

Development of a Life Cycle Inventory of Water Consumption Associated with the Production of Transportation Fuels

Energy Systems Division

About Argonne National Laboratory

Argonne is a U.S. Department of Energy laboratory managed by UChicago Argonne, LLC under contract DE-AC02-06CH11357. The Laboratory's main facility is outside Chicago, at 9700 South Cass Avenue, Argonne, Illinois 60439. For information about Argonne and its pioneering science and technology programs, see www.anl.gov.

DOCUMENT AVAILABILITY

Online Access: U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via DOE's SciTech Connect (<http://www.osti.gov/scitech/>).

Reports not in digital format may be purchased by the public from the National Technical Information Service (NTIS):

U.S. Department of Commerce
National Technical Information Service
5301 Shawnee Road
Alexandria, VA 22312
www.ntis.gov
Phone: (800) 553-NTIS (6847) or (703) 605-6000
Fax: (703) 605-6900
Email: **orders@ntis.gov**

Reports not in digital format are available to DOE and DOE contractors from the Office of Scientific and Technical Information (OSTI):

U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831-0062
www.osti.gov
Phone: (865) 576-8401
Fax: (865) 576-5728
Email: **reports@osti.gov**

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor UChicago Argonne, LLC, nor any of their employees or officers, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of document authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Development of a Life Cycle Inventory of Water Consumption Associated with the Production of Transportation Fuels

by

David Lampert, Hao Cai, Zhichao Wang, May Wu, Jeongwoo Han,
Jennifer Dunn, John Sullivan, Amgad Elgowainy, and Michael Wang
Energy Systems Division, Argonne National Laboratory

Jennifer Keisman

American Association for the Advancement of Science (AAAS),
Science & Technology Policy Fellow,
United States Department of Energy, Washington, DC

October 2015

TABLE OF CONTENTS

ACKNOWLEDGEMENTS.....	vii
LIST OF ABBREVIATIONS.....	ix
ABSTRACT.....	xi
1. INTRODUCTION.....	1
2. METHODOLOGY	1
2.1 Goal and Scope	2
2.2 Definition of Water Consumption	3
2.3 Standard Assumptions	4
2.4 System Boundaries.....	5
3. PETROLEUM FUEL PRODUCTION	6
3.1 Crude Oil Recovery	7
3.2 Oil Sands Recovery.....	8
3.3 Petroleum Refining.....	9
4. NATURAL GAS PRODUCTION	10
4.1 Conventional and Shale Gas Recovery and Processing.....	11
4.2 Biogas Upgrading	12
5. COAL MINING	14
6. URANIUM MINING AND ENRICHMENT	18
7. ELECTRICITY GENERATION.....	20
7.1 Thermoelectric Power Plants	21
7.2 Hydroelectric Power Plants.....	23
7.3 Geothermal Power Plants.....	24
7.4 Wind Power Plants.....	26
7.5 Solar Power Plants	26
8. HYDROGEN AND SYNTHETIC FUEL PRODUCTION	29
8.1 Steam Methane Reforming Process	29
8.2 Gasification Production Processes.....	29
8.3 Electrolysis Production Process.....	30
8.4 Process Water Pretreatment Technologies.....	30
8.5 Delivery and Scale Considerations	30
8.6 Production Processes for H ₂ in GREET.....	31
8.7 Water Consumption Estimates for SMR and Electrolysis.....	31
8.8 Water Consumption Estimates for Coal and Petroleum Coke Gasification	32
8.9 Water Consumption Estimates for Biomass Gasification.....	33
8.10 Summary	35

TABLE OF CONTENTS (CONT.)

9. AGRICULTURAL CHEMICALS	36
9.1 Ammonia.....	36
9.2 Urea.....	36
9.3 Nitric Acid	37
9.4 Ammonium Nitrate	37
9.5 Urea-Ammonium Nitrate	38
9.6 Sulfuric Acid.....	38
9.7 Phosphoric Rock	38
9.8 Phosphoric Acid.....	38
9.9 Potassium	39
9.10 Limestone.....	39
9.11 Lime	39
9.12 Ammonium Phosphates	39
9.13 Pesticides.....	40
9.14 Cooling and Process Water Assumptions	40
9.15 Agricultural Chemicals Summary.....	41
10. OTHER CHEMICALS	42
10.1 Sodium Chloride	42
10.2 Potassium Chloride	43
10.3 Sodium and Potassium Hydroxide.....	43
10.4 Sodium Nitrate	44
10.5 Potassium Sulfate.....	45
10.6 Ammonium Chloride	45
10.7 Other inorganic salts	45
10.8 Summary	45
11. BIOFUEL PRODUCTION.....	46
11.1 Corn Farming.....	47
11.2 Soybean Farming	49
11.3 Corn Grain Ethanol Produced by Dry-Mill Fermentation	50
11.4 Corn Grain Ethanol Produced by Wet Mill Fermentation	51
11.5 Corn Stover Ethanol Produced by Fermentation	52
11.6 Corn Stover Ethanol Produced by Gasification	53
11.7 Soybean Biodiesel Production	54
12. SUMMARY, RECOMMENDATIONS, AND FUTURE ANALYSIS	55
13. REFERENCES	58

LIST OF FIGURES

1	Generic water consumption for a process.....	3
2	Natural and anthropogenic water inputs and outputs for an agricultural operation.....	4
3	Pretreated process water flows.	5
4	System boundaries for primary transportation fuel pathways.	6
5	Input-output relationships between petroleum products in GREET.....	7
6	Input-output relationships for natural gas production in GREET.....	11
7	Capacity and number of biogas upgrading plants by different technology in the world and the U.S.....	13
8	Input-output relationships for coal production in GREET.	14
9	Input-output relationships for uranium production in GREET.....	18
10	Input-output relationships for electricity generation in GREET.	20
11	Thermoelectric Power Plant Water Consumption.	22
12	Input-output relationships for hydrogen production in GREET.....	31
13	Water consumption per unit fuel produced in gasification processes.	35
14	Input-output relationships for agricultural chemicals in GREET.....	37
15	Input-output relationships for biofuel production in GREET.....	47
16	Water system in a typical dry-mill ethanol plant.	51
17	Process flow diagram for wet milling.....	52
18	Process flow diagram for cellulosic ethanol fermentation.....	53
19	Process flow diagram for cellulosic ethanol gasification.	54
20	Process flow diagram for biodiesel production.	54

LIST OF TABLES

1	Fuel Pathways Classification	2
2	PADD Water Consumption Estimates and Production Shares.....	8
3	Oil Sands Recovery Water Consumption Estimates and 2005 Production Shares.....	9
4	Properties of Petroleum Refinery Products.....	9
5	Summary of Estimated Petroleum Recovery and Refining WCFs.....	10

LIST OF TABLES (CONT.)

6	Water Consumption for Natural Gas Recovery	11
7	Summary of Estimated Natural Gas Recovery and Processing WCFs	12
8	2011 United States Coal Production	15
9	Coal Energy Content.....	15
10	Regional Coal Energy Contents Used to Estimate Water Consumption	16
11	Coal Surface Mining WCFs by Region	17
12	Coal Underground Mining WCFs by Region	17
13	Water Consumption in U-235 Production Processes.....	19
14	Summary of Estimated Uranium Fuel Cycle WCFs.....	19
15	2013 U.S. Electricity Generation	20
16	Cooling Technology Shares for Thermoelectric Power Plants.....	22
17	Water Consumption Factors Associated with Different Cooling Technologies in Thermoelectric Power Plants	23
18	Geothermal Power Plant Water Consumption Estimates	25
19	Wet-Cooled Geothermal Water Consumption in gal/kWh.....	26
20	Solar Power Plant Water Consumption Factor Estimates.....	28
21	Summary of Estimated Electricity Generation WCFs	28
22	Water Consumption Estimates for Hydrogen Generation	32
23	Coal Gasification Process Estimates.....	33
24	Biomass Gasification Material Flows	34
25	Summary of Estimated Hydrogen and Synthetic Fuel WCFs	35
26	Direct Water Consumption Estimates for Agricultural Chemicals.....	41
27	Summary of Estimated Agricultural Chemical Process WCFs	42
28	Sodium and Potassium Hydroxide Production Statistics.....	44
29	Summary of Estimated Chemical Production WCFs.....	46
30	State-Level Corn Farming and Irrigation Statistics	48
31	State-Level Soybean Farming and Irrigation Statistics	49
32	Summary of Estimated Biofuel Process WCFs	55

ACKNOWLEDGEMENTS

This research effort by Argonne National Laboratory was supported by the Bioenergy Technologies Office, Fuel Cell Technologies Office, and the Vehicle Technologies Office of the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy under Contract Number DE-AC02-06CH11357.

The authors wish to thank Dr. Shelie Miller of the School of Natural Resources & Environment at the University of Michigan at Ann Arbor and Dr. Ashlynn Stillwell of the Department of Civil and Environmental Engineering at the University of Illinois at Urbana-Champaign for review comments.

LIST OF ABBREVIATIONS

BEV	battery electric vehicle
Btu	British thermal unit
CCS	carbon capture and storage
CNG	compressed natural gas
CNGV	compressed natural gas vehicle
CSP	concentrated solar panel
dilbil	diluted bitumen
DU	depleted uranium (isotope 238)
E10	gasoline blended with 10% ethanol by volume
E85	gasoline blended with 85% ethanol by volume
EFMA	European Fertilizer Manufacturers' Association
EGS	enhanced geothermal system
EIA	Energy Information Administration
EOR	enhanced oil recovery
FCEV	fuel cell electric vehicle
gal	gallons
GETEM	Geothermal Electricity Technology Evaluation Model
GHG	greenhouse gas
gpm	gallons per minute
REET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
GWh	Gigawatt-hours
H ₂	hydrogen gas
ICE	internal combustion engine
ICEV	internal combustion engine vehicle
IGCC	integrated gasification combined cycle
kWh	kilowatt-hour
LCA	life-cycle assessment
LHV	lower heating value
LPG	liquefied petroleum gas
mgd	millions of gallons per day
mmBtu	million British thermal units

LIST OF ABBREVIATIONS (CONT.)

NASS	National Agricultural Statistics Service
NGCC	natural gas combined cycle
NREL	National Renewable Energy Laboratory
PADD	Petroleum Administration for Defense District
PSA	pressure swing adsorption
PV	photovoltaic
PWTO	produced-water-to-oil ratio
RFO	residual fuel oil
SCO	synthetic crude oil
SMR	steam methane reforming
TJ	terajoules
U-235	enriched uranium fuel (isotope 235)
UAN	Urea and ammonium nitrate
U.S.	United States of America
USGS	United States Geological Survey
WCF	water consumption factor

Development of a Life Cycle Inventory of Water Consumption Associated with the Production of Transportation Fuels

David Lampert¹, Hao Cai¹, Zhichao Wang¹, Jennifer Keisman², May Wu¹, Jeongwoo Han¹, Jennifer Dunn¹, John Sullivan¹, Amgad Elgowainy¹, and Michael Wang¹

¹ Energy Systems Division, Argonne National Laboratory, 9700 South Cass Avenue, Lemont, IL 60439

² Association for the Advancement of Science (AAAS) Science & Technology Policy Fellow, United States Department of Energy, Washington, DC

ABSTRACT

The production of all forms of energy consumes water. To meet increased energy demands, it is essential to quantify the amount of water consumed in the production of different forms of energy. By analyzing the water consumed in different technologies, it is possible to identify areas for improvement in water conservation and reduce water stress in energy-producing regions.

The transportation sector is a major consumer of energy in the United States. Because of the relationships between water and energy, the sustainability of transportation is tied to management of water resources. Assessment of water consumption throughout the life cycle of a fuel is necessary to understand its water resource implications. To perform a comparative life cycle assessment of transportation fuels, it is necessary first to develop an inventory of the water consumed in each process in each production supply chain.

The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model is an analytical tool that can be used to estimate the full life-cycle environmental impacts of various transportation fuel pathways from wells to wheels. GREET is currently being expanded to include water consumption as a sustainability metric. The purpose of this report was to document data sources and methodologies to estimate water consumption factors (WCF) for the various transportation fuel pathways in GREET. WCFs reflect the quantity of freshwater directly consumed per unit production for various production processes in GREET. These factors do not include consumption of precipitation or low-quality water (e.g., seawater) and reflect only water that is consumed (i.e., not returned to the source from which it was withdrawn). The data in the report can be combined with GREET to compare the life cycle water consumption for different transportation fuels.

1. INTRODUCTION

Energy and water are two of the most fundamental components of the global economy. A complex relationship exists between the production and consumption of energy and water; energy production consumes water, while treatment and distribution of water consume energy. Energy and water are needed to produce many other economic resources and thus it is essential to develop sustainable management practices for producing these vital resources.

The transportation sector consumed approximately 28% of the 95.02 quadrillion Btu of total primary energy in the United States in 2012, and worldwide transportation energy consumption is expected to increase from 96.2 quadrillion Btu in 2010 to 142.1 quadrillion Btu in 2040 (Energy Information Administration, 2014a). Meeting this growing demand in a sustainable manner requires careful attention to the impacts of various transportation fuel alternatives on water resources.

Each production process for transportation fuels has a different impact on water resources. Because water is consumed throughout the production supply chain, water consumption must be assessed throughout the full fuel cycle to compare the water resource implications of different fuels. The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model, developed by Argonne National Laboratory, is an analytical tool that is used to perform life-cycle analysis (LCA) of transportation fuels (Wang, 1999). GREET provides a consistent platform for analyzing the impacts of transportation fuel production on different environmental resources. Currently the GREET model includes energy resource consumption, greenhouse gas (GHG) emissions, and emissions of air pollutants. The purpose of this document is to describe data sources for water consumption factors (WCFs) for the various production processes included in the transportation fuel pathways in GREET.

2. METHODOLOGY

GREET simulates over 100 transportation fuel *pathways* from well to wheels. Each pathway is composed of a series of *processes*. In GREET, processes represent methods to change the composition of energy and materials from one form (inputs) to another (outputs). For the sake of WCF development, the fuel production pathways in GREET were categorized into three groups—conventional fuel pathways, alternative fuel pathways, and emerging fuel pathways. The conventional pathways are those that produce fuels that currently comprise the majority of the U.S. transportation energy sector. These pathways include diesel derived from a mixture of petroleum and soybeans and gasoline derived from petroleum blended with 10% ethanol from corn (E10). Alternative fuel pathways include fuels used as energy sources, transportation, or process fuels in other pathways that can also be used for transportation. The alternative fuel pathways analyzed in this study include natural gas, electricity, and hydrogen gas pathways. These fuels are used in the production pathways of other fuels for recovery, transportation, distribution, processing and upgrading of other fuels and feedstocks. The primary and alternative fuel pathways collectively are needed to analyze all the other pathways in GREET. Emerging

pathways are those lacking large production volume due to infrastructure, economic viability, or other market considerations. Examples of emerging pathways are renewable gasoline and diesel production from biofeedstock sources, cellulosic ethanol, algal fuels, and coal or biomass gasification for the production of hydrogen or other synthetic hydrocarbon fuels. The focus of this report is to document and analyze water consumption data for the primary GREET fuel production pathways. Table 1 shows the division of the GREET pathways in this study.

Table 1. Fuel Pathways Classification

Conventional Fuel Pathways (analyzed)
Petroleum/corn ethanol blended gasoline (E10/E85)
Soy/conventional blended diesel
Alternative Fuel Pathways (analyzed)
Conventional natural gas
Coal-powered electricity
Natural gas-powered electricity
Petroleum-powered electricity
Nuclear-powered electricity
Hydro-powered electricity
Geothermal-powered electricity
Wind-powered electricity
Solar-powered electricity
Hydrogen from steam methane reforming
Hydrogen from coal gasification
Hydrogen from biomass gasification
Hydrogen from electrolysis
Emerging Fuel Pathways (for future analysis)
Biomass-based renewable gasoline and diesel
Cellulosic ethanol
Algal biofuels
Synthetic hydrocarbons

2.1 Goal and Scope

The goal and scope of the analysis described herein was to develop a baseline inventory of WCFs for the conventional and alternative fuel production pathways in the United States. WCFs were developed for each step in the supply chain for production of fuels for internal combustion engine vehicles (ICEVs) utilizing E10 or 85% ethanol by volume (E85), compressed natural gas vehicles (CNGV), battery electric vehicles from different feedstocks (BEVs), and hydrogen fuel cell electric vehicles (FCEVs). This baseline-level analysis provides the foundation for evaluating water consumption in emerging fuel production pathways in future studies.

2.2 Definition of Water Consumption

The definition of water consumption has a substantial impact on any life-cycle estimate of the quantity of water consumed in the production of a fuel or resource. The amount of water withdrawn may be quite different from the amount of water consumed in a production process. For example, only about 2% of the water withdrawn for thermoelectric power plants is consumed (Diehl et al., 2013), while the balance (98%) is returned to the source. The water that is withdrawn and not returned may be evaporated, incorporated into the products, or degraded to an insufficient quality for future use. Characterization of withdrawals is important at the local level, since sufficient water must be available for facility operation. GREET is based on United States national average values, however, and total nationwide withdrawal volumes were determined to be less important than consumption and were not characterized. Figure 1 shows a generic schematic for the definition of water consumption for processes used in this analysis.

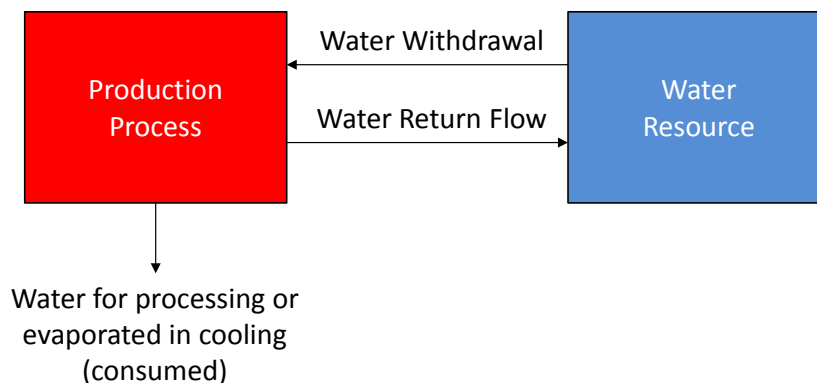


Figure 1. Generic water consumption for a process.

In agricultural operations, much of the water required is supplied by precipitation. In the absence of agricultural operations on a land segment, a large fraction of the water that reaches that land segment as precipitation is consumed by indigenous vegetation through the combination of evaporation on the land and transpiration from plant leaves that are collectively known as *evapotranspiration*. Irrigation water is often needed to improve agricultural yields or make the crop production process feasible in a given locale. Some of the irrigation water supplied to an agricultural operation returns to surface and groundwater bodies, but the remainder that is consumed represents the primary anthropogenic impact of the agricultural operation on the hydrological cycle. Land use changes associated with different forms of agriculture may alter the quantity of water consumed, but this effect is difficult to quantify explicitly and was ignored. Figure 2 shows a schematic of the water flows used in an agricultural production process.

Since the goal of this study was to quantify the impacts of production of transportation fuels on freshwater resources, *water consumption* was defined as the quantity of water taken from a freshwater resource and not returned to a resource at a similar level of quality. Thus, the evapotranspiration of water supplied by precipitation and the return flows of water withdrawn in cooling towers were not counted as consumption.

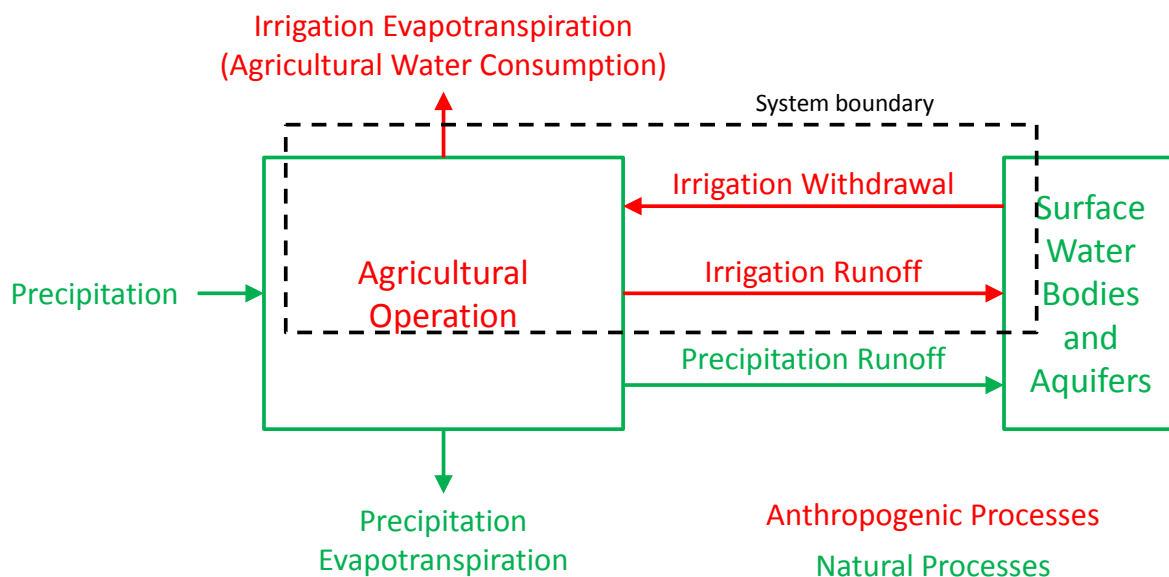


Figure 2. Natural and anthropogenic water inputs and outputs for an agricultural operation.

2.3 Standard Assumptions

To ensure a consistent accounting, a few standard assumptions were made when process-level water consumption data were unavailable. For chemical production processes, water is often used for cooling. To ascertain whether reported water usage constituted withdrawal or consumption, energy balances were performed comparing chemical energy released to latent heat of water. Cooling water consumption was assumed to be 5% of the cooling water withdrawals when water usage was reported as a withdrawal. This assumption is consistent with the fraction of water consumed in one pass through a typical cooling tower (McCabe et al., 1993).

When technologies for cooling or production were not specifically separated in the GREET database, technology-weighted averages of median values were used. When reported water consumption estimates included construction of infrastructure, these quantities were removed since infrastructure was outside the scope of this analysis. Water generated by combustion reactions was not credited as it is in the vapor form and not available as a resource for future use.

Some production processes require water of higher quality for operation (e.g., the generation of hydrogen), which necessitates a pretreatment of water. The pretreatment of water generates two streams—one of high quality (process water) and another of lower quality that is rejected. The rejected water is of lower quality than the influent water and thus is assumed to be consumed. If the rejection rate is high, the rejected water may still be of reasonable quality and the assumption that it is consumed represents a conservative estimate. Figure 3 illustrates the concept of water consumption in a water treatment process.

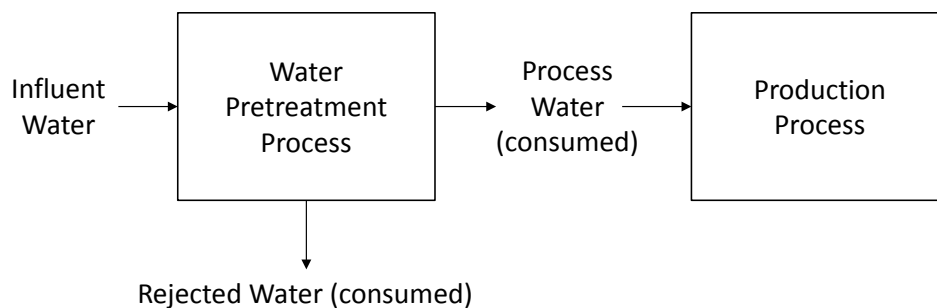


Figure 3. Pretreated process water flows.

2.4 System Boundaries

The existing implementation of GREET accounts for the environmental impact of the life cycle of conventional and alternative transportation fuels, including crude oil recovery, petroleum refining, conventional and shale natural gas recovery and subsequent processing, agricultural chemical mining and production, biomass production and conversion, uranium and coal mining, and electricity generation from fossil fuels, nuclear power, and renewable energy sources including wind, solar, geothermal and hydropower. Figure 4 shows a high-level overview of the production processes for the primary pathways in GREET. As discussed previously, the various production processes are heavily interdependent; electricity is consumed in the production of essentially all the other resources, while natural gas and petroleum products are heavily used in other steps in the supply chain for all the transportation fuels.

The water consumed in the processes in Figure 4 is broken down into more specific components in GREET. For each production process, the WCF was determined from an extensive literature survey. The GREET framework enables estimation of the indirect upstream water consumption associated with the production of each resource in the supply chain. The GREET framework includes resource consumption associated with intermediate transportation and, optionally, the construction of some of the infrastructure. WCFs associated with construction of infrastructure and other capital equipment were not included in this analysis. The following sections describe each of the pathways in Figure 4 and the literature sources used to estimate WCFs for the processes that constitute these pathways.

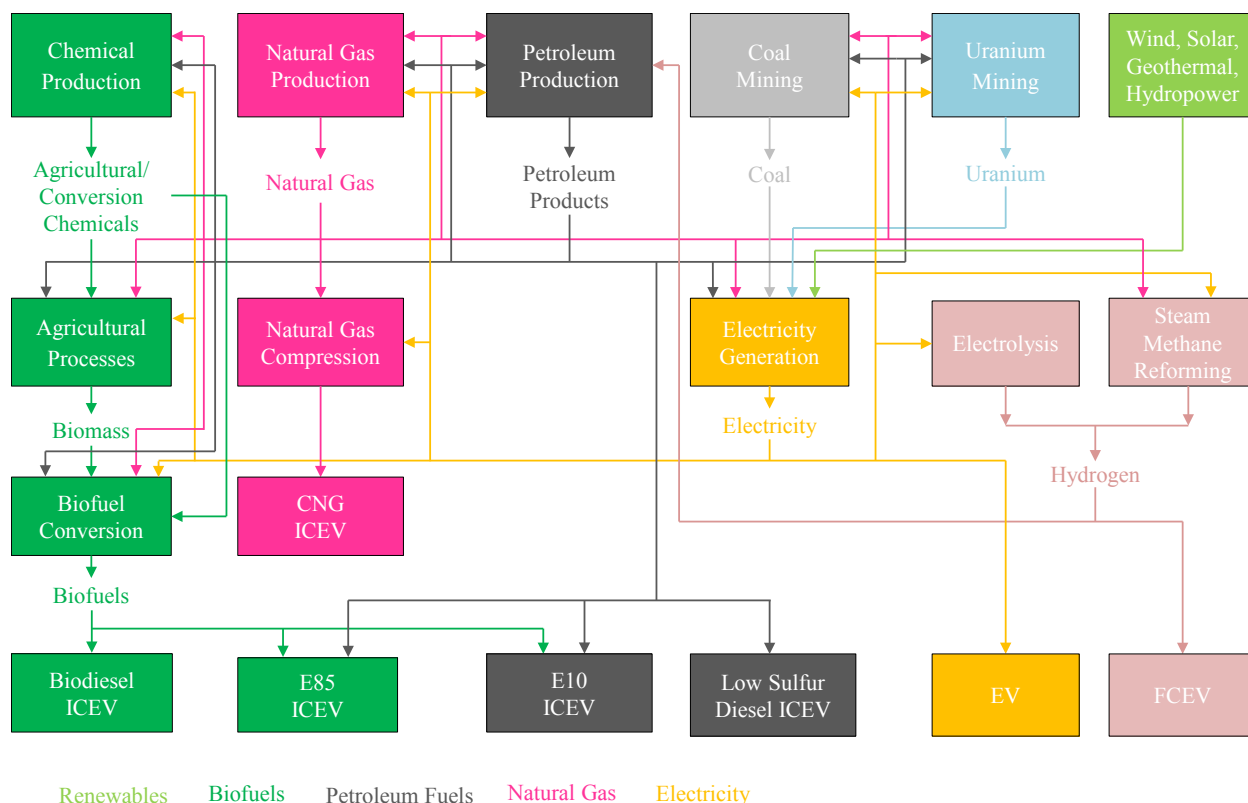


Figure 4. System boundaries for primary transportation fuel pathways.

3. PETROLEUM FUEL PRODUCTION

Petroleum production in GREET is divided into several stages including recovery of crude oil from conventional sources and oil sands followed by refining to liquefied petroleum gas (LPG), naphtha, residual oil, petroleum coke, jet fuel, and diesel. WCFs for each of the production processes were determined by surveying the available data in the literature. Figure 5 shows the production inputs and outputs for petroleum; each of the processes in the boxes in the figure represents a process with a direct water consumption component and associated WCF.

In the United States, petroleum is primarily derived from the production of crude oil from conventional, shale, and oil sand resources. Because of the differences between the sources of crude oil and differences in the ages of the wells, different technologies are used. In addition, the production of crude oil from different regions consumes different quantities of water. The recovery operations yield produced water in addition to the crude, which is often characterized by the produced-water-to-oil ratio (PWTO). Produced water represents a threat to the quality of existing water resources; however, water quality impacts were outside the scope of this analysis and not quantified. Produced water is often re-injected to enhance recovery from formations. Produced water injection alone may be insufficient to maintain reservoir pressure, however. The additional water must be supplied from an external water resource.

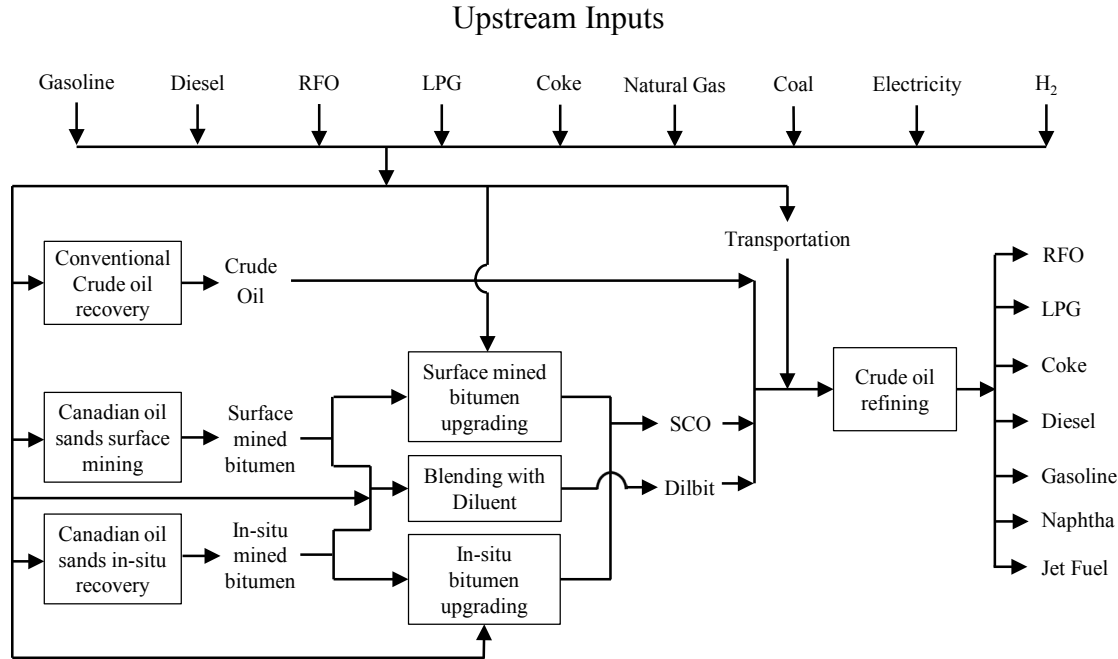


Figure 5. Input-output relationships between petroleum products in GREET.

3.1 Crude Oil Recovery

Approximately a third of U.S. oil production is offshore (Wu and Chiu, 2011). In these operations, ample water is available from the sea and thus the water consumption from offshore resources is negligible. Crude oil recovery operations change throughout the lifecycle of a well, and are often classified as primary, secondary, and tertiary. During the secondary period, water is injected to stimulate recovery from the well. Gleick (1994) utilized data from the late 60s to early 80s to estimate the water consumption for primary oil recovery and other tertiary enhanced oil recovery (EOR) methods, including injection of steam, micellar polymer, caustics, and combustion air. Bush and Helander (1968) performed an empirical estimation of the recovery rate and water flooding associated with crude oil production from depleted sands. Royce et al. (1984) estimated the water requirements for EOR methods, including injection with carbon dioxide (CO₂).

Veil et al. (2004) estimated the PWTO for crude oil in various states. A report sponsored by the American Petroleum Institute estimated the percentage of produced water used for re-injection (API, 2000). Wu and Chiu (2011) combined estimates of the water injection rates for secondary recovery (water flooding) from Bush and Helander (1968) with the fractional re-injection rates from API (2000) and the PWTOs from Veil (2004) to estimate the make-up water requirements for secondary recovery for each of the five Petroleum Administration for Defense Districts (PADDs I, II, III, IV, and V) in the United States. They then used water consumption estimates for primary oil recovery from Gleick (1994), CO₂ injection (a tertiary EOR method) from Royce et al. (1984), tertiary EOR methods from Gleick (1994), and the estimates water flooding with technology shares to compute technology-weighted average WCFs for each PADD. The results are shown in Table 2. The production shares for each PADD from

2013 (Energy Information Administration, 2014b) were used to estimate a nationwide average of 3.4 gal of water consumed per gal of conventional onshore crude oil produced. These values were converted to an energy basis using the estimated lower heating value (LHV) of crude oil from GREET (129,670 Btu/gal) and aggregated using a production-weighted average to arrive at an estimated WCF of 26.5 gal/mmBtu.

Table 2. PADD Water Consumption Estimates and Production Shares (data from Wu and Chiu, 2011)

PADD	Water Consumption (gal water per gal crude)	Shares of 2013 U.S. Domestic Crude Oil Production (%)
I	—	0.4
II	2.1	16.0
III	2.3	64.2
IV	—	12.7
V	5.4	13.3
Minimum	0	
Maximum	5.4	
Production-Weighted Average	3.4	

3.2 Oil Sands Recovery

Recovery from oil sands utilizes several different technologies. The product requires subsequent processing before it can be transported through pipelines to refineries. The recovery technologies are grouped into two categories in GREET, mining and in-situ production, which are followed by optional upgrading to synthetic crude oil (SCO) or the addition of diluents to produce diluted bitumen (dilbit). Wu and Chiu (2011) presented estimates of the water consumed and production shares for various in-situ and surface mining technologies in Table 15 of their report which is reproduced here in Table 3. Using technology-weighted averages from this source, the WCF for in-situ recovery was estimated to be 0.83 gal per gal of bitumen for in-situ recovery and 4 gal per gal bitumen for surface mining. According to Wu and Chiu (2011), the water consumed by the upgrading processes is approximately 1 gal per gal of SCO for in-situ production and negligible for surface mining because at the time the majority of surface-mined bitumen was diluted and transported before upgrading. Thus the upgrading estimate is in need of further investigation. Dilution of the bitumen requires solvents that consume embedded water indirectly, although the process does not consume any water directly. Estimated energy contents of 42.3 GJ/m³ for dilbit and 40.61 GJ/m³ for SCO were taken from the literature (S&T Consultants Inc., 2013) and used to convert the units of the water consumption estimates from a volume to an energy basis. The resulting values were 20.9 gal/mmBtu for surface mining recovery, zero for surface mining upgrading, 5.5 gal/mmBtu for in-situ recovery, and 6.9 for in-situ upgrading.

Table 3. Oil Sands Recovery Water Consumption Estimates and 2005 Production Shares (data from Wu and Chiu, 2011)

Location	Water Consumption (gal water per gal crude)	Production Share (%)
Athabasca – Mining	4.0	55.6
Athabasca – In-situ	0.3	22.0
Cold Lake – In-situ	1.2	21.2
Peace River – In-situ	4.0	1.2
Surface Mining	4.0	
In-situ Mining (Weighted Average)	0.83	

3.3 Petroleum Refining

Crude oil is refined into many products including gasoline, diesel fuel, residual fuel oil (RFO), liquefied petroleum gas (LPG), petroleum coke, naphtha, and jet fuel. Petroleum refineries utilize significant quantities of water both for cooling and for steam production in processes such as desalting, distillation, alkylation, cracking, and reforming. Several studies have quantified water consumption associated with petroleum refining (Buchan and Arena, 2006; Ellis et al., 2001; Gleick, 1994). Wu and Chiu (2011) summarized these results and found minimum and maximum values of 0.5 and 2.5 gal of water consumed per gal of crude oil processed.

(Elgowainy et al., 2014) analyzed the performance of 43 petroleum refineries comprising approximately 70% of the total U.S. capacity using a linear programming model. The model was used to allocate crude oil input energy amongst refinery products. Table 4 shows the values from this study and GREET estimates of the LHV for the various refinery products.

Table 4. Properties of Petroleum Refinery Products

Refinery Product	Allocation Factor ¹ (Btu crude oil per Btu product)	Lower Heating Value (Btu per gal)
Gasoline	0.863	116,090
California gasoline	0.750	112,194
Jet fuel	1.009	124,307
Liquefied petroleum gas	0.880	84,950
Residual oil	0.999	140,353
Diesel	1.001	128,450
Naphtha	0.989	116,920
Petroleum coke	1.026	140,353

¹ (Elgowainy et al., 2014)

The model estimated average make-up water consumption for cooling tower and other refining processing units of 0.994 gal water per gal of crude oil input, which falls in the range of values (0.5 – 2.5 gal water per gal crude oil) in Wu and Chiu's (2011) review. The allocation factors X_i from Table 4 were used with the total water per unit crude oil and the crude oil LHV (129,670 Btu per gal) to determine WCFs for the refinery products using Equation [1].

$$WCF = \frac{0.994 \text{ gal water}}{\text{gal crude oil}} * \frac{\text{gal crude oil}}{129,670 \text{ Btu crude oil}} * \frac{\text{Btu crude oil}}{X_i \text{ Btu product}} * \frac{10^6 \text{ Btu product}}{\text{mmBtu product}} \quad [1]$$

The resulting WCFs for refining crude oil into petroleum products and the WCFs for crude oil recovery processes are shown in Table 5.

Table 5. Summary of Estimated Petroleum Recovery and Refining WCFs

Process	WCF	Units
Conventional crude recovery	26.5	gal/mmBtu crude oil
Oil sands surface mining recovery	20.9	gal/mmBtu bitumen
Oil sands surface mining upgrading	0	gal/mmBtu SCO
Oil sands in-situ recovery	5.5	gal/mmBtu bitumen
Oil sands in-situ upgrading	6.9	gal/mmBtu SCO
Crude oil refining to gasoline	6.6	gal/mmBtu gasoline
Crude oil refining to California gasoline	5.8	gal/mmBtu gasoline
Crude oil refining to diesel	7.7	gal/mmBtu diesel
Crude oil refining to jet fuel	7.7	gal/mmBtu jet fuel
Crude oil refining to LPG	6.8	gal/mmBtu LPG
Crude oil refining to RFO	7.7	gal/mmBtu RFO
Crude oil refining to naphtha	7.6	gal/mmBtu naphtha
Crude oil refining to coke	7.9	gal/mmBtu coke

4. NATURAL GAS PRODUCTION

The production of natural gas requires water for both recovery and subsequent processing before it can be transported via pipelines. Natural gas that is consumed in the United States is derived from a combination of conventional gas wells or as a co-product from petroleum wells or coal beds. Recent technological advancements in horizontal drilling and hydraulic fracturing have enabled economically feasible extraction from shale and other tight gas formations. Each of these sources has a different direct and indirect water consumption component. Figure 6 shows the system boundary for the natural gas production pathway in GREET. WCFs for natural gas production were estimated for each of the processes represented by boxes in the figure.

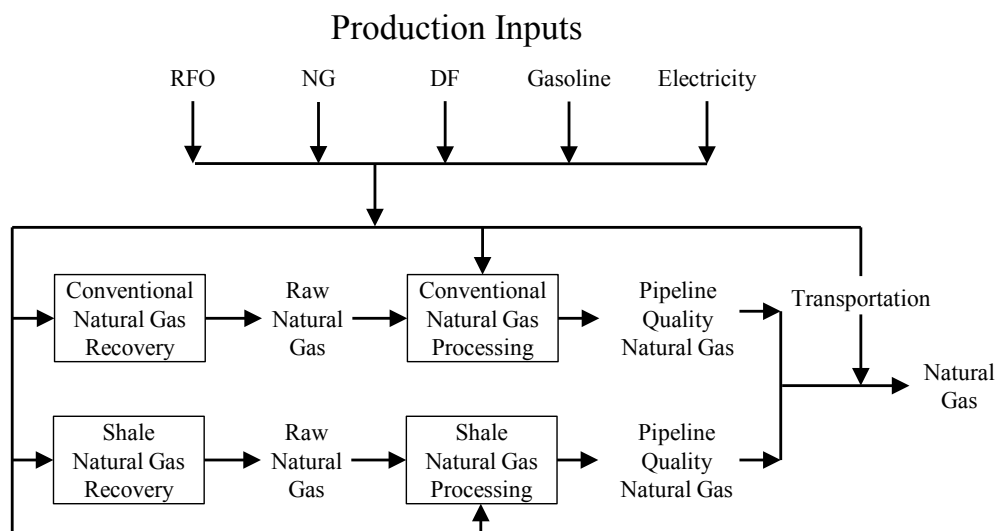


Figure 6. Input-output relationships for natural gas production in GREET.

4.1 Conventional and Shale Gas Recovery and Processing

A recent study analyzed the life-cycle water consumption of shale and conventional natural gas (Clark et al., 2013b). A summary of the data from this study is shown in Table 6. The data include contributions to overall water consumption from the typical range of operations associated with natural gas extraction (drilling, cementing, and fracturing). Hydraulic fracturing is essential for extraction from shale gas, but is not used for conventional natural gas. Hydraulic fracturing generally consumes substantially more water than well drilling and cementing for conventional gas recovery.

Table 6. Water Consumption for Natural Gas Recovery (data from Clark et al., 2013b)

Operation	Conventional (gal/mmBtu)		Barnett (gal/mmBtu)		Marcellus (gal/mmBtu)		Fayetteville (gal/mmBtu)		Haynesville (gal/mmBtu)	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
Drilling	0.065	0.142	0.083	0.18	0.034	0.13	0.067	0.102	0.046	0.084
Cement	0.006	0.013	0.009	0.02	0.005	0.018	0.007	0.011	0.006	0.011
Fracturing	—	—	1.3	6.4	1.94	3.35	2.22	7.96	1	4.26
Total	0.071	0.155	1.392	6.6	1.979	3.498	2.294	8.073	1.052	4.355

Glick (1994) estimated water consumption for processing and pipeline operations of 1.7 and 0.84 gal per mmBtu, respectively. The estimate for processing operations was assumed to be representative of all natural gas sources. The pipeline operation water estimates were likely based on indirect water consumption and were not included in this analysis. The ultimate

recovery-weighted average of the median values for the four different formations was used to estimate the WCF for shale gas production in the United States. For natural gas production outside North America, the water consumption is assumed to be the same as for conventional gas production in the United States. The estimated WCFs for the natural gas pathway appear in Table 7.

Table 7. Summary of Estimated Natural Gas Recovery and Processing WCFs

Process	WCF	Units
Conventional natural gas recovery	0.11	gal/mmBtu natural gas
Shale natural gas recovery	3.66	gal/mmBtu natural gas
Natural gas processing	1.7	gal/mmBtu natural gas
Biogas upgrading	9.3	gal/mmBtu natural gas

4.2 Biogas Upgrading

In addition to fossil carbon sources, natural gas is increasingly recovered from alternative sources such as landfills and wastewater treatment plants in the form of biogas. CH₄ content in raw biogas is typically 60–70% while the rest of raw biogas is largely CO₂ and other impurities such as H₂S and NH₃ (Persson et al., 2006). The raw biogas must be cleaned and purified before it can be transported, distributed, and consumed. A number of processes are commonly used for biogas upgrading including scrubbing, pressure swing adsorption (PSA), membrane separation and cryogenic separation.

Scrubbing is a common process used to remove impurities from raw biogas. Chemical scrubbers use amine solutions (e.g., monoethanolamine or dimethylethanolamine) as an absorbent and are one of the most common absorption processes in the natural gas industry. The raw gas is typically run counter-currently with an amine solution that absorbs CO₂, H₂S and other impurities. The purified gas is collected from the top of the absorber and the amine-gas mixture is collected at the bottom where it is sent to a regenerator for recycling. Water scrubbers preferentially absorb impurities based on their higher water solubility relative to methane. Organic physical scrubbers use an organic solvent (e.g., polyethylene glycol) as an absorbent. The primary advantage of the organic solvent is to reduce the size of upgrading plants since the solubility of CO₂ is higher in polyethylene glycol than in water.

In PSA, CO₂ is preferentially adsorbed on the surface of a material in a column under high pressure from raw biogas. PSA operates at relatively high pressures between 100 to 200 psi (Sperling Hansen Associates, 2007). When the adsorbent becomes saturated, the column is removed from service and the CO₂ is removed by equilibration under ambient conditions. PSA systems often use multiple vessels to maintain a constant feed flow and output gas product.

Membrane separation processes remove impurities from raw biogas by selective permeation. Membrane processes are amenable to a wide range of process stream volumes, CO₂

concentrations and product-gas specifications, and tend to be more environmentally friendly than amine processes. Since membrane separation operates at relatively high pressures, the compression requirements for production or injection into the gas grid are reduced.

Cryogenic separation processes preferentially remove impurities from biogas based on differences in their boiling points. Biogas enters the bottom of an absorber column and is cooled as it flows upward. The cryogenic separation occurs at the top of the absorber column as the gas temperature reaches the boiling point of CO₂ that is condensed out of the biogas. The condensed CO₂ flows back down the column, which absorbs other impurities. The CO₂ separated from biogas can be used to absorb other impurities, which is an advantage versus alternative technologies. The CO₂ concentration of the cleaned gas is still too high for pipeline transportation and consumption, however, and further treatment or post purification is required.

Figure 7 shows the capacity of biogas upgrading plants in the world and the U.S. (International Energy Agency Bioenergy, 2015). Water scrubbers are most common worldwide although they are not as common in the U.S. The average plant capacity in the U.S. is about 4 times the average plant capacity worldwide. Among the biogas upgrading processes, water scrubbers are the largest consumers of water. Tynell et al. (2007) surveyed fourteen water scrubbing plants in Sweden to investigate microbial growth on the pall-rings in the absorption column. Detailed process information including make-up water consumption was provided for nine plants, five with re-circulating water and four with single pass. For the five re-circulation plants, the make-up water consumption ranged from 4 to 192 gallons per mmBtu with an average of 59 gallons per mmBtu.

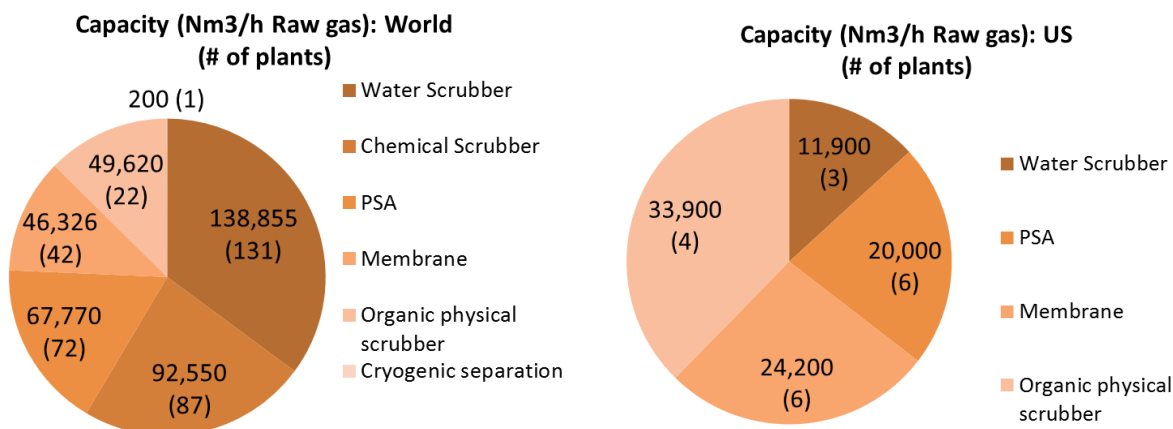


Figure 7. Capacity and number of biogas upgrading plants by different technology in the world and the U.S. (data from International Energy Agency Bioenergy, 2015)

Water consumption by the other biogas upgrading technologies is assumed to be small since no water-intensive process is used. Water consumption for the other processes was assumed to be similar to that of fossil natural gas processing (1.7 gals/mmBtu). For this analysis, the water consumption of water scrubbers in the U.S. was assumed to be consistent with that in

Europe. The technology shares and the WCFs for each technology were used to estimate a US average WCF of 9.3 gallons per mmBtu for biogas upgrading with a range of 2 to 27 gal per mmBtu.

5. COAL MINING

Coal is an important component in the production of electricity in the United States grid, and its production consumes water resources. Gleick (1994) reported that water consumption ranges from 3 to 20 m³ per TJ for underground coal mining and range from 2 m³ to 5 m³ per TJ for coal surface mining without/with surface re-vegetation, and that 4 m³ per TJ of water is consumed if the coal is beneficiated following extraction. Dust control is needed for protection of human health in coal mines; Mavis (2003) reported that 5.2 gallons of water were consumed per ton of coal produced for dust control in coal mining operations. Grubert et al. (2012) estimated that 16.1 gal of water are consumed per mmBtu of coal energy produced in Texas. In addition to differences in mining technologies and locations, the grade of coal is an important factor determining the water consumption associated with coal mining.

In addition to direct water consumption, coal mining processes consume water indirectly through production of the upstream energy inputs. Figure 8 shows the input-output relationships for various resources related to coal mining in GREET. The direct water consumption on a per-unit-energy basis was estimated for both surface and underground mining technologies and integrated into the GREET framework.

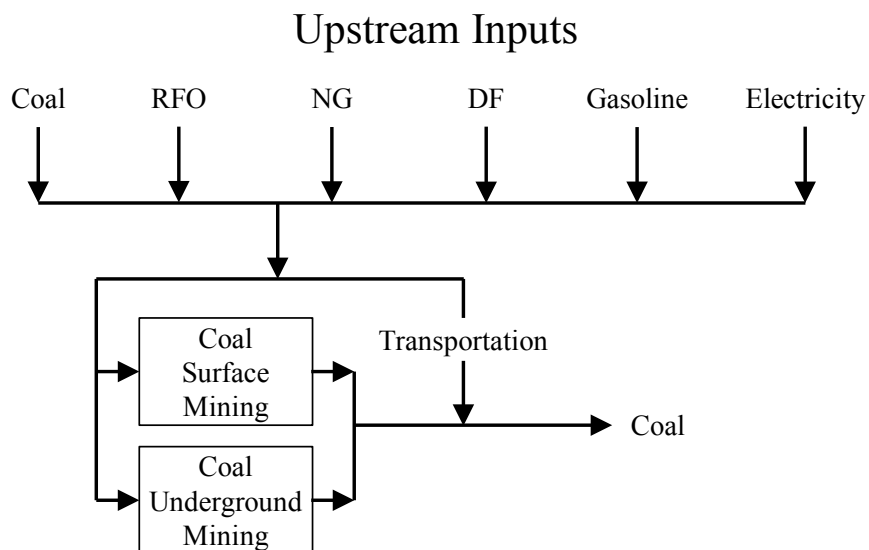


Figure 8. Input-output relationships for coal production in GREET.

The Energy Information Administration (EIA) provides estimates of coal production, including regional breakdown and divisions based on the mining technology (Energy Information Administration, 2012). Table 8 shows the top five states in coal production and the associated production levels for both surface and underground mining, and the associated numbers for the combined remaining states east and west of the Mississippi River.

Table 8. 2011 United States Coal Production (data from Energy Information Administration, 2012)

State/Region	Coal Production (tons)	Surface Mining Production (tons)	Underground Mining Production (tons)
Wyoming	438,673	435,630	3,043
West Virginia	134,662	51,267	83,395
Kentucky	108,766	43,518	65,248
Pennsylvania	59,182	11,865	47,317
Texas	45,904	45,904	0
Other states west of the Mississippi River	154,604	103,795	50,809
Other states east of the Mississippi River	152,186	56,393	95,793
U.S. Total	1,095,628	748,372	345,605

As coal minerals age, they undergo changes in chemical composition that produce different energy contents. The energy contents of different forms of coal based on guidance from the EIA (Energy Information Administration, 2014c) are shown in Table 9. The Powder River Basin in Wyoming and Montana is home to many of the largest coal mines in the United States. Given Wyoming's status as the most significant coal producer, the energy content of this state's coal is important for a nationwide production estimate of water consumption associated with coal. The North Antelope Rochelle Mine is owned by Peabody Energy, Inc. who estimated the energy content of coal from the Powder River Basin to be 8,800 Btu/ton (Peabody Energy, 2014). The value was taken as representative of coal throughout Wyoming as shown in Table 9.

Table 9. Coal Energy Content (data from Energy Information Administration, 2014c; Peabody Energy, 2014)

Coal Mineral	Heat Content (Btu/ton)
anthracite	12,500
bituminous	12,000
sub-bituminous	8,750
lignite	6,500
North Antelope Rochelle Mine	8,800

Coal produced in the states east of the Mississippi River is essentially all bituminous, while the coal in Texas is essentially all lignite (Energy Information Administration, 2012). In other states west of the Mississippi, the coal minerals are a mixture of bituminous and sub-bituminous coal. The shares of the total production for these two coal varieties for the remaining western states were calculated using EIA estimates (Energy Information Administration, 2012). The shares were used to estimate the average energy content of coal produced in states west of the Mississippi River other than Texas and Wyoming. The estimated energy contents for coal in the various regions in Table 8 appear in Table 10.

Table 10. Regional Coal Energy Contents Used to Estimate Water Consumption

State/Region	Assumed Energy Content (Btu/lb)
Wyoming	8,800
West Virginia	12,000
Kentucky	12,000
Pennsylvania	12,000
Texas	6,500
Other states west of the Mississippi River	9,182
Other states east of the Mississippi River	12,000

The literature values of water consumption for surface mining and beneficiation operations, energy content values from Table 10, and production shares from Table 8 were used to estimate the production-weighted average water consumption for coal surface mining in the United States. Gleick's (1994) estimates of 2 m³ per TJ for surface mining with no re-vegetation plus 4 m³ per TJ for beneficiation were used for all states east of the Mississippi River, including West Virginia, Kentucky, and Pennsylvania. Wyoming coal mining operations were assumed to require re-vegetation, thus consuming 5 m³ per 10¹² J (Gleick, 1994). Coal surface mining operations were also assumed to utilize dust control, for which the estimated amount of water consumed is 5.2 gal per ton (Mavis, 2003). The average water consumed for coal surface mining in Texas was recently characterized by Grubert et al. (2012). For the other states west of the Mississippi where water resources are scarce, the low estimates from Gleick (1994) of 3 m³ per 10¹² J for the mining operations plus 4 m³ per 10¹² J for beneficiation were used.

The estimated WCFs for each of the regions and the computed national production-weighted average appear in Table 11. Water consumption for surface mining in Texas is greater than other states as a result of surface de-watering, which is not necessary in all mines (Grubert et al., 2012). Surface de-watering is needed in mines that are below the natural water table. Other estimates of water consumed in coal mining do not discuss surface de-watering. More characterization of these impacts is needed at the national level to understand how and where the impact of coal mines on local water tables is significant.

Table 11. Coal Surface Mining WCFs by Region

State/Region	Production Share (%)	WCF (gal/mmBtu)
Wyoming	58.2	1.7
West Virginia	6.9	1.7
Kentucky	5.8	1.7
Pennsylvania	1.6	1.7
Texas	6.1	16.1
Other states west of the Mississippi River	13.9	1.9
Other states east of the Mississippi River	7.5	1.7
National Production-weighted Average	100.	2.60

The literature values of water consumption for underground mining and beneficiation operations in the various regions, energy content values from Table 10, and production shares from Table 8 were used to estimate the production-weighted average water consumption for coal underground mining in the United States. Gleick's (1994) low-range estimate of 3 m³ per 10¹² J for underground mining plus 4 m³ per 10¹² J for beneficiation was assumed to represent water consumption in Wyoming because of water stress in the region and a lack of high-water-consumption prepping plants. For other states west of the Mississippi River, the high estimate of 20 m³ per 10¹² J plus 4 m³ per 10¹² J for beneficiation was used. For all states east of the Mississippi River, including West Virginia, Kentucky, and Pennsylvania, the middle of the range of estimates from Gleick (1994) of 11.5 m³ per 10¹² J for the mining operations plus 4 m³ per 10¹² J for beneficiation was assumed to be representative. The regional WCFs and national production-weighted average appear in Table 12.

Table 12. Coal Underground Mining WCFs by Region

State/Region	Production Share (%)	WCF (gal/mmBtu)
Wyoming	0.9	1.9
West Virginia	24.1	4.3
Kentucky	18.9	4.3
Pennsylvania	13.7	4.3
Texas	0.0	
Other states west of the Mississippi River	14.7	6.7
Other states east of the Mississippi River	27.7	4.3
National Production-weighted Average	100.	4.64

6. URANIUM MINING AND ENRICHMENT

The production of electricity from nuclear power requires enriched uranium fuel. Uranium fuel is produced through numerous processing steps that consume different quantities of water. In addition to direct water consumption in these processes, water is indirectly consumed in the production of the upstream resources used to develop the fuel that is typically used at nuclear power plants (U-235). GREET provides a convenient framework to account for the indirect water consumption in these upstream processes. The uranium production inputs and outputs in GREET are shown in Figure 9. The direct water consumption for the processes of uranium mining, enrichment, and conversion were estimated using information from the literature.

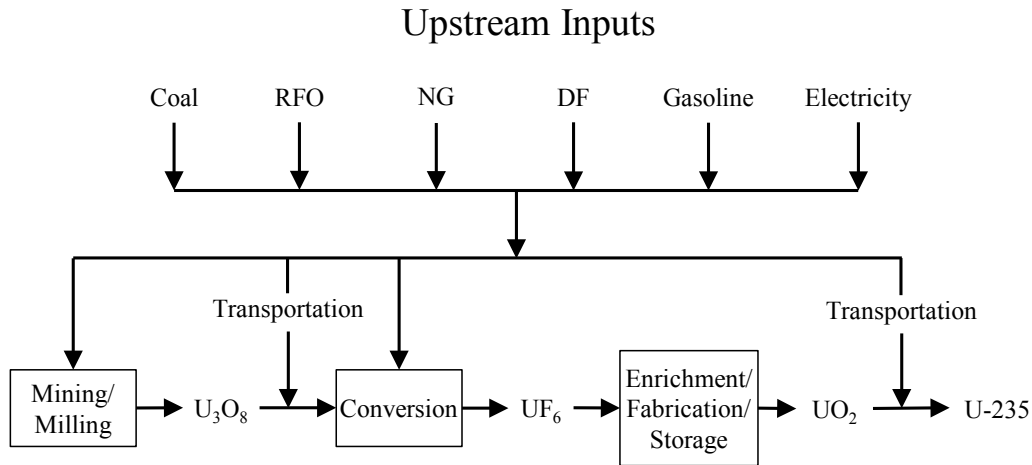


Figure 9. Input-output relationships for uranium (U-235) production in GREET.

Enriched uranium fuel production can be accomplished using several different process technology pathways. Uranium in the subsurface exists primarily in the form of uranium oxide (U₃O₈). Both surface and subsurface mining and in-situ leaching technologies are employed for extraction of uranium ore; the mining technologies also require milling to produce uranium concentrate (also known as yellowcake), which is sold on the open market. The uranium concentrate is transported to facilities where it is converted to uranium hexafluoride (UF₆), which is the form required for the enrichment process. The UF₆ is transported to enrichment facilities, where the concentration of the fissionable isotope U-235 is enriched from natural levels for light-water reactors. Two technologies are commonly employed for enrichment: gaseous diffusion and gas centrifugation. The enrichment process involves separation of the enriched uranium from depleted uranium (DU, isotope 238); thus, substantially higher levels of natural uranium are needed to yield the desired mass of U-235 in the final fuel product. The enriched fuel is converted into uranium dioxide (UO₂), processed into pellet form, and stored in fuel rods, which are used in reactor cores (Wilson, 1996).

The processes in the nuclear fuel cycle in GREET are grouped into uranium mining, enrichment, and conversion/fabrication/waste storage. The water consumption associated with exploration was ignored; the water consumption associated with waste tailings was assumed to be part of the conversion process; and the water consumption associated with the DU was assumed to be part of the enrichment process. Meldrum et al. (2013) provided an inventory of water withdrawal and consumption data in a recent LCA of electricity generation, including an analysis of U-235 production. The WCFs from this paper are summarized in Table 13. Meldrum et al. (2013) assumed the following conversion factors for harmonizing uranium processing data:

Conversion: 2.81 kg U₃O₈/kg UF₆ (natural)
 Enrichment: 10.4–10.8 kg UF₆ (natural)/kg UF₆ (enriched)
 Fuel fabrication: 3.42 kg UF₆/kg UO₂
 Fuel use: 0.0043 kg UO₂/MWh

Table 13. Water Consumption in U-235 Production Processes (data from Meldrum et al., 2013)

Process	Water Consumption (gal/MWh)			<i>n</i>
	Median	Min	Max	
In-situ leaching	18	13	23	2
Surface mining	32	4	92	6
Underground mining	30	<1	240	4
Milling	11	3	29	6
Conversion	10	4	13	3
Centrifugal enrichment	4	3	6	3
Diffusion enrichment	35	32	37	2
Fuel fabrication	1	1	3	4
Storage and disposal	3	1	5	3
Reprocessing spent fuel	7	7	7	1

The three extraction technologies and associated milling were not substantially different and were aggregated using the number of values into a final estimate. The technology-weighted average from GREET was used to aggregate the values for the enrichment technologies. The fabrication values, storage and disposal, and conversion values were aggregated together into a single WCF for consistency with the current GREET structure. The values were then converted into WCF per gram U-235 as shown in Table 14.

Table 14. Summary of Estimated Uranium Fuel Cycle WCFs

Process	WCF	Units
Uranium mining	201	gal/g U-235
Uranium enrichment	81	gal/g U-235
Uranium conversion/fabrication	97	gal/g U-235

7. ELECTRICITY GENERATION

Electricity is a fundamental resource in the U.S. economy. Electricity is generated from a variety of different energy sources including coal, natural gas, residual fuel oil, nuclear fuel, hydropower, biomass, geothermal power, wind, and solar energy. Electricity generation for each of these technologies consumes water directly in power plants and indirectly through the production of the energy sources in upstream processes. Table 15 shows the breakdown of electricity generation among different U.S. sectors in 2012 (Energy Information Administration, 2013).

Table 15. 2013 U.S. Electricity Generation (data from Energy Information Administration, 2014a)

Sector	Production Share (%)
Coal	39%
Natural Gas	27%
Petroleum and other gases	1%
Nuclear	19%
Hydropower	7%
Wind	4.1%
Geothermal	0.41%
Solar	0.23%
Biomass	1.5%
Others	<1%

The existing pathways in GREET account for electricity in the U.S. grid on the basis of the shares of the total energy production at wall outlets. The GREET framework for electricity generation is shown in Figure 10. WCFs for each of the electricity generation processes in GREET were estimated on the basis of the existing literature.

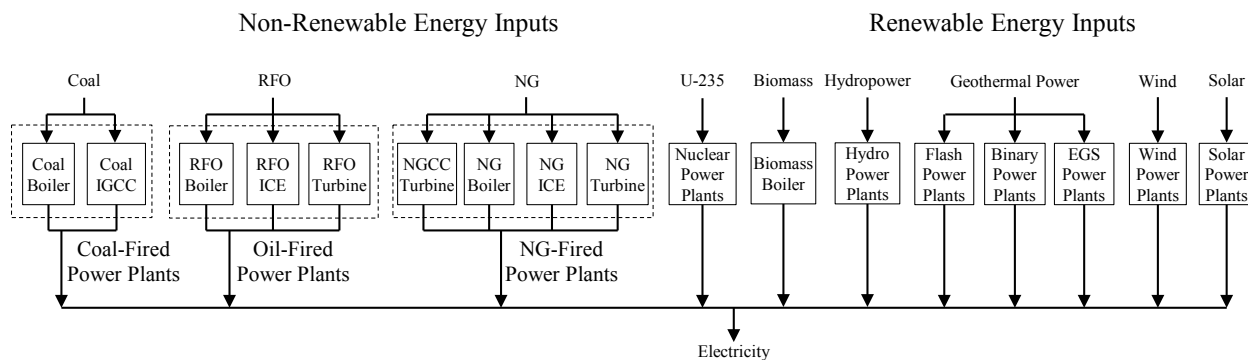


Figure 10. Input-output relationships for electricity generation in GREET.

7.1 Thermoelectric Power Plants

As shown in Table 15, coal-fired power plants generated the largest share of U.S. electricity production. Coal-fired power plants generate electricity primarily through steam boilers that are used with turbines to produce mechanical power that is converted to electricity using generators. The substantial waste heat that is generated in these processes requires cooling and consumes water. Coal can also be converted into syngas (a mixture of hydrogen gas and carbon monoxide), which can then be combusted to power a combination of gas and steam turbines through the integrated gasification combined cycle (IGCC). This technology enables the gas to be purified and thus reduces emissions of hazardous air pollutants. Water is consumed in coal power plants primarily in cooling applications.

Nuclear power plants and many natural-gas-fired and oil-fired power plants also employ steam boiler-turbine technology for converting heat energy into electricity. In addition, some oil-fired and natural-gas-fired power plants utilize portable internal combustion engines (ICEs) for electricity generation. Electricity is also generated using simple gas turbines at some plants. The natural gas combined cycle (NGCC) is an emerging, high-efficiency technology for natural gas plants. In NGCC plants the waste heat from the gas turbines is collected and used to generate steam in a heat recovery steam generator to drive an additional steam turbine.

Various technologies are used for cooling in thermoelectric plants. The choice of cooling technology impacts the cost, energy efficiency, and water consumption. Open-loop or once-through cooling refers to a system where water is withdrawn from a source, circulated once through heat exchangers, and then returned to the surface water body. These systems withdraw large quantities of water, but return the water to the source at a higher temperature. Recirculation or closed-loop cooling systems continuously re-use water that is withdrawn and thus require only small withdrawals of make-up water for cooling, drift, and blow-down, but consume the majority of the withdrawn water. Some thermoelectric plants recirculate water in a pond that utilizes the pond surface area to dissipate heat into the ambient air. A small number of thermoelectric plants utilize dry cooling either employing large fans or recirculating water that is not exposed to ambient air. Dry cooling reduces a power plant's energy efficiency, however. Figure 11 shows a schematic of the material and energy flows to a thermoelectric power plant including water withdrawals and consumption.

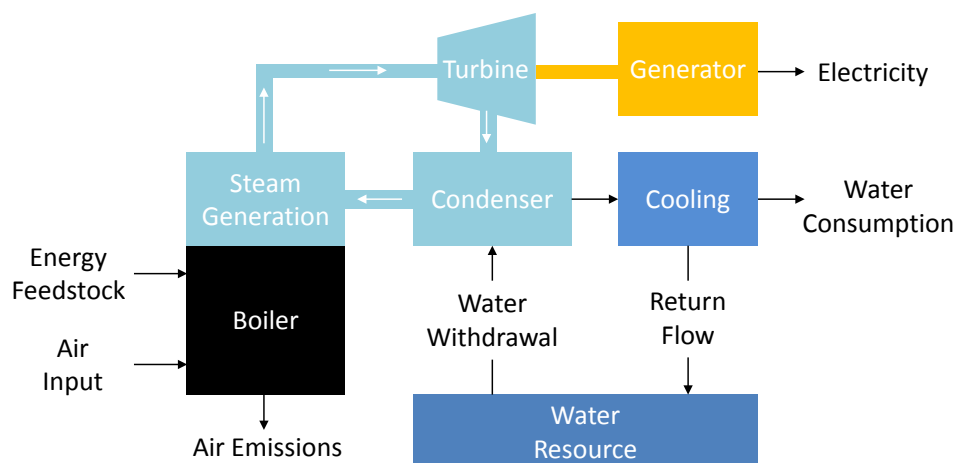


Figure 11. Thermoelectric Power Plant Water Consumption.

Wu and Peng (2011) compiled data from Feeley III et al. (2008) on cooling technologies in thermoelectric power plants. The cooling technology shares for these different plants are shown in Table 16. The combined cycle cooling water data are derived from a limited sample size of reporting facilities (approximately 7 percent of the total) and thus the authors suggested that these estimates may not be representative of a national average. These shares (particularly the dry cooling fraction) merit further investigation. Meldrum et al. (2013) compiled harmonized estimates of NGCC water consumption of 380 gal per MWh with carbon capture and 210 gal per MWh without carbon capture which were adopted for this analysis. Dziegielewski et al. (2006) compiled water use and consumption data for electricity generation for a variety of fuel sources. Wu and Peng (2011) used these data to estimate the water consumed per kilowatt-hour (kWh) of electricity generated for the different technologies. These estimates appear in Table 17.

Table 16. Cooling Technology Shares (%) for Thermoelectric Power Plants (data from Wu and Peng, 2011)

Energy Source	Single-loop	Recirculating	Cooling Pond	Dry Cooling
Coal	39.1	48.0	12.7	0.2
NGCC	8.6	30.7	1.7	59
Other Fossil ¹	59.2	23.7	17.1	0
Nuclear	38.1	43.6	18.3	0

¹ Petroleum coke, jet fuel, diesel fuel, residual oil, waste oil, kerosene, and natural gas steam turbine

The values for coal power plants in Table 16 and Table 17 were used to estimate technology-weighted WCFs for coal boilers. WCFs for NG and RFO boilers were estimated using the technology-weighted averages of the WCFs for “Other Fossil” from Table 16 and Table 17. Gas turbines for power generation do not directly use water, so the associated WCF is assumed to be zero. The values for nuclear power plants in Table 16 and Table 17 were used to

estimate technology-weighted average WCFs for nuclear power. Wu and Peng (2011) did not assess coal IGCC plants; however, Meldrum et al. (2013) reported a water consumption factor of 320 gal per megawatt-hour (MWhr) for plants using this technology.

Table 17. Water Consumption Factors (gal/kWh) Associated with Different Cooling Technologies in Thermoelectric Power Plants (data from Wu and Peng, 2011)

Energy Source	Single-loop	Recirculating	Cooling Pond	Dry Cooling
Coal	0.30	0.70	0.70	0
NGCC	0.10	0.16	0.24	0
Other Fossil ¹	0.30	0.48	0.11	0
Nuclear	0.40	0.80	0.50	0

¹ Petroleum coke, jet fuel, diesel fuel, residual oil, waste oil, kerosene, and natural gas steam turbine

Biomass from forest residue and municipal waste are also combusted to generate electricity using the steam cycle. Wu and Peng (2011) estimated that 0.61 gal of water are consumed per kWh for boilers in municipal waste and biomass-based electricity generation technologies.

7.2 Hydroelectric Power Plants

As shown in Table 15, hydropower was used to generate over 6% of the electricity in the U.S. in 2012. Dams used to produce hydroelectricity are also used to control flooding; to provide a water supply source for irrigation, municipal drinking water, and industrial cooling water; and for recreational purposes. Most assessments of water consumption have made no effort to allocate the reservoir water consumed in generating hydroelectricity to these other functionalities. Furthermore, the evaporation rate from a water body is a complex function of its geometry and the regional climate. As a result, WCFs for hydroelectricity may vary substantially from one facility to another.

Several attempts have been made to quantify the water consumption associated with hydroelectricity in the United States. Gleick (1992) quantified the evaporation rates from 100 reservoirs used for hydroelectricity generation in California. The WCFs for the reservoirs ranged from 0.04 to 200 L per kWh of electricity generated, with a median of 5.4 L per kWh. Torcellini et al. (2003) used average yearly pan evaporation data from the National Weather Service to develop a nationwide map of evaporation rates for hydroelectric-power-producing reservoirs in the U.S. The individual reservoir evaporation rates were then aggregated to compute a nationwide rate of 34.3×10^9 L of water consumed per day from reservoirs used for hydroelectric power. At the time of the study, the total production of hydroelectric power was 179,082 kWh per yr. The authors used these two estimates to arrive at a national average water consumption factor of 18.27 gal per kWh. Because the goal and scope of this study was to estimate national average water consumption, the value from Torcellini et al. (2003) was adopted initially.

The water consumption associated with hydroelectricity generation has a significant impact on the life cycle water consumption of many resources in GREET because of the pervasive use of electricity in other processes and the relative magnitude of the hydropower WCF versus the WCFs associated with other forms of electricity generation. The WCF for hydropower was re-analyzed using data from all facilities producing hydropower in the US. The facilities were divided into three categories—run-of-the-river facilities, multipurpose reservoir hydropower facilities, and dedicated reservoir hydropower facilities. Run-of-the-river facilities do not require a reservoir and have no associated artificial water consumption. For the remaining dedicated and multipurpose reservoirs, annual evaporation rates were estimated using state-level pan evaporation data. Background evapotranspiration for the submerged land prior to construction of the reservoirs was subtracted from the reservoir evaporation rates to estimate only the artificial water consumption associated with each reservoir. In the multipurpose reservoirs, the water consumption was then allocated between hydroelectricity and other purposes by assuming the hydropower was similar to dedicated reservoirs. A production-weighted average of 9.85 gallons per kWh for all facilities was then calculated. The details of this analysis are described elsewhere (Lampert et al., 2015).

7.3 Geothermal Power Plants

Geothermal power stations capture heat from the Earth’s core, which is used to generate electricity. Three primary technologies are to generate electricity from geothermal energy: enhanced geothermal steam (EGS), flash steam, and binary cycle power plants. EGS power plants inject water into the subsurface, capture the steam produced by the geothermal energy, and then convert it to electricity using a turbine and a generator. Flash steam power plants recover high-pressure, high-temperature water from the subsurface and bring it into “flash chambers” that release the steam to a turbine for power generation. Binary cycle power plants collect water at lower temperatures than other geothermal plants. The heat in the water is exchanged into another fluid with a lower boiling point that is vaporized to drive a turbine and generate electricity. Binary cycle power plants utilize both dry cooling systems and hybrid cooling systems.

Each geothermal technology utilizes water differently, and all are currently implemented in the GREET framework. Geothermal power plants utilize water during the construction phase for drilling, stimulation, and flow testing and during operations as a geofluid to produce steam and for supplemental cooling. Water consumption associated with the construction phase is relatively small compared with operations (Clark et al., 2013a) and was outside the scope of the current analysis. Water used as a geofluid need not be of high quality, whereas cooling water must be of reasonable quality to prevent corrosion of water-handling equipment. The energy production technology, fluid temperature, and cooling technology impact the energy efficiency and the water consumption of a geothermal plant.

Meldrum et al. (2013) compiled an inventory of water consumption estimates for various geothermal technologies from the literature. Their results are shown in Table 18, along with the energy production technology and the methodology used to make the assessments. Most of the information is based on thermodynamic modeling using the Geothermal Electricity Technology

Evaluation Model (GETEM) of expected geofluid heat exchange processes and cooling for electricity generation. Meldrum et al. (2013) summarized the results for the three technologies, but divided the estimates for binary plants into dry and hybrid cooling systems.

Table 18. Geothermal Power Plant Water Consumption Estimates (data from Meldrum et al., 2013)

Water Consumption (gal/kWh)	Technology	Methodology	Reference
0.29	EGS	GETEM ¹ , 20 MW, SW U.S., 150–225°C	Clark et al. (2011)
0.72	EGS	GETEM, 50 MW, SW U.S., 150–225°C	Clark et al. (2011)
0.01	Flash	GETEM, 50 MW, SW U.S., 150–185°C	Clark et al. (2011)
0.27	Binary	GETEM, 10 MW, SW U.S., 175–300°C	Clark et al. (2011)
0.22	Binary	Cooling Tower Model, 1 MW, NV U.S., 245°F	Kutscher and Costenaro (2002)
0.70	Binary	Cooling Tower Model, 1 MW, NV U.S., 245°F	Kozubal and Kutscher (2003)
0.63	Binary	Modeling, 150°C	Mishra et al. (2011)
0.29	Binary	Modeling, 200°C	Mishra et al. (2011)
0.011	Flash	Modeling, 50 MW, plant efficiency 0.1 to 0.35	Skone (2012)
0.019	Flash	10–40 gallon/MWhr withdrawal range, assuming withdrawals exceed consumption by 20%	California Energy Commission (2008)
0.360	Flash	CalEnergy, 4100 ML to produce 342 MW in 2009	Adee and Moore (2010)
0.005	Flash	6000 gal/day for 48-MW Calpine Corporation facility	Kagel et al. (2005)

¹ Geothermal Electricity Technology Evaluation Model

Clark et al. (2013a) compiled and analyzed data for a number of geothermal facilities in the United States. Dry cooling is used at many of these facilities due to local water resource availability. Clark et al. (2013a) estimated 0.04 gal of water were consumed per kWh at facilities using dry cooling for dust control, maintenance, and domestic use. This value represents a lower bound on WCF for geothermal power plants.

For plants with wet cooling, the operational water loss should be related to the efficiency of the plant. Latent heat fluxes (evaporation) from the cooling tower are used to transmit waste heat from the steam cycle to the surrounding environment. Thus the cooling water requirements

for evaporation, drift, and blowdown should be inversely proportional to the plant efficiency. Given that geothermal power plants operate at lower efficiencies than thermoelectric plants, the geothermal water consumption factors for wet-cooled plants should be higher than thermoelectric facilities. Clark et al. (2013a) collected data for wet-cooled geothermal plants that are summarized in Table 19. The minimum, maximum and mean values were 0.7, 3.8 and 2.4 gal per kWh for flash and 1.5, 4.6, and 3.4 for binary plants. No data were provided on wet-cooled EGS plants.

**Table 19. Wet-Cooled Geothermal Water Consumption in gal/kWh
(data from Clark et al., 2013a)**

Process	Minimum	Maximum	Average
Flash steam	0.7	3.8	2.4
Binary cycle	1.5	4.6	3.4

For EGS systems where water is continuously injected into the reservoir, water must be replaced over time to continue operations. While water for injection does not need to be fresh, if low-quality water is not available then the process will consume more fresh water. Clark et al. (2013a) indicated that the feasible loss rates for EGS systems are between 1 and 10%, which equates to 0.18 to 3.6 gal of water per kWh. They assumed a 5% below ground operational water loss to be representative which equates to a WCF of 0.95 gal per kWh.

Given the wide range in estimates and limited data, further investigation of geothermal water consumption is needed. For the purposes of this analysis, the median of the dry and wet-cooled values from Clark et al. (2013a) were selected for the flash and binary technologies (1.2 gal per kWh and 1.7 gal per kWh, respectively), and the loss associated with geofluids in dry-cooled systems (0.95 gal per kWh) was selected for EGS power plants.

7.4 Wind Power Plants

Wind power plants do not require water for cooling, and thus utilize very little water directly. The construction of wind plants consumes water, but as infrastructure was outside the scope of the current analysis and the associated water consumption was ignored. According to Meldrum (2013), a small amount of water (1 gal per MWh) is used for cleaning, which was the value taken for the GREET inventory.

7.5 Solar Power Plants

Solar energy is captured and converted to electricity using two primary technologies: photovoltaics (PVs) and concentrated solar panels (CSPs). CSPs use mirrors or lenses to concentrate sunlight onto a receiving fluid that is heated and used to drive a steam turbine, much

like other thermoelectric technologies. PVs take advantage of materials capable of capturing energy using the PV effect, which excites electrons into higher energy states where they act as carriers for electric current. Both PVs and CSPs require no fuel supply and thus have no upstream operational water consumption. Water consumption for solar plant construction may be important; however, construction water consumption was outside the scope of this analysis and was not considered.

CSP water withdrawals are similar to those for coal boilers, since both technologies generate power through steam power cycles. However, CSP plants are located in dry, remote areas and use evaporation ponds for disposal of blowdown water, and as a result consume essentially all make-up water withdrawals (Meldrum et al., 2013). Various technologies have been developed for concentrating sunlight, including dish stirlings, power towers, and troughs. As in the case of thermoelectric power plants, multiple technologies can be used for CSP cooling operations although open loop cooling is not feasible given water limitations in the regions where CSP is a viable technology.

PV power plants require no cooling or steam generation, and so the life-cycle water consumption of PVs is driven by equipment rather than operations. Meldrum et al. (2013) presented data on PV water consumption for construction and operations. The infrastructure water consumption is derived from manufacturing of the panels rather than direct consumption and, as such, is not included in this analysis. Some water is used for washing the PV panels (Meldrum et al., 2013). The primary technologies used in PV solar plants are flat panels and concentrated PV panels.

The various PV and CSP technologies consume different amounts of water. Meldrum et al. (2013) summarized water consumption associated with different CSP and PV technologies. The median water consumption estimates for operation and construction of both CSP and PV plants from this study are shown in Table 20. According to Mendelsohn et al. (2012), 57% of the operational solar power capacity of the U.S. is derived from PVs, with the rest coming from CSPs. The median values from Table 20 and the technology-weighted averages were used to estimate the WCFs for solar electricity plants.

The WCFs recommended for the different electricity generation plants are presented in Table 21. The table illustrates the importance of hydropower, which consumes substantially more water than the other technologies. Given the multiple utilities of hydroelectric dams, this number deserves greater scrutiny. For the thermoelectric plants the choice of cooling technology is the greatest indicator of the water consumption per unit electricity generated. GREET currently does not account for these differences.

Table 20. Solar Power Plant Water Consumption Factor Estimates (data from Meldrum et al., 2013)

Phase	Cooling Technology	Water Consumption Factor (gal/kWh)
CSP Power plant		
Construction (all technologies)	N/A	0.16
Operations		
Dish Stirling	N/A	0.005
Fresnel	N/A	1.0
Power tower	Cooling tower	0.81
Power tower	Dry cooling	0.026
Power tower	Hybrid cooling	0.17
Trough	Cooling tower	0.89
Trough	Dry cooling	0.078
Trough	Hybrid cooling	0.34
Median		0.26
PV Power Plant		
Construction (all technologies)	N/A	0.081
Operations		
Flat PV panel	N/A	0.006
Concentrated PV panel	N/A	0.030
Median		0.018

N/A = Not available

Table 21. Summary of Estimated Electricity Generation WCFs

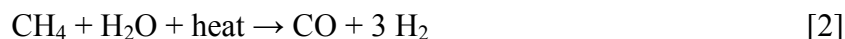
Process	WCF	Units
Coal boilers	0.54	gal/kWh
Coal IGCC	0.32	gal/kWh
Residual oil boiler	0.31	gal/kWh
Residual oil ICE	0	gal/kWh
Residual oil turbine	0	gal/kWh
Natural gas boiler	0.39	gal/kWh
Natural gas ICE	0	gal/kWh
Natural gas turbine	0	gal/kWh
NGCC turbine	0.21	gal/kWh
NGCC turbine with CCS	0.38	gal/kWh
Nuclear power plant	0.58	gal/kWh
Hydroelectric power plant	9.85	gal/kWh
Municipal waste power plant	0.61	gal/kWh
Biomass boiler	0.61	gal/kWh
Geothermal flash power plant	1.2	gal/kWh
Geothermal binary power plant	1.7	gal/kWh
Geothermal EGS power plant	0.95	gal/kWh
Wind power plant	0.001	gal/kWh
Solar PV plant	0.018	gal/kWh
Solar CSP plant	0.26	gal/kWh

8. HYDROGEN AND SYNTHETIC FUEL PRODUCTION

Hydrogen (H₂) is being considered as a fuel for use in FCEVs, and could be a fuel for direct combustion in ICEVs. Two primary methods are used to produce H₂: steam methane reforming (SMR) of natural gas and electrolysis of water.

8.1 Steam Methane Reforming Process

In the U.S., H₂ is produced primarily through SMR of natural gas. SMR is a two-stage reaction. In the first stage of the reaction, steam reacts with methane endothermically at high temperatures (~900°C) to yield synthetic gas (syngas), which is a mixture of carbon monoxide, H₂, and small amounts of carbon dioxide.



In the second stage, additional hydrogen is generated at lower temperatures (~360°C) through an exothermic water-gas shift reaction.



The energy produced in the second reaction helps to maintain the reaction. The overall reaction is endothermic, and the heat needed to maintain the reactions is generally supplied by combustion of additional natural gas. The H₂ fuel generated by the process is separated from by-products using pressure-swing absorption. The carbon dioxide emissions from the SMR process and the additional combustion can optionally be sequestered using a carbon capture and storage (CCS) process. The stoichiometry of reactions [2] and [3] implies 1.2 gal of water consumed per kg H₂, although excess water is typically used to drive the reaction. If CCS is used, additional water is needed for capturing and sequestering the recovered carbon before it can be stored. The water used to produce the steam must be of good quality to prevent fouling of the equipment.

8.2 Gasification Production Processes

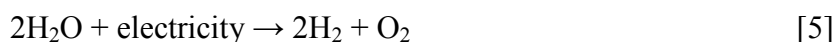
Gasification processes use carbon sources including coal, petroleum and biomass as a feedstock for syngas generation that can then be used to produce H₂. The feedstock is reacted with steam in an oxygen-limited environment at high temperature to generate the syngas. Input energy for gasification processes can be supplied directly by consuming some of the feedstock with a limited flow of air for combustion or indirectly using an external fuel source to generate the steam needed to drive the reaction. Gasification reactions are often written in terms of their elemental carbon content.



The CO in the syngas produced in [4] can then be converted into H₂ in a water-gas shift reaction [3]. The H₂ fuel is then cleaned with pressure swing adsorption. The carbon can be sequestered using CCS. The feedstock and the employment of CCS affect the amount of water consumption associated with producing the H₂.

8.3 Electrolysis Production Process

Electrolysis of water is an alternative process that can be used to generate H₂. In electrolysis, a power source is connected to two electrodes that are placed into an aqueous solution. The current that passes through the solution causes reduction of hydrogen ions to H₂ at the cathode and oxidation of the oxygen atoms in water molecules to oxygen gas at the anode.



The stoichiometry of reaction [5] implies the consumption of 2.4 gal of water per kg H₂. The water used in the electrolysis process is generally pre-treated to a high level of purity. Cooling water is also needed for steady electrolysis operation. Electrolysis of water thus consumes water as a process input in the hydrogen production reaction, as a reject in the water pre-treatment process, and in the cooling process.

8.4 Process Water Pretreatment Technologies

Both electrolysis and SMR require high-quality water (low dissolved-solids concentrations) as a feedstock for the production process. There are two principal technologies that can be used to pretreat water to the necessary quality: ion exchange and reverse osmosis. Reverse osmosis drives water across a membrane that prevents dissolved molecules from passing across by applying high pressure to the influent. Some of the water is rejected to maintain steady concentrations of the impurities in the reactor. The rejected water from the treatment process is of diminished quality and thus is assumed to be consumed. Ion exchange utilizes resins to selectively exchange dissolved ions in a solution with protons (cation exchange) and hydroxide ions (anion exchange). The protons and hydroxide ions neutralize one another, resulting in very high-purity water. The resin must be periodically regenerated using concentrated acids and bases. The ion exchange technology consumes negligible amounts of water.

8.5 Delivery and Scale Considerations

The infrastructure needed to produce and deliver H₂ on a large scale does not yet exist. The amount of water consumed in H₂ production would depend on the technologies employed and the distribution methods used. H₂ production could be performed at central facilities before distribution or directly in the forecourts at the refueling stations. Utilizing forecourt facilities for production may require consumption of greater amounts of water than central facilities, which provide economies of scale. Production at central facilities would make CCS more feasible, although utilizing CCS would increase the amount of water consumed.

8.6 Production Processes for H₂ in GREET

In addition to the water consumed directly in the H₂ production processes, water is indirectly consumed in the production of the upstream inputs. Figure 12 shows the inputs and outputs of the hydrogen production processes in GREET. WCFs for each of the production processes in Figure 12 were estimated from a detailed literature review.

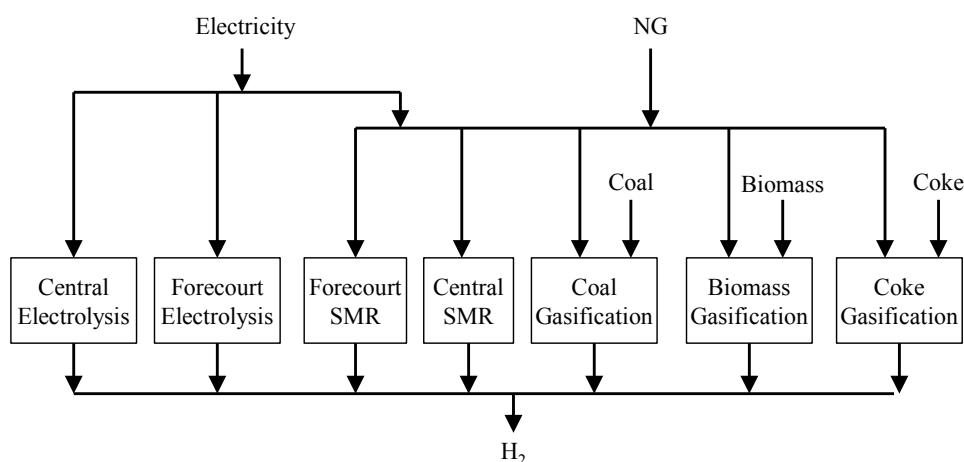


Figure 12. Input-output relationships for hydrogen production in GREET.

8.7 Water Consumption Estimates for SMR and Electrolysis

Water is consumed in both the SMR and electrolysis processes as a feedstock (process water) for the reaction (steam) and for cooling. The process water must have low dissolved-solids concentration, which generally requires pretreatment that consumes additional water. As cooling water is consumed, make-up water is added and blowdown water discharged to maintain steady levels of dissolved constituents. Dry cooling may be used for H₂ production associated with small reactors at refueling stations where the heat dissipation requirement is small. However, dry cooling diminishes process efficiency which makes it a less economical option.

Elgowainy et al. (2015) performed an assessment of the relationships between H₂ production and water for forecourt and central SMR based on information from industry sources and the literature. The WCFs in that assessment were based on steam-to-carbon ratios of 2.8 (range of 2.5–3) for central production and 4.2 (range of 4–5) for distributed production, resulting in 1.7 and 2.5 gal/kg H₂ for central and distributed production processes, respectively. The WCF for the different processes in central SMR plants, with and without CCS, were calculated based on a detailed process simulations developed by Gandrik et al. (2010) as shown in Table 22.

WCFs for hydrogen production via electrolysis were developed from data provided by several industrial sources. A water rejection rate using reverse osmosis water treatment was assumed to be 25% for distributed SMR, central electrolysis, and distributed electrolysis,

resulting in treatment water consumption factors of 3.3, 3.9 and 3.9 gal/kg H₂ for these three processes, respectively, as shown in Table 22. The water rejected from the reverse osmosis pretreatment was assumed to be consumed, although it remains unclear whether or not this water could be discharged back to municipal facilities or surface water resources. The salinity of the water will impact the rejection rate and potential for discharge.

With the exception of SMR w/CCS process, the cooling and process water consumption requirements for all pathways in Table 22 were confirmed with confidential data from a variety of different sources in the refinery and gas industries. A range of estimates for water consumption factors of the different hydrogen production technologies in Table 22 are provided based on another study (Simon et al., 2010). The WCFs were converted to an energy basis using a LHV for H₂ of 0.114 mmBtu/kg.

Table 22. Water Consumption Estimates for Hydrogen Generation (gal/kg H₂) (data from Elgowainy et al., 2015)

Process	Production Technology				
	SMR			Electrolysis	
	Central w/o CCS	Central w/CCS	Distributed	Central	Distributed
Water Treatment Process	0.7	0.75	3.3	3.9	3.9
Production Process	1.7	1.7	2.5	2.9	2.9
Cooling Process	0.65	1.15	0 ¹	1.2	0**
Total	3.1	3.6	5.8	8.0	6.8
Range (low-high) ²	(1.7–8.5)	N/A	(5.8–7.5)	(2.9–10.7)	(2.9–8.5)

¹ Assuming closed-loop dry cooling for distributed production

² Simon et al. (2010)

8.8 Water Consumption Estimates for Coal and Petroleum Coke Gasification

Rath (2010) characterized current state-of-the-art production of H₂ from SMR and coal gasification under two different process and cooling configurations that included CCS. In the first case, the gasifier was run in radiant-only mode to produce high pressure syngas while in the second case the gasifier was run in full quench mode. In the radiant-only case, make-up water is required by a condenser that is used to capture waste heat from the syngas, while the full quench mode more water is consumed by the quenching process. A summary of the process flows including water consumption estimates from that study is displayed in Table 23. The estimates were used to determine the water consumption rates per mass of coal input and per unit H₂ produced for the scenarios as shown in Table 23. The WCFs for the two scenarios were similar despite differences in water use practices, and the average value of 8.31 gal water per kg H₂ was assumed to be representative of coal gasification with and without CCS. This estimate was

converted using the LHV of H₂ to a WCF for coal gasification. A literature review revealed no data for water consumption associated with petroleum coke gasification. The coke gasification process is similar to coal gasification, however, and so the WCF for coal gasification was assumed to be representative of both processes.

Table 23. Coal Gasification Process Estimates (data from Rath, 2010)

Process	Units	Case Study 2-1	Case Study 2-2
Washing/quenching water	gpm	569	1,269
Condenser make-up water	gpm	622	0
Scrubbing water	gpm	-7	-10
Cooling water	gpm	2,345	2,345
Total water consumption	gpm	3,529	3,604
Coal input rate	kg/hr	220,889	220,904
H ₂ production rate	kg/hr	25,789	25,689
Water consumption	gal/kg coal	0.98	0.96
Water consumption	gal/kg H₂	8.38	8.24

Syngas generated from coal gasification can also be converted into diesel as described by Tarka (2012). As in the case of hydrogen fuel production, water is required to generate steam in the boilers and for process cooling. Wet or dry cooling can be used, and the decision generally represents an economic trade-off between cost and water savings. Tarka (2012) evaluated wet and dry cooling of coal to produce diesel and naphtha using gasification and the Fischer-Tropsch process. In the wet-cooled coal to diesel configuration, 34,302 barrels of diesel and 15,698 barrels of naphtha were produced with 9,741 gallons per minute of water consumption. In the dry configuration, the same fuel production was achieved with approximately 3.2% more coal to bring the water consumption down to 2,348 gallons per minute. The flows imply WCFs of 55.7 gallons and 13.4 gallons of water consumption per mmBtu of fuel produced for the wet and dry cases, respectively.

8.9 Water Consumption Estimates for Biomass Gasification

In addition to coal and petroleum coke, biomass can be used as a feedstock for gasification processes to generate a variety of fuels. Spath et al. (2005) characterized the feasibility of biomass gasification of wood chips to produce H₂ fuel by performing a detailed process design for an indirect gasification facility with integrated heat recovery using Aspen Plus[®] software. The study included material and energy balances for the inputs and outputs from the facility. A summary of the major energy and water-related inputs and outputs from the study appears in Table 24. Some of the process water would be supplied by the moisture in the feedstock. However, the majority of the moisture in the biomass was removed prior to gasification in a drying process. The remaining water is converted to steam in the gasifier, and the boiler make-up requirement therefore depends on the initial moisture content. For this analysis, the water associated with the biomass moisture was not counted as consumption since it

does not require withdrawal from a water resource. The blowdown was assumed to be consumed as it would be of poor quality and unlikely to meet effluent discharge limitations. Dry cooling of the shifted syngas accounted for over 10% of the total process input energy. It may possible to capture and re-use energy from the shifted gas, although heat recovery would require more water and increase the process water consumption. It is unclear whether the heat recovery would be economically feasible, however, so the water consumption associated with syngas heat recovery was ignored in this analysis. The LHV from GREET (114,000 Btu/kg H₂) and the material flows from Table 24 were used to estimate a WCF of 4.34 gallons per kg H₂ (38.1 gallons per mmBtu) for biomass gasification.

Table 24. Biomass Gasification Material Flows
(data from Spath et al., 2005)

Material	Material Flow (lb/hr)
Wood chips input	183,718
Wet Feedstock Moisture	183,718
Dry Feedstock Moisture	25,053
Boiler Make-up Water	102,749
Cooling Tower Make-up Water	131,921
Cooling Tower Blowdown	25,346
H ₂ fuel produced	14,260

Syngas generated from biomass gasification can also be converted into diesel as described by Tarka (2012). As in the case of hydrogen fuel production, water is required to generate steam in the boilers and for process cooling. Tarka (2012) evaluated wet and dry cooling of a 100% coal and an 85% coal/15% switch grass mixture to produce diesel and naphtha using gasification and the Fischer-Tropsch Diesel (FTD) process. Using the data from that study for the coal/biomass mixed cases, WCFs of 61.1 gallons per mmBtu and 13.7 gallons per mmBtu are obtained for the wet and dry cases, respectively. For the pure coal to diesel FTD process, the WCF is 55.7 gal per mmBtu.

Syngas from biomass gasification can also be converted into ethanol as described by Dutta et al. (2011). In that study, an Aspen Plus[®] simulation was performed of ethanol production via indirect gasification of 2,000 tonnes per day of woody biomass. As in the case of other gasification processes, make-up water is required for the boiler and the cooling system. The study examined two scenarios, a base case and an optimized water consumption scenario. In the base case, 1.42 gallons of water per gallon ethanol and 1.19 gallons of water per gallon ethanol are required for the cooling and boiler make-up water, respectively. Water present as moisture in the biomass supplies an additional 1.23 gallons water per gallon ethanol, although this water is not withdrawn from a resource so it is not counted as consumption. In the optimized water consumption case, 0.38 and 1.59 gallons water per gallon ethanol are required for cooling and boiler make-up water, respectively. The wet-cooled and dry-cooled scenarios translate to WCFs of 34.2 gallons per mmBtu and 25.8 gallons per mmBtu, respectively.

The water consumption breakdown for the coal to H₂, biomass to H₂, coal to diesel, coal/biomass to diesel and biomass to ethanol in wet-cooled systems are shown in Figure 13. The various processes have similar water consumption requirements. This observation may be the result of similar quantities of waste heat dissipation. A large portion of the waste energy (i.e, input energy in the feedstock minus output energy in the fuel) in conversion facilities is used to consume water.

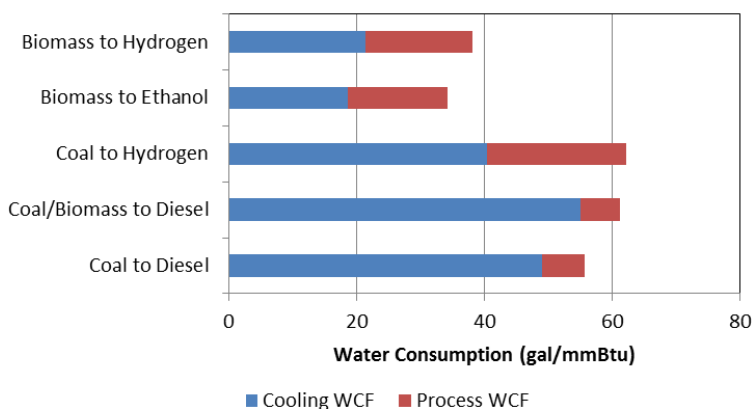


Figure 13. Water consumption per unit fuel produced in gasification processes.

8.10 Summary

The estimated WCFs for the various hydrogen generation technologies appear in Table 25. The quantity of water consumed per unit hydrogen generated does not vary substantially amongst the different technologies.

Table 25. Summary of Estimated Hydrogen and Synthetic Fuel WCFs

Process	WCF	Units
Central SMR	27.2	gal/mmBtu H ₂
Central SMR w/CCS	31.6	gal/mmBtu H ₂
Forecourt SMR	50.9	gal/mmBtu H ₂
Central electrolysis	70.2	gal/mmBtu H ₂
Forecourt electrolysis	59.6	gal/mmBtu H ₂
Petroleum coke gasification to H ₂	66.5	gal/mmBtu H ₂
Coal gasification to H ₂	66.5	gal/mmBtu H ₂
Biomass gasification	38.1	gal/mmBtu H ₂
Biomass FTD	61.1	gal/mmBtu FTD
Coal FTD	55.7	gal/mmBtu FTD

9. AGRICULTURAL CHEMICALS

The production of biofuels requires biomass from agricultural operations. Agricultural operations require many inputs, including fertilizers and pesticides to support biomass growth. Fertilizers and pesticides are produced using a complicated supply chain of different interconnected resources. Each of the steps in the production supply chain for these agricultural chemicals consumes water directly for purposes such as mineral extraction and process cooling. In addition, water is consumed indirectly in the production of the upstream resources. Figure 14 shows the agricultural chemical supply chain in GREET. An extensive literature review was performed to determine the WCFs for direct water usage for each step in this supply chain. In many cases, it was unclear whether the literature estimates for water use in chemical processing corresponded to water withdrawal or consumption. In these cases, the latent heat of the water and the reaction enthalpy were compared. If the latent heat of the water was much greater than the reaction enthalpy, the estimate was assumed to be a water withdrawal. If the latent heat and enthalpy were similar, then the estimate was assumed to be water consumption. When estimates were provided as a withdrawal, the consumption fraction was conservatively taken to be 5% of the withdrawal volume which is consistent with the water losses associated with a pass through a cooling tower (McCabe et al., 1993). In addition to cooling water, process water is needed for some chemical production processes. The following sections document cooling withdrawals, total consumption, and/or processing water requirements. The values are then aggregated to a final WCF for each process at the end of the section.

9.1 Ammonia

Production of ammonia (NH_3) is based on the Haber process, utilizing SMR to produce hydrogen which is then reacted with nitrogen gas in air to produce ammonia. The process requires steam energy and natural gas. The European Fertilizer Manufacturers' Association (EFMA) describes best available technologies for producing ammonia, including information on water consumption (EFMA, 2000a). Assuming the steam condensate is recycled, approximately 0.7–1.5 L of make-up water is required per kg of ammonia produced (EFMA, 2000a). This range of direct water consumption values is shown in Table 26.

9.2 Urea

Urea ($\text{CO}(\text{NH}_2)_2$) is produced by the reaction of ammonia with carbon dioxide to form ammonium carbamate, followed by dehydration using heat to produce urea and water. The reaction between carbon dioxide and ammonia is exothermic and requires cooling water. Reported cooling water withdrawals for best available technologies ranged from 51 to 80 L per kg urea for a 10°C change in cooling water temperature (EFMA, 2000b) as shown in Table 26.

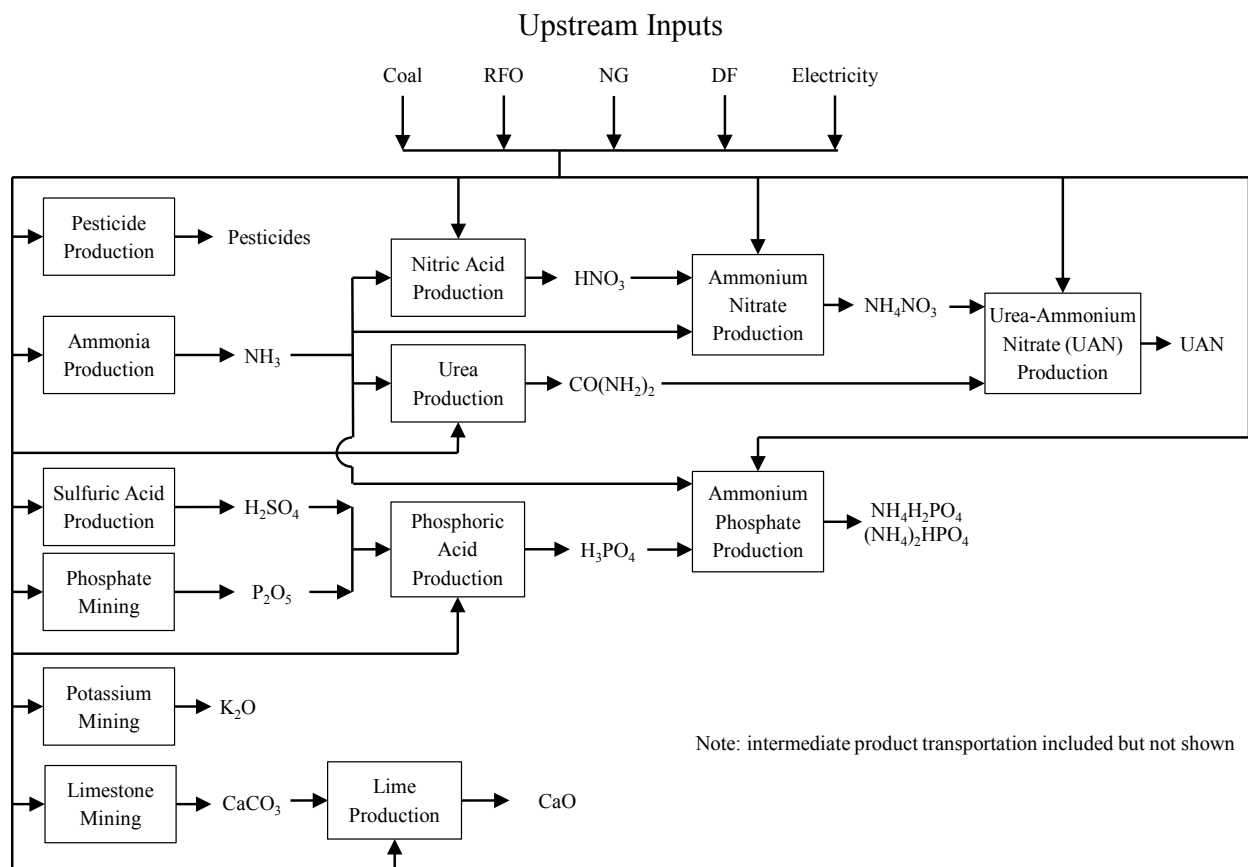


Figure 14. Input-output relationships for agricultural chemicals in GREET.

9.3 Nitric Acid

Nitric acid (HNO_3) is produced by a two-step reaction of ammonia with air to form nitric oxide and then nitric acid, which is then absorbed by process water. The reaction is exothermic and thus requires cooling water. The waste gas contains nitric oxides and requires scrubbing, which also consumes water. The Austrian Federal Environment Agency indicated a cooling water requirement of 72(+/-25%) L per kg and a process water requirement of 0.3 L per kg (Wiesenberger and Kircher, 2001). This range of process and cooling water values is shown in Table 26.

9.4 Ammonium Nitrate

Ammonium nitrate (NH_4NO_3) is produced from the reaction of ammonia with nitric acid. The reaction is exothermic ($\Delta H = -146$ KJ per mol NH_4NO_3) and thus requires cooling water. Assuming a heat capacity for water of 4.18 KJ per kg per $^\circ\text{C}$ and a temperature increase for the cooling water of 10°C , the cooling water requirement for the reaction is 43.6 L water per kg ammonium nitrate. The Austrian Federal Environment Agency indicates that 24.5 m^3 per day of cooling water is heated 10°C in the production of 1800 tonnes/day of ammonium nitrate at the

Agrolinz Melamin GmbH facility (Wiesenberger, 2002), which equates to a cooling water withdrawal of 23.5 L per kg ammonium nitrate, which is the value taken in Table 26.

9.5 Urea-Ammonium Nitrate

Urea and ammonium nitrate (UAN) are often mixed together in fertilizer applications. According to the EFMA, the process consumes 0.244 L water per kg UAN (EFMA, 2000b), as shown in Table 26.

9.6 Sulfuric Acid

Sulfuric acid (H_2SO_4) is produced from sulfur obtained as a by-product of other processes, of which the bulk is petroleum production. Sulfur dioxide is reacted with oxygen and absorbed by process water. The process is exothermic ($\Delta H = -99$ KJ per mol $\text{H}_2\text{SO}_4 = -1010$ KJ per kg H_2SO_4) and requires cooling water. Assuming a heat capacity for water of 4.18 KJ/kg °C and a temperature increase of 10°C, the cooling water requirement for the reaction is 24.2 L per kg sulfuric acid. The Finnish Pulp and Paper Institute reported a cooling water requirement of 48.8 L per kg sulfuric acid for European sulfuric acid manufacturing facilities (Finnish Pulp and Paper Institute, 2002), as shown in Table 26.

9.7 Phosphoric Rock

Phosphoric or phosphate rock (P_2O_5) is produced through a combination of mining and beneficiation. The mining process is either underground or in open pits. The phosphate ores require beneficiation before they are suitable for sale on the phosphate market. The combined mining and beneficiation processes require large quantities of water resources. Frischknecht et al. (2007) report water consumption estimates associated with the combined mining and beneficiation processes of 10 L per kg P_2O_5 for Florida (site of the bulk of North American production) and 3.8 L per kg P_2O_5 for Morocco (site of the bulk of production for Europe). The water consumption estimate for Florida is assumed to be representative, as shown in Table 26.

9.8 Phosphoric Acid

Phosphoric acid (H_3PO_4) is produced by reacting phosphoric rock with sulfuric acid. Calcium sulfate is a co-product of the reaction and is separated by filtration. The process has been described by the EFMA (EFMA, 2000c). Approximately 4–7 L of process water per kg of P_2O_5 is needed to dilute H_3PO_4 to the final concentration. The reaction is exothermic and thus cooling water is used at a rate of 100–150 L per kg P_2O_5 . The process and cooling water requirements are shown in Table 26.

9.9 Potassium

Potassium is one of the most important plant nutrients and is frequently applied in fertilizers. Potassium cannot easily be manufactured synthetically, so it is mined. Potassium ores are found with a complex mixture of anions, so mining data are often reported as mass as K_2O . Two mining techniques are commonly used: underground mining and solution mining. Solution mining uses hot water for extraction, whereas underground mining requires minimal water. The extract is then typically beneficiated at the surface to achieve a sufficiently concentrated product for the potassium market. The beneficiation process consumes large quantities of water resources. Rock salt is a common co-product.

According to its website, the Canadian province of Saskatchewan supplies 70% of the United States potassium demand (Government of Saskatchewan, 2014). The Potash Corporation provides water consumption and other environmental data on its website (Potash Corporation, 2014), including data for its Allan Facility in Saskatchewan, which produces over 1 million tonnes of K_2O annually, while the United States consumes approximately 4.7 million tonnes (USGS Minerals Information, 2012). Assuming the water consumption data for the Allan mine are representative, the water consumption associated with potassium mining is 2.5 L per kg K_2O , as shown in Table 26.

9.10 Limestone

Limestone ($CaCO_3$) is used to generate lime, which is applied with fertilizers to control soil pH. Limestone cannot be manufactured readily and must be mined and then transported to a cutting facility. The mining and transportation process requires minimal water. The cutting process, however, generates heat and requires cooling water. The Natural Stone Council performed a life-cycle inventory for limestone quarrying and processing (University of Tennessee, Center for Clean Products, 2008) and found that approximately 20,000 gal/ton $CaCO_3$ were used, according to data from production of 250,000 tons of limestone. The 20,000 gal/ton converts to a water consumption of 83 L per kg $CaCO_3$, as shown in Table 26.

9.11 Lime

Lime (CaO) is produced by grinding and combusting limestone followed by the addition of cooling and process water (slaking) for distribution. Hassibi (1999) described the lime slaking process and indicated that 2.5 to 6 L of water is needed per kg CaO , as shown in Table 26.

9.12 Ammonium Phosphates

Ammonium phosphates are manufactured by reacting ammonia with phosphoric acid. Two different salts are generally formed as a mixture, monoammonium phosphate ($NH_4H_2PO_4$) and diammonium phosphate ($(NH_4)_2HPO_4$). The production process for ammonium phosphates involves reaction, granulation and drying. The reaction is exothermic, so a cooling process is

needed to capture the excess heat produced. According to the EFMA, the heat generated is small enough that the process can utilize ambient air for cooling, and thus the process consumes no water directly (EFMA, 2000d). The scrubbing of the exhaust gas consumes water. The amount of make-up water needed depends on whether the scrubber liquor is recycled. The EFMA indicates that a typical scrubber gas composition is 60 mg ammonia, 500 mg nitrogen oxides, and 5 mg fluorine per standard m^3 wet air, and that 0.2 kg ammonia, 1.0 kg nitrogen oxides, and 0.01 kg fluorine are used per tonne of phosphate produced (EFMA, 2000d). These numbers imply a scrubber flow rate of 3.3 m^3 per kg phosphate (as P_2O_5) produced, which, combined with the concentration of water vapor in saturated air at standard temperature (18 g/m^3) implies a WCF of 0.06 L per kg phosphate as P_2O_5 (Table 17).

9.13 Pesticides

Unlike fertilizers, the production processes for pesticides rapidly change and are typically proprietary, as the industry constantly modifies its practices to deal with pest resistances, regulations, etc. As a result, there is limited information on the specific details of water consumed in the production of pesticides.

Monsanto Company is the largest producer of pesticides in the United States, and the company provides an annual corporate sustainability report for its facilities. In 2012, Monsanto reported production of 503,000 tonnes of pesticides, a withdrawal of 19,100 million L of water, and a return flow of 18,800 million L (Monsanto, 2012). Personal communications with the company (Monsanto, 2014) indicated that the production figure includes both the active ingredients (~50%) and non-active ingredients (~50%). In GREET and in agricultural practices, pesticide application rates are based on active-ingredient quantities. According to the data from Monsanto, the water consumption for a pesticide is 1.19 L water per kg active ingredient.

Water is used to dilute pesticides before they are applied in the field. Personal communications with an agricultural specialist from Conservation Agriculture (Plummer, 2014) indicated that 10–15 gal of water is used to dilute the active ingredient before field application to corn in the United States corn belt. The current U.S. corn yield is approximately 150 bushels (~9000 lb) per acre. Under these assumptions, the dilution water needed for pesticides is approximately 0.012 L per kg wet corn biomass. The total water consumption estimate for dilution and production is 1.21 L water per kg pesticides as shown in Table 26.

9.14 Cooling and Process Water Assumptions

Cooling water is used in many of the chemical production processes described above. Typically, the cooling water system is designed to achieve a temperature change of approximately 10°C . Vaporizing water at 20°C requires approximately 2450 kJ per kg, while a 10°C change in water temperature requires less than 42 kJ per kg (less than 2% of the latent heat of vaporization). The consumption associated with withdrawals for once-through cooling systems was assumed to be 5% of the withdrawal consistent with a single pass through a cooling tower (McCabe et al., 1993). The final amount of process water depends on the concentration in

the field application of the chemical, but is currently assumed to be accounted for in the inventory provided above. As with other processes, the water consumed in upstream inputs in chemical production processes is automatically accounted for in the GREET life-cycle analysis.

9.15 Agricultural Chemicals Summary

The compiled water usage and consumption data for the process and cooling water for the agricultural chemicals discussed above are shown in Table 26. The process water was assumed to be consumed, while 5% of the cooling water withdrawals are assumed to be consumed, and the median values were adopted when ranges were available. The WCFs for the production processes in Figure 14 were derived by converting the estimates in Table 26 to the final values in gal per ton (for consistency with GREET). The pesticide result was assumed to be representative of each of the herbicides and insecticides in GREET.

Table 26. Direct Water Consumption Estimates for Agricultural Chemicals

GREET Chemical Name	Process Water (L/kg)	Cooling Water Usage (L/kg)	Water Consumption (L/kg chemical)
Ammonia (NH ₃)			0.7–1.5
Urea (CO(NH ₂) ₂)		51–80	2.6–4.0
Nitric Acid (HNO ₃)	0.3–1.5	72	3.9–5.1
Ammonium Nitrate (NH ₄ NO ₃)		23.5	1.2
UAN (CO(NH ₂) ₂ NH ₄ NO ₃)			0.244
Sulfuric Acid (H ₂ SO ₄)		48.8	0.244
Phosphoric Rock (P ₂ O ₅)			10
Phosphoric Acid (H ₃ PO ₄)	4–7	100–150	9–14.5
Ammonium Phosphates (NH ₄ H ₂ PO ₄ , (NH ₄) ₂ HPO ₄)			0.06
Potassium (K ₂ O)			2.5
Limestone (CaCO ₃)	83		83
Lime (CaO)	2.5–6		2.5–6
Pesticides			1.21

The estimated WCFs for each of the agricultural chemicals in the units used in GREET are shown in Table 27. The limestone water consumption factor is particularly large on a per ton basis. Limestone is used to produce a variety of other resources in GREET, so this estimate warrants a more in-depth assessment in the future.

Table 27. Summary of Estimated Agricultural Chemical Process WCFs

Process	WCF	Units
Ammonia production	264	gal/ton NH ₃
Urea production	791	gal/ton CO(NH ₂) ₂
Nitric acid production	1080	gal/ton HNO ₃
Ammonium nitrate production	288	gal/ton NH ₄ NO ₃
UAN production	58	gal/ton UAN
Sulfuric acid production	58	gal/ton H ₂ SO ₄
Phosphoric rock production	2397	gal/ton P ₂ O ₅
Phosphoric acid production	2816	gal/ton H ₃ PO ₄
Monoammonium phosphate production	14.4	gal/ton (NH ₄) ₂ HPO ₄
Diammonium phosphate production	14.4	gal/ton NH ₄ H ₂ PO ₄
Potassium production	599	gal/ton K ₂ O
Limestone production	19891	gal/ton CaCO ₃
Lime production	1019	gal/ton CaO
Atrazine production	290	gal/ton atrazine
Metolachlor production	290	gal/ton metolachlor
Acetochlor production	290	gal/ton acetochlor
Cyanazine production	290	gal/ton cyanazine
Insecticide production	290	gal/ton insecticide

10. OTHER CHEMICALS

The conversion processes for biofuels and some of the processes in the alternative fuel pathways in GREET require production of chemicals not described in previous sections. The production of algal biofuels requires a complex mixture of nutrient media, and the conversion processes for bioethanol and biodiesel require additional chemicals that are accounted for in the GREET framework. The following subsections describe the water consumption associated with these processes.

10.1 Sodium Chloride

Sodium chloride (NaCl) is used in GREET to provide the chloride anion for ammonium chloride in the algal biofuel pathway. Commercial sodium chloride is typically produced either by mining or by concentration of brackish water supplies. Sodium chloride in the form of brine is used together with ammonia and carbon dioxide in the co-production of sodium bicarbonate (soda ash) and ammonium chloride via the Solvay process. The GREET energy inventory assumes that the sodium chloride comes from salt mining, which is a water- and energy-intensive operation. However, the Solvay process typically utilizes brine for ammonium chloride production. Brine is a by-product of many operations and, as a result, salt production from brine does not consume water resources. Alternatively, solution and underground mining are very energy and water intensive.

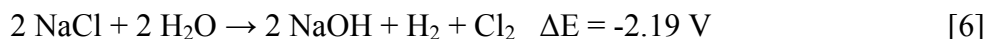
The U.S. Geological Survey (USGS) reported the following breakdown of production pathways for salt: vacuum and open pans (11%), solar (7%), rock salt mining (36%), and brine from sea/surface water (46%) (Bolen, 2014). For production of salt by evaporation of brine water, the water consumption is effectively zero. For underground rock salt mining, shafts are sunk down into the mine and the salt is extracted by drilling, cutting, and blasting followed by removal with a conveyor belt. Thus, the underground mining technique requires essentially no water. Solution mining, however, requires injection of large quantities of water which are used to dissolve the salt underground, then brought back to the surface and evaporated. Solution mining is typically used when high-purity salt is required. To minimize pumping costs and water consumption, mining operations are designed to saturate the solution mining water. The solubility of sodium chloride in water is 359 g/L; assuming the solution reaches saturation and is all consumed by evaporation; this equates to 1.79 kg water consumed per kg sodium chloride. The USGS indicates that 91% of sodium chloride used in the chemical industry in 2014 came from salt in brine (Bolen, 2014), so the saturated solution value was used to derive the recommended WCF.

10.2 Potassium Chloride

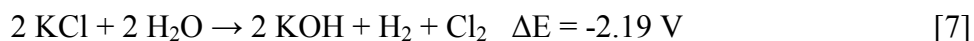
Potassium chloride (KCl) is produced by mining. Potassium chloride is the primary form of potassium used in fertilizers, as described in Section 9. However, potassium fertilizers have historically been characterized by mass of K₂O because of the complexity of the minerals. The estimated WCF for K₂O described previously of 1.51 L water per kg KCl was converted using the compounds' respective molecular weights into a WCF of 362 gal/ton for KCl.

10.3 Sodium and Potassium Hydroxide

Sodium hydroxide (NaOH) is generally produced by the electrolysis of sodium chloride, described by the following reaction:



Potassium hydroxide (KOH) is produced using a similar reaction:



As indicated by the standard electrochemical potential, the electrolysis reaction is not spontaneous and thus requires input electrical energy. Potassium hydroxide production generates hydrogen and chlorine gas, both of which are useful by-products. Process water is supplied and is incorporated into the final product and a concentrated waste stream. GREET currently utilizes data from another study (Worrell et al., 2000) to estimate the required electricity consumption for chlorine hydrolysis. The study was based on the production of sodium hydroxide, which has the same fundamental chemical processing requirements as potassium hydroxide production since the cation serves as only a spectator in the reactions in both cases. The net energy consumption factor for the reaction was 15.88 GJ per tonne, including an energy credit for the hydrogen

co-production. In GREET, a mass-based allocation between the chlorine and sodium was used to arrive at a final energy consumption factor of 8.5 mmBtu per ton. The report of Worrell et al. (2000) did not perform any water accounting, however.

The Chemical Economics Handbook presents information on the chlorine hydrolysis process (Linak et al., 2005). The common processes used for chloride/caustic production include diaphragm cells, mercury cells, and membrane cells. The production levels for these technologies are shown in Table 28. Wilson and Jones (1994) provided estimates of process water consumption and cooling water requirements for the technologies, which are shown in Table 28.

Table 28. Sodium and Potassium Hydroxide Production Statistics

Technology	U.S. Production Share ¹ (%)	Process Water Consumption ² (kg/kg)	Cooling Water Requirements ² (m ³ /tonne)
Diaphragm cell	61	5.96	290
Mercury cell	4	3.32	100
Membrane cell	34	3.16	100
Production-weighted average		4.89	217

¹ Linak et al., 2005

² Wilson and Jones, 1994

On the basis of the production-weighted averages, the process water consumption is 4.89 kg per kg and the cooling water requirements are 217 m³ per tonne. Conservatively assuming (consistent with other GREET water analysis numbers) that 5% of the cooling water withdrawals are consumed, the additional water consumption for cooling is 10.85 kg water/kg sodium/potassium hydroxide. Thus, the total water consumption for sodium and potassium hydroxide production is estimated to be 15.75 L per kg sodium/potassium hydroxide. Using a mass-based allocation between the hydroxide and chlorine co-products and converting the units provides WCFs of 2002 gal per ton for sodium hydroxide and 2329 gal per ton for potassium hydroxide production.

10.4 Sodium Nitrate

Sodium nitrate (NaNO₃) can either be mined directly or synthesized in a chemical plant. In GREET, sodium nitrate is assumed to come from mining operations, which exist only in Chile. The energy production in GREET is assumed to be the same as that used for potassium mining. A literature search revealed no data on water consumption in sodium nitrate mining, so given the absence of better data, the WCF is assumed to be the same as for potassium chloride mining.

10.5 Potassium Sulfate

Potassium sulfate ore, also known as Langbeinite ($K_2SO_4 \cdot 2MgSO_4$), is a potassium magnesium sulfate mineral. In GREET, Langbeinite is assumed to come from mining and serves as a source for potassium sulfate (commonly referred to as sulfate of potash) in algal biofuel production. Langbeinite is one of the principal ores of potassium, but can also be produced by manufacturing. In the United States, the majority comes from mining operations. Because it comes from the same mines, Langbeinite is assumed to have the same WCF as potassium chloride after an adjustment for molecular weight.

10.6 Ammonium Chloride

Ammonium chloride (NH_4Cl) is typically co-produced with sodium bicarbonate (soda ash) via the Solvay process. The energy inventory in GREET is based on the assumption of mining of sodium chloride, which is then combined with synthetic ammonia to co-produce ammonium chloride and sodium bicarbonate. The energy input for the process is divided between the co-products using a mass allocation. The process has high energy requirements (Schlag and Fukada, 2009). However, aside from the initial dissolution of the sodium chloride, the process utilizes no water. Therefore, the value of the solubility of sodium chloride (1.79 kg water per kg NaCl) is used for the process water consumption. Assuming a mass allocation between the sodium carbonate and ammonium chloride and converting the units, the WCF is 168 gal per ton for ammonium chloride production.

10.7 Other inorganic salts

The existing material and energy flows in GREET ignore energy inputs associated with simple mixing processes to form salts from the inorganic salts described previously. Some of the formation reactions for these mixtures are exothermic and require small amounts of cooling water. For example, the formation of calcium nitrates (limestone dissolved in nitric acid), superphosphates (phosphate rock dissolved in acid), and potassium phosphates (potassium hydroxide and phosphoric acid) utilizes water directly. Calcium nitrate is often produced concurrently in mixtures with ammonium nitrate by a similar neutralization process (EFMA, 2000e). The estimated WCF for ammonium nitrate is 288 gal per ton, as described in Chapter 9 on the basis of the neutralization of ammonia and nitric acid. The cooling water requirements and consumption are assumed to be the same for each of these mixtures following an adjustment for molecular weight.

10.8 Summary

The final WCFs for the chemicals described in this section are shown in Table 29. The hydrolysis reactions are particularly water-intensive on a per unit mass basis.

Table 29. Summary of Estimated Chemical Production WCFs

Process	WCF	Units
Sodium chloride production	429	gal/ton NaCl
Potassium chloride mining	362	gal/ton KCl
Potassium hydroxide electrolysis	2329	gal/ton KOH
Sodium hydroxide electrolysis	2002	gal/ton NaOH
Sodium nitrate mining	362	gal/ton NaNO ₃
Langbeinite mining	131	gal/ton K ₂ SO ₄ •2MgSO ₄
Ammonium chloride production	168	gal/ton NH ₄ Cl
Potassium nitrate production	228	gal/ton KNO ₃
Calcium nitrate production	140	gal/ton Ca(NO ₃) ₂
Calcium nitrate production	98	gal/ton Ca(NO ₃) ₂ •4H ₂ O
Potassium phosphate production	132	gal/ton K ₂ HPO ₄
Potassium phosphate production	101	gal/ton K ₂ HPO ₄ •3H ₂ O
Potassium phosphate production	169	gal/ton KH ₂ PO ₄
Ammonium phosphate production	175	gal/ton (NH ₄) ₂ HPO ₄
Potassium sulfate production	132	gal/ton K ₂ SO ₄
Superphosphate production	46	gal/ton Ca(H ₂ PO ₄) ₂ •2CaSO ₄
Triple superphosphate production	98	gal/ton Ca(H ₂ PO ₄) ₂
Triple superphosphate production	91	gal/ton Ca(H ₂ PO ₄) ₂ •H ₂ O

11. BIOFUEL PRODUCTION

Biofuel production involves a complicated supply chain including production of agricultural chemicals, farming operations, irrigation, transportation to refineries, and conversion to the final fuel. Water is consumed throughout the supply chain, both directly in these processes and indirectly through the production of the upstream inputs. Figure 15 shows the GREET biofuel supply chain. WCFs were estimated from either the literature or other data for each process in the figure.

The biomass derived from corn farming includes both corn grain and corn stover, both of which can be used to generate ethanol for transportation fuels. Corn grain is rich in starches that can be converted into ethanol by yeast and other enzymes using either a dry-mill or a wet-mill fermentation process. The processes use different amounts of water and generate different co-products. Corn stover can also be converted into ethanol using fermentation following pre-treatment. Alternatively, the stover can be converted into syngas thermochemically via a gasification process and then fermented into ethanol. Soybeans (or other oil seeds) can be converted into biodiesel using a transesterification reaction with methanol or other alcohol following extraction from the biomass. The direct water consumption to produce the chemicals required for the conversion technologies was largely excluded, although the indirect water consumption used to produce these inputs (e.g., water embedded in the upstream energy) is included in the GREET framework.

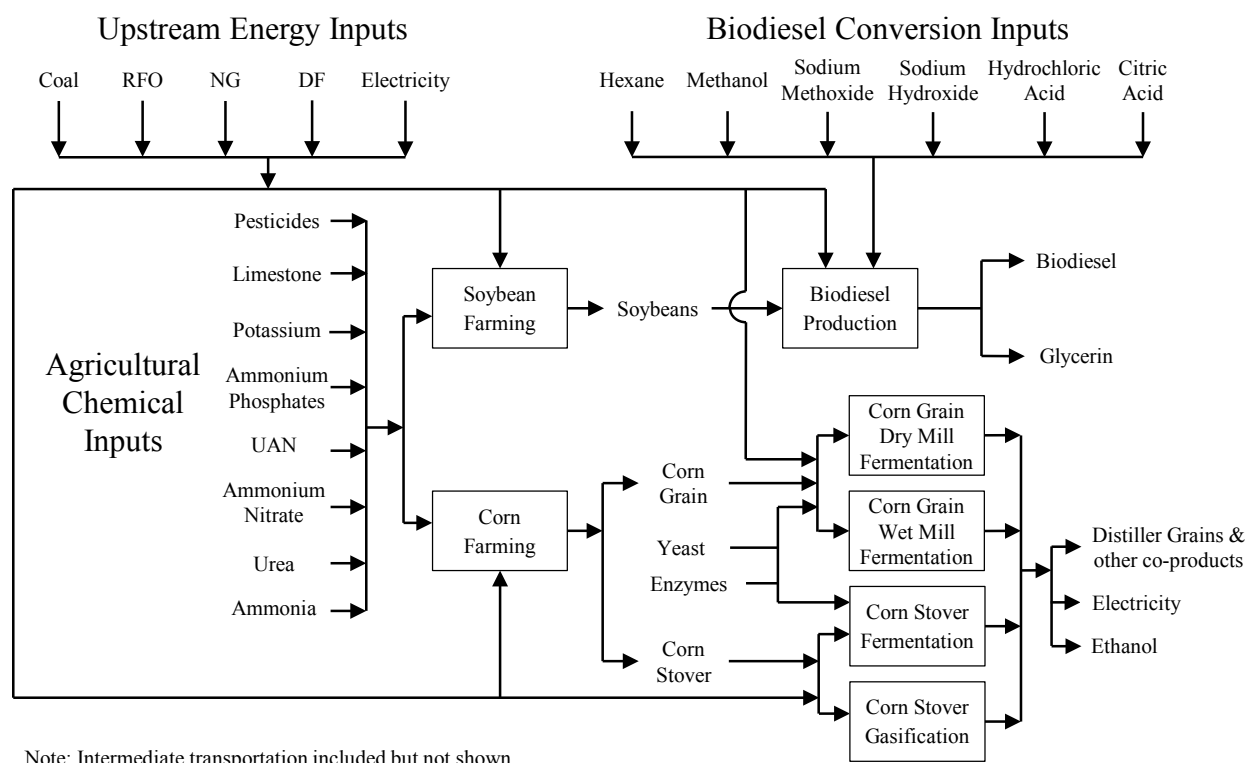


Figure 15. Input-output relationships for biofuel production in GREET.

In addition to biofuels, biorefineries co-produce several useful items. Glycerin is co-produced with soy biodiesel. Distiller grains, corn oil, corn syrup, gluten, and other animal feeds are co-produced with corn ethanol. Heat from the process can be captured and converted into electricity. As shown in Figure 15, some of the water consumption burden should be allocated to these co-products; however, the allocation methodology is specified in GREET and not discussed in this report. Allocation methodologies and the resulting implications have been analyzed and discussed previously (Wang et al., 2011).

11.1 Corn Farming

As discussed in Section 2, the water consumption definition associated with agricultural activities accounts for only the irrigation water that is not returned to the original water resource. Because of variability in climate and vegetation, the amount of water needed to grow a particular crop exhibits a high degree of spatial variability. Chiu and Wu (2012) estimated irrigation water consumption for corn grown in the U.S. on a county-level basis by disaggregating state-level estimates based on irrigation and agricultural surveys to the county level using climate data. As the goal of this analysis was to provide data for a national-level estimate of water consumption associated with bioethanol, the approach used by Chiu and Wu (2012) for the state-level estimates was replicated and then used to develop a production-weighted average for the U.S.

A number of data sources were used to estimate U.S. corn farming water consumption. The USGS has previously estimated water withdrawals and consumption including irrigation in millions of gal per day (mgd) at the state level (Solley et al., 1998). The United States Department of Agriculture collects information through the National Agricultural Statistics Service (NASS), including county and state-level corn production from the Census of Agriculture (NASS, 2009, 2004, 1999). NASS also conducts a Farm and Ranch Irrigation Survey to estimate a variety of other statistics, including the volume of water applied per unit area of farmland or water depth and irrigated acreage for corn at the county and state level the year after each census. Chiu and Wu (2012) estimated water withdrawals on a state-level basis using irrigation acreages and depths from the 1998, 2003, and 2008 surveys and production data from the 1997, 2002, and 2007 censuses for corn. The state-level USGS data from Solley et al. (1998) were then assumed to be representative of the ratio of irrigation consumption relative to withdrawals and were used to extend the withdrawal estimate into state-level consumption estimates for corn.

Water conservation practices and technology for irrigation have improved as water resources have become more stressed. The data from the most recent census (2007) and survey (2008) were assumed to be representative of water consumption associated with corn farming. Previous GREET analysis of corn energy (Shapouri et al., 2002) utilized data from the nine states that are the major ethanol producers: Illinois, Indiana, Iowa, Minnesota, Nebraska, Ohio, Michigan, South Dakota, and Wisconsin. Table 30 shows the data for these states, including the total water consumption estimate and total production. The application rates d and acreages A were used to estimate the corn irrigation water withdrawals. The 1995 consumption C and withdrawal W estimates were assumed to be representative of corn irrigation and used to convert the withdrawals into state level corn farming water consumption estimates Q using the following equation:

$$Q = \frac{dAC}{W} \quad [7]$$

The resulting values are shown in the table. The total water consumption for these states was then normalized by the corn production to estimate a WCF of 146 gal per bushel for corn farming.

Table 30. State-Level Corn Farming and Irrigation Statistics

State	Corn Irrigation Estimates ¹		1995 USGS Irrigation ²		Estimated Water Consumption (acre-ft)	Corn Production Estimates ³ (bushel)
	Area (acre)	Depth (ft)	Withdrawal (mgd)	Consumption (mgd)		
Illinois	309,187	0.5	180	180	154,594	2,248,664,947
Indiana	244,574	0.6	116	104	131,564	959,947,232
Iowa	107,979	0.5	39	39	53,990	2,292,163,101
Minnesota	254,960	0.6	157	140	136,412	1,138,660,229

Table 30. (Cont.)

State	Corn Irrigation Estimates ¹		1995 USGS Irrigation ²		Estimated Water Consumption (acre-ft)	Corn Production Estimates ³ (bushel)
	Area (acre)	Depth (ft)	Withdrawal (mgd)	Consumption (mgd)		
Missouri	361,275	0.8	567	421	214,599	439,417,160
Nebraska	5,058,195	0.8	7,550	6,740	3,612,422	1,426,459,812
Ohio	7,260	1.5	27	26	10,487	526,601,789
South Dakota	175,593	0.8	269	175	91,387	518,552,101
Wisconsin	105,809	0.7	169	151	66,178	437,174,706
Total					4,471,630	9,987,641,077

¹ NASS (2009)

² Solley et al. (1998)

³ Includes production from irrigated and non-irrigated farmland (NASS, 2009)

11.2 Soybean Farming

Water consumption associated with soybean farming for the biodiesel pathway was estimated following a methodology similar to that used for corn farming. The approach used by Chiu and Wu (2012) for the state-level estimates was replicated and then used to develop a production-weighted average for the U.S. The spatial variability in soybean production for biodiesel was not considered, and data for all soybean-producing states were used in the accounting. Table 31 shows the data for all the states using the 2008 survey and 2007 census data from NASS for soybeans. The estimated WCF associated with soybean farming of 530 gal per bushel.

Table 31. State-Level Soybean Farming and Irrigation Statistics

State	2008 Soybean Irrigation Estimates ¹		1995 USGS Irrigation ²		Estimated Water Consumption (acre-ft)	2007 Soybean Production ³ (bushel)
	Area (acre)	Depth (ft)	Withdrawal (mgd)	Consumption (mgd)		
Alabama	8,779	0.6	139	139	5,267	3,660,854
Arkansas	2,167,646	0.9	5,940	4,390	1,441,813	98,903,025
Colorado	4,832	1.2	12,700	4,910	2,242	148,420
Connecticut	0	0	28	28	0	13,365
Delaware	33,770	0.6	48	48	20,262	3,990,694
Florida	212	0.8	3,470	2,170	106	291,981
Georgia	71,621	0.6	722	722	42,973	7,970,113
Illinois	90,497	0.5	180	180	45,249	353,741,105
Indiana	102,279	0.5	116	104	45,849	211,074,079

Table 31. (Cont.)

State	2008 Soybean Irrigation Estimates ¹		1995 USGS Irrigation ²		Estimated Water Consumption (acre-ft)	2007 Soybean Production ³ (bushel)
	Area (acre)	Depth (ft)	Withdrawal (mgd)	Consumption (mgd)		
Iowa	48,946	0.4	39	39	19,578	430,739,578
Kansas	396,613	1	3,380	3,220	377,838	82,719,224
Kentucky	6,173	0.4	12	11	2,263	29,582,097
Louisiana	184,976	0.7	769	596	100,354	24,717,263
Maine	0	0	27	24	0	22,570
Maryland	26,119	0.6	62	57	14,408	10,381,954
Massachusetts	0	0	82	81	0	10,530
Michigan	73,986	0.5	227	216	35,200	67,515,728
Minnesota	100,513	0.6	157	140	53,778	259,891,979
Mississippi	712,268	0.8	1,740	1,110	363,502	54,316,854
Missouri	488,319	0.7	567	421	253,805	165,947,323
Montana	624	1	8,550	1,820	133	16,084
Nebraska	2,272,944	0.6	7,550	6,740	1,217,455	189,547,373
New Jersey	3,418	0.5	125	46	629	2,443,231
New York	0	0	30	26	0	7,456,657
North Carolina	14,839	2.5	239	239	37,098	29,142,115
North Dakota	18,939	0.7	117	105	11,898	106,556,290
Ohio	1,702	3.2	27	26	5,245	191,559,567
Oklahoma	23,793	0.8	864	401	8,834	4,559,245
Pennsylvania	363	0.2	16	16	73	17,386,829
South Carolina	12,741	0.6	52	52	7,645	7,833,696
South Dakota	79,296	0.5	269	175	25,793	130,377,538
Tennessee	27,325	0.6	24	24	16,395	18,552,793
Texas	30,607	1	9,450	8,140	26,364	3,439,765
Vermont	0	0	4	4	0	75,318
Virginia	8,796	0.5	30	18	2,639	12,624,547
Washington	382	1.9	6,470	2,800	314	27,781
Wisconsin	30,410	0.6	169	151	16,303	54,701,222
Total					4,201,304	2,581,938,787

¹ NASS (2009)² Solley et al. (1998)³ Includes production on irrigated and non-irrigated farmland (NASS 2009)

11.3 Corn Grain Ethanol Produced by Dry-Mill Fermentation

Corn ethanol production from corn grain requires water for grinding, liquefaction, fermentation, separation, and drying (Wu and Chiu, 2011). The water system in a typical dry-mill corn ethanol plant is shown in Figure 16. The cooling tower and dryer account for the majority (53% and 42%, respectively) of the water consumption at a corn ethanol plant (Wu and Chiu, 2011). Advancements in refining technologies have improved water consumption efficiency in ethanol conversion facilities in recent years. Wu and Chiu (2011) summarized this

trend, comparing water consumption of 5.8 gal per gal ethanol in 1998 to 3.0 gal per gal in 2007. Another recent survey (Mueller and Kwik, 2013) found that the average water consumption for corn ethanol production has further decreased to 2.70 gal per gal ethanol, driven by the more efficient use of water. This study of the biorefinery industry's 2012 status explored the adoption of modern energy and processing technologies that have reduced the energy and environmental footprint of the corn ethanol production pathway. Mueller and Kwik (2013) covered over 50% of currently operating dry-grind (dry-milling) corn ethanol plants, which produce around 90% of the total corn ethanol in the U.S. The estimated WCF for dry-mill fermentation was of 2.7 gal per gal ethanol.

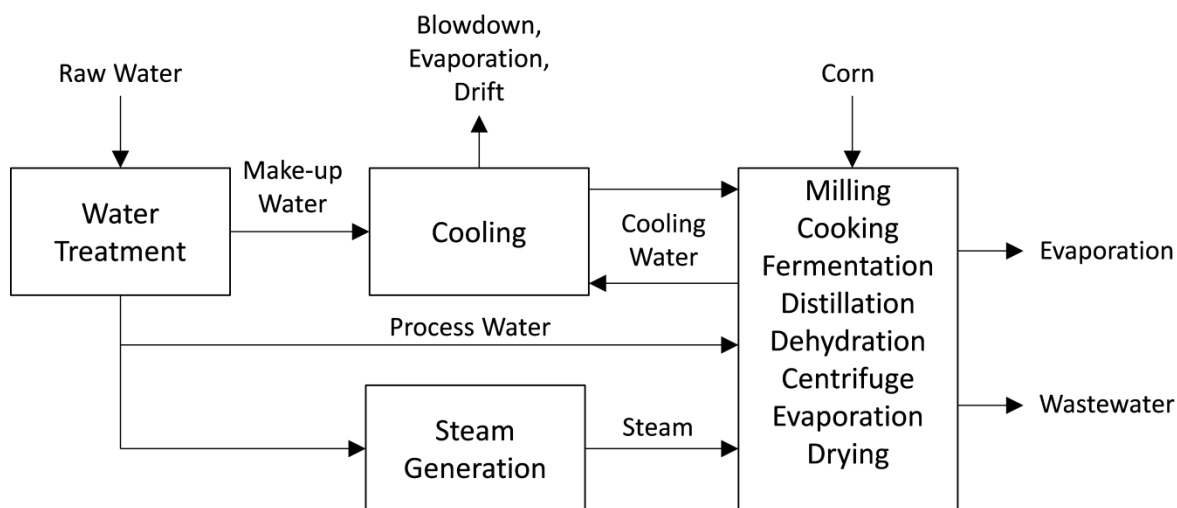


Figure 16. Water system in a typical dry-mill ethanol plant (redrawn on the basis of Wu and Chiu, 2011).

11.4 Corn Grain Ethanol Produced by Wet Mill Fermentation

In the wet-mill fermentation process, grain is soaked in water for 24 to 48 hours before grinding and separating the resulting slurry into a number of different streams to produce a number of different co-products, as shown in Figure 17. Wu (2008) summarized the efficiency of ethanol production, including the wet-milling industry, on the basis of a survey of ethanol production plants. The study found that wet mills consume 3.92 gal of water per gallon of ethanol produced, which was taken for the WCF for this analysis.

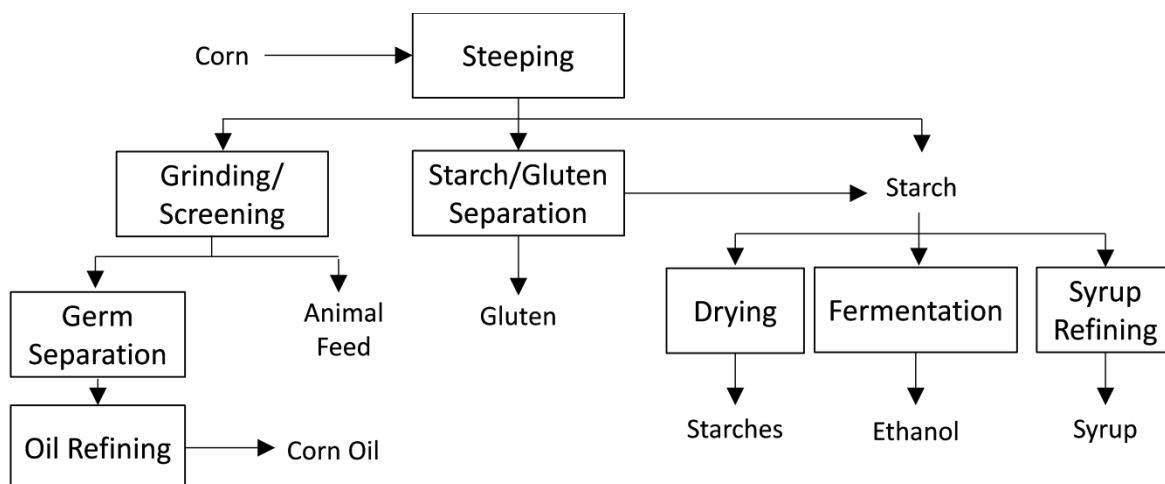


Figure 17. Process flow diagram for wet milling (redrawn on the basis of Renewable Fuels Association, 2014).

11.5 Corn Stover Ethanol Produced by Fermentation

In a typical corn stover ethanol plant, the cellulosic biomass is pretreated and hydrolyzed to sugars, which are then fermented to produce ethanol. The National Renewable Energy Laboratory (NREL) designed a process that uses co-current dilute-acid pretreatment of lignocellulosic biomass (corn stover), followed by enzymatic hydrolysis (saccharification) of the remaining cellulose, and fermentation of the resulting glucose and xylose to ethanol (Humbird et al., 2011). The process flow diagram is shown in Figure 18. The lignin fraction is combusted for process energy use. Water is used for pretreatment, cellulase production, sugar fermentation, separation, and cooling. Humbird et al. (2011) reported a total water input for the cellulosic ethanol plant of 7.65 gal per gal ethanol. However, this value included water in the biomass, embedded water in other inputs, and water recycled from various processes. The make-up water usage for cellulosic ethanol production from fermentation was estimated to be 5.35 gal per gal ethanol (Humbird et al., 2011) of which the major water consumer was the cooling tower, which was estimated to use 5.00 gal per gal ethanol produced (over 90% of the make-up water). For consistency with GREET, the water associated with the upstream inputs was ignored and the WCF of 5.35 gal per gal ethanol was selected.

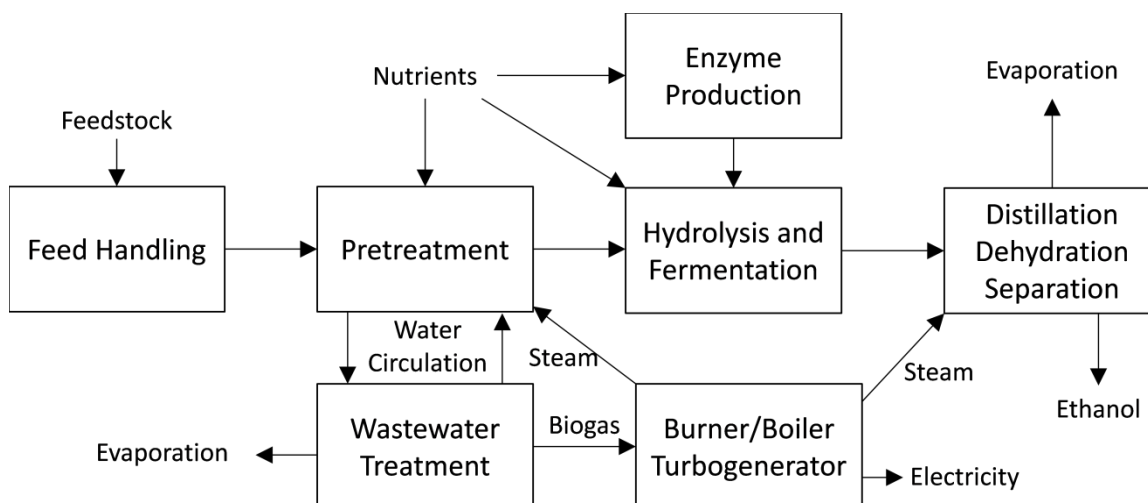


Figure 18. Process flow diagram for cellulosic ethanol fermentation (redrawn on the basis of Humbird et al., 2011).

11.6 Corn Stover Ethanol Produced by Gasification

Ethanol can also be produced via a thermochemical pathway consisting of indirect gasification and mixed alcohol synthesis. Thermochemical ethanol gasification includes feedstock handling and pretreatment, gasification, gas cleanup, alcohol synthesis, alcohol separation, and purification, as depicted in Figure 19. Water is mainly used for gas cleanup and cooling. Dutta et al. (2011) assessed gasification of cellulosic biomass using Southern Pine trees as a feedstock. Two case studies were conducted: one base-case scenario without water optimization and one water optimization scenario in which process condensate was treated and combined with the cooling water make-up to reduce freshwater consumption. For the base-case scenario, the consumptive water usage was 2.61 gal per gal ethanol, including 1.42 gal per gal ethanol for the cooling tower and 1.19 gal per gal ethanol for the boiler. For the optimized water consumption case, the estimated water consumption was 1.97 gal per gal ethanol, including 0.38 gal per gal ethanol for the cooling tower and 1.59 gal per gal ethanol for the boiler. The WCF of 2.61 gal per gal ethanol for the base case for the Pine feedstock was assumed to be representative of current cellulosic production (i.e., corn stover) and was selected for this analysis.

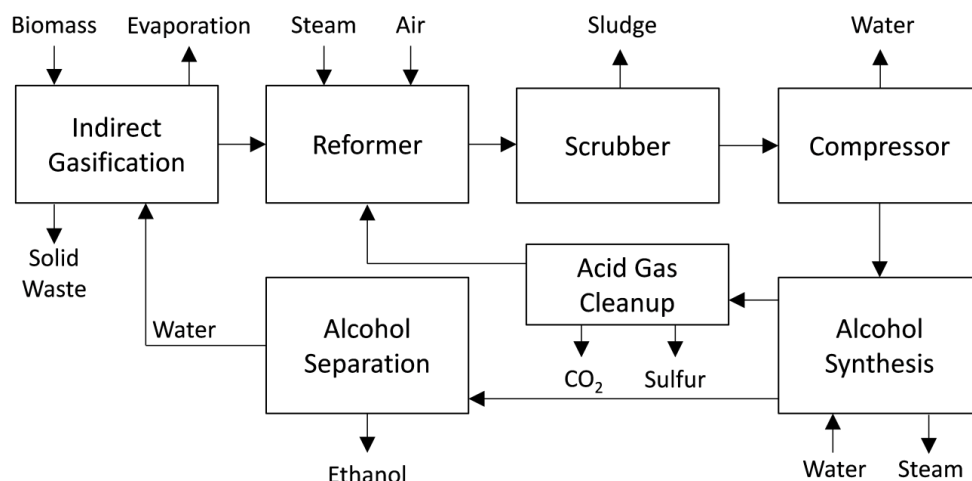


Figure 19. Process flow diagram for cellulosic ethanol gasification (redrawn on the basis of Dutta et al., 2011).

11.7 Soybean Biodiesel Production

In a typical soybean-to-biodiesel production plant, soybean oil is first extracted, then converted to crude fatty acid methyl esters by esterification and trans-esterification processes, and then purified by washing to remove trace impurities, as shown in Figure 20. Glycerin is a valuable co-product of biodiesel production. Water is consumed in biodiesel plants during washing, cooling and drying. According to the National Biodiesel Board, water consumption at biodiesel plants varies between 0.32 and 1.0 gal per gal biodiesel (O'Connor, 2010). The median value of 0.66 gal per gal biodiesel was assumed to be representative of the WCF and adopted for this analysis. The final values for the biofuel production processes are summarized in Table 32.

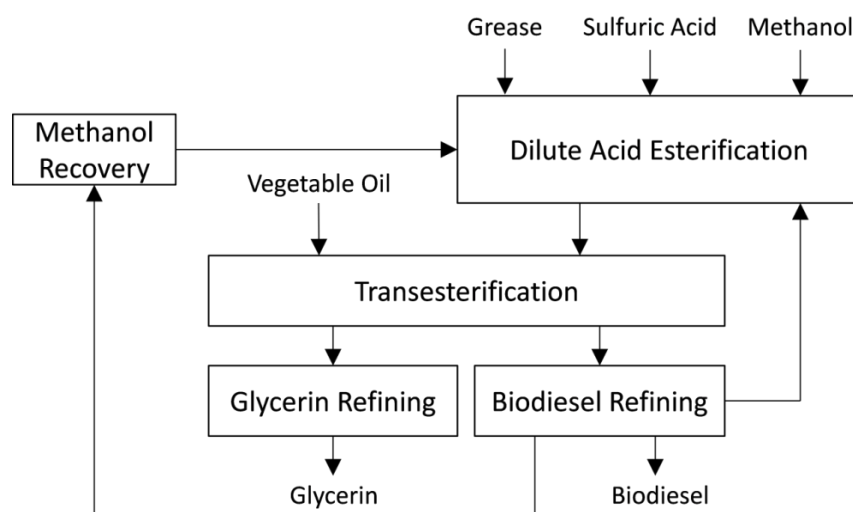


Figure 20. Process flow diagram for biodiesel production (redrawn on the basis of O'Connor, 2010).

Table 32. Summary of Estimated Biofuel Process WCFs

Process	WCF	Units
Corn farming	146	gal/bushel corn
Soybean farming	530	gal/bushel soybeans
Corn grain dry-mill fermentation	2.7	gal/gal ethanol
Corn grain wet-mill fermentation	3.92	gal/gal ethanol
Corn stover fermentation	5.35	gal/gal ethanol
Corn stover gasification	2.61	gal/gal ethanol
Soybean biodiesel production	0.66	gal/gal ethanol

12. SUMMARY, RECOMMENDATIONS, AND FUTURE ANALYSIS

The values of the estimated WCFs described in this report coupled with the GREET framework can be used to perform life cycle analysis of water consumption associated with the primary and alternative transportation fuel pathways in GREET. Several gaps remain in the data, primarily related to the water consumption associated with the construction of infrastructure and some of the chemicals used in small quantities in some of the production processes. A thorough analysis of the impact and sensitivity of the WCFs in this document with respect to life-cycle water consumption is needed to highlight the key issues related to water consumption. Such an assessment will be useful for assessing the sustainability of transportation in the United States.

GREET provides estimates of life-cycle water consumption for many emerging fuel pathways, including higher-generation biofuels such as switchgrass, *Miscanthus*, algae, and municipal solid waste. The inventory described in this document enables a baseline-level analysis of the water consumed in the primary and alternative transportation fuel pathways. In the future, the inventory provided herein can be extended to assess the water consumption associated with emerging pathways for comparative scenario analysis.

This investigation has revealed several key issues where further analysis of the water consumed and allocated in the production of resources is needed. The following are areas where further characterization of the impacts of energy production technologies on water resources is needed:

1. The water consumption associated with emerging energy production pathways (emerging bio oils, cellulosic ethanol, synthetic fuels, etc.) should be characterized.
2. The water consumption associated with hydroelectric power is much larger than other electricity generation technologies. Because hydropower dams serve multiple purposes, an allocation methodology is needed for the water consumption associated with evaporation from the surface of the reservoir in hydroelectric dams.
3. Thermoelectric power generation water withdrawals represent a substantial share of the total withdrawals in the United States. The cooling technology used to dissipate excess

heat influences the amount of water consumed in these processes. Once-through cooling technologies withdraw large amounts of water that are discharged at higher temperatures, which increases water consumption. A thorough characterization of the associated increase in water consumption would be helpful for water resources planning during periods of low flows in summers and in droughts. Such analysis could also be applied to chemical processing and other thermal-polluting facilities.

4. The methodology used to allocate the evapotranspiration of water in agricultural processes between irrigation withdrawals and runoff is derived from older USGS estimates of state-level withdrawal versus water consumption for irrigation. The source of these estimates is unclear and appear inconsistent from state-to-state. Given the large water quantities consumed in biofuel feedstock generation and the implications of these estimates on the life cycle, it is important to characterize these ratios accurately.
5. The agricultural processes used for biomass growth exhibit a high degree of spatial and temporal variability and should be characterized in a manner that accounts for the regional water availability and drought scenarios.
6. Water consumption factors associated with crude oil recovery are based on a small number of old estimates of water consumption associated with recovery technologies. A more detailed geospatial characterization would be helpful to minimize the uncertainty in the water consumption associated with reservoir stimulation.
7. The growth of the shale oil and shale gas industries has been achieved largely because of new technological developments in hydraulic fracturing and horizontal drilling. Limited data exist on water consumption for shale oil. The water consumed in wells producing both shale and gas should be characterized and allocated between these two products.
8. Water consumption associated with coal surface mining exhibits high variability related to the location of the deposits relative to the groundwater table. Mining operations below the natural water table require drawdown and consumption of water resources. The current literature provides little insight into the location and magnitude of these impacts.
9. Geothermal power utilizes water for cooling, stimulation, drilling and for processing in EGS systems. The cooling technology impacts water consumption and energy efficiency. Geospatial characterization of water availability (including low-quality water for injection) and water consumption based on physical and geological properties are needed to establish the long-term viability of geothermal power plants.
10. For hydrogen production, the quality of the water (salinity) affects the consumption rates. The water pretreatment technology and local water availability will impact the lifecycle water and energy consumption. Local water resource availability and quality must be considered in the development of hydrogen delivery infrastructure.

11. The literature value for water consumption associated with limestone mining is considerably larger than values for other mining products. The water consumption associated with limestone mining may be important in the context of the life cycle water consumption for biofuels and other products derived from limestone and may warrant deeper investigation.
12. A methodological approach is needed to characterize the impacts of diminished water quality on water resources. Nonpoint source runoff from agricultural operations and water pollution associated with mining and chemical production were not characterized by the current analysis. The impacts of produced water from petroleum recovery and flow back water from shale gas on water quality are currently ignored. Water of slightly diminished quality (e.g., rejected water from reverse osmosis) is assumed to be consumed even though it may be of suitable quality for discharge to a water resource. These impacts should be characterized to provide a consistent comparison of different energy sources.
13. Given the inherent local impact of water issues, geospatial and temporal characterizations of the impacts of energy production technologies on water resources would provide policy-makers with a helpful tool for planning energy production in drought scenarios.

13. REFERENCES

- Adee, S., Moore, S.K., 2010. 1 THIRSTY MACHINES-THE POWER OF WATER-In the American Southwest, the energy problem is water. IEEE Spectr. 47, 26.
- API (American Petroleum Institute), 2000. Overview of Exploration and Production Waste Volumes and Waste Management Practices in the United States.
- Bolen, W.P., 2014. Salt [WWW Document]. URL <http://minerals.er.usgs.gov/minerals/pubs/commodity/salt/mcs-2014-salt.pdf>
- Buchan, M., Arena, B., 2006. Water and the refinery—an introduction to growing issues impacting refinery water use, in: American Institute of Chemical Engineers (AIChE) Chicago Symposium, Oct.
- Bush, J.L., Helander, D.P., 1968. Empirical prediction of recovery rate in waterflooding depleted sands. J. Pet. Technol. 20, 933–943.
- California Energy Commission, 2008. 2007 Environmental Performance Report of California's Electrical Generation System: Final Staff Report, CEC-700-2007-016-SF.
- Chiu, Y.-W., Wu, M., 2012. Assessing county-level water footprints of different cellulosic-biofuel feedstock pathways. Environ. Sci. Technol. 46, 9155–9162.
- Clark, C.E., Harto, C.B., Schroeder, J.N., Martino, L.E., Horner, R.M., 2013a. Life Cycle Water Consumption and Water Resource Assessment for Utility-Scale Geothermal Systems: An In-Depth Analysis of Historical and Forthcoming EGS Projects. Argonne National Laboratory (ANL), Argonne, IL (United States), ANL/EVS/R-12/8.
- Clark, C.E., Harto, C.B., Sullivan, J.L., Wang, M.Q., 2011. Water use in the development and operation of geothermal power plants. Argonne National Laboratory (ANL), ANL/EVS/R-10/5.
- Clark, C.E., Horner, R.M., Harto, C.B., 2013b. Life cycle water consumption for shale gas and conventional natural gas. Environ. Sci. Technol. 47, 11829–11836.
- Diehl, T.H., Harris, M.A., Murphy, J.C., Hutson, S.S., Ladd, D.E., 2013. Methods for Estimating Water Consumption for Thermoelectric Power Plants in the United States. US Geol. Surv. Rep. 5188, 2013.
- Dutta, A., Talmadge, M., Hensley, J., Worley, M., Dudgeon, D., Barton, D., Groenendijk, P., Ferrari, D., Stears, B., 2011. Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol Thermochemical Pathway by Indirect Gasification and Mixed Alcohol Synthesis (No. NREL/TP - 5100 - 51400). National Renewable Energy Laboratory Golden, CO.

Dziegielewski, B., Bik, T., Alqalawi, U., Mubako, S., Eidem, N., Bloom, S., 2006. Water use benchmarks for thermoelectric power generation. Prep. U. S. Geol. Surv. South. Ill. Univ. Carbondale.

EFMA, 2000a. BAT Production of NPK Fertilizers by the Nitrophosphate Route.

EFMA, 2000b. Production of Ammonium Nitrate and Calcium Ammonium Nitrate.

Elgowainy, A., Han, J., Cai, H., Wang, M.Q., Forman, G.S., Divita, V.B., 2014. Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at US Refineries. Environ. Sci. Technol.

Elgowainy, A., Lampert, D.J., Hao, C., Han, J., Dunn, J., Wang, M., 2015. Life-Cycle Analysis of Water Use for Hydrogen Production Pathways (DOE Hydrogen and Fuel Cells Program No. FY 2015 Annual Progress Report).

Ellis, M., Dillich, S., Margolis, N., 2001. Industrial water use and its energy implications. Wash. DC US Dept Energy Off. Energy Effic. Renew. Energy.

Energy Information Administration, 2014a. Annual Energy Outlook 2014.

Energy Information Administration, 2014b. Crude Oil Production [WWW Document]. URL http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbb1_a.htm (accessed 12.19.14).

Energy Information Administration, 2014c. Coal Production and Preparation Report (Instructions).

Energy Information Administration, E., 2012. Annual Coal Report 2011.

Energy Information Administration, (first), 2013. Short-Term Energy Outlook.

European Fertilizer Manufacturers' Association, 2000a. Best Available Techniques for Pollution Prevention and Control, Production of Ammonia. Brussels, Belgium.

European Fertilizer Manufacturers' Association, 2000b. Best Available Techniques for Pollution Prevention and Control, Production of Urea and Urea Ammonium Nitrate. Brussels, Belgium.

European Fertilizer Manufacturers' Association, 2000c. Best Available Techniques for Pollution Prevention and Control, Production of Phosphoric Acid. Brussels, Belgium.

Feeley III, T.J., Skone, T.J., Stiegel Jr, G.J., McNemar, A., Nemeth, M., Schimmoller, B., Murphy, J.T., Manfredo, L., 2008. Water: A critical resource in the thermoelectric power industry. Energy 33, 1–11.

Finish Pulp and Paper Institute, 2002. KCL EcoData – Life Cycle Inventory Database, H₂SO₄ manufacturing. Espoo, Finland.

- Frischknecht, R., Jungbluth, N., Althaus, H.-J., Hischier, R., Doka, G., Bauer, C., Dones, R., Nemecek, T., Hellweg, S., Humbert, S., 2007. Implementation of life cycle impact assessment methods. Data v2. 0 (2007). Ecoinvent report No. 3. Ecoinvent Centre, Swiss Federal Laboratories for Materials Testing and Research (EMPA), Duebendorf (Switzerland).
- Gandrik, A.M., Wood, R.A., Patterson, M.W., Mills, P.M., 2010. HTGR-Integrated Hydrogen Production via Steam Methane Reforming (SMR) Economic Analysis. Doc. ID TEV-954 INL.
- Gleick, P.H., 1994. Water and energy. *Annu. Rev. Energy Environ.* 19, 267–299.
- Gleick, P.H., 1992. Environmental consequences of hydroelectric development: the role of facility size and type. *Energy* 17, 735–747.
- Grubert, E.A., Beach, F.C., Webber, M.E., 2012. Can switching fuels save water? A life cycle quantification of freshwater consumption for Texas coal-and natural gas-fired electricity. *Environ. Res. Lett.* 7, 045801.
- Hassibi, M., 1999. An overview of lime slaking and factors that affect the process, in: Presentation to 3rd International Sorbalit Symposium.
- Humbird, D., Davis, R., Tao, L., Kinchin, C., Hsu, D., Aden, A., 2011. Process design and economics for biochemical conversion of lignocellulosic biomass to ethanol.
- International Energy Agency Bioenergy, 2015. Plant Lists [WWW Document]. URL <http://www.iea-biogas.net/plant-list.html> (accessed 5.15.15).
- Kagel, A., Bates, D., Gawell, K., 2005. A guide to geothermal energy and the environment. Geothermal Energy Association Washington, DC.
- Kozubal, E., Kutscher, C., 2003. Analysis of a Water-Cooled Condenser in Series with an Air-Cooled Condenser for a Proposed 1-MW Geothermal Power Plant. *Trans.-Geotherm. Resour. Counc.* 587–592.
- Kutscher, C., Costenaro, D., 2002. Assessment of evaporative cooling enhancement methods for air-cooled geothermal power plants. *Trans.-Geotherm. Resour. Counc.* 775–780.
- Lampert, D.J., Lee, U., Hao, C., Elgowainy, A., Analysis of Water Consumption Associated with Hydroelectric Power Generation in the United States, Argonne National Laboratory, unpublished information, 2015.
- Linak, E., Schlag, S., Yokose, K., 2005. Chlorine/sodium hydroxide. SRI Consulting.
- Mavis, J., 2003. Water Use in Industries of the Future: Mining Industry.
- McCabe, W.L., Smith, J.C., Harriott, P., 1993. Unit operations of chemical engineering. McGraw-Hill New York.

Meldrum, J., Nettles-Anderson, S., Heath, G., Macknick, J., 2013. Life cycle water use for electricity generation: A review and harmonization of literature estimates. *Environ. Res. Lett.* 8, 015031.

Mendelsohn, M., Lowder, T., Canavan, B., Mendelsohn, M., Kreyck, C., 2012. Utility-Scale Concentrating Solar Power and Photovoltaics Projects: A Technology and Market Overview (No. NREL/TP - 6A20 - 51137). National Renewable Energy Laboratory.

Mishra, G.S., Glassley, W.E., Yeh, S., 2011. Realizing the geothermal electricity potential—water use and consequences. *Environ. Res. Lett.* 6, 034023.

Monsanto, 2012. Monsanto Corporate Social Responsibility and Sustainability Report [WWW Document]. URL <http://www.monsanto.com/whoweare/pages/corporate-sustainability-report.aspx> (accessed 9.9.14).

Monsanto, P.C., 2014. Monsanto Crop Protection Products.

Mueller, S., Kwik, J., 2013. Corn Ethanol: Emerging Plant Energy and Environmental Technologies University of Illinois at Chicago, Dominion Energy Services, LLC.

NASS, 2009. 2007 Census of Agriculture.

NASS, 2004. 2002 Census of Agriculture.

NASS, 1999. 1997 Census of Agriculture.

O'Connor, T., 2010. Water Usage in Biodiesel Production.

Peabody Energy, 2014. Peabody Energy : North Antelope Rochelle Mine [WWW Document]. URL <http://www.peabodyenergy.com/content/274/Publications/Fact-Sheets/North-Antelope-Rochelle-Mine> (accessed 7.28.14).

Persson, M., Jönsson, O., Wellinger, A., 2006. Biogas upgrading to vehicle fuel standards and grid injection, in: IEA Bioenergy Task.

Plummer, M., 2014. Pesticide Water Dilution Rates.

Potash - Economy - Government of Saskatchewan [WWW Document], n.d. URL <http://economy.gov.sk.ca/Potash> (accessed 8.15.14).

Rath, L., 2010. Assessment of Hydrogen Production with CO₂ Capture Volume 1: Baseline State of the Art Plants, DOE/NETL-2010/1434.

Renewable Fuels Association, 2014. How Ethanol is Made | RFA: Renewable Fuels Association [WWW Document]. URL <http://www.ethanolrfa.org/pages/how-ethanol-is-made> (accessed 9.16.14).

- Royce, B., Kaplan, E., Garrell, M., Geffen, T.M., 1984. Enhanced oil recovery water requirements. *Miner. Environ.* 6, 44–53.
- Schlag, S., Fukada, C., 2009. Chemical Economics Handbook Marketing Research Report: Sodium Carbonate.
- Shapouri, H., Duffield, J.A., Wang, M.Q., 2002. The energy balance of corn ethanol: an update. United States Department of Agriculture, Economic Research Service.
- Simon, A.J., Daily, W., White, R.G., 2010. Hydrogen and Water: An Engineering, Economic and Environmental Analysis. Lawrence Livermore National Laboratory (LLNL), Livermore, CA.
- Skone, T.J., 2012. Role of Alternative Energy Sources: Geothermal Technology Assessment.
- Solley, W.B., Pierce, R.R., Perlman, H.A., 1998. Estimated use of water in the United States in 1995. United States Geological Survey.
- Spath, P., Aden, A., Eggeman, T., Ringer, M., Wallace, B., Jechura, J., 2005. Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly Heated Gasifier. Tech. Report Biomass Hydrog. NRELTP-510-37408 Prod.
- Sperling Hansen Associates, 2007. Highland Valley Centre for Sustainable Waste Management – Landfill Gas Utilization Options.
- S&T Consultants Inc, 2013. GHGenius Version 4.03.
- Tarka, T.J., 2012. Production of Zero Sulfur Diesel Fuel from Domestic Coal: Configurational Options to Reduce Environmental Impact (No. DOE/NETL-2012/1542). National Energy Technology Laboratory, Pittsburgh, PA.
- Torcellini, P.A., Long, N., Judkoff, R., 2003. Consumptive water use for US power production. National Renewable Energy Laboratory Golden, CO.
- Tynell, Å., Börjesson, G., Persson, M., 2007. Microbial growth on pall rings. *Appl. Biochem. Biotechnol.* 141, 299–319.
- University of Tennessee, Center for Clean Products, 2008. Limestone Quarrying and Processing: A Life Cycle Inventory. The Natural Stone Council.
- USGS Minerals Information: Potash [WWW Document], 2012. URL <http://minerals.usgs.gov/minerals/pubs/commodity/potash/> (accessed 8.15.14).
- Veil, J.A., Puder, M.G., Elcock, D., Redweik Jr, R.J., 2004. A white paper describing produced water from production of crude oil, natural gas, and coal bed methane. Argonne National Laboratory, ANL/EA/RP-112631.

Wang, M., Huo, H., Arora, S., 2011. Methods of dealing with co-products of biofuels in life-cycle analysis and consequent results within the US context. *Energy Policy* 39, 5726–5736.

Wang, M.Q., 1999. GREET 1.5-transportation fuel-cycle model-Vol. 1: methodology, development, use, and results. Argonne National Lab., IL (United States), ANL/ESD-39 Vol. 1.

Wiesenberger, H., 2002. State-of-the-art for the production of fertilisers with regard to the IPPC-DIRECTIVE. Umweltbundesamt.

Wiesenberger, H., Kircher, J., 2001. State-of-the-art for the production of nitric acid with regard to the IPPC directive. Umweltbundesamt.

Wilson, B., Jones, B., 1994. The Phosphate Report: A Life Cycle Study to Evaluate the Environmental Impact of Phosphates and Zeolite A-PCA as Alternative Builders in UK Laundry Detergent Formulations. Landbank Environmental Research & Consulting.

Wilson, P.D., 1996. The nuclear fuel cycle from ore to wastes.

Worrell, E., Phylipsen, D., Einstein, D., Martin, N., 2000. Energy use and energy intensity of the US chemical industry. Lawrence Berkeley Natl. Lab.

Wu, M., Analysis of the Efficiency of the US Ethanol Industry 2007. Argonne National Laboratory, unpublished information, 2008.

Wu, M., Chiu, Y., 2011. Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline–2011 update. Argonne National Laboratory, ANL/ESD/09-1.

Wu, M., Peng, J., 2011. Developing a tool to estimate water withdrawal and consumption in electricity generation in the United States. Argonne National Laboratory, ANL/ESD/09-1 - Update.



Energy Systems Division

9700 South Cass Avenue, Bldg. 362
Argonne, IL 60439-4854

www.anl.gov



Argonne National Laboratory is a U.S. Department of Energy
laboratory managed by UChicago Argonne, LLC