Section II. Water for Energy

INTRODUCTION

The nature of the energy cycle varies, depending upon the source of that energy and its intended end use. In this section, we evaluate the literature addressing the water intensity of coal, natural gas, oil and uranium extraction and processing, thermoelectric generation and transportation biofuels. Every step of that cycle involves water inputs, sometimes from different sources, as well as waste discharges, again frequently into different water bodies. Gaps and limitations in the existing literature and research present opportunities and needs for future investigation.

COAL

This section explores the research and literature on water withdrawal and consumption, as well as associated pollution from the mining, processing and transportation of coal. Coal remains one of the most widely used energy resources in the United States and many parts of the world. The combustion and use of coal for electricity generation is covered under a separate section (see Thermoelectric Generation). A review of the literature is preceded by a brief overview of the coal mining cycle (Figure 1a) and industry.

While relatively modest in its use of water compared with thermal electric generation, the extraction and processing of coal has substantial impacts on both the quantity and quality of water resources. The vast majority of the research and writing in this area is limited to few papers (Gleick, 1994; U.S. DOE, 2006; Chan et al., 2006; Elcock, 2010; Mielke et al., 2010; Allen et al., 2011; Lovelace, 2009). However, most of these papers rely completely or in large part on the work done by Peter Gleick of the Pacific Institute in 1994, which is based on data from the 1970s and 1980s. Recently, Grubert et al. (2012) have done work on Texas coal, which brings updated data to this field.

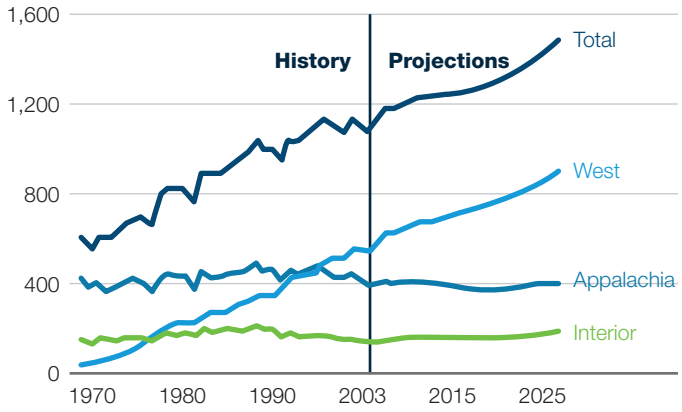
Possible reasons for the limited literature could be due to the data gap on water use for coal extraction. Coal mines are not required to report water usage to any government body. In addition, the current focus on a broader scale is on coal-related emissions and global warming rather than water use and pollution (as shown in Epstein et al., 2011, where water issues are under-represented). The use of water for thermal electric production is covered in a later section, and the water impacts of conversion of coal to transportation fuels will not be addressed by this literature review project.

Coal was linked to the economic success of the United States throughout the 19th and 20th centuries; historically, it powered trains, factories and power plants. The abundance of coal – the U.S. has the world's largest reserves (BP 2011) and an estimated reserve-to-production ratio of 214 years – still makes it an attractive energy source. While there are questions about the accuracy of the coal reserve-

to-production ratio (Grubert 2012), coal still plays a major role in the U.S. energy mix today. Twenty-one percent of the U.S. primary energy consumption and 45 percent of the electricity generation in 2011 (EIA, 2012). U.S. coal is primarily produced in three regions: Appalachia, the interior and the West (Figure 1b). The primary use of coal is electricity generation, which withdraws large amounts of water every year for cooling. The "water bill" of coal mining and processing is also quite high. Figure 2 shows a general schematic of the embedded water in the coal mining, processing, transportation and electricity generation process.

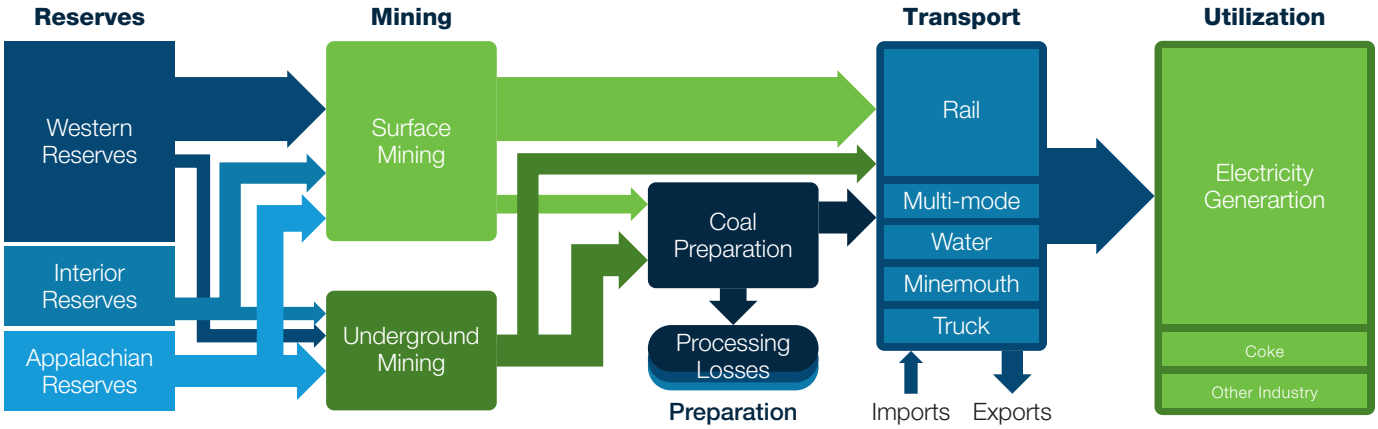
The coal mining industry currently directly employs roughly 50,000 people, but this number is rapidly declining due to mechanization (EIA Annual Coal Report, 2011a). Indirect employment effects are broader, although mine closures can have a big impact as well. The U.S. coal market was worth $35 billion in 2008 (Kohler & Lukashov, 2009). With relatively constant prices and production levels, this estimate probably still holds. The EIA reports (2011b) direct federal subsidies for the coal industry of $1.3 billion (compared to $14.8 billion for renewables and $2.8 billion for petroleum and natural gas). Forms of indirect subsidies, which greatly exceed direct ones but are extremely complex to estimate, include the U.S. Treasury Department's backing of tax-exempt bonds for the electric sector or the tax credits, loans and loan guarantees for the electric sector through the U.S. Department of Energy (2005 Energy Policy Act), property tax structures, and uncollected or underpriced royalties and bonuses from the Bureau of Land Management.

Figure 1b. Coal Production by Region, 1970 to 2025



Source: EIA, 2005

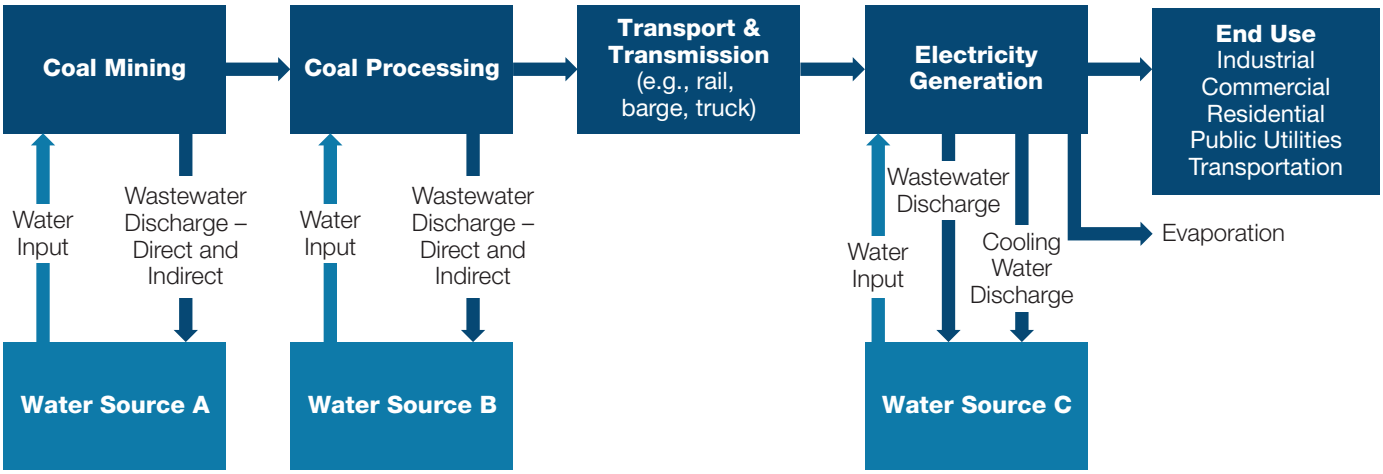
Figure 1a. U.S. Coal Cycle



Note: Tonnage approximated by thickness.

Source: Adapted from National Research Council, 2007.

Figure 2. Flow Chart of Coal and Embedded Water



Note: Water inputs and outputs may be in different water bodies.

Coal production is expected rise by about 50 percent by 2025, with the bulk of the new production going to electricity generation (EIA, 2005). However, several studies are predicting a U.S. peak coal based on multi-Hubbert cycle analysis as early as 2015 (Epstein et al., 2011). Due to legislation and price, availability and technology, the U.S. coal production is shifting from the traditional underground mines of the Appalachian Mountains to the large open mines of the arid Western U.S. , such as in Wyoming (Höök & Aleklett, 2009).

1. Mining

The primary investigation of the water use of coal mining is the 1994 work of Peter Gleick with the Pacific Institute. Since then, his work has remained relevant to and often has been the basis of subsequent literature (U.S. DOE, 2006; Chan et al., 2006; Mielke, 2010). The literature suggests that coal mining requires large water inputs. Water withdrawal (de-watering) occurs from mining, and water consumption is required for both mining and the reclamation of the mined land (subject to the 1977 Surface Mining Conservation and Recovery Act). Both underground (30 percent of U.S. production) and surface mining (the remaining 70 percent) require water to cool and lubricate equipment and manage dust (EIA, 2011a).

Gleick found that the water consumed in underground coal mining for Appalachian coal with high sulfur content ranges from 0.8 to 5.6 gal/Million Metric British Thermal Units (MMBTU). Surface mining for Western coal with low sulfur content usually requires less water: 0.6 gal/MMBTU if no revegetation is required, and up to 1.4 gal/MMBTU if it is. More recent work by Grubert (2012) for Texas coal suggests 16.1 gal/MMBTU (including dewatering) or 1.6 gal/MMBTU (excluding dewatering). Water use estimates depend on the mine, the geology, the depth and width of the coal seam and the energy content of the coal. How "use" or "consumption" is defined is also important.

Underground mining may also require water to be pumped out of the mine, which can in turn be used to supply mining needs. This water may be contaminated, requiring treatment. Most researchers agree that reuse of this water significantly reduces the need for other freshwater withdrawals, thus reducing the total water and energy impact of the mines. Major spills from mining operations (particularly settling ponds) can represent huge environmental and human risks (U.S. DOE, 2006; Epstein, 2011).

The major water-related concern of coal mining is not the quantity of the water that is used, but the discharge of pollutants affecting local water quality. Mining activities produce polluted industrial wastewater that is regulated under the Clean Water

Act, and which has to be treated prior to discharge. Moreover, the CWA (under section 404) often requires mining operations to have a permit for discharging or depositing overburden into a water body. The Clean Water Act identifies four major pollutants that are regulated in discharge water from strip or underground mines: pH, iron, manganese and suspended solids. Some researchers considers pH to be a major water quality concern of coal mining because it poses an immediate danger to aquatic wildlife, increases leaching, destroys structures and endangers recreational use (Squillace, 2009).

Coal mining creates large mine tailings constituted by the excavated material, topsoil and rocks (also called overburden). Allen et al. (2011) estimate that the "overburden"-to-coal ratio can range from 5:1 to 27:1. In most cases, this overburden is used to fill the hole left by surface mining operations (with the notable exception of mountaintop removal). These tailings are exposed to wind and rain and pose a direct threat to air quality through wind erosion, and to water quality through leaching. This kind of pollution is not regulated and seems underestimated (Chan et al., 2006; Epstein et al., 2011). In particular, several studies show that elevated levels of arsenic in drinking water are typically found in coal mining areas (Epstein et al., 2011). More complete sampling of water supplies seems necessary in coal-mining areas in order to protect local populations.

In Appalachia, mountaintop mining or mountaintop removal (MTR) is a form of surface coal mining that alters landforms (EPA, 2005; Figure 3). Epstein et al. (2011) report that about 500 sites in Kentucky, Virginia, West Virginia and Tennessee have experienced mountaintop mining, affecting 1.4 million acres and filling 2,000 miles of streams. Valley fill techniques bury streams and contaminate ground and surface water with leachate from the overburden. Pond et al. (2008) studied the downstream effects of mountaintop coal mining, particularly on streams and aquatic organisms, but further studies to fully assess impacts on headwaters and associated aquatic habitats, terrestrial ecosystems and freshwater supplies would enrich the literature for decision-makers and researchers.

Figure 3. Mountaintop Mining

Source: paradiseearth.com

Coal mining can impact groundwater quality (Wolkersdorfer, 2008). Groundwater can become contaminated, particularly in open-pit mining, where the coal beds are exposed. Groundwater pollution can occur both directly and indirectly: Direct degradation comes from contaminated drainage and rainfall infiltration (Epstein et al. 2011), whereas indirect degradation could result from blasting (in mountaintop removal mining in Kentucky and West Virginia mainly), which can create new rock fractures. Underground mining can affect overlaying aquifers due to land subsidence, as the structural support provided by the coal in the ground is removed (Booth, 2002).

The long-term effects are still not fully understood. In 1994 Gleick commented on the fact that there is no good estimate of the total amount of water contaminated by coal production, and while there are still few estimates today (Allen et al., 2011), the U.S. Environmental Protection Agency's work in Appalachia for the programmatic environmental impact statement on mountaintop coal mining is providing more information (EPA, 2005).

The literature highlights that regulatory authorities place a higher importance on groundwater, but are limited in their efforts because the effects of coal mining on groundwater are poorly understood. Several authors (National Research Council, 1990; Chan et al., 2006; Squillace, 2009) notice that the Surface Mining Conservation and Recovery Act of 1977 is starting to incorporate more elements than previously, such as surface and groundwater quality and quantity.

2. Processing

Very little literature dwells on coal processing *per se,* although some studies report the recurrent environmental impacts of coal slurry spills (Epstein et al., 2011). The 1994 estimates by Gleick are still used as the reference in the literature corpus on the water intensity of coal processing.

After being excavated and crushed, coal may be washed to reduce sulfur content (pursuant to the Clean Air Act), reduce the amount of ash produced and increase the heat content of the coal by removing impurities. Western coals have low sulfur contents, therefore are seldom washed, but an estimated 80 percent of Appalachian coal goes through this process (U.S. DOE, 2006). Water requirements for washing are rather high (1 to 2 gal/MMBTU, Gleick, 1994) and necessitate treatment of the wash water prior to discharge into the environment. Moreover, chemicals can also be used to enhance cleaning performances. These chemicals further degrade the quality of the water.

Coal gasification and coal-to-liquid (CTL) processes are thought by some to hold a promise for the future, particularly in reducing demand for foreign sources of oil. Both processes require large amounts of water. While commercial CTL only exists in South Africa and China (Younos et al., 2009), coal gasification is already in use in the U.S. Coal is converted into a mixture of carbon monoxide and hydrogen (syngas) by putting it under pressure and subjecting it to steam. This process requires 11 to 26 gal/MMBTU (Younos et al., 2009). Syngas can then be used in gas turbines, such as in Integrated Gasification Combined-Cycle (IGCC) power plants. Currently, only two IGCC power plants are operational (U.S. DOE website), but several others are under construction or planned.

3. Transportation

Even though coal is usually associated with rail (70 percent of coal, U.S. DOE, 2006, which represents 70 percent of U.S. rail traffic, NRC, 2010), 10 percent of the coal used in the U.S. is barged along waterways. The U.S. DOE report (2006) and estimates by Gleick (1994) are once again the cornerstone studies for the water intensity of the transportation of coal. These studies identify the transport of coal through waterways as an energy management challenge during low flow periods along these rivers and a water management challenge due to the water cost in lock operations. The report estimates that reservoirs can lose 2 million to 10 million gallons of water for each operation.

Sulfur emission regulations, availability of coal reserves and changes in mining technology are all working together to slowly shift coal production westward toward more arid regions, even though most coal is still consumed by power plants in the East. This geographic shift increases the energetic and water intensity of coal transportation. The U.S. DOE 2006 report estimates that this shift to Western coal has corresponded to an increase of up to 12 billion gallons per year in water use.

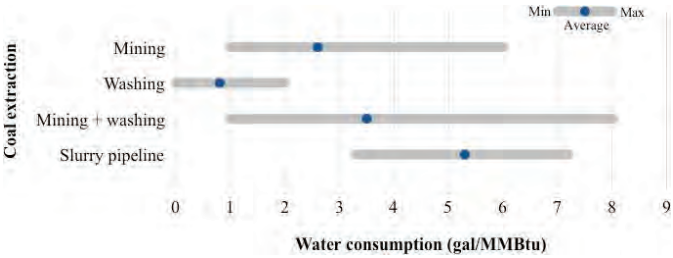
4. Conclusion

There is no consensus around the actual water withdrawals/consumption by the coal mining industry. By looking at Lovelace (2005), the 2011 EIA Annual Coal Report (1,084.4 million short tons produced in 2010) and the results from Mielke et al. (2010), an estimate of U.S. water consumption for coal extraction (mining and processing) is 185 million gallons per day (MGD). This is the water needed for a city like Dallas, or about 1.2 million people, since the U.S. average is 150 gallons per person per day.

In a report for the DOE's National Energy Technology Laboratory, Chan et al. (2006) estimate the freshwater withdrawals to range from 86 to 235 MGD (3 percent to 13 percent of freshwater withdrawals from the mining sector, which accounts for 2 billion gallons per day). By considering the U.S. Geological Survey (USGS) estimate that in mining operations, approximately 30 percent of the freshwater withdrawn is consumed (i.e., not reusable or discharged), coal-mining activities would account for 26 to 70 MGD in freshwater consumption. In line with this, Averyt et al. (2011), in a report for the Union of Concerned Scientists, estimate a water use of 70 to 260 MGD for the U.S. coal mining industry.

However, this withdrawal, consumption and contamination of water is particularly focused in localized areas where coal mining takes place. Coal mining can stress the local water supply and may be competing with other human activities such as agriculture, fishing and recreation, as well as the environment. There is a range of water impacts depending on whether it is mountaintop mining, other surface mining or underground mining; the region (Appalachia versus the Western U.S.); and the type of coal, among other variables.

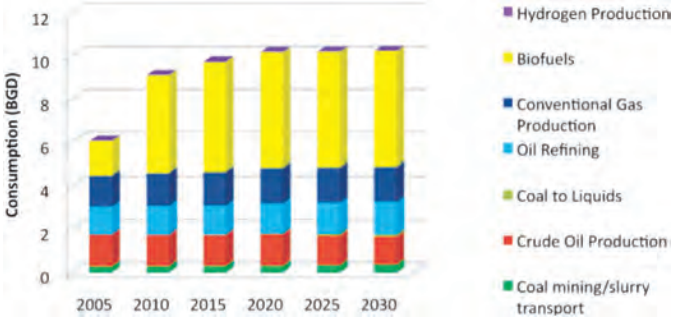
Figure 4. Water Consumption Data for Coal



Source: Mielke et al., 2010

Mielke et al. (2010) combined the "consensus" estimates of Gleick (1994) and the 2006 U.S. DOE Report to compute averages in water consumption of the coal mining industry for mining, processing and transport (Figure 4). One must bear in mind the fact that these estimates come from a limited number of sources. In addition, there is wide variation by mine location (e.g., water intensity of Powder River Basin coal is likely less than Appalachia coal). They can nevertheless be effectively used to compare the water intensities of different energy sources (Figure 5).

Figure 5. Projected Water Consumption in Primary Energy Production

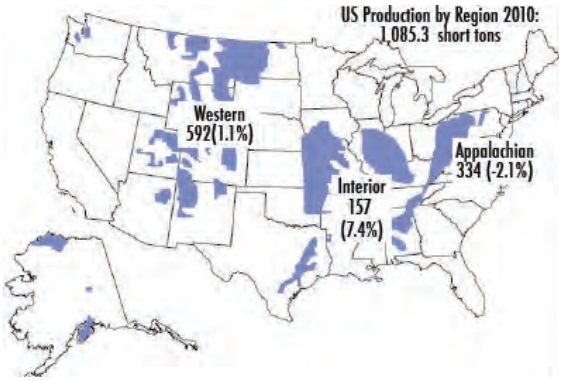


Source: Elcock, 2010

Chan et al. (2006) also point to the USGS' methodology for explaining changes in water withdrawals from one survey to the other (Kenny et al., 2009). In particular, they highlight the fact that the surveys were not administered in all states (West Virginia and Kentucky, two large coal-mining states, were left out of the 2000 survey). Moreover, in the USGS report, there is no quantification of water use for extraction of individual resources (coal, uranium, metals), making it very difficult to assess the particular impact of coal.

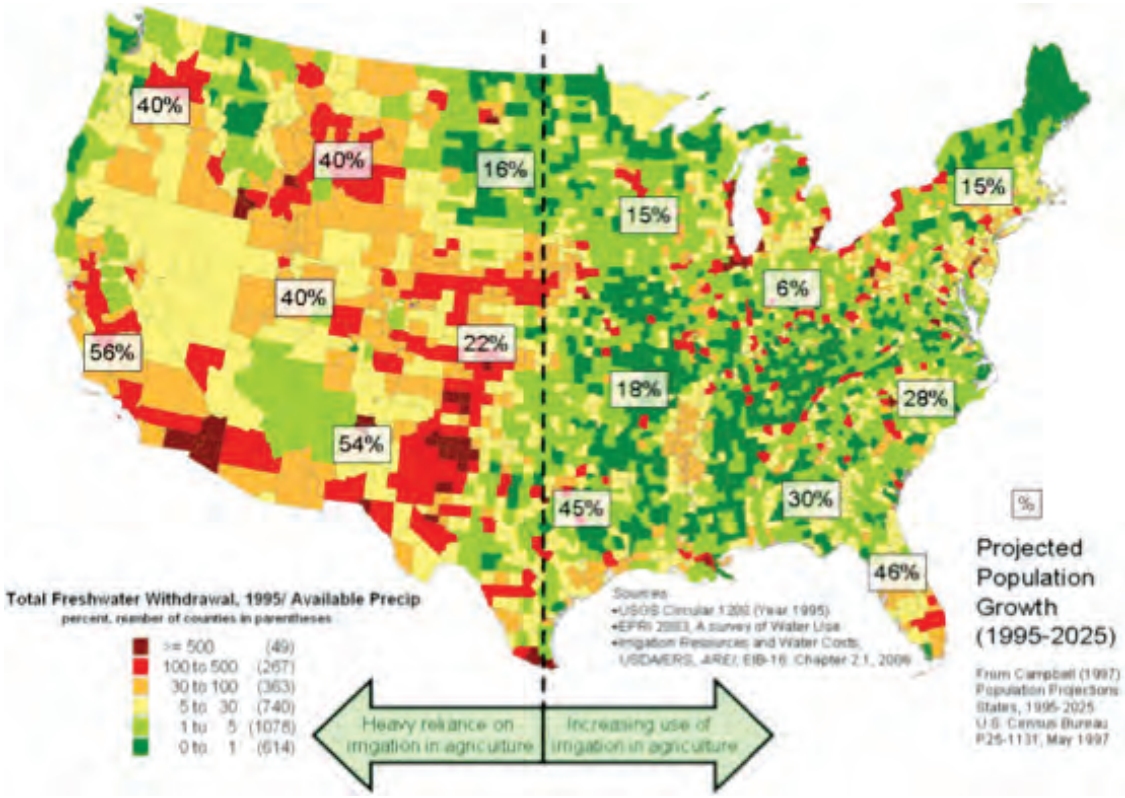
Although the total water withdrawals related to coal mining are relatively small when taken as a whole compared to sectors like agriculture, it appears that local and regional consumption may be acute in some cases. Unfortunately, there is little in the literature that quantifies or estimates the local impacts of freshwater withdrawals linked to mining activities. This will be increasingly important as U.S. coal production shifts to the water-stressed Western U.S., as shown in Figures 6a and 6b. Moreover, as production moves westward, the average energy content of coal is expected to decline (Höök & Aleklett, 2009). For example, Powder River Basin coal (around Wyoming and Montana) has an average energy content of 8 to 9 KBTU/lb., while Appalachia and interior coal is around 12 to 14 KBTU/lb. Powder River Basin coal will most likely be responsible for the bulk of the nationwide production, as most of the higher-energy eastern coal has been depleted and the environmental impact of coal mining east of the Mississippi is gaining increased attention. This shift in coal production and its implications for total water intensity of coal needs further study.

Figure 6a. U.S. Production by Region 2010



Source: EIA, Annual Coal Report, 2011

Figure 6b. Availability of Water in the U.S.



Source: Pate et al., 2007

There have been no estimates on nationwide figures for the total surface disturbed by coal mining since a U.S. Geological Survey report in the 1970s. Different interest groups have made estimates ranging from 5 million acres (truthaboutsurfacemining.com) to 8.5 million acres (sourcewatch.org). Source Watch estimates that the land intensity of coal mining is approximately 8.8 acres per MMBTU.

The most complete and available report on the energy intensity of coal mining and processing is by the U.S. Department of Energy (U.S. DOE 2002). It is estimated that the coal mining industry consumed about 0.3 percent of the total industrial energy use in 1997, or 103.1 x 10^{12} BTU. This means that the energy intensity of coal mining is approximately 0.5 percent of the extracted energy. The U.S. DOE reports that the major energy requirements are electricity (ventilation systems, water pumping, and crushing and grinding operations) and diesel fuel (hauling and other transportation needs). The energy bill of transporting coal is also significant: 70 percent of coal is transported by rail (mainly diesel locomotives) over increasingly long distances as coal production shifts westward.

NATURAL GAS

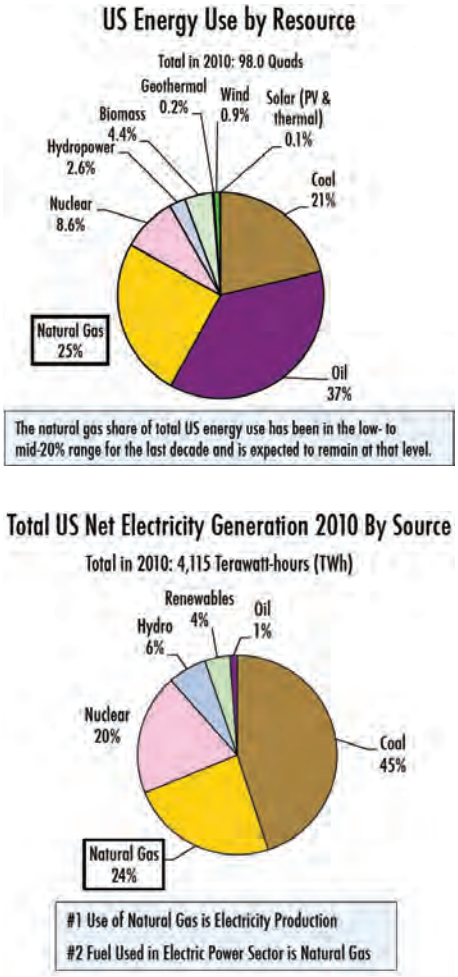
This section reviews the research and literature about the water and energy intensity of natural gas exploration, drilling, processing and transportation. It also addresses some research about water and air pollution impacts. Natural gas is the fastest-growing source of energy in the United States and throughout many parts of the world. The combustion and use of natural gas for electricity generation is addressed under a separate section (see Thermoelectric Generation).

Water is needed in all steps of the life cycle of natural gas from the well to end use. The water intensity of natural gas is relatively low compared to the other energy sources. Water issues are linked to water quality, and more specifically to degradation of potable water resource, rather than to water quantity. Most of the literature concerning the water intensity of natural gas refers to the papers by Peter Gleick (1994) and the U.S. Department of Energy report (2006). Mielke et al. (2010) provided the first true study of the water intensity of natural gas shale using industry information.

However, the rapid evolution and development of unconventional sources have rendered those studies obsolete, and most of the new data and analysis is from the natural gas industry itself, with the exception of Grubert et al. (2012), whose study quantified water use for natural gas extraction from 11 conventional and unconventional basins in Texas. A new report by Park and Bower (2013) on the role of natural gas in California's water and energy nexus helps frame the value proposition for natural gas pumping. It is difficult for government agencies to regulate these practices based on limited independent information. There is widespread public and political support for domestic energy sources like natural gas, but little peer-reviewed literature to analyze water and environmental impacts from natural gas extraction.

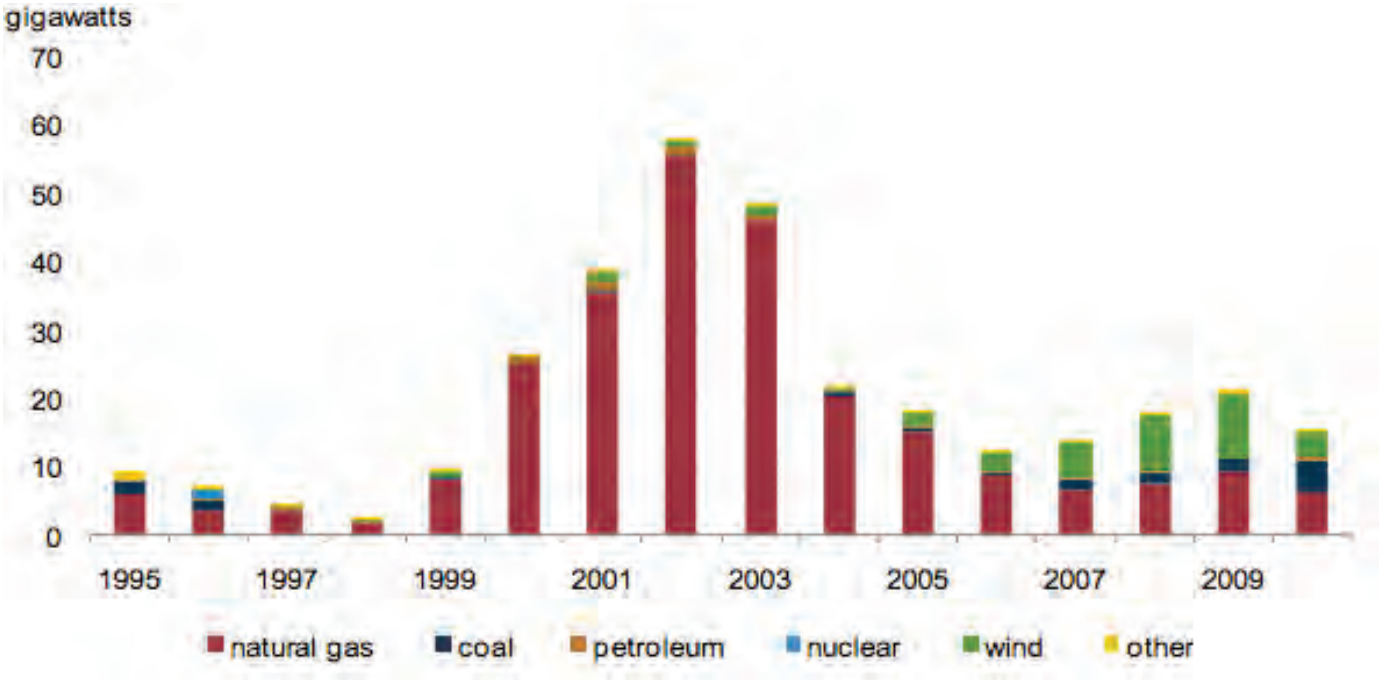
Natural gas was long considered an inconvenient by-product of oil production and of oil extraction, and was often flared or vented. As the cleanest-burning carbon-based fuel, the value of natural gas to the industry, as well as for electricity generation, has greatly increased over the past three decades. Like coal, natural gas is an American domestic resource, with a production that nearly meets domestic needs. The U.S. is among the world's largest producers and consumers of natural gas (BP, 2011), accounting for one-quarter of U.S. energy use and electricity generation (Figure 7). With the massive expansion of new unconventional energy sources (e.g. shale, tight sand, coal bed methane, coal mine methane), natural gas will continue to play a major role in the American energy mix. Indeed, most of the added electricity generation in the last decade has been from natural gas-fired thermoelectric power plants (Figure 8).

Figure 7. U.S. Energy Use by Resource and Net Electricity Generation in 2010



Source: Adapted from K. Knapp, Stanford; EIA, 2011

Figure 8. Electricity Generating Capacity Additions by Year

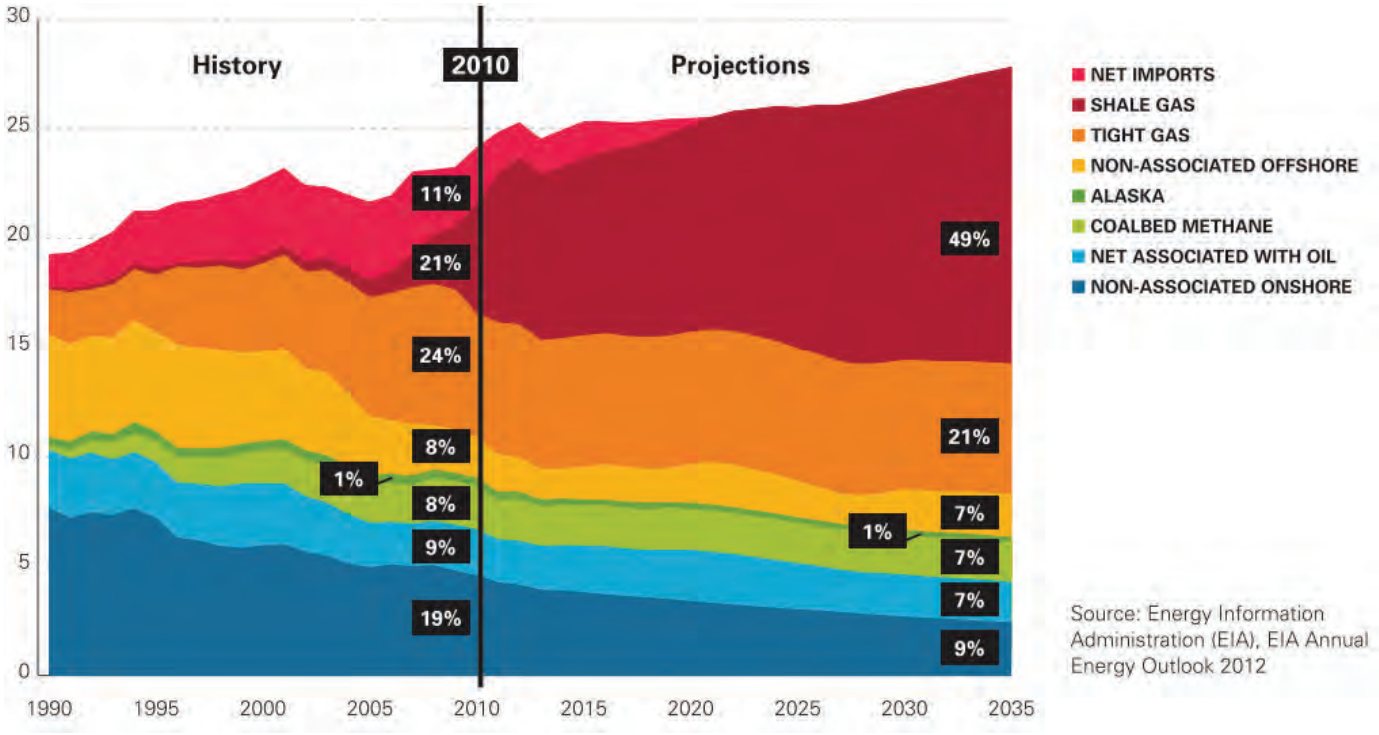


Source: EIA, 2011b

Natural gas, constituted primarily of methane, has the lowest carbon footprint per unit energy of all fossil fuel, with nearly no particulate matter, sulfur oxide (SOx) and nitrous oxide (NOx) emissions. The carbon and domestic production benefits of gas must be weighed against the environmental impacts of its extraction, some of which can be significant. Concern over methane emissions at the well head of drilling sites, as well as in the storage and transport of natural gas, has become an ever-increasing concern given the greenhouse gas potency of methane. The environmental impacts of unconventional natural gas most frequently cited are those on water withdrawals and water quality. On-site drilling and extraction operations require varying amounts of water (see Grubert et al., 2012), but of more concern are the water needs for single wells in unconventional reservoirs. Hydraulic fracturing (commonly called fracking) requires large amounts of water for every well drilled and also produces highly degraded wastewater as a by-product, which must be stored and treated.

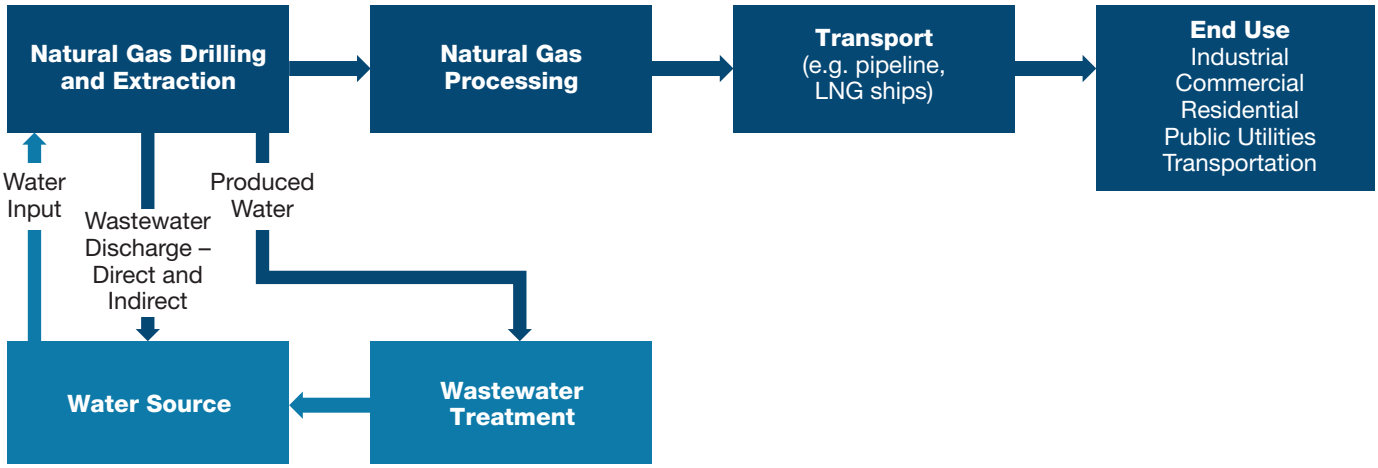
According to the BP Statistical Review of World Energy (BP, 2011), the U.S. has 272.5 trillion cubic feet (TCF) of proven natural gas reserves and a reserves-to-production ratio of 12.6 years. Note that the average price of natural gas (which in 2011 was quite low) affects the reserves number. However, the Energy Information Administration estimates that the U.S. possesses the potential of 2,500 TCF (EIA, 2012), which is enough to provide nearly 100 years of gas at the current rate of production. Connors et al. (2010) report that U.S. natural gas resources have grown by nearly 80 percent since 1990, which shows the large uncertainty inherent in all resource estimates. The U.S. production was 26.8 TCF in 2010 (EIA, 2011).

Figure 9. Natural Gas Supply, 1990 to 2035, in Trillion Cubic Feet Per Year



Source: Kennedy, 2012

Figure 10. Flow Chart of Natural Gas and Embedded Water



Numbers on direct and indirect employment as well as economic contributions to the economy are most meaningful with detailed definitions and impartial data sources. The EIA reports (2011b) total direct federal subsidies for the natural gas and oil industry of $2.8 billion (compared to $14.8 billion for renewables). Estimates of total indirect subsidies are not readily available.

The U.S. Energy Information Administration (EIA) projects that the U.S. natural gas demand will grow from about 25 TCF today to 28 TCF in 2035, which would be a 12 percent increase (EIA, 2012; Figure 9). With the development of unconventional natural gas resources, the share of shale gas will rise sharply in the coming years, reducing the need for imports. However, the development of unconventional natural gas may have a major impact in water-scarce regions. The embedded water in natural gas drilling and extraction is shown in Figure 10.

1. Extraction

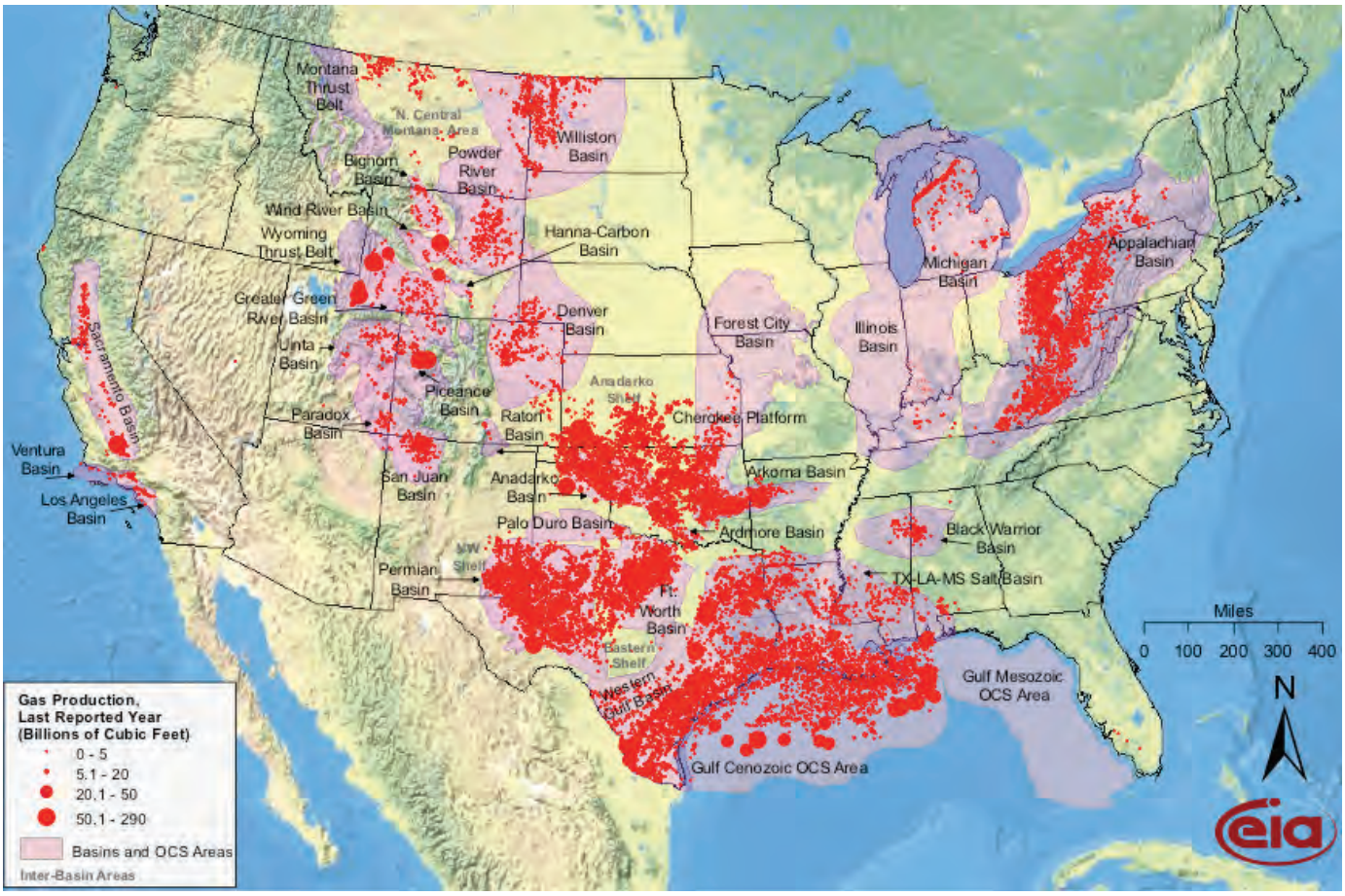
Natural gas can be found in many different geological formations. Natural gas is mostly methane (over 90 percent) and is the product of degraded organic matter trapped within buried sediment. There are two main classes of gas deposits: conventional (high permeability reservoirs) and unconventional (low permeability and often deep reservoirs such as shale gas, tight sands and coal bed methane).

1.1 Conventional Natural Gas

Conventional natural gas is extracted either without oil or in association with oil. Figure 11 shows the gas production in conventional fields in the U.S. The conventional natural gas extracted without oil, called non-associated natural gas, represents 31.5 percent of U.S. production of natural gas and can be divided into onshore (22.5 percent) and offshore (9 percent – mainly in the Gulf of Mexico) production. Associated natural gas, which is co-located with oil, accounts for 10 percent of U.S. production. Associated gas was once considered an inconvenient byproduct of oil drilling, and it was vented or flared on site. Due to the value of natural gas and growing environmental concerns, associated gas is increasingly used on site for cogeneration (production of electricity and steam for enhanced oil recovery) or simply processed and sold. The role of conventional gas sources is expected to decline over the coming decades as the easily accessible natural gas is depleted.

Conventional natural gas wells require relatively modest amounts of water for exploration and drilling processes. Drilling natural gas and oil wells is extremely similar and only requires water for preparing drilling fluid (cleaning and cooling of the drill bit, evacuation of drilled rocks and sediments, providing pressure to avoid collapse of the well). Many reports and papers (e.g., Gleick, 1994) often treat conventional oil and natural gas together, although oil requires much more water for extraction, particularly the heavy oil of California or the oil fields requiring enhanced recovery (if the enhanced recovery is water flooding or steam flooding). The drilling fluid contains potential contaminants and must be treated to separate excavated material and dissolved compounds. On site, this water is often treated in decantation basins and reused.

Figure 11. Gas Production in Conventional Fields



Source: EIA website, 2012

1.2 Unconventional Natural Gas

i. Shale and Tight Sand Gas

Water impacts from unconventional natural gas extraction have become an important topic with the recent surge in unconventional gas drilling. The drilling and development of shale and tight sand gas reservoirs requires hydraulic fracturing, which entails millions of gallons of water per well. The EPA (U.S. EPA, 2012) estimates that about 11,000 new wells are hydraulically fractured every year. The rapid decrease in the productivity of individual wells over time requires drilling new wells to maintain current production.

Since low-permeability unconventional natural gas resources are often deeper and may use horizontal drilling techniques, much more water is needed for drilling. Based mainly on industrial data, it is estimated that water needed for drilling a single well can range from 60,000 gallons in the Fayetteville Shale to 1 million gallons in the Haynesville Shale (Harto, 2011).

Low-permeability natural gas resources are in geologic formations located at depths of 1,500 to 15,000 feet below the surface, with natural gas wells averaging 6,500 feet (EIA website, 2012). At these depths, the formations may underlie drinking water aquifers, which are commonly 100 to 300 feet below the surface. As such, there is attention on the effect of drilling on these underground reservoirs.

The literature and industry sources agree that drilling a single well requires 1 million to 5 million gallons of water for hydraulic fracturing. The volume of water required per well and the number of wells being drilled or proposed for drilling in the same region raises concerns. Mielke et al. (2010) evaluate the water intensity to be relatively low: 0.6 to 1.8 gal/MMBTU, compared with other sources. The range could be due to different shale plays (geologic formations), which make the water intensity of a certain well extremely site-specific. However, their estimates were based on information made available by Chesapeake Energy (Table 1). These results are specific to one company's operations and therefore do not necessarily reflect the industry as a whole. Their results are nevertheless supported by a USGS report (Soeder & Kappel, 2009).

Grubert et al. (2012) suggest 1.8 to 6.7 gal/MMBTU for the Texas basins, including a 30 percent indirect impact from Texas-sourced water embedded in proppant and chemicals. Unconventional natural gas extraction separates itself from other mining industries because the water consumption is front loaded, and the water intensity greatly depends on the type of shale (or tight sand) and the hard-to-measure expected productivity of the well. The shale plays for the lower 48 states in the U.S. are shown in Figure 12.

Aside from the water quantity issue, two major problems of water quality arise from shale and tight sand gas development, including fracturing (or fracking) chemicals injected in the wells, which can return to the surface, and man-made and natural compounds and salts in the processed water. To ensure optimal hydraulic fracturing natural gas, the natural gas companies inject proppants (sand, ceramic or silicon pellets), gels, biocides and other chemicals into the wells. According to industry, the fracking fluid contains 0.5 percent of chemicals and 10 percent of proppants by volume (Chesapeake Energy). It is estimated by that about 15 percent to 25 percent of the total fracking fluid is recovered in the process (Mielke et al., 2010; Zoback et al., 2010). The flowback, which contains some of the original fracking fluid along with some deep groundwater (of differing qualities), returns to the surface and is re-injected, transported off-site in trucks, or collected in lined pits and ponds. This produced water may be treated on site and reused, although some is discharged.

Table 1. Estimates of Water Consumption for Different Shale Plays

	Water consumption per well (million gal)			Gas reserves per well		Water intensity
Shale play	Drilling	Hydraulic Fracturing	Total	BCF	MMBtu (million)	gal/MMBtu
Barnett	0.3	3.8	4.1	2.7	2.7	1.5
Fayetteville	0.1	4.0	4.1	2.4	2.5	1.7
Haynesville	0.6	5.0	5.6	6.5	6.7	0.8
Marcellus	0.1	5.5	5.6	4.2	4.3	1.3
Average						1.3

Source: Adapted from Chesapeake Energy, 2010

Figure 12. Lower 48 States Shale Plays

Source: EIA website, 2012

There have been rising concerns about the influx of this degraded water in municipal wastewater systems (Sapien, 2009); however, this impact is not clear and warrants further investigation. Kiparsky and Hein (2013) examined the regulation of hydraulic fracturing in California from a water quality and wastewater perspective. Urbina (2012) investigated natural gas drilling in a series for *The New York Times*. Part of the problem is that local wastewater systems and agencies do not know what chemicals they should be looking for because the identity of these chemicals is often considered proprietary information and not disclosed.

Large volume multi-stage hydraulic fracturing and multiple wells per well pad are ways to increase drilling efficiency and reduce potential risk of groundwater contamination because equivalent production can be obtained with fewer well bores, which means fewer routes for potential groundwater contamination due to casing problems.

According to its authors, the federal Energy Policy Act of 2005 was amended to expedite permitting and environmental analysis of the production of natural gas. Hydraulic fracturing was exempted under the federal Safe Drinking Water Act, bringing into prominence state regulations that govern natural gas drilling. As a result, shale and tight sand gas drillers do not have to disclose what chemicals they use for hydraulic fracturing to the federal government (although some states require this information). The

EPA is currently conducting a multi-year study to evaluate the impacts of hydraulic fracturing on water resources (U.S. EPA, 2011). In April 2012 the EPA (U.S. EPA, 2012) issued a set of regulations for the oil and natural gas industries, but under the Clean Air Act (only addressing emissions, leaks and spills) and not the Safe Drinking Water Act (pumping chemicals underground). In 2009 and again in 2011 a Fracturing Responsibility and Awareness of Chemical Act (the FRAC Act) was proposed in Congress but was not passed. The proposed act would have required producers to publicly disclose a list of all chemical constituents, though not proprietary formulas, in their fracking fluids.

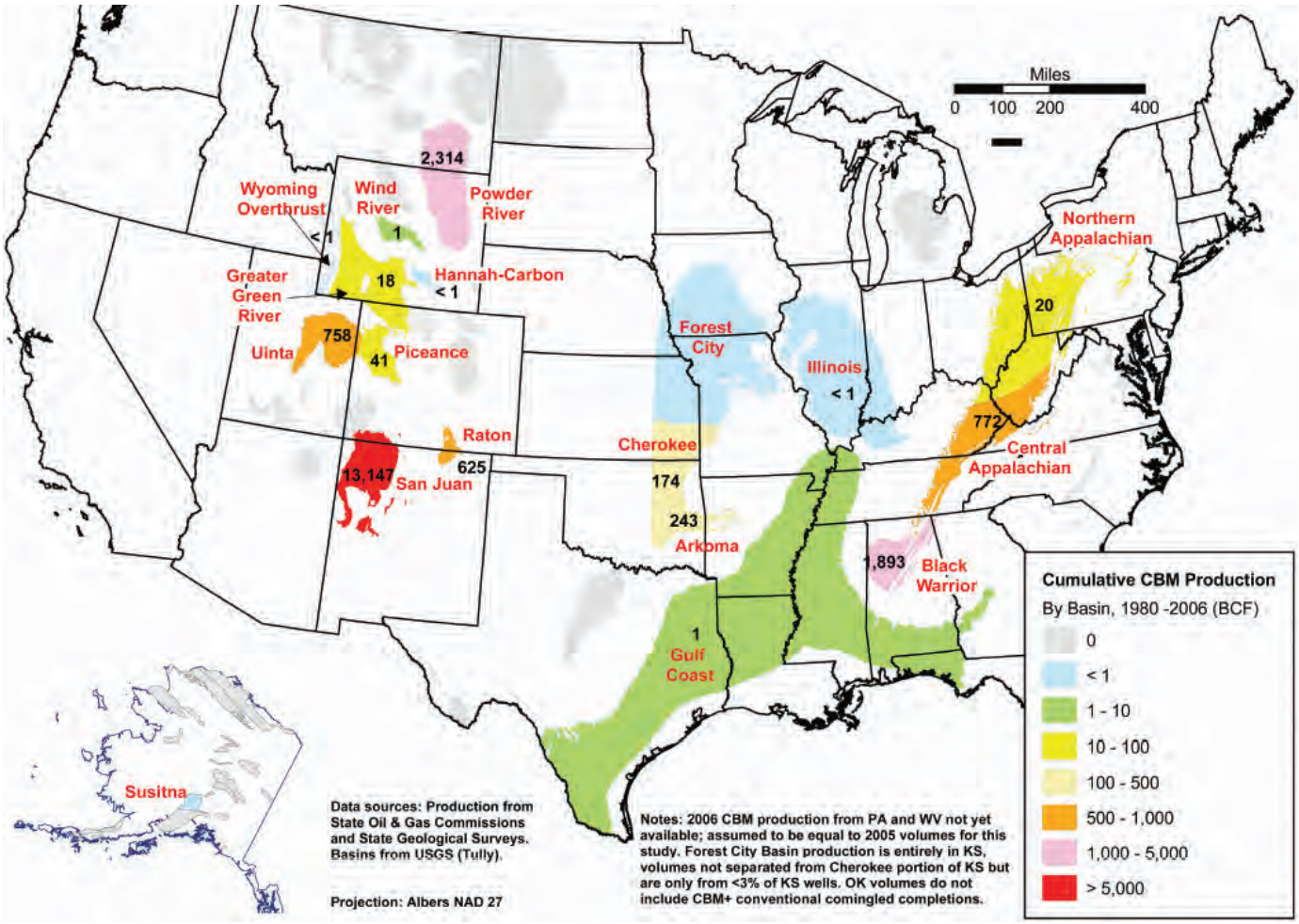
In addition to the proprietary fracking chemicals, flowback water may also contain high concentrations of sodium, chloride, bromide, arsenic, barium and other heavy metals leached from the subsurface, as well as radionuclides that significantly exceed drinking-water standards (Soeder & Kappel, 2009). These high concentrations of inorganics are not usually successfully treated by municipal wastewater facilities and require much more expensive industrial-grade systems. There are reports that link higher salinity measurement in some Appalachian rivers to the disposal of this degraded water in Marcellus Shale operations (Soeder & Kappel, 2009). It is not clear whether these industrial grade systems are widely utilized by the industry or whether the technologies are sufficient to adequately remove all of these contaminants.

The USGS reports that another disposal option is re-injection of the flowback at shallower depth (Barnett Shale) or into deeper formations (Oriskany or Potsdam Sandstones). However, there is much concern about the contamination of underground water supplies. Another more expensive and energy-intensive option is to evaporate the wastewater in large tanks and treat the dry residue as solid waste. The EPA categorizes the wastes generated during the exploration, development and production of natural gas as "special wastes." These wastes are exempt from federal hazardous waste regulations of the Resource Conservation and Recovery Act. Much work is needed by the industry and competent agencies to assess the different environmental impacts of each disposal method.

ii. Coal Bed Methane

Another source of unconventional natural gas is coal bed methane, which currently accounts for approximately 9 percent of U.S. production (EIA, 2012), although its importance is not expected to rise in the next 20 years. Most of the production comes from New Mexico, Utah and Wyoming (Figure 13). Coal bed methane extraction produces a large amount of water because the coal bed itself is an aquifer. Individual wells can produce from 1.3 to 161 gal/MMBTU in Colorado and Wyoming, respectively (U.S. DOE, 2006). Some of the produced water can be used for drilling, but much more is produced than can be used. Some states consider this produced water as a waste, while others consider it as a beneficial byproduct (National Research Council, 2010). Disposal of the produced water into natural streams can also create water quality problems as the geomorphology of a receiving stream is developed for a particular range of natural flows. There could be significant water quality problems from coal bed methane extraction if hydraulic fracturing is used, because the fracturing would be taking place in an aquifer, and some wells are not lined (or cased), enabling potential migration of fracturing chemicals into the aquifer.

Figure 13. U.S. Coal Bed Methane Production in BCF



Source: National Research Council, 2010

The water chemistry of coal bed basins can vary widely; total dissolved solids can range from 500 to 15,000 mg/L (National Research Council, 2010). Accordingly, treatment requirements, potential water quality impacts and disposal options will be different. In some cases, the produced water will need extensive treatment, whereas in other cases the water is of high quality and will need little to no treatment before disposal. The produced water is discharged to surface streams, re-injected in underground aquifers or evaporated. Under the Safe Drinking Water Act (1974), the EPA developed minimum standards for the Underground Injection Control (UIC) Program to protect actual and potential drinking water sources from underground injection of contaminants. The EPA (U.S. EPA, 2002) concludes that the injection of hydraulic fracturing fluids into coal bed methane wells poses minimal threat to underground supplies of drinking water. The literature explains the lack of understanding of the environmental impacts of coal bed methane extraction by citing the industry's youth and calls for more research to investigate the impacts of extensive groundwater extraction and the subsequent disposal of wastewater (produced water). There is increased interest in Western states for the reuse of this produced water in agriculture (irrigation and livestock), which may prompt further analysis (National Research Council, 2010).

2. Processing and Storage

Unlike oil, extracted natural gas is very close to the end product and requires minimal refining. Natural gas processing plants remove water, hydrocarbon liquids (which can have substantial market value), helium (the totality of global helium production comes from natural gas processing), carbon dioxide, hydrogen sulfide and other contaminants. These processing plants are often located very close to production sites and often receive the natural gas directly from the well heads. Because natural gas is naturally odorless, sulfur compounds are added to it for safety reasons (methyl mercaptan or thiophane).

Water is needed in these processes for scrubbing purposes and cooling. Gleick (1994) reports that approximately two gallons of water per MMBTU are consumed for gas processing, but there has been little independent evaluation of the water intensity of processing newer sources of natural gas using more modern technologies. Mielke et al. (2010) estimate that water consumption varies between 0 to 2 gal/MMBTU.

2.1 Liquefied Natural Gas

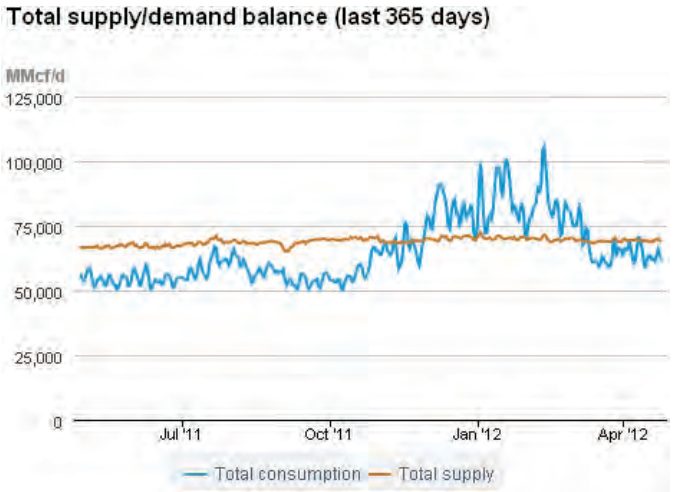
Overseas imported natural gas is shipped as liquefied natural gas (LNG). Approximately 15 percent of U.S. natural gas imports are LNG (EIA, 2011). Aside from the energy required for liquefying and cooling the gas, water is needed for regasification in an open-loop system (LNG is gasified in a heat exchanger using sea or river water). Similarly to thermoelectric cooling, this requires significant volumes of water as coolant, and poses the same environmental problems (marine life disruption, salinity changes, heat transfers). The Thermoelectric Generation section of this *Review* has additional information.

There is very little data available on the withdrawals or consumption of water for LNG terminals. Only the U.S. DOE (2006) mentions water withdrawals of up to 200 MGD per terminal. The Federal Energy Regulatory Commission (FERC) website states that as of April 2012 there are 12 LNG terminals currently active in the U.S. for a total capacity of 19 billion cubic feet per day (BFCD), ranging from 0.5 to 4.0 BCFD, while the U.S. imports only 1.2 BCFD as LNG. Assuming that 200 MGD corresponds to the maximum capacity terminal of 4.0 BCFD, this would mean the water intensity of LNG terminals is extremely high: about 50 gallons per MMBTU. The potential impact of these water withdrawals seems to have been largely overlooked and will certainly need closer attention. This will be particularly true in the event that the U.S. does not meet its energetic independence vis-à-vis natural gas and has to rely in the future on imported LNG from the Middle East or Russia. The FERC website reports that there are as many as 40 LNG terminals planned in the U.S., but most may not be built unless prices go up.

2.2 Gas-to-Liquids

Gas-to-Liquids (GTL) refers to the conversion of natural gas into petrol distillates such as transportation fuel (gasoline or diesel) or other chemicals. Similar to Coal-to-Liquids (CTL), there are not yet any GTL plants in the U.S., although one is planned and designed for Louisiana (Krauss, 2012). Widespread use of GTL is limited by high capital investment costs and the uncertainty of natural gas prices. The water-intensity average is 42 gallons per MMBTU and ranges from 19 to 86 gal/MMBTU (Mielke et al., 2010). There are very few running GTL plants in the world. In 2010, GTL and CTL comprise less than 0.3 percent of world liquid fuels and are projected by the EIA to remain less than 2 percent by 2035. The 2006 Annual Energy Outlook (EIA, 2006) projects domestic GTL production to originate in Alaska in an attempt to monetize the natural gas resources on the North Slope. The GTL liquid would be transported in the continental U.S. for refining.

Figure 14. Total Supply/Demand Balance Over the Last Year



Source: EIA website, 2012

2.3 Gas Storage

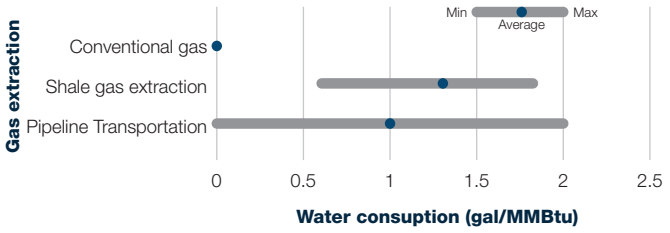
Due to the multiple end-uses of natural gas (electricity generation, residential and commercial heating), natural gas demand has major seasonal variations, while supply remains globally constant (Figure 14). Weather and the economy are the two main reasons for this high fluctuation. To compensate for this, natural gas is stored in underground areas including depleted gas and oil fields, aquifers and salt formations (i.e., salt caverns). Salt caverns make up about 7 percent of total capacity but can supply up to 23 percent of the natural gas from underground storage in a given day (EIA, 2013).

Salt caverns are created through slurry mining. Water is pumped into salt formations and the resulting saline solution is then discharged, which poses water quality and environmental problems. Slurry mining requires seven gallons of water to create one gallon of storage capacity (U.S. DOE, 2006). Seawater can be used, but nearby surface water sources are more common. The depth of the salt cavern limits the operating pressure. The U.S. DOE estimates that a salt cavern operating at 2,000 pounds per square inch (psi) would require a one-time use of 500 to 600 gallons per MMBTU of storage.

3. Transportation

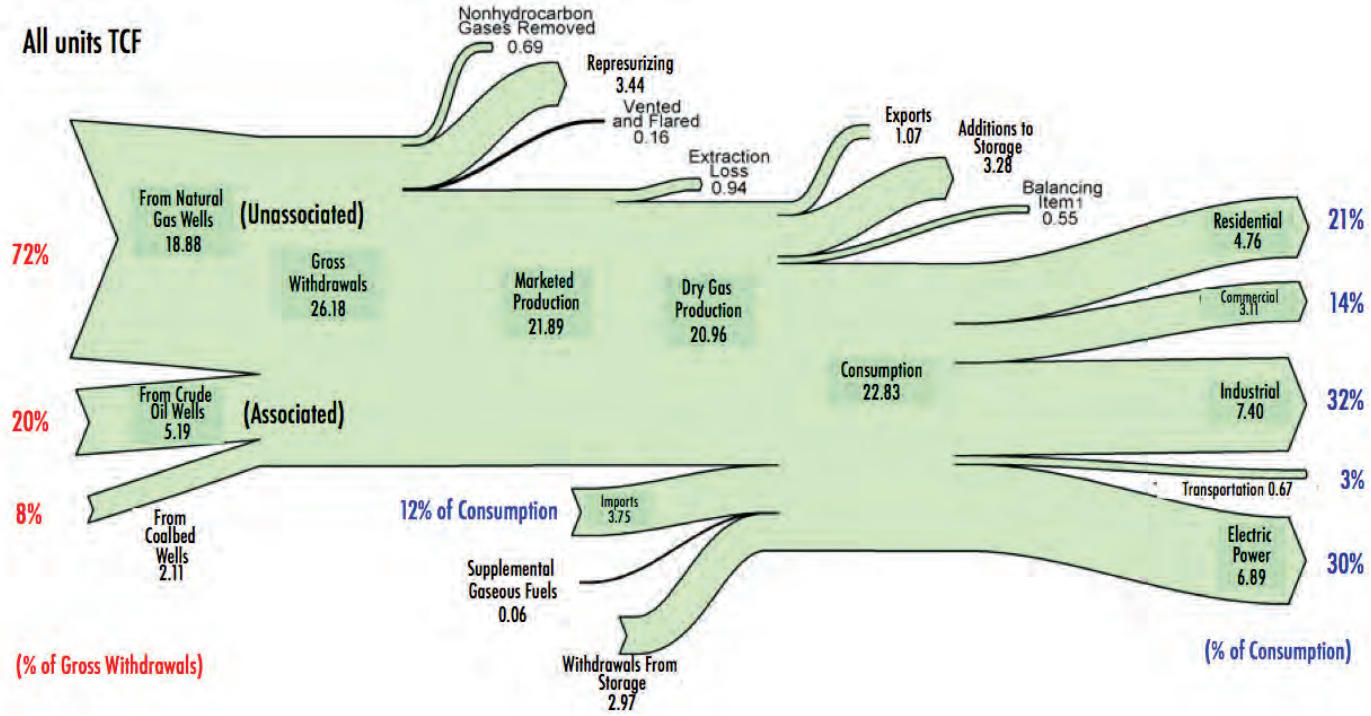
While oil is transported mainly by rail, truck, tanker and pipeline, and coal is transported by rail and barge, natural gas moves almost exclusively via pipeline because of its lower energy density and compressibility. Gleick (1994) and Mielke et al. (2010) estimate that approximately 1 gallon/MMBTU is associated with pipeline operations (Figure 15). After processing or delivery by LNG tanker (and its gasification), the natural gas is compressed to between 200 and 1,500 psi. This reduces the volume of the natural gas (up to 600 times) and provides the propellant force to move it along pipelines. To maintain the pressure to move the natural gas through the pipeline, it has to be compressed periodically. (This requires compressor stations about every 100 miles.) Pipelines use about 3 percent of total natural gas consumed in the U.S. (Figure 16) to operate the compressors. (Electric compressors comprise only 6 percent of the compressor power.) The U.S. natural gas transportation network includes about 210 mainline natural gas pipeline systems, which represents 300,000 miles (naturalgas.org, 2012).

Figure 15. Water Consumption During Natural Gas Extraction and Transportation



Source: Mielke et al, 2010

Figure 16. Natural Gas Flows in the U.S. in 2009



Notes:
(a) Balancing item reflects minor differences between data sources
(b) Transportation includes pipeline compressor consumption, and a tiny amount of transportation fuel (3% of total consumption)

Source: EIA, Annual Energy Review, 2010

4. Conclusion

Natural gas has quickly become one of the most important components of the U.S. energy portfolio. This rapid ascent is largely attributable to the development of deep shale deposits through the use of hydraulic fracturing and directional drilling. The water quantity and quality impacts of natural gas have been studied to the same degree and through many of the same efforts as other carbon-based fuels (Gleick, 1994), but the advent of new technologies and the exploration of new deposits has left much of the literature wanting. In fact, most information about the water intensity of today's natural gas comes from the industry itself and is therefore lacking in independence. This lack of information has limited the ability to regulate and oversee these important resources at a critical time in their development.

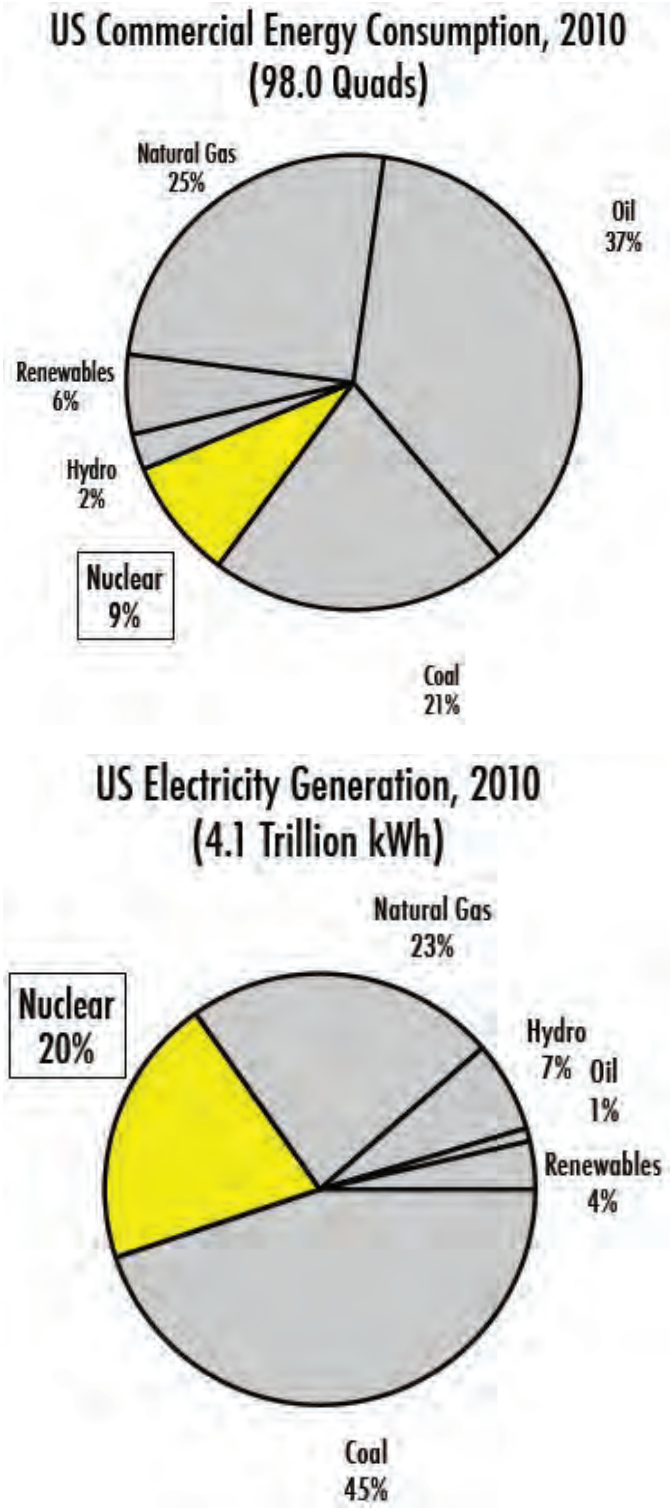
What we do know is that there is an extremely wide range of water intensity of natural gas, 0.6 to 6.7 gal/MMBTU, depending upon the technology and the formation. Similarly, the water quality issues surrounding natural gas vary greatly depending upon the geologic formation and the technologies employed. One additional challenge surrounding questions of water quality is that federal regulation exempts disclosure of some chemicals used in the process. Additional research is required to better understand the water quality challenges associated not only with fracking but also with drill casing in general. Finally, there is little new information and research on the water intensity and quality impacts of processing natural gas, whether for immediate use, liquefication or transmission through pipelines.

URANIUM

This section explores the research and literature on water withdrawal and consumption as well as associated pollution from the mining and processing of uranium. While uranium remains one of the principal ingredients for thermoelectric generation from nuclear fission, it is a resource that has until recently been on the decline in terms of its importance to the U.S. and global electricity mix. Its future is uncertain. Water use and associated pollution from using uranium in electricity production is covered under a separate section (see Thermoelectric Generation). A brief overview of the uranium and nuclear industry precedes a review of the limited research and literature on the subject.

Nuclear energy is a way of generating electricity that uses the power of the atom to unleash energy, so little feedstock is needed to fuel these power plants compared to coal or natural gas. Nuclear power is a form of thermal electric generation and thereby requires large quantities of water at the power plant for cooling (see section on thermoelectric generation). This large water consumption often shadows the substantial impacts on both the quantity and quality of water resources in the extraction and processing of uranium. The majority of the research and writing in this area is limited to several papers (Gleick, 1994; U.S. DOE, 2006; Mudd & Diesendorf, 2008; Mielke et al., 2010). As noted in other sections (Coal, Natural Gas), most of these papers rely on work done by Peter Gleick of the Pacific Institute in 1994, which is based on data from the 1970s and 1980s. Despite significant changes in technology and other aspects of the industry, only the work of Mudd & Diesendorf addresses them in any detailed way (Allen et al., 2011).

Figure 17. U.S. Energy Consumption and Electricity Generation, 2010



Source: K. Knapp, Stanford; EIA, 2011

Figure 18. U.S. Uranium Reserve Areas

Source: Adapted from Karl Knapp; EIA, 2011a

The U.S. is the world's largest producer of nuclear energy, with about 800 billion kWh in 2011 (EIA, 2011a). However, this infrastructure is aging. Nuclear power is a cornerstone of the electricity mix in the U.S. as it provides base-load capacity along with coal-fired power plants (Figure 17). Although interrogations remain after the Fukushima disaster, the International Atomic Energy Administration (IAEA, 2010) expects worldwide nuclear energy production to grow substantially in the next century.

Uranium is a naturally occurring element in the Earth's crust, and while vast amounts may be recoverable from the ocean, this has not been done (IAEA, 2010). Resources are currently considered economically recoverable at $130/kg of uranium. The 2010 weighted average spot price of uranium was about $62/kg. Four countries (Australia, Kazakhstan, Canada and Russia) hold nearly two-thirds of the reserves and production. The U.S. has about 200,000 tons of uranium in pitchblende, the richest uranium ore (about 4 percent of world reserves). Worldwide production is 53,663 tons of uranium per year (Reserves-to-Production ratio of 100 years) and American domestic production is 1660 tons of uranium per year, which provided 9 percent of demand (Reserves-to-Production ratio of 125 years – EIA, 2012). The uranium mining industry employs roughly 1,000 people nationwide (EIA, 2011a). New Mexico and Wyoming have 80 percent of the proven U.S. reserves (Figure 18).

It is to be noted that for the past two decades, about a third of global uranium reactor fuel demand was supplied by secondary sources: warheads, military and commercial inventories, re-enrichment of uranium mining waste, reprocessed uranium and mixed oxide fuel (IAEA, 2010). Future international nuclear disarmament agreements will have a major impact on the future availability of secondary uranium.

The nuclear power industry is a heavily subsidized industry. The federal government paid for all of the R&D that led to commercial development in the U.S. The General Mining Act of 1872 stipulates that no

federal agency can refuse a mining permit on federal land or charge a royalty, although the price of a land claim ranges from $2.5 to $5 per acre (a figure that has not changed since 1872). Uranium is treated just like other hard-rock minerals such as gold or copper (in contrast, oil, natural gas, coal and timber all pay royalties). Several attempts have been made to change this legislation, such as the Hard Rock Mining and Reclamation Acts of 2007 and 2009, both of which have failed to pass. The Nuclear Regulatory Commission heavily regulates the entire fuel-cycle. The federal government is supposed to take care of disposal under the Nuclear Waste Policy Act of 1982, although no permanent solution has been found, and the Yucca Mountain Project in Nevada remains politically infeasible. The Price-Anderson Act of 1957 limits the liability of plant operators for accidents (this was renewed in the 2005 U.S. Energy Policy Act). The EP Act of 2005 created loan guarantees, tax credits, support for construction delays, direct financial support for construction and R&D funding for advanced nuclear power. It also changed the rules for nuclear decommissioning funds by repealing the cost of service requirement for contributions to a fund.

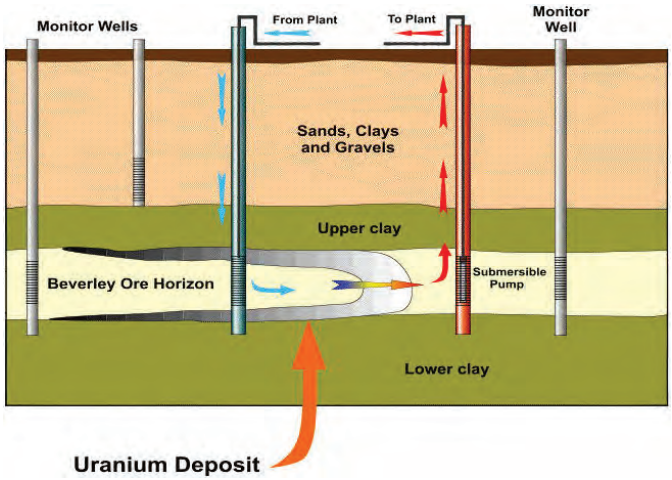
1. Mining

Most of the literature cites Gleick (1994) for the water intensity of uranium mining operations. His estimates are based on practices and figures from the 1970s and 1980s, and industry practices have changed. Mudd and Diesendorf (2008) produced a thorough investigation of the impacts of uranium mining using international data from 1975 to 2005. As a whole, uranium mining requires much more academic attention, particularly in-situ leaching.

Uranium has been mined for over 100 years in the U.S., although mining methods have changed considerably over time. All of these mines are located in the West. The EPA has documented up to 4,000 mines, most of which are abandoned. The U.S. DOE is overseeing the reclamation of 24 of them (EPA website, 2012). The EIA reports that there are four underground mines and four In-Situ Leaching (ISL) mines in operation in the U.S., with 90 percent of the production coming from ISL (EIA, 2011a). It is important to note that there are no longer any uranium open mines in operation in the U.S.

In-Situ Leaching (Figure 19) is a mining process that involves minimal surface disturbance, by extracting uranium from porous sandstone deposits with acidic or basic aqueous solutions (depending upon the underlying geology) injected into the subsurface through a number of injection wells. This requires the deposit to be in a permeable sandstone aquifer, which often needs to be hydraulically fractured. Although this process is much less disruptive than open or underground mining, there are many concerns about groundwater quality.

Figure 19. In-Situ Leaching



Source: NEA, 2010

Much like other mining industries, uranium mining requires water for dust control, ore benefaction and reclamation of mined surfaces (mainly through revegetation), which amounts to about 1 gallon per MMBTU for underground mining and up to 6 gallons per MMBTU in surface mining, which are no longer in activity (Gleick, 1994; U.S. DOE, 2006; Mielke et al., 2010). It is quite surprising to note that these reports do not even mention ISL, which accounts for 90 percent of U.S. production. ISL requires very

different amounts of water as it is based on the injection and recovery of fluids in an aquifer.

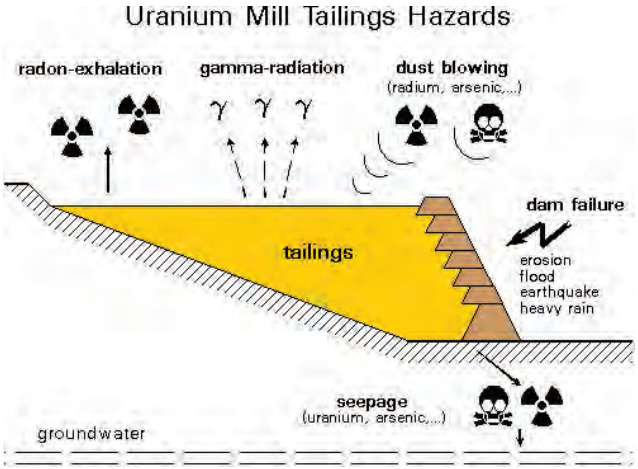
Mudd and Diesendorf (2008) provide evaluations for water, energy and carbon intensity of different mining methods. For surface mining, water intensity is of 0.1 to 1.5 gallons per MMBTU of ore, and for underground mining, of 0.5 to 1 gallon per MMBTU. These figures are a little lower than those given by Gleick (1994), which could be linked to changes in industry practices.

Additionally, the water intensity of ISL (the example is from a mine in Australia) is estimated to be 14.6 gallons per MMBTU of ore. Cooley et al. (2011) assess the water intensity of ISL to be about 1.1 gallon per 1 kWh of usable electric energy, which is about 322 gallons per MMBTU of electricity (data from Mudd and Diesendorf, 2008), which shows the significant water intensity of uranium mining and processing. Moreover, Mudd and Diesendorf (2008) evaluate the energy intensity of uranium mining to be approximately 0.1 percent (10^{-3} MMBTU/MMBTU of ore). This is about five times less than for coal mining (see "Coal: Extraction and Processing" section). However, the processing burden for uranium ore is high and that energy requirement may not be included in this number.

As uranium prices go up, there is increased interest in U.S. uranium supplies, bringing back projects to reopen some old mines in New Mexico and Utah. The 2006 U.S. DOE report estimates that these mines could generate 3 million to 5 million gallons of polluted wastewater per day, which would need to be handled and disposed of. Additionally, ISL is expected to have an increasing importance, which could dramatically increase the water requirements for the industry. These mining operations would all take place in water-scarce regions of the West, increasing the risks on the availability of water resources in the future.

The impact of uranium mining is not limited to water withdrawals and consumption. Indeed, mining operations can cause the mobilization of radioactive minerals that may reach waterways and aquifers used for drinking water. Due to low uranium concentrations in the ore (0.06 percent to 2.71 percent, Mudd and Diesendorf, 2008), uranium extraction requires processing enormous quantities of mineral. This leaves behind massive stockpiles of radioactive and toxic waste rock and sand-like tailings, which can lead to leaching of radioactive (radon, uranium), toxic (selenium, arsenic, uranium and thorium) and conventional pollutants in surface water and groundwater (Figure 20). While many of these same pollutants resulting from ISL threaten to contaminate groundwater (U.S. NRC, 2009), this process nevertheless has the advantage of not producing surface mining tailings. All U.S. tailings piles are located in the West, except for one abandoned site located in Pennsylvania (milling tailing). The EPA lists about 200 million tons of licensed tailings piles (EPA, 2012). These contaminations have led to numerous EPA Superfund sites (e.g., 500 closed uranium mines await remediation in the Navajo Nation; Cooley et al., 2011). Mining and process waste is often disposed of in evaporation ponds, threatening surface and groundwater quality (Gleick, 1994). All agree that these water quality impacts are often ignored or poorly understood.

Figure 20. Uranium Tailings Hazards



Source: WISE Uranium Project website, 2012

Because mine overburden and uranium tailings are not considered as radioactive waste but as Technologically Enhanced Naturally Occurring Radioactive Materials (TENORM), placement in radioactive waste disposal facilities is not required. The Atomic Energy Act, the

Nuclear Regulatory Commission and the Department of Energy do not require controls on uranium mining overburden and mining wastes. Under the Uranium Mill Tailings Radiation Control Act of 1978, the EPA issued two sets of standards controlling hazards from uranium mill tailings. This requires the cleanup and disposal of mill tailings at abandoned sites and the disposal of tailings when operations stop. In 1993 an amendment required that all licensed sites no longer in operation were to start remediation as soon as possible to minimize impacts to surface and groundwater. However, the uranium produced from the mined ore (or brought into the circuit as uranium yellowcake) is directly regulated: the U.S. Nuclear Regulatory Commission (U.S. NRC) regulates its possession, processing, transport and use.

2. Processing and Transportation

As noted previously, uranium concentrations are very low in the ore (0.06 percent to 2.71 percent, Mudd and Diesendorf, 2008), and the first processing step requires separating uranium from other minerals, in uranium mills. This requires substantial amounts of water and sulfuric acid (to leach out the uranium), and the process leaves behind huge milling tailings, which are often radioactive and toxic. The most abundant form of natural uranium (^{238}U, about 99.3 percent) is not 235 fissile itself, and thus uranium yellowcakes (U_3O_8) must be enriched in fissile ^{238}U, the remaining 0.7 percent. Most nuclear reactors in power plants run on Low Enriched Uranium (usually 3 percent to 5 percent ^{235}U), whereas atomic bomb-grade uranium must be enriched over 90 percent.

Conventional mills are usually located near the mines, and ISL mills are located on site. The EIA (2011a) reports that in 2010 a single uranium mill was operating in the U.S. (Utah) with a capacity of 2,000 short tons of ore per day. Three others in Utah and Colorado are on standby. This shows the fact that U.S. uranium is not currently competitive at today's prices, but this could change in the foreseeable future. It is to be noted that the U.S. does not reprocess ^{239}Pu (fissile plutonium) produced in the nuclear reactors for fuel, due to proliferation concerns (although several countries do, including France, the U.K., Russia, Japan and India). Gleick (1994) reported that milling of uranium can consume about 3 gallons per MMBTU of product almost entirely as evaporation from tailings ponds.

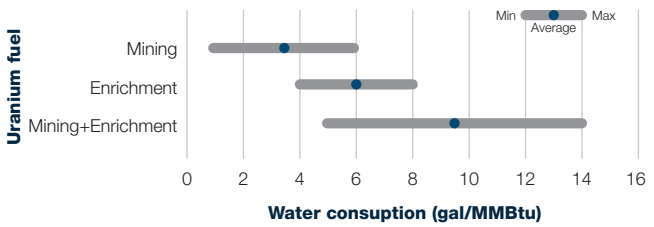
Once uranium has been separated from the ore into yellow cakes (63 percent of uranium imports are also under this form – the rest is in UF_6 [EIA, 2012a]), it has to be enriched in specialized facilities. U.S. yellowcake production was 4.2 million pounds in 2010, while total consumption was 29.4 million pounds (EIA, 2012a). Two processes are mainly used for enrichment using gaseous UF_6: centrifugation or diffusion. Another 0.3 gallons per MMBTU is consumed during the conversion to uranium hexafluoride and reprocessing of used fuel (Gleick, 1994). The only uranium conversion facility in the U.S. is located in Metropolis, Ill., and produces about 14,000 tons of uranium per year (National Research Council, 2010).

Gaseous diffusion, which requires a lot of water due to evaporative cooling, requires an additional 3 to 4 gallons per MMBTU. Enrichment in the U.S. is primarily done at the gaseous diffusion plant at Paducah, Ky. (Sovacool, 2008). Gaseous diffusion is extremely energy intensive. The amount of this energy needed for enrichment is about 4.4 percent of the energy produced from the fuel (U.S. Atomic Energy Commission, 1974; Davis and Velikanov, 1976). These facilities are about 40 years old and industry practices have not changed much. However, this gaseous diffusion facility is to be replaced by centrifuge facilities. Centrifuge separation requires less water, but is not often used. One is operational in Eunice, N.M., and the other is under construction in Piketon, Ohio. These facilities would use half of the water and 65 times less electricity than gaseous diffusion facilities (NRC, 2010).

On the whole, data from Gleick indicates that milling, processing and refining of uranium consumes 12 to 13 gallons of water per MMBTU of product for diffusion and 10 to 11 gallons per MMBTU for centrifugation, including energy requirement for enrichment. The 2006 U.S. DOE report and Mielke et al. (2010, Figure 21) estimate 7 to 8 gallons per MMBTU for gaseous diffusion and 4 to 5 gallons per MMBTU for centrifugation.

These newer numbers seem lower, but leave out energy requirements from Gleick's assessment. As noted previously, these estimates are based on publications and estimates from the 1970s; thus, an updated full study of the life cycle of uranium fuel would be useful.

Figure 21. Water Consumption During Uranium Mining and Enrichment



Source: Mielke et al., 2010

Enrichment also produces large quantities of depleted uranium in UF_6 form. This depleted uranium is often stored on site of enrichment, processed back into yellowcake or UO_2 for military uses (armor or penetrating ordnance), or simply disposed of in uranium mill tailings. These mill tailings continue to pose serious water, environmental and human threats, and long-term solutions have yet to be found.

Following enrichment, UF_6 is chemically converted into UO_2 powder. This powder is then converted in small ceramic pellets by a ceramic process. These harmless pellets are mounted into fuel rods, which include thousands of pellets. These fuel rods are then transported to nuclear power plants under the supervision and authority of the U.S. Nuclear Regulatory Commission (NRC). Concerning transport, uranium tends to travel a lot, from the place where it is mined to the place where it is consumed. Sovacool (2008) reports that Canadian uranium travels an average of 4,000 miles during its life cycle. This transportation, which requires vehicle fuel, further adds to the energy and water intensity of uranium.

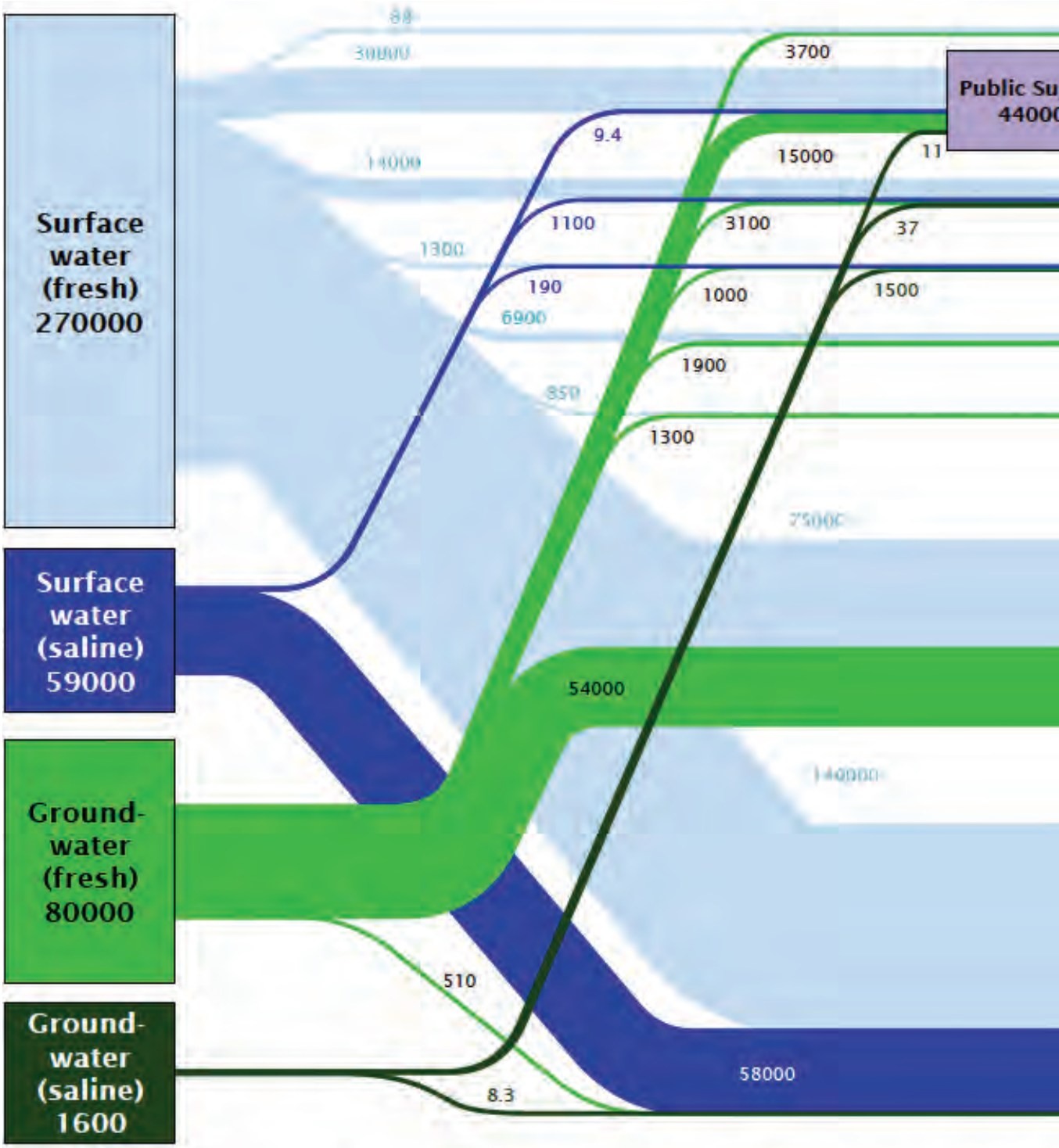
Nuclear power is often touted as a carbon-free source of electricity. However, this is only true for power generation; there are numerous upstream steps that are both energy and water intensive: mining, milling, processing, enriching and transport. In an extensive review of life-cycle analyses, Sovacool (2008) concluded that nuclear power plants produce 66 grams of carbon dioxide equivalent (gCO_2-eq) per kWh throughout the cradle-to-grave life cycle of uranium fuel, the front end (extraction and processing) contributing 25 gCO_2-eq/kWh. This is still small compared to coal-fired power plants (about 1,000 gCO_2-eq/kWh).

3. Conclusion

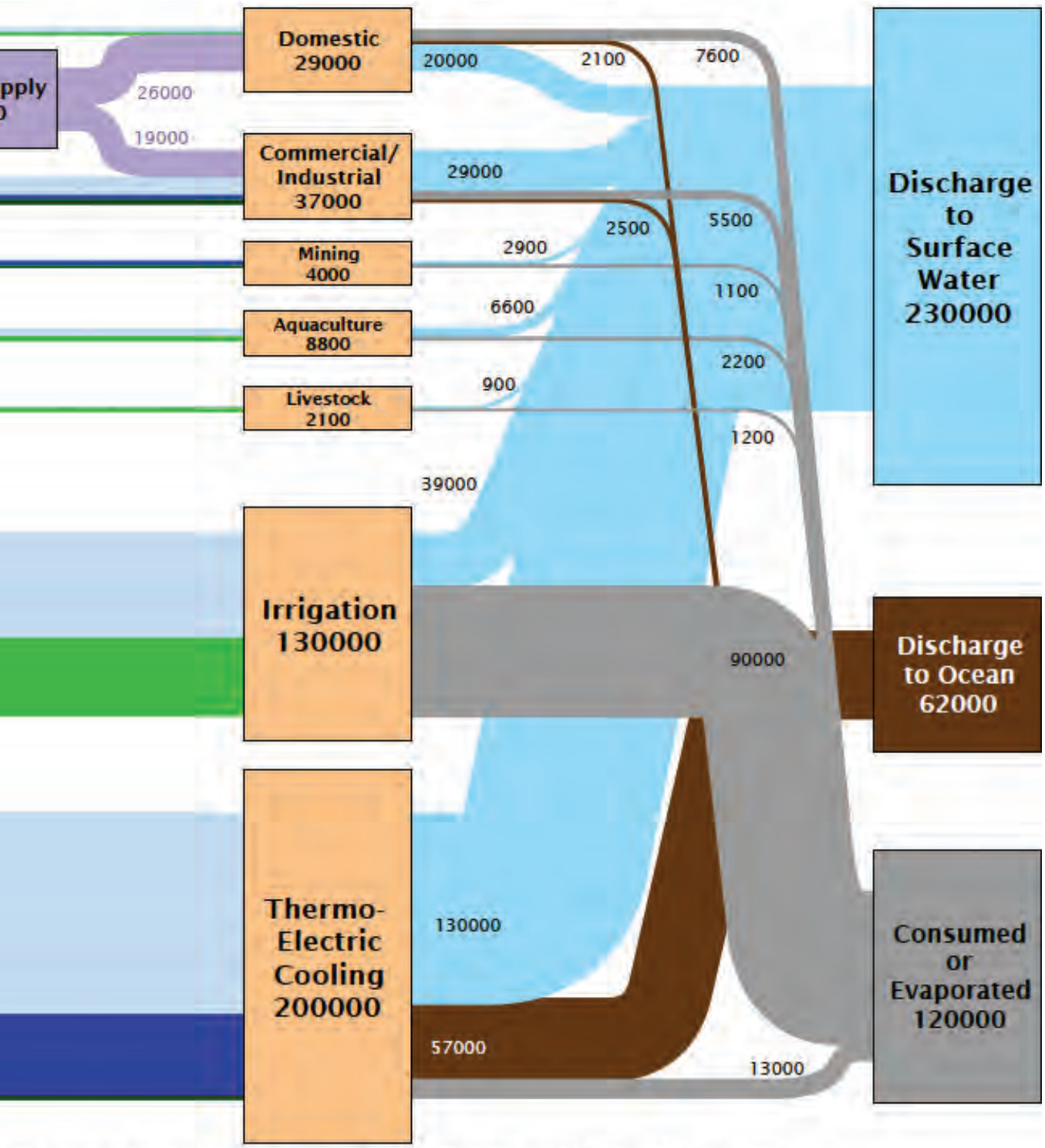
Questions abound about the future of nuclear power in the United States and throughout the world. With concern about carbon emissions competing with concerns about public health and safety as well as the expense of reactors, no one is quite sure whether we are likely to see more or less nuclear power in the future. Nevertheless, numerous questions remain about the water intensity of the mining and processing of the fuels used for nuclear fission.

As with other resources, the literature about the water intensity of uranium mining relies heavily on Peter Gleick's work from 1994, which in turn relies heavily on government and industry data from the 1970s and 1980s. While there has been little change in the design and operation of power plants since that time, the industry has certainly changed, particularly in the area of mining and processing. This is particularly true with the almost exclusive use of in-situ leaching in lieu of more traditional and historic surface mining. Cooley et al. (2011) estimate the water intensity of ISL to be 322 gallons per MMBTU of electricity, many times greater than surface mining. Additional research about ISL is clearly warranted, as is additional data collection and analysis about the water quality impacts of uranium mining and processing.

Figure 22. Estimated U.S. Water Flow in 2005: 410,000 MGD



Source: LLNL 2011. Data is based on USGS Circular 1344, October 2009. If this informatio
and the Department of Energy, under whose auspices the work was performed. All q
included. Totals may not equal sum of flows due to independent rounding. Further d



Source: Smith et al., 2011

THERMOELECTRIC GENERATION

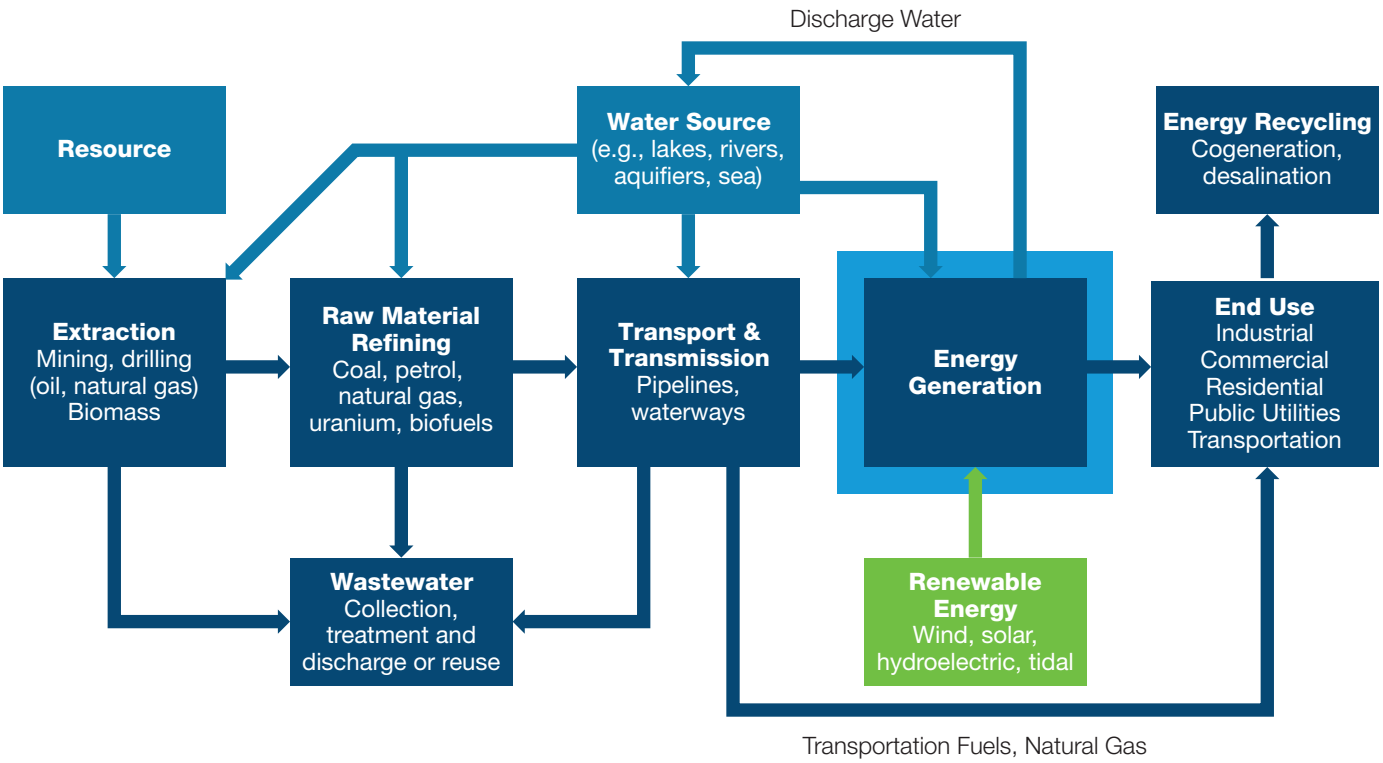
This section explores the research and literature on the water withdrawal and associated pollution from the generation of electricity from thermoelectric sources. Thermoelectric power is typically generated through the combustion of fossil fuels such as coal, natural gas or oil, through the fission of nuclear material or through the concentration of solar energy. Each of these sources of thermoelectric power uses water for the extraction, processing and transportation of these fuels, which are addressed in other sections of this report (see Coal, Natural Gas, Uranium). Centralized thermoelectric generation of electricity remains the leading source of energy in the U.S. and is likely to remain so for the foreseeable future. This section begins with an overview of the literature covering this subject, followed by a discussion of cooling technologies, estimates of the water intensity of various feedstocks, a review of water quality and ecological impacts, and an exploration of the future with climate change.

In 2009, the USGS published its report on the U.S. water flows in 2005 (Figure 22). The results indicate that electricity generation is responsible for nearly 52 percent of surface freshwater withdrawals and 43 percent of total water withdrawals. Power plants only consume 7 percent of this water, returning the rest to the environment, albeit altered. This section explores the research and literature that examines the use of water for thermoelectric production.

Due to its importance in water management and supply, there are numerous papers on the subject. Some papers are literature reviews (Gleick, 1994; U.S. DOE, 2006; Fthenakis & Kim, 2010; Mielke et al., 2010; MacKnick et al., 2011), others are technical (EPRI, 2007; NETL, 2006), or address the difficulties of data collection (Dziegielewski & Bik, 2006; Averyt et al., 2011) and future needs and climate change (Sovacool & Sovacool, 2009; Chandel et al., 2011; Cooley, 2011). However, most papers rely upon the same sources (EPRI, NETL) to compute water intensities for thermoelectric production. It is important to note that much of this literature comes directly from federal laboratories and agencies (EIA, USGS) or from work commissioned by federal or state agencies (e.g., EPRI by the California Energy Commission). Moreover, there is little international literature on the subject, and even when available, it is not at the spatial resolution available in the U.S., which suggests the pivotal role of key government agencies like the USGS and EIA in these studies (Vassolo and Döll, 2005).

The fundamental idea of thermoelectric generation is to use high-pressure steam to drive a turbine generator, which in turn produces electricity. Heat is required to boil water into steam, and following Carnot's principles, steam at the turbine exhaust must be cooled. Heat can be provided by a variety of sources such as coal, natural gas and oil, nuclear energy, biomass, concentrated solar energy and geothermal energy. Most of the water withdrawals and consumption in thermoelectric power generation relate to cooling. Three main technologies exist: open-loop (once-through), closed-loop (recirculation) and dry cooling. Hybrid cooling is an emerging option, combining closed-loop and dry cooling. All these technologies and heat sources do not have the same water intensities and environmental impacts. These impacts are also vastly different from one location to another, depending on the sources (rivers, lakes, aquifers, reclaimed water, seawater). Figure 23 presents a flow chart of the embedded water in energy, highlighting energy generation.

Figure 23. Flow Chart of Embedded Water in Energy



Note: Water inputs and outputs may be in different water bodies.

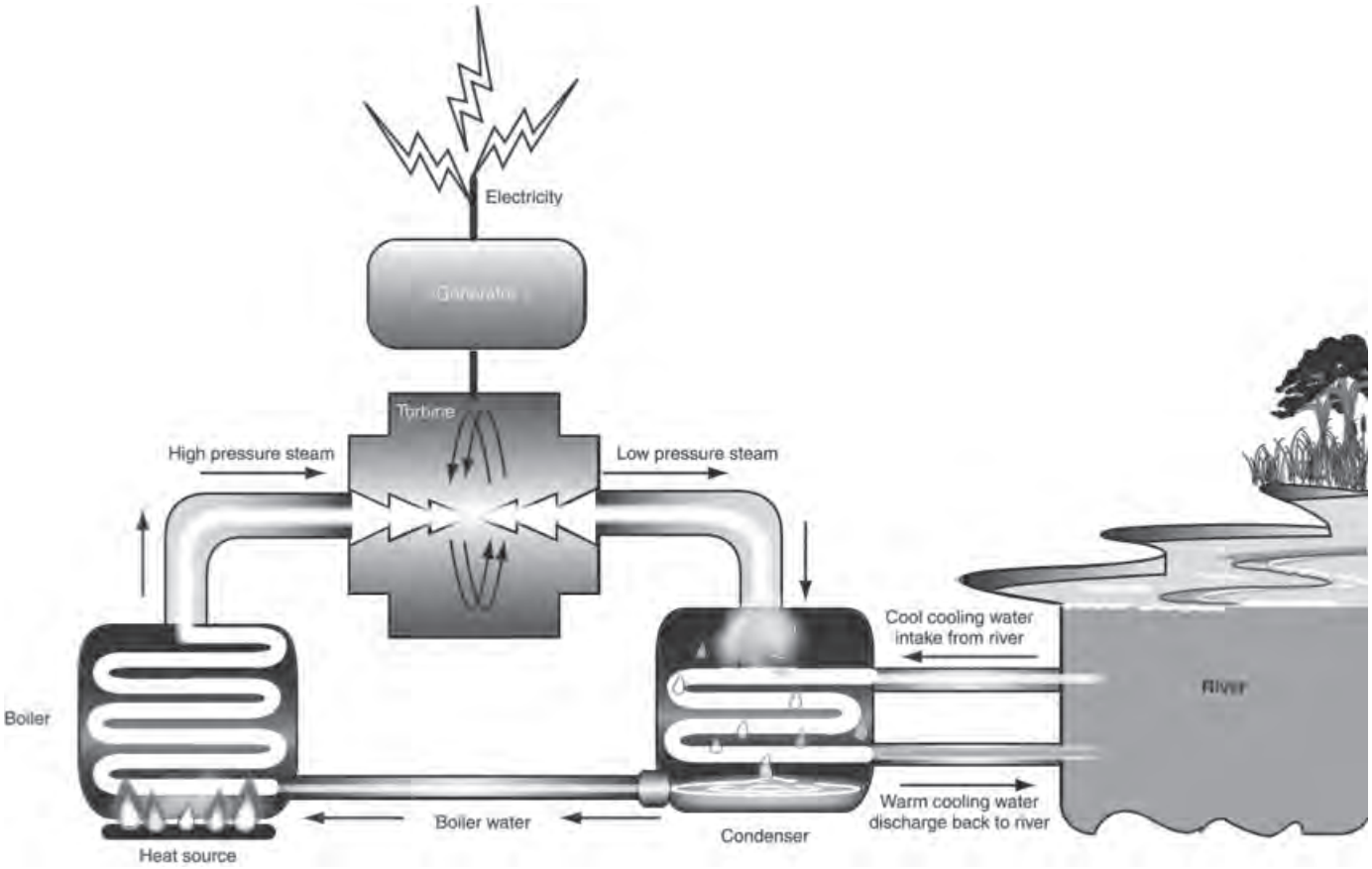
1. Cooling Technologies

1.1 Once-Through (Open-Loop) Cooling

Once-through cooling uses an ample supply of water (from an ocean, river, lake, cooling pond or canal) to run through the system's heat exchanger to condense the low-pressure steam at the exhaust of the turbines (Figure 24). Water is returned to the water body about 10°C to 20°C warmer. Until the 1970s, thermoelectric power plants commonly used water withdrawal intensive open-loop cooling and were built next to abundant surface waters near large population centers (U.S. DOE, 2006). These are cheap and sturdy systems (about $20/kW – EPRI, 2007). Today, open-loop cooling power plants account for about 31 percent of U.S. generating capacity.

Although these plants do not consume much water (i.e., they return about 99 percent of the water to the source), the availability of water is critical to plant operation because of the huge demand. This makes these plants extremely vulnerable to droughts, high-temperature events and competition for water resources. This is particularly exacerbated by the fact that electricity demand is disproportionately high in water-scarce areas such as the Southwest. Moreover, the large intake of water is extremely disruptive for aquatic life, and the discharge temperatures alter aquatic ecosystems considerably. The intake structures kill millions of fish and other aquatic organisms per plant each year and the discharge of heated water can be particularly lethal to native aquatic species. The 1972 Federal Water Pollution Control Act and Section 316(a) of the Clean Water Act (regulating intake structures and thermal pollution discharges) placed restrictions on the impact of open-loop cooling. Following this act, construction of open-loop cooling power plants slowed abruptly. Only 10 such power plants have been built since 1980, mainly along the coast (U.S. DOE, 2006).

Figure 24. Diagram of a Once-Through Cooling System

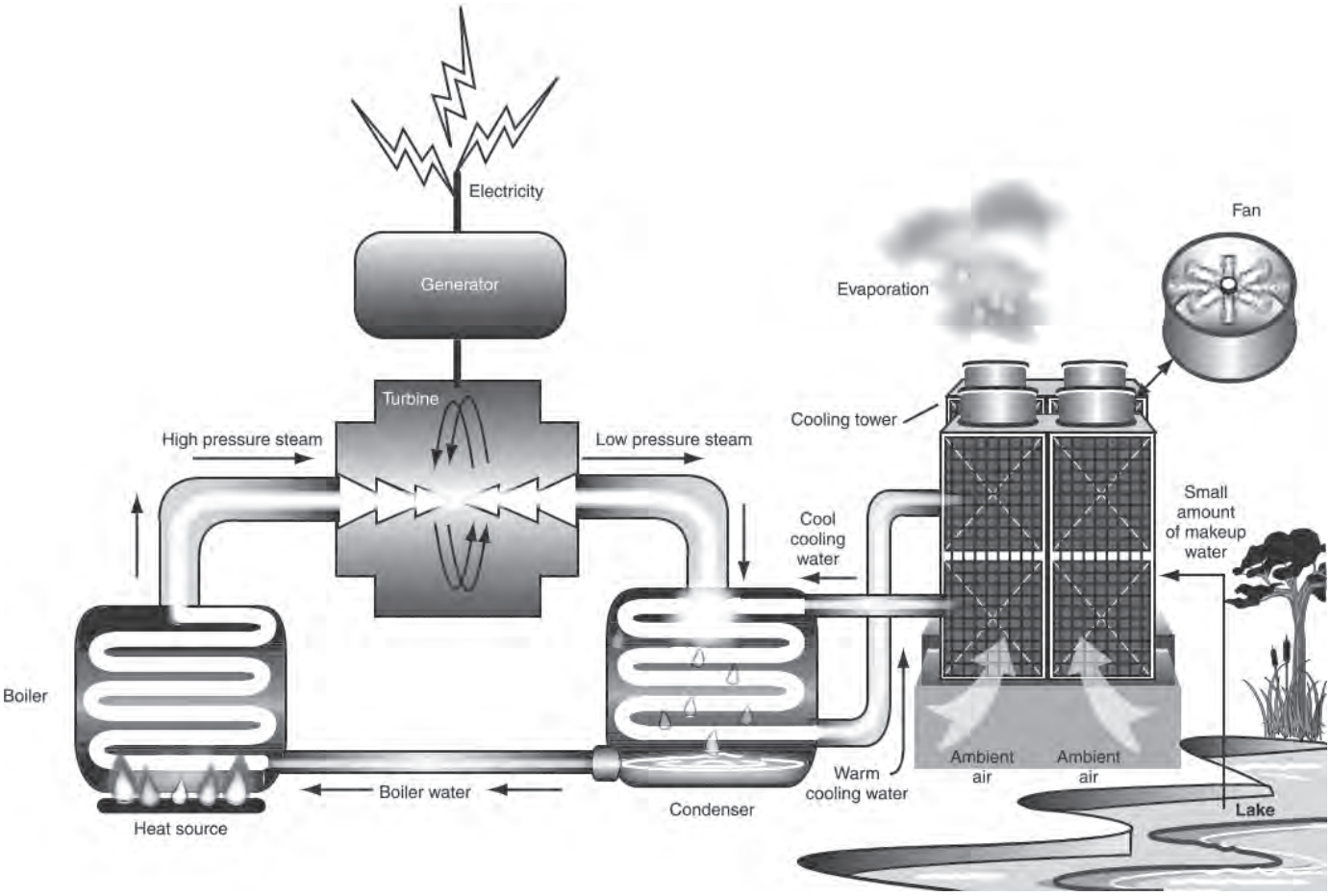


Source: U.S. GAO, 2009

1.2 Closed-Loop (Wet) Cooling

While once-through cooling relies on the high thermal capacity of water, closed-loop cooling relies on the high-energy requirements of water evaporation (Figure 25). Cooling water circulates between the condenser and a cooling tower. These cooling systems have much lower water requirements but consume much more of the withdrawn water. The water source can be from the ocean, a lake, a river, a cooling pond or a canal. Due to stringent regulations concerning open-loop cooling, closed-loop cooling has become the technology used since the 1970s. Lower water requirements make these power plants less vulnerable to water shortages and are often less disruptive for the environment due to lower discharges. But intake problems regarding aquatic life still hold, and net consumption of water is higher per kWh produced. Closed-loop cooling costs about $30/kW (EPRI, 2007), or 50 percent more than open-loop cooling systems per kWh produced.

Figure 25. Diagram of a Closed-Loop Cooling System

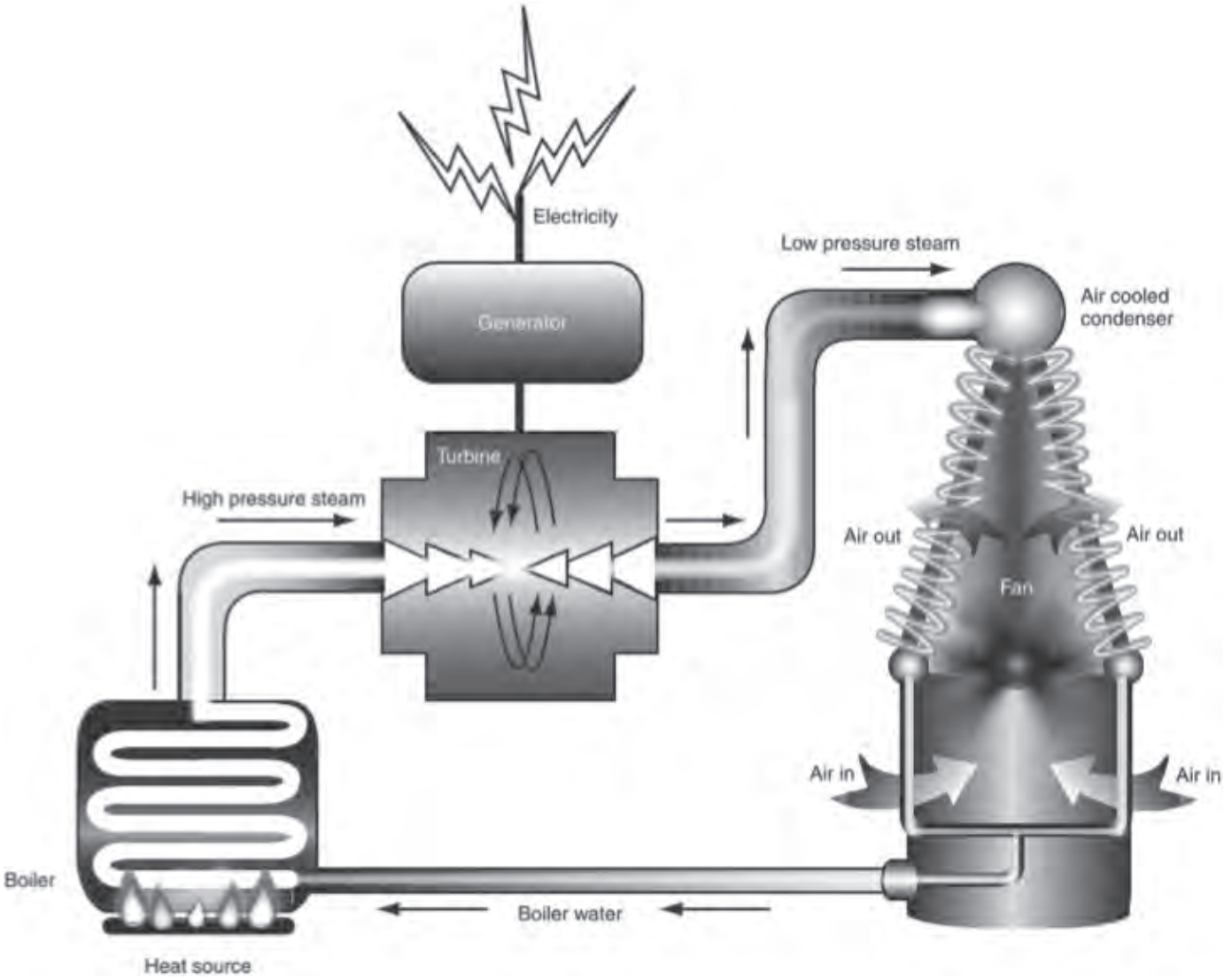


Source: U.S. GAO, 2009

1.3 Dry (Air) Cooling

Dry cooling systems are very similar to closed-loop systems, but air replaces water to cool the circulating cooling fluid, thus eliminating water withdrawal and consumption (Figure 26). However, this greatly impacts plant efficiency due to a lower thermodynamic theoretical maximum (Carnot cycle) and high electricity use for powering the massive fans used in cooling. Dry cooling is heavily impacted by ambient temperatures and humidity and will perform less well than wet cooling, particularly in hot and dry climates (where the use of such technologies is most desirable). The average loss of output is about 2 percent annually (Mielke et al., 2010), but can be as high as 25 percent at the peak of summer when demand is highest (U.S. DOE, 2006). Moreover, the capital cost of such a system is about 10 times more than that of an open-loop system (about $180/kW, EPRI, 2007), which makes it very unattractive to utilities without massive subsidies and grants.

Figure 26. Diagram of a Dry Cooling System

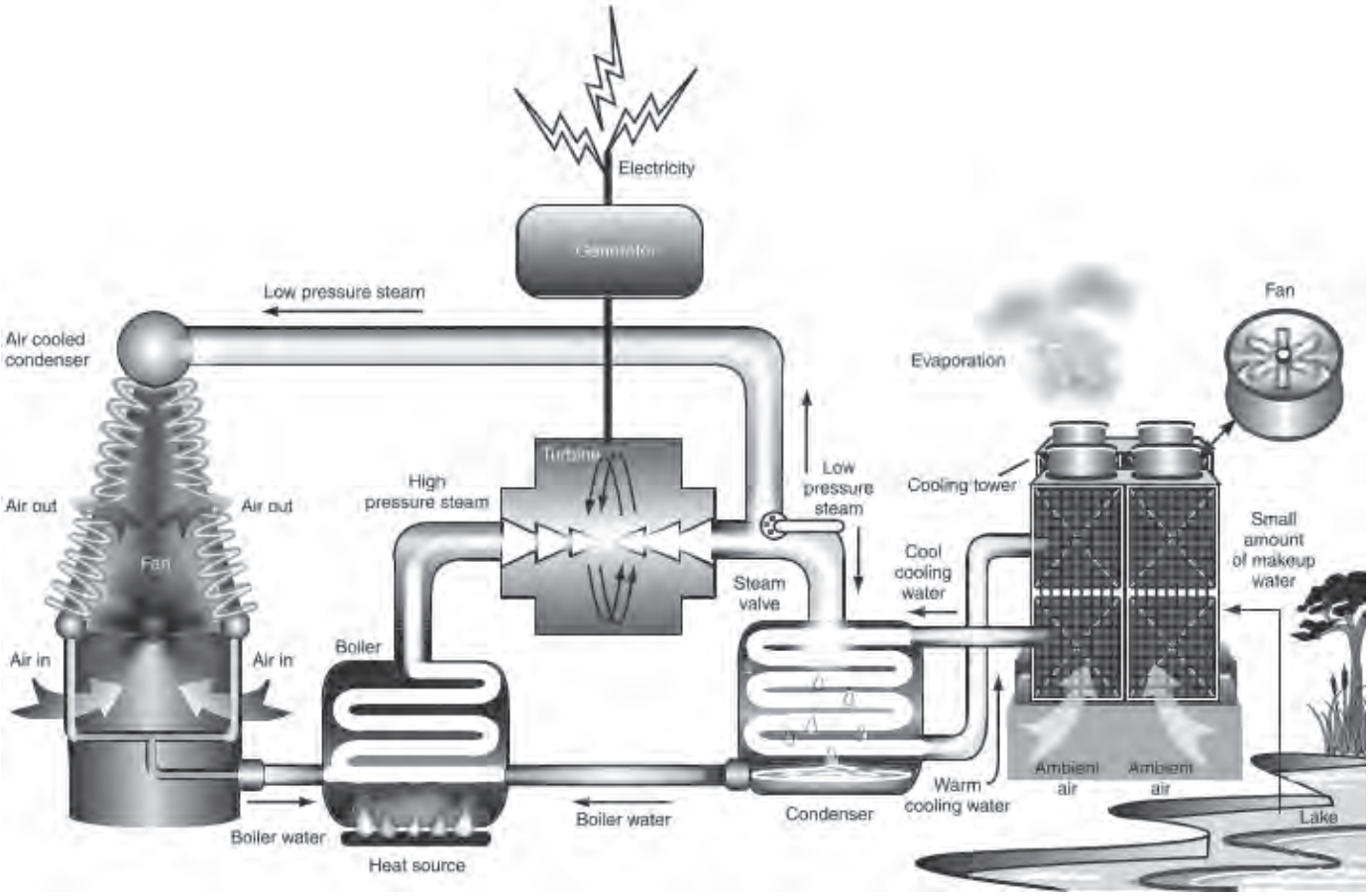


Source: U.S. GAO, 2009

1.4. Hybrid Cooling

Hybrid cooling technology uses a combination of wet and dry cooling systems, where wet and dry cooling components can be used either separately or simultaneously (Figure 27). This way, the system can operate both the wet and dry components together or only rely on dry cooling to avoid water use, economically reducing water requirements of wet systems by up to 80 percent. Capital costs usually fall midway between wet and dry cooling systems (EPRI, 2007). This technology is in early phases of development.

Figure 27. Diagram of a Hybrid Cooling System



Source: U.S. GAO, 2009

2. Water Use for Thermoelectric Generation

Estimates of thermoelectric water use at the national level are not available (Dziegielewski and Bik, 2006). Main methods available to estimate water intensities of electricity generation include using national estimates of federal agencies (EIA, USGS), using state data (Sanders et al. & Webber, 2012), and extrapolating data from generic facilities (engineering handbooks).

2.1 Survey Approach

The USGS, under the National Water Use Information Program, compiles reported water uses across the U.S. every five years. The USGS mission is to provide reliable scientific information to manage water, energy and other resources (U.S. GAO, 2009). According to USGS (2009), thermoelectric withdrawals were 200 billion gallons a day (BGD – or 670 gallons per U.S. inhabitant) in 2005 and consumption was 13 BGD. Thermoelectric power generation was of 3.7 trillion kWh in 2005 (EIA, 2005). Combining these numbers, we can obtain the water withdrawal intensity, 20 gallons per kWh, and water consumption intensity, 1.4 gallons per kWh, for thermoelectric generation. These estimates are lower than the values calculated by Dziegielewski and Bik (2006) of nearly 26 gallons/kWh. Still, these averages do not show the extremely local impacts of electricity generation and the huge variability between power plants, which are all unique. The

EIA's role is to provide independent information on the energy sector in the U.S. for policymakers and lawmakers, researchers and the industry. Most of the data is collected from electricity facilities by the EIA through Forms 923 and 860, which replace several previous forms including Form 767, which was heavily criticized (Dziegielewski & Bik, 2006; U.S. GAO, 2009).

These long surveys offer precious but often incomplete or erroneous information. One of the difficulties for operators is that readings on intake pumps are often used to fill out these forms, and these readings often reflect peak generation or rely on gross averages. Some operators report no water use/consumption at all, while others completely overestimate. However, when these extreme values were excluded from calculations, the benchmark values of water intensities were much more consistent with "best practice" values from engineering handbooks (Dziegielewski & Bik, 2006; U.S. GAO, 2009). Moreover, the EIA form requires net generation, which can be extremely different from gross generation (electricity is used on site), particularly with peak-power suppliers. Thus, estimated water withdrawals and consumptive use per kilowatt-hour of net generation of electricity show very high variability. The main reason is that "base-load" plants have lower water intensities than "load following" and "peak load" facilities (U.S. GAO, 2009).

2.2 Technology Approach

Thermoelectric power plants are unique facilities; fuel type, generating capacity, cooling technology, water source and use in the grid all contribute to their water intensity. For that reason, it is difficult to estimate water use for an individual plant or across a broad portfolio. Most studies point to work done by national laboratories (National Energy Technology Laboratory or National Renewable Energy Laboratory) or publicly contracted laboratories such as EPRI in Palo Alto, Calif. (by the California Energy Commission).

Table 2. Cooling Technology by Generation Type

	NETL (2009) Based on Platts (2005)				EIA Forms 860 & 923 (2012)					
Generation Type	Wet Recircu-lation	Once-Through	Cooling Ponds	Dry	Wet Recircu-lation	Once-Through		Cooling Ponds	Dry	Hybrid
						Freshwater	Seawater			
Coal	48.0%	39.1%	12.7%	0.2%	46.3%	33.5%	2.8%	17.0%	0.4%	0.0%
						36.3%				
Fossil Non-Coal	23.8%	59.2%	17.1%	0.0%	30.2%	28.1%	25.5%	16.2%	0.0%	0.0%
						53.6%				
Combined Cycle	30.8%	8.6%	1.7%	59.0%	71.3%	7.4%	6.1%	2.9%	11.7%	0.6%
						13.5%				
Nuclear	43.6%	38.1%	18.3%	0.0%	36.0%	31.1%	20.2%	12.7%	0.0%	0.0%
						51.3%				
Total	41.9%	42.7%	14.5%	0.9%	49.1%	26.7%	8.5%	12.7%	2.9%	0.1%

Source: NETL, 2009; EIA, 2012

Table 2 shows the NETL values for cooling technologies by generation type (from Platts, 2005) and the values based on EIA Forms 860 and 923. The information extracted from EIA information is based on generated electricity in 2011 and not nameplate. This information should be explicitly published by the EIA, being of importance to understand the water intensity of electricity generation. Table 3 summarizes the results of different studies and literature reviews examining the water intensities of different thermoelectric facilities. The results of this analysis show the strong variability within fuel types and cooling types. It also highlights the distinction between water consumption and water withdrawals for these different technologies.

i. Fossil Fuels (Coal, Natural Gas, Oil, Biomass)

Fossil-fuel plants often have similar thermal efficiencies and display similar technologies (Integrated Gasification Combined Cycle and Natural Gas Combined Cycle excluded). However, the overall system efficiencies are extremely dependent on the steam pressure at the outlet of the generating turbine. Coal-fired power plants tend to withdraw and consume more water than natural gas-fired plants. This is partially due to the fact that additional water is used in coal-fired power plants for dust suppression, ash handling, flue-gas desulfurization and other plant operations; and also because natural gas combined cycle plants are partially air-cooled (the gas turbine part) (Gleick, 1994).

Steam turbine (coal, gas, biomass) (gal/kWh)								
Once-through			Closed-loop			Dry		
Low	High	Ave.	Low	High	Ave.	Low	High	Ave.
Withdrawal								
10.00	60.00	35.00	0.10	1.46	0.64	0.00	0.03	0.00
Consumption								
0.09	0.14	0.11	0.16	1.17	0.56	0.00	0.03	0.00

ii. Nuclear

Nuclear power plants typically withdraw and consume more water than fossil-fuel plants. This is mainly due to technological characteristics and restrictions. Fossil-fuel plants can discharge waste heat through flue gas and there are limits to maximum steam temperature (Gleick, 1994). Many U.S. nuclear power plants built in the 1970s also have once-through cooling, which is the most water-intensive form of energy production. Some of these nuclear power plants use saltwater, which is water withdrawal-intensive, but not water consumption-intensive (although entrainment and impingement are notable environmental impacts).

Steam turbine (nuclear) (gal/kWh)					
Once-through			Closed-loop		
Low	High	Ave.	Low	High	Ave.
Withdrawal					
25	61	42	0.53	2.60	1.25
Consumption					
0.10	0.43	0.31	0.40	0.90	0.86

iii. Advanced Natural Gas Technologies

New generations of natural gas facilities, using combined-cycle gas turbines, are much less water-intensive and have higher efficiencies than traditional natural gas power plants. These power plants combine a gas turbine and a steam turbine, powered by heat drawn from flue gas of the gas turbine. These facilities have higher capital costs.

Table 3. Water Intensities of Different Theromelectric Facilities

		Steam turbine (coal, gas, biomass)									Steam turbine (nuclear)								
Main Literature Reviews	All units in gal/kWh	Once-through			Closed-loop			Dry			Once-through			Closed-loop			Dry		
		Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.
Feely et al. (2008)	Withdrawal	22.50	27.10	24.80	0.25	0.67	0.46	–	–	–	–	–	31.50	–	–	1.10	–	–	–
	Consumption	0.09	0.14	0.11	0.16	0.52	0.34	–	–	–	–	–	0.14	–	–	0.62	–	–	–
Dziegielewski & Bik (2006)	Withdrawal	–	–	44.00	–	–	1.00	–	–	–	–	–	48.00	–	–	2.60	–	–	–
	Consumption	–	–	0.22	–	–	0.70	–	–	–	–	–	0.40	–	–	0.80	–	–	–
Fthenakis & Kim (2010)	Withdrawal	20.08	50.19	35.13	0.09	1.17	0.65	–	–	–	25.10	60.76	42.93	0.79	1.11	0.95	–	–	–
	Consumption	0.12	0.32	0.22	0.16	1.16	0.72	–	–	–	0.14	0.40	0.27	0.74	0.90	0.82	–	–	–
Gleick (1994)	Withdrawal	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	Consumption	–	–	0.32	–	–	0.69	–	–	–	–	–	–	–	–	1.80	–	–	–
Goldstein & Smith (EPRI, 2002)	Withdrawal	20.00	50.00	35.00	0.50	0.60	0.55	0.00	0.00	0.00	25.00	60.00	42.50	0.80	1.00	0.90	–	–	–
	Consumption	0.30	0.30	0.30	0.48	0.48	0.48	0.00	0.00	0.00	0.40	0.40	0.40	0.72	0.72	0.72	–	–	–
MacKnick et al. (2011) (and Averyt et al., 2011)	Withdrawal	10.00	60.00	35.96	0.50	1.46	1.06	0.00	0.00	0.00	25.00	60.00	44.35	0.80	2.60	1.10	–	–	–
	Consumption	0.10	0.32	0.25	0.48	1.17	0.73	0.00	0.00	0.00	0.10	0.40	0.27	0.58	0.85	0.67	–	–	–
USDOE (2006) (and Mielke et al., 2010)	Withdrawal	20.00	50.00	35.00	0.33	0.63	0.48	0.03	0.03	0.03	25.03	60.03	42.53	0.53	1.13	0.83	0.03	0.03	0.03
	Consumption	0.30	0.30	0.30	0.30	0.48	0.39	0.03	0.03	0.03	0.40	0.43	0.42	0.40	0.75	0.58	0.00	0.03	0.02
	Withdrawal			34.98			0.64			0.01			41.97			1.25			0.03
	Consumption			0.25			0.56			0.01			0.31			0.86			0.02

Combined-cycle gas turbine									IGCC (coal)			Geothermal Steam			Solar trough			Solar tower			Sources
Once-through			Closed-loop			Dry			Closed-loop			Closed-loop			Closed-loop			Closed-loop			
Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	Low	High	Ave.	
–	–	9.01	–	–	0.15	–	–	–	–	–	0.23	–	–	–	–	–	–	–	–	–	NETL (2006), EIA AEO 2006, EIA-860
–	–	0.00	–	–	0.13	–	–	–	–	–	0.17	–	–	–	–	–	–	–	–	–	
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	Form EIA-767 (USDOE)
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
7.40	20.08	11.37	0.15	0.50	0.29	–	–	0.00	0.23	0.82	0.41	1.80	2.00	1.90	0.82	1.00	0.91	0.77	0.85	0.81	NETL (2009), EPRI (2002), NETL (2007), NETL (2005), USDOE (2006)
0.02	0.10	0.06	0.13	0.50	0.31	–	–	0.00	0.17	0.83	0.37	1.40	1.80	1.60	0.82	1.00	0.91	0.77	0.85	0.81	
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
–	–	–	–	–	–	–	–	–	–	–	–	–	–	1.80	–	–	1.06	–	–	–	
7.50	20.00	13.75	0.23	0.23	0.23	0.00	0.00	0.00	–	–	–	–	–	–	–	–	–	–	–	–	EPRI reports, federal agencies (NRC, EIA, USGS), engineering handbooks
0.10	0.10	0.10	0.18	0.18	0.18	0.00	0.00	0.00	–	–	–	–	–	–	–	–	–	–	–	–	
7.50	20.00	11.38	0.15	0.28	0.25	0.00	0.00	0.00	0.36	0.68	0.53	–	–	–	–	–	–	–	–	–	EPRI (2002), NETL (2009), NETL (2010), USDOE (2006), Gleick (1994) and others
0.02	0.10	0.10	0.13	0.30	0.20	0.00	0.00	0.00	0.32	0.44	0.37	0.01	3.96	1.98	0.73	1.06	0.87	0.74	0.86	0.79	
7.53	20.03	13.78	0.26	0.26	0.26	0.03	0.03	0.03	0.39	0.39	0.39	2.00	2.00	2.00	0.76	0.92	0.84	0.75	0.75	0.75	EPRI (2002), CEC (2002), CEC (2006), Grande (2005), Leitner (2002), Cohen et al. (1999)
0.10	0.13	0.12	0.18	0.21	0.20	0.00	0.03	0.02	0.34	0.40	0.37	1.40	1.40	1.40	0.76	0.92	0.84	0.75	0.75	0.75	
		11.86			0.24			0.01			0.39			1.95			0.88			0.78	
		0.08			0.20			0.01			0.32			1.70			0.92			0.78	

Combined-cycle gas turbine (gal/kWh)								
Once-through			Closed-loop			Dry		
Low	High	Ave.	Low	High	Ave.	Low	High	Ave.
Withdrawal								
7.40	20.08	11.86	0.13	0.50	0.24	0.00	0.03	0.01
Consumption								
0.02	0.13	0.08	0.13	0.50	0.20	0.00	0.03	0.01

iv. Advanced Coal-Fired Facilities

Next-generation coal-fired power plants have slightly lower water withdrawal and consumption rates. Most research papers note that IGCC may include carbon-capture and sequestration (CCS) technologies, which would substantially increase water consumption. This is due to water required for the process and for the overall reduction in efficiency of the system. Additional mining is also required to supply the electrical parasitic load. Mielke et al. (2010) report that water withdrawal and consumption levels may increase from 66 percent to 100 percent.

IGCC (coal) (gal/kWh)		
Withdrawal		
Closed-loop		
Low	High	Ave.
Withdrawal		
0.23	0.82	0.39
Consumption		
0.17	0.82	0.32

v. Solar Thermal

Solar thermal is another energy source available for thermoelectric production. In this technology, mirrors are used to focus solar energy on a boiler (solar tower) or a collector tube (solar troughs) to evaporate water or another fluid. Beyond this point in the process, the technology used is the same as for any other thermoelectric facility. There is a wide range of estimates for the water intensity of these power plants. Water is used for cooling the working fluid, washing the mirrors, etc. Notably, solar thermal facilities are usually located where sunlight is abundant and where water is often not. Thus, these power plants face major water supply challenges. Efforts to develop dry cooling systems would alleviate some of the water needs required by solar thermal technology.

Solar Through					
Once-through			Closed-loop		
Low	High	Ave.	Low	High	Ave.
Withdrawal					
0.76	1.00	0.90	0.74	0.85	0.78
Consumption					
0.73	1.00	0.90	0.75	0.86	0.78

vi. Geothermal

Geothermal is another form of alternative thermoelectric power production. Two technological forms are currently feasible: dry-steam and hot water systems. Dry-steam systems use wells drilled into a steam field. This steam is used to operate a generator. The biggest geothermal facility in the world is located in the Geysers region of California with a 2 GW nameplate capacity. There are only two dry-steam facilities in the world (the other is in Italy). At the Geysers, no outside source of water is used, although the extracted steam is characterized as groundwater (Gleick, 1994). It is to be noted that groundwater overdraft at this location has significantly reduced the steam pressure and has reduced the capacity of the power plant. Hot water systems use flash-steam systems and binary systems. These systems often use geothermal condensate for cooling reducing requirements for alternative water sources. Flash geothermal systems also use geothermal condensate for cooling whenever possible, minimizing outside water requirements.

Geothermal Steam		
Closed-loop		
Low	High	Ave.
Withdrawal		
0.01	3.96	1.95
Consumption		
0.01	3.96	1.70

2.3 Understanding Discrepancies

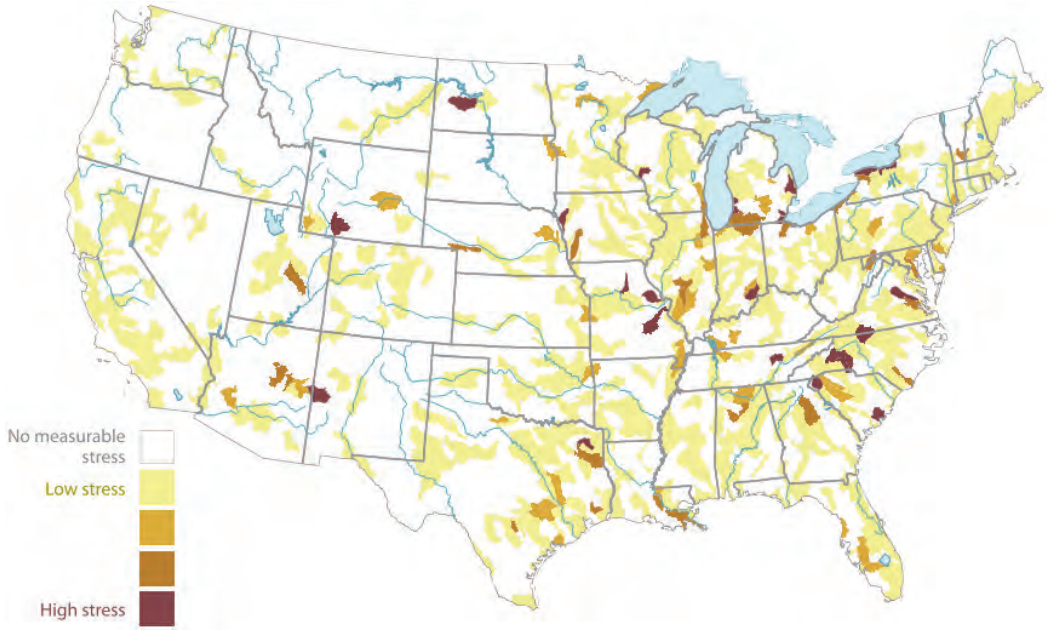
The two main studies investigating current methods of data collection and dissemination show that these have gaps and imprecisions and outline the need for policy changes (Dziegielewski & Bik, 2006; Averyt et al., 2011). The EIA used to require that all generation facilities report the average annual rate of water withdrawals to the U.S. Department of Energy (U.S. DOE) via Form 767. This was the principal source of information used by federal agencies (U.S. GAO, 2009). After surveying power plant officials, Dziegielewski and Bik concluded that many utilities grossly under- or overestimate their withdrawals. There were also several important flaws in the Form 767 such as omitting certain power plants, or leaving out recent technologies such as hybrid cooling or solar thermoelectric. Most of these issues were resolved when the EIA replaced six different forms for operators with two, Forms 860 (environmental aspects) and 923 (electricity generation and fuel use), in 2008.

Averyt et al. (2011) compared water withdrawal and consumption data from power plants (EIA Form 767) to calculate values using technology specific water intensity ranges from an NETL report. Calculated freshwater withdrawals are estimated to be between 60 and 170 BGD, compared to 125 BGD for reported withdrawals by the EIA and 140 BGD by the USGS (2009). Calculated freshwater consumption ranges from 2.8 to 6.0 BGD, compared to 10 BGD of reported consumption by the EIA and 13 BGD by the USGS (2009). Using information from Tables 1 and 2, as well as information from the Annual Energy Review from the EIA, withdrawals are estimated by the authors of this paper to be around 110 BGD for freshwater (plus 40 BGD for seawater) and consumption is estimated to be around 3.5 BGD for freshwater (plus 0.2 BGD for seawater). The estimates by the USGS and the EIA fall within the range estimated by Averyt et al. (2011), but are far larger than the estimates given above by this paper. In addition, reported numbers for water consumption are much higher. Moreover, the authors of the report found important differences between states in the accuracy of estimates, with some states grossly underestimating or overestimating water consumption and withdrawals.

The discrepancies between reported and calculated water intensities, particularly on the state-by-state level, are thought to have several origins. Every year, some water-cooled natural gas and coal power plants report using no water although millions of kWh of electricity is generated. These plants should be withdrawing 3 to 7 BGD and consuming 0.2 to 0.36 BGD according to estimates by Averyt et al. (2011). Moreover, nuclear power plants were exempted from reporting their water use to the EIA since 2002 (U.S. GAO, 2009). According to Averyt et al., this left 27 percent of all freshwater withdrawals and 24 percent of all freshwater consumption unaccounted for. Other power plants, such as those less than 100 MW, geothermal or concentrating solar plants, were also exempt from EIA data.

By analyzing EIA data, Dziegielewski & Bik (2006) and Averyt et al. (2011) show other types of misreporting, such as water consumption greater than or equal to withdrawals, when it should be smaller. Most often, operators estimate annual water use instead of measuring it, do not distinguish consumption and withdrawal, or use peak flow values. Cooley et al. (2011) also noted dramatic discrepancies between datasets provided by the USGS and the EIA for thermoelectric generation in the Intermountain West. The authors attributed this to the exclusion of certain power plants and gross underestimations of the withdrawal factors of once-through and closed-loop cooling by the USGS.

Figure 28. Water-Supply Stress Due to Thermoelectric Power Plants



Source: Averyt et al., 2011

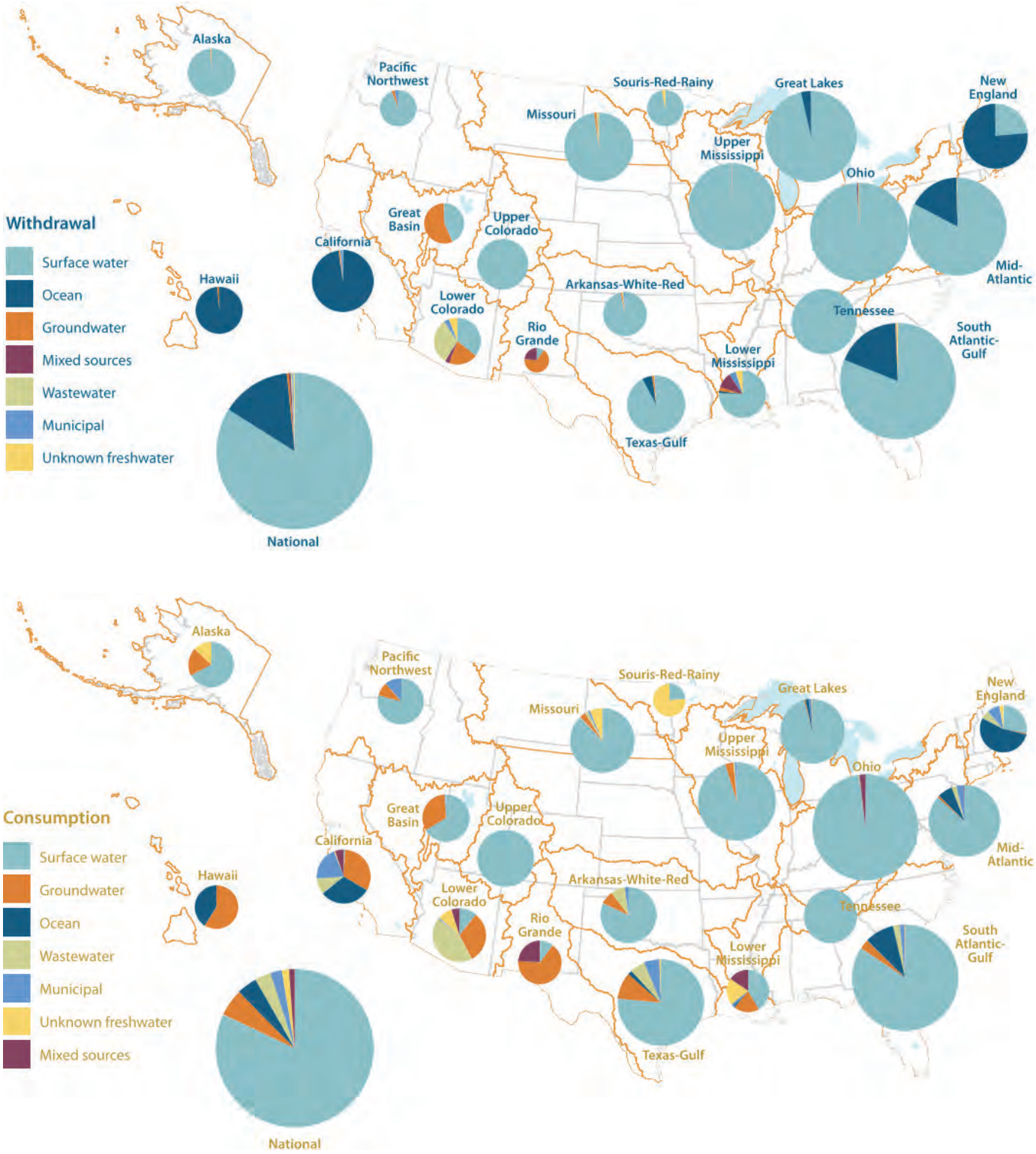
This shows that much work has yet to be done on improving data collection. As noted by the GAO (2009), without comprehensive information on power plant water use, policymakers have an incomplete picture of the impact that thermoelectric power plants will have on water resources. This is particularly true at the state and county level. Indeed, water stresses of thermoelectric power plants are often local, but can also adversely affect entire river basins. To address these deficiencies, the EIA changed its data collection methods and requirements following the recommendations by the NRC and the GAO. Since 2011, all plant operators must report their water use on a monthly basis. Nuclear, geothermal and solar power plants have been added. Hybrid cooling has been added. However, this information has yet to be used in research.

3. Environmental Impact

3.1. Freshwater Sources and Supplies

According to data from USGS (2009), thermoelectric generation accounts for 52 percent of freshwater withdrawals and 10 percent of freshwater consumption. Dziegielewski and Bik (2006) and Averyt et al. (2011) show that accuracy of the information about the local impacts of power plants varies considerably. Supplying high volumes of water to power plants impacts aquatic environments and can conflict with water needs for other purposes such as irrigation, municipal water, recreation and environmental services. The impact of these power plants on local watersheds and water supply can be seen in Figure 28 for the continental U.S. Surprisingly, this water stress indicator by Averyt et al. (2011) shows that power plants have a higher impact on watersheds in the Eastern U.S. than they do in the water-scarce West. One explanation may be that there are many more power plants in the East, many of which use once-through cooling. Another factor is that the West has many power plants along the coast, using seawater, which coincides with where most of the Western population lives.

Figure 29. Sources of Water Used by Power Plants, Withdrawal and Consumption



Source: Averyt et al., 2011

Most power plants using wet technologies are located near a large water body. Averyt et al. (2011) report that these sources, such as a river, a lake or ocean, account for 94 percent of water withdrawals, and roughly 86 percent of consumption, by thermoelectric power plants. Other sources are groundwater, treated wastewater or municipal sources. These sources are often used where surface water is scarce, such as in the Southwest (Figure 29). Wastewater is increasingly used in power plants close to large population areas, such as the 3.3 gigawatt (GW) nuclear power plant in Palo Verde near Phoenix, Ariz. In some of these places, thermoelectric power plants are largely contributing to the overdraft of rapidly declining aquifers (Alley, 2010). A monitoring of these aquifers would provide much-needed information on local impacts of power plants, particularly around the rapidly growing and extremely dry regions around Las Vegas, Phoenix and Tucson, Ariz.

3.2 Water Quality and Aquatic Life

There are significant environmental impacts linked to the water intakes for once-through cooling, although the Clean Water Act requires new plants to utilize the best technology available to minimize these effects. The EPA follows a regulatory schedule (currently in Phase II of III due to litigation) which requires that intake facilities reduce the impingement mortality of aquatic organisms and in some cases must reduce the intake of small aquatic life.

Aside from the fact that power plants are the largest withdrawers of surface freshwater in the U.S., power plants are also the largest dischargers of thermal pollution. Warm water reduces dissolved oxygen and elevates metabolic rates, leading to higher oxygen and food needs. It can also disrupt food chains. There are documented fish kills linked to both effects. In the Great Lakes, for example, it is estimated that power plants kill more than 100 million fish a year due to impingement (trapping against a screen) and 1.3 billion larval fish through entrainment (pulling through the cooling process) (Averyt et al., 2011). Under the Clean Water Act (2002), plants may be shut down, seasonal restrictions may be applied on water pumping, or additional once-through systems may be prevented where streams and rivers are being impacted by thermal pollution. However, it is to be noted that only 10 percent of power plants (none of which are nuclear power plants) reported temperature data to the EIA in 2008, making it once again very hard to fully assess the impact of thermal pollution on the environment.

During the process of electrical generation in wet systems (closed-loop cooling), treated water used for the boiler, called boiler make-up, enters the boiler and collects impurities over time. To maintain quality, this impurities-laden water is periodically purged from the boiler and is called "boiler blowdown." Boiler blowdown is usually alkaline and contains the chemical additives used to control scale and corrosion, as well as trace amounts of copper, iron and nickel that leach from boiler parts (Baum et al., 2003). Local regulations may limit disposal options, sometimes requiring alternatives such as brine concentration or evaporation, having a significant impact on the system cost (EPRI, 2002).

Moreover, for daily operations of wet cooling systems, scaling and biofouling chemicals are used, and there are thus concerns over water treatment chemicals and waste streams (EPRI, 2007; Baum et al., 2003). Chlorine and bromine compounds used for biological fouling control can be found in large quantities on site and are often used at high doses. For scaling and fouling, acids and bases (sulfuric acid, sodium hydroxide, hydrated lime) are often used in pH control. Baum et al. (2003) also underlined the presence of copper and other metals in boiler blowdown due to leeching of boilers and pipes. All these aspects of water quality are very poorly understood or researched (Baum et al., 2003; Cooley et al., 2011).

Although indirectly linked to thermoelectric generation, coal power plants also have a large impact on water quality. Indeed, large quantities of water are used for flue-gas desulfurization and ash

handling (for an overview of water use for these systems, see Grubert et al. [2012] and Grubert & Kitasei [2010]). Water is used in flue-gas scrubbers to remove SO2, which causes acid rain. This water must then be retreated before discharge. According to the EPA, coal fly ash is "one of the largest waste streams generated in the United States." Coal fly ash is often stored on site with water (ash slurry) in retention ponds. This ash is particularly loaded with heavy metals and naturally occurring radionucleotides. These retention ponds are of great concern, as shown by the TVA Kingston Fossil Plant coal fly ash slurry spill in December 2008, where 1.1 billion gallons of slurry was spilled into the Emory and Clinch Rivers (tributaries of the Tennessee River), causing human and environmental devastation. The volume of the spill gives an idea of the large amount of highly polluted water stocked at these coal-fired facilities.

4. Future Demand and Climate Change

Several recent studies have examined the future water demands of the electricity sector (Feeley et al., 2008; Elcock, 2010; Shuster, 2009; Sovacool & Sovacool, 2009; Cooley et al., 2011). Most groups used projections from the EIA and federal population projections. Under different scenarios (status quo, different types of regulations, mainly coal, mainly natural gas, mainly nuclear, mainly renewables), these groups showed similar results for projections in 2025 to 2035: Electricity generation will increase sharply (by about 20 percent between 2010 and 2035), and water withdrawals are likely to increase or decrease slightly while consumption is expected to increase dramatically, except in cases with expanded use of renewables (Cooley et al., 2011). This can be explained by a shift from once-through cooling to closed-loop cooling technologies.

The water intensity of electricity production is expected to drop as more efficient facilities replace old ones. For example, current trends in the power industry, especially the predominance of natural gas-fired, combined-cycle plants for new capacity, are decreasing the quantity of water consumed per MWh generated (Goldstein & Smith, 2002). Chandel et al. (2011) studied the impact of climate-change policy on water withdrawals and consumption in the U.S. The impacts on water consumption are approximately the same as the ones stated above if stronger climate-change policy is adopted. However, water intensity of electricity production could rise sharply if carbon capture and sequestration (CCS) is further developed and widely adopted.

However, the impacts from these changes will have very strong regional variations, particularly in the West, which is expected to bear most of the population growth (Sovacool & Sovacool, 2009) and to be the most impacted by climate change (Cooley et al., 2011). Increased population will induce energy and water needs in a region that seems to have exceeded its carrying capacity, increasing the stress on an already dire situation. Several studies noted that due to water limitations, construction and operating permits could be increasingly hard to obtain due to water limitations.

Water-energy conflicts are most important during a drought and "summer water deficits" (Sovacool & Sovacool, 2009), when energy demands are high and water availability is especially low. These extreme weather conditions are likely to be exacerbated by climate change (Cooley et al., 2011). During these heat waves, such as the one in France in 2003 or the recurrent droughts in Texas since 2007, thermoelectric power plants are forced to shut down because of low water availability despite record electricity demand, causing major blackouts (U.S. GAO, 2009; Averyt et al., 2011; Cooley et al., 2011). Finally, rising temperature will negatively affect power plant efficiencies and drive electricity demand for cooling.

5. Conclusion

Aside from collecting better information on water withdrawals and consumption from power plants, there are many fields that need to be addressed by

future research. There is an urgent need to develop and improve technologies with low water intensities such as dry and hybrid cooling technologies. Research could also investigate the reduction of water losses in cooling towers. New and more sustainable water resources such as industrial and municipal wastewater, gray water and non-potable brackish water should be investigated for plant operations.

As stated previously, this report estimates (using engineering handbook values and information from Tables 2 and 3) that withdrawals are around 110 billion gallons per day (BGD) for freshwater (plus 40 BGD for seawater) and consumption is around 3.5 BGD for freshwater (plus 0.2 BGD for seawater). This equates to a water withdrawal intensity of 12 gallons/kWh and a water consumption intensity of 0.38 gallons/kWh for thermoelectric generation.

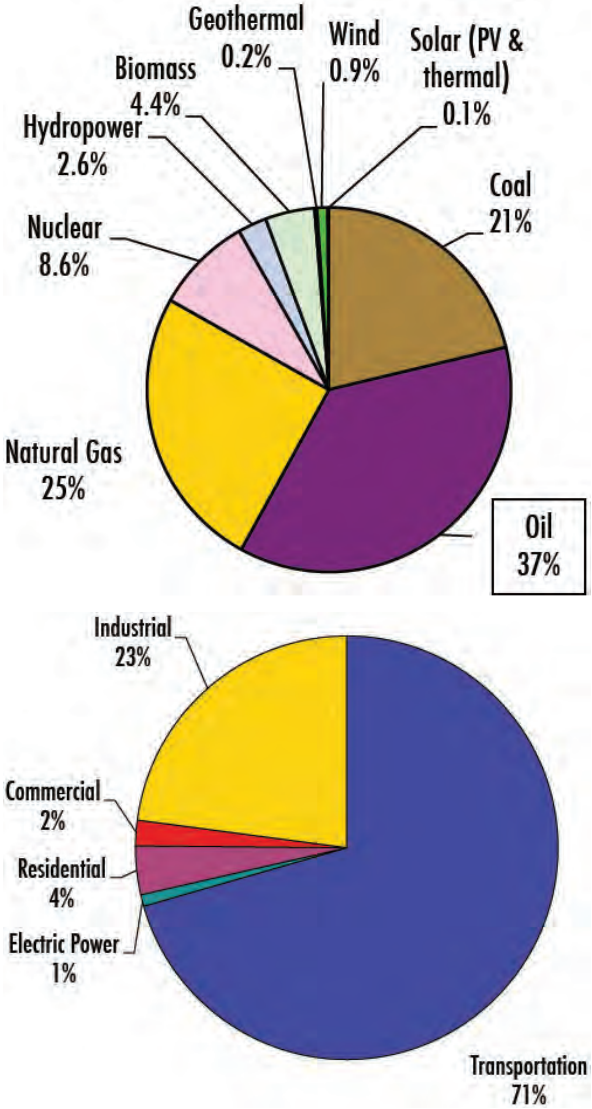
Research and policy questions include: Where will the water for increasing energy use come from? Agriculture? Recycled water? What about the relationship between water and electricity price?

OIL

This section explores the research and literature on water withdrawal and associated pollution from the exploration, drilling and processing of oil. While modest in comparison to the water needs of thermoelectric generation, oil remains a water-intensive enterprise and can have significant local impacts on the quantity and quality of water resources. The section begins with an overview of the connections between oil and water, followed by a focus on extraction and the impacts of drilling for different grades and qualities of oil, a brief review of transportation, and then a focus on processing and storage.

The U.S. is currently the world's first consumer and third producer of oil (BP, 2011). Oil accounts for a quarter of U.S. energy use, most of which is consumed in transportation and industrial use (Figure 30). Most of the literature concerning the water intensity of the oil and natural gas industries points to work done by Peter Gleick (1994) or commissioned by the U.S. Department of Energy (U.S. DOE, 2006; Veil & Quinn, 2008; Wu et al., 2009). Gleick's work is based on data from the 1970s and 1980s, and few updated or conflicting studies have been conducted since (Allen et al., 2011). The development of unconventional sources makes many sources outdated. New data which are available are often from the oil industry. More peer-reviewed research on the impacts of oil mining, transportation and processing on water quality and quantify in the U.S. is needed.

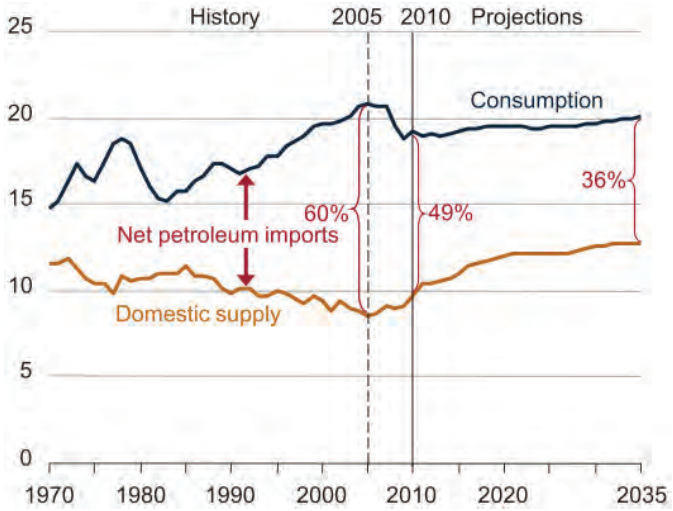
Figure 30. U.S. Energy Use by Resource in 2010 and U.S. Oil Consumption by End Use Sector, 2010



Source: Adapted from Karl Knapp, Stanford University; EIA, 2011

According to the BP Statistical Review of World Energy (BP, 2011), the U.S. has 30.9 billion barrels of proved oil reserves (2.3 percent of the world total) and a current reserves-to-production ratio of 11.3 years. Although conventional oil resources are dwindling, the U.S. has the largest reserves of oil shale in the world with an estimated 3.7 trillion barrels of oil, or 500 years of production at current level of consumption (World Energy Council, 2011). The EIA (2012) reports an increase in the domestic oil production over the past few years, reversing a decline started in 1986. U.S. oil production was of 5.5 million barrels a day in 2010, up 7 percent since 2007. This increase is attributed to continued development of tight oil and offshore resources in the Gulf of Mexico. The EIA predicts that oil production will continue to rise through 2020 (6.7 million barrels per day) and beyond, reducing net imports, which reached an all-time high in 2005 (Figure 31). The U.S. is by far the world's largest oil consumer (one-fourth of world production, 19 million barrels a day, more than the entire European Union and twice as much as China; BP, 2011). The U.S. imported roughly 50 percent of its crude oil in 2011 (EIA, 2012), the main importers being Canada, Saudi Arabia, Mexico, Venezuela and Nigeria. Transportation accounts for 71 percent of oil consumption, trailed by industrial use (plastics, pharmaceuticals, chemicals), accounting for 23 percent of consumption (Figure 30).

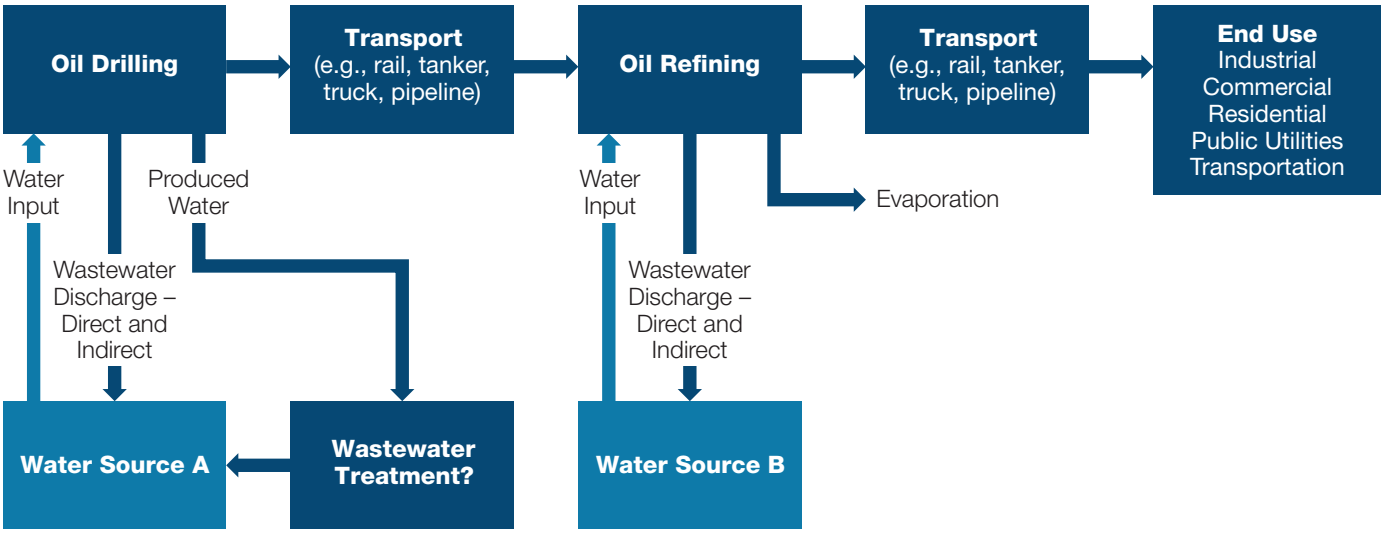
Figure 31. U.S. Liquid Fuels Supply, 1970 to 2035 (in Million Barrels Per Day)



Source: EIA, 2012

The American Petroleum Institute (API) reports that the oil and natural gas industry currently employs about 9 million people directly and indirectly (2012), and that the industry accounts for approximately 7.7 percent of the gross domestic product. The EIA reports (2011) total federal subsidies for the natural gas and oil industry of $2.8 billion (compared to $14.8 billion for renewables). The oil and gas industry also has tax breaks and incentives, including the oil and gas depletion allowance (oil companies can withhold 15 percent of sales revenue), the manufacturing tax deduction (oil as a "manufactured good"), deductions for intangible drilling costs and for geological and geophysical expenditures (aid in drilling and exploration), and drilling on federal lands in the Gulf of Mexico without royalty fees.

Figure 32. Flow Chart of Oil and Embedded Water



Note: Water inputs and outputs may be in different water bodies.

1. Drilling and Extraction

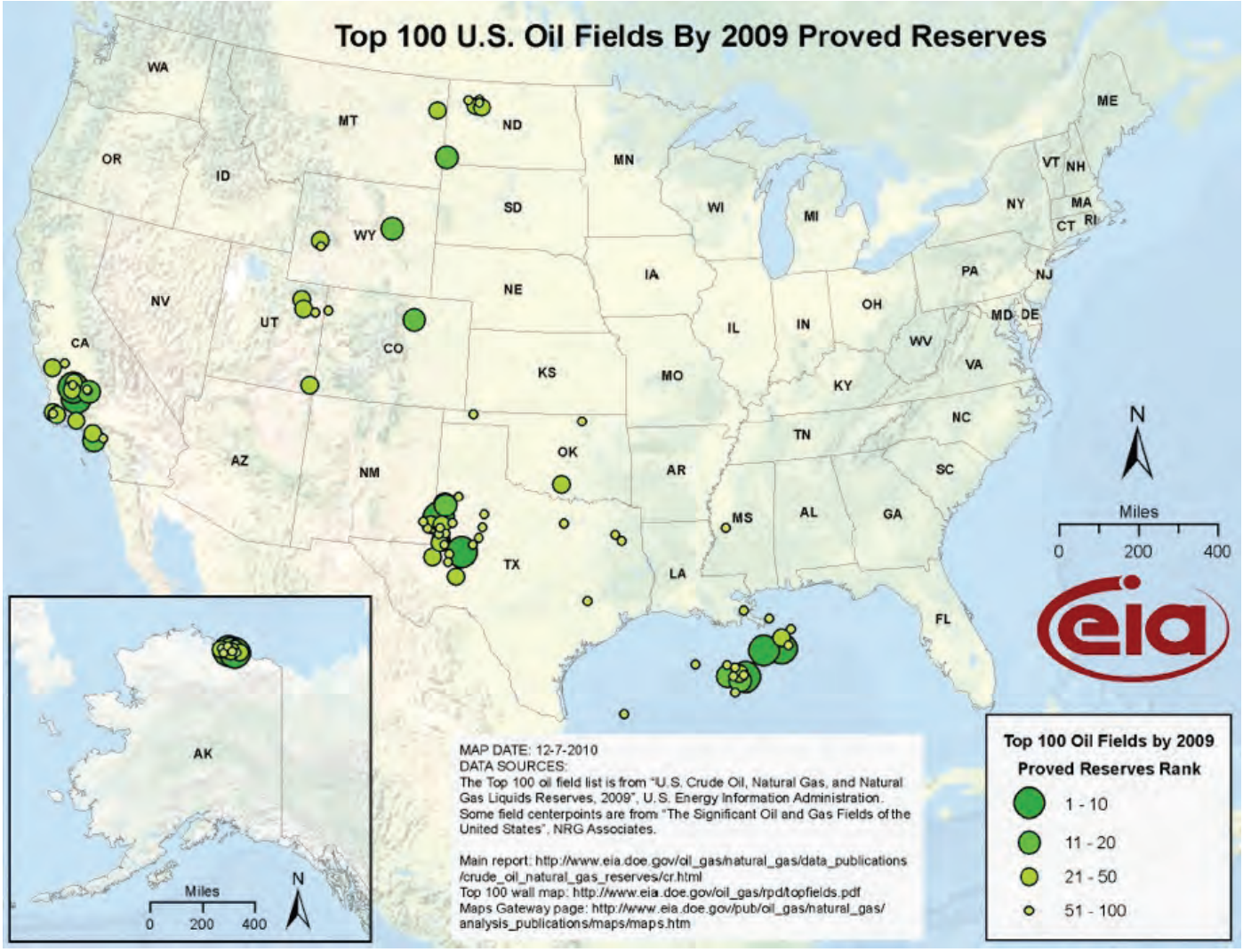
1.1 Conventional Oil

Like other forms of energy development, oil drilling and extraction affects surface and groundwater quality and quantity. Figure 32 shows a flow chart of the embedded water in oil production. Drilling itself is not very water intensive, but has large impacts on water quality (U.S. DOE, 2006). During extraction, the important volumes of produced water are the main connection between oil production and water quality (Allen et al., 2011). For conventional resources, although drilling for oil and natural gas wells are extremely similar, the differences in geology and chemistry of the deposits lead to different water-quality issues.

Conventional oil comes from organic matter trapped in sediments subjected to heat and pressure for millions of years. Over time, petroleum accumulated between layers of impermeable rock. Wells have to be drilled to access these deposits. The average depth of an oil well is about 5,000 feet in the U.S. (EIA, 2012). Oil is extracted from these reservoirs using different recovery methods: using the initial pressure (primary recovery), or pressurizing reservoirs with water, steam or other gases (such as CO2) to force the oil to the surface (secondary and tertiary, or enhanced, recovery). The major oil-producing areas in the United States are in the Gulf of Mexico region (onshore and offshore), California and Alaska. There are about 500,000 active oil wells in the U.S., both onshore and offshore (NRC, 2010).

Depending on the quality of the oil (API gravity), the location (inland, offshore), or depth of the deposit, recovery methods are more or less water and energy intensive. In the U.S., about one-quarter of domestic production comes from offshore wells (mainly in the Gulf of Mexico), while the rest mainly comes from the West (Figure 33). Oil in Texas is relatively light, while the oil in California is much heavier and harder to extract. Overall, the literature agrees with the figures estimated by Gleick in 1994 of 0.8 to 2.2 gallons per MMBTU required to extract oil, including water for drilling, flooding and treating (U.S. DOE, 2006; Elcock, 2010; Wu et al., 2009; Mielke et al., 2010; Allen et al., 2011). This is on average much more than the extraction of natural gas, coal or uranium (see corresponding chapters).

Figure 33. Top 100 U.S. Oil Fields by 2009 Proven Reserves



Source: EIA website

Drilling wells requires water for preparing drilling fluid: cleaning and cooling of the drill bit, evacuation of drilled rocks and sediments, and providing pressure to avoid collapse of the well. Gleick (1994) estimates that 0.6 gallons per MMBTU are needed for drilling. Drilling fluid contains potential contaminants and must be treated to separate excavated material and dissolved species. Reserve pits are excavated and lined to store wastes from drilling. Moreover, drilling wastes in offshore operations can cause a build-up of debris layers on the ocean floor dangerous for benthic (bottom-dwelling) communities. Drilling wastes may contain trace amounts of mercury, cadmium, arsenic, radionucleotides and hydrocarbons (NRC, 2010). These wastes are managed differently from one state to the other, according to regulations. On site, this water is often treated in decantation basins and reused.

After the well has been drilled and prepared, extraction can take place. Initially, oil may rise under the pressure in the reservoir. As pressure falls or if it was insufficient to start with, secondary recovery by mechanical pump, gas injection, or water flooding and tertiary recovery, or Enhanced Oil Recovery (EOR)

(steam injection, in-situ burning or surfactant injection), will be used to recover a portion of the remaining oil. Mielke et al. (2010) report that the most comprehensive analysis was done by the U.S. Department of Energy in 1984, which was partly updated in 2009 by Wu et al. These water intensities are reported in Table 4.

The most common extraction method is secondary oil recovery through water flooding and mechanical pumping. The large volumes of water injected for secondary recovery contribute to the high water intensity (62 gal/MMBTU) of oil extraction. Tertiary production or EOR also typically uses large volumes of water and is particularly energy intensive (as much as 1 unit of energy is needed for 3 units of recovered resource). This water use is entirely consumptive, although salt, brackish or recycled water may be used for some of these processes. These techniques are expensive, energy intensive and require handling and treatment facilities for volumes well over the volumes of oil produced. As oil prices increase, water usage (unless water prices rise) is likely to increase as well, as higher-cost wells and tertiary recovery techniques become more economic.

Oil is often located in geological formations with large volumes of water with high salt concentrations. The extracted water is known as produced water. Khatib and Verbeek (2003) estimated that oil production generates three times more produced water than crude oil. However, there is very high variability in these figures from one location to another, some wells producing as much as 20 times more water than oil. The ratio of produced water to crude oil usually rises as the wells age. Produced water can contain hydrocarbon residues, heavy metals, hydrogen sulfide and boron, as well as high salt concentrations (NRC, 2010).

Traditionally, oil producers disposed of this waste directly into the environment or into evaporation pits (often unlined pits that allowed leakage). Today, most oil producers re-inject produced water or reuse it as part of EOR activities for onshore wells (98 percent of produced water; Clark & Veil, 2009). However, 91 percent of produced water from offshore wells is simply discharged into the ocean (Clark & Veil, 2009). The main areas of concern in terms of environmental impacts are saltwater contamination of groundwater due to poor casing and well decommissioning procedures, as well as releases of oil and improper disposal of saline water produced with oil.

Table 4. Water Consumption for Different Oil Production Techniques

	gal/MMBtu	% of U.S. output
Primary	1.4	0.2%
Secondary	62	79.7%
Tertiary		
Steam injection	39	5.5%
CO_2 injection	94	11.0%
Caustic injection	28	0.0%
Forward combustion/air injection	14	0.1%
Other	63	3.5%
Micellar polymer injection	2,485	0.0%

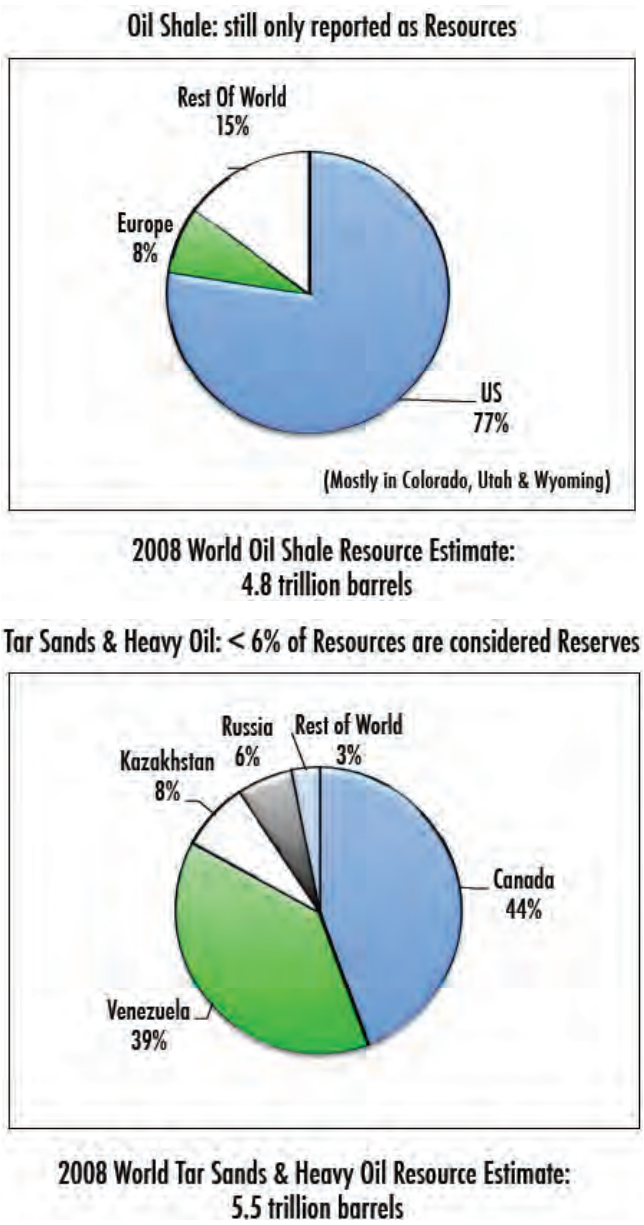
Source: Mielke et al., 2010

1.2 Unconventional Oil

Unconventional oil resources, such as oil sands (i.e., bitumen or tar sand) and oil shale, are having an increasing importance in the U.S. energy mix. Oil sands are a mix of clay, sand, water and bitumen (a dense and extremely viscous form of petroleum). Oil shale is a type of sedimentary rock that contain kerogen, a waxy substance that liquefies when heated, producing a precursor to crude oil. Oil from Canadian oil sand from Alberta encompasses nearly 10 percent of imported oil in the U.S., making it the No. 1 crude oil imported (Wu et al., 2009; NRC, 2010). Although there are no large-scale industrial applications of oil shale extraction, the U.S. possesses most of the world's oil shale resources (Figure 34). Techniques used for unconventional oil extraction are from the mining industry (open pit, in-situ mining and retorting), and are particularly water

and energy intensive. Potential environmental impacts of oil shale and oil sands surface mining are similar to those of surface mining of coal, but are amplified in terms water intensity due to the low energy content of the mined material (often 1 percent to 10 percent oil in mass; Gosselin et al., 2010).

Figure 34. Unconventional Oil Resources, 2008 Estimates



Source: Adapted from Karl Knapp, Stanford University; World Energy Council, 2010

i. Oil Sands

Oil sands are a mix of clay, sand, water and bitumen (a dense and extremely viscous form of petroleum). Depending on the depth of the seam, oil sands will be extracted by surface mining using methods used by the coal industry or by in-situ mining (over 250 feet deep). Currently, oil sands production is evenly split between the two technologies, but long-term trends favor in-situ production, most deposits being too deep (Wu et al., 2009).

For surface mining, the sands are excavated and trucked to extraction plants, to separate bitumen from the sands using hot water and chemicals. However, approximately two tons of oil sands generates one barrel of synthetic crude oil, which leads to enormous mining tailings. Moreover, these waste products are usually composed of 50 percent to 60 percent water, and occupy considerably more volume than the original ore, making their transport and storage more difficult. Thus, much of the used water leaves the processing plant with the waste, retained in tailings areas (Davis & Velikanov, 1979; Gleick, 1994). These huge mining tailings can then leach hydrocarbons, heavy metals, arsenic, selenium and other hazardous materials into surrounding waterways. Moreover, tailings are mounded to create retaining ponds for contaminated water (processing water and water released from the oil sands during extraction), which contains high concentrations of hydrocarbons and other contaminants and must be treated or contained. Canada's National Energy Board (NEB) (2006) estimates surface mining operations require 2 to 4.5 tons of water for one barrel on synthetic crude oil, or 15 to 33 gal per MMBTU. Wu et al. (2009) report an average of 29 gal per MMBTU.

For in-situ extraction, heat or steam is applied underground to decrease the bitumen's viscosity, which is pumped to the surface for subsequent refining. In-situ production uses two technologies: Cyclic Steam Simulation (CSS) for deep, thicker reservoirs and Steam-Assisted Gravity Drainage (SAGD) for thinner deposits. Altogether, in-situ water consumption is 9.4 gallons per MMBTU for SAGD and 16 gallons per MMBTU for CSS (Wu et

al. 2009). Natural gas is used to produce steam and generate electricity needed for operations.

After extraction using both techniques, the bitumen is upgraded to synthetic crude oil through either carbon rejection using thermal cracking (coking) or hydrogen addition using hydrocracking technology (Mielke et al., 2010). As a whole, Canada's National Energy Board (2006) estimates that 1 MCF of natural gas per barrel of synthetic crude oil (for heating and electricity) is needed, which is corresponds to an energy intensity of approximately 18 percent (this is much lower than some EOR technologies used in California). This synthetic crude is then transported to conventional refineries for a final transformation into fuels.

Oil sands extraction and processing can have high water and environmental impacts (Figure 35). Water consumption and water quality impacts from mining tailings also can be high. Estimates of water intensity for crude oil extraction from oil sands range from 10 to 50 gallons per MMBTU, although more recent averages are between 20 and 30 gallons per MMBTU (Gleick, 1994; NEB, 2006; Mikula et al., 2008; Wu et al., 2009; Gosselin et al., 2010; Allen et al., 2011). These values are lower than the water intensity of conventional oil extraction in the U.S.; the average for U.S. wells is 64 gal/MMBTU (Mielke et al. 2010). Altogether, the production of crude oil from oil sands requires 26 billion gallons of water annually (Gosselin et al., 2010) and 0.6 TCF of natural gas, which is over 10 percent of all natural gas production in Canada in 2010 (5.38 TCF in 2010).

Figure 35. Oil Sands Operations in Athabasca, Canada

Source: Unknown

ii. Oil Shale

Oil shale is a type of sedimentary rock that contains kerogen, a waxy substance that liquefies when heated, producing a precursor to crude oil. Oil shale deposits can be considered as an immature oil field. This waxy substance has to be extracted from the rock, upgraded to synthetic crude oil and refined before it can be used commercially. With resources estimated between 1.5 trillion and 3.7 trillion barrels, the U.S. has more than three-quarters of the world's oil shale deposits (World Energy Council, 2011), most of which are in the Green River Formation covering parts of Utah, Colorado and Wyoming. Of this, more than 1 trillion barrels of oil could be recoverable; this is four times current proven reserves in Saudi Arabia (Bartis et al., 2005). These resources have been known for a hundred years, leading politicians and oil companies to regularly dub oil shale the fuel of the future. Despite federal and private investment, particularly in the 1970s, which amounted to several billions of dollars, research and development has yet to show convincing results (Allen et al., 2011). Volatile oil prices and slumps in the economy put down the first attempts to industrialize oil shale extraction, forcing Exxon to shut down its $5 billion Colony Oil Shale project.

Although the industry has not yet found a feasible way to extract oil from kerogen, there are two primary methods considered: mining and retort, and in-situ. Mining and retort would require mining the shale using conventional mining methods, and then crushing and heating the ore to separate the kerogen from the rock. Gleick (1994) estimates that to produce one barrel of oil, one ton of shale would have to be mined and processed. This is two times less than for Canadian oil sands, but the oil shale deposits are often much deeper than oil sands. Moreover, retorting oil shale requires large amounts of water and energy. Since there is no commercial production of oil shale, there is little available data on water consumption of such techniques. As a whole, oil shale extraction by mining methods is estimated to use similar amounts of water as surface mining techniques of oil sands, estimates ranging between

7.2 to 38 gal/MMBTU (Gleick, 1994; Bartis, 2005; U.S. DOE, 2006). Most of this water goes for processing the shale, upgrading the kerogen to synthetic crude oil through hydrogenation, for cooling, and for disposing of the tailings. Because oil shale deposits are located in some of the driest parts of the U.S., one of the challenges for the industry is to secure already-stressed local and regional water resources.

In-situ mining, also called the In-situ Conversion Process (ICP), accelerates the natural process of oil and gas maturation by a slow heating of the oil shale. This is accomplished by drilling holes into shale layers and inserting electric heaters. The shale rock is heated for three to four years to about 400°C, requiring about 250 to 300 kWh of electricity per barrel of oil to drive the process (U.S. DOE, 2006). During the heating process, kerogen is converted to very light crude oil and natural gas. Unlike the mining and retort process of oil shale extraction, in-situ mining does not involve surface mining or create mining tailings. Shell has been studying this method for more than 30 years at the Mahogany Ridge project (O'Connor, 2008). Shell and DOE experts believe that ICP could produce as much as a million barrels per acre of high quality crude oil. Shell estimates an extraction price of $30/barrel (O'Connor, 2008), while EIA analysts estimate that three times this amount ($90/barrel) is needed (EIA, 2009). In-situ mining is the most promising method for oil shale, but is not likely to be fully developed for another decade (Bartis, 2005; Allen, 2011).

The water embedded in the electricity required for the process dominates water consumption associated with ICP. However, processing and decommissioning operations also use water. U.S. DOE (2006) estimates that the total amount of natural gas produced (about a third of the energy content) by the process would have to be used for extraction (production of electricity or heat). Although it would depend on the electricity source, the water intensity of the process could be 8 to 9 gallons per MMBTU (U.S. DOE, 2006), if natural gas is used. Another in-situ method being explored is the separation of the kerogen via chemical processes.

In addition to the carbon footprint of oil shale extraction, water quality and quantity impacts from oil shale development are potentially significant. The large quantities of mining tailings from mining and retort are a very important threat to water resources, as they potentially leach hydrocarbons, salts, nitrate, arsenic, boron, barium, iron, lead, selenium and strontium into surface-water and groundwater supplies (Bartis, 2005; NRC, 2010; Allen et al., 2011). Oil shale extraction could generate large quantities of produced water in similar quantities to oil sands. This water must be reinjected or withheld in retention ponds. These ponds are extremely dangerous to waterfowl and could leak, contaminating surface and groundwater.

1.3 Water Rights and Regulations

i. Water Rights

Production of crude oil in the U.S., from conventional or unconventional sources, requires and produces large quantities of water. Figure 33 shows that the biggest U.S. oil fields are in some of the driest places of the nation (Southern California, Western Texas, Utah, Colorado, Wyoming). Thus, water is not always available in desirable volumes to meet agricultural, domestic, commercial and industrial demand. In the West, water resources are subject to complicated water rights provisions and are often already allocated to other uses. Obtaining water rights is a prerequisite for production, and may be one of the hurdles to the development of oil shale, for example. States have their own procedures regarding water rights, described by Veil et al. (2007). Usually, groundwater rights relate to land rights. But several systems exist: absolute dominion (rule of capture), reasonable use (American rule), restatement of torts and correlative rights (common resource rule) (Veil & Quinn, 2008). In other states, groundwater is state property and rights are based on special authorizations.

ii. Regulations

Most regulations concerning water for the oil and natural gas industry regard the disposal of water, which requires regulatory approval. Discharge of wastewater or process water to surface water bodies requires a National Pollutant Discharge Elimination System (NPDES) permit under the Clean Water Act (CWA). The EPA can authorize states, territories and tribes to implement all or parts of the program. The injection of fluids for production activities or for disposal requires a permit or from the EPA's Underground Injection Control (UIC) program under the Safe Drinking Water Act (SWDA). Wastes generated during the exploration, development and production of crude oil, natural gas and geothermal energy are categorized by EPA as "special wastes" and are exempt from federal hazardous waste regulations under Subtitle C of the Resource Conservation and Recovery Act (RCRA) (EPA, 2012).

2. Transportation

Oil imported to the U.S. is mainly transported by ocean tanker, except for imports from Canada, which flow through several pipelines that connect with the U.S. pipeline system. This system consists of a network of about 30,000 to 40,000 gathering pipelines and 55,000 trunk pipelines (NRC, 2010). Crude oil is transported from oil fields and terminals to refineries by barges, rail cars, tank trucks and pipelines. Transport and distribution of oil is a major source of air pollution (evaporative losses) and water pollution, through oil leaks, spills and large-scale accidents (1989 Exxon Valdez, 2008 Deepwater Horizon oil spills). For on-shore spills, surface water contamination via runoff and seepage into groundwater are major concerns. Oil spills from wells are not uncommon and can pollute vast areas. Offshore spills can have a huge variety of effects, depending on distance to the shore, depth of the well, etc. (NRC, 2010). In the U.S., freshwater spills systems occur more frequently than marine spills: between 1995 and 1996, 77 percent of all spills greater than 1,000 gallons and 88 percent of spills greater than 10,000 gallons were inland spills, the majority of which were from oil pipelines (Allen et al., 2011).

3. Processing, Refining and Storage

Once crude oil has been extracted, it must be separated into its different constituents (fuels, lubricants, chemical feedstocks and other oil-based products) before use. Water consumption in a refinery depends on its design and on the type of oil that it is refining. The higher the API gravity, the lighter the crude oil will be and the more valuable the distillates will be (gasoline, kerosene and diesel). Before the 1980s, refineries only used crude distillation. They used an average water withdrawal demand of 80 gallons per MMBTU of crude-oil input and an average consumption of 6.4 gallons per MMBTU (Davis & Velikanov, 1979).

Most of the withdrawn water is used in different cooling processes at different stages of the refining processes. Some of these traditional factories still exist today (Gleick, 1994; U.S. DOE, 2006; Mielke et al., 2010). Most U.S. refineries also have Fluid Catalytic Cracking units, using catalytic reforming and hydrogenation to restructure hydrocarbons into more valuable molecules. Water is used as a source of hydrogen, and large cooling requirements are needed.

There are no consensus values for these systems, which can be very different from one to another for the reasons stated above. Gleick (1994) considers that these systems use as much as 32 gallons per MMBTU. Wu et al. (2009), after thoroughly investigating available literature, estimate that between 7.2 and 13 gallons of water per MMBTU of crude oil are needed. Newer facilities are more water efficient and are often at the lower end of this range. The disposal of process and cooling water, degraded with organic compounds, sulfur, ammonia and heavy metals, is of major concern (Davis & Velikanov, 1979; Allen et al., 2011). It is important to note that many

refineries depend on municipal water supplies to meet their needs (Wu et al., 2009).

The U.S. stores oil in the salt caverns of the Strategic Petroleum Reserve, formed by slurry mining of salt formations. The U.S. DOE (2006) estimates that these methods require 7 gallons of water per gallon of storage capacity. The mined slurry (a highly saline solution) must be disposed of. High volumes of water are required to excavate these large reservoirs. The SPR currently holds 695 million barrels of oil (U.S. DOE, 2012). For mining a cavern for oil storage, a one-time use of about 50 gallons per MMBTU of oil storage capacity is required (U.S. DOE, 2006).

After refining, petroleum products continue to affect water quality during transport and storage. In the U.S., the EPA has recorded more than 490,000 confirmed leaks from underground storage tanks (USTs), mainly storing petroleum products (Allen et al., 2011). The EPA regulates more than 600,000 USTs in the U.S. (NRC, 2010; Allen et al., 2011). Leaking USTs contaminate groundwater resources with compounds such as benzene and toluene. There is no information available about the volumes of leaked fuel. Research on the subject would help better understand the full impact of the life cycle of transportation fuels and other refined petroleum goods on water resources. These tanks are also a considerable source of volatile organic compound (VOC) emissions (NRC, 2010).

4. Conclusion

As oil is the world's principal transportation fuel, it is easy to overlook the connections between it and water. The combustion of oil and its byproducts typically does not involve water, as does the combustion of other carbon-based fuels, and while pollution from that combustion affects water, it typically does so via air or land. Nevertheless, there is a tremendous connection between water and oil.

The literature once again relies upon Gleick (1994), as well as some newer research sponsored by the U.S. Department of Energy. As with natural gas, there recently have been rapid changes in the industry, involving new technologies that allow for development of new and once unrecoverable formations. This rapid change has left even some recent publications out of date. Much of the available data and information is also tightly controlled by the industry, leaving it lacking in terms of independent verification.

Oil drilling and processing uses more water than natural gas, coal and uranium and produces large amounts of polluted water. That water intensity increases with lower-quality oil deposits, including advanced recovery of secondary and tertiary sites. The significant diversity of formations makes any generalizations about water intensity and water pollution less important and meaningful, since the affected water bodies are site-specific as well.

TRANSPORTATION BIOFUELS

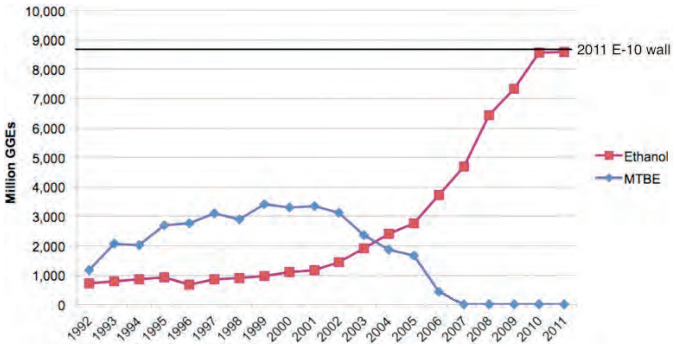
This section explores the research and literature on water withdrawal and associated pollution from the harvesting and gathering of raw material, processing and transportation of various forms of biofuels. Biofuels take many forms and are used for a variety of purposes, but this section addresses the major categories and is focused entirely on their use in the transportation sector. While biofuels constitute only a fraction of U.S. transportation fuels overall, they have enjoyed a great deal of focus and attention in federal energy and agricultural policy. The section begins with an overview of the sector, followed by a focus on feedstock production, a review of processing and transportation, and a discussion of several lifecycle analyses that focus on water.

Spurred by the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, the bioethanol industry developed quickly. Ethanol has displaced methyl tertiary butyl ether (MTBE) as a fuel additive (Figure 36). Bioethanol production increased tenfold in a decade, creating jobs and helping to revitalize rural areas of the Midwest. The increase in bioethanol production has also led to water quality impacts from nutrient runoff

and erosion and increased water demands for crop irrigation. Moreover, experts are divided on the question of the energy balance of ethanol production – whether energy inputs are greater than outputs.

This section explores the literature that examines the use of water and energy for growing feedstock, processing and transporting biofuels, as well as the associated water impacts (Perlack et al., 2005; Congressional Research Service [CRS], 2012; Du & Hayes, 2012, 2009; Fingerman et al., 2010; Chiu et al., 2011; Wu et al., 2009; Mielke et al., 2010; U.S. DOE, 2006; NRC, 2010; Farrel et al., 2006; Hammerschlag, 2006; and others). A report by the U.S. DOE (Wu et al., 2009) extensively reviews the literature up to 2009 and appears to still be the preferred reference since. The abundance of papers and reports on the subject explores the political and controversial nature of biofuel production as a replacement for fossil fuels. Because this is a young industry, the technology and practices of farmers and refiners are ever changing; reports and papers are quickly outdated.

Figure 36. U.S. Oxygenate Consumption by Year

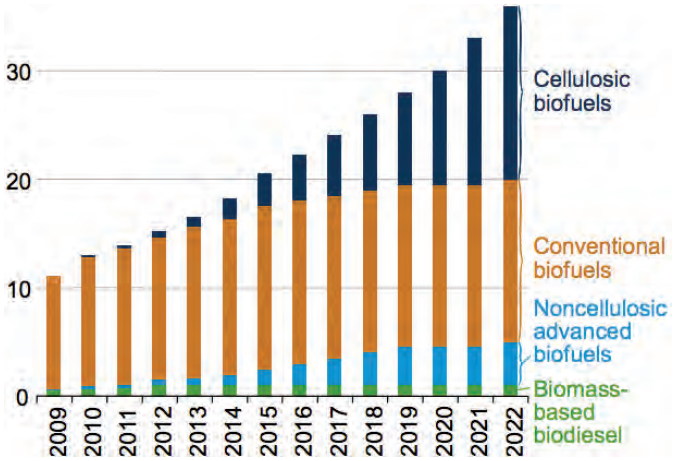


Source: Adapted from AFDC Website, 2012

Biofuel describes any fuel produced from biological materials, burned for heat or processed into alcohol or diesel fuel. It mainly refers to transportation fuels produced from food crops (e.g., corn, sorghum, sugar cane, soybean), crops for energy (e.g., switchgrass or prairie perennials), crop residues, wood waste and by-products, and animal manure. A study by the U.S. DOE and the U.S. Department of Agriculture (USDA) estimated that more than a billion tons of biomass are available for biofuel production (Perlack et al., 2005). In the U.S., nearly all biofuel production comes from corn ethanol used as a gasoline substitute (10 percent blended into gasoline in 2011), and to a lesser extent, vegetable oil and soybean for biodiesel (2 percent of diesel consumption in 2011). About 20 pounds of corn are required for a gallon of ethanol and about 7.5 pounds of vegetable oil for a gallon of biodiesel (CRS, 2012; RFA, 2013).

The Renewable Fuel Standard (RFS) mandated by the 2005 Energy Policy Act and the 2007 Energy Independence and Security Act are the major forces behind the major transformation of the biofuel revolution in the U.S. of the past decade (Figure 37). These acts provided subsidies, tax incentives, tariffs on biofuel imports and R&D funds for the industry in an effort to reduce U.S. dependence on foreign oil, reindustrialize rural areas and shift to renewable energy resources (CRS, 2007). The industry has achieved the E-10 (10 percent ethanol, 90 percent gasoline) "blend wall," with nearly 10 percent ethanol by volume added to gasoline nationwide.

Figure 37. RFS Mandated Consumption of Renewable Fuels, 2009 to 2022 (in Billion Gallons Per Year)



Source: AEO, EIA 2012

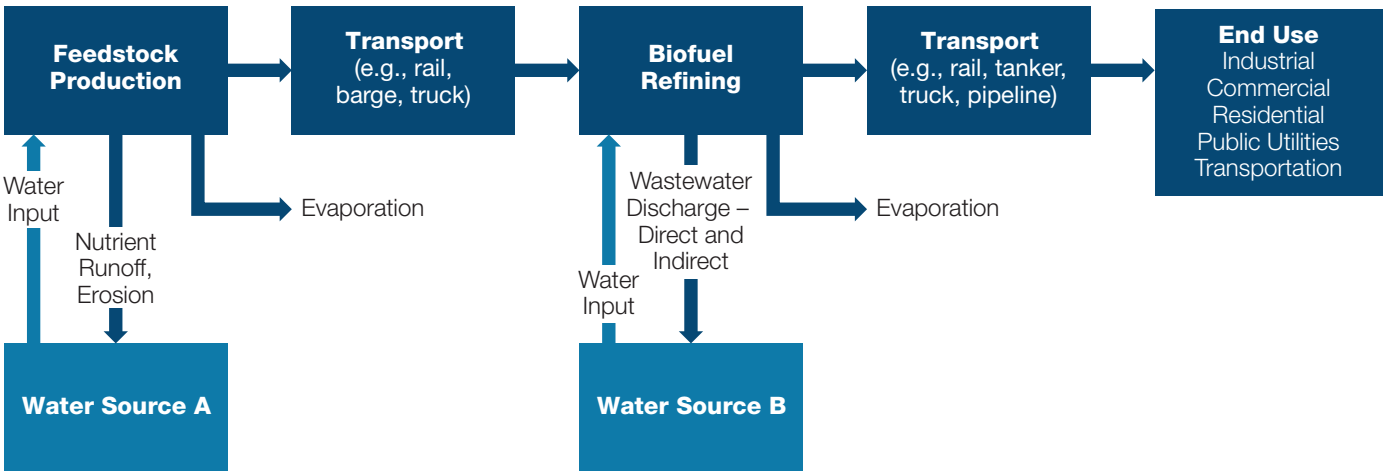
Supply will continue to greatly exceed domestic demand unless E-85 gasoline can be successfully developed at the retailer level and the U.S. EPA approves E-15 gasoline nationwide. Moreover, the tax incentive for ethanol blending, known as the

Volumetric Ethanol Excise Tax Credit (VEETC), created by the American Jobs Creation Act of 2004, expired on Jan. 1, 2012. The EISA07 caps the amount of corn that can be used for ethanol at 15 billion gallons beginning in the year 2015. Although exports are rising, there are several trade issues (including E.U. and China anti-dumping and countervailing duty proceedings against imports of subsidized U.S. ethanol) that emerged in 2011 and could slow further development of the U.S. biofuel sector (CRS, 2012).

According to the Renewable Fuels Association (RFA), a corn ethanol industry group, 2011 production reached 13.9 billion gallons of ethanol, consuming 40 percent of all corn grown in the U.S. (5 billion bushels; RFA, 2013). Corn ethanol processing produces waste that can be used for feeding livestock, which reduces the de facto amount of corn used by the industry to 25 percent of produced corn. According to RFA, the bioethanol industry is responsible for 90,200 direct jobs and 311,400 indirect jobs across the country and contributes $42.4 billion to the national gross domestic product. It is estimated that total federal subsidies for the bioethanol sector were $6 billion, nearly 43 cents per gallon (CRS, 2012). Du & Hayes (2009 and 2012) found that the average effect of bioethanol on gasoline prices in 2011 across all regions is a reduction of $1.09/gallon gasoline compared with $0.14/gallon in 2008. Regional impacts range from $0.73/gallon in the Gulf Coast to $1.69/gallon in the Midwest.

In 2011, ethanol effectively replaced MTBE in the vehicular fuel system as an oxygenate. Ethanol and MTBE are both types of oxygenates, which is mandated by federal law to be added to gasoline to help it burn more completely, reducing harmful tailpipe emissions from motor vehicles (EPA, 2013). About 5 billion gallons of ethanol were needed to replace 4 billion gallons of MTBE (Figure 36). MTBE is made from natural gas and butane, a product of crude oil refining. Due to the lower energy content of ethanol, 9 billion gallons of ethanol replaced the equivalent of nearly 6 billion gallons of gasoline (4.5 percent of gasoline demand in the U.S.). U.S. biodiesel consumption represented about 2 percent of national diesel transportation fuel use, at 40.7 billion gallons (CRS, 2012). Figure 38 shows a flow chart of biofuel and its embedded water.

Figure 38. Flow Chart of Biofuel and Embedded Water



Note: Water inputs and outputs may be in different water bodies.

1. Feedstock Production

1.1 Bioethanol

Corn ethanol and cellulosic ethanol are two main forms of bioethanol discussed in this section. Sugarcane and sugar beet ethanol, while not included in this literature review, are other forms of bioethanol currently under consideration in Hawaii and on the U.S. mainland.

i. Corn Ethanol

Corn is the primary feedstock in the U.S. for bioethanol production and is converted to ethanol through dry-milling or wet-milling production processes. One bushel of corn (56 pounds) produces about 2.8 gallons of ethanol. In 2011, the bioethanol industry used 40 percent of all corn grown in the U.S., and an equivalent of 15 percent of the production was returned to the market in the form of animal feed. The world's second biggest ethanol producer is Brazil, where sugar cane is the primary crop input (the U.S accounts for 60 percent of worldwide production and Brazil 30 percent).

Corn production takes up much of the water needs of the whole bioethanol cycle (Gerbens-Leenes et al., 2009). Water use is variable among and within the states (Fingerman et al., 2010; Chiu et al., 2011), mostly depending on climate conditions and related annual rainfall. Producing one bushel of corn in USDA Region 7 (North Dakota, South Dakota, Nebraska and Kansas) consumes 865 gallon of freshwater from irrigation. Producing one bushel of corn in USDA Regions 5 (Iowa, Indiana, Illinois, Ohio and Missouri) and 6 (Minnesota, Wisconsin and Michigan) requires only 19 and 38 gallons respectively, because of sufficient water from precipitation (Table 5; Wu et al., 2009). These three regions produce about 90 percent of U.S. corn and 95 percent of corn ethanol. This is an average of 263 gallons per bushel, or 94 gallons of water per gallon of ethanol, or, to be consistent with the other sections, 1,200 gallons of water per MMBTU, just for the feedstock.

In all three regions, most of the water used for irrigation is withdrawn from groundwater aquifers and particularly from the immense Ogallala Aquifer, one of the largest fossil water aquifers. The extensive corn agriculture in Nebraska in particular is displacing fossil fuel dependence for fossil water dependence. Although the previous figure is derived from national averages given by the USDA, Chiu et al. (2011) report from studying existing literature that with irrigated agriculture, ranges are from 250 to 1,600 gallons of water per gallon of ethanol, or 3,300 to 21,000 gallons per MMBTU. The origin of the feedstock is therefore extremely important when considering the water footprint of bioethanol. Various sources report that about 15 percent of corn production is irrigated (Wu et al., 2009; RFA, 2012).

An estimated 71 percent of the water input from irrigation is consumed via evapotranspiration, with the remaining 29 percent becoming surface runoff and groundwater recharge (Wu et al., 2009). This water is potentially available for reuse as irrigation water but is often degraded due to intensive use of fertilizers and pesticides for corn production. Water management has become a major concern in the agricultural sector in recent years; the amount of irrigation water applied for corn declined 27 percent despite consistent corn yield increase over the past 20 years (Wu et al., 2009). This trend is likely to continue, particularly as breakthroughs are made in genetic engineering. Monsanto and DuPont are soon expected to commercialize drought-resistant corn.

Table 5. Precipitation and Corn Irrigation by Major Corn-Producing Regions

USDA farm region	Average annual precipitation	Area irrigated	Percent of U.S. irrigation water consumption for corn	
	(cm)	(%)	Groundwater (%)	Surface water (%)
5	96	2.2	3.4	0.2
6	75	3.9	1.8	0.4
7	55	39.7	53.4	9.5
3 regions total		12	59	10

Source: Wu et al., 2009

ii. Cellulosic Ethanol

The RFS mandates that by 2022, the annual production of cellulosic ethanol should be at least 16 billion barrels. This mandate attempts to reduce the water use required to produce ethanol by using plant material that does not require additional water. This includes crop and forestry waste and crops that do not require much irrigation, such as switchgrass (U.S. DOE, 2006). Research is under way to develop the processes to produce ethanol from the lignocellulose in these materials. Commercial-scale cellulosic refineries are still at an early stage in development. These second-generation technologies for ethanol from biomass are expected to have lower full-cycle CO2 emissions and reduced competition with food crops because they mainly use perennial plants as feedstock (Mielke et al., 2010).

Water requirements for cellulosic biomass vary depending on the type and origin of the feedstock (Grubert et al., 2011). Forest wood does not require irrigation, crop wastes share the irrigation requirements with the crop, and algae and short-rotation woody crops may require high levels of irrigation (Wu et al., 2009). Switchgrass is considered to be one of the most promising perennial crops as it is relatively drought-tolerant and does not need irrigation in its native habitat (U.S. DOE, 2006; Wu et al., 2009). The native grass can be grown on marginal, highly erodible lands similar to those enrolled in the federal Conservation Reserve Program, which pays farmers not to grow traditional crops on their land. Note that many candidates for biofuels can behave as invasive species outside of their native habitat (Grubert et al., 2011).

1.2 Biodiesel

Another biofuel receiving attention is biodiesel, which is a substitute for traditional diesel fuel. Biodiesel is often produced from oil-containing crops, like soybeans, or used vegetable oils. Biodiesels are biodegradable and have very low amounts of sulfur and aromatics, while providing fuel economy, horsepower and torque similar to conventional diesel (CRS, 2012).

The focus in this review is on soybeans, which accounts because of its prominence, accounting for over 50 percent of U.S. feedstock for biodiesel (EIA, 2013), and availability of literature. The conversion process from soy to biodiesel requires one bushel per gallon of fuel. The USDA reports that water use for irrigated soy production in the U.S. varies from 0.2 acre-feet/acre for Pennsylvania to about 1.4 acre-feet/acre for Colorado, with a national average of 0.8 acre-feet of water (U.S. DOE, 2006). The average output is estimated at 42 bushels per acre, or 42 gallons of biodiesel per acre. The average water use for the production of soy is of 50,000 gallons of water per MMBTU, with a range of 14,000 to 60,000 gal/MMBTU. This is significantly more than for corn bioethanol.

The NRC (2010) estimates that due to limitations on soybean production and to avoid significant impacts on the food and agricultural markets, the industry could

only produce about 1.5 billion gallons per year of soy-based diesel fuel (currently about 0.8 billion gallons). Mielke et al. (2010) report that the estimates for biodiesel from rapeseed show lower water consumption than the comparable estimates for corn ethanol, with a range of 11,500 to 20,000 gal/MMBTU.

2. Processing, Refining and Storage

2.1 Ethanol

i. Corn Ethanol

Once produced and harvested, corn is transported to a refinery, where it is biologically processed into ethanol. Figure 39 shows the conversion process for a typical corn-based ethanol biorefinery. Water is needed in this step for grinding, liquefaction, fermentation, separation, drying, heating, electricity and steam generation (Wu et al., 2009). Water sources often come from municipal water and groundwater, sometimes stressing existing water supplies (CRS, 2012). Most ethanol is produced via dry mills, with only 10 percent of ethanol produced in wet mill facilities (RFA, 2012).

The overall efficiency of these refineries and newly available technologies are changing very rapidly. Water consumption in dry mills has decreased by nearly 50 percent over a decade and thermal energy needed per gallon has fallen by nearly 30 percent (Wu et al., 2009; RFA, 2012). Water use in wet mills averages 4.7 gallons per gallon of ethanol, or 62 gallons per MMBTU, while in dry mills it is 3 gallons per gallon of ethanol, or 40 gallons per MMBTU (U.S. DOE, 2006; Wu et al., 2009). The weighted average is therefore of 42 gallons per MMBTU, although dropping rapidly. The industry maintains that zero water consumption is achievable in the near future by water reuse and better practices. As a comparison, the petrochemical process to produce ethanol from ethylene, a petroleum derivative, has a water intensity of approximately 110 gallons of water per gallon of ethanol, or 1,500 gallons of water per MMBTU, and an energy intensity of about 10 percent (based on the best available data, dating from the 1980s; Chauvel & Lefebvre, 1989).

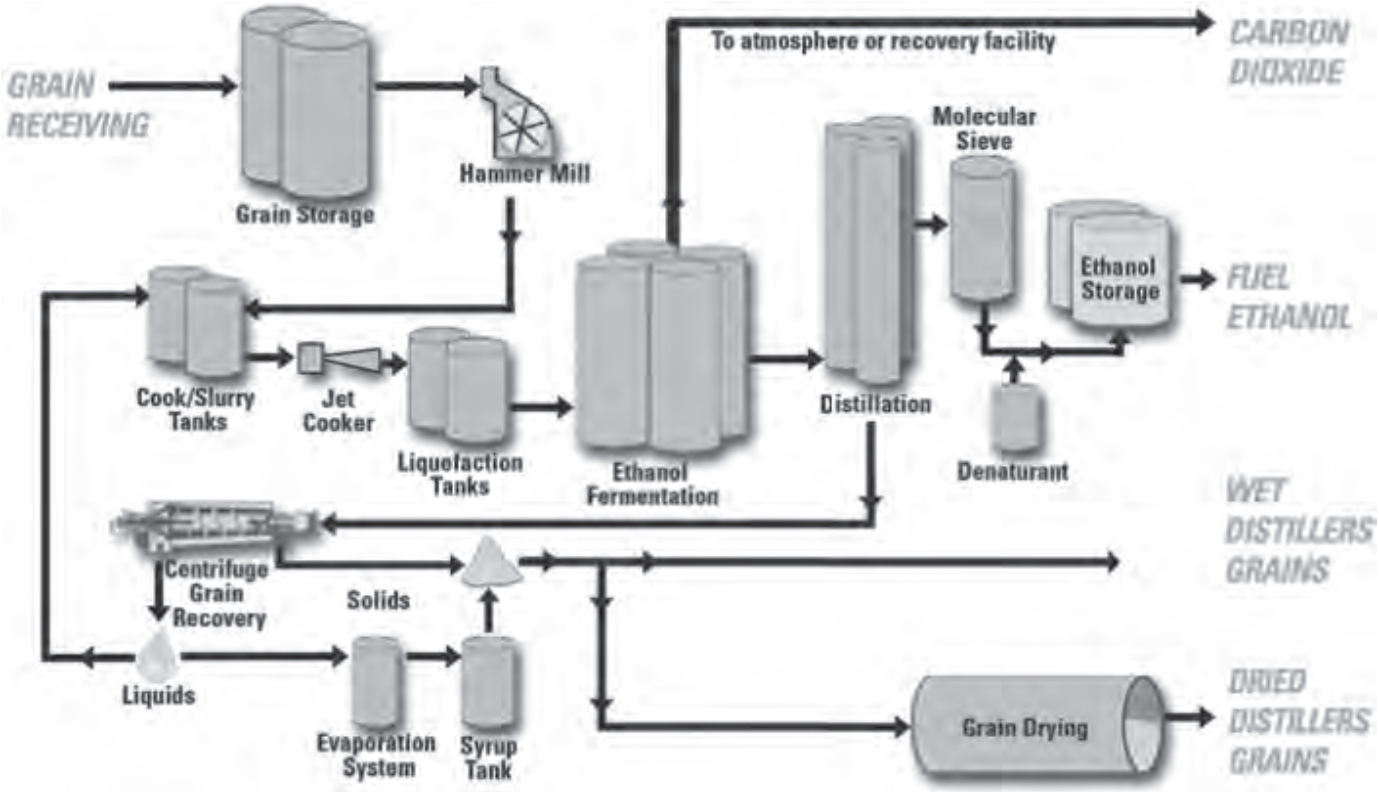
ii. Cellulosic Ethanol

There are two main processes to produce cellulosic ethanol: biochemical conversion (BC – enzymatic hydrolysis and fermentation) and thermochemical conversion (TC – gasification and catalytic synthesis, pyrolysis and catalytic synthesis, or a hybrid of the two). Generally, thermochemical conversion requires little water but more energy input. Biochemical conversion requires water to break down the cellulosic feedstock into sugars. Thus, BC consumes 78 to 130 gallons of water per MMBTU, while TC consumes 25 to 30 gallons per MMBTU (Wu et al., 2009). Most cellulosic ethanol plants are in development stage and industry data on these technologies are not readily available. However, optimization to reduce freshwater and energy use are priorities in development efforts. If these breakthroughs occur, the water use averages would be on the lower ends of the previous ranges. The water intensity of the production of ethanol from non-irrigated switchgrass is therefore comparable to that of ethanol from non-irrigated corn.

2.2 Biodiesel

Biodiesel is produced from vegetable oils, soybean in most cases. The main process used is transesterification. Much less attention is paid to biodiesel than bioethanol, as shown by the limited literature on the subject. A study of biodiesel was left out of the 2009 U.S DOE report (Wu et al., 2009). Earlier reports show that water use during processing is only 4.2 gallons per MMBTU produced (U.S. DOE, 2006). This can be explained by the fact that this process does not require biological digestion or water extraction, leading to less energy requirements and producing much less processed water. Over a decade, many improvements were made on the processes in the conversion facilities. In particular, the energy input in soybean agriculture was reduced by 52 percent, in soybean crushing by 58 percent and in transesterification by 33 percent per unit volume of biodiesel produced (Pradhan et al., 2011). Overall energy use was reduced by 42 percent, which is comparable to improvements made in the bioethanol industry.

Figure 39. Diagram of Conversion Process for a Typical Corn-Based Ethanol Biorefinery



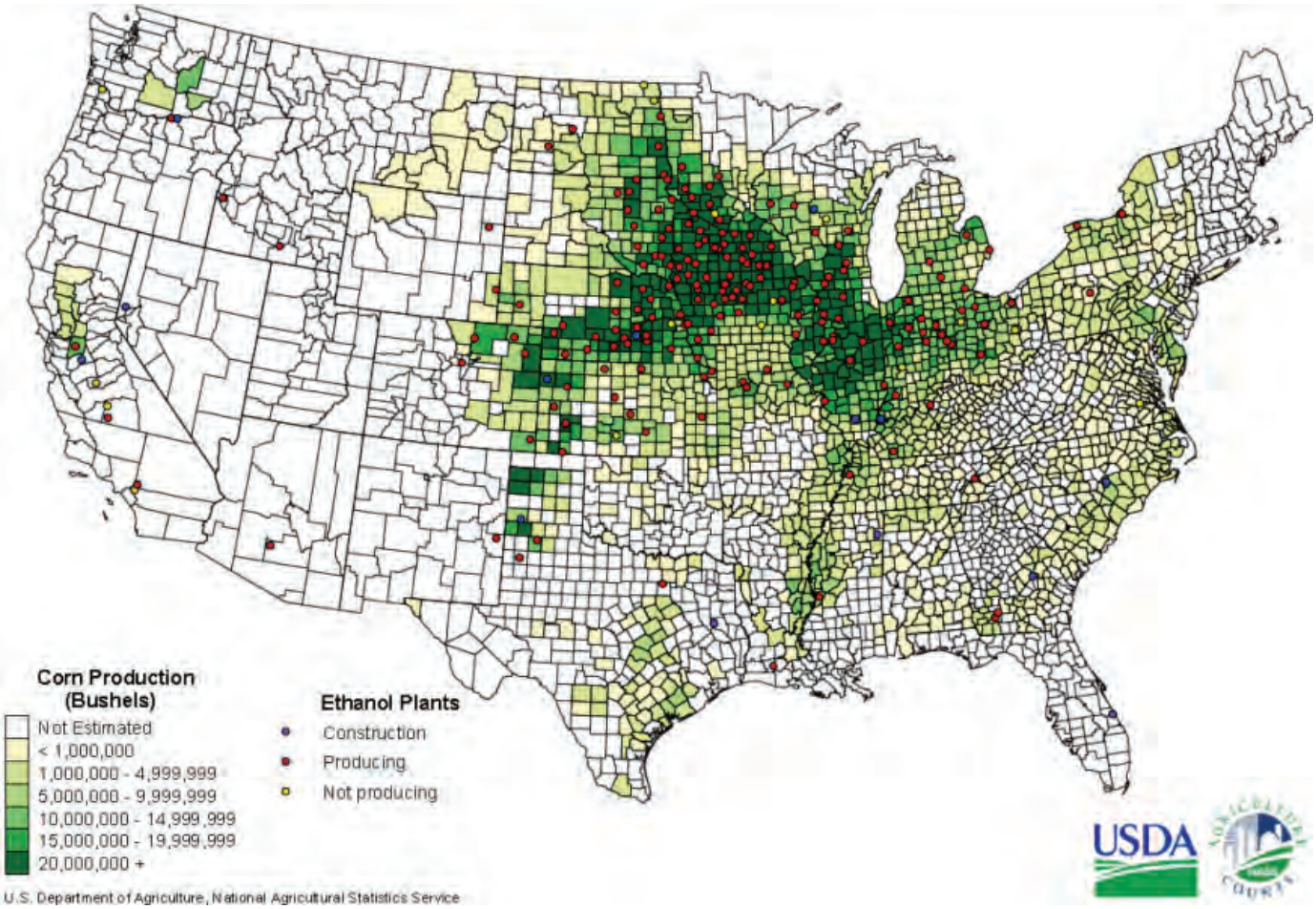
Source: U.S. GAO, 2008

3. Transportation

Ninety-five percent of the corn produced for ethanol is in the Corn Belt – USDA zones 5, 6 and 7 – and refineries usually use local corn (Figure 40). Shapouri & Gallagher (2005) estimate that most ethanol refineries get their corn from within a 40-mile radius. However, trucks do most of this transport, which adds to the carbon and energy footprint of the bioethanol industry. Once produced, the ethanol is shipped to distribution centers or to individual gasoline retail stations, where the ethanol is blended into gasoline (E-10 and E-85 blends or E-15 for retailers with EPA waivers).

Due to the fact that ethanol is mainly produced in the Midwest, transportation costs by trains, trucks or barges are high to get ethanol to the coasts for consumption (Alvarez et al., 2010). Refined product pipelines are used to transport gasoline relatively cheaply from refineries to distribution centers for transport. Unfortunately, due to fuel quality (ethanol is corrosive) and pipeline integrity concerns, as well as economic barriers, ethanol is unfit for these conventional refined goods pipelines. Ethanol also tends to mix with water. Ethanol-specific pipelines are under investigation (RFA, 2012; CRS, 2012).

Figure 40. Biorefinery Locations in the U.S.



Source: USDA website, 2012

Ethanol and biodiesels are biodegradable and have a very short half-life in the environment, particularly when compared to gasoline components such as benzene and toluene. Ethanol has replaced MTBE, which is thought to be potentially carcinogenic at high levels, according to the EPA. Low to high levels of MTBE (less than 20 ppb to 610 ppb) have been detected in ground and surface waters due to leaking underground storage tanks – in a severe case, contamination led the city of Santa Monica, Calif., to shut down pumping from its aquifers and buy replacement water (EPA, 2013). According to the literature, the preferential degradation of ethanol will cause gasoline plumes to spread farther than when MTBE was used as an additive (Patzek et al., 2005; U.S. GAO, 2009; Alvarez et al., 2010).

4. Life-Cycle Analyses and Water Balance

Much more attention has been paid to life-cycle analyses (LCA) of different biofuels rather than their water intensity and their local impact on water resources. There are numerous conflicting reports on the net positive or negative energy benefit of biofuels and particularly of corn ethanol (Farrel et al., 2006; Hammerschlag, 2006). One of the major causes of the discrepancies in energy LCA reports is the difference in the way the energy is allocated among the coproducts (Farrel et al., 2006; Pradhan et al., 2011). Recent literature seems to agree that ethanol has shifted from an energy sink in the early

1990s to a net energy producer as well as a net greenhouse gas (GHG) sink, although at a cost to the environment and to water resources. The latest estimates by the USDA on the energy balance of corn ethanol, using recent industry data, are that for each unit of energy invested, 1.9 to 2.3 units of ethanol are produced; this is an energy intensity of 53 percent to 43 percent respectively (Shapouri et al., 2010). Cellulosic ethanol energy returns on investment are somewhat higher, reported to range from 4.5 to 10, or an energy intensity of 22 percent to 10 percent respectively (Farrel et al., 2006; Mulder et al., 2010). Biodiesel is reported to have an energy return of 2.3 to 5.5, or an energy intensity of 43 percent to 18 percent (Mulder et al., 2010; Pradhan et al., 2011).

In 2011, 13.9 billion gallons of ethanol were produced, mainly using corn as a feedstock. According to previous sections, this corresponds to an average of 3.5 billion gallons of freshwater a day (BGD), although irrigation does not occur year round. According to the USGS report of water use in 2005 (Kenny et al., 2009), irrigation used 130 BGD; therefore approximately 3 percent of all irrigation in the U.S. goes to the production of corn as feedstock for the bioethanol industry. Another 0.2 BGD goes to processing corn in biorefineries. If the Renewable Fuel Standard (RFS) were only met by corn ethanol, this would more than double this amount, requiring 9 BGD for feedstock production and 0.5 BGD for ethanol fermentation. If the current RFS remains unchanged, and corn ethanol production does not continue to rise while the rest of the mandated 36 billion gallons comes from cellulosic using rain-fed perennial plants, feedstock production would probably require the same level of water, while about 0.5 BGD would be needed in refineries.

Concerning biodiesels, approximately half of the production comes from soybeans, a water-intensive crop. According to the USDA, nearly 100 million bushels of soybeans are used yearly for biodiesels. Approximately 1.5 BGD are thus used to produce 1 percent of diesel consumption in the U.S., using the reported water intensity of growing soybeans (Wu et al., 2009; Mielke et al., 2010). This represents 1.1 percent of all irrigation in the U.S. If production of soy biodiesel reached the 1.5 billion-gallon limit estimated by the NRC (2010), this would require 24 BGD, or 18 percent, of 2005 irrigation in the U.S.

5. Conclusion

As a whole, there is an important need to assess the water impact of biofuels at a local level, similar to the studies done by Chiu et al. (2011) and Fingerman et al. (2010), on Minnesota and California, respectively. Often, the impacts of this rapidly changing and maturing industry are unknown. This calls for the implementation of a water accounting system, to better track the embedded water of biofuels in different feedstock. Fingerman et al. (2010) report that increased corn production for ethanol in California would actually reduce overall freshwater withdrawals, replacing more water-intensive crops such as rice and alfalfa. However, irrigated California corn would still have a higher water intensity than rain-fed corn grown in Minnesota. Research should be conducted to incorporate water consumption into regulatory frameworks instead of simply GHG emissions and energy intensity.

The literature shows that many different metrics are used to describe the water or energy intensity of biofuels: L water/L ethanol, gal water/MMBTU ethanol, L of water/MJ ethanol, MJ of invested energy/MJ of ethanol, gal water/mile traveled, etc. A harmonization of these metrics would benefit the industry and researchers alike. Published official data through the EIA could achieve this. The EIA also needs to do much more on the topic of biofuels. Although data is available, it is often outdated and misleading. The addition of an Annual Biofuel Report may be useful.

The corn ethanol industry has largely exceeded expectations. This underlines the need for government agencies like the USDA, GAO, CRS and U.S. DOE to continue to publish reports on the industry and updating previous reports. The water intensity of irrigated feedstock for biofuels shows

that work needs to be done to change agricultural practices to increase water efficiency, such as through precision farming.

The estimations made in the previous section demonstrate the need for federal quantitative data on the water consumption required for the production of biofuels in the U.S. A quantitative forecast of the national impact of the RFS should be conducted under several different scenarios.