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The water consequences of a transitioning US power sector

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HIGHLIGHTS

- Shifts in cooling water use due to recent US power sector transitions are studied.
- New natural gas combined cycle units have significantly reduced water withdrawals.
- Increases in dry cooling and reclaimed water have reduced freshwater use for cooling.
- Troubling trends include increases in groundwater for power plant cooling.
- Changes in cooling water usage vary significantly across watersheds.

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ABSTRACT

The US power sector is in a state of transition, prompted by significant shifts in technological innovations, energy markets, regulatory structures, and social pressures. As the electricity generation fleet changes, so too does the spatial & temporal distribution of the cooling water requirements for power plants. However, to date, these impacts have yet to be quantified. This study uses power plant-specific fuel consumption, generation, and cooling water use data to assess changes in the water withdrawn and consumed by thermoelectric power plants across 8-digit Hydrologic Unit Code (HUC-8) watersheds between 2008 and 2014. During this period, a few prominent trends are noted, including transitions in generation from coal-fired steam to natural-gas combined cycle units, from once-through cooling to wet recirculating towers and dry cooling systems, and from traditional fresh and saline surface cooling water to reclaimed water and groundwater sources. Total US cooling water withdrawals and consumption volume decreased from 2008 to 2014. The average water withdrawn per unit of electrical output decreased over this time, while changes in water consumption rates stayed relatively flat. Changes in water use at the watershed scale were unevenly distributed, as some water-scarce regions experienced increases in cooling water usage for thermal power plants, while others experienced significant water reductions and environmental benefits, especially where coal-fired generation was retired or retrofitted. The results from this study underscore the importance of evaluating water withdrawals and consumption at local spatial scales, as the water extraction, water quality and environmental health consequences of power plants on downstream users are non-uniform.

1. Introduction

Recent shifts in resource availability, economics, environmental policy and public opinion have prompted large transitions in the US electricity generation fuel mix [1,2]. Between 2005 and 2015, domestic natural gas production increased by almost 40% largely due to advances in horizontal drilling and hydraulic fracturing techniques used for US shale gas extraction, putting downward pressure on natural gas fuel costs and prompting large investments in natural gas-fired generation units [3]. This growth in natural gas-fired generation, as well as renewable electricity in recent years, has reduced the competitiveness of coal-fired and nuclear power plants in many US regions.

These technological and market transformations across the power sector have translated into environmental consequences that have yet to be quantified. Although a growing body of literature has addressed the emissions ramifications of increasing natural gas-fired and decreasing coal-fired generation [4,2,5,6], much less analysis in the literature has been dedicated to assessing how recent fuel transitions in the power sector have affected US water availability or water quality at the national level.

Recent studies have analyzed the cooling water tradeoffs that follow more general shifts in fuel use [7–9], pollution controls [10–14],

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cooling system technologies [15–18], environmental fees [19], and generator dispatch order [20–22]. Grubert et al. (2012) completed a detailed comparison of the water intensity of natural gas and coal extraction, cooling for electricity production, and emissions controls at fossil-fueled power plants in Texas using the peer-reviewed literature and government data. The researchers note that the efficiency benefits of switching coal-fired power plants to natural gas combined cycle offer the potential for a 60% reduction in annual freshwater consumption, even given the water-intensity of hydraulic fracturing for the natural gas fuel [7]. Stillwell et al. (2011) assessed the reduction in water diversions for thermal power plant cooling in Texas from switching traditional once-through cooling systems to alternatives such as recirculating towers or dry cooling using a water availability model from the Texas Commission on Environmental Quality. The authors noted potential reductions in annual diversions up to 700 million m^3 from switching from coal-fired to natural gas-fired combined cycle power plants, which could contribute to increased stream flow and reduced water stress along the Texas Gulf in particular [15]. Another study by Tidwell et al. (2014) assessed the transition of the whole US thermoelectric fleet to alternative cooling water sources (dry cooling or wet cooling using reclaimed water) to achieve zero freshwater withdrawals using a custom algorithm incorporating cost models, geographic proximity to water resources, and resource availability. The results suggest that retrofits could be beneficial in the East by reducing plant vulnerabilities to thermal discharge limits and in the West by reducing freshwater consumption during times of drought or reduced water availability [18]. Similarly, a case study by Stillwell and Webber (2014) investigated the potential of utilizing reclaimed water as a cooling source for thermoelectric power plant cooling in Texas using a geospatial multi-criteria analysis. They found that over 60% of thermoelectric capacity in the state is located within 25 miles of a reclaimed water source and could be feasibly retrofitted to help alleviate water availability concerns [23].

A recent body of work has also evaluated the long-term water use impacts of various electricity futures. In 2008, the Department of Energy (DOE) completed a report estimating the volumes of freshwater required to meet future electricity demand based on five scenarios defined in the US Energy Information Administration's (EIA) 2008 Annual Energy Outlook forecast. With the exception of the business-as-usual scenario (i.e. no changes), all case studies showed decreases in water withdrawals and increases in water consumption for thermoelectric cooling, largely due to transitions away from once-through cooling and towards recirculating cooling [24]. Clemmer et al. (2013) modeled low-carbon electricity futures through 2050 using the Regional Energy Deployment System (ReEDS) model developed by the National Renewable Energy Laboratory (NREL) to calculate changes in national and regional cooling water use, finding that investments in energy efficiency and renewable energy technologies resulted in considerable water savings over other technology-based investments, such as carbon capture and sequestration [25]. Another study modeled changes in cooling water usage using a GAMS optimization model to estimate water withdrawals and consumption at thermoelectric, non-thermoelectric, and dry-cooled facilities based on energy portfolio scenarios developed by NREL for high renewables penetration and a scenario retrofitting all existing wet cooling systems to recirculating cooled systems through 2050. The study found that significant water withdrawal and consumption reductions are achieved under the high renewable energy scenario, while only water withdrawal reductions are achieved in the second scenario but at the expense of increased water consumption [26]. In another study that evaluates changes in the electricity fleet through 2095 using an integrated assessment model (GCAM) to investigate the electric sector's global water demand, water withdrawals remained relatively constant over the five scenarios examined (i.e. three climate change futures and two strategic technology improvement scenarios), mainly due to the retirement of once-through cooling systems [27]. The water use implications of a global 2 °C warming policy (by end of century) were analyzed by Fricko et al. (2016) using a global integrated assessment model. The authors found that noticeable reductions in water withdrawals are achieved if large transitions toward recirculating cooling systems occur, but water consumption increased for all electricity futures analyzed [28]. On a smaller spatial scale, the influence of 2 °C of warming, prolonged drought, and population growth on water use until mid-century in the southwestern US showed a continued or increased reliance on fossil fuels in the business as usual and Annual Energy Outlook scenarios, leading to greater water stress. Conversely, carbon policy, renewable energy integration, and increased energy efficiency led to decreased water stress and carbon emissions [29].

Despite the large changes that have occurred to the US generation fleet recently, no study to the authors' knowledge has evaluated the cooling water tradeoffs resulting from these transitions at the national scale. This research fills this knowledge gap by evaluating how recent shifts in thermoelectric power generation affected the spatial and volumetric distribution of US cooling water withdrawals and consumption between 2008 and 2014.

2. Methodology

Self-reported data by power plant operators from EIA forms 923 [30,31] and 860 [32,33] were used to characterize US power plants and their respective generation units in the years 2008 and 2014. Power plant operators are required to complete these forms for all plants of 1 MW capacity or greater that are connected to a regional power grid [34].

EIA Form 860 details power plant locations (i.e. latitude and longitude), as well as power plant cooling system information including cooling system ID number and cooling water source type (i.e. surface water, groundwater, plant discharge water, etc.). In some cases, cooling water source type data were missing, but information was available on the physical source (i.e. wells, rivers, ocean, etc.), which enabled an adequate estimation of cooling water source type for many of these plants. Information on cooling water quality (i.e. freshwater, reclaimed water, saline water, etc.) was only available for 2014 power plants. Although all power plant operators are required to report generation, fuel use, and boiler information for generating units with capacity 1 MW or greater, they are not explicitly required to report volumetric water usage via the EIA 860 form unless they have a capacity of 100 MW or greater. While annual cooling water usage data in 2014 were relatively abundant, these data for 2008 are considerably less complete [32,33,30,31]. In addition, there is no streamlined methodology imposed upon power plant operators for data collection to ensure consistent reporting of water use. Consequently, many facilities use different methodologies for measuring water withdrawals, consumption, diversions, and discharge [35].

EIA Form 923 details electricity generation unit technology, fuel type, combined heat and power (CHP) status, and annual generation for operational units at each US power plant. When applicable, this form was also used to cross-check and identify missing cooling system and water source data from the EIA 860 form. Each unit operating at a thermoelectric power plant requiring a cooling system was categorized by fuel type, generation technology, CHP status, cooling technology, and cooling water source type. Full details of this categorization procedure are documented in Peer and Sanders (2016) [36].

Plant-specific cooling water consumption and withdrawal factors (i.e. rates in gallons/MWh) calculated by Peer and Sanders [36] using EIA's 2014 water usage data were applied to power plants based on generator technology (i.e. fuel type, prime mover type, and cooling system type) when all units within the plant reported a single fuel, prime mover, and cooling system. These water use factors were applied consistently to power plants that were operating in both 2008 and 2014 and/or only in 2014 (i.e. new power plants). The Union of Concerned Scientists' (UCS) vetted database of 2008 water use at thermal power plants were used to calculate total water withdrawal and consumption volumes for power plants that were operating 2008 but had no reported 2014 generation or water use (i.e. units that were retired before 2014) [37].

There were cases when assumptions and approximations had to be made due to data issues in the EIA databases. These typically resulted when power plants were missing cooling-related data or reported multiple fuels, prime movers or cooling systems. (Collectively, the excluded power plants from this analysis represent approximately 10% of thermoelectric generation requiring cooling for both 2008 and 2014). The following rules were followed when possible to fill in data gaps.

- Power plants less than 100 MW (less than 0.3% of annual 2014 generation) in capacity were not assigned a water use rate.
- For power plants that reported a single fuel and prime mover, but did not specify the type of recirculating tower (i.e. natural draft, forced draft, induced draft) or cooling pond (i.e. once through or recirculating), average water use rates calculated by Peer and Sanders (2016) for all recirculating cooling tower or cooling pond types were applied.
- Power plants that did not report a cooling system in 2014, but were operating in 2008 were assumed to have maintained the same cooling system throughout the time period.
- Power plants that reported using a dry-cooling system were assigned consumptive and withdrawal water use rates equal to 10% of a recirculating tower cooled plant's consumptive water use rate for its respective fuel and prime mover category based on the literature, as power plant operators were inconsistent in reporting water use for these facilities.
- Water use rates from the literature were applied to geothermal and concentrating solar power (CSP) for both 2008 and 2014 based on [38], as these generators were not consistent in reporting.
- For power plants that reported a single prime mover and single cooling system, but reported multiple fuels, median water use rates consistent with their main fuel source (i.e. coal or natural gas) were applied.
- Custom water use rates were calculated with reported EIA data for water-cooled power plants with multiple cooling systems that had only one fuel and one prime mover type. The custom calculated water use rates for 2014 were applied to power plants reporting multiple cooling systems for both 2008 and 2014 and/or only in 2014. For power plants reporting multiple cooling systems only in 2008, custom calculated rates based on 2008 data were applied. Power plants with multiple cooling systems that omitted water use data or reported a withdrawal or consumption volume of zero were unable to be classified and were excluded from this analysis.
- Power plants that reported multiple cooling systems and fuels, multiple fuels and prime movers, multiple prime movers and cooling systems, or multiple fuels, prime movers, and cooling systems that could not be otherwise classified (via a custom rate if water use was reported or a water use rate from the literature) were excluded.

The EIA did not require reporting water use for nuclear facilities in 2008. Given the large water implications of these generators, they were handled carefully on a case by case basis. For nuclear power plants reporting multiple cooling systems in 2008, the median water use rate consistent with the reported 2014 cooling system from Peer and Sanders (2016) was applied. Custom water use rates based on plant-specific EIA reported water use data were calculated for nuclear power plants that reported multiple cooling systems in 2014, to reduce error, as nuclear power plants were often the most significant cooling water users across an individual watershed. A geographic inspection to confirm cooling system type with Google Earth was performed for new power plants added to the grid with capacity greater than 100 MW that did not report a cooling system.

The geographic analysis of water use for thermoelectric power plants was performed using 8-digit Hydrologic Unit Code (HUC-8) watershed areas. Each thermoelectric power plant was linked to its respective HUC-8 code based on its geographic location (i.e. latitude, longitude) provided in EIA form 860. Changes to net generation, capacity, and water withdrawal and consumption between 2008 and 2014 were evaluated for each basin containing at least one thermoelectric power plant requiring cooling.

The equations used to calculate changes in generation, installed capacity, water withdrawal, and water consumption are defined in Eqs. (1)–(4). X represents annual generation, nameplate capacity, water withdrawal, or water consumption, depending on the metric of interest. y represents the 18 categories for fuels, cooling systems, and cooling water with which the data were classified (5 fuel, 7 cooling system, and 6 cooling water categories). $\Delta X_{net,y}$ is defined as "net change between 2008 and 2014 for category y", meaning any changes to X regardless of whether the change is a result of (1) a new power plant, (2) a power plant that was retired, or (3) changes in total annual generation at an existing power plant in the year 2008 as compared to 2014. On the other hand, $\Delta X_{pp,y}$, only accounts for changes in X that result because of a newly installed power plant, added at any time from the beginning of 2009 to the end of 2014, or the loss of generation from a power plant that retired any time during 2008 up to the end of 2013. ($\Delta X_{pp,y}$ would not include individual units that are added or retired at power plants with other units operational in both 2008 and 2014.) $\Delta X_{net,y}$ and $\Delta X_{pp,y}$ only include changes to all thermoelectric units requiring cooling. Eqs. (1) and (2) were used to calculate values in Table 1 and Eqs. (3) and (4) were used to calculate watershed specific results, where the subscript *ws* refers to a HUC-8 watershed.

$$\Delta X_{net,y} = \Sigma_{i=1}^{n} X_{2014,y} - \Sigma_{i=1}^{n} X_{2008,y} \tag{1}$$

$$\Delta X_{pp,y} = \Sigma_{i=1}^{n} X_{add2009-2014,y} - \Sigma_{i=1}^{n} X_{ret2008-2013,y} \tag{2}$$

$$\Delta X_{net,ws,y} = \Sigma_{i=1}^{n} \Delta X_{net,y} \tag{3}$$

$$\Delta X_{pp,ws,y} = \Sigma_{i=1}^{n} \Delta X_{pp,y} \tag{4}$$

A water stress metric developed by the Aqueduct Water Risk Atlas [39], describing overall global water risk was used to give further context to the impacts of a transitioning electricity sector on water resources in the US. The metric reports an aggregated risk value (i.e. low risk, low to medium risk, medium to high risk, high risk, and extremely high risk) based on twelve water-stress categories included in physical water quantity (baseline water stress, inter-annual variability, seasonal variability, flood occurrence, drought severity, upstream storage, and groundwater stress), physical water quality risk (return flow ratio, and upstream protected land), and regulatory & reputational risk (media coverage, access to water, and threatened species). This metric has also been applied in recent energy-water studies [40].

3. Results

A summary of net changes in the US power sector for generation, capacity, water withdrawal volume, and water consumption volume across all US thermoelectric power plants requiring cooling systems (i.e. including steam cycle and gas cycle units, but excluding pure gas turbine units) is shown in Table 1, separated by fuel type, cooling system technology, and cooling water type. The "Net Changes from 2008–2014" columns, calculated with Eq. (1), reflect (1) fully retired or newly installed power plants, (2) added, retired, or retrofitted generation units at existing power plants, and (3) changes incurred by differences in generation across the two years of study. The "Changes from new or retired power plants" columns, by contrast, are calculated with Eq. (2) and only reflect changes in (1) and are detailed in Fig. 3 below. It should be noted that generation and capacity data in Table 1 is representative of all US thermoelectric power plants requiring cooling systems, regardless of whether or not they reported data to the EIA.

Table 1
Net changes across the US Power Sector between 2008 and 2014 were characterized for 1836 thermoelectric power plants requiring cooling systems in the US, as well as the subset of changes resulting exclusively from the installation and retirement of 164 and 153 unique thermoelectric power plants requiring cooling systems that were newly installed and retired, respectively.

		Net changes from 2008 to 2014				Net changes across power plants installed and retired from 2008 to 2014			
		Generation (TWh)	Capacity (GW)	Withdrawn water (Billion gallons)	Consumed water (Billion gallons)	Generation (TWh)	Capacity (GW)	Withdrawn water (Billion gallons)	Consumed water (Billion gallons)
Fuel type	Coal	−368	−6.19	−7110	−151	−0.820	−4.20	−86.5	−9.48
	Natural gas	653	75.5	1750	108	91.8	15.6	−163	13.2
	Nuclear	10.4	−0.182	1160	−5.21	−12.1	−2.81	−536	−3.25
	CSP	1.66	0.662	0.625	0.625	1.00	0.650	0.026	0.026
	Other	−110	−41.2	−2182	−2.29	−7.47	−4.92	−386	−1.19
Cooling system type	Once-through	71.5	58.5	636	32.6	−45.4	−17.9	−1730	−8.98
	Recirculating tower	415	79.2	23.5	63.1	67.0	14.0	−20.3	10.2
	Cooling ponds	24.6	17.2	−569	−4.35	17.7	0.115	574	−2.50
	Hybrid cooling	15.9	3.39	5.23	4.24	2.73	0.654	0.886	0.544
	Dry cooling	60.8	8.69	0.183	0.145	30.4	7.38	0.116	0.104
	Complex	−398	−135	−6470	−146	–	–	–	–
	Not Reported	−2.73	−3.04	–	–	–	–	–	–
Cooling water type	Surface water[a]	117	62.6	−126	−32.2	22.1	−4.52	−426	−6.20
	Ocean water	−190	−61.3	−7090	−48.8	−13.1	−6.76	−695	−3.00
	Groundwater	88.3	7.91	−11.3	10.2	8.15	2.06	−25.9	0.721
	Reclaimed water	58.2	−16.3	−180	5.35	46.2	11.0	−23.6	7.74
	Dry cooling	39.8	11.3	0.051	0.053	8.54	2.05	0.031	0.031
	Multiple types	73.6	24.5	1030	15.0	0.433	0.350	−0.021	−0.003
	Totals[b]	187	28.6	−6380	−50.4	72.4	4.31	−1170	−0.692

[a] Surface water does not include ocean water.
[b] Totals for thermoelectric power plants with cooling systems only.

However, the cooling water withdrawal and consumption estimates in Table 1 are only representative of cooling water used at power plants included in the analysis.

Net electricity generation from thermoelectric power plants requiring cooling systems grew by 187 TWh between 2008 and 2014 (5.90% increase from 2008 thermoelectric generation requiring cooling). Generation from new net capacity installations (including units added at existing facilities as well as new facilities) surpassed losses in generation and capacity from retired units during this time, which is expected as newer power plants are generally more efficient than older units, and therefore, are often running more frequently. Net generation from natural gas combined cycle facilities increased approximately 720 TWh from 2008 to 2014 across the US, while capacity additions were 107 GW, prompting decreased use of coal-fired generators. (The increase across the entire natural gas category shown in Table 1 is tempered by retirements of natural gas steam cycle generators.) Nuclear retirements occurred, but net generation increased (due to higher capacity factors for operating facilities) during this period. Net negative generation in the “Other” category reflects the decreased use of oil-, bio-, and multi-fueled (i.e. combination of coal, natural gas, various types of oil, jet fuel, etc.) units.

Net changes in US electricity generation and power generation capacity between 2008 and 2014 were calculated with Eq. (1) and are shown in Fig. 1A and B, respectively. The subset of changes to US electricity generation and power generation capacity resulting from new or retired power plants during this period (i.e. Eq. (2)) are illustrated directly below, in Fig. 1C and D, respectively.

The largest capacity retirements for thermoelectric generation requiring cooling were in Texas, California, Pennsylvania, Florida and Arizona, which retired 6.7, 6.1, 5.0, 3.7 and 3.1 GW of capacity, respectively, between 2008 and 2014 [32,33]. Collectively, these retirements represented 49% of US retirements during this period and were comprised of coal, natural gas, and nuclear steam-fired retirements, primarily. The largest capacity additions were in Texas, California, Florida, North Carolina and Louisiana, which added 12.8, 9.8, 5.9, 4.0, and 3.9 GW, respectively, between 2008 and 2014 [32,33]. In total, these states installed about 46% of new thermoelectric generation capacity requiring cooling between 2008 and 2014. Coal and natural gas steam-fired as well as natural gas combined cycle units represented the majority of additions.

Our results indicate that the total water withdrawn and consumed for power generation decreased between 2008 and 2014. The relative water withdrawal intensity of the grid in 2008 was approximately 20,000 gallons per MWh versus approximately 16,000 gallons per MWh in 2014. The relative water consumption intensity of the grid in 2008 was approximately 400 gallons per MWh versus approximately 345 gallons per MWh in 2014. Water use intensities only reflect power plants reporting both generation and water use (or power plants that could be assigned a water use rate if no water use was reported) to reduce error in intensity values. In total, water data from units representing 337 TWh of generation in 2008 and 360 TWh of generation in 2014 were excluded from the analysis (typically from very small generators), which is assumed to have a small impact on these results.

Retired power plants were generally fueled by coal, nuclear and natural gas-steam boiler units cooled using once-through cooling systems, while added power plants were mostly natural gas combined cycle cooled with recirculating towers. New natural gas combined cycle power plants withdrew approximately 10 times less water per unit of electricity generated on average compared to retired steam-fired power plants. However, most newly installed natural gas combined cycle power plants use recirculating tower cooling systems and the water consumption per unit of electricity generated is comparable to average steam-fired, once-through cooled power plants that were retired during this period. Volumetric cooling water withdrawals and consumption decreased in every major fuel category, when only net changes across new and retired power plants were considered, except for the water consumed by natural gas generators. When all changes in net generation were considered, total net water consumption also rose for natural gas generators and despite retirements of large once-through cooled facilities, total net water withdrawals rose for nuclear generators,

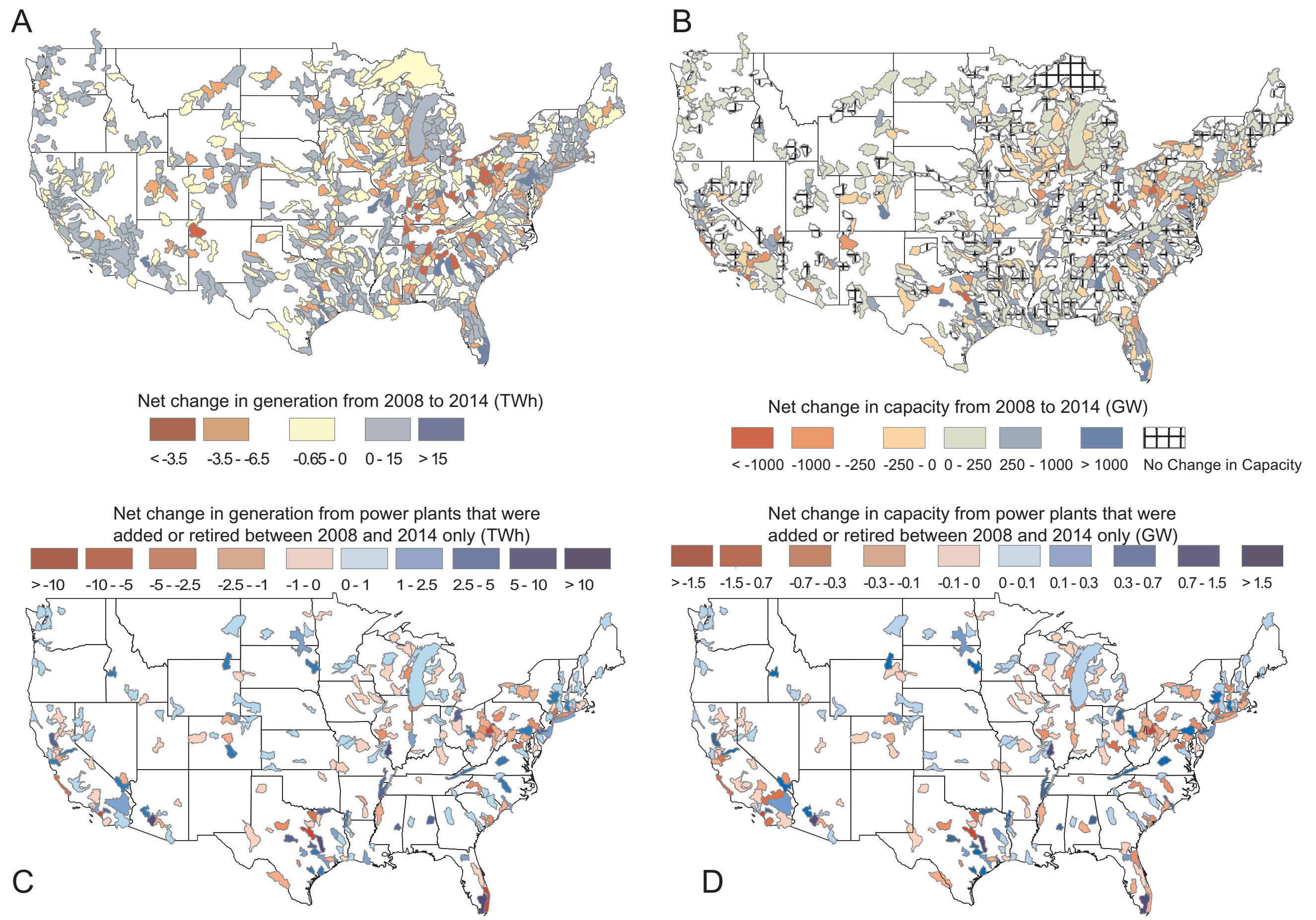

Fig. 1. Left: (A) Net changes in US thermoelectric generation requiring cooling and (C) the subset of these changes to US electricity generation resulting exclusively from new or retired power plants between 2008 and 2014. Right: (B) Net changes in US power generation capacity and (C) the subset of these changes to US power generation capacity resulting exclusively from new or retired power plants between 2008 and 2014. These maps only include units that are greater than 1 MW.

further reflecting the transition toward recirculating cooled natural gas generation as well as increases in demand for electricity.

Net changes in the volume of water withdrawn and consumed for thermoelectric power plant cooling are illustrated in the left-hand (A, C) and right-hand (B, D) sides of Fig. 2, respectively. The net changes in water withdrawals are much larger than net changes in water consumption, given that water consumption is a subset of water withdrawals, and water withdrawal rates (i.e. cooling water withdrawn per MWh) can span several orders of magnitude depending on cooling technology. It is important to note that the volumetric changes in water withdrawals and water consumption occurring across HUC-8 subbasins reflect a combination of factors such as the spatio-temporal distribution, technological composition, and operational characteristics of the generation fleet, as well as spatio-temporal changes in the magnitude of electricity demand, in addition to any added and retired power plants. This is evidenced in the differences between Fig. 2A and B compared to Fig. 2C and D.

Net generation for facilities using dry cooling increased approximately 60 TWh with capacity additions of almost 9 GW over this time period. It should be noted that Table 1 shows changes in water use across each respective category. Thus, although the increased generation and capacity from facilities reporting dry cooling resulted in increased water withdrawals and water consumption across its own category, the impact of retrofitting cooling systems to dry cooling across the power sector decreases the net water intensity of the fleet, as it requires approximately 10% of the water required per unit of electricity of an average recirculating cooled power plant. Net generation cooled using reclaimed water increased 58 TWh from 2008 to 2014, while capacity was reduced by just over 16 GW.

Fig. 3 illustrates changes in generation, calculated with Eq. (2) from added (i.e. positive values of generation) or retired (i.e. negative values of generation) power plants between 2008 and 2014 are quantified for each US HUC-8 subbasin. Results are ordered from West to East based on subbasin location. The shaded blue and white regions distinguish the larger HUC-2 regions (containing many HUC-8 subbasins), which correspond to the numbered HUC-2 regions labeled on the US map of Fig. 3. The first three rows detail identical generation data, but categorize these data in terms of the fuels (row 1), cooling systems (row 2), and cooling water sources (row 3) utilized by each added or retired power plant(s) in the subbasin. Corresponding cooling water consumed and withdrawn for these added/retired power plants are illustrated in the fourth and fifth rows of Fig. 3, respectively.

The spatial location and generation of newly installed and retired natural gas-fired and coal-fired power plants during the period of study are illustrated in the bottom map of Fig. 3. New natural gas-fired combined-cycle power plants dominated installations in western and eastern regions of the US, while a handful of new coal-fired steam cycle power plants were added in the central US. Generally, new natural gas combined cycle power plants were larger in number but smaller in capacity, compared to new coal-fired power plants.

Fig. 3 does not include new generation units installed at existing power plants or changes in generation from existing power plants from increased demand (these net shifts are summarized in Table 1). A much clearer shift from coal-fired to natural-gas fired generation is seen when changes in net generation are considered. During the study period, low natural gas prices in combination with higher efficiency combined-

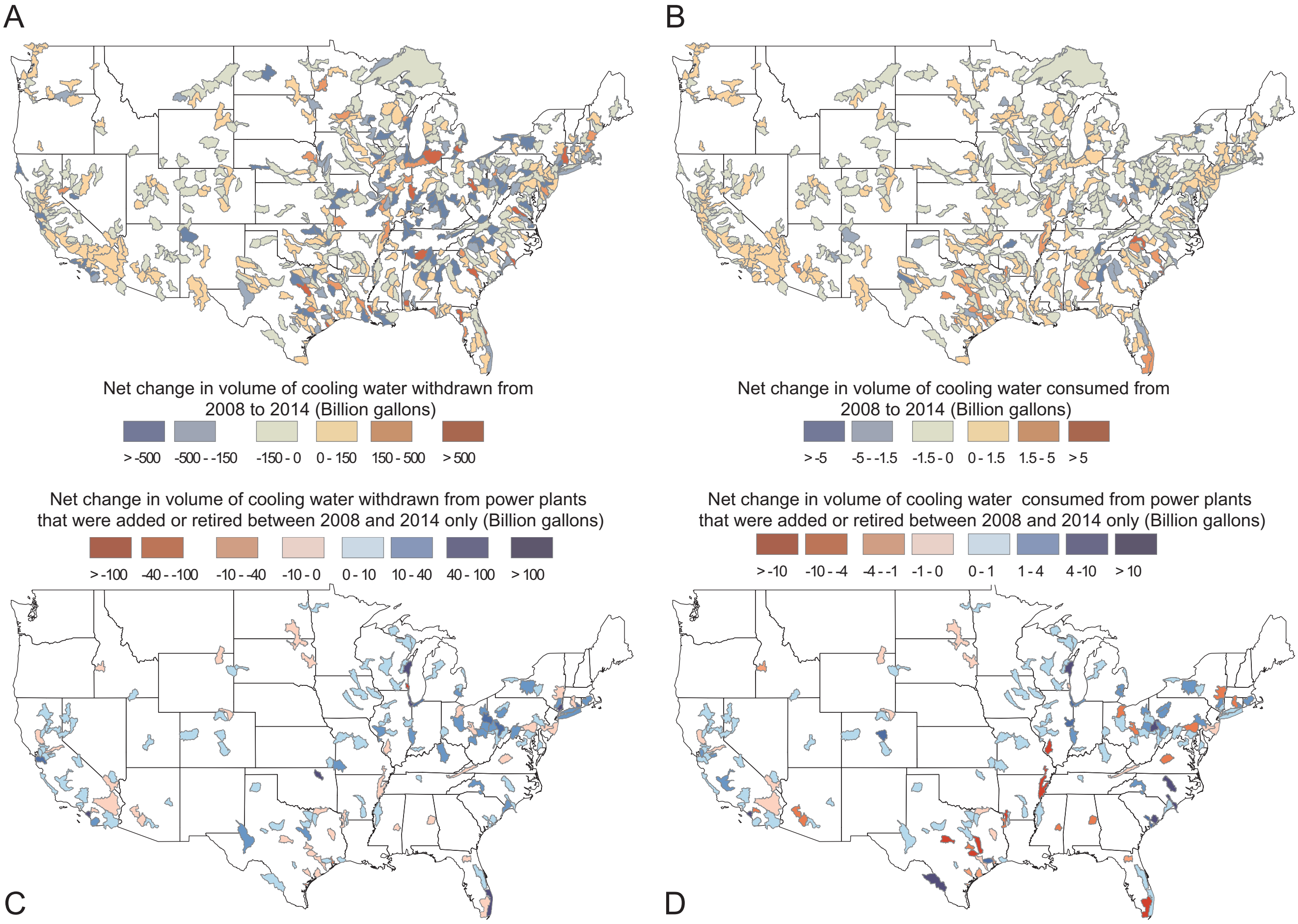

Fig. 2. Left: (A) Net changes in US cooling water withdrawals and (C) the subset of these changes in withdrawals resulting exclusively from new or retired power plants between 2008 and 2014. Right: (B) Net changes in US cooling water consumption and (B) the subset of these changes to US cooling water consumption resulting exclusively from new or retired power plants between 2008 and 2014. Includes thermoelectric power generation units requiring cooling greater than 100 MW.

cycle units caused natural gas combined-cycled plants to out-compete many existing coal-fired generators. This trend resulted in increased natural gas generation and decreased coal-fired generation, even when capacity at existing power plants remained the same. Installations of natural gas-fired units at existing power plants totaled almost 24 GW of new net capacity, whereas 11 GW of coal capacity was retired at existing power plants. These trends in retrofitting or adding new generation units to existing power plants has resulted in 15 power plants operating with both coal and gas units in 2014. These trends are discussed more in the Discussion section.

4. Discussion

4.1. Shifting fuels

Recent shifts in the US electricity generating sector are driven primarily by declining natural gas prices, which dropped from $9.02 to $5.00 per MMBTU for the electric power industry between 2008 and 2014, respectively. (For reference, the average natural gas price in the power sector between 2004–2008 and 2010 −2014 was $7.45 and $4.51, respectively) [41]. Natural gas prices have fallen because of technical advances in horizontal drilling and hydraulic fracturing, which have increased domestic production significantly during this period [5]. Low natural gas prices prompted a market-based response in the electricity sector, as natural gas combined cycle facilities gained competitive market advantage over coal-fired facilities due to lower fuel costs. Additionally, newer natural gas-fired combined cycle units are often more efficient than older units, which can increase their cost-competiveness with existing generators. Thus, net changes in generation between 2008 and 2014 are skewed towards newer, more efficient units.

Concurrently, more stringent environmental policies and regulations (e.g. Coal Combustion Residuals rule, Mercury and Air Toxics Standards for Utilities, Clean Power Plan, Renewable Energy Portfolio Standards, etc.) have also reduced the competitiveness of coal-fired power plants compared to natural gas-combined cycle facilities due to higher operational costs [42]. The relative efficiency improvements of combined-cycle facilities versus other steam-cycle facilities also improve the cost competitiveness of new natural gas units especially against coal as well as nuclear generators.

Electricity markets close to the Marcellus shale have seen a particularly large switch from coal-fired to natural-gas generation because of their proximity to areas of high gas production. As a result, newly installed gas plants have replaced a significant amount of coal-fired power generation in this region. In Pennsylvania alone, just over 3.4 GW of coal-fired capacity was retired from 2008 to 2014. Many coal-fired power plants, especially older plants in the Ohio valley, have been retired in the past six years (Fig. 3, HUC-2 region 05). In this basin, 17 coal-fired power plants were retired and 7 existing facilities retired coal-fired generating units from 2008 to 2014, totaling almost 5.7 GW in retired capacity. Some of coal's national decline has been tempered by a few new large coal-fired generating units, particularly in Texas, which added over 4 GW of new coal capacity during the period of study.

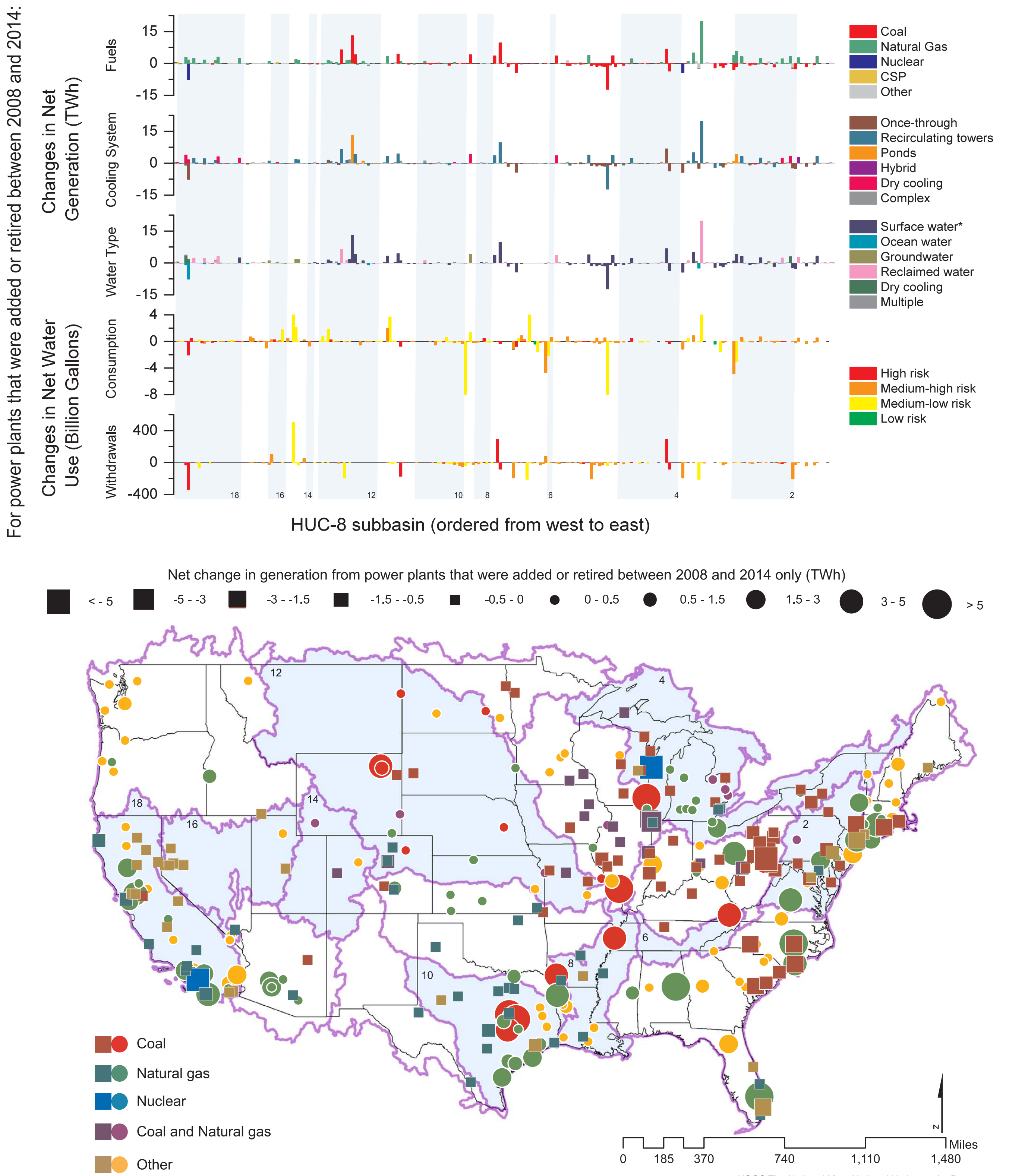

Fig. 3. Top: Generation (rows 1–3), water consumption (row 4), and water withdrawal (row 5) changes from the retirement of 153 and addition of 164 thermoelectric power plants with cooling systems between 2008 and 2014 in each HUC-8 watershed. Changes in generation are colored according to fuel type (row 1), cooling system (row 2), cooling water type (row 3), while changes in water usage are colored according to water risk (rows 3 and 4). HUC-8 watersheds are ordered from west to east based on HUC-8 number. Shaded white and blue regions represent HUC-2 watersheds, numbered on the bottom of the figure. Bottom: Geographic representation of the 153 retired and 164 added thermoelectric power plants greater than 1 MW requiring cooling, classified by fuel type and scaled to represent power plants added (circles) or retired (squares) between 2008 and 2014. Shaded regions correspond to shaded HUC-2 regions in the bar chart (top). The "Other" fuel type classification includes geothermal, solar, biofueled, and multi-fueled power plants.

4.2. Shifting cooling technologies

Shifts in cooling water technologies have an impact on operational cooling water usage at power facilities. A fraction of retired power plants illustrated in Fig. 3 represented relatively large volumes of water withdrawals, corresponding to once-through cooled power plants. Most new power plants withdraw relatively small volumes of water, reflecting a transition in the electricity sector towards recirculating cooled facilities, which markedly reduce water withdrawals per unit of electricity, typically at the expense of higher rates of consumption across similar fuel, cooling technology, prime mover classifications [38]. However, these water benefits are unevenly distributed across US watersheds (and more importantly, unevenly distributed across water-stressed watersheds) as illustrated in Fig. 3. Net changes in water consumption are driven by increased electricity demand, as the relative consumption rate (i.e. total reported consumption normalized per unit of electricity generated) in 2008 compared to 2014 remained relatively stable. Aside from capacity additions, increases in net water consumption on an individual plant basis were typically linked to increases in generation. Decreases in water withdrawals versus water consumption offer different benefits. For example, a decrease in net water withdrawals across a watershed may reduce the risk of a curtailment due to low water flows during droughts or heat waves and also reduces the occurrence of the entrainment and impingement of living organisms across intake screens. A reduction in water consumption can increase the water that can be allocated to other water users in periods of severe drought, as net evaporative losses across a watershed are reduced.

The trend towards the retirement of once-through (i.e. open-loop) cooled power plants and the addition of recirculating (i.e. closed-loop) tower cooled power generation units (Fig. 2) reflect environmental regulations, namely the 316 a & b amendments to the Clean Water Act (CWA). These amendments address the ecosystem impacts associated with the thermal pollution and entrapment/entrainment issues caused by once-through cooled facilities, respectively, are driving transitions away from once-through cooled facilities [43,1,44]. For example, in California, 5.45 GW of reported once-through cooled thermoelectric capacity was retired between 2008 and 2014. The state was the first to actively force the phase out of once-through cooled power plants (Fig. 3 HUC-2 region 18) [45]. Only 11 power plants remain in the state reporting once-through cooling as their only cooling technology. Of these facilities, nine are natural gas-fired, one is nuclear powered, and one reports the use of multiple fuels. With the exception of two facilities, all of these plants operate a simple steam cycle. Five of the existing once-through cooled facilities in 2014 are greater than 1 GW in capacity, the largest of which is Diablo Canyon Nuclear Generating Facility. All of these large power plants reported using surface water from the Pacific Ocean for cooling. The remaining once-through cooled generating facilities in California (and elsewhere in the US) are currently under evaluation for compliance with the 316 amendments to the CWA. In fact, the planned decommissioning of Diablo Canyon Nuclear Generating Facility in 2025 was announced in 2016, partly due to concerns over the environmental impacts of its cooling system [46].

There is a clear trend toward the use of dry cooling systems for new power plants, despite higher capital and operational costs [47]. Although dry cooling technologies impose efficiency penalties, the technology can relieve freshwater dependency in drought-prone and water-stressed regions, especially when coupled with reclaimed water usage. Approximately 2.4 GW of generating capacity (8.64 TWh of generation) in 2014 came from power plants that retrofitted to dry cooling systems. Furthermore, capacity additions from dry-cooled power plants added to the grid between 2008 and 2014 totaled approximately 7.8 GW (31 TWh of generation). In fact, dry cooling systems were used to cool almost 3.2% of thermoelectric generation requiring cooling in 2014.

4.3. Shifting cooling water sources

The transition to less water withdrawal intensive generation is also reflected in the source of water used for cooling new power plants. Surface water is the most common water source for cooling thermal power plants. However, this analysis reveals a number of transitions to other cooling sources. Many new power plants are utilizing alternative water sources, such as reclaimed water from municipal waste water treatment facilities, relieving some of the pressure on fresh surface water [36]. However, at the same time, there is an appreciable growth in new power plant capacity using groundwater for cooling, which could add pressure to groundwater depletion if not managed sustainably. Net decreases in groundwater withdrawals coupled with net increases in consumption highlight the transition towards using groundwater for cooling recirculating towers. A noticeable decrease in the use of ocean water for cooling in California and on the East Coast of the country highlights the influence of regulations and policies on cooling water sources for thermoelectric generators, namely CWA a & b (Fig. 3).

As ocean water cooling has decreased, reclaimed water use for cooling has increased, tempering the trend's impact on freshwater consumption. Between 2008 and 2014, 8.4 GW of capacity transitioned fully to reclaimed water for cooling, 6.4 GW of capacity reported using some reclaimed water for cooling (in addition to groundwater or surface water), and 13.4 GW of capacity cooled using reclaimed water was added to the grid from new power plants (representing approximately 30, 0.3, and 53.6 TWh of generation, respectively). The use of reclaimed water can also relieve cooling water related disruptions in the power sector, especially in drought-prone areas, by reducing dependence on freshwater usage and alleviating down-stream water stress. California, Nevada, and New York are among the top states for reclaimed water use at power plants (Fig. 3). In California, many of the large facilities that use reclaimed water are recirculating or dry cooled natural gas combined cycle plants; smaller reclaimed water users (in terms of power plant capacity) are geothermal plants and plants using multiple biofuels, oils, and/or other gases (Fig. 3).

The CWA amendments are also driving a shift towards reclaimed water use, as many coastal power plants must use an alternative cooling water source to the ocean. Due to policy, water availability, and drought vulnerability, many new power plants are using reclaimed water for cooling recirculating or coupled with dry cooled systems. Alternative cooling water sources represent a much larger fraction of water-cooled thermoelectric generation than previously understood. In fact, reclaimed water was used to cool almost 8% of thermoelectric generation requiring cooling in 2014. In addition, the feasibility of reclaimed water use for thermoelectric cooling has been studied and research in Texas shows that reclaimed water sources are located close enough to 92 power plants (50% of fresh water-cooled thermoelectric generation in Texas) to be a suitable cooling water source [23]. Therefore, it is reasonable to assume that the transition toward alternative cooling water sources will continue, as water resources become increasingly scarce and policies push thermoelectric generators to look for alternatives to traditional power plant cooling.

5. Conclusion

This study investigates how recent shifts in thermoelectric power generation in the US has impacted the spatial distribution of cooling water usage across HUC-8 basins. Results from the study illustrate some key trends that occurred in the US power sector between 2008 and 2014, including transitions (1) from coal-fired steam to natural-gas combined cycle units, (2) from once-through cooling to wet-recirculating towers and dry cooling systems, and (3) from traditional fresh and saline surface water to reclaimed water sources. Consequently, the electricity sector is moving towards more water-withdrawal efficient technologies, which can result in a water consumption penalty (in the case of wet-recirculating towers) or a water consumption benefit (in the case of dry cooled systems). In addition to the expansion of dry cooling across the power sector, much of the added capacity in recent years has been from natural gas combined-cycle facilities with recirculating towers, which benefit from large efficiency increases compared to the once-through steam-cycle facilities they are typically replacing; thus, this water consumption penalty due to cooling technology transitions has not yet been significant, although results are highly variable by watershed. Accordingly, the net impact to cooling water usage has been a reduction in the average volume of water withdrawn and relatively flat average water consumption when normalized per unit of electricity produced in 2014 versus 2008. Some of these trends have been tempered slightly by increased electricity demand during this time. Because of the uneven spatial distribution of new and retired power generation capacity, changes in the relative cost-competitiveness of one generator to another (affecting frequency of dispatch and duration of operation), and the shifts in demand, the changes to water usage and the ratio of water withdrawals to water consumption vary significantly across watersheds.

Overall, the most important regulatory efforts affecting the water consumed and withdrawn by power plants has been the CWA 316 a & b amendments that are driving the power fleet from once-through towards recirculating technologies. These amendments have mixed-implications for water use by the power sector. While most retirements that required high water withdrawals have been replaced with relatively high water consumptive technologies, much of the existing once-through cooled capacity in the interior US is where water is relatively abundant since these systems generally require higher-flow rates for operation. In water-constrained states such as Texas and California that utilize a lot of ocean-cooled capacity, this transition needs to be managed with freshwater impacts in mind. Although these shifts are generally ubiquitously good for ecosystem health, the transition away from once-through cooled facilities that use ocean water for cooling, can result in an increase of freshwater usage, since recirculating tower power plants typically do not use ocean water. Reclaimed water and dry cooling technologies are attractive options to avoid these freshwater impacts, although they can induce other operational tradeoffs (e.g. decreased efficiency in the case of dry cooling or increased fouling concerns in the case of reclaimed water use).

There are not clear trends in terms of net increases or decreases of cooling water usage as a function of relative water scarcity. However, there are signs that freshwater availability is affecting trends in decisions regarding new power plant installations. Dry and hybrid cooling systems, as well as the use of alternative water sources, such as reclaimed water, are growing in terms of net capacity. However, power plant capacity utilizing groundwater in water-constrained locations is also growing, which is a trend that will be important to moderate moving forward, as aquifers across much of the US are being exploited at rates much faster than they recharge.

This analysis points to the importance of considering the water use requirements of power plants when new installations are being planned, as freshwater availability across the US varies significantly. While the framework developed in this analysis provides an estimate of the cooling water demands across HUC-8 subbasins, resolving data limitations (i.e. omissions, zero-values, erroneous values, variable measurement techniques) associated with federal cooling water usage reporting by power plants would improve the utility of the results presented here.

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