur in the Mid-Atlantic (MAAC), Texas (ERCOT) and New England (NPCC/NE). In terms of water use, New York (NPCC/NY) and Texas (ERCOT) are the only regions with a significant decrease in freshwater withdrawal, whereas WECC/RM has a significant increase in freshwater withdrawal by 2030. Freshwater consumption on the other hand increases in all regions not only because of the greater electricity generation to meet rising per-capita demand, but also because of the assumed shift to recirculating cooling systems in all new power plants.

The impacts of a climate-change policy relative to BAU will vary regionally across the U.S., reducing power generation in some regions while increasing it in others. Under the CAP scenarios, electricity generation using freshwater cooling tends to decline in the northwest and north central parts of the country and tends to increase in the southwest, southeast and northeast regions by 2030 compared to 2010. The greatest electricity generation declines are in the MAPP and WECC/NWPP (31% and 27%, respectively). The greatest increases in generation are in the Florida (FRCC/FL) and Mid-Atlantic (MAAC) regions (69–74% and 29–35%, respectively).

By 2030, the CAP scenarios lead to decreases in freshwater withdrawals of 5–10%, 14–17%, 12–17% and 8–33% in the ECAR, MAIN, NY and NRCC/NE regions, respectively. Conversely, the FRCC/FL and RM regions experience increased freshwater withdrawals by 2030 of 10% and 13–44%, respectively. For freshwater consumption, all but WECC/NWPP region (i.e., the Northwest) undergo increases. These are most pronounced in the South and East, with Florida (FRCC/FL), New England (NRCC/NE), New York (NRCC/NY), Texas (ERCOT) and the Mid-Atlantic (MAAC), respectively, experiencing rises of 136–142%, 53–81%, 40–72%, 20–83% and 33–56% by 2030 compared to 2010 levels. The significant rises in water consumption in the South and East result from combinations of factors: an increase in generation, change in generation mix and retrofit of coal plants with CCS. The effects are greatest under the HCAP_R scenario, which leads to a doubling or more of freshwater consumption relative to LCAP_R everywhere but in Florida (FRCC/FL).

4. Discussion

A major finding of our analysis is that the climate policy scenarios considered, including those that would follow the type of the carbon prices proposed in the former Waxman–Markey and Kerry–Boxer bills, lead to a reduction in freshwater withdrawals for power generation relative to BAU. Freshwater consumption on

Fig. 4. Regional electricity generation with freshwater cooling and freshwater usage in 2010 (left column) and their percentage change from 2010 to 2030 under business-as-usual (BAU), low-carbon allowance price with retrofits (LCAP_R) and high-carbon allowance price with retrofits (HCAP_R) scenarios (right column); (Row a) electricity generation; (Row b) freshwater withdrawal; (Row c) freshwater consumption. North American Electric Reliability Corporation (NERC) Regions Name and Abbreviations are: ECAR: East Central Area Reliability Coordination Agreement, ERCOT: Electric Reliability Council of Texas, MAAC: Mid-Atlantic Area Council, MAIN: Mid-America Interconnected Network, MAPP: Mid-Continent Area Power Pool, NPCC/NY: Northeast Power Coordinating Council/New York, NPCC/NE: Northeast Power Coordinating Council/New England, FRCC/FL: Florida Reliability Coordinating Council, SERC: Southeastern Electric Reliability Council, SPP: Southwest Power Pool, WECC/NWPP: Western Electricity Coordinating Council/Northwest Power Pool, WECC/RM: Western Electricity Coordinating Council/Rocky Mountains, AZ, NM, Southern NV, WECC/CA: Western Electricity Coordinating Council/California.

the other hand remains approximately equal to BAU unless carbon prices reach those modeled in HCAP_R and trigger CCS retrofits of a number of existing coal plants. These modeled trends in water withdrawal and consumption by 2030 are primarily caused by a change in the mix of power plant types and by the assumption that all new thermoelectric power plants will use recirculating cooling systems. We believe the latter assumption is well founded, as it adheres to Phase I of the EPA Clean Water Act 316(b), which

mandates that all new power plants use the best available technology for cooling to mitigate adverse environmental impacts (U.S. Environment Protection Agency, 2009c). The assumption is also in line with the National Energy Technology Laboratory (2008a) assessment that most new plants would use recirculating cooling systems.

Although all of our scenarios project new nuclear power plants, the construction of such plants would require not only a

supportive energy policy, but societal acceptance of the technology and favorable financing for building the plants. The latter criteria are currently uncertain given the radiation releases from Fukushima Diachi nuclear power plant after it was severely damaged by a large earthquake and subsequent tsunami along the northeast coast of Japan on March 11, 2011. Furthermore, the recent exploitation of shale gas suggests that in fact it may be natural gas that plays a larger role in future power generation. To assess this possibility, we analyzed the impact on water use if all new nuclear power plants were replaced by natural gas combined cycle plants in our scenarios (Fig. S3, Appendix B). The results show that under these circumstances, freshwater withdrawal in 2030 decreases by less than 2%, and freshwater consumption decreases by 3–19% with a maximum decrease in the HCAP_R scenario.

Future water use could also be reduced by incentivizing renewable power generation that does not require cooling water, such as wind and solar photovoltaic (PV) farms. If electricity generated from wind and solar PV is increased to 20% of the total generation in 2030 as compared to 4–7% in our scenario, and if the increased wind and solar PV facilities replace conventional coal plants, then freshwater withdrawal and consumption would decrease by 18–23% and 14–21%, respectively (Fig. S3, Appendix B). Note that these results are similar to those reported by U.S. Department of Energy (2008b) in its report on the possibility of 20% market penetration by wind energy in 2030.

As pointed out earlier, NETL (National Energy Technology Laboratory, 2009a) estimates an increase in water withdrawals and consumption if all existing coal plants are retrofitted with CCS and if the derated capacity of these plants is compensated for by new IGCC with CCS, pulverized coal with CCS or nuclear plants. However, our results suggest withdrawals will instead decline and that consumption increases will be significantly less than the NETL estimate. One reason for this difference is that under climate change policies, utilities pass the cost of carbon emissions on to the consumer in the form of higher electricity prices, and these higher prices dampen demand for power and thus the demand for fresh water to cool power plants. Secondly, even under our highest-price CO_2 allowance scenario (HCAP), not all coal plants retrofit for CCS. As a result, the demand for fresh water for both the CCS systems and the new plants needed to make up for the capacity lost in powering these systems is not as great as that required to fully implement CCS as considered by NETL. Our analysis also allows for a broader range of plant types to be used to offset lost capacity, and this change in generation mix helps to further mitigate the demand for freshwater cooling. Again, the only new generations considered in the NETL analysis are nuclear, pulverized coal, and IGCC plants. The NI-NEMS runs that we base our analysis on replace lost capacity with all forms of generation that are economically feasible and that satisfy modeled federal legislation and regulations, including renewable energy power plants.

While climate policy should have a generally positive impact on freshwater withdrawal in power generation, we also project that on regional level, Florida, New York, Texas and New England will increase freshwater consumption > 30% above BAU by 2030 if carbon prices become high enough to spur significant CCS retrofits in these regions. Smaller but still significant increases in water use are projected to occur elsewhere in the country. These projections, however, assume no limit to water availability, which in fact could restrict the locations and extent to which CCS might be implemented nationally. Multi-year and in some cases severe droughts have affected the U.S. South and West, where water supplies are already limited. Such droughts have the potential to further stress water use for power generation, particularly if this water use is increased not only by new power plants needed to

meet rising demand for electricity but also by CCS retrofits to existing plants.

These stresses could be reduced if the EPA's proposed 316(b) Phase II regulation (U.S. Environment Protection Agency, 2009d) are enacted. This regulation extends the use of best available cooling systems for minimizing adverse environmental impacts to existing power plants, potentially forcing the operators of plants with once-through cooling systems to replace them with recirculating cooling systems. Were such a turnover in cooling systems carried out on the current fleet of power plants, freshwater withdrawals would decrease five-six fold, whereas freshwater consumption would only increase 31–41% in 2030 (Fig. S3, Appendix B). And though recirculating cooling systems are more energy intensive than once-through cooling systems, the resulting energy penalty would be 0.8–1.5% (U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability, 2008). The biggest hurdle to swapping out existing once-through cooling systems for recirculating systems is likely to be additional cost, which if high enough could make a number of plants uneconomical to operate.

There remain however other, more flexible, ways that CCS could still be deployed in regions prone to water scarcity. For example, the potential impact of retrofits could be reduced if current amine-based systems are replaced by new post-combustion capture technologies that use less water. And if new coal plants with CO_2 capture are to be built, more energy and water efficient IGCC plants with pre-combustion capture capabilities can be used in place of PC plants. Dry and hybrid air cooling systems (Feeley et al., 2008) are another future possibility for decreasing water use in power generation, though these could end up being more costly than existing wet cooling systems, and may not be suitable in warm regions where high ambient temperatures could render the systems significantly less efficient than recirculating-water cooling. A final option is to use saline water and/or treated wastewater from municipal and industrial sources, though cleaning the water enough to avoid scaling, corrosion and damage by biological organism to the cooling equipment could increase the cost (United States Government Accountability Office, 2009). This additional cost could end up being a limiting factor for the use of saline water and treated wastewater.

Overall, our analysis suggests that climate policies and a carbon price should reduce electricity generation and freshwater withdrawals for several decades compared to the business-as-usual scenario. Population growth and higher demand increases electricity generation from freshwater-cooled coal plants by 16.4% from 2010 to 2030 in our business-as-usual scenario, with decreases under high carbon price climate-policy scenarios. In general, freshwater withdrawals decrease and consumption remains relatively unchanged compared to the BAU scenario. The only exception to this result is the possibility of extensive CCS retrofits that arises with relatively high carbon prices of > $50/tonne; in that case numerous coal plants retrofit to capture CO_2, thereby increasing freshwater consumption 15% over BAU nationally, and by more than 30% in Florida, New York, Texas and New England. Such significant jumps in water consumption raise the possibility that regional water scarcity could limit where and to what degree carbon capture and storage (CCS) might be deployed.

Appendix A. Supplementary materials

Supplementary data associated with this article can be found in the online version at doi:10.1016/j.enpol.2011.07.022.

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