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TECHNOLOGY ASSESSMENT

Highlights of GAO-15-545 a report to congressional requesters

August 2015

Water in the energy sector

Reducing freshwater use in hydraulic fracturing and thermoelectric power plant cooling

Why GAO did this study

Many regions within the United States experience moderate to exceptional drought forcing state officials to make difficult choices regarding energy and water. Competition for freshwater continues to increase due to industrial, municipal, and especially agricultural and energy sector demand. The thermoelectric power industry, for example, accounted for 38 percent of all freshwater withdrawals in the United States in 2010.

GAO has issued a series of six reports on the interdependencies between energy and water. In this report, GAO assessed advanced and emerging technologies that can reduce water use in hydraulic fracturing and thermoelectric power plant cooling. GAO also examined the impact of regional differences in thermoelectric power generation on water use in water-stressed versus unstressed areas of the United States.

To perform this technology assessment, GAO reviewed relevant peer-reviewed scientific literature and government reports and consulted experts with a wide variety of backgrounds and expertise. Experts convened with the assistance of the National Academy of Sciences advised GAO, and reviewed a draft of this report. GAO incorporated their comments in the final report as appropriate.

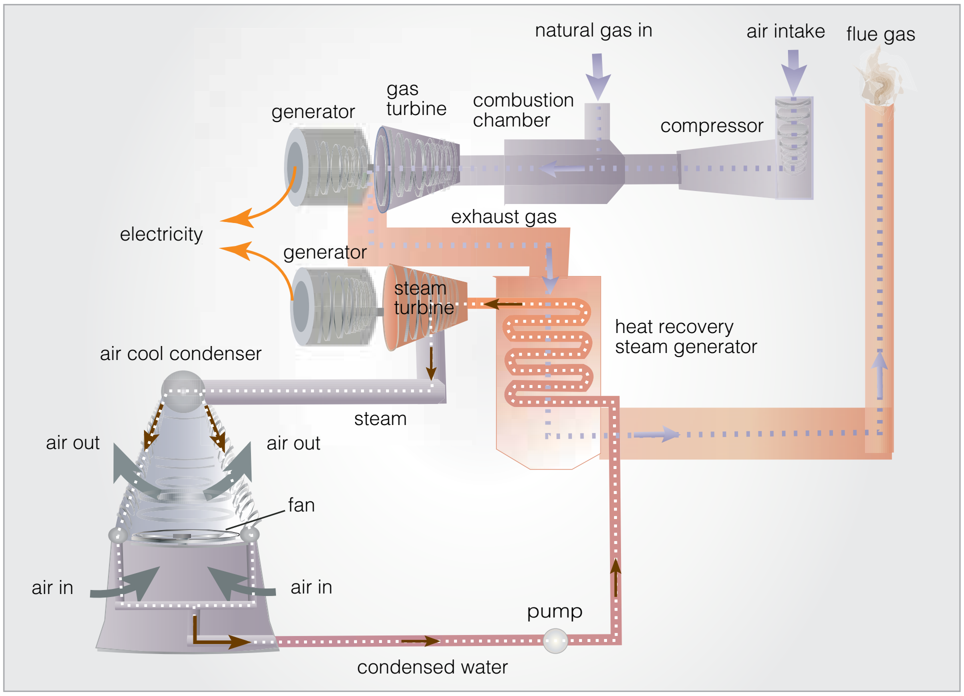
View GAO-15-545 or key components at www.gao.gov. For more information, contact Chief Scientist, Timothy Persons at (202) 512-6412 or personst@gao.gov

What GAO found

Waterless and water-efficient fracturing technologies such as gas-based fracturing or foams have been used to reduce the use of freshwater in hydraulic fracturing operations, although the main benefit is enhanced hydrocarbon recovery. The geologic formation characteristics of shale plays largely determine their use. According to experts GAO consulted, hydraulic fracturing operators are managing their water resources more efficiently—for example, by treating produced water for recycle and reuse—as an important part of their overall strategy to reduce cost, improve operational efficiency, and reduce the demand for freshwater.

Dry and hybrid (wet-dry) cooling systems are mature technologies to cool thermoelectric power plants, and are highly efficient in terms of water usage. These technologies are commercially operational at some power plants, particularly in the arid western regions of the United States where water is scarce. However, these technologies cost more than conventional wet cooling systems and can result in an energy penalty that requires more fuel to be burnt per unit of electricity produced, thereby reducing the net electricity output from the plant. Some emerging cooling technologies which may help reduce water use in wet recirculating cooling systems are at the prototype or conceptual stage of development, and their effectiveness at saving water for power plant cooling applications is still uncertain.

The regional distribution of electricity generation using different types of cooling systems, fuels, and generation technology—the combination of which largely determine a plant's overall water usage—reflects water stress conditions to a certain extent. Options for plants to switch between various types of cooling systems and generation technologies are limited or have drawbacks. In the most water-stressed regions, there is an emerging trend of new construction natural gas combined cycle plants that also use dry cooling technology, a combination which is both energy and water efficient.



A natural gas combined cycle (NGCC) power plant with a dry cooling system. Source: GAO. | GAO-15-545

August 7, 2015

The Honorable Raul Grijalva
Ranking Member
Committee on Natural Resources
House of Representatives

The Honorable Alan Lowenthal
Ranking Member
Subcommittee on Energy and Mineral Resources
Committee on Natural Resources
House of Representatives

The Honorable Edward J. Markey
United States Senate

The Honorable Peter DeFazio
House of Representatives

To respond to your request that we conduct a technology assessment on current and proposed technological approaches toward reducing freshwater consumption in energy production, we examined the current state of technologies that are either available or being developed to reduce freshwater consumption or that employ alternative water sources in hydraulic fracturing and in the process of generating electricity in thermoelectric power plants. We also examined regional water stress distributions and water usage in thermoelectric power generation across the United States to identify how water-scarce regions in the United States could benefit from the applications of these technologies.

As agreed, we plan no distribution of this report until 30 days after its issue date unless you publicly announce its contents earlier. We will then send copies of this report to the appropriate congressional committees, the Secretaries of Energy and the Interior, the Administrator of the Environmental Protection Agency, and other interested parties. In addition, the report will be available at no charge on the GAO website at www.gao.gov.

If you have any questions concerning this report, you may contact me at (202) 512-6412 or personst@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs can be found on the last page of this report. GAO staff who made major contributions to this report are listed on page 89.

T.M. Persons

Timothy M. Persons, Ph.D.
Chief Scientist

Executive Summary

In conducting this technology assessment, we focused primarily on the status of current and emerging technologies that conserve freshwater for both hydraulic fracturing and thermoelectric power generation. In addition, we analyzed regional water stress distributions and water usage in thermoelectric power generation across the United States to identify how water-scarce regions in the United States could benefit from the application of these technologies.[1]

Technologies to reduce freshwater use in hydraulic fracturing

While water-based fracturing remains the most common technique for hydraulic fracturing, other techniques that either do not use water or are more efficient in their use of water have been demonstrated and used in selected shale formations in various regions in the United States, including ones where water is scarce.

Liquid Petroleum Gas (LPG) fracturing, for example, which uses a mixture of propane and chemical additives in lieu of water, has been used primarily to increase production in low permeability, low pressure shale formations where water-based fracturing can reduce gas production. LPG has much lower viscosity and density compared with water, which in some cases can facilitate the flow of hydrocarbons out of these types of formations.

Foam-based fracturing fluids, which consist of a mixture of water, a foaming agent, and nitrogen or carbon dioxide, can reduce the volume of water required for fracturing. However, the effectiveness of this technique, which has been used most commonly in formations where the reservoir pressure is too low to drive a column of water out of the well, is still being debated.

Channel fracturing involves the intermittent injection of proppant-laden fluid followed by injection of proppant-free gelled fluid to create open channels through which hydrocarbons can more easily flow.[2] This technique has reportedly been used in most of the key shale plays in the United States and has been shown to reduce water use. However, the extent of its ability to achieve productivity gains is still being assessed.

While these alternative fracturing techniques reduce water use, their primary benefit is in promoting enhanced product recovery. Moreover, because of their dependence on specific geologic formation characteristics, they are not widely deployed or generally applicable. However, recent technological advances coupled with water use and disposal issues have created the need for water management strategies, and have resulted in an increase in the reuse of produced water and the ability to use more

1 The term 'water stress' mentioned throughout this report refers to a water stress index that combines regional factors of water supply and demand into a single measure to quantify water stress and expressed on a scale from 0 to 1, with 0 being the least water-stressed and 1 the most.

2 Proppants are particles mixed with fracturing fluid to maintain fracture openings after hydraulic fracturing. These typically include sand grains, but they may also include engineered proppants.

brackish water in hydraulic fracturing.[3] In some regions facing water scarcity, such as the Barnett and Eagle Ford Shale in Texas, shale gas operators are managing their water resources better—for example, by treating water for recycle and reuse to limit the increase in freshwater use. According to experts we consulted, including shale oil and gas operators, although water reuse and recycling are sometimes driven by water scarcity or regulatory concerns, they are also being driven by the need to reduce costs. Reusing produced water—which can result in a reduction in the amount of water that needs disposal—can drive down costs and increase operational efficiency.

Technologies to reduce freshwater use for cooling in thermoelectric power generation

Once-through cooling systems and wet recirculating systems, both of which use water to cool and condense steam used to power turbines that generate electricity are the most commonly used cooling technologies. Advanced cooling technologies—direct dry, indirect dry, or hybrid wet-dry cooling systems—eliminate or significantly reduce the amount of water needed for cooling. In addition, some emerging cooling technologies exist at the prototype or conceptual stage, most aimed largely at saving water within the context of an existing wet cooling tower.

Dry cooling systems use no water for cooling. Hybrid systems use a combination of dry and wet cooling systems. Our assessment shows that both dry and hybrid cooling technologies are fully mature and are commercially operational at some power plants, particularly in the arid western regions of the United States. However, these cooling systems cost more than conventional wet recirculating systems and may result in an energy penalty that reduces the net electricity output from the plant, requiring more fuel to be burnt per unit of electricity produced. For example, a dry cooling system with an air-cooled condenser (ACC) can have up to a 10 percent power production penalty on hot days and about 3 to 4 times higher capital costs compared to current wet recirculating systems. Additionally, dry cooling has a larger land-use footprint and is likely to result in increased green-house gas emissions. Hybrid cooling technologies may mitigate some of these cost and energy penalty concerns by adopting the best of both wet and dry cooling methods. Dry cooling systems are generally not retrofittable, but are mainly used at newer natural gas combined cycle (NGCC) plants.

In contrast to dry and hybrid cooling, we found emerging cooling technologies—the thermosyphon cooler, M-cycle dew point cooling, adsorption chiller, and air cooling to recover freshwater from an evaporative cooling tower—to be at varying levels of maturity ranging from low to medium. Their effectiveness at saving water at the current stage in their development is uncertain. The costs associated with these systems are unknown as some of them have not been evaluated for power plant cooling applications, and their maturity may depend on a number of site-specific factors. None of the emerging cooling technologies we describe in this report are currently ready for full scale commercial operation given our assessment of their maturity, potential effectiveness, and cost factors.

3 Produced water is all the water that is returned to the surface through a well borehole that includes water injected during the fracture stimulation process that flows back to the surface (flowback water), as well as natural formation water.

Regional water use and technology options for cooling in thermoelectric power plants

Using a water-stress metric based on water consumption and supply data from the U.S. Geological Survey (USGS), we determined water scarcity levels at the regional level. To illustrate how electricity generation, water consumption or withdrawal, cooling systems, fuel sources, and water source types vary regionally, we matched thermoelectric power plants across the nation to the water stress region where each was located. We found that there are distinct differences between the ways that water is used for cooling in electric power generation in the more water-stressed regions of the United States compared with less water-stressed regions. For example, we found that regions that are among the least water-stressed (where water supplies are high relative to demand) accounted for a much larger share of U.S. electricity generation and thus a larger share of water consumption and withdrawal compared to the most water-stressed regions. Nearly half of the electricity in the United States in 2008 was generated in the least water-stressed regions. In contrast, the corresponding share for the most water-stressed regions—mostly in the west—was only about 17 percent. Furthermore, while the average water consumption rates relative to electricity generation were roughly similar in the least and most water-stressed regions, the average water withdrawal rates were significantly higher in the least stressed regions than in the most stressed regions.[4]

We also found that power plant characteristics, such as the type of cooling system used, the type of fuel and power generating technology employed, and the sources of cooling water varied across stressed and unstressed regions.

We found that choice of cooling system impacts water use. For example, once-through cooling systems are generally more prevalent in regions where water is plentiful. Forty percent of the electricity in the least water-stressed regions is generated by power plants having once-through cooling systems, whereas in the most water-stressed regions only 19 percent of the generation involves once-through cooling systems. The greater share of once-through systems in the least stressed areas is in large part due to greater availability of large bodies of water in those regions.

However, options for existing plants to switch between various types of cooling systems may be limited or have drawbacks. For example, retrofitting a plant that currently uses a once-through cooling system to a recirculating system in order to reduce water withdrawals may, in effect, result in an increase in water consumption since recirculating cooling systems withdraw less water but consume more. On the other hand, retrofitting an existing thermoelectric plant with a dry cooling system may be technically and economically impractical, according to experts. In general, retrofits of existing cooling systems must take into account many considerations including design, cost, impact on net electric output, site-specific characteristics such as climate and space, and the availability of water resources.

We found that there are differences in the share of electricity generation by the type of fuel used in the least water-stressed regions versus the most water-stressed regions. For example, coal-fired plants, which,

4 The water consumption rate is the ratio of the amount of water consumed to the amount of electricity generated. The water withdrawal rate is the ratio of the amount of water withdrawn to the amount of electricity generated. Both are expressed in gallons per megawatt-hour (gals/MWh).

on average, consume more water per unit of electricity produced than gas-fired plants, are more prevalent in the least water-stressed regions. In other words, greater reliance on natural gas in the most water-stressed regions contributes to less water use in these regions.

Since the early 2000s, there has been an emerging trend of new NGCC plants that use dry cooling technology. The efficient NGCC design offsets the energy penalty incurred with dry cooling systems, making this an attractive option for water-stressed regions. Renewable power sources, including wind and solar photovoltaic power, may also reduce water use.

Cooling towers will likely remain a predominant cooling technology for the foreseeable future due to the limited applicability of dry cooling and increasing restrictions on the use of once-through cooling systems. However, opportunities for water savings exist within plants with recirculating cooling systems, such as the use of alternative sources of water for cooling in lieu of freshwater, cooling towers operating at higher cycles of concentration, and, in coal plants, reusing water recovered from the flue gas. Further, since the amount of water used in power generation depends on how much electricity is generated, influencing the demand for electricity can also have important implications for water use.

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Abbreviations

ACC	Air-cooled condenser
ANL	Argonne National Laboratory
CO_2	Carbon dioxide
CSP	Concentrating solar power
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EW3	Energy and Water in a Warming World
FGD	Flue gas desulfurization
GAO	Government Accountability Office
LPG	Liquefied petroleum gas
M-cycle	Maisotsenko cycle
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NREL	National Renewable Energy Laboratory
PC	Pulverized coal
PV	Photovoltaic
TRL	Technology readiness level
TSC	Thermosyphon cooler
U.S.	United States
USDA	U.S. Department of Agriculture
USGS	U. S. Geological Survey

Units of Measure

gal	Gallons
gals/MWh	Gallons per megawatt-hour
MW	Megawatt
MWh	Megawatt-hour

1 Introduction

While water, covering about 70 percent of the planet's surface, is one of the earth's most abundant resources, freshwater available for use by humans and ecosystems makes up less than 1 percent of the earth's water (GAO 2014). Competition for this critical natural resource continues to increase due to agricultural, industrial, municipal, and energy sector demand; population growth; and changing demographic patterns. We found in May 2014 that since 2003, concerns about population growth straining water supplies, lack of information on water availability and use, and trends in types of water use have continued to make freshwater management and planning difficult (GAO 2014). In fact, our 2014 review found that water managers in 40 states anticipated freshwater shortages within the next 10 years in some portion of their states under average weather conditions (GAO 2014). Nowhere is this more evident than in California where, for the first time, the state has introduced mandatory conservation and is taking immediate action to safeguard the state's remaining potable urban water supplies in preparation for a possible fifth year of drought.[1]

The energy sector places significant demands on freshwater resources. GAO has a body of work examining the relationship between energy and water use, and has found that many stages of the energy development and delivery lifecycle affect the availability of water resources.[2]
Two key processes—the extraction of fuels to generate electricity (primarily coal, gas, and uranium) and the thermoelectric power generation process itself—depend heavily on freshwater resources (Meldrum et al. 2013).[3]
For example, in some areas of the country, shale gas operators—who extract fuel through fracturing—require significant amounts of water and are more frequently reusing their produced water in lieu of trying to locate new freshwater sources.[4] Thermoelectric power plants, which rely heavily on water for cooling, have also reduced electricity production due to limited freshwater availability in some locations. Other power plants have adapted to continue to operate in water scarce environments by using technologies that reduce water

1 On April 1, 2015, the Governor of California issued the fourth Executive Order on actions necessary to address the state's severe drought conditions. Executive Order B-29-15 directed the State Water Resources Control Board to implement mandatory water reductions in urban areas to reduce potable urban water usage by 25 percent statewide. The State Water Board adopted an emergency conservation regulation, effective May 18, 2015, in accordance with the Governor's directive.

2 GAO has issued six reports on the interdependencies between energy and water: GAO, *Energy-Water Nexus: Improvements to Federal Water Use Data Would Increase Understanding of Trends in Power Plant Water Use*, GAO-10-23 (Washington, D.C.: Oct. 16, 2009); GAO, *Energy-Water Nexus: Many Uncertainties Remain about National and Regional Effects of Increased Biofuel Production on Water Resources*, GAO-10-116 (Washington, D.C.: Nov. 30, 2009); GAO, *Energy-Water Nexus: Amount of Energy Needed to Supply, Use, and Treat Water Is Location-Specific and Can Be Reduced by Certain Technologies and Approaches*, GAO-11-225 (Washington, D.C.: Mar. 23, 2011); GAO, *Energy-Water Nexus: A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development*, GAO-11-35 (Washington, D.C.: Oct. 29, 2010); GAO, *Energy-Water Nexus: Information on the Quantity, Quality, and Management of Water Produced during Oil and Gas Production*, GAO-12-156 (Washington, D.C.: Jan. 9, 2012); and GAO, *Energy-Water Nexus: Coordinated Federal Approach Needed to Better Manage Energy and Water Tradeoffs*, GAO-12-880 (Washington, D.C.: Sept. 13, 2012). These reports have shown that, among other things, a considerable amount of water is used to cool thermoelectric power plants, grow feedstocks and produce biofuels, and extract oil and natural gas.

3 While there are many end uses of fossil fuels (oil or gas) such as direct combustion or transportation, the focus of this report is on electric power plant operations as an end user of fossil fuels and water consumed in the generation of electricity.

4 Produced water is all the water that is returned to the surface through a well borehole that includes water injected during the fracture stimulation process that flows back to the surface (flowback water), as wellas natural formation water.

requirements in electricity generation.

In fact, the U.S. Geological Survey (USGS) found that the majority of water withdrawals in the United States have consistently been for thermoelectric power generation (USGS 2014b). Specifically, according to the USGS, thermoelectric power continued to account for the largest withdrawals for any category of water use at 161 billion gallons per day, or 45 percent of the total withdrawals from all categories of use in 2010.

Electricity industry stakeholders are recognizing that water consumption rates at thermoelectric power plants equipped with certain types of cooling systems may not be sustainable in some locations. At the same time, thermal discharges from other types of cooling systems face increasing regulatory scrutiny that may prompt plant operators to consider alternative cooling technologies (EPRI 2012a).

Compounding the problem, the U.S. Energy Information Administration (EIA) projects that the total U.S. electricity generation is expected to rise from approximately 4 trillion kilowatt hours in 2012 to 5 trillion kilowatt hours in 2040, a 25 percent increase as shown in figure 1.1 (EIA 2014c).

At the same time, the United States remains the world's largest natural gas producer as hydraulic fracturing expands to allow more oil and natural gas to be developed. According to EIA, shale gas is expected to be the primary driver of growth in domestic natural gas production, as shown in figure 1.2. Shale gas as a share of total natural gas production is projected to increase from 34 percent in 2011 to 50 percent in 2040 (EIA 2013b).

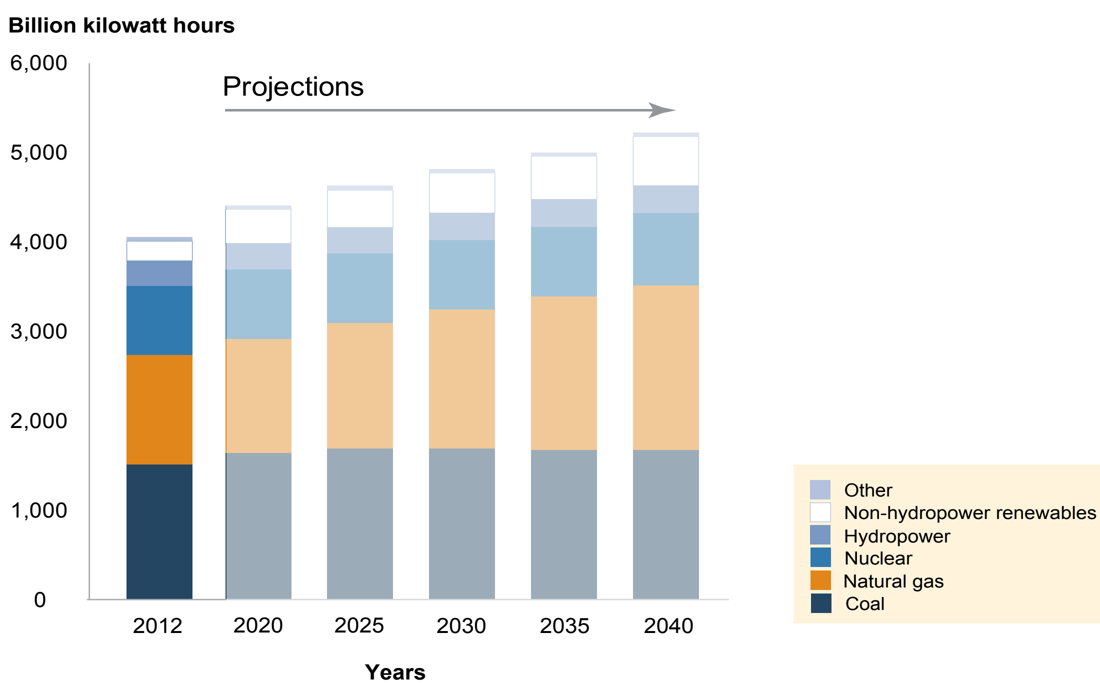


Figure 1.1: Projected U.S. total electricity generation by energy source (2012-2040)

Source: GAO Analysis of U.S. Energy Information Administration 2014c | GAO-15-545

Note: Non-hydropower renewables include solar, wind, geothermal, municipal waste, and wood and other biomass.

In an October 2012 report, we found that oil and gas development, whether conventional or shale oil and gas, poses inherent environmental and public health risks, but the extent of these risks is unknown (GAO 2012b).

In this context, we reviewed available and developing technologies that could reduce freshwater use in unconventional resource development activities—primarily hydraulic fracturing— and in thermoelectric power plants, as well as to identified water-scarce regions in the United States that would benefit from these technologies.

To identify technologies that may reduce freshwater use in hydraulic fracturing, we examined reports that describe and quantify water use in hydraulic fracturing. We consulted with oil and gas operators to determine how they use water in their operations, and measures they adopt in water scarce regions to conserve water while also reducing operational costs. We examined the status of technologies and practices that could potentially be applied in water-scarce regions to reduce freshwater requirements.

To identify technologies that may reduce freshwater use in thermoelectric power generation, we identified and reviewed key reports and scientific papers describing advanced and emerging cooling technologies for thermoelectric power plants. We assessed the current state of these technologies by categorizing reported technical information in four areas: 1) maturity, 2) potential effectiveness, 3) cost factors, and 4) potential constraints, trade-offs, and consequences. We rated the maturity of each technology on a scale of 1 to 9 using technology readiness levels (TRL)—a standard metric for assigning technological maturity. We examined the status of advanced and emerging cooling technologies that could potentially be applied in thermoelectric power plants to reduce freshwater requirements. In

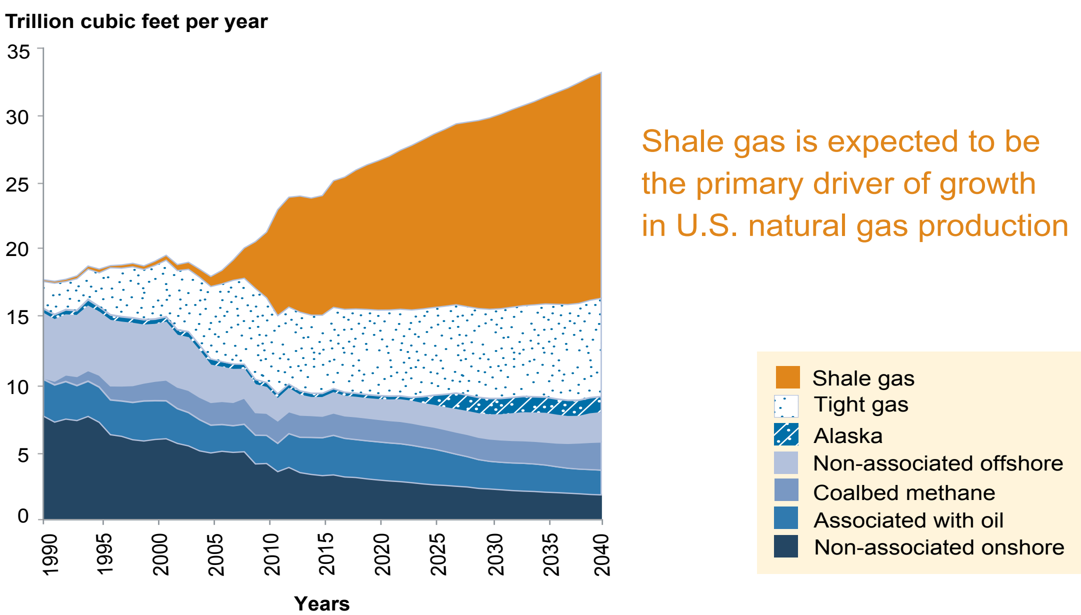


Figure 1.2: Natural gas production by source (1990-2040)

Source: GAO analysis of U.S. Energy Information Administration 2013b | GAO-15-545 addition, we identified and examined the use of alternative sources of water to replace freshwater use in thermoelectric power plants.

To determine which water scarce regions in the United States could benefit from technologies to reduce water consumption, we examined regional aspects of water use in thermoelectric power plants.

In addition, we collaborated with the National Academy of Sciences to convene a two-day meeting of experts bringing together a diverse group of scientists, engineers, and other technical experts and stakeholders involved in researching, developing, and demonstrating advanced and emerging technologies for reducing water consumption in hydraulic fracturing and thermoelectric power generation. The experts provided us with additional information on published studies, reports by technology vendors, information on field sites, and conferences and workshops related to our technology assessment. Consistent with our quality assurance framework, we provided them with a draft of our report and solicited their feedback, which we incorporated as appropriate.

We conducted our work from October 2012 to August 2015 in accordance with all sections of GAO's quality assurance framework that are relevant to technology assessments. The framework requires that we plan and perform the engagement to obtain sufficient and appropriate evidence to meet our stated objectives and to discuss any limitations to our work. We believe that the information and data obtained, and the analysis conducted, provide a reasonable basis for any findings and conclusions in this product.

2 Background

Water use in hydraulic fracturing and thermoelectric power generation

Hydraulic fracturing, the principal means of developing shale gas, is a water intensive operation. In addition to the 65,000 to 600,000 gallons of water required to drill each well, it is estimated that between 2 and 9 million gallons of water are required to fracture the well, depending on the shale play (Clark et al. 2013 and Mantell 2010).[5] For example, a recent estimate of all fracturing water use for the Eagle Ford Shale in Texas totaled 40 billion gallons for 8,301 wells from 2009 through 2013, with approximately 93 percent of the water use occurring from 2011 through 2013 (Scanlon et al. 2014). The same report showed hydraulic fracturing in the Bakken Shale in North Dakota and Montana used approximately 16 billion gallons of water for 7,868 wells from 2005 through 2013, less than half of the water used for the Eagle Ford Shale.[6]

Water use by thermoelectric power plants can be characterized as either withdrawal or consumption. Water withdrawals refer to water removed from the ground or diverted from a surface water source—for example, an ocean, river, or lake. Water consumption refers to the portion of the water withdrawn that is no longer available to be returned to a water source and includes downstream losses of water that are no longer available for other use, such as water that has evaporated. These distinctions are important because each can be a limiting factor in power plant design choices. For example, some power plant cooling systems withdraw vast amounts of water but consume very little, returning most of the withdrawn water back to its original source, although sometimes at higher temperatures.[7] Others withdraw comparatively little at a time but consume almost all of it.

According to USGS, the thermoelectric power industry accounted for approximately 38 percent of total freshwater withdrawals in the United States in 2010, as shown in figure 2.1.

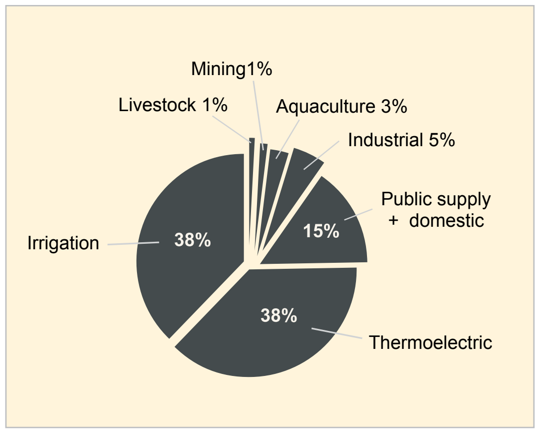


Figure 2.1: U.S. freshwater withdrawals by various sectors (2010)

Source: GAO analysis of U.S. Geological Survey 2014b | GAO-15-545

Note: The data include only freshwater. Total does not add to 100 percent due to rounding.

In the United States, the water withdrawn for thermoelectric power generation is primarily surface freshwater.[8] For example, in 2010, over 99 percent of all water withdrawn for

5 Play refers to an area in which accumulations of hydrocarbons, such as oil or gas, or prospects of a given type occur.

6 Both of these shale plays accounted for two-thirds of U.S. unconventional oil production in 2013.

7 According to EPA, the elevated return temperature also contributes to water scarcity issues when multiple systems in close proximity to each other share the source water. When a thermoelectric facility withdraws water for cooling that is at a higher temperature, more water is needed to remove a given quantity of waste heat from the system. This situation may be exacerbated in the summer when source water temperatures are already high.

8 Surface water collects in surface water bodies, like oceans, lakes, or streams.

thermoelectric power generation was surface water, 73 percent of which was fresh.[9], [10] In all, 117 billion gallons per day of freshwater were withdrawn for thermoelectric power generation in 2010.

In contrast to withdrawals, the thermoelectric power industry is not a dominant consumer of freshwater. Freshwater consumption by the thermoelectric power industry in 1995—the last year for which data was compiled—was approximately 3 percent of all freshwater consumption by various sectors as shown in figure 2.2 (USGS 1998).

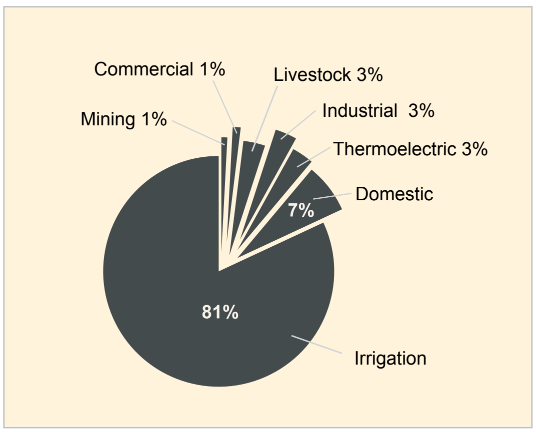


Figure 2.2: U.S. freshwater consumption by various sectors (1995)

Source: GAO analysis of U.S. Geological Survey 1998 | GAO-15-545

Note: Total does not add to 100 percent due to rounding.

9 The remaining water was largely saline water used primarily by coastal states, with California, Florida, and Maryland accounting for almost half of the use (USGS 2014b).

10 Proppants are particles mixed with fracturing fluid to maintain fracture openings after hydraulic fracturing. These typically include sand grains, but they may also include engineered proppants.

While this is a relatively small percentage, water consumption by the electric power industry is projected to grow notably in proportion to the forecasted increase in electricity demand. EIA forecasts that, assuming current policies remain in place, total electricity demand will grow by 28 percent (0.9 percent per year)—from 3,839 billion kilowatt-hours in 2011 to 4,930 billion kilowatt-hours in 2040 (EIA 2013b). This growth in demand for electricity is expected to increase the demand for freshwater for cooling systems of thermoelectric power plants. For example, researchers at the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) estimate that water consumption by the coal-fired power industry will increase 21 percent (from 2.4 billion to 2.9 billion gallons per day) from 2005 to 2030, while consumption for all water users will increase by only 7 percent in the same period (NETL 2010a).[11]

In some instances, alternative sources of water are being used to supply the needs of thermoelectric power plants. A significant volume of reclaimed municipal wastewater is being used for thermoelectric power plant cooling in some places—Arizona and California, for example—where surface freshwater sources are particularly under stress (Averyt et al. 2011).[12]

A study to estimate the life cycle water use in electricity generation showed that water withdrawal for the cooling systems of thermoelectric power plants dominates the life

11 However, according to experts we talked to, these projections could be based on continued buildup of coal-fired generation capacity that may be affected by regulatory and policy decisions and natural gas price among other factors. For example, the introduction of natural gas based efficient plants, alternative cooling technologies, or some renewable generation would decrease future water consumption, as shown in the recent water use estimates published by USGS (USGS 2014b).

12 Reclaimed water refers to treated municipal wastewater.

cycle in most cases (Meldrum et al. 2013). For example, USGS data showed that freshwater withdrawal by the mining industry—which included withdrawals for hydraulic fracturing—in 2010 was 2,250 million gallons per day compared to 117,000 million gallons per day for thermoelectric power plants. However, Meldrum's life cycle water use study showed that the water intensity—gallons of water used per megawatt-hour of electricity produced (gals/MWh)—for hydraulic fracturing for shale gas can be considerable.

Shale oil and gas development process

The process to develop shale oil and gas is similar to the process for conventional onshore oil and gas, but unlike conventional resources where gas or oil flows on its own during initial stages of production, the extremely low permeability of shale requires additional reservoir stimulation techniques, such as hydraulic fracturing to enable the oil or gas to flow. [13,14]

Once proper permits are approved and the site is prepared, the drilling process begins with a vertical wellbore.[15] This initial vertical portion of the well is drilled using the same technique that is used in conventional wells. Drilling is conducted in stages where a steel casing is often sealed into place in the wellbore with cement at predetermined depths to provide a solid support for the wellhead and help maintain wellbore integrity (preventing collapse of the borehole).[16] According to one oil field expert, vertical drilling continues to a predetermined level above the target depth.[17] At this point, the wellbore is gradually deviated laterally until its direction is close to horizontal by the time the target shale bed is reached.

To drill the horizontal portion of the well, specially designed drilling tools and diagnostic tools are used to steer the well horizontally into the target zone with great precision and across long distances. Horizontal stretches of wells typically range from 2,000 feet to 6,000 feet long, but can be as long as 12,000 feet in some cases (GAO 2012c). This change in the direction of the well from vertical to horizontal exposes a larger portion of the shale formation to the wellbore, thus maximizing recovery from the reservoir.

The hydraulic fracturing process is initiated by blasting holes through the wellbore at specified locations within the wellbore. This is done by perforation equipment containing explosive charges that is lowered into the wellbore at the precise location of the shale production zone. The perforations place the wellbore in direct contact with the shale production zone, thereby creating a pathway to allow gas or oil to flow to the well. After the perforations are made, the fracturing process begins. This involves pumping a large volume of fracturing fluids through high pressure lines. About 98 percent of the fluid mixture used in hydraulic fracturing is water and proppant, according to a report about shale gas development by the Ground Water Protection

13 Reservoir stimulation is a treatment performed to restore or enhance the productivity of a well. Hydraulic fracturing is a type of reservoir stimulation.

14 Permeability is defined as the ability of fluids to flow within rock formations.

15 The wellbore is also referred to as a borehole. This includes the inside diameter of the drilled hole bounded by the rock face.

16 Casing is a pipe lowered into an open hole and cemented in place.

17 Target depth refers to the depth below the surface where gas or oil is found.

Council.[18] The remaining amount consists of a variety of chemicals that are designed to prevent degradation of the fracturing fluid by bacteria, prevent corrosion of the casing and downhole equipment, suspend the proppant, and aid in the hydrocarbon flow, taking into account a variety of factors such as formation depths, geological properties and types of hydrocarbon present (ANL 2012). For each section of the well (called a "stage"), fracturing fluid is injected under steadily increasing pressure, causing multiple fractures in the shale formation, while the proppant material holds the fractures open after pressure is released. This fracturing fluid, consisting of low-viscosity water-based fluid and proppant mixture is called slickwater.[19]

This fracturing process sequence is repeated on adjacent sections of the wellbore and fractured one stage at a time with each stage being isolated from others by means of plugs. The fractures created in the rock generally propagate a few feet to a few hundred feet from the wellbore, although long fractures extending perhaps 1000 feet are possible. These fractures provide a conductive pathway that guides the oil and gas to the wellbore so they can be brought to the surface.

Figure 2.3 shows a horizontal well drilled through a shale gas formation using multi-stage fracturing conducted on the horizontal portion of the wellbore. Key elements of the well are:
(1) the wellhead, which is used to maintain pressure on the formation to prevent any unintended influx of formation fluids into the wellbore; (2) the wellbore—the drilled hole or borehole; (3) the well casing, which isolates the wellbore from the formation and also maintains well integrity during drilling and production; and (4) the horizontally deviated wellbore, where the hydraulic fracturing occurs.

After the completion of drilling and hydraulic fracturing operations, the well is prepared for production. The pumping pressure is relieved from the well at the start of production to allow the trapped oil and gas to flow through the fracture network to the wellbore. The fracturing fluids also begin to flow back up through the well casing to the wellhead. This fluid is commonly called flowback water and consists of fracturing fluids and naturally occurring brine water with dissolved constituents from the formation itself (e.g. minerals present in the shale, water present in the natural pore space of the shale, and, gas or oil that, ideally, are separated from the water). The majority of flowback water is produced over a range of time spanning from several hours to a couple of weeks from start of production. Flowback water volume may range from 10 to 80 percent of the original fracture fluid volume injected into the well (Baker Hughes Inc. 2011). The naturally present formation water continues to be produced along with the oil or gas with varying levels of formation contaminants throughout its production life cycle. The flowback water along with water that occurs naturally in the oil or gas-bearing formation is collectively referred to as produced water. Where allowed, the produced water is often disposed of through underground disposal

18 Ground Water Protection Council is a nonprofit organization whose members are state groundwater regulatory agencies. Ground Water Protection Council and ALL Consulting. "Modern Shale Gas Development in the United States: A Primer." Prepared for the Department of Energy and National Energy Technology Laboratory. April 2009.

19 Slickwater is a low-viscosity water-based fluid and proppant sand having no significant gelling agents.

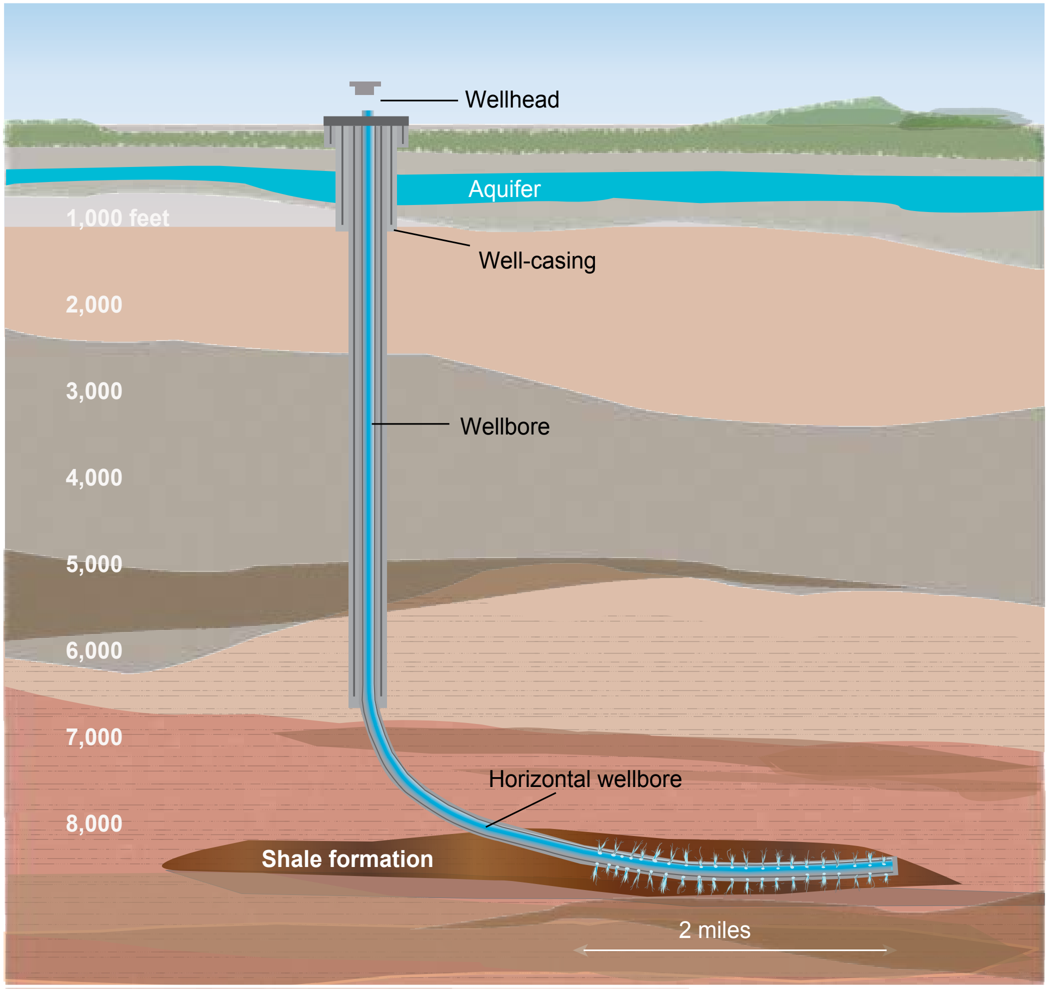


Figure 2.3: A horizontally drilled, hydraulically fractured shale gas well

Source: GAO adapted from Argonne National Laboratory 2012 | GAO-15-545

wells constructed for this purpose.[20] Over 90 percent of the produced water is managed this way; the remaining water is generally discharged to surface water, stored in surface impoundments, reused for irrigation, or recycled (GAO 2012a). For example, produced water can be treated and recycled for hydraulic fracturing if re-injection is not technically, logistically, or economically appropriate at a location. Recently, due to water constraints in some drought afflicted regions, some operators have begun to recycle this water for use in future hydraulic fracturing operations (Nicot et al. 2012).

Once a well begins producing gas, it can

20 The disposal wells (known as class II injection wells) are regulated under the Safe Drinking Water Act and its protection of underground sources of drinking water provisions. As of 2012, there were over 170,000 class II injection wells operating in the United States. According to Baker Hughes and McCurdy, the wells are constructed like production wells (and in some cases are actually depleted or non-producing oil or gas wells) with the same natural and manmade protections afforded to actual oil or gas wells. However, a vast majority of these wells are used to maintain reservoir pressure or for waterflood in conventional oil/gas recovery (neither of which is applicable to shale)—that is, wastewater disposal wells for shale are relatively few in number.

continue to produce for decades, although annual production volumes decrease rapidly. For example, the production rate for the Barnett Shale in Texas declined by approximately 50 percent at the end of first year of production (Baihly et al. 2010).

Electric power generation

In the United States, electricity is generated predominantly by thermoelectric power plants that use a variety of fuel types including coal, natural gas, nuclear material, and petroleum. A relatively small percentage of plants are non-thermoelectric, using renewable fuels such as wind, sunlight, and hydropower. Figure 2.4 shows that in 2014, 39 percent of the electrical generation was from coal, followed by natural gas (27 percent), and nuclear (19 percent), while renewable sources—including hydropower—accounted for 13 percent (EIA 2015).[21]

Thermoelectric power plants use their fuel source to boil water to produce steam at high pressure and temperature, which is used to turn a turbine connected to a generator that makes electricity. The steam is then condensed back to a liquid, which is pumped back to the boiler to be heated again to steam. Water is used in thermoelectric power generation in several ways, but the vast majority is used in this cooling process. Water (as opposed to air) is generally used as a cooling medium because it has a higher capacity to dissipate heat from the system.

Other types of power plants, such as hydroelectric, wind turbine-driven plants, and solar photovoltaic plants do not rely on generating steam. Instead, they use energy in

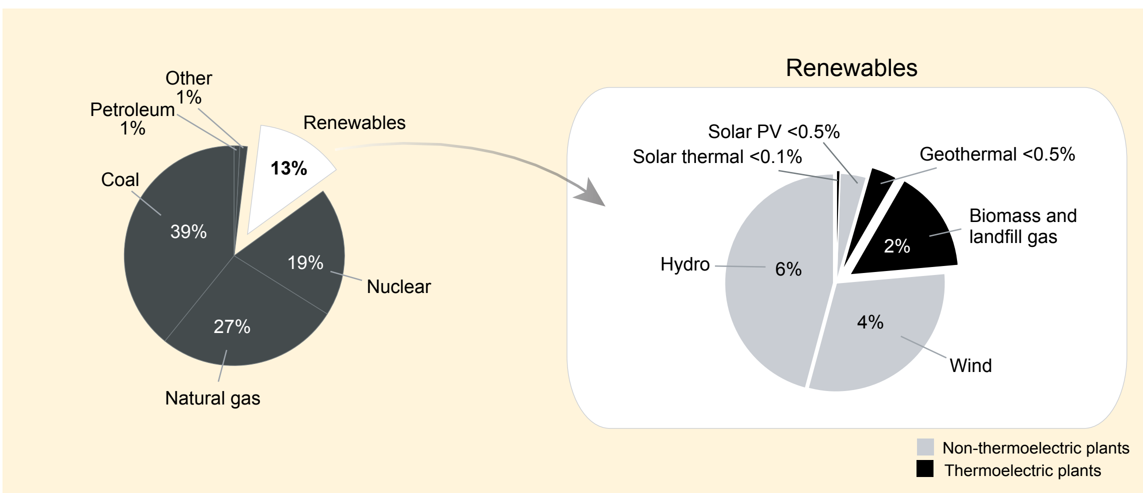


Figure 2.4: Electricity generation in the United States by energy source

Source: GAO analysis of U.S. Energy Information Administration 2015 | GAO-15-545

21 Some non-thermoelectric power plants, such as hydroelectric, wind-turbine based, and solar PV do not require any water for cooling. A small number of natural gas based plants are purely gas turbine and have no steam cycle, thus they do not require any water for cooling.

other ways to generate electricity. Conventional hydroelectric plants use dams to limit flow in rivers and produce electricity by selectively releasing water through turbines. Wind turbines use wind to power turbines and produce electricity directly, without the need for steam and its associated cooling requirements. Solar photovoltaic (PV) plants are large arrays of photovoltaic cells which directly convert sunlight into electricity. None of these non-thermoelectric plants have the kind of cooling requirements during electricity generation that thermoelectric plants have, and hence, do not have the same need for cooling water.

Coal-fired thermoelectric power plants

Most coal-fired power plants blow pulverized coal into a large combustion chamber which is part of the boiler, where it burns rapidly, creating hot gases to heat the water and turn it to steam to drive a turbine to generate electricity. This steam is then cooled to liquid water, or condensed. This is typically done in a condenser, in which the steam flows over the outside of tubes filled with cooling water that is kept separate from the condensing steam. The condensed steam is pumped back to the boiler where it is again heated to produce steam. The separate cooling water, which carries the heat removed from the steam during condensation, is usually pumped back to its source (e.g., lake, river, or ocean) or cooled using a cooling tower. Conventional coal-fired plants have an efficiency of 33 to 40 percent—that is, 33 to 40 percent of the energy in the coal is converted to electricity.

Natural gas-fired thermoelectric power plants

Natural gas-fired plants use natural gas to generate electricity. There are currently three types of natural gas-fired power plants in operation:

- Steam-turbine generating plants burn natural gas in their boilers to generate steam to turn the steam turbine. These plants have an efficiency of 33 to 35 percent.

- Gas turbine generating plants, also known as combustion turbine generating plants, use the hot gases from burning natural gas to turn a gas turbine. These plants are primarily used to handle peak loads as they can be quickly started and shut down.[22] These plants have an efficiency of 35 to 42 percent.

- Natural gas combined cycle (NGCC) plants use a gas turbine and a steam turbine in combination to achieve greater efficiency than would be possible using either one independently.[23] In an NGCC plant, filtered air is compressed and used to fire natural gas in the combustion chamber to produce hot gases at high pressures that drive both the gas turbine and the compressor. The hot gas-turbine exhaust (waste heat) is used in a heat recovery steam generator to generate steam that is then used to power a steam turbine to generate additional electricity. Gas turbine exhaust then leaves the heat recovery steam generator and is discharged to the atmosphere. The exhaust steam from the steam turbine is condensed in the same way as a conventional thermoelectric plant by a cooling system to be reused in the heat recovery steam generator. The gas turbine and steam turbines both drive their respective electric generators to

22 Peak load describes a specified period of time during which electric power is expected to be provided at a significantly higher than average supply level—for example, during peak summer heat. A power plant normally used during peak load is called a peak load plant.

23 Besides being more efficient it has a much lower emissions of sulfur dioxide and carbon dioxide and also a lower water footprint compared to coal fired plants (Grubert et al. 2012).

generate electricity. These plants have among the highest power generation efficiency at approximately 50 percent.

Similarly, with an integrated gasification combined cycle plant, gasified coal can be used as a fuel, which is then burned in a combined cycle similar to an NGCC design.[24] An integrated gasification combined cycle is an emerging technology for advanced power generation, providing efficiencies potentially beyond 60 percent. It has among the lowest emission of pollutants while also producing net water savings that come from combined cycle plant designs.

Nuclear power plants

Nuclear plants use the heat from a nuclear reactor to boil water and generate steam, which is then used to turn a steam turbine to generate electricity. The remainder of the plant is similar to a coal fired plant. The most common reactor design in the United States is a Pressurized Water Reactor (PWR), where heat is first extracted from the core using a primary loop of pressurized water. For safety reasons, the steam is then generated in a secondary steam generator using heat from the pressurized water. This system minimizes the risk of the spread of radioactive contamination in the event of certain types of system failures. This indirect steam generation arrangement results in lower boiler temperatures and pressures and thus a slightly lower efficiency compared to coal fired plants—ranging from 33-35 percent.

24 Gasification involves mixing coal, steam, and air or oxygen at high temperatures and pressures to generate synthesis gas, which can be used as a fuel for a power plant.

Thermoelectric power plants using renewable fuels

Some renewable sources—for example, biomass, geothermal, and sunlight—can also be used as energy sources for steam-driven thermoelectric power generation. In each of these instances, the renewable energy replaces a fossil fuel as the heat source, while the rest of the plant—including the cooling system—generally operates like other thermoelectric power plants. Biomass, for example, is burned to heat water to generate steam that can in turn drive the steam turbine. Alternatively, biomass can also be gasified in a manner analogous to coal gasification in integrated gasification combined cycle plants. Concentrating solar power (CSP) plants use parabolic mirrors arranged in a trough configuration to concentrate sunlight to heat a heat-transfer fluid, such as oil, which in turn is used to boil water to generate steam that spins a conventional turbine generator. Geothermal power plants use heated geothermal fluid found in underground geothermal reservoirs as their source of thermal energy. Because the fluid is already hot, there is no boiler.[25] Some geothermal wells provide steam, while others provide pressurized hot water. As this pressurized hot water moves up from deeper regions in the earth to shallower levels, it quickly loses pressure, boils, and flashes to steam, which then drives a turbine to generate electricity. While all these systems eliminate the burning of fossil fuels and the associated emissions, they typically require water for condensing the steam back to liquid form.

25 Geothermal power plants do not have boilers. However, approximately 15 percent of the geothermal power plants in the United States are binary geothermal power plants which use geothermal fluids in heat exchangers to generate steam in closed loops to drive turbines and generate electricity.

Cooling systems in thermoelectric power plants

The vast majority of water used by thermoelectric power plants is required for cooling. Thermoelectric power generation processes inherently produce large quantities of low-grade "waste" heat in the exhaust steam exiting the steam turbine, which must be dissipated to the environment, typically via a cooling system that rejects this heat either into the atmosphere or dissipates it to surface water bodies.

Various types of cooling systems can dissipate this waste heat, but they generally fall under two categories: wet cooling systems, which use water to condense the steam from the turbine; and dry cooling systems, which use air.

There are generally two types of wet cooling systems: once-through systems, and wet recirculating systems (sometimes called closed-cycle wet cooling). Dry cooling systems can be broadly categorized as either direct or indirect dry cooling systems. Hybrid systems use a combination of wet and dry cooling methods.

In addition to the cooling system, which is the predominant user of water, coal-fired plants also have effluent gas scrubbing systems, which contribute to a relatively small amount of water consumption. For example, a flue gas desulfurization unit (FGD) that is used to remove sulfur dioxides can typically consume up to 10 percent of the total water consumed by a plant, or approximately 66 gals/MWh.

Today in the United States, the vast majority of electricity is generated by plants that have wet cooling systems. Our analysis of a dataset developed by the "Energy and Water in a Warming World" (EW3) group shows that, in 2008, approximately 33 percent of electricity generated in the United States was by plants that used once-through cooling systems, 51 percent by plants that used wet recirculating systems, and 13 percent by plants that used cooling ponds.[26] The remaining 2 percent of electricity was generated by plants that used dry or other types of cooling systems (Averyt et al. 2011).[27] However, stressed water resources and environmental concerns have increased the interest in dry cooling, and its adoption has been growing, particularly in new NGCC plants. The energy penalty associated with dry cooling is reduced notably when it is used in NGCC plants. For example, EPA's energy penalty estimates for the various types of power plants show that NGCC plants have among the lowest energy penalty relative to fossil fuel and nuclear plants. In 2000, most U.S. dry-cooling installations were in smaller power plants, predominantly in NGCC plants.[28]

26 Cooling ponds are man-made bodies of water constructed to provide cooling water to a plant. They can be operated as once-through or recirculating systems or as a hybrid of the two (NREL 2011).

27 Percentages do not sum to 100 due to rounding.

28 Small power plants are defined as having an electricity generating capacity less than 300 MW.

Once-through cooling systems

In once-through systems, water is drawn from a local body of water, such as a lake, river, or ocean, and used to extract waste heat from the plant. Then it is usually returned to the same body of water, where the heat is dissipated. These systems have a relatively high rate of water withdrawal but generally low levels of water consumption.

system, and flue gas scrubbing systems—DeNO$_x$ and flue gas desulfurization (FGD).[29]

As water is drawn into the once-through cooling system, it is usually filtered to remove debris and aquatic organisms before it is pumped through the tubes of a water-cooled surface condenser.[30] The steam is condensed on the outside surface of this condenser and the condensate is returned to the boiler, steam generator, or reactor, where it is

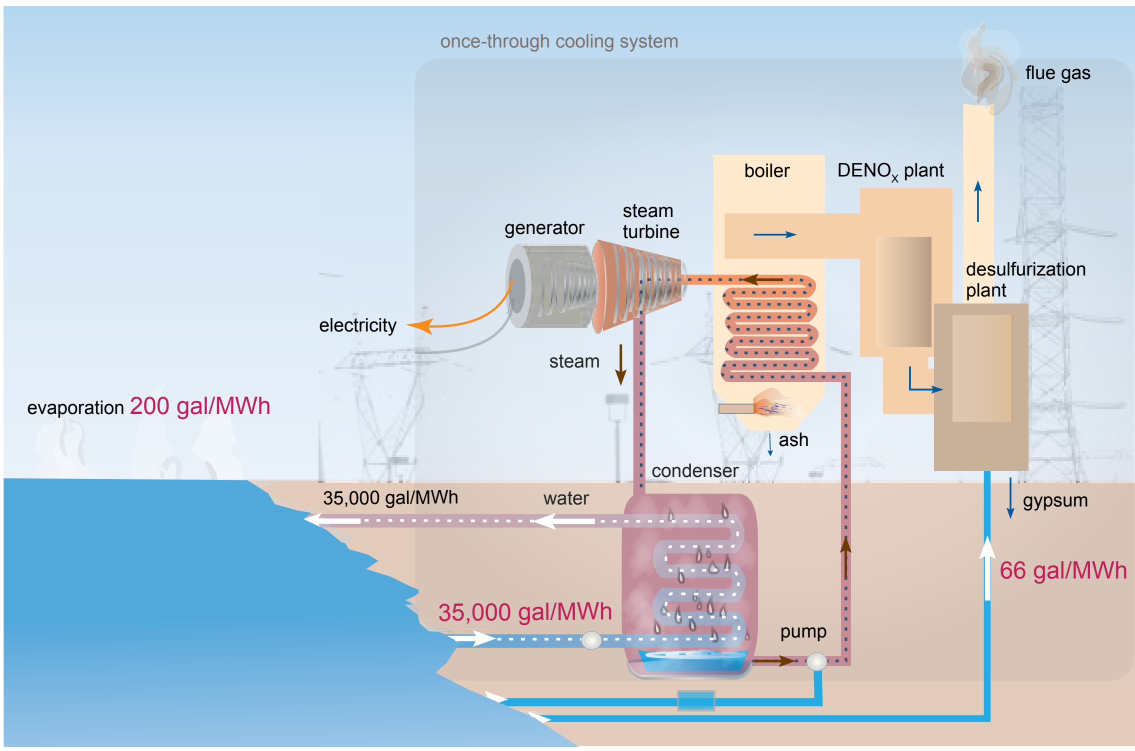


Figure 2.5: A coal power plant with a once-through cooling system

Source: GAO adaptation of Electric Power Research Instiutue 2013, U.S Department of Energy 2007, and Meldrum et al. 2013 | GAO-15-545

Figure 2.5 shows a coal power plant with a once-through cooling system's key components, such as the boiler, steam turbine, electric generator, steam condenser, cooling

29 DeNO$_X$, also referred to as selective catalytic reduction unit, removes nitrogen oxides (NO$_X$), and FGD removes sulfur oxides (SO$_X$). These oxides are generated as part of fuel combustion in the boiler and their removal is necessary to control pollution. Coal-fired power plants typically utilize this emission control equipment to limit the emissions of sulfur dioxide and NO$_X$. A relatively small amount of water is consumed by the FGD process.

30 Conventional surface condensers or heat exchangers are the most versatile type of heat exchangers used in energy applications to transfer heat. They consist of a number of tubes mounted inside a cylindrical shell and provide relatively large ratios of heat transfer area to volume.

again heated back to steam to turn the turbine to generate electricity.[31] The condenser discharges the warmed cooling water back to its source 10° F to 20° F warmer than when it was withdrawn. Typical cooling water withdrawal rates are 500 to 700 gallons per minute per MW. For a 1,000 MW plant, this corresponds to 700 million to 1 billion gallons of cooling water withdrawal per day (EPRI 2012b).

Because the cooling water does not contact air within the boundaries of the plant, there is no evaporative loss and water consumption is very low to zero. However, evaporative losses do occur after the water is returned to the source because of the water's elevated temperature, which can increase the amount of water consumption. According to NREL, this evaporation is about one half of the evaporation that occurs in the cooling towers of wet recirculating systems (NREL 2011). However, according to EPA, evaporative loss will vary depending on many factors, including the water source and temperature, and the size of the source water. For example, large water bodies such as oceans or the Great Lakes can act as heat sinks, reducing the evaporative loss.[32] In addition, with lower cooling water temperatures, once-through cooling systems tend to deliver the best power generation efficiency of all cooling alternatives.

While once-through cooling systems are generally the simplest, most energy efficient, least costly, and lowest in water consumption, they require a large, nearby body of water to serve as a source and withdraw about 35,000 gals/MWh, according to a study from the National Renewable Energy Laboratory (NREL) in 2011. In addition, the physical operation of withdrawing large quantities of water and expelling large amounts of heated water into the same source can adversely affect aquatic systems or life forms. Once-through cooling systems are rarely used by newly built power plants due to permitting requirements related to thermal discharges and cooling water intake structures, among other factors (EPRI 2005).[33]

Wet recirculating cooling systems

Wet recirculating cooling systems (also called evaporative or closed-loop cooling) also use cooling water to condense steam. However, the heated cooling water is not discharged after use as in a once-through design. Instead, it is sent to a cooling tower before being recirculated back to the condenser to be used again. This type of closed loop cooling system minimizes water withdrawal by more than 90 percent over once-through cooling. The relatively small amount of water that is withdrawn is partly consumed as evaporative loss or drift from the tower, while the remaining water is discharged

31 Condensate is condensed steam that is collected and, if suitable, returned to the boiler.

32 In comments on a draft of this report, EPA stated that the latest research and modeling for once-through cooling systems shows "the net water consumption for inland freshwater systems are generally comparable to modern cooling towers with drift eliminators." However, we did not have an opportunity to review this research or modeling.

33 Thermal discharges and cooling water intake structures are regulated under the Clean Water Act (CWA). All facilities that discharge pollutants from any point source into U.S. waters are required to obtain a permit for that discharge. Permit limitations are based on, among other things, the performance and availability of the best pollution control technologies or pollution prevention practices for the industry. Facilities can obtain a variance from limitations for thermal discharges if they can show that the proposed limitation is more stringent than necessary to assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the body of water into which the discharge is to be made. Permits also impose standards for minimizing adverse environmental impacts, such as the impingement and entrainment of fish and other aquatic organisms, associated with the use of cooling water intake structures.

as "blowdown" (NETL 2011).[34] Water lost to the system by evaporation, drift, or blowdown is replenished continually by adding "make-up" water to the cooling tower.

A study on power plant water usage and loss conducted by NETL showed that coal fired power plants with wet cooling towers typically require 600 gals/MWh of make-up water, about 450 gals/MWh of which is lost through evaporation, and the remaining 150 gals/MWh is discharged as blowdown (NETL 2007c).

A schematic of a coal-fired power plant with a wet recirculating cooling system design is shown in figure 2.6.

Dry cooling systems

Dry cooling systems dissipate heat from power plants directly to the atmosphere. These systems do not require water for cooling, but rely instead on ambient air.

There are two types of dry cooling systems: direct dry cooling and indirect dry cooling. In direct

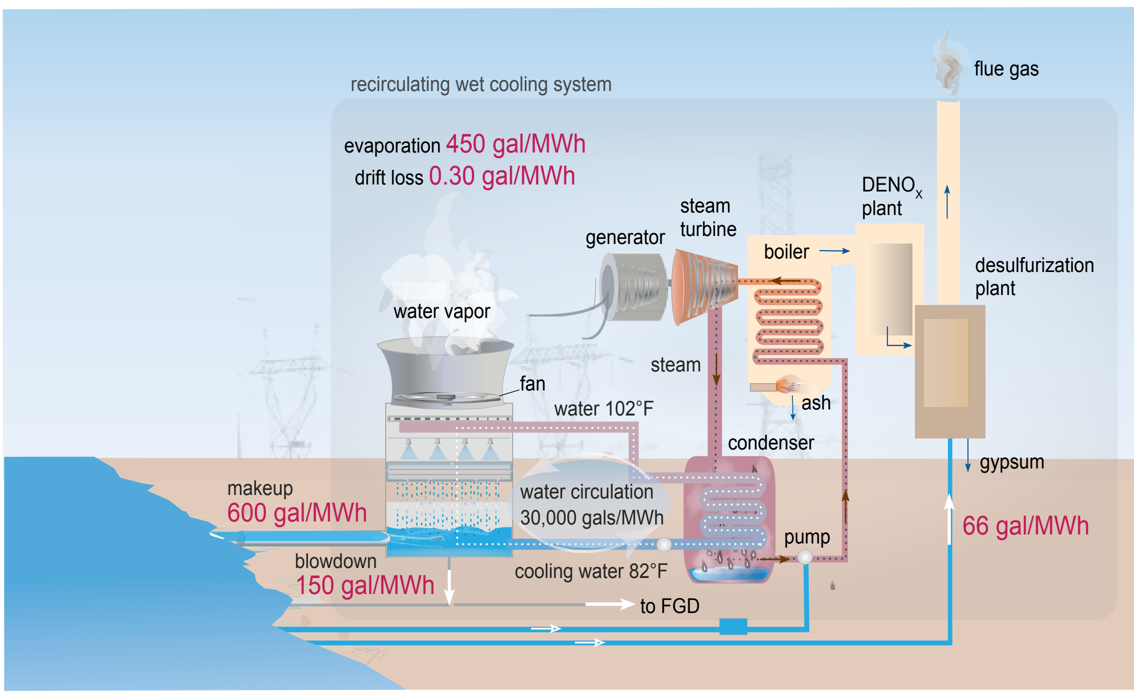


Figure 2.6: A coal power plant with a wet recirculating cooling system

Source: GAO adaptation of Electric Power Research Institute 2013a and National Energy Technology Laboratory 2007c | GAO-15-545

dry cooling, the turbine exhaust steam flows through tubes of an air-cooled condenser (ACC) where the steam is cooled directly. For indirect dry cooling (also known as a Heller system), a conventional water-cooled surface condenser is used to condense the turbine exhaust steam, but

34 As water is continually evaporated in a cooling tower, the concentration of salts and solids left in the remaining water increases. A high concentration of salts and solids can cause scaling, fouling, and corrosion in the internal components of the cooling system. Therefore, a small fraction of recirculating water is continually discharged from the bottom of the tower that is replenished by new cooling water. This discharged water is called blowdown. Drift is the water expelled with the heated air plume in the cooling tower in the form of droplets (EPRI 2012b).

a dry cooling tower, similar to an ACC, is used to transfer the heat from the water to the ambient air. There is no evaporative loss of cooling water with either direct or indirect dry cooling systems, and both water withdrawal and consumption are minimal. However, dry cooling systems have higher capital costs and incur an energy penalty, which makes them less energy efficient than wet cooling system. Lower efficiencies mean more fuel is needed per unit of electricity, which can in turn lead to higher air pollution, among other issues. The lower efficiencies are caused by higher steam condensing temperatures compared to water cooling.

3 Assessment of technologies to reduce freshwater use in hydraulic fracturing

Shale oil and gas are found in shale plays—a set of discovered or undiscovered oil and natural gas accumulations or prospects that exhibit similar geological characteristics—on private, state-owned, and federal lands across the United States. Shale plays are located within basins, which are large-scale geological depressions, and are often hundreds of miles across. They may also contain other oil and gas resources. A shale play can be developed for oil, natural gas, or both. Figure 3.1 shows the location of some important shale plays in the United States.

As of 2012, shale gas was produced in 22 of the 50 states (Nicot and Scanlon 2012). Some of these plays are in areas that are generally not water-stressed. The Marcellus Shale gas play, for example, is located in the Appalachian Basin across the eastern part of the United States, which runs from West Virginia through Pennsylvania and up into New York. However, water–stressed regions such as central Texas, Nebraska, and North Dakota are home to the Barnett, Niobrara, and Bakken, respectively, all of which are major shale oil or gas plays (figure 3.1).

Hydraulic fracturing for shale gas is a water

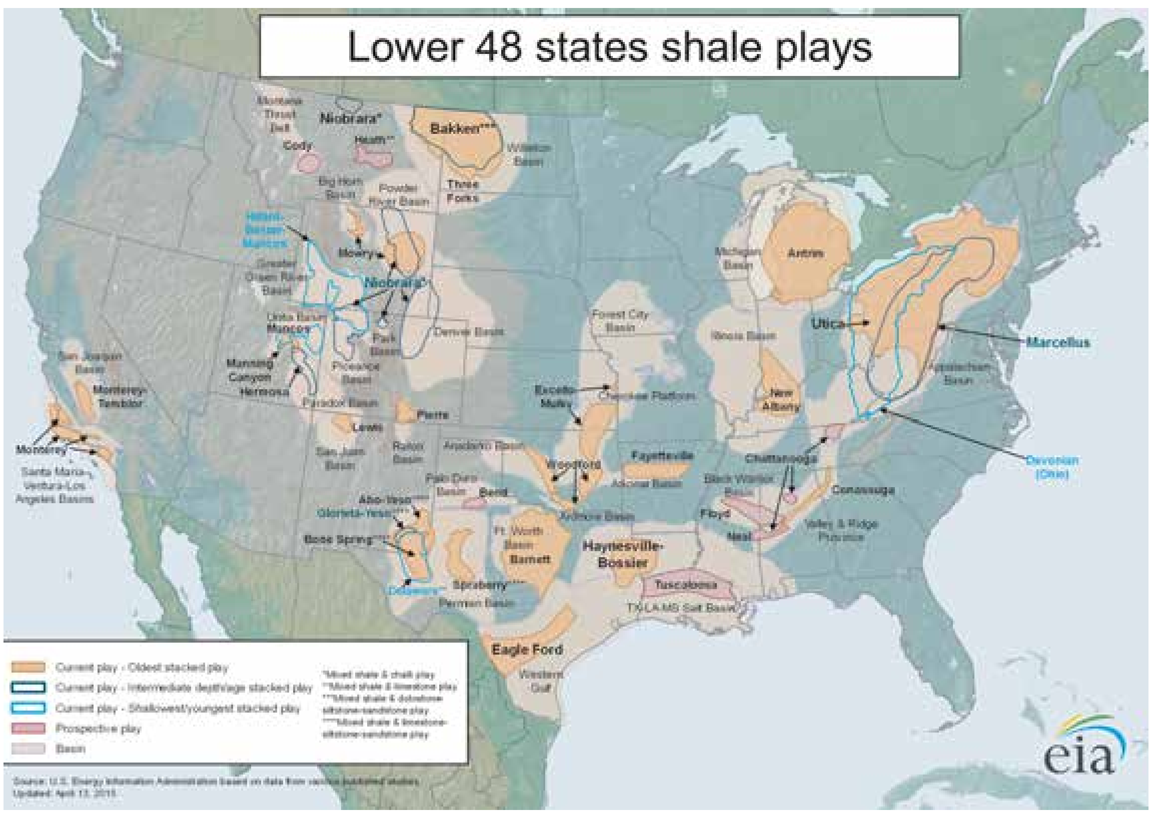


Figure 3.1: Map of U.S. shale gas and shale oil plays (2015)

Source: U.S. Energy Information Administration | GAO-15-545 intensive operation, estimated to consume between 2 to 9 million gallons of water per well (Clark et al. 2013).[35] Many factors influence the amount of water used in fracturing a well, including the geology of the shale, the number of fracturing stages (generally related to the length of the horizontal section of the well), and the specific characteristics of the fracturing process itself.[36]

In water-scarce regions, the impact of using surface water or groundwater at multiple shale oil and gas development sites can be significant at a local level. For example, in Texas, it was reported in 2012 that water used for hydraulic fracturing for shale gas made up less than 1 percent of statewide water withdrawals. However, it was also noted that water use varied within the state and this amount might have represented a higher portion of the total water use at a local county level—as high as 29 percent of the total annual net water use for some counties (Nicot and Scanlon 2012, Nicot et al. 2012). Similarly, we found in a May 2014 report that in Colorado, while just 0.08 percent of state water was used for hydraulic fracturing in 2010, officials in the state told us that over the last 10 years, energy production, particularly shale oil and gas production, have increased significantly, and they are monitoring for its potential impact on water resources (GAO 2014).

The increasing growth and importance of hydraulic fracturing in U.S. gas production is likely to increase the demand for water in the energy sector. For example, in a September 2012 report, we found that from 2007 through 2011, annual production of shale oil and gas experienced significant growth. Specifically, shale oil production increased more than five-fold, and shale gas production increased approximately four-fold over this 5-year period. In a May 2014 report, we found that anticipated increases in energy production in Colorado could further drive demand for water use in the state in the future. The Colorado Oil and Gas Conservation Commission projected that the annual demand of water for hydraulic fracturing would increase approximately 35 percent between 2010 and 2015. Such increases in water use could pose problems in certain areas because the state receives only 12-16 inches of precipitation annually, and drought occurs frequently (GAO 2014).

In this section, we assess alternative fracturing technologies and water management techniques that operators have used in the field to reduce freshwater use in hydraulic fracturing. These technologies include the use of waterless and water-efficient fracturing fluids such as those utilizing liquefied petroleum gas (LPG)[37] and foams, and the technique of channel fracturing, which has been shown to improve operational efficiency while reducing material cost and water usage in selected formations (Altman et al. 2012). Use of these techniques is similar in many respects to conventional water-based fracturing except that water—the base fluid—is largely replaced by alternatives. Although these techniques reduce water requirements during fracturing, conventional water-based slickwater fracturing—which uses large amounts of fresh water—remains a commonly used hydraulic

35 We focused mainly on shale gas because of its rapid growth, its increased scrutiny due to water requirement concerns, and its significance to many cross-cutting industrial sectors (Baihly et al. 2010).

36 Additionally, some studies have also examined re-fracturing or the frequency of re-fracturing a well as a key variability factor in the amount of water required during the entire lifetime of a well (Clark 2013). Some experts told us, however, that there is not much evidence that re-fracturing is actually happening as a trend. Only a few wells in each play have been fractured more than once. It is unknown whether or not all wells will require re-fracturing in the future and if it actually increases the hydrocarbon recovery from a well.

37 LPG refers to a group of hydrocarbon gases mainly composed of propane and butane, which has been liquefied at low temperatures and moderate pressures.

fracturing technology today. We also examined water management practices such as water treatment, recycle, and reuse, that shale oil and gas operators are starting to use as part of their overall strategy to reduce cost, improve operational efficiency, and limit the increase in demand for freshwater use. These measures have the dual benefit of conserving water and reducing the amount of waste water that needs disposal, thereby saving money.

In conducting our assessment, we examined federal agency, academic, and scientific documents that describe and quantify water use in unconventional resource extraction techniques such as hydraulic fracturing. We consulted with oil and gas operators involved in developing various shale plays around the country to determine which technologies might need to be applied differentially across plays. We interviewed U.S. shale oil and gas operators and water management companies to understand how they use water in their operations and the ways in which technology could help reduce their water usage. We reviewed reports and interviewed authors of pilot projects, as well as demonstrations of the use of fracturing fluids other than water. Appendix 7.1 describes our methodology for this assessment.

3.1 Alternative waterless and water-efficient fracturing technologies

Waterless and water-efficient fracturing technologies are similar in many respects to water-based fracturing but use a different fracturing fluid. For example, waterless techniques might use (LPG) instead of water. Other formulations may include a mixture of light oil and a gas, such as carbon dioxide (CO_2), to fracture oil and gas formations, though these formulations typically use some water. Water-efficient fracturing fluid may use foams in combination with water and nitrogen or carbon dioxide gas. These alternative fracturing fluids are designed to be viscous enough to deliver proppants into the formation to keep the fractures open and then flow back along with the produced gas. Some operators seek waterless fractures to increase the productivity of wells in specific regions—that is, to increase the amount of oil or gas that can be recovered. This is reportedly because when water is used in certain formations, the injected water may react with minerals and salts in the rock, or may damage the formation, impairing or hindering oil or gas recovery during production. In some cases, as little as 30 percent of injected water may be recovered as flowback water while the rest remains in the formation, where it can close flow pathways, preventing oil and gas from being produced.

3.1.1 LPG, nitrogen, and carbon dioxide as alternatives to water

LPG and other gas-based fracturing techniques utilizing nitrogen or CO_2 have been researched and used in some shale formations.[38] CO_2-based fracturing was introduced in the early 1990s by DOE (NETL 2007a).

More recently, LPG fracturing using a mixture of propane and chemical additives is reportedly a promising technology, but still in its early stages. This technology has been used primarily to increase production in a select group of shale

38 The first hydraulic fracturing experiment was a waterless technique that was performed using a gasoline gel injected into a Hugoton field well in 1947.

formations mainly in Canada, but also in some regions of Texas. In these low permeability, low pressure shale formations, water-based fracturing seems to reduce gas production. According to experts we spoke with, some gas formations are sensitive to the freshwater used for fracturing, which may result in productivity loss. Furthermore, in some specific dry gas formations, the downward pressure of the water used during fracturing could potentially exceed the natural formation pressure of the gas in the pores of the rock, preventing the gas from flowing out to the wellbore. In such cases, the injected water must be removed from the well after the completion of fracturing for efficient gas production. In contrast, LPG has much lower viscosity and density compared to water, thus making it easier to flow out of the formation while also exerting lower back-pressure on the formation. Initial results of LPG-based fracturing used in three different shale formations in south Texas have reportedly shown a notable increase in production of oil and gas.

However, there are barriers to widespread use of LPG-based fracturing. For example, given its lack of extensive production history, uncertainty persists as to whether gas-based fracturing could improve long term productivity. The high cost of propane can also be a barrier to LPG-based fracturing. Given the high cost, this technology works best when appropriate infrastructure is in place that allows the propane to be captured and reused. Nonetheless, proponents of this technology assert that, in some situations, it can cost less to use propane versus transporting and treating large quantities of water.

Concerns about the safety of these operations can be another barrier. Propane, for example, is flammable, leading to public concerns about worker safety, although the service providers say they have implemented appropriate safety features and follow best practices developed by the industry for propane use.

3.1.2 Foam-based fracturing

Foam-based fracturing is another type of formation stimulation technology most commonly used in formations where the reservoir pressure is too low to drive a column of water out of the well. In some water-sensitive, low pressure, and water-scarce shale gas formations foams have been the preferred fluid (European Commission 2013).

Foam-based fluids consist of a mixture of water, a foaming agent, and nitrogen or carbon dioxide, which allows the proppant to be transported while reducing the volume of water used. Furthermore, the low liquid content of foams leaves less liquid behind to remove from the well after fracturing.

Foam-based fracturing was first tested and used in the Devonian Shale by joint DOE and industry cooperative shale gas programs around the late 1970s and became the preferred commercial method of stimulation for Devonian Shale gas wells (Komar et al. 1979). NETL reported that foam fracture reduced the volume of water used by 75 to 90 percent as compared to conventional hydraulic fracturing (NETL 2007a).

However, the success of foam-based fracturing could not be replicated when applied to formations of higher pressure that typically require large volumes of fracturing fluids, such as the Barnett Shale in Texas (Jacobs 2014). These considerations led to its discontinued use and replacement by slickwater fracturing, which gave comparable results at reduced costs, although required more water. Specifically, in 1997, Mitchell Energy found that results from slickwater fracture, with far less amounts of proppants and gel, were comparable to or better than the more costly alternative fracturing methods, reducing the cost of stimulation by approximately 50 percent.[39]

While foam-based fracturing uses less water than the conventional slickwater fracturing and can be less costly in some circumstances (Jacobs 2014), depending on water sourcing and disposal costs, its effectiveness depends upon a variety of reservoir attributes, such as pressure levels in the formation, that could influence the economic feasibility. Thus, the adoption of foam-based fracturing by the industry on a large scale is expected to be slow because of the lack of supply infrastructure and logistics, and its limited use in the past. In addition, the expected increased production benefits from foam are still debatable and uncertain (Jacobs 2014). According to one expert, while slickwater is more commonly used in deeper high-pressure shale formations, nitrogen-foamed fracturing fluids are commonly pumped in shallower shales and shales with low reservoir pressures.

As concerns over the large amounts of water required for slickwater fracture have increased, however, there is renewed interest by researchers, industry, and service companies to reexamine their exclusive use of slickwater and investigate new formulations of foam-based fracture procedures as an alternative.

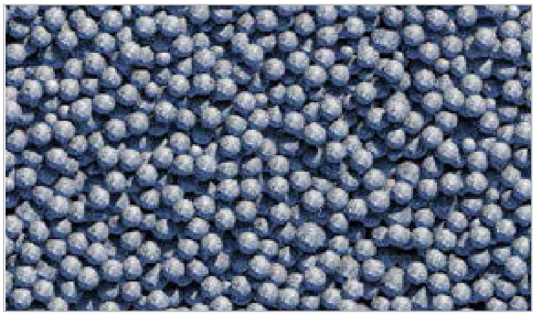
3.2 Channel fracturing technology

Channel fracturing is an alternative formation stimulating technology to increase oil or gas recovery while using fewer resources, including water. This technology involves the intermittent injection of proppant-laden fluid followed by injection of proppant-free gelled fluid at a frequency designed to promote a clustered placement of proppant in formations. This creates open channels around the proppant clusters through which hydrocarbons can easily flow (Altman et al. 2012).

In conventional hydraulic fracturing, hydrocarbon flows through the homogeneously placed proppant media where the flow is limited by the permeability of the proppant region. Channel fracturing circumvents this limitation by achieving a discontinuous or clustered placement of proppant with intermittent open flow channels that improve the flow of hydrocarbons to the well bore. Figure 3.2 shows the uniformly distributed proppant and the open flow channels achieved with channel fracturing.

Channel fracturing has reportedly been used in most of the key shale plays in the United States, including the Eagle Ford Shale, Marcellus Shale, and Barnett Shale, as well as oil and gas fields overseas. The impact of channel fracturing on well productivity has been studied and demonstrated as a driver for improving well productivity over conventional stimulation techniques. For example, one study in the Eagle Ford Shale using reservoir simulation showed that wells stimulated using the channel fracturing technique experienced 60 percent greater normalized gas production for the first six months, and an enhancement in fracture volume by 50 percent, compared to wells stimulated with conventional techniques, such as slickwater fracturing. In addition, wells stimulated with channel fracturing used 28 percent less proppant and 60 percent less fluid per cluster (Altman et al. 2012).

39 Gel refers to a form of solid suspended in a liquid medium. It is typically added to water-based fracturing fluid to improve proppant transport to the fractures because slickwater is an inherently poorer proppant carrier. Conventional hydraulic fracturing uses gels as one of the constituents that are mixed with water to form the fracturing fluid.



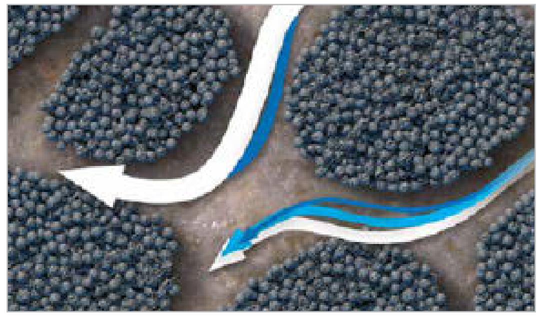


Figure 3.2: Flow channel creation with channel fracturing technology

Source: Schlumberger | GAO-15-545

Left image: Proppant media placement typical of conventional hydraulic fracturing. Hydrocarbons flow through the homogenously-placed proppant.

Right image: Hydrocarbon flow patterns created by a channel fracturing technique creates open channels through which hydrocarbons can flow more easily.

Another case study on two wells in the Eagle Ford Shale in Texas using channel fracturing experienced reduction in water consumption of up to 58 percent, conserving more than 10 million gallons of water and 2.6 million pounds of proppant while increasing oil and gas production (Schlumberger 2012).[40] According to the study, the reduction in materials and water consumption for fracturing also reduced operational costs, as well as safety and environmental risks.

However, according to representatives of a research and consultancy organization with whom we spoke, while channel fracturing has been successful in specific shale plays, it has not been used over a sufficiently long time span or across different types of shale plays to demonstrate the capacity to deliver productivity gains and water savings. According to the representatives we spoke with, some oil and gas operators view channel fracturing as part of a variety of improvements by the oil and gas industry to realize gains in operational efficiency, reduced cost, and increased productivity.

40 Schlumberger is a global oil and gas well service provider.

3.3 Water management practices: treatment, recycle, and reuse

While the alternative fracturing techniques described above reduce water requirements, their primary benefit is in promoting enhanced product recovery. Moreover, because of their dependence on specific formation characteristics, these techniques are not widely deployed or generally applicable. However, recent technological advances coupled with water consumption and disposal issues have created the need for water management strategies, which has led to more frequent water reuse and the ability to use more brackish water in hydraulic fracturing. Further, in some regions facing water scarcity, such as the Barnett and Eagle Ford Shale, shale gas operators are managing their water resources—for example, by treating water for recycle and reuse—as an important part of their overall strategy to help reduce cost, improve operational efficiency, and limit the increase in demand for freshwater use.

Water management activities include securing and transporting water supplies, recycling and reuse, and disposal. Water recycling and reuse involve treating the produced water from a well, often blending it with freshwater, and reusing it as fracturing fluid in subsequent fracturing operations. The use of alternative sources of water, such as brackish water, in lieu of freshwater resources is also practiced in some shale plays.[41] For most shale gas operations, disposal involves transporting all the produced water to designated Class II disposal wells, where it is injected into the wells.[42] Discharging produced water to surface bodies is not typically done because of remediation costs and federal and state requirements surrounding such practices. However, with proper permits, the produced water can sometimes be trucked from the well site and discharged to an offsite commercial disposal facility, also known as a centralized waste treatment facility, or to a municipal treatment facility, often referred to as publicly-owned treatment works.[43]

These efforts can be a substantial portion of an operation's overall cost. For example, total water management and handling costs reportedly account for approximately 10 percent of the operating cost of a typical well in the Marcellus Shale play (Gay et al. 2012). Shale gas operators in regions where water is scarce or where disposal of produced water is costly or difficult are recycling and reusing produced water to partially offset the need for freshwater and to increase operational efficiency. Even in regions with sufficient water supplies, such as the Marcellus Shale, operators have begun recycling their produced water into new fracturing fluids because they can save on costs associated with disposal and trucking, while reducing the volume of freshwater used for new fracturing fluids (ANL 2010). While reuse incurs the cost of treatment, it can save freshwater, which can be costly or scarce, and it reduces the overall amount of produced water that needs to be disposed, an expensive part of shale gas operations.[44] Reuse may also be spurred by a lack of waste water disposal infrastructure or tighter environmental regulations on disposal methods.

Because of its generally poor quality, produced water typically requires some treatment to allow its reuse as a fracturing fluid base for future fracturing use. The presence of residual hydrocarbons, for example, can foul membranes and filters, and the presence of unwanted bacteria can be problematic. Certain types of dissolved compounds can also pose significant scaling issues. Blending produced water with freshwater can improve the quality, but often treatment is also required to remove residual hydrocarbons, solids, salts and possibly other contaminants—often formation dependent—before the produced water can be reused. For example, according to the EPA, technologically-enhanced, naturally-occurring radioactive materials are a concern in the Bakken and the Marcellus Shale.[45] There are

41 Shale gas operators may use a variety of sources of water including traditional water sources (surface water, ground water), purchased water (such as from municipalities, river authorities), wastewater sources (wastewater treatment plant effluent, power plant cooling tower effluent), recycled water (such as reused produced water), and alternative water sources (such as brackish groundwater). In this report, however, we focus on recycle or reuse of produced water and the use of brackish water that has been frequently reported in the literature.

42 Class II wells inject fluids associated with oil and natural gas production.

43 For more information on the current practices and requirements for the discharge of produced water, see http://water.epa.gov/scitech/wastetech/guide/oilandgas/unconv.cfm#background

44 Disposal cost can vary depending on the availability and proximity of disposal wells. For example disposal wells are relatively abundant in the Barnett Shale whereas they are nonexistent in the Marcellus Shale due to regional geology. This means wastewater would have to be transported to out-of-state disposal wells thus increasing the cost of transportation.

45 According to the EPA, technologically-enhanced, naturally-occurring radioactive material is produced when activities such as uranium mining, or sewage sludge treatment, concentrate or expose radioactive materials that occur naturally in ores, soils, water, or other natural materials.

readily available water treatment technologies that can remove many of these contaminants and render produced water more suitable for reuse.[46] For example, suspended solids in produced water can be removed through filtration. Dissolved solids, such as chlorides, are generally mitigated by blending with freshwater.

In water-scarce regions such as the Permian basin in west Texas, oil and gas producers are using large amounts of recycled water or water that is of lower quality than fresh water, such as saline water, to reduce their freshwater usage during fracturing. Use of brine as an alternate source of water and reuse of flowback water are now common in those regions, though the percentages of freshwater, brackish water, and reused and recycled water all vary notably across different shale plays. For example, a report on shale oil and gas water use in Texas estimated percentages of water recycle and reuse varying from zero to 20 percent, the use of brackish water varying from zero to 80 percent, and freshwater use varying from 20 to 95 percent across different plays (Nicot et al. 2012). Water recycling and reuse has also been reported in other shale plays such as the Barnett, Fayetteville, Haynesville, and Marcellus shale (Mantell 2010).

46 Advanced water treatment technology includes reverse osmosis membranes, thermal distillation, evaporation and/or crystallization processes. These technologies are used to treat dissolved solids, primarily consisting of chlorides and salts but also including dissolved barium, strontium and some dissolved radionuclides (Mantell 2011).

4 Assessment of technologies to reduce freshwater use in thermoelectric power generation

To address one of the core objectives of this work, we conducted an assessment of advanced and emerging cooling technologies that may help reduce water consumption in thermoelectric power generation. In assessing advanced cooling technologies for thermoelectric power plants, we analyzed published scientific literature, technical reports—primarily by Electric Power Research Institute (EPRI) and the National Energy Technology Laboratory (NETL)—technical brochures, and equipment vendor studies. We also reviewed data presented at conferences and technical workshops, and interviewed selected experts from the electric power industry, academia, and advocacy groups.

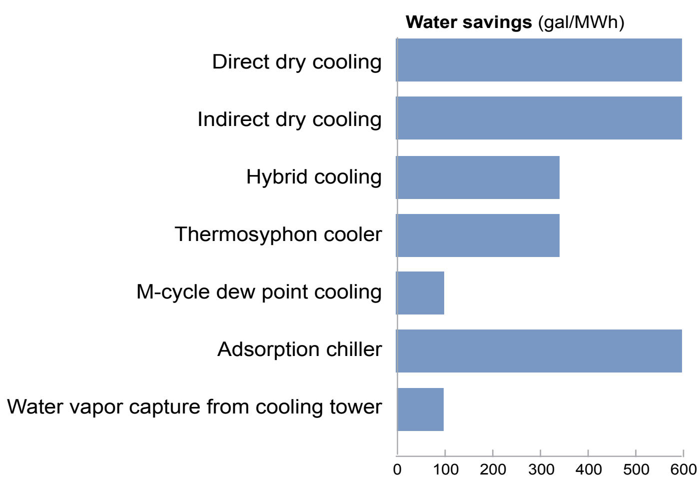
We assessed three advanced cooling technologies—direct dry cooling, indirect dry cooling, and hybrid wet-dry cooling. In addition, we assessed four emerging cooling technologies: thermosyphon cooling, M-cycle dew point cooling, adsorption chiller, and air cooling technology to recover freshwater from an evaporative cooling tower.

We summarize our assessment of these technologies in four areas: (1) maturity, which we rated on a scale of 1 to 9 using technology readiness levels (TRL)—a standard metric for technological maturity; (2) potential effectiveness, which we analyzed in terms of water saving potential; (3) cost factors, which represent the resources necessary to implement the respective technologies; and (4) potential challenges and consequences. Our methodology for technology readiness assessment is described in appendix 7.1.

Our assessment shows that the three advanced cooling technologies—direct dry cooling, indirect dry cooling, and hybrid wet-dry cooling—are fully mature at the highest TRL rating of 9 because they are commercially operational at some power plants. For example, several dry cooling systems are in operation particularly in the arid western regions of the United States. Dry cooling systems are highly effective in terms of water usage because they use no water for cooling; however, they cost more than conventional wet recirculating systems and may result in an energy penalty that reduces the net electricity output from the plant, requiring more fuel to be burnt per unit of electricity produced. For example, a dry cooling system with an air-cooled condenser (ACC) can have an energy penalty of as much as 10 percent on hot days and capital costs about 3 to 4 times higher compared with current wet recirculating systems. Hybrid wet-dry cooling technologies mitigate some of these cost and energy penalties by incorporating both wet and dry cooling methods. Additionally, dry cooling has a large land-use footprint, and may result in increased green-house gas emissions. Dry cooling is generally not retrofittable to existing thermoelectric power plants, but is mainly used at newer natural gas combined cycle (NGCC) plants in the arid West.

In contrast, we found the four emerging cooling technologies—the thermosyphon cooler, M-cycle dew point cooling, adsorption chiller, and air cooling to recover freshwater from an evaporative cooling tower—are at varying low to medium levels of maturity ranging from TRL 3 to TRL 7. Their potential effectiveness at saving water is also variable and uncertain. The costs associated with these systems are also unknown, as some of them have not been evaluated for power plant cooling applications, and their readiness may depend on a number of site-specific factors. None of these emerging cooling technologies are ready for full scale commercial operation given our assessment of their maturity, potential effectiveness, cost factors, and potential challenges.

Figure 4.1 summarizes our quantitative estimates of potential water savings associated with each of the advanced and emerging cooling technologies we assessed. This figure shows that dry cooling technologies—both direct and indirect—have among the highest water savings potential.



Note: Our estimated water savings with the various advanced and emerging cooling technologies are relative to a baseline 500 MW coal fired power plant operating with an evaporative cooling system.

Figure 4.1: Estimated cooling water savings based on our assessment of the advanced and emerging cooling technologies

Source: GAO analysis of Meldrum et al. 2013, National Energy Technology Laboratory 2007c, and Electric Power Research Institute 2012e | GAO-15-545

4.1 Assessment of advanced cooling technologies: direct dry, indirect dry, and hybrid wet-dry cooling

Dry cooling can be broadly categorized as either direct or indirect. The vast majority of dry cooling systems in the United States are direct dry cooling, while indirect dry cooling systems are used in fewer than 10 percent of dry cooled plants worldwide. In direct dry cooling, steam is condensed—converted back to liquid water—directly by air in an air-cooled condenser. An indirect dry cooling system uses a two-step process for condensing steam and cooling the condensed water, where the steam is first condensed in a condenser similar to a conventional condenser using water that is next cooled in a dry cooling tower using air, a configuration known as an air-cooled heat exchanger.[47] Hybrid wet-dry systems use a combination of dry and wet cooling systems to alleviate the energy penalty with an all dry system.

Table 4.1.summarizes our assessment of the advanced cooling technologies.

47 A heat exchanger is a device used to transfer heat from one fluid to another without direct contact of the fluids. It is designed to maximize the transfer of heat by maximizing the contact surface area between fluids.

Maturity[a]	Potential effectiveness[b]	Cost factors[c]	Potential challenges and consequences
Direct dry cooling			
High (TRL 9): • Full-scale commercial system implemented at several natural gas combined cycle (NGCC) power plants in the arid west and northeast	**High:** • Near zero water consumption for plant cooling, or an equivalent water savings of 1.84 billion gallons per year (equivalent to 600 gallons per megawatt-hour of electricity generated—gals/MWh) compared to traditional wet cooling tower systems	• Generally has about 3 to 4 times higher capital costs than wet recirculating cooling systems • Less efficient than wet recirculating cooling systems and poses an energy penalty that requires running the plant longer to meet the same power quota; and increases the cost of generating electricity • Viability may depend on the cost of water versus the site-specific capital and operations and maintenance costs and the associated energy penalty	• More complex than wet cooling systems • Estimated maximum energy penalty associated with a new direct dry cooling system at a new plant ranged from about 12-18 percent during extreme heat • Energy penalty requires additional fuel and may reduce power generation capacity and increase emissions • Retrofitting is generally considered economically infeasible and technically challenging • Air-cooled condenser requires large land footprint (about two times that of a wet cooling tower with equivalent cooling capacity) and needs to be in close proximity to the steam turbines • Fans required for direct dry cooling consume more power than pumps and fans in a wet cooling system

Table 4.1: Assessment of advanced cooling technologies, continues on next page.

Maturity[a]	Potential effectiveness[b]	Cost factors[c]	Potential challenges and consequences
Indirect dry cooling			
High (TRL 9): • Commercially available technology; Not used in the United States, but a few, fully integrated commercial scale systems have been built and are operating at power plants in some Eastern European and Middle Eastern countries (Hungary and Turkey)	**High:** • Near zero water consumption, or an equivalent water savings of 1.84 billion gallons per year (equivalent to 600 gals/MWh) compared to traditional wet cooling tower systems	• Generally cost more than wet recirculating cooling systems or a direct dry cooling system • Viability may depend on the cost of water versus the site-specific capital and operations and maintenance costs and the associated energy penalty	• More complex than wet cooling systems • Energy penalty of 9-12 percent during extreme heat; average annual penalty is 4-5 percent • Energy penalty may reduce power generation capacity and increase emissions • May be more amenable to retrofit because it works in conjunction with the conventional steam condenser

Table 4.1: Assessment of advanced cooling technologies, continues on next page.

Maturity[a]	Potential effectiveness[b]	Cost factors[c]	Potential challenges and consequences
Hybrid wet-dry cooling			
High (TRL 9): • Hybrid systems with separate wet and dry cooling modes are operating at a few plants in the United States and many more abroad • A prototype configured as a single structure housing both wet and dry cooling systems is being tested at a power plant • Limited commercial operation at full-scale power plants in the United States, though more abroad	**Medium:** • Ability to save water is highly variable depending on ambient temperature, humidity, and plant operating conditions • Approximately 20-90 percent annual reduction in make-up water could be achieved. A 55 percent representative reduction would equate to an savings of 1.0 billion gallons per year (equivalent to 330 gals/MWh) compared to traditional wet cooling tower systems, while still retaining efficiency and capacity advantages during hot weather's peak load periods, compared to an all-dry system	• May cost more than wet recirculating cooling systems • Viability may depend on the cost of water versus the site-specific capital and operations and maintenance costs and the associated energy penalty	• More complex than wet cooling systems • Up to 10 percent more power production on the hottest days compared to an air-cooled condenser of an all-dry system • Existing dry cooled plants could be retrofitted with a separate wet cooled unit to improve cooling performance during hot days

Table 4.1: Assessment of advanced cooling technologies.

Source: GAO analysis of reports from Electric Power Research Institute, U.S. Department of Energy's National Energy Technology Laboratory (NETL), U.S. Department of Energy, U.S. Environmental Protection Agency; consultations with experts through collaboration with the National Academy of Sciences; various publications and reports; and interviews with selected stakeholders. | GAO-15-545

[a] Note: Technology readiness levels (TRL) are a standard tool that some federal agencies use to assess the maturity of emerging technologies. Details of our methodology for assessing maturity of a technology using TRL scale are described in section 7.1.

[b] Details of our methodology for assessing potential effectiveness are described in section 7.1.

[c] Cost factors represent the resources entailed in implementing the respective technologies.

Note: Our estimated water savings with the various advanced cooling technologies are relative to a baseline 500 MW coal-fired power plant operating with an evaporative cooling system.

4.1.1 Direct dry cooling

Direct dry cooling dissipates all the waste heat from the steam cycle to the atmosphere via sensible heat transfer rather than the heat transfer by evaporation that characterizes wet cooling systems.[48] Dry cooling systems do not consume any water for cooling and generally use only air to draw heat away from the process fluids. As shown in figure 4.2, the steam from the power plant's turbine exhaust is directed through ducts to the top of the ACC, from where it is distributed to a network of finned tubes to dissipate its heat. The tubing network is arranged in groups called cells. A fan at the bottom of each cell blows ambient air across the tubes to draw the heat from the steam and dissipate it to the surrounding atmosphere, condensing the steam back to a liquid form which is called the condensate. The condensate flows to a collection line at the bottom of the ACC and is pumped back to the boiler. Because this steam circuit is completely isolated from the outside air, there is no water lost to the atmosphere (Tetra Tech, Inc. 2008). The water consumption for plant cooling can be reduced to near zero, so these systems are highly effective at saving water.

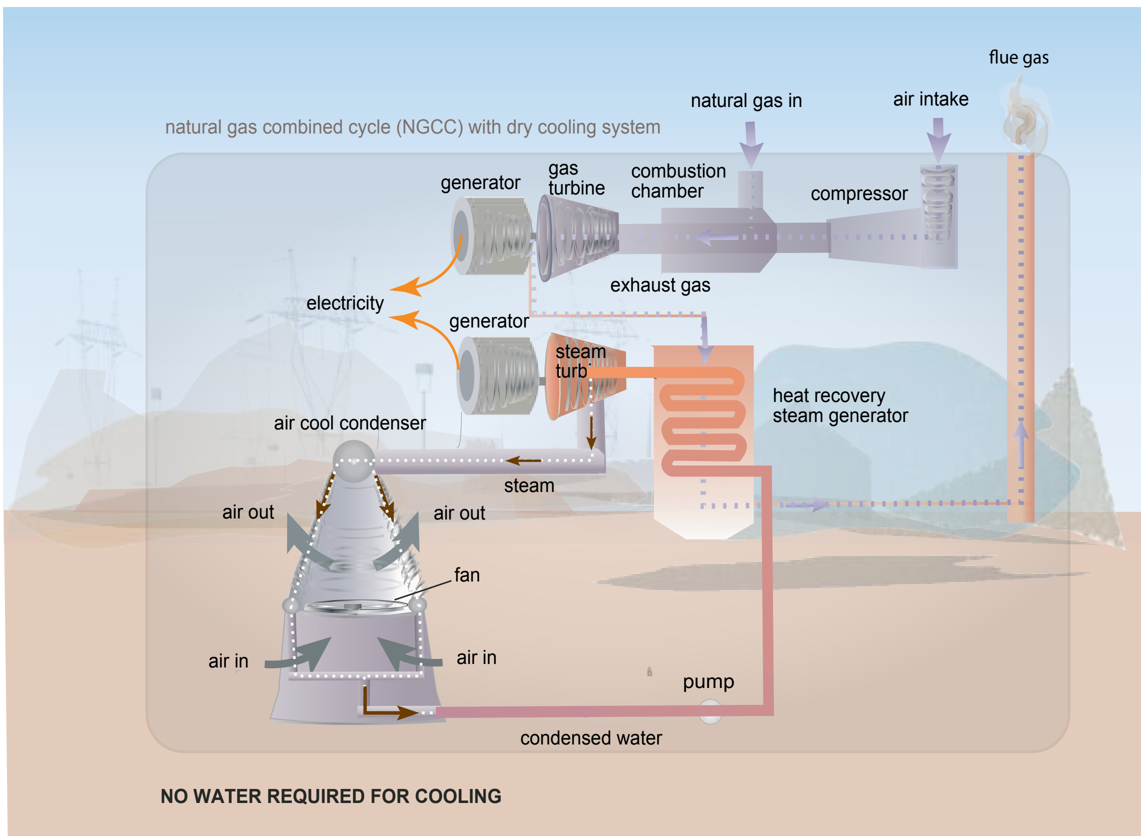


Figure 4.2: A natural gas combined cycle (NGCC) power plant with a dry cooling system

Source: GAO adaptation of GAO 2009a and Electric Power Research Institute 2008 | GAO-15-545

48 In this context, sensible heat transfer is a form of heat transfer in which a warm fluid is cooled by contact with a cooler fluid resulting in a change in temperature. In contrast, evaporative heat transfer is a form of heat transfer in which the evaporation of a liquid lowers the temperature of the remaining liquid.

Specifically, our estimates show water savings of approximately 600 gals/MWh compared to traditional wet cooling tower systems. Figure 4.2

shows an NGCC plant with a dry cooling system. As shown in this figure, the air-cooled condenser does not consume any water during cooling.

Because air cooling is less efficient than water cooling, plants with dry cooling systems incur an energy penalty that may decrease their net power generation per unit of fuel used, typically requiring additional generation to maintain the same power output. This requires additional fuel and increases emissions. The energy penalty tends to peak during the summer and may substantially decrease during cooler times of the year. For example, data from the Environmental Protection Agency (EPA) indicates that an average peak summer energy penalty of 10 percent is incurred in the conversion from a once-through cooling to a direct dry cooling system, whereas only a 1.7 percent peak summer energy penalty is incurred in a conversion from a once-through cooling to a wet recirculating system for a fossil fuel plant (EPA 2002). Additionally, higher costs, increased land footprint, and a limited remaining life span of existing power plants would generally make retrofitting plants with dry cooling system technically challenging or economically infeasible. Appendix 7.4 provides a more detailed analysis of these challenges.

We rated direct dry cooling technology as fully mature (TRL 9) because full-scale commercial systems are in use at several NGCC plants across the United States, mainly in the arid west, although some are also in operation in the northeast.

4.1.2 Indirect dry cooling

Indirect dry cooling uses a water-based condenser and an air-cooled heat exchanger in tandem to condense steam and dissipate the heat to the atmosphere. The condenser may be either a conventional water-cooled surface condenser used in a steam plant, or a direct contact condenser in which the exhaust steam is condensed directly by a spray of cooling water.[49] The condensed water is then circulated through an air-cooled heat exchanger, where it is cooled and reused in the condenser to absorb more heat.

As with direct dry cooling, because the water is never exposed to the ambient air, there is no water lost to the atmosphere through evaporation, which makes these systems effective at saving water. An EPRI report indicated that for both a 750 MW coal plant and a 500 MW combined-cycle plant, the Heller system can provide water conservation and plant performance comparable to an ACC dry cooling system (EPRI 2004). Specifically, near zero water consumption or an equivalent annual water savings of 1.84 billion gallons/year or 600 gals/MWh could be achieved as compared to traditional wet cooling tower systems according to our estimates. However, in comparison to an evaporative cooling system, it incurs both efficiency and capacity penalties but still achieves significant water savings.

Because an indirect dry cooling system uses either a surface condenser or a direct contact condenser, it eliminates the requirement of transporting exhaust steam to an ACC which can result in reduced plant efficiency. EPA reported that an indirect dry cooled system can be considered as a retrofit option for a wet recirculating cooling system, because a potential retrofit would only require the addition of an extra air-cooled heat exchanger (EPA 2002), provided the turbine back pressure limits are not exceeded. However, for a plant with a once-through cooling system, the economics of a retrofit would be more difficult to justify.

The main disadvantage of an indirect dry cooling

49 Systems incorporating a direct contact condenser are known as Heller systems.

system relative to a direct dry cooling system (ACC) stems from the two-step process of condensing the steam and cooling the water for reuse. This makes such systems more inefficient and may also require a larger air-cooled tower at increased capital and operational costs than for a similar ACC system.

We rated indirect dry cooling technology as fully mature (TRL 9) because full-scale commercial systems are in use in some countries, such as Hungary and Turkey for power plant applications, although such systems are not currently used in the United States.

4.1.3 Hybrid wet-dry cooling

Hybrid systems combine wet and dry cooling technologies to conserve water but do not completely eliminate the use of water for plant cooling. Hybrid systems can use one or both of the cooling systems as conditions warrant. During the hottest periods of the year, the plant heat load is allocated between evaporative cooling and dry cooling to mitigate losses in the plant's efficiency and capacity associated with an all-dry operation. However, when the temperature drops to a certain level, the dry cooling system can provide all necessary heat rejection for condensing steam. Hybrid systems have been considered for use during peak load periods of hot weather to provide short-term enhancement of dry cooling system performance and plant efficiency.

Hybrid cooling systems can be implemented in various configurations that have separate wet and dry towers with cooling water apportioned to each, depending on climate conditions. According to experts we spoke with, such systems are operating at three or four power plants in the United States and some European countries. A novel configuration being tested currently by EPRI is a single-structure combined tower with integrated wet and dry systems. EPRI estimates that such a single unit hybrid system could provide up to 90 percent savings in make-up water use relative to a wet cooling tower, and up to 10 percent more power production on the hottest days compared to an all-dry cooled system.

Hybrid systems typically limit water use between 20 percent and 80 percent annually, depending on local climate conditions and site-specific circumstances compared to all-wet systems. They also still achieve efficiency and capacity advantages during hot weather's peak load periods compared to an all-dry system (EPRI 2008). For example, a 55 percent representative reduction would be equivalent to a water savings of 330 gals/MWh (1.0 billion gallons/year) relative to a typical coal fired plant with a wet cooling tower, according to our estimates.

We rated this technology as fully mature (TRL 9) because such hybrid systems have been commercially deployed in the United States and abroad.

4.2 Assessment of emerging cooling technologies

Both EPRI and NETL have been engaged in research and development of advanced and emerging cooling technologies by sponsoring research to encourage novel cooling concepts with high potential to reduce water consumption. We identified several prototypes or concepts, most aimed largely at working within the context of wet cooling towers. Specifically, we assessed four emerging technologies: (1) thermosyphon cooling; (2) M-cycle dew point cooling; (3) adsorption chiller; and (4) air cooling technology to recover freshwater from an evaporative cooling tower. While some of these technologies have the potential to be retrofitted and can save varying amounts of water, they are mainly at the research and development stage. According to experts we spoke with, some of these technologies are intended to be implemented in a support role to existing evaporative cooling towers by offloading some of the heat to be dissipated, rather than as a replacement of cooling towers.

A summary assessment of these technologies is provided below, while further details are given in appendix 7.5.

- **Thermosyphon cooling** reduces the heat load to the cooling tower by pre-cooling the hot water intake. This reduces evaporative loss and conserves water. Thermosyphon coolers can be implemented in a hybrid wet-dry configuration to conserve water by 30 to 80 percent compared to traditional wet-cooling tower systems, while maintaining the power plant's maximum output on the hottest summer days. For example, one EPRI-sponsored research project based on a power plant model indicated that a 500 MW plant in Seattle could achieve a water savings of 1.38 billion gallons/year (450 gals/MWh), or 75 percent annually. We rated this technology as medium in maturity, assigning it a TRL 6 as there has been no full scale demonstration.

- **Advanced M-cycle dew-point cooling** pre-cools the ambient air flowing into the tower. It is capable of delivering cooler water to the steam condenser, potentially lower than the wet-bulb temperature, as opposed to being limited to wet bulb temperatures as in traditional cooling towers.[50] This can improve cooling tower performance not only by lowering the cooling water temperature, but also by improving the energy efficiency of the power turbines. M-cycle dew point cooling can reduce the evaporative loss of water by up to 20 percent, according to EPRI. However, a technical brief from the developer of this technology noted that the reduced temperature of the cooling water may come at the expense of increased evaporation rates and increased water loss. Therefore, water savings by this technology is uncertain. We rated this technology as low to medium in maturity and assigned it a TRL 4 because while it has been used in other commercial or industrial fields, it has not yet been demonstrated for power plant applications. However, preliminary testing and qualification of a system prototype has been done at a thermoelectric power plant to demonstrate its water saving potential (EPRI 2012d).

- **The adsorption chiller** provides the cooling effect, in principle, without any water consumption. However, the energy requirement can be higher than conventional power plant cooling. It is currently used in other fields such as commercial buildings. We rated this technology as low in maturity and assigned it a TRL 3 because we did not find any system models or prototypes tested or demonstrated at a power plant or other similar environment, although functional systems exist for applications in other industries.

50 The wet-bulb temperature reflects the cooling effect when water evaporates into air. It can be defined as the lowest temperature that can be reached by evaporating water into the air up to the point at which air is fully saturated with water (that is, 100 percent relative humidity). In contrast, the dry-bulb temperature is the temperature of air measured by an ordinary thermometer freely exposed to the air—that is, it is the ambient air temperature. The wet-bulb temperature is always less than or equal to the dry-bulb, or ambient air, temperature.

- **Air cooling technology to recover freshwater from an evaporative cooling tower** is a method to partially recover water from the cooling tower exhaust. The rate of water recovery from a cooling tower with air cooling technology is estimated to range from 15 percent to 25 percent of the evaporation annually, depending on the climate, according to a study by an equipment vendor and funded by the Department of Energy (SPX 2009b). Testing and demonstration of this technology on a pilot-scale system has led to improvements. The equipment vendor has partnered with a utility in the western United States to install and research the performance potential of this technology for use in thermoelectric power plants. We rated this technology as medium to high in maturity, assigning it a TRL 7.

Table 4.2 summarizes our assessment of the emerging cooling technologies.

Maturity[a]	Potential effectiveness[b]	Cost factors[c]	Potential challenges and consequences
Thermosyphon cooling			
Medium (TRL 6): • Very small sub-scale prototype hybrid thermosyphon-mechanical draft tower system has demonstrated its water saving potential	**Medium to high:** • Approximately 30-80 percent—or a mid range of 55 percent— annual reduction in make-up water over traditional wet cooling tower systems while maintaining the maximum power plant output on the hottest summer days. This corresponds to makeup water savings of 0.6 to 1.5 billion gals/year (mid range of 330 gals/MWh) • Ability to save water is highly variable depending on ambient temperature, humidity, and plant operating conditions	• Viability may depend on the cost of water versus the site specific capital costs and the associated energy penalty	• Can be applied to existing or new power plants with fewer challenges than dry cooling systems • Challenges of operation at full scale are unknown

Table 4.2: Assessment of emerging cooling technologies, continues on next page.

Maturity[a]	Potential effectiveness[b]	Cost factors[c]	Potential challenges and consequences
M-cycle dew point cooling			
Low to medium (TRL 4): • Fully functioning system prototype demonstrated, validated, and deployed in a relevant environment for other industrial applications but not for power plant cooling • No system models or prototype tested or demonstrated at a power plant or other simulated environment	**Low to medium:** • Ability to save water is uncertain	• Operations and maintenance costs are unknown	• Ease of retrofit compared to dry cooling systems • Potential to cool water to a lower temperature may enhance power generation efficiency of the plant, though this may come at the expense of increased evaporation rate and increased water loss • Similar to wet cooling towers, the cooling capacity may be reduced in high humidity conditions
Adsorption chiller			
Low (TRL 3): • EPRI performed a preliminary assessment of this technology for power plant application • Commercial-scale systems available for other industrial or commercial cooling applications but not for power plant cooling applications • No system models or prototype tested or demonstrated at a power plant or other simulated environment, although fully functional systems exist for applications in other industries	**High:** • Theoretically near zero water consumption for plant cooling, or an equivalent water savings of 1.84 billion gallons per year (600 gals/MWh) could be achieved versus traditional wet cooling tower systems • Up to 5 percent more power production compared to power plants with wet recirculating cooling systems due to reduced steam condensation temperature	• Operations and maintenance costs are unknown	• Present systems are bulky and costly due to low specific cooling power of the adsorption chillers due in part to poor heat and mass transfer properties of the existing solid adsorbents

Table 4.2: Assessment of emerging cooling technologies, continues on next page.

Maturity[a]	Potential effectiveness[b]	Cost factors[c]	Potential challenges and consequences
Air cooling technology to recover freshwater from evaporative cooling tower			
Medium to high (TRL 7): • Pilot scale system developed under National Energy Technology Laboratory funding and tested and demonstrated at a power plant, saving about 19 percent of the evaporated water • Testing and demonstration has led to further improvements in the technology and the first commercial scale system is being built	**Low to medium:** • The rate of water recovery from cooling tower was estimated from 15-25 percent of the evaporation, depending on the local climate. A 20 percent recovery rate would equate to a water savings of about 0.3 billion gallons per year (90 gals/MWh) versus traditional wet cooling tower systems	• Operations and maintenance costs are unknown • Expected high cost of water recovery makes it difficult to justify this approach	• Can be retrofitted to an existing cooling tower • A major drawback is the increased fan power needed to achieve the water capture

Table 4.2: Assessment of emerging cooling technologies.

Source: GAO analysis of reports from Electric Power Research Institute, U.S. Department of Energy's National Energy Technology Laboratory (NETL), U.S. Department of Energy, U.S. Environmental Protection Agency; consultations with experts through collaboration with the National Academy of Sciences; various publications and reports; and interviews with selected stakeholders. | GAO-15-545

a Technology readiness levels (TRL) is a standard tool that some federal agencies use to assess the maturity of emerging technologies. Details of our methodology for assessing maturity of a technology using TRL scale are described in section 7.1.

b Details of our methodology for assessing potential effectiveness are described in section 7.1.

c Cost factors represent the resources entailed in implementing the respective technologies.

Note: Our estimated water savings with the various advanced cooling technologies are relative to a baseline 500 MW coal-fired power plant operating with an evaporative cooling system.

5 Regional water use and technology options in thermoelectric power generation

Regional differences with respect to water scarcity and the use of technology both affect water used for cooling thermoelectric power plants in United States. In our evaluation of both water-stressed and unstressed regions, we found that water use reflects local conditions, and that practical limitations may limit the applicability of technologies to reduce water use in some locations.

To characterize the extent of water scarcity in the United States, we analyzed data on water use in electricity generation collected by a team of government and private sector researchers. Specifically, the water use dataset contained data on location, electricity generation, water withdrawal, water consumption, the type of cooling system used, the type of fuel used, the sources of cooling water, and other data at the level of individual electricity generating units located across the United States.[51] In order to study regional differences in the use of water for cooling electricity generation units, we utilized a measure of water stress calculated by a team of experts using water consumption and supply data from the U.S. Geological Survey (USGS) (Tidwell et al. 2014). This water stress measure, or index, combines regional factors of water supply and demand into a single measure to quantify water stress, and is expressed on a scale from 0 to 1, with 0 being the least water-stressed and 1 the most. We focused on differences in water use variables across regions of the country according to the USGS hydrologic unit code classification system, and segmented these water regions into five quintiles ranging from the most water-stressed regions to the least water-stressed regions. Figure 5.1 shows a water-stress distribution map using the water stress index and the USGS hydrologic unit code classification system described above. In this figure, the locations that are most water-stressed—with stress indices between 0.8 and 1.0—are shaded in dark red/brown, while the locations that are least water-stressed (indices less than 0.2) are shaded in blue.

The figure shows that the most water-stressed regions of the U.S. are generally located in the West. However, other regions also experience water stress, particularly south Florida.

To determine how the cooling systems, the type of power units, and the source of cooling water were distributed across the various regions, we merged the water stress data with the water use data so that every thermoelectric power plant was assigned a water stress index according to its geographic location. In our analysis, we focus mainly on the two extreme groups—that is, quintiles 0 to 0.2, and 0.8 to 1 respectively—to illustrate how electricity generation, water consumption and withdrawal, fuel sources, and cooling systems vary regionally. Details of our methodology on regional water stress and water use patterns are provided in appendix 7.1.

Our analysis of these two groups shows that there are important differences in electricity generation between the more water-stressed regions of the United States versus less water-stressed regions, and that these differences are related to the ways that water is used for cooling electric generating

51 According to experts from the national laboratories we spoke with, many electricity generation plants in the United States have several generating units each.

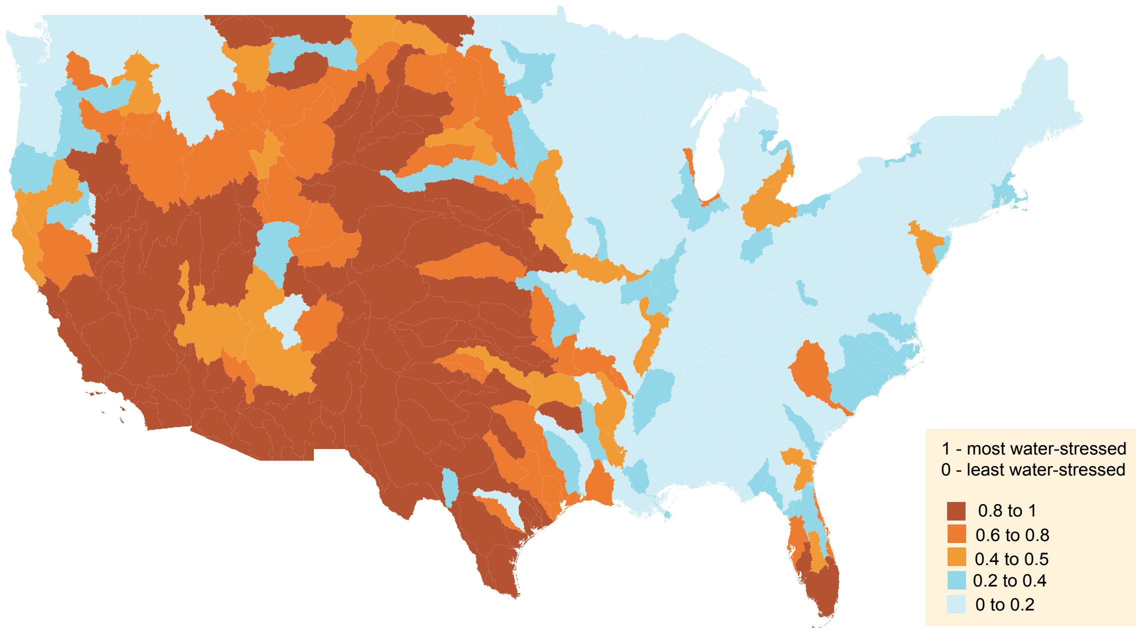


Figure 5.1: Map of water stress in the United States (lower 48)

Source: GAO analysis of (1) a dataset developed by the "Energy and Water in a Warming World" (EW3) group, which included researchers from federal agencies, national laboratories, universities, consulting firms, and the Union of Concerned Scientists; this dataset is described in Appendix A of Averyt et al. 2011; and (2) a drought index of watersheds in the United States as described in Tidwell et al. 2014 | GAO-15-545

units.[52] For example, regions that are least water-stressed (where water supplies are high relative to demand) accounted for a much larger share of U.S. electricity generation and thus a larger share of water consumption and withdrawal compared to the most water-stressed regions (figure 5.2). Nearly half of the electricity in the United States in 2008 was generated in the least water-stressed regions.[53] In contrast, the corresponding share for the most water-stressed regions—mostly in the west—was only about 17 percent.

Furthermore, while the average water consumption rates relative to electricity generation were roughly similar in the least and most water-stressed regions, the average water withdrawal rates were significantly higher in least-stressed regions than in the most-stressed regions as shown in figure 5.3.

In addition to these aggregate factors, if we look regionally at the characteristics of electricity generation units, such as cooling systems used, type of fuel and power generating units employed, and the use of various water sources, we also see patterns related to water stress. For example, electricity generation units in the most water-stressed regions tend to rely less on once-through cooling systems that withdraw large volumes of water per unit of electricity generated. In addition, in water-stressed regions, there is relatively greater use of natural gas-fired electricity generation than in the least water-stressed

52 Description of the dataset we used is provided in appendix section 7.1.

53 Note that in the comparisons we make in this section, we focus on the least water-stressed regions and the most water-stressed regions, without presenting information on the 3 other groupings in the middle of our dataset. This focus on the polar ends is illustrative and can help understand how water scarcity and other variables relate to the patterns of water use in electricity generation.

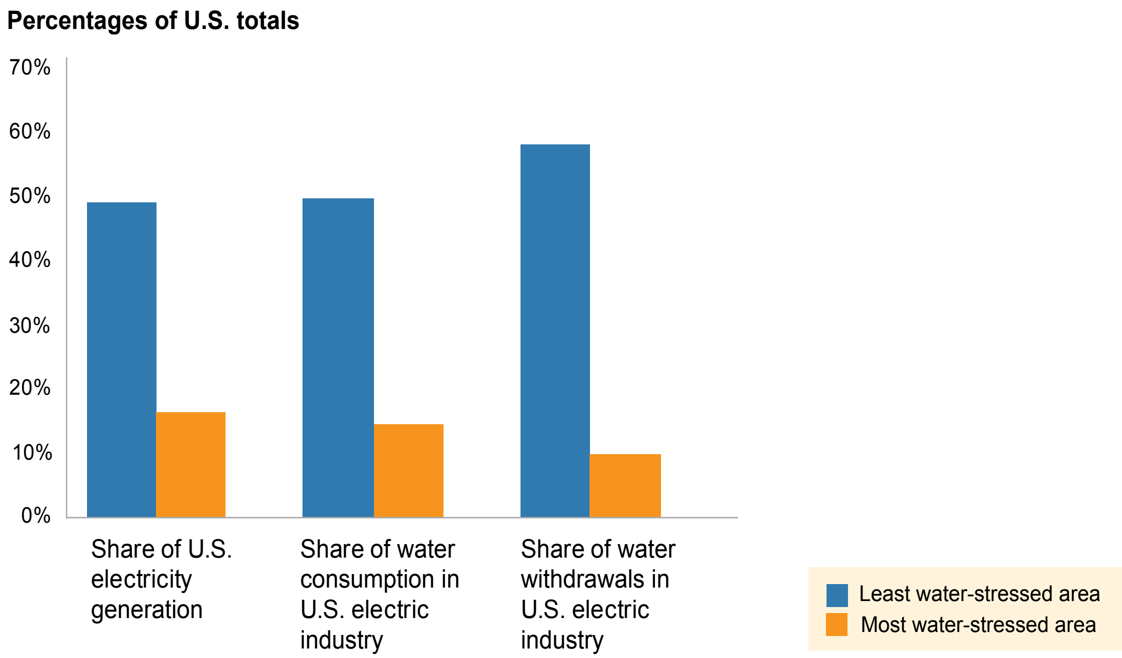


Figure 5.2: Shares of total U.S. electricity generation and water consumption and withdrawals in the electricity sector for the least and most water-stressed regions in the United States (2008)

Source: GAO analysis of dataset developed by the “Energy and Water in a Warming World” (EW3) group, which included researchers from federal agencies, national laboratories, universities, consulting firms, and the Union of Concerned Scientists; this dataset is described in Appendix A of Averyt et el. 2011 | GAO-15-545

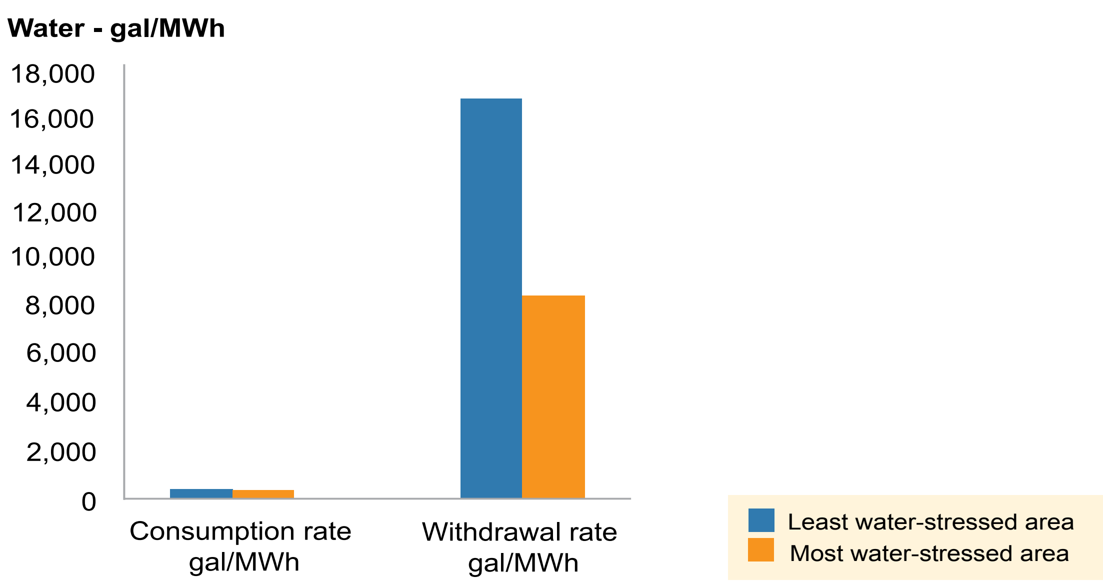


Figure 5.3: Water consumption and withdrawal intensities for the least and most water-stressed regions in the United States (2008)

Source: GAO analysis of dataset developed by the “Energy and Water in a Warming World” (EW3) group, which included researchers from federal agencies, national laboratories, universities, consulting firms, and the Union of Concerned Scientists; this dataset is described in Appendix A of Averyt et el. 2011 | GAO-15-545 regions. On average, NGCC units, used more frequently in water-scarce regions, consume less water for cooling per unit of electricity generated than coal-fired generating units.

5.1 Choice of cooling system impacts water use but retrofit options may be limited

According to our data analysis, once-through cooling systems are generally more prevalent in regions where water is plentiful. Figure 5.4 shows the share of electricity generation by the various types of cooling systems in the least and the most water-stressed regions. This figure shows that 40 percent of the electricity in the least water-stressed regions is generated by power plants having once-through cooling systems, whereas in the most water-stressed regions only 19 percent of the generation uses once-through cooling systems. The greater share of once-through systems in the least water-stressed areas is due in part to greater availability of large bodies of water in those regions where plants with once-through cooling systems are usually located. In contrast, the most water-stressed regions rely to a greater extent on recirculating cooling systems and cooling ponds that generally withdraw much less water per unit of electricity generated than once-through systems. For example, once-through systems withdraw approximately 35,000 gals/MWh, whereas wet recirculating systems withdraw about 660 gals/MWh (Meldrum et al. 2013). Figure 5.4 also shows that recirculating cooling systems accounted for 59 percent of electricity generation in the most water-stressed regions in 2008, compared to 49 percent in the least water-stressed regions.

As figure 5.4 shows, dry cooling, which uses far less water than the other cooling system types, accounted for 3 percent or less of the electricity generated in both the least and the most water-stressed regions.

The differences in water withdrawals suggest that retrofitting existing power plant cooling systems

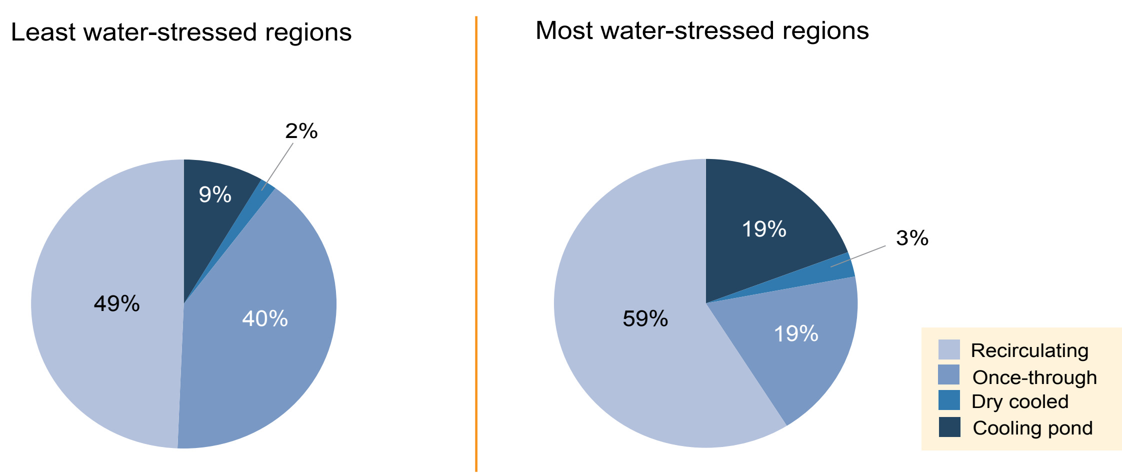


Figure 5.4: Share of U.S. electricity generation by type of cooling system in the least and most water-stressed regions in (2008)

Source: GAO analysis of a dataset developed by the “Energy and Water in a Warming World” (EW3) group, which included researchers from federal agencies, national laboratories, universities, consulting firms, and the Union of Concerned Scientists; this dataset is described in Appendix A of Averyt et el. 2011 | GAO-15-545 with ones that withdraw less can reduce water use in the electricity sector. California's experience though sheds some light on the implications of major cooling system retrofits. The California State Water Resources Control Board adopted a policy in 2010 aimed at reducing the mortality of marine organisms caused by once-through cooling systems due to impingement of larger organisms by screens on the cooling water intake structures, entrainment, and thermal impacts of heated water discharge.[54, 55] This policy requires 19 power plants with such systems to reduce their use of seawater for cooling by 93 percent. Alternatives for these plants include retrofitting their once-through to recirculating cooling systems or dry cooling systems, installing screens on their water intake systems, or ceasing operations. Compliance entails considerable cost that may contribute to plant owners withdrawing some affected generation units from operation. Indeed, a number of affected generating units have ceased operations.[56]

Besides the cost involved, retrofitting a plant that currently uses a once-through cooling system to a recirculating system to reduce water withdrawals may, in effect, result in an increase in water consumption because recirculating cooling systems withdraw less but consume more. Retrofitting to a recirculating system may be difficult for plants that rely on surface water and are located in an area of the country where other human demands compete for the same water.

Nationwide, the EPA's regulations implementing section 316(b) of the Clean Water Act impose standards to protect aquatic life that may reduce the amount of water withdrawals by power plants.[57] EPA's assessment shows that a number of alternatives can be considered to mitigate the entrainment requirement, including the use of wet recirculating systems, which withdraw significantly less water.

In contrast to wet cooling systems, dry cooling systems significantly reduce both withdrawals and consumption of water. Dry cooling systems have very low water consumption per unit of electricity generated because they rely on air for cooling. However, these systems generally incur an energy penalty because they require a considerable amount of energy to run the cooling fans among other energy requirements. Therefore, the net electricity generation of such systems is reduced. Furthermore, although retrofitting to dry cooling would reduce both water withdrawals and consumption, retrofits are likely to be costly and increase carbon dioxide and other emissions stemming from the energy penalty.

Dry cooling systems have been increasingly adopted for newly built NGCC plants. To some extent, this is because NGCC plants have among the lowest energy penalty relative to coal and nuclear plants, according to EPA's estimates for various cooling system conversions (see figure 7.1 in the appendix). However, according to experts, it may be technically and economically

54 Impingement is the entrapment of fish, shellfish, or other aquatic life on the screens at the intake of the cooling water structure to prevent their entry into the system, which could cause blockages of the condenser tubes.

55 Entrainment is the passage of small fish, shellfish, or other aquatic life through the screens filtering the water drawn for cooling, through the cooling system, and back out to the water source. As these organisms pass through the system, they are exposed to pressure changes and mechanical stresses of the system, temperature changes, and biocides, which can kill them.

56 In response to our enquiries, the California State Water Resource Control Board cautioned that the once-through cooling policy may not be the decisive factor in the retirement of an electric generating unit. Other operational and regulatory factors can contribute to owners' decisions to cease operations.

57 40 C.F.R. §§ 125.80-125.99 (2014). Section 316(b) of the Clean Water Act requires that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.

impractical for existing thermoelectric power plants to be retrofitted with dry cooling systems.[58] As noted in Section 4, the higher cost and the energy penalty associated with dry cooling systems, and location-specific needs and resources may limit the practicality of adopting dry cooling systems. Further, according to some experts with whom we spoke, safety concerns may preclude the consideration of dry cooling for retrofitting nuclear plants.

The availability of real estate and the implications of major construction may also pose challenges. For example, in the case of the Diablo Canyon nuclear power plant, replacing once-through cooling with recirculating cooling towers would cost billions of dollars according to one company's estimate, partly because of the need to make room for the cooling towers.

In all cases, retrofits of existing cooling systems or selection of a cooling system for a new plant are influenced by design, cost, impact on net electric output, and site-specific considerations (such as climate and space), as well as the availability of water resources.

The various characteristics of cooling systems, including water withdrawal and consumption rates, efficiency of power generation, environmental impacts, and other factors such as cost are summarized in table 5.1.

58 Experts we talked with noted that, changes to a plant would be needed to retrofit a dry cooling system to address the higher turbine back pressure stemming from the use of dry cooling—such as redesigning the condenser. These changes, together with limited remaining life span of existing plants would generally make such a retrofit economically infeasible if not technically challenging.

	Cooling system types		
Characteristics	Once-through	Wet recirculating	Dry cooling
Water withdrawal	Ten to 100 times more water withdrawn per unit of electricity generated than wet recirculating	About 1 to 10 percent of the water withdrawn per unit of electricity generated than once-through	Negligible when compared with wet recirculating and once-through
Water consumption	About half the water consumed per unit of electricity generated than with wet recirculating, but factors such as temperature and size of the water source can affect evaporative loss	About twice as much water consumed per unit of electricity generated as once-through, but factors such as local climate and wind speed can affect evaporative loss	Zero to 5 percent of wet recirculating
Cost	Lowest capital costs of all cooling systems	About 40 percent higher capital costs than once-through cooling systems	About 3 to 4 times higher capital costs than wet recirculating systems
Impact on electricity generation efficiency[a]	The most efficient cooling system and therefore the least adverse impact	Less efficient than once-through cooling systems and therefore more of an adverse impact	Least efficient cooling system and therefore the most adverse impact
Environmental impacts	Mortality of marine organisms due to impingement and entrainment Thermal impacts of once-through cooling due to heated water discharge	Visible plumes from cooling towers can produce localized fog or icing in freezing weather Increased emission of air pollutants over once-through cooling systems due to its adverse impact on electricity generation efficiency	Larger space footprint for equal capacity when compared with wet cooling systems. Highest emission of air pollutants due to its adverse impact on electricity generation efficiency

Table 5.1: Characteristics of wet and dry cooling systems for power plants

Source: GAO analysis of Electric Power Research Institute 2002 and 2012b; National Energy Technology Laboratory 2009b, 2011a, 2011b, and 2013c; and SPX Cooling Technologies, Inc. 2009a | GAO-15-545

[a] In this context, more efficient cooling systems produce lower turbine exhaust pressures which result in more efficient electricity generation.

5.2 Power generation technology impacts water use

As with the type of cooling system, there are differences in the share of electricity generation by the type of fuel used in the least water-stressed regions versus the most water-stressed regions. Generally, coal-fired generating units are more prevalent in areas with the least water stress and they consume more water per unit of electricity produced on average than gas-fired units. In other words, greater reliance on natural gas in the most water-stressed regions contributes to less water use in these regions. Figure 5.5 shows that the least water-stressed regions have a greater proportion of electricity generated from coal-fired units, whereas the most water-stressed regions rely more on natural gas fired units.

According to USGS, a decrease in use of coal and increase in use of natural gas coupled with new power plants that use more water-efficient cooling technologies has helped to reduce water withdrawal levels for thermoelectric power plants from 2005 to 2010—the latest year for which USGS reported water use estimates. On average, both water withdrawals and water consumption for electricity generated from natural gas in 2008 were considerably lower per unit of electricity generated than they were for electricity generated from coal or nuclear power.

Our recent work discusses the fact that experts and stakeholders anticipate increased reliance on natural gas at the expense of coal in future generation assets (GAO 2012e). Greater reliance on natural gas will likely lower rates of water withdrawals and consumption in electricity generation. The degree to which the use of coal versus natural gas will shift depends on various factors, particularly future prices of these energy sources, environmental and climate-related legislation and regulations, and technological changes in the electricity industry. Nonetheless, the electricity supply plans of a number of electric utility companies, which include plans to replace some existing coal-fired units with new gas-fired units, indicate that the trend towards greater reliance on natural gas may continue into the future.

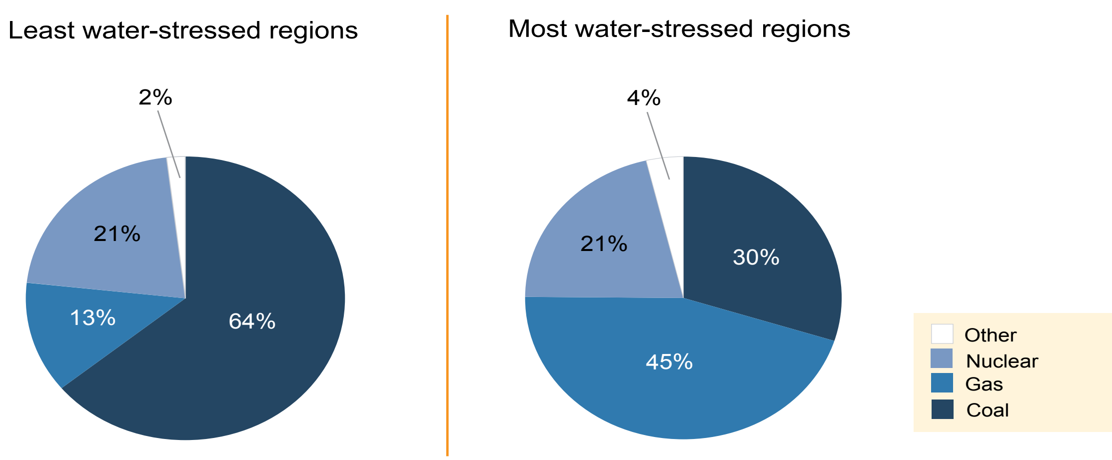


Figure 5.5: Share of U.S. electricity generation by fuel source in the least and most water-stressed regions (2008)

Source: GAO analysis of a dataset developed by the "Energy and Water in a Warming World" (EW3) group, which included researchers from federal agencies, national laboratories, universities, consulting firms, and the Union of Concerned Scientists; this dataset is described in Appendix A of Averyt et el. 2011 | GAO-15-545

5.3 The combination of cooling system, type of fuel, and type of power generation determines a plant's overall water use

Apart from regional differences in climate, three factors influence the rates of water withdrawals and consumption per unit of electricity generated: the type of cooling system, type of fuel, and type of power generation.

Figure 5.6 shows typical water consumption for various combinations of fuel source, type of electrical power generation, and type of cooling system. As shown in this figure, NGCC plants have, on average, noticeably lower water consumption than most coal-fired and nuclear power plants with equivalent cooling systems.

In terms of cooling systems, plants with cooling towers generally consume more water than once-through cooling systems across all fuel categories.

Figure 5.6 also illustrates how advanced power generation technologies can present opportunities for reducing water consumption. For example, some coal plants use supercritical steam at higher temperatures and pressures to operate more efficiently, which reduces water requirements for cooling per unit of electricity generated.[59] However, experts we spoke with noted that this is not considered a feasible retrofit technology as modifications to the boiler and the steam turbine and other plant equipment on an existing plant would be cost-prohibitive.

For certain plant types, practical concerns may restrict what is achievable in the way of water

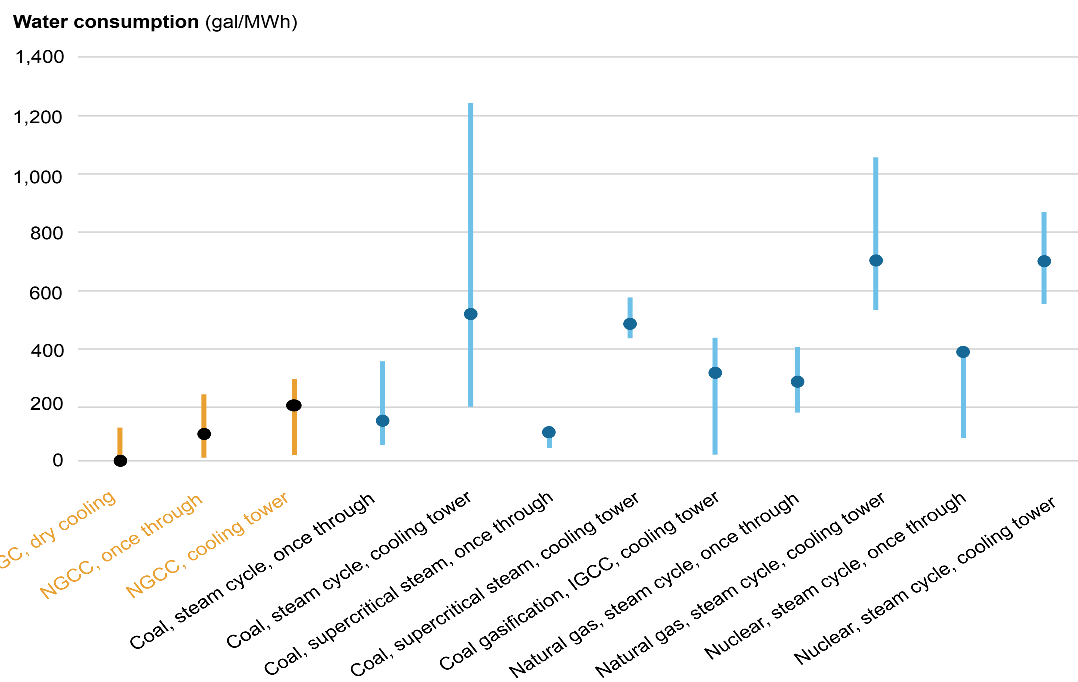


Figure 5.6: Estimates of water consumption by various thermoelectric plant types and cooling systems

Source: GAO analysis of Meldrum et al. 2013 and National Renewable Energy Laboratory 2011 | GAO-15-545

Notes: NGCC denotes natural gas combined cycle; IGCC denotes integrated gasification combined cycle. The data points indicate median values while the error bars show the extent of variability of water consumption in the given data set.

59 Overall plant efficiency gains are reportedly low (NETL 208)

savings through efficiency increases. Nuclear plants, for example, may have a slightly lower overall efficiency because, for safety reasons, they generally operate at lower steam temperatures and pressures, which can increase water consumption.

5.3.1 NGCC power plants have an efficient power generation design which results in relatively low water consumption per megawatt-hour of electricity generated

As shown in figure 5.6, NGCC plants have one of the lowest water consumption rates among thermoelectric plants. The combined cycle design of these plants—where a gas turbine and a steam turbine are used in combination—allows the plants to convert more of the input heat into electricity than other types of thermoelectric power plants, resulting in higher power generation efficiency. That is, this configuration dissipates relatively less heat to the cooling system and therefore reduces water lost through evaporation. In an NGCC plant, approximately two-thirds of the electricity is generated by a gas turbine, which requires no cooling, and the remaining one-third of the electricity is generated by a steam turbine, where water is needed to condense the steam. Figure 5.7 compares the heat flow in a typical coal-fired plant with that of an NGCC plant. A coal-fired plant dissipates approximately 46 percent of its input heat to the cooling system, compared to only 28 percent for an NGCC plant. Therefore, an NGCC plant consumes less water per megawatt-hour of electricity generated than a conventional coal-fired plant with an equivalent cooling system, as shown in figures 5.6 and 5.7.

A shift to more NGCC generation would increase the overall efficiency of thermoelectric power from the current mix of plants in the United States, thereby contributing water savings. A study by a research group at the University of Texas at Austin concluded that replacing all

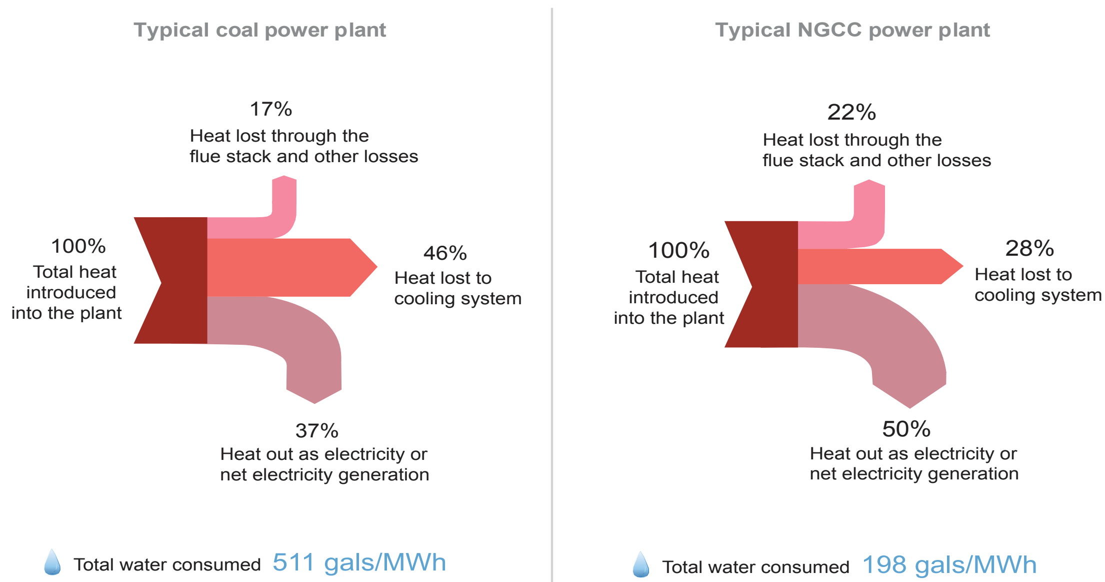


Figure 5.7: Comparison of heat flows and water consumption in typical coal-fired and natural gas combined cycle power plants with cooling towers

Source: GAO analysis of National Energy Technology Laboratory 2010c | GAO-15-545

Texas coal-fired power plants with NGCC plants would reduce annual freshwater consumption by an estimated 53 billion gallons per year, or 60 percent of the state's coal-fired power plants water footprint for the same amount of electricity generated, largely due to the higher efficiency and lower cooling water needs of the NGCC design (Grubert et al. 2012).[60]

Since the early 2000s, there has been an emerging trend of new NGCC plants that use dry cooling technology. The efficient NGCC design partly offsets the energy penalty incurred with dry cooling systems, making this an attractive option for water-stressed regions. For example, a plant manager of an NGCC plant that uses dry cooling noted that his station uses only14 gals/MWh compared to a conventional plant that uses approximately 650 gals/MWh, saving over 600 gallons/MWh without significant impact on power generation capacity (i.e. energy penalty).

5.3.2 Electricity generation from renewable wind and solar photovoltaic sources can save freshwater

Renewable power sources, especially wind and solar photovoltaic power, could reduce water use in water-stressed regions.

The EIA long-term forecast of renewable electricity generation in the United States shows that wind powered electricity generating capacity will continue to increase at a fast rate (EIA 2014c)—growing from less than 60 gigawatts in 2012 to about 87 gigawatts in 2040. Unlike thermoelectric power generation, wind-based generation does not need water for cooling. Therefore, it can contribute to less intensive use of water in electricity generation.[61]

Similarly, solar power capacity in the United States is also expected to continue to increase, potentially producing nearly 50 gigawatts by the end of 2040 (EIA 2014c). However, large-scale solar electric generating projects in the United States are fairly new, and they include two of the largest in the world, the Agua Caliente solar photovoltaic (PV) project in Arizona, and the Ivanpah CSP project in the California Mojave desert. While photovoltaic electricity generation requires essentially no water, some CSP-based power plants can consume substantial amounts of water unless dry cooling is used. For example, the Ivanpah project uses a dry cooling system to greatly reduce the rate of cooling water use by up to 95 percent more than competing wet-cooled CSP plants.

In addition to water savings, electricity generated from wind and photovoltaic sources also has significantly reduced lifecycle greenhouse gas emissions. For example, studies show that a coal-fired plant has lifecycle greenhouse gas emissions of about 1,900 pounds of equivalent CO_2 per megawatt-hour of electricity produced (lbs/MWh), while an NGCC plant has notably reduced lifecycle emissions of about 1,100 lbs/MWh of equivalent CO_2. In contrast, a solar photovoltaic power generation plant has lifecycle greenhouse gas emissions of about 190 lbs/MWh of equivalent CO_2, mostly occurring during the manufacturing and processing of solar cells, while virtually no greenhouse gases are emitted during the power generation stage. Similarly, wind-based generation has lifecycle greenhouse gas emissions

60 Additionally, the authors indicated that switching to NGCC plant would also reduce CO_2 emissions by approximately 48 percent per unit of electricity produced compared to pulverized coal-fired power plant while also reducing emissions of other harmful gas such as SO_2 and NO_x.

60 Other renewable sources of electricity require water for cooling. For example, concentrated solar power requires a great deal of water for cooling. The overall impact of the increase in electricity generation will depend on the types of renewable generation in the future, and the technologies employed for condensing the exhaust steam.

of only 60 lbs/MWh of equivalent CO_2 occurring during the manufacturing and construction phase of the plant, but virtually none during its power generation phase. However, in addition to the potentially higher cost per unit of electricity generated, a second disadvantage with some of the renewable-based power generation, such as solar PV or wind energy is they can only generate power when the sun is shining or the wind is blowing, unless coupled with energy storage solutions.

Water consumption and plant efficiencies for various types of generating plants, including some renewable fuel options, are illustrated in figure 5.8. NGCC plants consume less water per unit of electricity produced compared to other fossil fuel plants due in large part to their relatively high generation efficiency. Nuclear plants and conventional coal plants consume relatively more water. Some renewable energy sources, such as solar PV, have negligible water consumption while generating electricity. However, CSP plants generally have high water consumption levels unless they use dry cooling. The figure also shows that the cooling process is the predominant consumer of water in thermoelectric power plants.

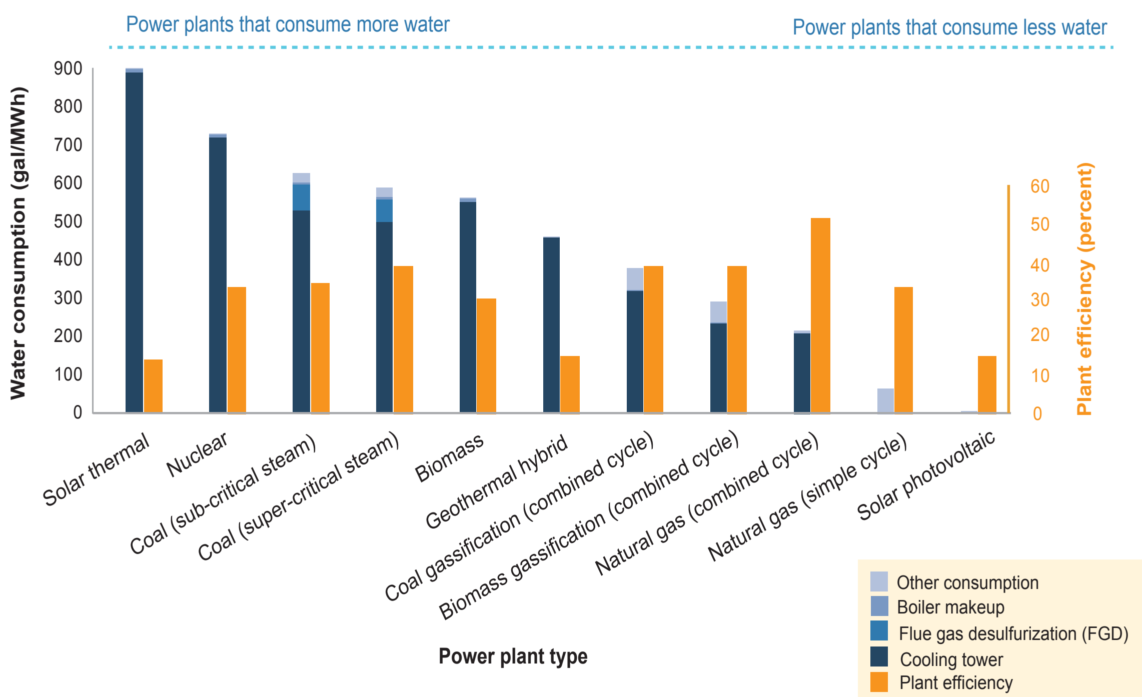


Figure 5.8: Water consumption and plant efficiencies for various types of power plants

Source: GAO analysis of Electric Power Research Institute 2008, Geothermal Energy Association 2009, Meldrum, et al. 2013, National Energy Technology Laboratory 2007c, National Renewable Energy Laboratory 1996 and 2010, and U.S. Environmental Protection Administration 2002 | GAO-15-545

Note: NGCC denotes natural gas combined cycle; IGCC denotes integrated gasification combined cycle; FGD denotes flue gas desulfurization. All plants shown above have wet recirculating cooling systems with the exception of natural gas (simple cycle) and solar photovoltaic.

5.4 Other technological opportunities may exist for water savings in thermoelectric power generation

Cooling towers will likely remain a predominant cooling technology for the foreseeable future due to limitations on the applicability of dry cooling, and increasing restrictions on use of once-through cooling systems. However, opportunities for water savings exist within plants with recirculating cooling systems, including the use of alternative sources of water for cooling in lieu of freshwater, cooling towers operating at higher cycles of concentration, and in the case of coal plants, reusing water recovered from the flue gas. Further, since the amount of water used in power generation depends on how much electricity is generated, influencing the demand for electricity can also have important implications for water use.

5.4.1 Alternative water sources can be treated and used in lieu of freshwater

We found that the least water-stressed regions rely mainly on surface water withdrawals for thermoelectric power generation, whereas the most water-stressed regions used water from a variety of sources, including groundwater, ocean water, and wastewater. As shown in figure 5.9, in the least water-stressed regions, surface water accounts for 92 percent of water used to generate electricity, whereas the most water-stressed regions rely on a variety of sources of water, including surface water (50 percent).

While freshwater is the most commonly used type of water in power plant operations, alternative sources of water can be used, provided they are adequately treated to achieve the necessary quality. Water used in cooling systems of power plants must adhere to important quality requirements, often specific to an individual power plant's design and construction. Contaminants often found in fresh and degraded water can reduce the efficiency of the plant and potentially degrade the metallurgy of the cooling tower and its components if found in elevated levels.

A wide variety of commercially available technologies exist to treat degraded water to acceptable quality levels for use in power plants. It is important to determine the appropriate set and sequence of treatments to achieve the water quality requirements for each unique plant. EPRI has produced quality criteria for water used for cooling in wet recirculating cooling towers. These criteria specify maximum concentration numbers for some constituents of concern and other quality parameters, with the purpose of minimizing operating issues with cooling tower systems, such as loss of heat transfer, fouling, and corrosion.

Many types of degraded water have been investigated for use as power plant cooling water including municipal wastewater, mine pool water, saline water, and even produced water.[62] For example, both NETL and ANL have reported on the use of reclaimed water for power plant cooling (NETL 2009d; ANL 2007).[63] NETL has also reported on the use of other nontraditional waters such as mine pool water and produced water from oil and gas wells (NETL 2009d). Additionally, in October 2009, we found that reducing the amount of freshwater used by power plants through the use of advanced cooling technologies and alternative water sources had

62 Groundwater collected in underground pools associated with coal mines is referred to as mine pool. Produced water is a term used to describe water produced from a wellbore as a by-product associated with oil and gas recovery operations.

63 Reclaimed water refers to treated municipal wastewater.

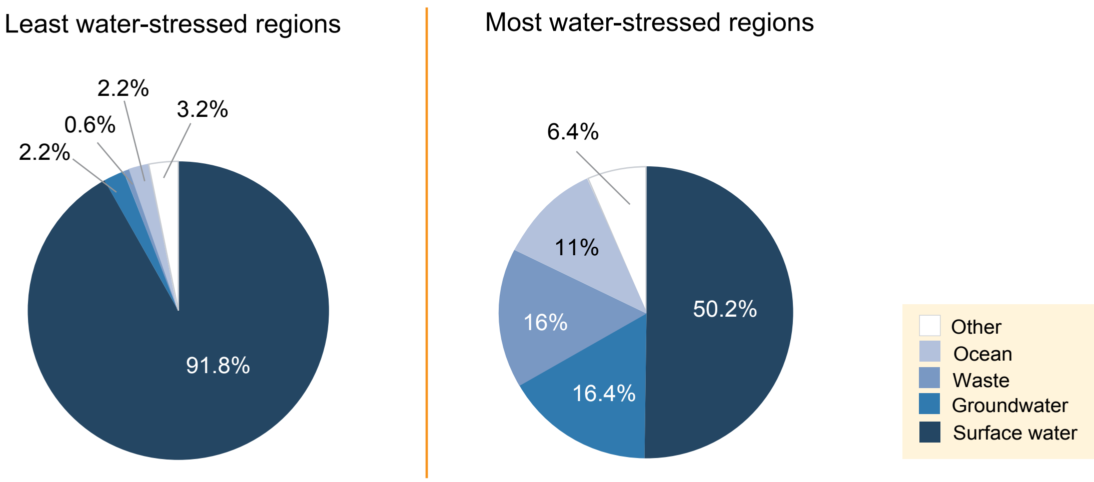


Figure 5.9: Sources of cooling water in electricity generation in the United States in (2008)

Source: GAO analysis of dataset developed by the "Energy and Water in a Warming World" (EW3) group, which included researchers from federal agencies, national laboratories, universities, consulting firms, and the Union of Concerned Scientists; this dataset is described in Appendix A of Averyt et el. 2011 | GAO-15-545

social and environmental benefits including limiting freshwater use that may reduce the impact to the environment associated with withdrawals, consumption, and discharge (GAO 2009a).

Of the various alternative sources of water, treated municipal wastewater is considered widely available across the United States in sufficient volumes, consistent quantities, and from reliable sources to be looked to for use as power plant cooling water (NETL 2009d). In situations where freshwater is a constraint, switching from traditional water sources to wastewater may be an alternative. Such was the case in Amarillo, Texas, which converted a 1,080 megawatt power plant to use treated wastewater in 2006 (Averyt et al. 2011). Some cities in historically water-stressed areas have been proactive in designing new power plant construction to use alternative water sources. The Palo Verde Station, in the Arizona desert, the largest nuclear power plant in the United States, with a capacity of around 4,000 megawatts, was designed to use treated municipal wastewater purchased from Phoenix and other cities for 100 percent of its cooling needs. It uses approximately 20 billion gallons of treated effluent annually from treatment plants that serve several area municipalities, comprising over 1.5 million people.

Some states also have been active in promoting use of alternatives to freshwater for power plant cooling. For example, California has had such a policy since 1975.[64] Between 1996 and 2004, 22 percent of the new electric capacity brought on-line in California used reclaimed water for cooling, while 52 percent of the electric capacity currently under construction, permitted, or in licensing review planned to use reclaimed water

64 State Water Resources Control Board, Resolution No. 75-58 (June 19, 1975). One of the policy's stated purposes was to guide planning of new power generating facilities "to protect beneficial uses of the state's water resources and to keep the consumptive use of freshwater for power plant cooling to that minimally essential for the welfare of the citizens of the state."

(California Energy Commission 2005).[65]

A relatively small percentage of U.S. power plants are currently using municipal wastewater for wet recirculating cooling operations. In 2007, ANL did a nationwide investigation and found that 57 power plants across the country were using municipal wastewater for a portion of their cooling operations (ANL 2007). These plants were primarily located in California (13) and Florida (17), and to a lesser extent Texas (7). The other 20 plants were divided among 13 other states.

While the use of alternate sources of water in lieu of freshwater can mitigate water concerns in arid regions of the west, many factors—usually site specific—influence their practicality. For example, though wastewater in sufficient quantities may be available in some locations, there may be competing uses for it. Furthermore, the expense of retrofitting existing plants that use freshwater with brackish or waste water capability can be costly or not feasible. However, a major study by the National Renewable Energy Laboratory and Sandia National Laboratories evaluated tradeoffs related to retrofitting the 1,178 power plants in the United States that use freshwater for cooling to greatly reduce water use (Tidwell et al. 2014). The study considered alternatives to achieve reductions in the use of water for cooling generators. It employed a life-cycle analysis using estimates for the different options, starting with switching from the use of freshwater to brackish water or wastewater. Their research found that over half of the 1,178 plants in the United States that use freshwater for cooling could be retrofitted at an expense that would add less than 10 percent to current power plant generation expenses.

65 Consistent with the original 1975 policy, in 2003, the California Energy Commission stated that it would approve the use of freshwater for cooling purposes by power plants only where alternative water supply sources and alternative cooling technologies are shown to be "environmentally undesirable" or "economically unsound."

5.4.2 Operating at higher cycles of concentration can reduce the amount of make-up water needed

Cooling tower operation in a wet recirculating system results in a continual loss of water through evaporation (E), blowdown (B) and drift (D), thus fresh make-up water (M) is added to the cooling tower to compensate for these losses.

A water balance across a cooling tower in units of gallons per minute [gpm] shows that

Make-Up = Evaporation + Blowdown + Drift

The above equation can also be shown as

$$B = E\left(\frac{1}{n_{cc} - 1}\right) - D$$

Blowdown (B) is the rate of water discharged in gallons per minute (gpm) from the tower to maintain a constant level of "cycles of concentration". Evaporation (E) in gpm is the rate of water lost from the tower due to the evaporative cooling process. Drift loss (D) in gpm is the rate of water lost to the atmosphere due to physical entrainment of liquid droplets in the air stream and is typically small, amounting to less than 0.0005 percent of the total water circulating through the cooling tower. Cycles of concentration (n_{cc}) is the ratio of dissolved solids in circulating water to the dissolved solids in make-up water and is given by,

$$n_{cc} = \left(\frac{E + B + D}{B + D}\right)$$

Cycles of concentration is one important parameter that determines the performance of a cooling tower. The above equations show that by increasing the cycles of concentration, blowdown loss can be reduced thereby reducing make-up water requirements.

Figure 5.10 is a plot of the blowdown loss (in terms of percentage of water recirculating in the tower) as a function of cycles of concentration for various tower "ranges" using equations shown above.[66] This plot is based on the approximate evaporation and drift losses and water circulation rates shown in published NETL and EPRI reports.

Figure 5.10 shows that the tower blowdown is inversely related to the cycles of concentration, and decreases rapidly with increasing cycles of concentration, although at higher cycles of concentration, the blowdown loss becomes almost constant.[67] In contrast, the evaporative loss is constant for a given tower range and does not vary with cycles of concentration as expected, because among other things, it depends on the ambient temperature. For example, for a tower range of 20°F and a cycles of concentration of 5 (typical value for coal-fired power plant), the blowdown loss is approximately 0.4 percent of circulating water or 1,000 gpm (120 gals/MWh), whereas at cycles of concentration of 10 it drops to 0.177 percent or 443 gpm (53 gals/MWh).

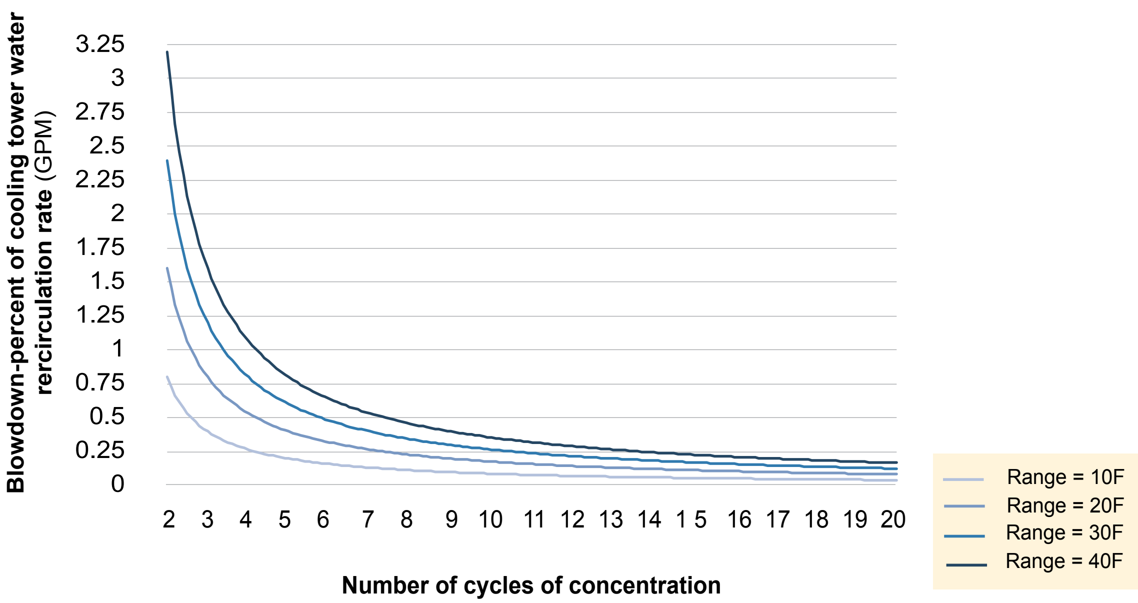


Figure 5.10: Cooling tower water blowdown as a function of cycles of concentration

Source: GAO analysis of Electric Power Research Institute 2012b and the National Energy Technology Laboratory 2007c | GAO-15-545

Note: Blowdown refers to the rate of water discharged from an evaporative cooling tower to maintain a maximum tolerable salt and solids concentration in the recirculating water. The discharged water is replenished by new cooling water.

66 "Range" is the difference between the cooling tower water inlet and outlet temperature.

67 Data maintained by EIA indicate that thermoelectric power plants with a cooling tower typically operate at an average cycles of concentration of 5, and figure 5.10 shows that in this range of operation, water savings could be realized by increasing the cycles of concentration.

This translates to a savings in make-up water of approximately 67 gals/MWh or 11 percent reduction as a result of reduced blowdown loss. NETL showed a similar reduction in make-up water requirements of approximately 11 percent by increasing the cycles of concentration from a baseline of 5 to 10 (NETL 2009c). Therefore, to reduce make-up water required in wet cooling tower operations, efforts could be made to operate at higher cycles of concentration.

However, increasing cycles of concentration typically require additional treatment of the cooling water to compensate for the corresponding rise in salts concentration. A variety of treatment options exists to accomplish this.

5.4.3 Recovered water from flue gas can be reused

Water vapor present in flue stacks of coal-fired power plants is an additional source of water that could help meet part of the internal needs of a power plant. For example, recovered water from flue stacks could serve as make-up water for the steam boiler or a cooling tower. However such systems and concepts come at the expense of relatively higher energy requirements, costs, and reduced power plant performance.

Water vapor present in the flue gas originates from three sources: (1) a by-product of fuel combustion, (2) the inherent water content of the coal itself, and (3) evaporated water vapor from the wet FGD process that becomes part of the effluent in the flue stack. As a result, the flue gas is almost saturated with water vapor.

NETL's water usage and loss study for a coal-fired power plant generating 520 MW net power (equipped with FGD) indicates that the water vapor flow rate in flue gas is approximately 928 gpm or 107 gals/MWh.[68] Several concepts, including liquid and solid sorption, cooling with condensation, cryogenic separation, liquid desiccant dehumidification system, and membrane based selective capture of water vapor from flue gas (Daal et al. 2012; Copen et al. 2005), are being researched to potentially recover this water. However, none have emerged as a preferred approach so far. NETL's research on reclaimed water from combustion flue gas projected a recovery of 50 percent of the water present in the flue gas stream that could be used for internal plant use, such as make-up water for cooling tower operation (NETL 2009c). However, the overall percent of reduced water consumption depends on the plant type and the type of FGD system, and can range from 3.8 percent for coal-fired power plants to 8.8 percent for NGCC power plants, according to this study. Based on NETL's study, we estimate a water recovery of approximately 25 gals/MWh that could be used as make-up water for the cooling tower. Potential issues with this technology that have been highlighted by NETL and experts from the power plant industry include the need for large and expensive heat rejection equipment that must work in high ambient temperatures of flue gas, adding to the parasitic load or energy penalty of the plant.

5.4.4 Demand-side efficiencies can also save water

In addition to improving power generation efficiency, efforts to reduce the demand for electricity can reduce the levels of electricity needed, and thus reduce the amount of water needed for cooling in thermoelectric power plants.

68 The NETL study indicates that the same plant loses water at a rate of about 5,180 gpm or 598 gal/MWh through evaporation and blow-down in the cooling tower.

Further, some electric utility companies have indicated in their long-term electricity resource plans that they will increase investments in energy efficiency, reducing the rate of growth in the demand for electricity in their jurisdictions. For example, a number of regions in the United States have already experienced slower growth rates in the demand for electricity, partly due to energy efficiency. If this trend continues, it may also contribute to lowering demand from this sector for water resources.

A 2008 study commissioned by the EPA highlighted the relationship between energy efficiency and water savings, and concluded that it is instructive to view water and energy conservation together (ICF International 2008). It affirmed that water and energy efficiency measures may conserve these resources at a lower cost than alternative approaches. Notwithstanding the benefits of implementing energy efficiency measures, there are some potential barriers or tradeoffs to implementing technology solutions or water conservation measures. For example, owners of power generating facilities may not make costly changes unless they feel compelled to do so, or unless they are assured that most of their incremental costs will be retrieved in the future. In all cases, higher costs of water conservation measures may result in consumers paying higher rates for electricity. In this case, the degree to which consumers will face higher costs will depend on the types of water conservation measures that are implemented.

6 Concluding observations

In this technology assessment, we have evaluated technologies that may reduce freshwater use in hydraulic fracturing and thermoelectric power generation that could be part of a portfolio of water management and policy options. We found that alternative fracturing technologies that reduce water consumption in hydraulic fracturing are neither widely deployed nor applicable to all plays, and operators concerned over water scarcity or water costs are seeking to adopt measures to more efficiently manage their water use, such as water recycling and reuse. With respect to thermoelectric cooling designs, we found that there are already deployed operational approaches which greatly reduce the consumption of scarce freshwater resources, yet each held practical or economic limitations for retrofitting into most of the existing fleet of power plants, regardless of modality. Nevertheless, newer thermoelectric power plant designs with greater overall energy efficiency (i.e., more energy for power production and less as waste heat) have the potential to lower demand for freshwater resources and can more readily incorporate water-efficient cooling approaches such as dry cooling into their designs. In general, the combination of fuel source, power generation type, and cooling system design determine overall water consumption.

Based on projected increases in energy demand in the coming decades, freshwater resource stress—particularly in the western states—will continue to pose challenges to the energy sector and policymakers alike. In general, more water-stressed regions of the United States have already been reducing freshwater consumption for energy through newer cooling designs or water reuse and recycling approaches. Even so, greater efficiencies in the energy supply chain (i.e., including extraction and generation) can still be realized ranging from increased power plant operational efficiencies to the recycling of produced water in hydraulic fracturing.

7 Appendices

7.1 Objectives, scope, and methodology

We describe our objectives, scope, and methodology for addressing the three objectives outlined below, related to technologies for reducing water use in the energy sector.

Objectives

1. Assess current and emerging technologies that reduce freshwater use in hydraulic fracturing
2. Assess current and emerging technologies that reduce freshwater use in thermoelectric power plants.
3. Analyze water-scarce regions in the United States that could benefit from the application of water conservation technologies.

Scope and methodology

To address these objectives, we developed our scope and methodology to identify and evaluate available and developing technologies that can reduce water use in hydraulic fracturing and in thermoelectric power generation. Additionally, we conducted an assessment of the benefits of adopting these technologies in locations facing water scarcity.

We reviewed the U.S. Department of Energy's (DOE) report to Congress on the interdependency of energy and water. This report was produced by Sandia National Laboratories in collaboration with multiple federal agencies and a multi-laboratory energy-water nexus committee. We conducted a site visit to Sandia National Laboratories to interview the authors of the report as well as researchers and scientists who contributed to the report. This visit provided us with initial information on stakeholders and experts in the federal government, public sector, and academia involved in the research and development of technologies to reduce water use in the energy sector.

In addition, we collaborated with the National Academy of Sciences to convene a two-day meeting of experts bringing together a diverse group of scientists, engineers, and other technical experts and stakeholders involved in researching, developing, and demonstrating advanced and emerging technologies for reducing water use in hydraulic fracturing and thermoelectric power generation. Experts who participated in this meeting are listed in section 7.2.

During this meeting we solicited input from the experts on the design for our work. They provided us with information on published studies, reports by technology vendors, information on field sites where such advanced and emerging technologies were being developed or demonstrated, and related conferences and workshops.

Following the meeting, we continued to seek the experts' advice to clarify and expand on what we had heard. Consistent with our quality assurance framework, we provided the experts with a draft of our report and solicited their feedback, which we incorporated as appropriate. The experts who provided comments on our draft report are listed in section 7.3.

The visit to Sandia National Laboratories and the meeting of experts helped us frame and scope the methodology we describe below. We adopted an iterative process, soliciting additional experts from each person we interviewed.

As part of our scope and methodology we:

- Systematically examined published scientific literature on the use of water for energy resource development and electricity generation to assess the lifecycle water-use footprint spanning from use in energy production in the field to use in thermoelectric plants to generate electricity;
- Interviewed external experts—specialists and stakeholders from the government, national laboratories, industry, academia, and advocacy groups—to identify advanced and emerging technologies that could be used to reduce freshwater consumption in the energy sector;
- Attended relevant technical conferences and workshops to inform our data gathering and assessment process;
- Conducted site visits to electric power plants and research and development sites where some of these advanced and emerging water-conserving technologies are being deployed and tested on a pilot scale;
- Examined differences in water use in electrical power generation along with regional differences in water scarcity, types of technology used for cooling systems, types of fuel used for power generation, and sources of water used for cooling;
- Reviewed federal and state regulations and policies surrounding water disposal and discharges from shale gas development and thermoelectric power plants; and
- Reviewed GAO's prior work in this area.

We engaged with the following entities to gather information on technologies to reduce water use in the energy sector:

- Federal agency officials from the Department of Energy's national laboratories (Sandia, Los Alamos, Argonne, National Renewable Energy Laboratory (NREL), National Energy Technology Laboratory (NETL)), Office of Fossil Energy, and Energy Information Administration (EIA), U.S. Department of Agriculture (USDA), Department of the Interior's U.S. Geological Survey (USGS), Environmental Protection Agency (EPA), and National Science Foundation;
- State government officials (Western Governors Association, Texas Railroad Commission);
- Academic researchers from universities including the University of Texas at Austin, Texas A&M University, MIT, University of California Berkeley, University of California Irvine, and Ohio State University;
- The National Academy of Sciences
- Water and energy industry representatives from the Electric Power Research Institute (EPRI) and the American Water Works Association;
- Power plant operators from Applied Energy Services Corporation's Huntington Beach gas fired power plant, Nevada Energy's gas fired electric power generating stations, Arizona Public Service's Palo Verde nuclear power plant, Georgia Power's coal fired Plant Bowen, and AREVA Resources;
- Operators developing unconventional energy resources (shale gas and shale oil) and service providers from Chesapeake Energy, Blackbrush Oil and Gas, and Schlumberger;
- Industry representatives from Bechtel Power Corporation, Evapco, and Hitachi; and

- Nongovernmental organizations and private consultation groups, such as the Pacific Institute, Maulbetsch Consulting, Fountain Quail Water Management, and Veil Environmental, among others.

To identify technologies that may reduce freshwater use in shale gas development and production, we identified and examined published scientific literature and technical reports from federal agencies, academia, and research organizations. These reports describe and quantify water use in unconventional resource extraction techniques, such as hydraulic fracturing. We identified, reviewed, and summarized reports and studies that examined the constraints, consequences, and tradeoffs associated with these technologies, and best practices adopted by industry. We consulted with oil and gas operators involved in various shale plays around the country to determine how the various alternative technologies take into account local conditions and constraints. We reviewed and assessed technical reports on alternatives to water-based fracturing methods. We interviewed U.S. shale gas and oil operators and water management companies to understand how they use water in their operations and ways in which technology could help reduce their water usage. We reviewed reports and interviewed authors of pilots and demonstrations of alternative sources of water for hydraulic fracturing operations to identify where and how technology can enable the use of degraded or alternative water sources. We identified key drivers and barriers to the adoption of these technologies.

To identify advanced and emerging cooling technologies that may reduce freshwater use in thermoelectric power generation, we identified and examined published scientific literature, technical reports by EPRI and NETL, technical brochures and equipment vendor studies, and data presented at conferences and technical workshops. We consulted with various experts and stakeholders in collaboration with the National Academy of Sciences, and interviewed selected experts from the electric power industry, academia, federal government, and advocacy groups. We also identified and assessed technologies and processes that can improve internal operational efficiencies of power plants. We identified key drivers and barriers that can influence adoption of these technologies and evaluated them on the basis of attributes such as technology readiness level (TRL), effectiveness, maturity, cost, and constraints or trade-offs involved in their implementation.

To determine the regional variation in water used in shale gas development and to identify technologies to reduce such usage, we analyzed factors associated with water use, water management, and environmental issues that could impact the water footprint of shale gas development. We then examined the role of technology in mitigating water challenges of shale gas development.

Additionally, we examined life-cycle water consumption across different fuel and power plant types to identify the water intensity of various aspects of energy resource development and its end use in power generation. While there are many possible end uses of fossil fuels (oil or gas), such as a direct source of heat in the industrial sector or as a fuel source in the transportation sector, this report focuses on fossil fuels and water used in the generation of electricity.

Technology assessment methodology

We assessed three advanced dry cooling technologies: direct dry cooling, indirect dry cooling, and hybrid wet-dry cooling. In addition, we assessed four emerging cooling technologies: thermosyphon cooling, M-cycle dew point cooling, adsorption chiller, and air cooling technology to recover freshwater from an evaporative cooling tower.

We summarized our assessment of these technologies by categorizing reported technical information under four categories: (1) maturity, (2) potential effectiveness, (3) cost factors, and (4) potential constraints, trade-offs, and consequences.

Assessment of technology maturity: In this report, we rated each technology's maturity in terms of its readiness for application in a system designed to conserve water in a thermoelectric power plant. We used technology readiness levels (TRL), a standard metric that some federal agencies use to assess the maturity of emerging technologies before their full-fledged production or incorporation into an existing technology or system. This metric rates the readiness level of a technology on a scale from 1 to 9, with scores lower than TRL 6 indicating an immature technology. We rated TRLs 1 through 3 as being low in maturity; TRLs 4 and 5 as low to medium maturity; TRLs 5 and 6 as medium; TRLs 7 and 8 as medium to high; and TRL 9 as high maturity. TRL 9 is considered a fully mature technology ready for deployment on a commercial scale. The TRL rating describes the maturity level of the whole integrated system for its intended use for a specific application, rather than individual components of a particular technology. Agencies in the United States including the Department of Defense (DOD) and the National Aeronautics and Space Administration use TRLs, as does the European Space Agency.

We used the Air Force Research Laboratory's Technology Readiness Level Calculator (Nolte 2004) to determine technology readiness levels for the advanced and emerging cooling technologies for power plant application. Table 7.1 outlines TRL levels and other key features defined by the Air Force Research Laboratory. We adopted these definitions to power plant cooling systems. The first column in the table presents definitions of TRL levels. To achieve a rating at any level, a technology must satisfy the requirements for all lower levels as well. For example, to achieve a rating of TRL 2, a technology must also satisfy the requirements for a rating of TRL 1. To achieve a rating of TRL 3, a technology must also satisfy the requirements for a rating of TRL 2, and thus must also satisfy the requirements for a rating of TRL 1.

GAO has previously recommended that a technology should be at a TRL level 7—that is, a prototype has been demonstrated in an operational environment—before being moved to engineering and manufacturing development (GAO 1999). We also recommended that a technology be at a TRL 6 before starting program definition and risk reduction (GAO 1999). Consistent with this recommendation, we characterized technologies whose TRL scores are below 6 as immature.

Level	Description	Example
1. Basic principles have been observed and reported.	The lowest level of technology readiness. Scientific research begins translation into applied research and development.	Paper studies of the technology's basic properties
2. Technology concept or application has been formulated.	Invention begins. Once basic principles are observed, practical applications can be invented. The application is speculative and no proof or detailed analysis supports the assumption.	Limited to paper studies
3. Analytical and experimental critical function or characteristic proof of concept has been defined.	Active research and development begins. Includes analytical studies and laboratory studies to physically validate analytical predictions of separate elements of the technology.	Components that are not yet integrated or representative
4. Component or breadboard validation has been made in laboratory environment.	Basic technological components are integrated to establish that the pieces will work together. This is relatively "low fidelity" compared to the eventual system.	Ad hoc hardware integrated in a laboratory
5. Component or breadboard validation has been made in relevant environment.	Fidelity of breadboard technology increases significantly. The basic technological components are integrated with reasonably realistic supporting elements so the technology can be tested in a simulated environment.	"High fidelity" laboratory integration of components
6. System and subsystem model or prototype has been demonstrated in a relevant environment.	Representative model or prototype system is well beyond level 5 testing in a relevant environment. Represents a major step up in the technology's demonstrated readiness.	Prototype tested in a high- fidelity laboratory or simulated operational environment
7. System prototype has been demonstrated in an operational environment.	A prototype is operational or nearly operational. Represents a major step up from level 6, requiring the demonstration of an actual system prototype in an operational environment, such as in an aircraft, vehicle, or space..	Prototype tested in a test bed aircraft

Level	Description	Example
8. Actual system is complete and has been "flight qualified" in testing and demonstration.	Technology has been proven to work in its final form and under expected conditions. In almost all cases, this level represents the end of true system development.	Developmental test and evaluation of the system to determine if it meets design specifications
9. Actual system has been "flight proven" in successful mission operations.	The technology is applied in its final form and under mission conditions, such as those encountered in operational test and evaluation. In almost all cases, this is the end of the last "bug fixing" aspects of true system development.	The system is used in operational mission conditions

Table 7.1: Description of nine technology readiness levels

Source: GAO based on Nolte 2004h | GAO-15-545

Note: A breadboard is a representation of a system which can be used to determine concept feasibility and to develop technical data. It is typically configured for laboratory use only. It may resemble the system in function only.

Assessment of potential effectiveness: We gauged potential effectiveness of a technology by its ability to save cooling water consumed (through evaporation and drift loss) in a conventional coal fired power plant of 500 MW capacity running at 70 percent capacity-factor and utilizing a evaporative cooling tower. We considered a cooling technology as being highly effective if it is capable of saving over 90 percent of cooling water consumed in a conventional evaporative cooling tower; medium to high in effectiveness for water savings ranging from 70 to 90 percent; medium effectiveness when water savings range from 50 to 70 percent; low to medium effectiveness when water savings range from 20 to 50 percent; and low in effectiveness for savings below 20 percent.

Assessment of cost factors: We did not independently determine costs of implementing the technologies. Instead, we report cost factors and estimates from the literature we reviewed. The reported cost factors for technologies represent resources needed to implement alternative cooling systems and the trade-offs or cost penalties involved therein. Some studies by DOE report a detailed analysis of cost associated with dry cooling systems.

We were not able to determine the reliability of estimated costs in the literature because of the nascent and evolving nature of these emerging technologies. For example, the cost factors for one of the cooling technologies, the adsorption chiller, have not been evaluated yet.

Assessment of potential challenges and consequences: We assessed the potential challenges and consequences of implementing these emerging technologies, to the extent that has been reported in the literature, by examining the reported risks and barriers to their implementation.

Analyzing regional differences in water use for thermoelectric power generation

To determine the regional variation in water used in thermoelectric power generation and to identify technologies to reduce such usage, we analyzed data on the number of individual generating units in the United States. We compared water use in the electricity generation sector in regions of the country that are most water-stressed and regions that are least water-stressed. We focused on differences in water withdrawal and consumption rates per unit of electricity generated, and the cooling systems and fuel used in the generating units. We then examined and identified various regional factors that can play a role in reducing the use of water in electricity generation. This analysis also points to the regions in the United States that can benefit the most from these technologies to reduce water consumption in thermoelectric power generation.

We analyzed a dataset that was developed by the "Energy and Water in a Warming World" (EW3) group, which included researchers from federal agencies, universities, consulting firms, and the Union of Concerned Scientists. This dataset (henceforth the EW3 data) covers nearly 15,000 electric power generation units in the United States. It includes the following groups of data and estimates:

- Data on electric generating units for the year 2008 from the Energy Information Agency (EIA). The EIA-based data include location, type of fuel, electric generating capacity, type of cooling system used, water source, and electricity generated for that year. The EIA-based data were supplemented and modified by research and additional data gathering from various sources, as described in the report by the EW3 group (Averyt et al. 2011).
- Estimates of the annual water withdrawals and consumption for each generating unit based on an analysis of published coefficients of water use by various types of cooling technologies and electric generating units (NREL 2011).

The EW3 research team identified the watershed in which the unit is located for each generating unit in the dataset, based on the Hydrologic Unit Code (HUC) developed by the USGS.

We supplemented the EW3 dataset by allocating a measure of water scarcity to each HUC. Hence, each of the electric power generating units in our dataset is associated with a water scarcity index based on the HUC in which it is located. The water scarcity measure that we used was calculated by a team of experts using water consumption and supply data from the USGS (Tidwell et al. 2014).

Data sources used in the regional analysis: The EW3 team constructed the data on the use of water in power generation at the level of generating units rather than power plants. This is because some power plants have generating units that are quite different depending on the type of turbine, fuel used, and cooling systems. Water use varies considerably depending on these differences.

The EW3 team had to make important modifications to the EIA data, partly in order to construct it at the level of individual generating units. The modifications required independent research to correct some errors in the EIA data, such as the longitude and latitude data needed to assign a watershed to each unit. The modifications also included making certain assumptions related to generating unit configurations, electricity generation, and water use. For example, the team had to make certain assumptions in order to assign a particular cooling system to a given generating unit in the presence of multiple generating units, multiple boilers, and multiple cooling systems. They also allocated a power plant's electricity generation for the year 2008 to individual generators based on units' nameplate generating capacities.

While the EIA data do include water withdrawals and consumption data that are self-reported by electric power plant operators, the EW3 team judged the data to be inadequate, partly because no water use was reported for many generating units that did generate electricity in 2008 and clearly did need cooling. The EW3 team therefore used a study by the National Renewable Energy Laboratory (NREL) that relied on an analysis of published estimates of water use rates by electric power plants (NREL 2011). The study by NREL gives a set of water use rates for cooling electric power generators that vary by the type of fuel, technology, and cooling system. These rates are both for withdrawal and for consumption and are expressed as gallon per megawatt-hour of electricity generated. The study also gives a low, median, and high estimate for withdrawal and consumption rates. For example, a natural gas generator with a combined cycle design and a once through cooling system has a set of six rates, namely a low, median and high for withdrawals and a low, median, and high for consumption.

The low, median, and high estimates for a specific category of electric power generator (defined by a specific fuel type, technology, and cooling system) are intended to capture actual variation within each category that the authors identified. For example, individual coal-fueled power generators with a generic boiler design and a recirculating cooling system have different water withdrawal and consumption rates depending on local climate conditions, age, generating efficiency, and other factors.

A generator's use of water in the EW3 dataset is estimated by multiplying the rates of withdrawal and consumption per unit of electricity as given in NREL by the estimate of electricity generation for the particular unit for the year 2008. Hence, each individual generator will have a low, median, and high calculated estimate for its water withdrawals in 2008, expressed in millions of gallon for that year, and a low, median, and high calculated estimate for its water consumption.

Analysis of water use in the U.S. electricity generation sector: Out of a total of 14,772 generating units in the EW3 dataset, we identified 4,591 units that required cooling. The others did not require cooling for various reasons, such as small size or because they were hydroelectric or wind-powered generators. The 4,591 units that did require cooling accounted for approximately 90 percent of the electric power generation in 2008, according to the EW3 dataset. However, out of these 4,591 units, our analysis is limited to 3,750 units for which the type of cooling system is identified in the EW3 dataset. These 3,750 units accounted for 87 percent of the electric power generation of all the 14,772 generating units.

In analyzing the EW3 data and estimates, we focused on differences in electricity generation and water use variables across watersheds, based on the level of water stress in these watersheds.[69] We scaled the water-stress measure, or index, from 0 to 1, with 0 being the least water-stressed and 1 the most. We segmented water regions across the United States into five quintiles ranging from the most water-stressed regions to the least water-stressed regions

69 Our analysis dataset contains data on electricity generation and water consumption variables at the generation unit level. Many electricity generation plants in the United States consist of several generating units each. We conducted some of the analysis on the unit level and some on the plant (often consisting of multiple units) level.

(see figure 5.1). We then compared water use in only two of the five quintiles: the most and the least water-stressed. The majority of the water-stressed regions are located in the western United States, but also in southern Florida. The least water-stressed regions are located in the northeast and the eastern half of the United States, including much of the midwest.

We used Statistical Analysis Software and Microsoft Excel to produce graphic representations comparing water use in the most water-stressed and the least water-stressed regions with a focus on the following differences:

- Difference in total electricity generation and in total water withdrawals and water consumption in the electricity generation sector.

- Difference between water withdrawals and consumption in the most and least water-stressed regions, depending on the cooling systems used for the generators.

- Difference between water withdrawals and consumption in the most and least water-stressed regions depending on the fuel used for generation.

- Different sources of water used in electricity generation (e.g., surface water, groundwater, or ocean water).

The analysis is intended to illustrate tradeoffs power plant owners make when considering employing technologies to reduce water consumption.

Limitations of the regional analysis of water use in the electricity sector: There are important limitations in the underlying data we used. GAO has noted in the past that there is a need for improving USGS data collection and reporting on water use and consumption. USGS data are the basis of the water scarcity index that we used to segment the United States into the five categories of water stress. We note that the water withdrawal and consumption quantities for individual generating units in our dataset are not actual measured quantities, but rather estimates based on the work of NREL. However, we determined the data to be sufficiently reliable for the purpose of our analysis, namely to show broad differences in water use between the most water-stressed and the least water-stressed regions of the United States.

We conducted our work from October 2012 to August 2015 in accordance with all sections of GAO's quality assurance framework that are relevant to technology assessments. The framework requires that we plan and perform the engagement to obtain sufficient and appropriate evidence to meet our stated objectives and to discuss any limitations to our work. We believe that the information and data obtained, and the analysis conducted, provide a reasonable basis for any findings and conclusions in this product.

7.2 Experts who participated in our meeting on water conservation technologies in energy production and resource development

The experts who participated in our meeting on water conservation technologies in energy production and resource development are listed below.

Breckenridge, Richard, Program Manager, Generation, Electric Power Research Institute, Palo Alto, California

Burnett, David, Director of Technology of Global Petroleum Research Institute, Texas A&M University, College Station, Texas

Chan, Desmond, Manager of Technology, Bechtel Power Corporation, Frederick, Maryland

Clark, Corrie E., Environmental Policy Analyst and Sustainable Systems Engineer/Team Lead, Natural Resource Economics and Systems Analysis Team, Argonne National Laboratory, Washington, D.C.

Cooley, Heather, Co-Director, Water Program, Pacific Institute, Oakland, California

Feeley, Thomas. J. III, Senior Management Technical Advisor/Congressional Affairs, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, Pennsylvania

Halldorson, Brent, Chief Operating Officer, Fountain Quail Water Management, Roanoke, Texas

Hightower, M. Michael, Distinguished Member Technical Staff, Sandia National Laboratories, Albuquerque, New Mexico

Ho, W. S. Winston, Distinguished Professor, Engineering and Chemical and Biomolecular Engineering, Ohio State University, Columbus, Ohio

Kleinberg, Robert, L., Unconventional Resources, Schlumberger-Doll Research, Cambridge, Massachusetts

Macknick, Jordan, Energy and Environmental Analyst, Strategic Energy Analysis Center, National Renewable Energy Laboratory (NREL), Golden, Colorado

M**aulbetsch, John, S.,** Maulbetsch Consulting, Menlo Park, California

McCurdy, Rick, Senior Engineering Advisor, Chemicals & Water Reclamation, Chesapeake Energy Corporation, Oklahoma City, Oklahoma

Nicot, Jean-Philippe, Research Scientist, Bureau of Economic Geology, University of Texas at Austin, Austin, Texas

Puckorius, Paul, R., Puckorius & Associates, Inc.: Water & Wastewater Consultants, Arvada, Colorado.

Rowson, John, Scientific Consultant, AREVA Resources Canada Inc., Saskatoon, Saskatchewan, Canada

Sharma, Mukul, Professor, “Tex” Moncrief Centennial Chair in Petroleum and Geosystems Engineering, University of Texas at Austin, Austin, Texas

Tidwell, Vincent, C., Distinguished Member Technical Staff, Sandia National Laboratories, Albuquerque, New Mexico

Veil, John, President, Veil Environmental, LLC, Annapolis, Maryland

Wilson, Jeff, Principal Engineer, Southern Company, Birmingham, Alabama

Zammit, Kent, Senior Program Manager, Environment, Electric Power Research Institute, Arroyo Grande, California.

7.3 Experts' review and comments on our report draft

We invited all participants from our group of experts to review our draft report. We asked them to review the draft with respect to factual accuracy, scientific and technical quality, and for errors of omission. Although we asked them to focus their review particularly on sections of the draft on which they had specific expertise, we nevertheless invited their feedback on the draft in its entirety.

Ten experts provided technical or other comments. These 10 reviewers represented expertise relevant to each of the three objectives of our report, including water use in resource extraction, particularly shale gas development, water use in thermoelectric power generation, and regional aspects of water use in energy development. We received comments on each of these areas, as well as on the overall scope and structure of the draft, which we incorporated as appropriate.

The 10 reviewers of our draft are listed below.

Clark, Corrie E., Environmental Policy Analyst and Sustainable Systems Engineer/Team Lead, Natural Resource Economics and Systems Analysis Team, Argonne National Laboratory, Washington, D.C.

Feeley, Thomas. J. III, Senior Management Technical Advisor/Congressional Affairs, U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, Pennsylvania

Kleinberg, Robert, L., Unconventional Resources, Schlumberger-Doll Research, Cambridge, Massachusetts

Maulbetsch, John, S., Maulbetsch Consulting, Menlo Park, California

McCurdy, Rick, Senior Engineering Advisor, Chemicals & Water Reclamation, Chesapeake Energy Corporation, Oklahoma City, Oklahoma

Nicot, Jean-Philippe, Research Scientist, Bureau of Economic Geology, University of Texas at Austin, Austin, Texas

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V**eil, John,** President, Veil Environmental, LLC, Annapolis, Maryland

Zammit, Kent, Senior Program Manager, Environment, Electric Power Research Institute, Arroyo Grande, California

7.4 Challenges with dry cooling technology

Energy penalty

Energy penalty in an electric power generation plant refers to the reduction in net energy output resulting from a variety of factors, such as the turbine backpressure, the auxiliary power consumption associated with alternative cooling systems, or additional energy required to operate new equipment or units such as a carbon dioxide capture system, or a flue gas scrubbing system that removes sulfur dioxide. For example, an energy penalty of 2 percent indicates that the plant output power would be reduced by 2 percent. Energy penalties generally lead to a reduction in the efficiency of the electricity generation process. Therefore, to compensate for this penalty and maintain the same level of electricity generation would require increasing quantities of fuel consumption per unit of electricity generated leading to increased emissions of greenhouse gas such as carbon dioxide (CO_2) among others.

According to industry experts, dry cooling incurs an energy penalty that depends on ambient temperature, among other things. Dry cooling cools to a temperature approaching the dry-bulb (ambient) temperature, whereas wet recirculating cooling can cool to a temperature approaching the wet-bulb temperature—which is generally lower than the dry-bulb temperature.[70] Dry cooling is less effective because it typically has higher steam condensing temperature and higher turbine exhaust pressure for the same steam flow under the same ambient conditions.

The United States Environmental Protection Agency (EPA) has researched and derived energy penalty estimates based on empirical data and theoretical concepts for a variety of operational conditions and types of cooling systems (EPA 2002). Their study indicates that steam condensation temperature at the condensing surface is a key parameter that impacts turbine exhaust pressure that in turn directly impacts plant efficiency.[71] The steam condensation temperature is directly dependent on the cooling water (or air, in air-cooled systems) entering the steam cycle condensers. In general, a lower cooling water or air temperature at the condenser inlet will result in a lower steam condensing temperature and consequently a lower turbine exhaust pressure. In figure 7.1, we summarize EPA's energy penalty estimates of the turbine exhaust pressure for various power plants.[72] This figure depicts the functional relationship between energy penalty and turbine exhaust pressure. It shows that the energy penalty rises and drops in direct response to the turbine exhaust pressure, which in turn is impacted by the temperature of the cooling-water (or air in air-cooled systems). As a result, the energy penalty tends to peak during the summer and may be substantially diminished or not exist at all during cooler times of the year. The energy penalties for natural gas combined cycle (NGCC) plants are relatively smaller compared to coal or nuclear plants at similar exhaust pressures. As also noted previously, dry cooling systems

70 The dry-bulb temperature is the temperature of air measured by an ordinary thermometer freely exposed to the air—that is, it is the ambient air temperature. The wet-bulb temperature reflects the cooling effect when water evaporates into air. It can be defined as the lowest temperature that can be reached by evaporating water into the air—up to the point at which air is fully saturated with water (that is, 100 percent relative humidity). Wet-bulb temperature is always less than or equal to the dry-bulb, or ambient air, temperature.

71 Both once-through cooling systems and wet cooling towers use surface condensers to condense steam.

72 Besides the energy penalty related to turbine exhaust, there are other additional factors that consume energy and thus contribute to the overall energy penalty of a thermoelectric power plant such as cooling system energy requirements, though these factors have a relatively smaller energy penalty.

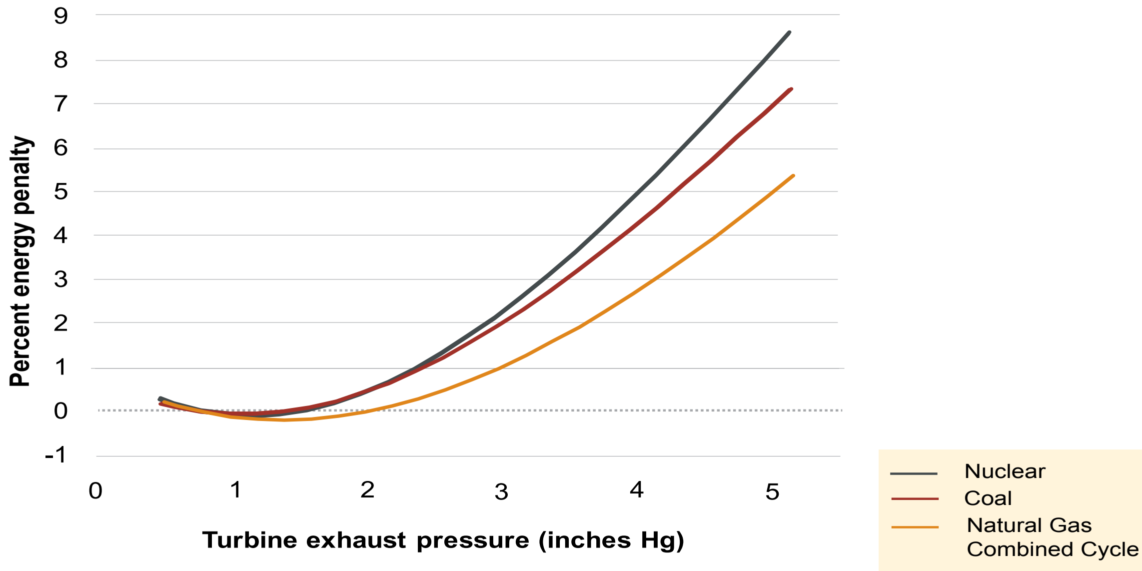

Figure 7.1: Energy penalties as a function of turbine exhaust pressure for various types of power plants

Source: GAO, adapted from U.S. Environmental Protection Agency 2002 | GAO-15-545

Note: NGCC denotes natural gas combined cycle. Higher exhaust pressure results in higher energy penalty. This means the turbine's output in the form of electricity generation decreases.

tend to operate at higher exhaust pressures for the same steam flow conditions and thus have a relatively higher energy penalty.

In an investigation of the possibility of replacing once-through cooling systems with alternative cooling systems, DOE found annual energy penalties of 0.8 to 1.5 percent for wet cooling tower and 8 to 9 percent for indirect dry cooling tower systems when compared to once-through cooling systems (the most efficient). Moreover, on the hottest days DOE found energy penalties of 2.4 to 4.0 percent and 13 to 16 percent respectively, for wet cooling towers and indirect dry systems, noting that, in the latter case, it would be technically infeasible to operate turbines safely under the conditions that lead to 13 to 16 percent energy penalties (DOE 2002).[73]

Increased land footprint

Because dry cooling systems rely on air rather than the evaporation of water to perform cooling, they require a large air flow rate that is typically three or more times greater than the air flow rate in a wet recirculating cooling system. This larger air flow requires either large fans, which use 1 to 2 percent of the total electrical output, thus decreasing the net power output from the plant, or the construction of much larger natural draft

73 This investigation was in support of EPA's interest in reducing the environmental impact of once-through cooling systems by replacing these systems with the best available alternative technology. Direct dry cooling systems were not investigated because EPA determined that they are unlikely replacement candidates. This is because use of direct dry cooling systems would require replacement or substantial reconfiguration of steam turbines used with existing once-through cooling systems (EPA 2002).

towers. The net effect can be an increased land footprint. For example, to achieve a comparable heat rejection, one study estimated that a direct dry cooling system will have a footprint about 2.2 times larger than a wet-cooling tower and a height of about 1.9 times greater. This issue could limit the viability of a potential retrofit of an indirect dry cooling tower to an existing plant.

Air emissions increase

The relatively higher energy penalty associated with dry cooling systems would mean a similar increase in emissions of air pollutants (resulting from burning additional fuel), such as sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM), among others, that are of national concern to human health and welfare. For example the NETL and ANL report that converting once-through systems to dry cooling towers could increase air emissions by 4 percent, depending on how the power company compensates for the lost energy as a result of this conversion.

Increased capital costs

The capital cost of an air-cooled condenser (ACC) system is considerably higher compared to a once-through cooling system. According to NETL, wet recirculating systems are roughly 40 percent more expensive than once-through systems, while dry cooling systems (ACC) are 3 to 4 times more expensive than a wet recirculating system (NETL 2009b).

According to experts we spoke with, these challenges make dry cooling unfeasible as a retrofit technology—the required changes to balance of plant equipment to address the higher turbine back pressure, revised condenser design, land area requirements, and limited remaining life span would generally make such a retrofit economically unreasonable if not technically challenging.

7.5 Assessment of emerging cooling technologies for water savings

We assessed four emerging technologies for their technological maturity, effectiveness at saving water, cost factors, and potential constraints and consequences. The technologies described below are: thermosyphon cooling; M-cycle dew point cooling; adsorption chiller; and air cooling technology to recover freshwater from an evaporative cooling tower.

7.5.1 Thermosyphon cooling

The premise underlying thermosyphon cooling (TSC) technology is that reducing the heat load to the wet-cooling tower by precooling the hot water intake would reduce evaporative loss and thereby conserve water. Thermosyphons are two-phase heat transfer devices operating in a closed loop.

Reports and experts from industry note that TSC can be implemented in a hybrid wet-dry configuration to enable water conservation of 30 to 80 percent, compared to traditional wet-cooling tower systems, while still maintaining the maximum peak power plant output on the hottest summer days. For example, EPRI sponsored research, based on a power plant model, indicates that for a 500 MW Plant in Seattle, potentially 75 percent water savings could be realized annually or 1.38 billion gallons/year (450 gals/MWh). Therefore, we rated this technology as medium to high in effectiveness in terms of water savings.

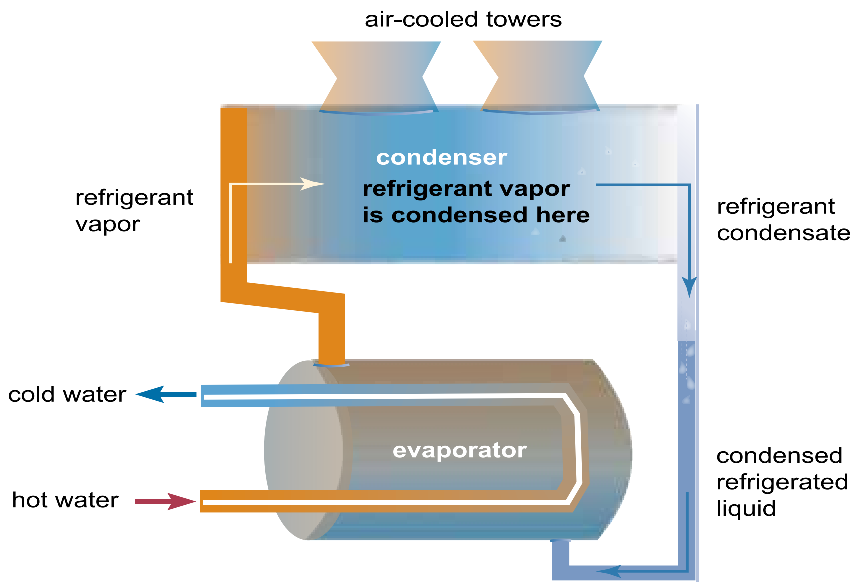

Figure 7.2: Thermosyphon cooling technology

Source: GAO, adapted from Electric Power Research Institute 2012e and Johnson Controls | GAO-15-545

In contrast with an all-dry cooling system, a TSC can be retrofitted to existing or new power plants (including nuclear), in incremental modular sections. However, challenges of operation at full scale are unknown therefore entail some degree of risk. Based on an EPRI report of a successful test of a very small sub-scale prototype hybrid TSC-mechanical draft tower cooling system on an operational power plant, we rate this technology as medium in maturity (TRL 6). It cannot be rated higher because a system prototype has not yet been demonstrated in an operational environment.

Thermosyphon cooling technology in detail

TSC is a dry cooling technology that transfers heat from the condenser cooling water to a refrigerant and then to the air without water evaporation.[74] It is intended to work in a hybrid-cooling approach where a part of the cooling water is fed to the TSC, thereby reducing the heat load to the cooling tower. Reducing the heat load to the cooling tower reduces the evaporative loss with simultaneous reduction in tower blowdown, thereby realizing notable water savings.

A closed two-phase TSC is illustrated in figure 7.2. It is similar in concept to a typical air conditioner unit, consisting of an evaporator and a condenser unit, but with minor differences. In the evaporator, the heat of the warm cooling-water from the steam surface condenser unit is transferred to the liquid refrigerant, causing it to boil and evaporate. In this way, the refrigerant absorbs the heat load and vaporizes.

The refrigerant vapor flows upward to an air-cooled condenser. The vapor is condensed in the condenser tubes by the transfer of latent heat of condensation from the refrigerant to the ambient airstream as air is moved over the finned condenser tubes. The refrigerant flow

74 A refrigerant is used in a cooling mechanism, such as an air conditioner or refrigerator, as the heat carrier which changes from gas to liquid and then back to gas in the refrigeration cycle.

circuit is completed by the condensed liquid refrigerant being forced by gravity back to the evaporator section in the form of a thin liquid film to repeat the cycle.

Thermosyphon cooling system advantages

TSC has been proposed as a dry cooling technological option for decreasing water consumption in power plants. The TSC in conjunction with a conventional wet-cooling tower would form a hybrid wet-dry cooling system where the TSC provides for non-evaporative dry cooling while the conventional wet cooling tower provides for evaporative cooling. In an actual full-scale power plant operation, TSC would typically be installed upstream and in-series with the wet-cooling tower. The total heat load of the steam condenser that needs to be dissipated can be allocated between the dry cooling TSC and the conventional wet cooling tower based on factors such as the ambient temperature, cost of water, electricity cost, and plant heat load. In general the heat load allocated to TSC could be increased during cooler days, thereby increasing the water savings. In some cases, it could be possible for the plant to operate "all dry" at a predetermined ambient temperature (such as 40° F) during the winter months thereby completely eliminating water loss from a cooling tower.

The TSC system uses water by switching to all-evaporative cooling when it is advantageous and then saving water by using increased dry cooling through the Thermosyphon when ambient weather conditions permit. In contrast with direct dry cooling options, the TSC hybrid system can be applied to existing or new power plants (including nuclear), in incremental modular sections. Additionally, since the dry cooling component (TSC) works with the traditional surface condenser water loop, the location of the sensible dry heat rejection device is not required to be close to the steam turbine (unlike with traditional dry cooling systems).

7.5.2 M-cycle dew point cooling

The M-cycle (Maisotsenko cycle) dew point cooling technology works by pre-cooling the ambient air-intake to the tower. The premise behind M-cycle dew point cooling technology is that pre-cooling the ambient intake air can in principle lower the temperature of cooling-water exiting the tower to below the ambient wet-bulb temperature (theoretically as low as the dew point temperature).[75] This would result in a reduction in steam condensation temperature that consequently lowers the turbine back-pressure leading to an increase in power generation. It also has the potential for reducing evaporative loss by up to 20 percent compared to wet cooling towers (EPA 2002; EPRI 2012d; Zammit et al. 2011).

Reports and experts from industry note that wet cooling towers employing an M-cycle dew point cooling system could improve overall power generation efficiency through a lower condenser inlet water temperature (and therefore lower turbine back-pressure) compared to conventional wet cooling towers. Further, M-cycle dew point cooling has the potential to improve not only the cooling tower performance in terms of lower cooling water temperature, but also improve energy efficiency of power turbines, thereby improving overall thermoelectric power plant efficiency. However, it may come at the expense of increased evaporation rates and increased water loss. Similar to a TSC system, this is also amenable to retrofitting because it entails only a change of cooling tower "fill" design and water and air distribution systems. Similar to wet cooling towers, the cooling capacity of M-cycle

75 Dew point is the temperature at which a vapor will condense.

would be reduced when there is an increase in humidity of ambient air. Operations and maintenance costs are unknown as they have not been evaluated for power plant cooling applications, but they are expected to be much lower than those for dry cooling.

We rated this technology as low to medium in effectiveness in terms of water savings based on a potential 20 percent reduction in evaporative loss per our effectiveness criteria defined earlier in this section (Zammit et al. 2011). Fully functioning system prototypes have been demonstrated, validated, and deployed in a relevant environment for other industrial applications, but not for power plant cooling. We rated this technology as low to medium in maturity (TRL 4) because we found no system models or prototypes tested or demonstrated at a power plant or other similar environment.

M-cycle dew point cooling in detail

The M-cycle process for power plant applications, works by modifying designs of "fills" (packing materials) in towers. Temperatures of cold water produced using these unique "fills" are limited to ambient air dew point temperatures.[76] Conventional wet cooling towers use direct evaporative cooling where air and water come in direct contact. The lowest temperature that can be achieved using a conventional wet cooling tower is the wet-bulb temperature of the ambient air. That is, heat transfer in conventional wet cooling is driven by wet-bulb temperatures. In contrast, heat transfer within the M-cycle is driven by dew point temperatures, which are higher driving forces because dew point temperatures are lower than the wet-bulb temperatures.[77] The M-cycle process, with modified fill designs, can produce cooler water temperatures than conventional wet cooling process.

M-cycle dew point cooling system advantages

M-cycle is a unique thermodynamic cycle that, in principle, can enhance wet cooling tower performance by cooling water to its dew point temperature, as opposed to being limited to wet-bulb temperatures in traditional cooling towers. This has the potential to improve not only the cooling tower performance in terms of lower cooling water temperature, but also improve the energy efficiency of power turbines through a lower condenser inlet water temperature (and therefore lower turbine back-pressure), thereby improving overall thermoelectric power plant efficiency.

Similar to a TSC system, this is also amenable to being retrofitable because it entails only a change of cooling tower fill design and water and air distribution systems. Similar to wet cooling towers, the cooling capacity of M-cycle would be reduced with an increase in humidity of the ambient air because the driving force for evaporation is the temperature difference between the dry-bulb and wet-bulb temperature of the ambient air.

7.5.3 Adsorption chiller

Adsorption chiller is a type of all-dry cooling technology that has the potential to reduce water withdrawal and consumption to near

76 The purpose of the fill in the cooling tower is to expose greater water surface to air within a given packed volume. This enhances the heat transfer between cooling water and air.

77 In unsaturated air, the dew point temperature is always less than the wet-bulb temperature.

zero.[78] Additionally, it may produce up to 5 percent more power production due to reduced steam condensation temperature. While it is largely used in other cooling applications, such as commercial buildings, it has the potential to replace current cooling towers and surface cooled condensers in power plants.

Adsorption chillers generally use water as a refrigerant, unlike other chemical refrigerants used in conventional chilling technology that could be harmful to the environment. However, a precondition of using this technology is the availability of large quantities of inexpensive low-grade heat, such as waste steam exhaust from electrical power generation plants or solar heat. Conventional chillers use electricity to produce chilled water, but adsorption chillers take advantage of waste heat or solar heat to produce the same cooling effect. Literature reports and technical discussions with experts from industry report that adsorption chillers have the potential for theoretically near-zero water withdrawal and consumption for steam condensation, which currently accounts for 90 percent of power plant water use and consumption. For a 500 MW plant running at 70 percent capacity factor, this would mean a theoretical savings of approximately 600 gals/MWh or 1.84 billion gallons per year. Because of its potential of near zero water consumption for power plant cooling, we rated this technology as high in effectiveness in terms of water savings.

In terms of power generation efficiency, the adsorption chiller may produce up to 5 percent more power due to reduced steam condensation temperature and lower turbine exhaust pressure. It may also achieve full power production, even on the hottest days unlike an air-cooled condenser. However, it is less energy efficient compared to electrically driven vapor compression cooling systems, with a lower coefficient of performance of about 0.68.[79] This means that much more energy is required to produce the same cooling effect with these systems as compared to vapor compression cooling systems. Further, refrigeration capacities rendered by these chillers are thousands of times smaller than those required for power plant steam condensation. Therefore, the requirements of space and costs are high. We rated this technology as low in maturity (TRL 3) for power plant steam condensation application because we found no system models or prototypes tested or demonstrated at a power plant or other similar environment, although fully functional systems exist for applications in other industries.

Adsorption chiller advantages

In comparison with mechanical vapor compression used in conventional refrigeration systems, adsorption systems have the benefits of energy savings if powered by waste heat or solar energy, no compressors, and the use of environmentally benign refrigerants, such as water, unlike the ozone-depleting refrigerants used in vapor compression systems (Wang and Oliveria 2005). However, such systems are not often used because they are less energy efficient compared to electrically driven vapor compression cooling systems. This means that much more energy is required to produce the same cooling effect with these systems as compared to vapor compression cooling systems. This disadvantage is mitigated in instances where solar energy or waste heat is readily available, such as from a power plant. Second, the large energy

78 Adsorption occurs when molecules of gases, liquids, or dissolved substances adhere in a thin layer onto a surface. Adsorption is different than absorption, which occurs when a substance penetrates into the actual interior of a solid or liquid.

79 The coefficient of performance of an energy device is the ratio of heating or cooling provided to electrical energy consumed.

flow requirement with such systems, due partly to the poor heat and mass transfer properties of existing solid adsorbents and the intermittent nature of its operations, necessitates bigger dimensions and also a heavier weight in relation to its cooling capacity. This would result in larger space requirements and costs in comparison to vapor compression systems (Sarkar et al. 2013). These systems could potentially be used where large quantities of low-cost heat are available to offset some of the other costs.

According to EPRI, this technology has not yet been used in electric power plants for steam condensation due to the aforementioned reasons. Commercial adsorption chillers require significant amounts of hot and cold water to enable desorption and adsorption processes (EPRI 2012c). The available refrigeration capacities rendered by these chillers are thousands of times smaller than those required for power plant steam condensation.

7.5.4 Air cooling technology to recover freshwater from evaporative cooling tower

A conventional cooling tower uses the evaporative cooling process to cool circulating water. A small portion of the circulating cooling water is continually evaporated (typically about 1 to 2 percent of the circulating flow rate) in the tower as it comes into direct contact with the counter-flowing air. Evaporative water loss in this type of tower is approximately 449 gals/MWh of electricity produced. Therefore, recovering part of this water lost through evaporation and using it in internal plant processes could reduce freshwater intake in a plant. For example, recovering just 20 percent of the evaporated water could save about 90 gals/MWh (approximately 0.3 billion gallons per year for a 500 MW plant operating at 70 percent net capacity factor).[80] Hence, there is an incentive to capture and reuse this water that is otherwise dissipated to the atmosphere via the cooling tower.

Air cooling technology in detail

DOE funded a study to test and verify such a water conservation technology called air-to-air cooling, and demonstrated its water conserving capability (SPX 2012). The study reported on recovering part of this water vapor from a cooling tower plume by condensing it using a draft of cool ambient air. The process involves installing a condensing module in the pathway of the rising water-vapor laden air in the tower. Typically, it is installed above the wet-fill media. The condensing module is essentially a direct contact air-to-air heat exchanger.[81] The warm moisture-laden air rising up towards the tower exit is cooled by a separate draft of cross-current cool ambient air. This cool ambient air extracts partial heat from the hot moist vapor, thereby condensing it in the process. This condensed water is then recovered for reuse in the plant.

According to a DOE-funded study performed by an equipment vendor, the rate of water recovery from a cooling tower was estimated to range from 15 percent to 25 percent of the evaporation annually, depending on the climate where the cooling tower is located.

Operations and maintenance costs are unknown, as they have not been evaluated for power plant

80 The net capacity factor of a power plant is the ratio of its actual output over a period of time, to its potential output if it were possible for it to operate at full nameplate capacity indefinitely. To calculate the capacity factor, take the total amount of energy the plant produced during a period of time and divide by the amount of energy the plant would have produced at full capacity.

81 A heat exchanger is a device used to transfer heat from one fluid to another without direct contact of the fluids. It is designed to maximize the transfer of heat by maximizing the contact surface area between fluids.

applications. However, the expected high cost of water recovery makes it difficult to justify this approach. We rated this technology as low to medium in effectiveness in terms of water savings.

This technology can be retrofitted to an existing evaporative cooling tower of a thermoelectric power plant to reduce freshwater consumption. Additionally, as per NETL, plume abatement is an added benefit of this technology. A pilot scale system has been developed under NETL funding and tested at a power plant, saving about 19 percent water. Improvements to this technology have been made based on test results and the first commercial scale system is being built. Therefore, we rated this technology as medium to high in maturity (TRL 7).

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Related GAO products

Energy-Water Nexus: Improvements to Federal Water Use Data Would Increase Understanding of Trends in Power Plant Water Use
GAO-10-23
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