NATIONAL ENERGY TECHNOLOGY LABORATORY

Role of Alternative Energy Sources: Hydropower Technology Assessment

August 28, 2012

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Acronyms and Abbreviations

ASTM	American Society for Testing and Materials
Btu	British thermal unit
C	Carbon
CCS	Carbon capture and sequestration
CH_4	Methane
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of electricity
CWA	Clean Water Act
ECF	Energy conversion facility
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EROI	Energy return on investment
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
HMI	Hydropower modernization initiative
H_2O	Water
INEEL	Idaho National Engineering and Environmental Laboratory
IPCC	Intergovernmental Panel on Climate Change
kg/hr	Kilograms per hour
kJ	Kilojoule
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
LC	Life cycle
LCA	Life cycle analysis
LCC	Life cycle cost
LCOE	Levelized cost of electricity
MACRS	Modified accelerated cost recovery system
MW,MWe	Megawatt electric
MWh	Megawatt-hour
NEPA	National Environmental Policy Act
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NHA	National Hydropower Association
O&M	Operating and maintenance
PSFM	Power systems financial model
RFS	Renewable fuel standard
RMA	Raw material acquisition
RMT	Raw material transport
SF_6	Sulfur hexafluoride
T&D	Transmission and Distribution
TVA	Tennessee Valley Authority
USACE	U.S. Army Corps of Engineers

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Executive Summary

This report discusses the role of hydropower in meeting the energy needs of the United States (U.S.). This includes an analysis of key issues related to hydropower and, where applicable, the modeling of the environmental and cost aspects of hydropower.

Conventional hydropower is a significant source of electricity in the U.S. In 2009, conventional hydropower in the United States produced 253 terawatt-hours of electricity, equivalent to 72 percent of total renewable power generation or 6.9 percent of the total power generation in the United States during that year (EIA, 2010; NREL, 2010). The capacity of installed hydropower has remained relatively flat since 2000 (near 77 GW) (NREL, 2010). The resource base for very large hydropower sites in the U.S. has already been developed. However, many smaller conventional hydropower sites, such as those with capacities up to 400 MW, are still available along with upgrades to existing facilities. Newer technologies for generating hydropower are emerging. For example, hydrokinetic systems harness the energy that is contained in water as it moves past a fixed point by employing in-stream turbines that typically resemble small scale horizontal axis wind turbines. New hydrokinetic turbines are currently being installed along the Mississippi River system.

The Federal Energy Regulatory Commission (FERC), which licenses hydropower projects, has approved preliminary permits for the installation of nearly 3.1 GW of new conventional hydropower, comprising nearly 260 separate facilities (2011b). There are an additional 122 projects with pending preliminary permits with a total capacity of 1.6 GW. Preliminary permits give the applicant approval to study the site; however, they do not authorize construction (FERC, 2011b). These new proposals appear to be driven substantially by recent regulatory and cultural shifts towards implementation of renewable energy technologies. New hydrokinetic turbines are currently being installed along the Mississippi River system, and FERC has approved preliminary permits for an additional 3.6 GW (spread over 36 projects) of proposed hydrokinetic power installations on rivers across the U.S. There are an additional 8.7 GW of hydrokinetic river-based capacity spread over 87 projects that are pending preliminary permits (FERC, 2011b). As of September 1, 2011, 7.9 GW of the hydrokinetic projects in the lower Mississippi River are in the pre-filing stages for a license.

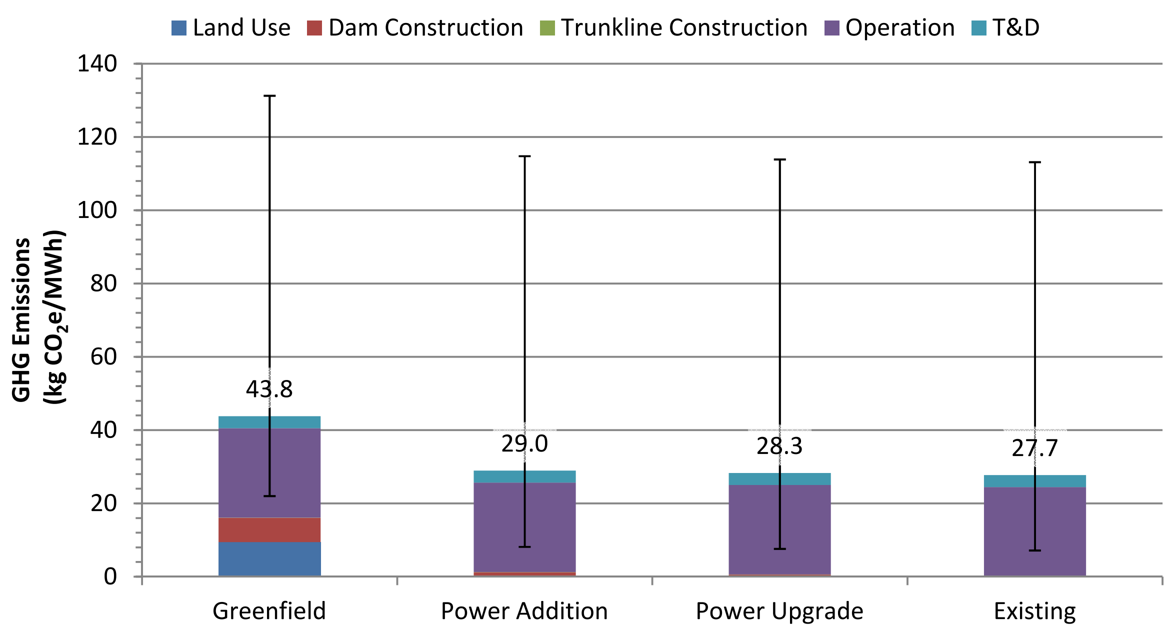
The average annual growth of hydropower as forecasted by the U.S. EIA Annual Energy Outlook (AEO) is 0.5 percent per year from 2.53 to 3.09 quadrillion Btu for hydropower production between 2008 and 2035 and a 0.1 percent capacity increase for the same period (EIA, 2011). The AEO increase in hydropower capacity is substantially smaller than the projected capacity increase based on the issued and pending preliminary FERC permits for new hydropower, which total to a potential of 22.5 GW of additional capacity on top of the existing capacity of 77 GW.

A life cycle analysis (LCA) was conducted to assess the environmental characteristics of hydropower. The boundaries of the LCA account for the cradle-to-grave energy and material flows for hydropower. The boundaries include five life cycle stages, beginning with raw material extraction; including the intermediate steps of raw material transport, energy conversion, and electricity transmission and distribution; and ending with electricity delivered to the consumer. In contrast to fossil energy and some forms of renewable energy conversion, the primary energy source for hydropower is water, a natural resource that does not require extraction or transport to a power plant. The functional unit of this analysis (which serves as the basis of comparison between systems) is one MWh of electricity delivered to the consumer. The key environmental metric that is accounted for in this analysis is greenhouse gas (GHG) emissions from the life cycle of hydropower, including

GHG emissions from land use change. Additionally, the LCA inventories criteria air pollutants and other air emissions of concern, water use, water quality, resource energy, and solid wastes.

Figure ES-1 shows the life cycle (LC) GHG emissions for the four hydropower scenarios in this report. The expected value for all scenarios falls within range from 27.7 to 43.8 kg CO_2e/MWh. Carbon dioxide and methane emissions from the reservoir during hydropower operations dominate the life cycle GHG emissions and range from 56 to 88 percent of total GHG emissions. GHG emissions from land use account for 22 percent of the GHG from greenfield hydropower (the greenfield scenario is the only scenario that includes land use emissions). Land use GHG emissions increase the total GHG emissions from 34.4 to 43.8 kg CO_2e/MWh. Unless specified otherwise, all GHG results in this analysis are expressed on the basis of 2007 IPCC 100-year global warming potentials.

Figure ES-1: Greenhouse Gas Emissions from Hydropower



A life cycle cost (LCC) analysis was conducted to assess the cost performance of hydropower. Capital costs are the key component of the greenfield, power addition, and power upgrade scenarios; the total COE for these scenarios are $253, $125, and $72 per MWh. For these three scenarios, between 95 and 99 percent of the total COE is due to capital costs. As a renewable energy technology, hydropower does not require the purchase of fuel for operation, and other operating and maintenance costs are small in comparison to the annualized capital costs. Thus, the COE of the existing scenario is particularly low ($3/MWh) because it does not have any capital burdens. An important aspect of the cost results is that the conventional hydropower scenarios are assigned the full capital costs of site preparation and dam construction. In addition to power generation, conventional dams also provide irrigation control and recreation. The metrics for measuring irrigation control and recreation are different from the metric for measuring power output (i.e., MW), and thus it is difficult to develop a fair scheme for apportioning cost burdens among the services provided by a conventional dam.

The barriers to implementation of hydropower include the characteristically difficult environmental review and permitting of large conventional hydropower in the U.S. Conventional hydropower facilities may be subject to permitting under the National Environmental Policy Act (NEPA), Clean Water Act (CWA), and Endangered Species Act (ESA), as well as environmental compliance and permitting efforts required at the state level. Environmental review and acquisition of needed permits can take 5 to 10 years or more (Contra Costa Water District, 2011). These issues substantially slow conventional hydropower development in the U.S. In contrast, large conventional hydropower, environmental review and permitting for hydrokinetic installations have proven to be much less arduous. FERC has initiated programs to streamline the permitting process for these types of installations (FERC, 2010). The systems are low profile and turbines are installed underwater without the need for a dam or other impoundment. As a result, projects to date have not realized the same level of public scrutiny as large conventional hydropower installations

The risks of conventional hydropower include its dependence on natural flow and water storage volumes. In drought years, the total volume of water is reduced, and therefore the effective generation capacity of the reservoir is also reduced. Water availability for power generation is also affected by various other factors, including competing use for water supply and flood control. Climate change is also expected to alter natural weather patterns in many regions. Because they are installed into flowing rivers, hydrokinetic technologies may be subject to substantial damage from debris or washout, especially during high flow or flood events. These concerns could potentially increase the lifetime cost of hydrokinetic installations substantially, depending upon turbine design and site selection. Like conventional hydropower, hydrokinetic technologies are also subject to variation in river flows and water availability.

Since 1999, the number of hours for forced outages for U.S. Army Corps of Engineers (USACE) hydropower assets has more than doubled as the age of the facilities continues to increase (2011). Modernization efforts for some USACE assets could yield an 8 percent increase in electricity production output; however, federal funding for even the most promising rehabilitation projects is difficult to secure because of competing priorities. The Electric Power Research Institute (EPRI) compares the potential expansion of hydropower, particularly hydrokinetics, to the expansion of wind energy that has taken place over the last 10 years (EPRI, 2007). The expansion in the case of wind installations appears to be a combination of the commitment to research, development, demonstration, and deployment by the public and private sectors along with extensions to the production tax credit and clean renewable energy bond programs. In order to spur development of these projects, the National Hydropower Association (NHA) is lobbying to extend the same level of tax credits to hydropower that are available to other renewable sources (2011). Currently, new hydropower electricity generation, either via efficiency gains/upgrades at conventional facilities or new hydrokinetic installations, qualifies for half of the value of the renewable electricity production tax credit (IRS, 2010).

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1 Introduction

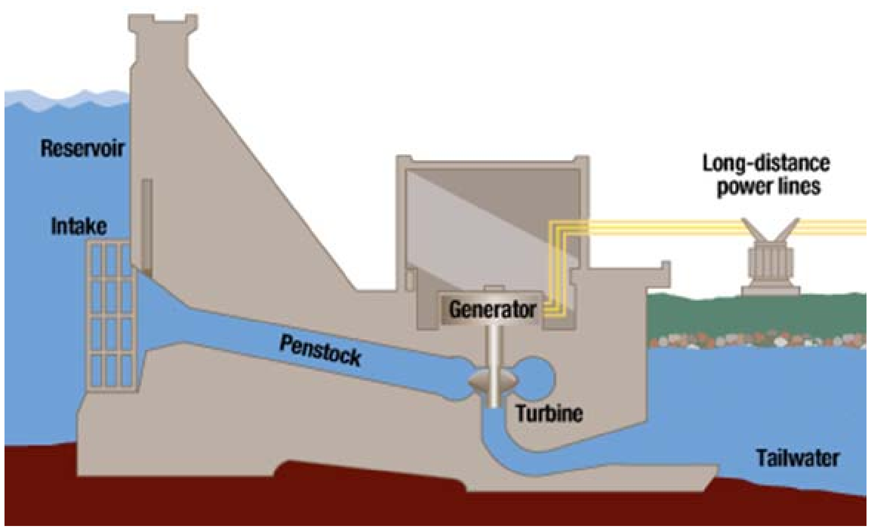
This analysis evaluates the role of hydropower in the energy supply of the United States (U.S.). This objective is met by focusing on the resource base, growth, environmental characteristics, costs, barriers, and expert opinions surrounding hydropower. The criteria used by the National Energy Technology Laboratory (NETL) to evaluate the roles of energy sources are summarized in **Table 1-1**.

Table 1-1: Criteria for Evaluating Roles of Energy Sources

Criteria	Description
Resource Base	Availability and accessibility of natural resources for the production of energy feedstocks
Growth	Current market direction of the energy system – this could mean emerging, mature, increasing, or declining growth scenarios
Environmental Profile	Life cycle (LC) resource consumption (including raw material and water), emissions to air and water, solid waste burdens, and land use
Cost Profile	Capital costs of new infrastructure and equipment, operating and maintenance (O&M) costs, and cost of electricity (COE)
Barriers	Technical barriers that could prevent the successful implementation of a technology
Risks of Implementation	Non-technical barriers such as financial, environmental, regulatory, and/or public perception concerns that are obstacles to implementation
Expert Opinion	Opinions of stakeholders in industry, academia, and government

Hydropower uses flowing water to spin a turbine that is connected to a generator that produces electricity. There are two types of hydropower systems used in the U.S. – conventional hydropower and run-of-river hydropower. Conventional hydropower systems use dams that are downstream from large reservoirs of water (TVA, 2012). Run-of-river (or "hydrokinetic") systems divert streams of water from rivers to spin small turbines (DOE, 2011). A conventional hydropower system is illustrated in **Figure 1-1**.

Figure 1-1: Diagram of a Conventional Hydropower Facility (TVA, 2012)



Most conventional hydropower systems are large scale facilities that are capable of generating millions of MWh of electricity per year, while run-of-river systems are small scale installations that produce thousands of MWh of electricity per year.

2 Hydropower Technology Description

Conventional hydropower includes the installation of a large-scale dam or other impoundment, combined with a controlled release mechanism and turbine/generator train. Water is collected into the reservoir behind the dam. Water is then released at the toe of the dam, through a series of tunnels, penstocks, or other facilities, routed through hydroelectric turbines, and released to the river downstream. The hydraulic head (height of the reservoir surface above the turbines) from the reservoir drives the turbines and generators, providing electricity that can be exported to an electric power grid.

Conventional hydropower accounted for approximately seven percent of U.S. electricity generation in 2010 (EIA, 2011). In 2009, conventional hydropower in the United States produced 253 terawatt-hours of electricity, equivalent to 72 percent of total renewable power generation or 6.9 percent of total power generation in the U.S. (EIA, 2010; NREL, 2010). The capacity of installed hydropower has remained relatively flat since 2000 (near 77 GW) (NREL, 2010). Conventional hydropower is distinguished from other types of hydropower by its relatively large power generation capacities and its use of hydraulic head, stored by a dammed reservoir, for the generation of electricity.

Hydrokinetic power has been used for centuries to turn waterwheels to drive mills and other facilities. Recently it has also emerged as a potential generation source to be installed along rivers, to generate electricity. Much like wind turbines, hydrokinetic systems harness the energy that is contained in water as it moves past a fixed point. Hydrokinetic systems employ in-stream turbines that typically resemble small-scale horizontal axis wind turbines. These may be installed individually or in arrays, sited in areas of a river so as not to interfere with navigation. Hydrokinetic technologies can be employed virtually wherever water is flowing sufficiently fast (above about 5-6 miles/ hour, although some small-scale technologies are applicable to flows below this range) with sufficient depth to cover the turbine, without interfering with other beneficial uses along the river (DOE, 2011). Hydrokinetic turbines can be installed directly into a channel bottom as permanent installations, or on the underside of a barge, which can be moved as in-stream conditions change or to allow for passage of ships (DOE, 2011).

The first commercial scale in-river hydrokinetic installation was completed in January 2009 near the City of Hastings, Minnesota, downstream from an existing run-of-the-river installation (Hydro Green Energy, 2011). Locating hydrokinetic facilities immediately downstream from conventional or run-of-the-river facilities is often convenient, because the existing facilities already have power line infrastructure. New hydrokinetic turbines are currently being installed along the Mississippi River system.

The performance characteristics of a 2,080 MW hydropower plant are shown in **Table 2-1**, which includes the mass and energy flows per one MWh of electricity produced. The emissions of carbon dioxide and methane from the conventional reservoir surface were based on the results of a study that published the gas flux from the surface of different reservoirs in North and South America. This study uses the results from reservoirs in Colorado and Wisconsin (St. Louis, Kelly, Duchemin, Rudd, & Rosenberg, 2000). The capital costs for hydropower are highly variable and depend on the extent of construction (greenfield vs. upgrading) and also include the costs of site preparation. More details on the costs of hydropower are provided in **Section 5**. No data are available on the performance of hydrokinetic power, so it is not included in **Table 2-1**.

Table 2-1: Performance Characteristics of Conventional Hydropower

Parameter	Units	Conventional Dam
Plant Lifetime	Years	80
Average Net Power Output of Plant	MW	2,080
Average Annual Capacity Factor	%	37
Reservoir Area	Acres	158,000
	m^2	640,000,000
CO_2 Emissions from Reservoir	kg/m^2-yr.	2.42E-01
	kg/MWh_{net}	23.0
CH_4 Emissions from Reservoir	kg/m^2-yr.	3.40E-03
	kg/MWh_{net}	0.323
Total Project Capital	2002$/kW	1,900 to 6,300

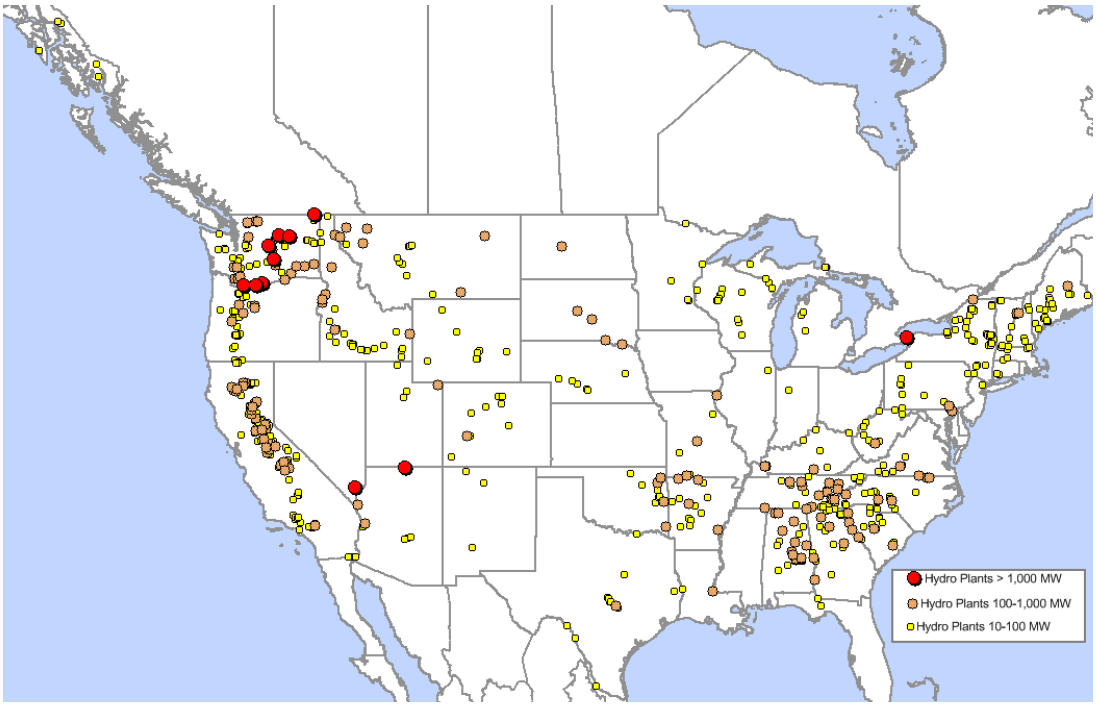
The types of technologies used by a hydropower facility are important factors in the overall plant efficiency and emissions. However, the activities that occur during construction of the facility and the infrastructure for power delivery also incur environmental burdens, making LCA a necessary framework for understanding the environmental burdens of the entire hydropower cycle. In addition to environmental concerns, the role of hydropower in the U.S. energy portfolio is also affected by costs, resource availability, public perception, and other issues. An LCA and a discussion of other issues associated with hydropower are presented below.

Adequate data are not available for the performance of hydrokinetic power, so it is not included in the environmental or cost sections of this analysis. However, hydrokinetic power is discussed in the context of resource base, growth, barriers and other issues pertinent to hydropower.

3 Resource Base and Potential for Growth

Under current and anticipated future conditions, conventional hydropower comprises 7 percent of the U.S. electricity supply mix. The capacity of installed hydropower has remained relatively flat since 2000 (near 77 GW) (NREL, 2010). While it is true that most of the available large scale sites for hydropower have already been used, there are many available sites for smaller scale installations – up to several hundred megawatts. **Figure 3-1** shows the existing hydropower installations in the United States by size of installed capacity, with the majority of the large installations in the Western and Southeast U.S.

Figure 3-1: U.S. Hydropower Installations by Capacity



The Federal Energy Regulatory Commission (FERC), which licenses hydropower projects, has approved preliminary permits for the installation of nearly 3.1 GW of new conventional hydropower, comprising nearly 260 separate facilities (FERC, 2011b). There are an additional 122 projects with pending preliminary permits with a total capacity of 1.6 GW. Preliminary permits give the applicant approval to study the site; however, they do not authorize construction (FERC, 2011b). These new proposals appear to be driven substantially by recent regulatory and cultural shifts towards implementation of renewable energy technologies. New hydrokinetic turbines are currently being installed along the Mississippi River system, and FERC has approved preliminary permits for an additional 3.6 GW (spread over 36 projects) of proposed hydrokinetic power installations on rivers across the U.S. There are an additional 8.7 GW of hydrokinetic river-based capacity spread over 87 projects that are pending preliminary permits (FERC, 2011b).

Table 3-1 shows the issued and pending preliminary permits issued by FERC for the various hydropower technologies, along with the potential additional capacity.

Table 3-1: Projected Hydropower Capacity and Preliminary Permits by Technology

Technology	Potential Capacity (GW) (EPRI, 2007)	Issued Preliminary Permits (FERC, 2011b)		Pending Preliminary Permits (FERC, 2011b)	
		Capacity (GW)	No. of Projects	Capacity (GW)	No. of Projects
Conventional	62.3	3.1	259	1.6	122
Hydrokinetic	12.8	3.6	36	8.4	87
Ocean Energy	20.0	5.7	34	<0.1	4
Total	**95.1**	**12.5**	**329**	**10.0**	**213**

Over the next 10 to 20 years, installed capacity is expected to grow rapidly. The Mississippi River system provides well-suited waterways for hydrokinetic installation. But the facilities can also be installed downstream of existing dams, and are expected to be applicable in many other river systems. **Figure 3-2** shows (with purple hashes) the location of pending hydrokinetic preliminary permits at FERC with the majority of the projects being located in the lower half of the Mississippi River which, as shown in **Figure 3-1**, has limited hydropower facilities. As of September 1, 2011, 7.9 GW of the hydrokinetic projects in the lower Mississippi are in the pre-filing stages for a license. In-river hydrokinetic technologies are similar in design to many tidal and wave energy systems that also use hydrokinetic technologies. FERC has approved preliminary permits for 5.7 GW of tidal and wave hydrokinetic capacity across 34 projects.

Figure 3-2: Pending Hydrokinetic Preliminary Permits (FERC, 2011a)

The early release for EIA's 2012 Annual Energy Outlook (AEO) forecasts an average annual hydropower generation growth of 0.5 percent per year, from 926 to 1,058 trillion Btu for annual conventional hydropower production between 2009 and 2035. During the same period, the projected capacity increase of conventional hydropower is 0.16 percent per year, from 78.01 to 81.25 GW (EIA, 2012). The AEO projections are consistent with the conventional hydropower capacity of issued and pending FERC permits, which, at a total capacity of 82.2 GW and a capacity factor of 37 percent, would total 1,071 trillion Btu per year. Issued and pending FERC permits also show that hydrokinetic plants could further increase total hydropower capacity to 100 GW (FERC, 2011b).

4 Environmental Analysis of Hydropower

An LCA accounts for the material and energy flows of a system from cradle to grave, where the cradle is the extraction of resources from the earth and the grave is the final disposition of used products (when applicable).

4.1 LCA Scope and Boundaries

The boundaries of the LCA account for the cradle-to-grave energy and material flows for hydropower. The boundaries include five life cycle (LC) stages:

LC Stage #1, Raw Material Acquisition (RMA): Accounts for the acquisition of fuels from the earth or forest. RMA is not relevant to an LCA of hydropower because water is the primary input to the energy conversion facility and does not require anthropogenic inputs prior to power generation.

LC Stage #2, Raw Material Transport (RMT): Accounts for transport of fuels between acquisition and the energy conversion facility. RMT is not relevant to an LCA of hydropower because water is the primary input to the energy conversion facility and does not require anthropogenic inputs prior to power generation.

LC Stage #3, Energy Conversion Facility (ECF): Includes all construction and operation activities at a hydroelectric power plant. This analysis models conventional hydropower operation and, when applicable, also accounts for construction, installation, and land use transformation. The output of this stage is electricity ready for transmission.

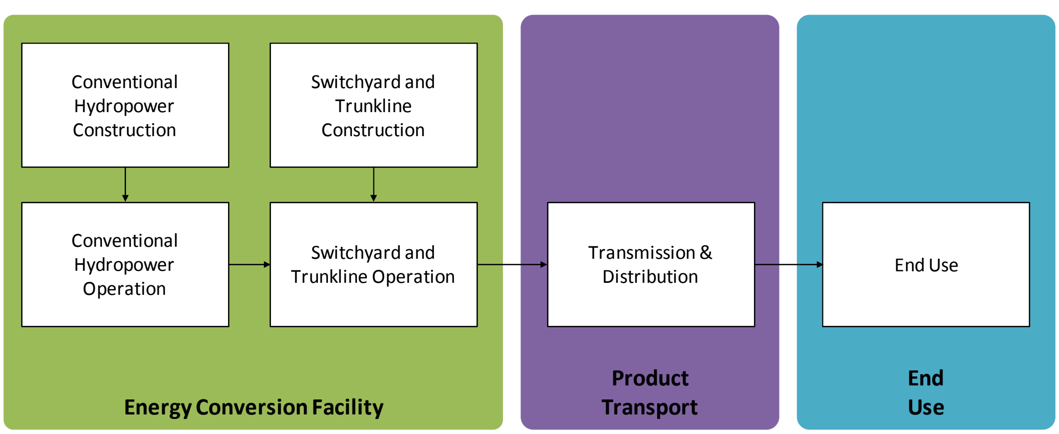
LC Stage #4, Product Transport (PT): Accounts for the transmission of electricity from the energy conversion facility to the end user.

LC Stage #5, End Use (EU): represents the use of electricity by the consumer. No environmental burdens are incurred during this stage.

The use of a consistent functional unit is necessary for enforcing comparability between LCAs. The functional unit of this analysis is the delivery of 1 MWh of electricity to the consumer. All results are expressed according to this functional unit.

An LCA model is an interconnected network of unit processes. The throughput of one unit process is dependent on the throughputs of upstream and downstream unit processes. **Figure 4-1** shows the structure for the hydropower LCA network of unit processes.

Figure 4-1: Hydropower LCA Modeling Structure



4.2 LCA Scenarios

The LCA includes four scenarios for conventional hydropower:

- Greenfield
- Power Addition
- Power Upgrade
- Existing

The greenfield scenario accounts for the construction and installation of a new dam with a hydroelectric facility. It represents an 80/20 split between concrete and earthen dams (EPA, 2010). The transformation of land (and associated GHG emissions) during construction of the dam and reservoir is also included. The operation of the hydropower facility is included; the only emissions from the operation of the hydropower facility are GHG emissions from the reservoir.

The power addition scenario includes the construction and installation of an electricity generation system to an existing dam. The operation of the hydropower facility is included. The only emissions from the operation of the hydropower facility are GHG emissions from the reservoir.

The power upgrade scenario includes the replacement of turbines and modifications to other power generation systems on an existing hydropower facility. The operation of the hydropower facility is included; the only emissions from the operation of the hydropower facility are GHG emissions from the reservoir. Examples from literature provide a broad definition for hydropower upgrades. An upgrade could be improvements to existing turbines and generators that would result in marginal gains in the output of a hydropower facility, or it could be the replacement of old turbines and generators with new equipment (EERE, 2009). This LCA uses the material requirements of a new turbine to approximate the construction burdens of the upgrade scenario.

The existing scenario includes the reservoir emissions during the operation of a hydropower facility. It does not include any construction or land transformation burdens.

Table 4-1: Scenarios for LCA of Hydropower

Scenario	Dam Construction	Land Transformation	Powerhouse Construction	Turbine Construction	Operation
Greenfield	x	x	x	x	x
Power Addition			x	x	x
Power Upgrade				x	x
Existing					x

4.3 Land Use Method

Analysis of land use effects is considered a central component of an LCA under both ISO 14044 and standards. This analysis uses the second version of the U.S. Environmental Protection Agency (EPA) Renewable Fuel Standard (RFS2) method for assessing land use change and associated GHG emissions (EPA, 2009). It quantifies both the area of land changed and the GHG emissions associated with that change.

Land use effects can be roughly divided into direct and indirect. In the context of this study, direct land use effects occur as a direct result of the life cycle (LC) processes in the hydropower life cycle. Direct land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports electricity production. For hydropower, these include dams, reservoirs, and trunklines.

Indirect land use effects are changes in land use that occur as a result of the direct land use effects. For instance, if the direct effect is the conversion of agricultural land to land used for energy production, an indirect effect might be the conversion to new farmland of native vegetation, but at a remote location, in order to meet ongoing food supply/demand. This specific case of indirect land use change has been studied in detail by the U.S. EPA and other investigators, and sufficient data are available to enable consideration of this specific case of indirect land use within this study (EPA, 2009). There are also other types of indirect land use change that could potentially occur as a result of the installation of new energy production and conversion facilities. For instance, the installation of a new power plant at a rural location could result in the migration of employees to the site, causing increased urbanization in surrounding areas. However, due to the uncertainty in predicting and quantifying this and other less studied indirect effects, such phenomena were not considered in this analysis.

A variety of land use metrics, which seek to numerically quantify changes in land use, have been devised in support of LCAs. Two common metrics in support of an LCA are transformed land area (square meters of land transformed) and GHG emissions (kg CO_2e). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the amount of carbon emitted in association with that change. **Table 4-2** summarizes the land use metrics included in this analysis.

Table 4-2: Primary Land Use Metrics

Metric	Description	Units	Type of Effect
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of the advanced energy conversion facilities	Square Meters (Acres)	Direct and Indirect
GHG Emissions	Emissions of GHGs associated with land clearing/transformation, including emissions from aboveground biomass, belowground biomass, soil organic matter, and lost forest sequestration	kg CO_2e (lbs. CO_2e)	Direct and Indirect

This assessment of GHG emissions from land use change includes those emissions that would result from the direct and indirect activities associated with the following:

- Quantity of GHGs emitted due to biomass clearing during construction of each facility
- Quantity of GHGs emitted due to oxidation of soil carbon and underground biomass following land transformation, for each facility
- Evaluation of ongoing carbon sequestration that would have occurred under existing conditions, but did not occur, under study/transformed land use conditions

Additional land use metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g., farmland quality), and many other land use metrics may conceivably be included in the land use analysis of an

LCA. However, much of the data needed to support accurate analysis of these metrics are severely limited in availability (Canals, Bauer, & Depestel, 2007; Koellner & Scholz, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area and GHG emissions are quantified for this study.

Due to data limitations, land transformation to agricultural production was used as a proxy for land transformation to reservoir and dam land uses. The RFS2 method was designed to evaluate potential land use change emissions that would result from the conversion of existing agricultural, forest, savannah, and other existing land uses to energy production, agriculture, or pastureland. The RFS2 method was not designed to evaluate land use change emissions that result from conversion of existing agriculture, forest, or savannah to a reservoir. This analysis uses the agricultural land category as a proxy for calculating the GHG emissions from converting land to a hydropower reservoir and dam. This is a reasonable proxy, because, like agriculture, installing a reservoir involves land clearing for the reservoir site. A limitation of this proxy is that the use of a reservoir does not involve the periodic turning of surface sediments as does tilling for agriculture.

4.4 LCA Results

This analysis accounts for a comprehensive list of environmental metrics. Key results are discussed below and are expressed on the basis of 1 MWh of electricity delivered to the consumer.

4.4.1 GHG Emissions

Figure 4-2 shows the LC GHG emissions of the four conventional hydropower scenarios. The expected value for all scenarios falls within range from 27.7 to 43.8 kg CO_2e/MWh. Carbon dioxide and methane emissions from the reservoir during hydropower operations dominate the life cycle GHG emissions and range from 56 to 88 percent of total GHG emissions. GHG emissions from land use account for 22 percent of the GHG from greenfield hydropower (the greenfield scenario is the only scenario that includes land use emissions). Unless specified otherwise, all GHG results in this analysis are expressed on the basis of 2007 IPCC 100-year global warming potentials.

Figure 4-2: Greenhouse Gas Emissions from Hydropower

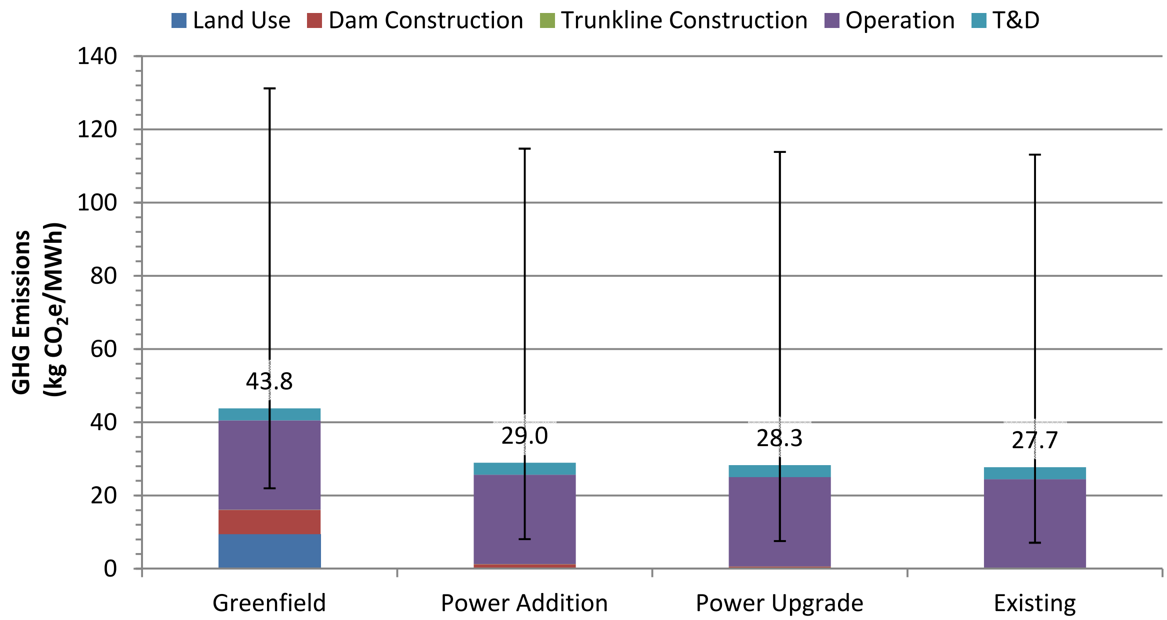


Figure 4-3 through **Figure 4-6** show the GHG emissions for specific processes within each hydropower scenario. They further illustrate that the operation of hydropower facilities are the predominant source of GHG emissions for the addition, upgrade, and existing scenarios. The greenfield scenario also has a significant GHG contribution from land use in addition to operations

Figure 4-3: Detailed GHG Emissions for Greenfield Conventional Hydropower

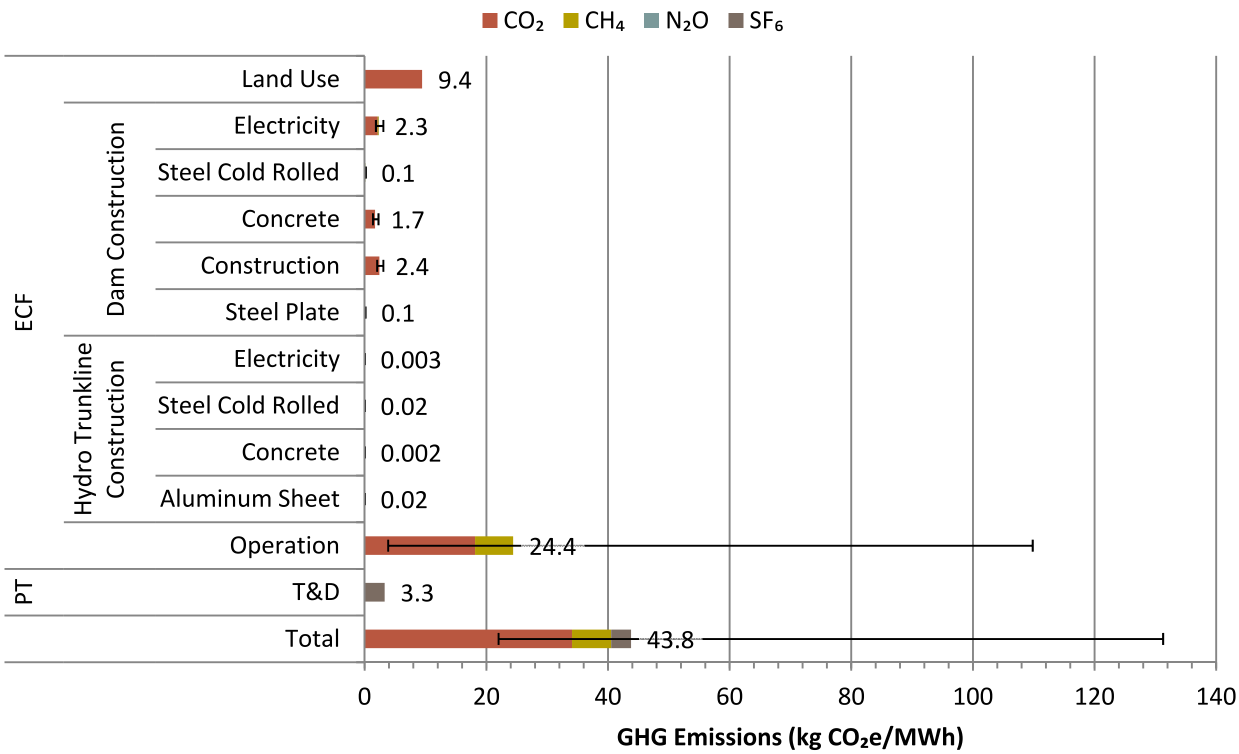


Figure 4-4: Detailed GHG Emissions for Conventional Hydropower Addition

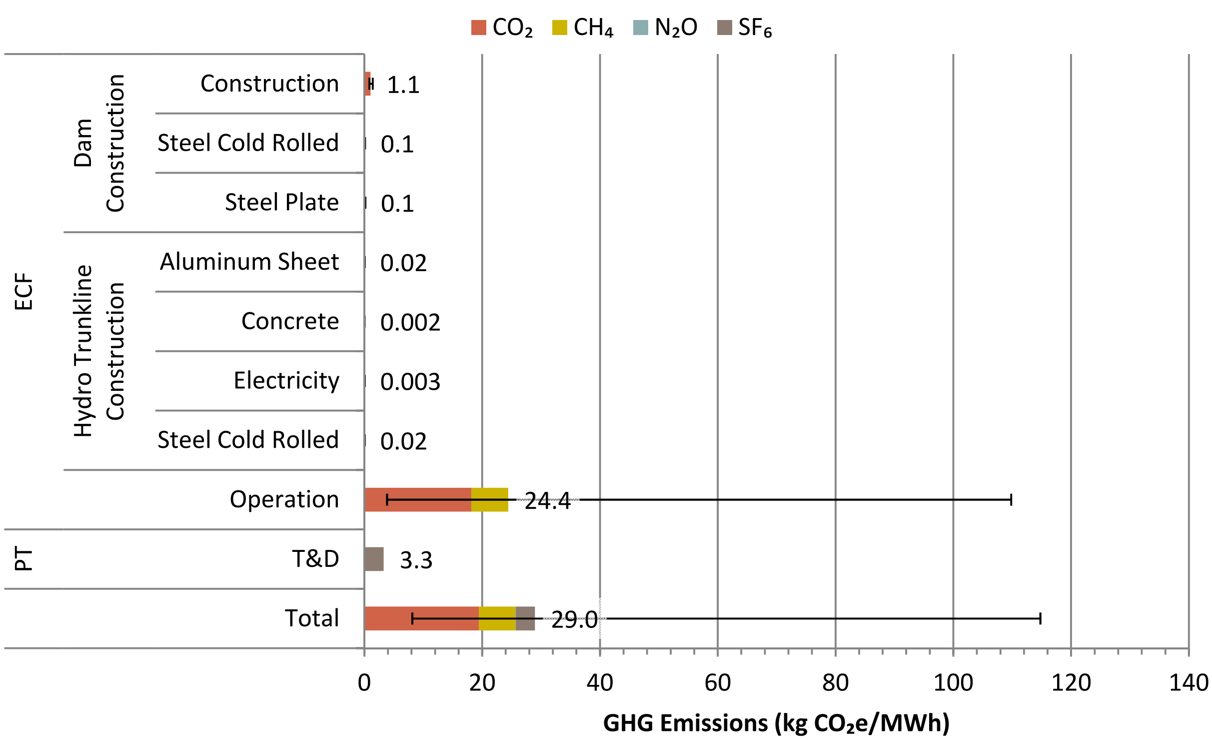


Figure 4-5: Detailed GHG Emissions for Conventional Hydropower Upgrade

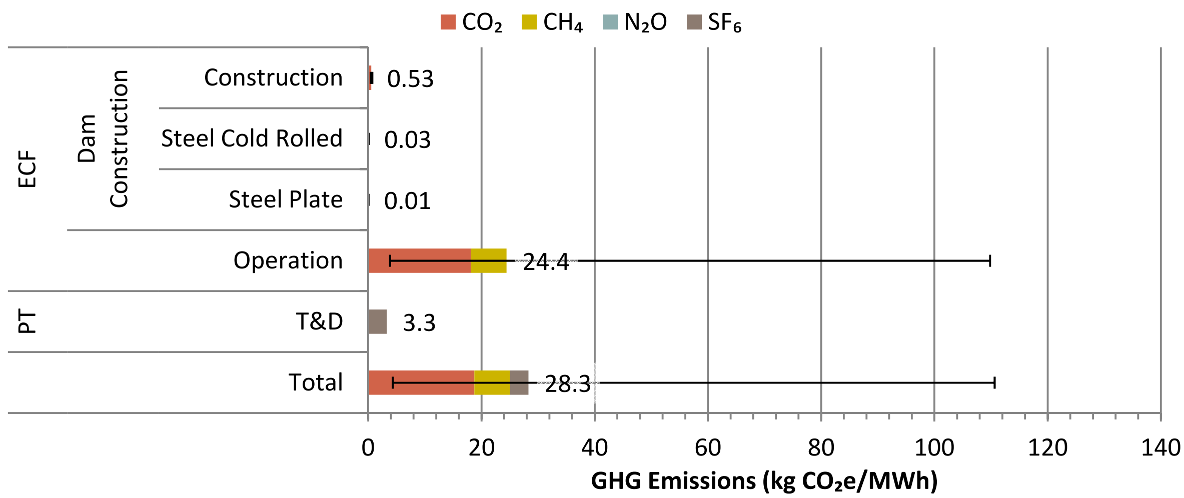
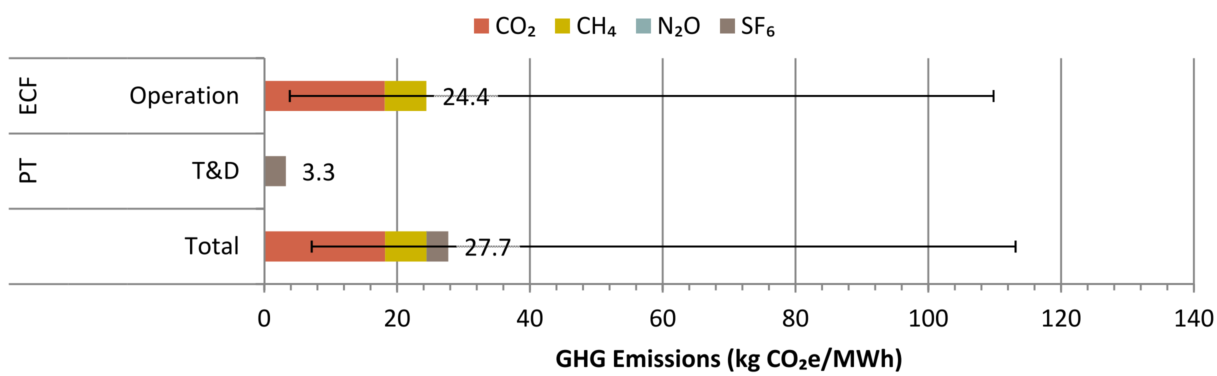


Figure 4-6: Detailed GHG Emissions for Existing Conventional Hydropower



The error bars in the above figures represent the uncertainty in capacity factor, plant lifetime, reservoir capacity, and reservoir emission factors. The low, expected, and high values for these parameters are summarized in **Table 4-3**.

Table 4-3: Selected Conventional Hydropower Model Parameters

Parameter	Low Value	Expected Value	High Value	Units
Capacity Factor	26.3	37.1	52.0	%
Plant Lifetime	60	80	100	Years
Reservoir Capacity	0.3500	0.7000	0.8500	Proportion
CO_2 Emission Factor	0.0657	0.2424	0.5110	kg/m^2-yr.
CH_4 Emission Factor	0.0011	0.0034	0.0292	kg/m^2-yr.

The contribution of key modeling parameters (as shown in **Table 4-3**) to LC GHG emission is illustrated for each scenario in **Figure 4-7** through **Figure 4-10**. The vertical range of each line indicates its contribution to the overall uncertainty range, and the slope of each line indicates the sensitivity of the GHG emissions to changes in each parameter.

The emission factor for CO_2 and CH_4 emissions from a reservoir contribute the most uncertainty the GHG results of all scenarios. Capacity factor also contributes significantly to the uncertainty of greenfield hydropower; as the capacity factor increases, lifetime electricity generation increases, and in turn, the portion of GHG emission from construction are lower on a MWh basis.

Figure 4-7: Uncertainty and Sensitivity of GHG Emissions for Greenfield Hydropower

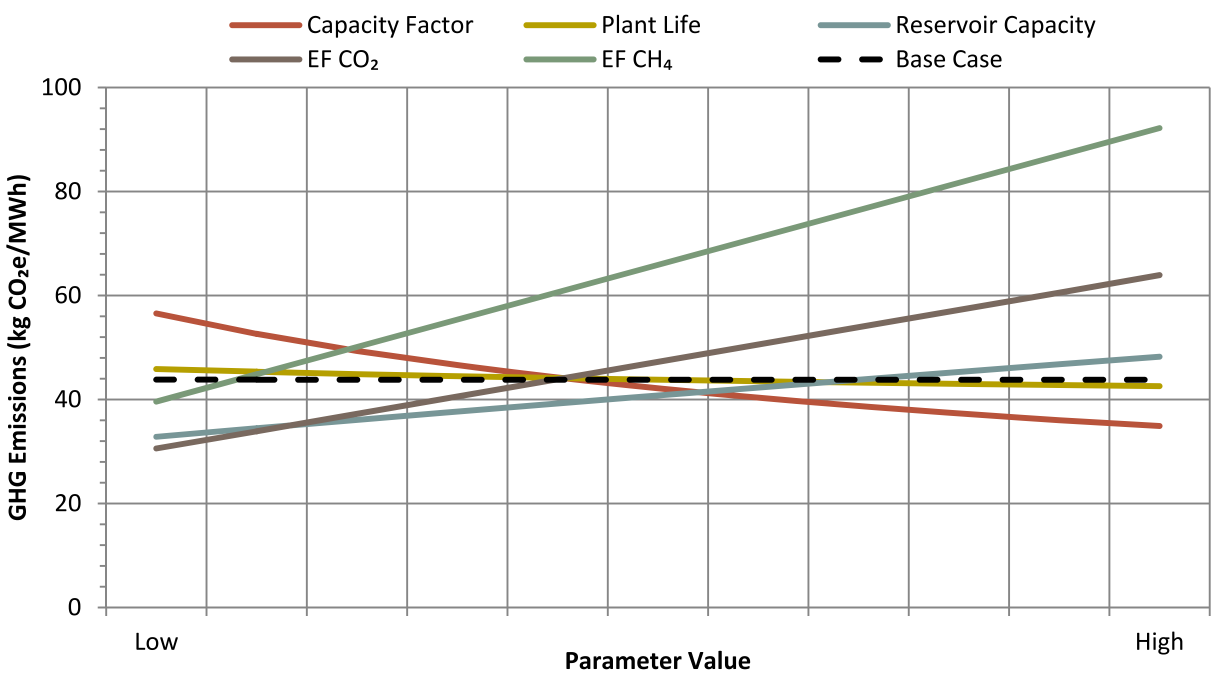


Figure 4-8: Uncertainty and Sensitivity of GHG Emissions for Hydropower Addition

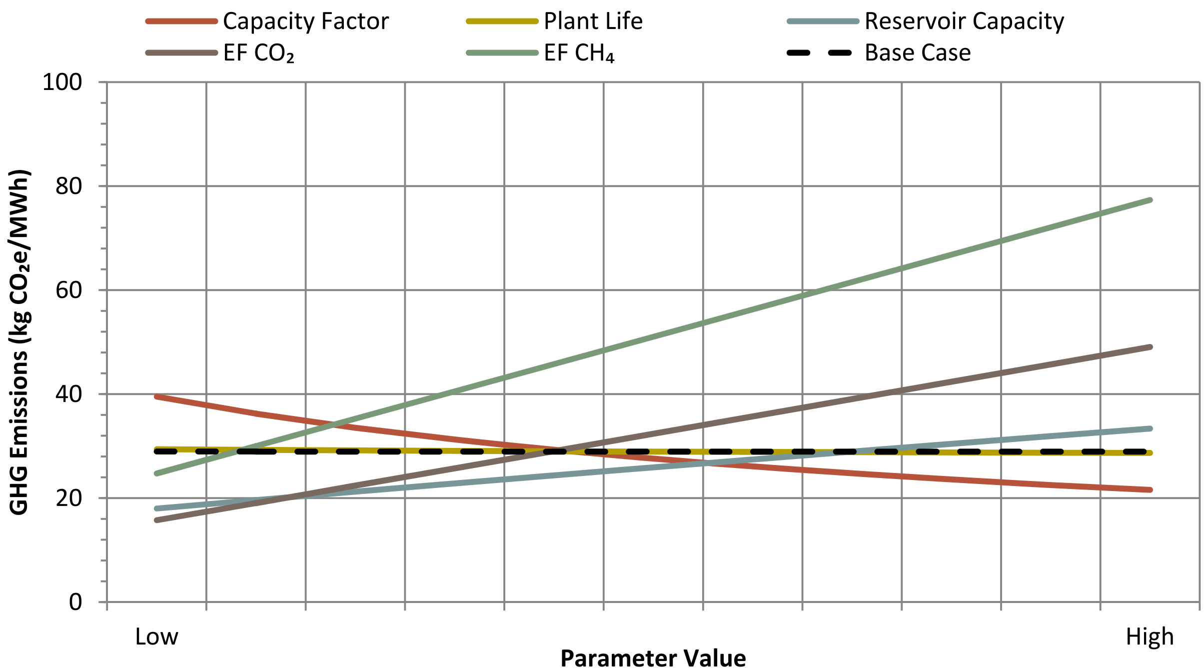


Figure 4-9: Uncertainty and Sensitivity of GHG Emissions for Hydropower Upgrade

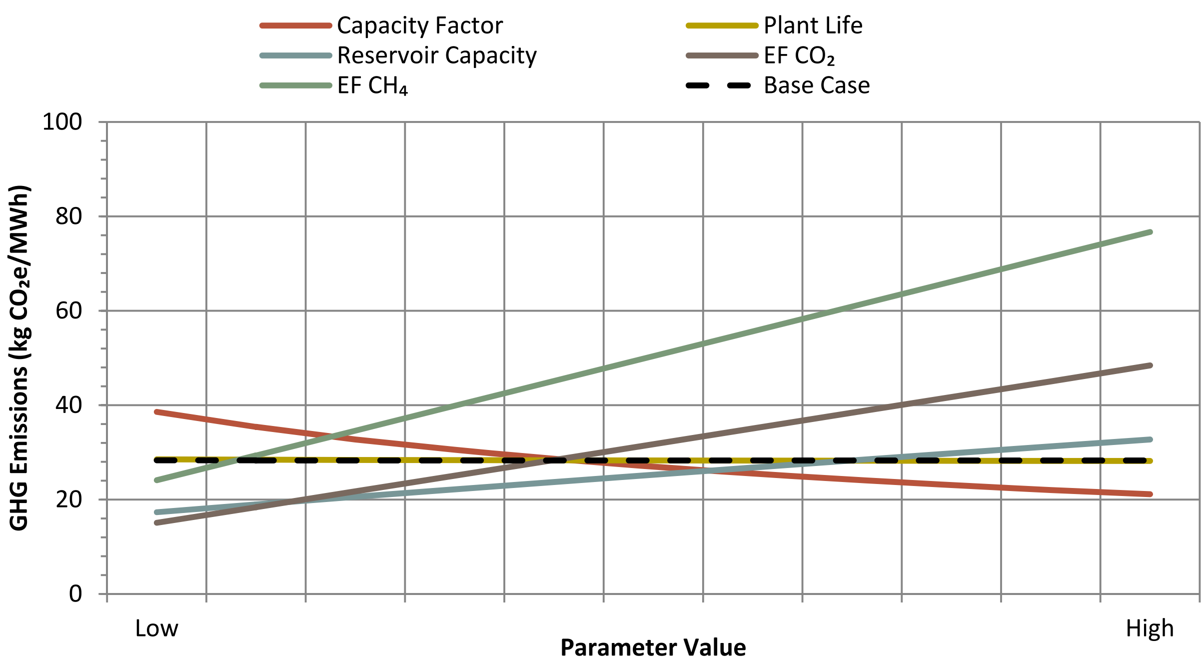
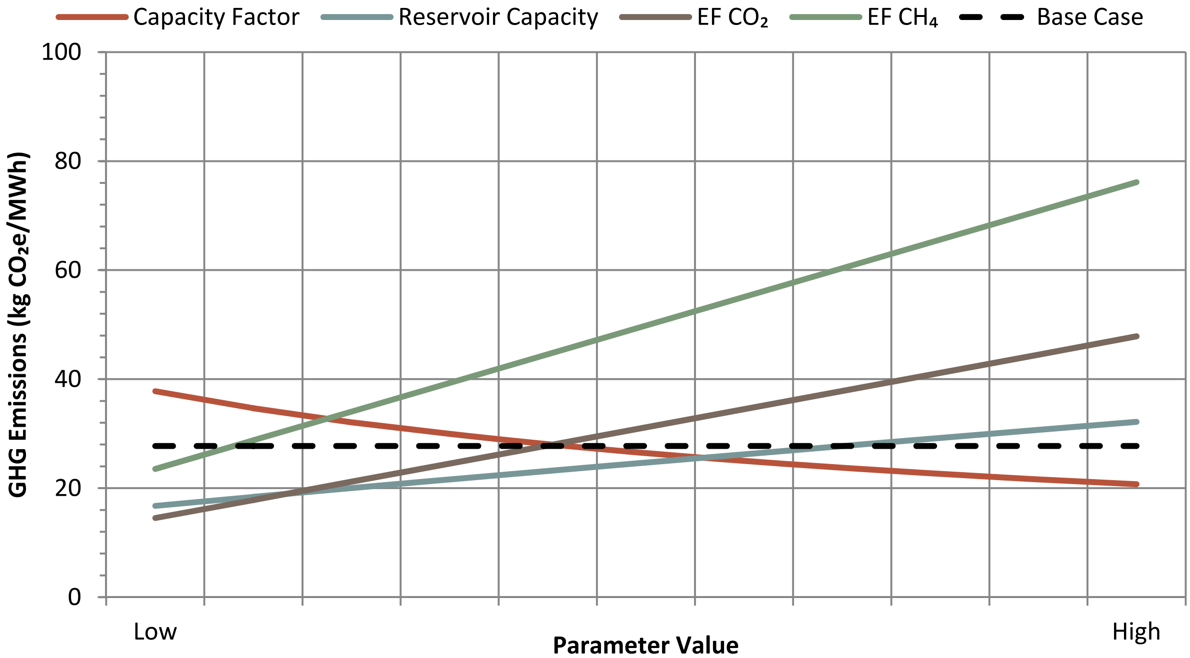


Figure 4-10: Uncertainty and Sensitivity of GHG Emissions for Existing Hydropower



4.4.2 GHG Emissions from Land Use

The transformed land area metric was assessed using reservoir surface area data obtained from satellite imagery, aerial photographs, and reported land use areas for various reservoirs located in the U.S., and based on study assumptions for transmission line length and width. Precise locations were not chosen for the facilities analyzed within the study. Therefore, to evaluate existing land use, regional average values for percent cover of grassland, forest, and agricultural land were derived from the most recent major land use data series available from the U.S. Department of Agriculture (USDA, 2006). Capacity factor, generation capacity, and other key parameters were set to be consistent with the remainder of the hydropower LCA model. Region-specific capacity factor data were available for conventional hydropower, and therefore existing land use type was considered and reported independently for conventional hydropower located within the following regions: Northeast, Midwest, South, West, Southwest, and U.S. Average.

As shown in **Table 4-4**, hydropower facilities evaluated for land use change include the reservoir and a 160 km trunkline for conventional hydropower, and the 40 km trunkline for hydrokinetic. Hydrokinetic facilities installed under LC Stage #3 were not considered for the land use analysis because these facilities would be installed within a river, not on land. No land use change occurred under LC Stages #1, #2, or #5. Transmission line infrastructure was considered existing and therefore effects of installation on land use were not included in the system boundary.

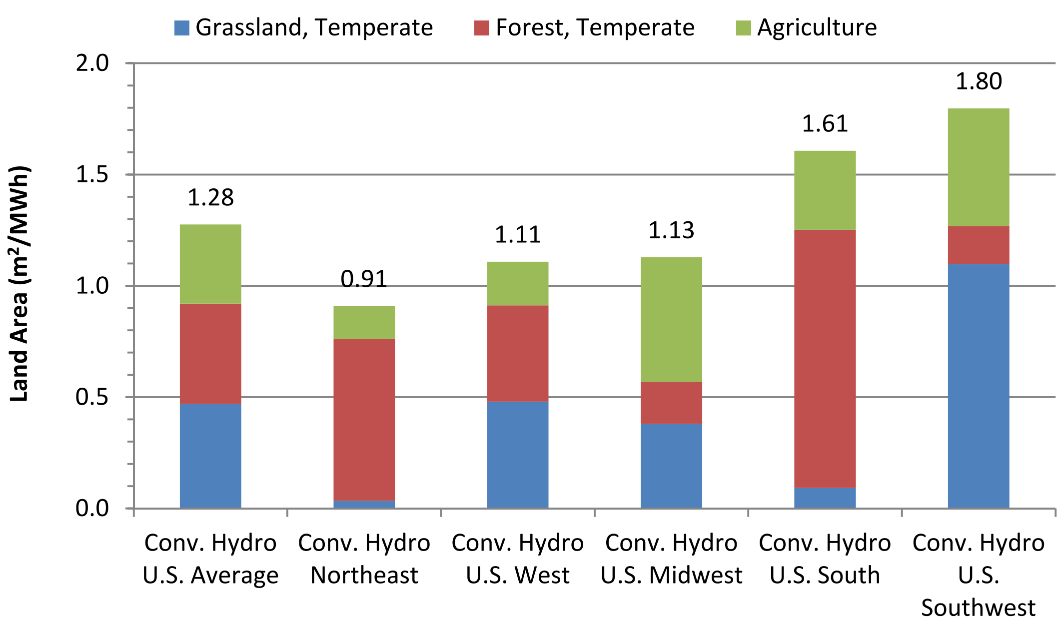
Table 4-4: Conventional Hydropower Facility Locations

LC Stage	Facility	Location
ECF	Conventional Hydropower Reservoir	Varies/Regional
PT	160 km Trunkline	Varies/Regional

Removal of onsite existing land use was assumed to be complete (100 percent removal) for all facilities. For indirect land use change, consistent with EPA's RFS2 analysis, it was assumed that 30 percent of all agricultural land that was lost as a result of the installation of facilities within the study resulted in the creation of new agricultural land. The creation of new agricultural land in turn was assumed to result in the conversion of either forest or grassland/pasture to farmland, according to regional land use characteristics identified by USDA (2006).

Results from the evaluation of transformed land area are shown in **Figure 4-11**. As shown, total transformed land area varies regionally for conventional hydropower on a per MWh basis. A consistent reservoir area (158,000 acres) and a consistent nameplate generation capacity (2,080 MW) were considered for each region for conventional hydropower. Variation in total land use area results from regional differences in capacity factor, while regional differences in existing land use type composition reflect regional variability in vegetative cover. For this study, the Northeast region had the highest average capacity factor (52 percent), the highest proportion of forest biomass (80 percent), and the lowest total land use area (0.91 m^2/MWh). The Southwest had the lowest average capacity factor (26 percent), the lowest proportion of forest biomass (9.5 percent), and the highest total land use area (1.8 m^2/MWh).

Figure 4-11: Transformed Land Area for Conventional Hydropower



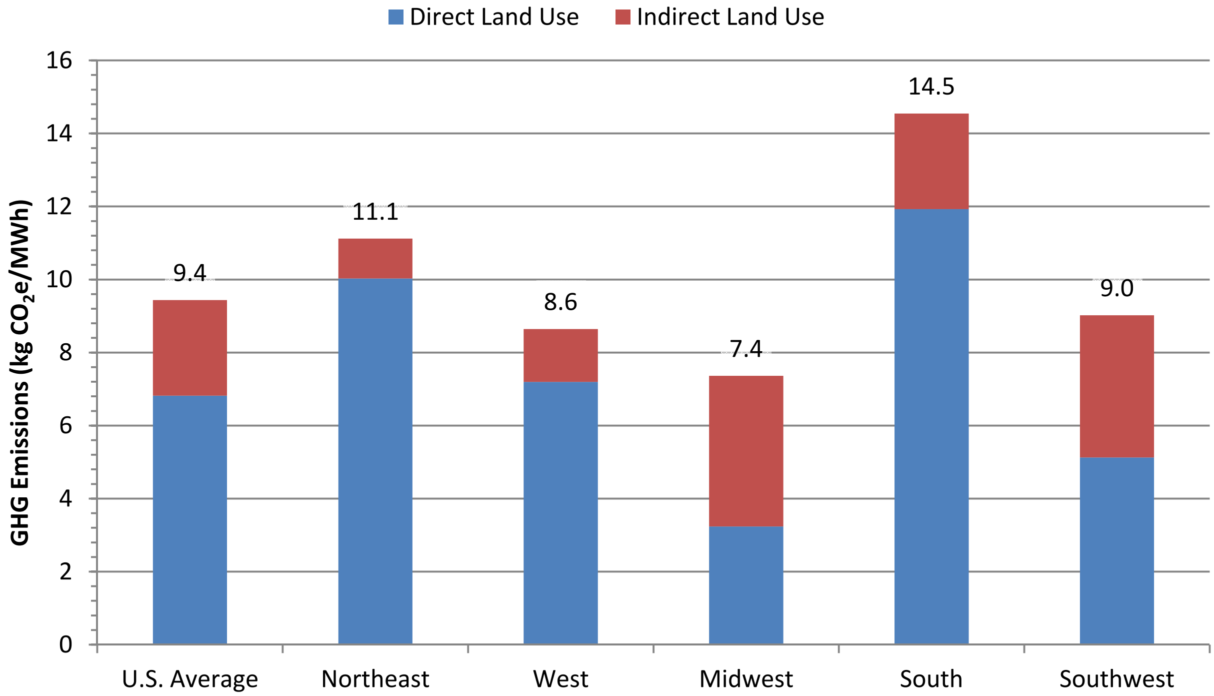
GHG emissions due to land use change were evaluated using the U.S. EPA's RFS2 method for the quantification of GHG emissions (EPA, 2009). EPA's analysis quantifies GHG emissions that are expected to result from land use changes from forest, grassland, savanna, shrubland, wetland, perennial, or mixed land use types to agricultural cropland, grassland, savanna, or perennial land use types. Relying on an evaluation of historic land use change completed by Winrock, EPA calculated a series of GHG emission factors for the following criteria: change in biomass carbon stocks, lost forest sequestration, annual soil carbon flux, methane emissions, nitrous oxide emissions, annual peak emissions, and fire emissions that would result from land conversion over a range of timeframes. EPA's analysis also included calculated reversion factors, for the reversion of land use from agricultural cropland, grassland, savanna, and perennial, to forest, grassland, savanna, shrub, wetland, perennial, or mixed land uses. Emission factors considered for reversion were change in biomass carbon stocks, change in soil carbon stocks, and annual soil carbon uptake over a variety of timeframes. Each of these emission factors, for land conversion and reversion, was included for a total of 756 global countries and regions within countries, including the 48 contiguous states.

Based on the land use categories (forest, grassland, and agriculture/cropland) affected by the facilities studied, EPA's emission factors were applied on a regional basis, as indicated previously. Only land conversion factors were considered for the facilities considered in this study. Land reversion factors, which are relevant after the removal of a facility when the prior land use begins to regenerate, were not applied. For a more extensive review of the methods used to evaluate GHG emissions from land use change used by EPA for RFS2, please refer to EPA (EPA, 2009). Specific to the conventional hydropower analysis, CO_2 emissions from the reservoir that result from the slow decay over time of biomass that was originally left on the floor of the reservoir when the reservoir was built, were considered outside of the land use analysis. Therefore, emissions resulting from the removal and decay of existing biomass based on existing land use type, which are analogous to this process, were discounted for the land use analysis. Emissions resulting from the removal and decay of existing biomass along the trunkline alignments were considered.

GHG emissions from indirect land use were quantified only for the displacement of agriculture, and not for the displacement of other land uses. Indirect land use GHG emissions were calculated based on estimated indirect land transformation values, as discussed previously. Then, EPA's GHG emission factors for land use conversion were applied to the indirect land transformation values, according to transformed land type and region, and total indirect land use GHG emissions were calculated.

Results from the analysis of transformed land area are illustrated in **Figure 4-12**. As shown, conventional hydropower facilities located in the Midwest result in the lowest net land use GHG emissions, at 7.3 kg/MWh including direct (3.2 kg/MWh) and indirect (4.1 kg/MWh) land use emissions. Southern conventional hydropower resulted in the highest net land use GHG emissions for conventional hydropower, at 14.5 kg/MWh, including direct (11.9 kg/MWh) and indirect (2.6 kg/MWh) land use emissions. The land use GHG emissions for average U.S. conventional (9.4 kg CO_2e/MWh) hydropower are included in the results for GHG emissions from greenfield hydropower (shown in **Figure 4-2**).

Figure 4-12: Land Use GHG Emissions for Conventional Hydropower



4.4.3 Other Air Emissions

In addition to GHG emissions, the LC model also included an extended set of air emissions. **Table 4-5** shows the LC results for a selected group of air pollutants, including criteria air pollutants, ammonia, and mercury. All of these emissions are produced by construction or installation activities. The greenfield hydropower scenario has the most construction activity, so it has the highest inventory of these air emissions. The existing hydropower scenario does not have any construction activities, so it does not release any of these emissions. A detailed profile of emissions is provided in **Appendix C.**

Table 4-5: Other Life Cycle Air Emissions for Hydropower (kg/MWh)

Emission	ECF Construction	Trunkline Construction	Hydropower Operation	Electricity T&D	Total
Greenfield					
Pb	4.49E-07	3.43E-08	0.00E+00	0.00E+00	4.83E-07
Hg	5.24E-08	2.62E-10	0.00E+00	0.00E+00	5.26E-08
NH_3	2.41E-06	1.40E-07	0.00E+00	0.00E+00	2.55E-06
CO	1.19E-02	3.38E-04	0.00E+00	0.00E+00	1.22E-02
NO_X	1.72E-02	6.95E-05	0.00E+00	0.00E+00	1.73E-02
SO_2	1.11E-02	1.07E-04	0.00E+00	0.00E+00	1.12E-02
VOC	5.90E-04	6.60E-06	0.00E+00	0.00E+00	5.97E-04
PM	5.22E-03	5.05E-05	0.00E+00	0.00E+00	5.27E-03
Power Addition					
Pb	3.26E-07	3.43E-08	0.00E+00	0.00E+00	3.61E-07
Hg	1.31E-08	2.62E-10	0.00E+00	0.00E+00	1.34E-08
NH_3	2.15E-07	1.40E-07	0.00E+00	0.00E+00	3.55E-07
CO	2.00E-03	3.38E-04	0.00E+00	0.00E+00	2.33E-03
NO_X	1.18E-03	6.95E-05	0.00E+00	0.00E+00	1.25E-03
SO_2	3.29E-04	1.07E-04	0.00E+00	0.00E+00	4.36E-04
VOC	9.45E-06	6.60E-06	0.00E+00	0.00E+00	1.60E-05
PM	6.55E-05	5.05E-05	0.00E+00	0.00E+00	1.16E-04
Power Upgrade					
Pb	6.52E-08	N/A	0.00E+00	0.00E+00	6.52E-08
Hg	7.58E-10	N/A	0.00E+00	0.00E+00	7.58E-10
NH_3	9.77E-08	N/A	0.00E+00	0.00E+00	9.77E-08
CO	3.56E-04	N/A	0.00E+00	0.00E+00	3.56E-04
NO_X	1.15E-04	N/A	0.00E+00	0.00E+00	1.15E-04
SO_2	5.42E-05	N/A	0.00E+00	0.00E+00	5.42E-05
VOC	4.29E-06	N/A	0.00E+00	0.00E+00	4.29E-06
PM	1.97E-05	N/A	0.00E+00	0.00E+00	1.97E-05

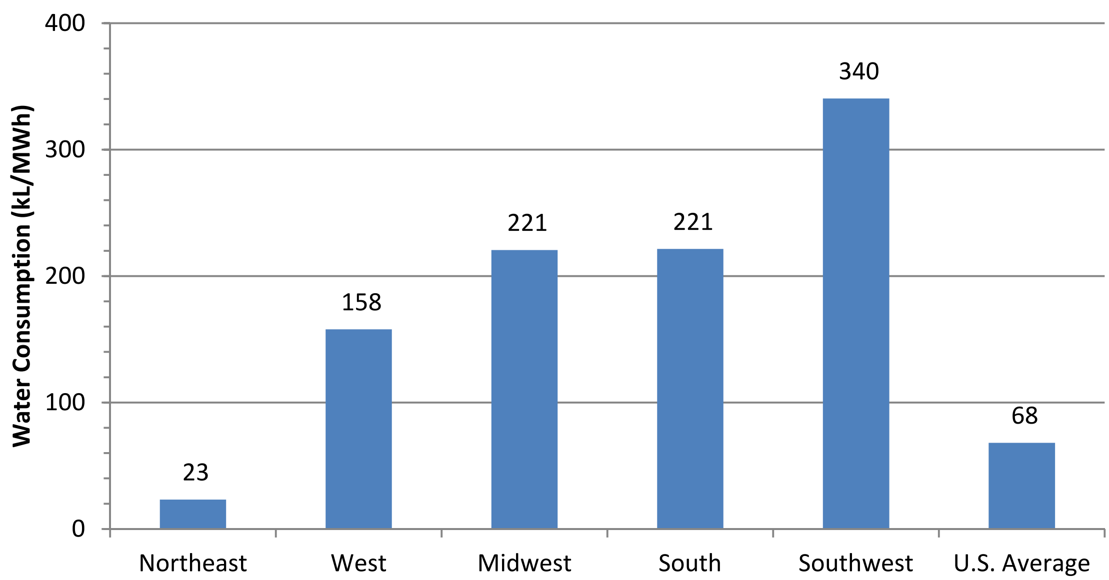
4.4.4 Water Use

Life cycle water consumption for conventional hydropower was quantified based on anticipated evaporation, per a regional evaluation of evaporation potential from reservoirs, completed by NREL (NREL, 2003). NREL's analysis evaluated water evaporation rates within 18 U.S. states, located in all regions considered in this analysis, normalized to net hydropower production. These factors were averaged regionally for the U.S. Northeast, Midwest, South, West, Southwest, and an overall U.S. Average. As shown in **Table 4-6**, evaporation from the U.S. Average conventional hydropower case results in a net water consumption of 73,270 L water/MWh (NREL, 2003). Evaporation rates vary regionally based on climate, and **Figure 4-13** shows the regional and U.S. Average evaporation values, which range from a minimum of 23,261 L/MWh (Northeast) to a maximum of 340,447 L/MWh (Southwest) values. Net water consumption during hydropower construction is negligible when compared to the water consumption during hydropower operation. Water used during construction is primarily related to dust control and/or cement production, during the construction process for the reservoir and 160 km trunkline. As shown by **Table 4-6** the water consumed by operations is nearly 1,000 times greater than consumed during construction.

Table 4-6: Average Life Cycle Water Use for Conventional Hydropower

Conventional Hydropower Technology	Net Water Consumption, Construction (L/MWh)	Net Water Consumption, Operation (L/MWh)
Conventional Concrete Dam	9.54E+00	7.33E+04
Conventional Earthen Dam	3.82E-02	7.33E+04
80/20 Mix of Conventional Concrete and Earthen Dams	7.64E+00	7.33E+04

Figure 4-13: Conventional Hydropower Life Cycle Water Consumption by Region (NREL, 2003)



4.4.5 Energy Return on Investment

EROI is defined as the ratio of usable, acquired energy to energy expended. The greenfield hydropower scenario has an EROI of 175:1, the lowest return of this analysis. The power addition and upgrade scenarios have higher EROIs of 1,273:1 and 7,511:1, respectively. The existing scenario does not expend any energy, because it does not have any construction requirements and resource energy is not applied to the primary energy source (flowing water). **Appendix C** shows a detailed profile of the resource energy and EROI for each hydropower scenario.

5 Cost Analysis of Hydropower

This analysis includes a life cycle cost (LCC) analysis of hydropower. Four hydropower scenarios are modeled in the LCC:

1. Greenfield conventional hydropower
2. Power addition to an existing dam
3. Power upgrade to an existing hydropower dam
4. Existing conventional hydropower

The approach, data, and results for the LCC analysis of hydropower are discussed below.

5.1 LCC Approach

The LCC analysis accounts for the significant capital and O&M expenses incurred by the hydropower systems during their assumed 60-year life. The LCC calculates the cost of electricity (COE), which is the revenue received by the generator per net MWh during the first year of operation, as well as the levelized cost of electricity (LCOE), which is current-dollar cost based on the discounted cash flows over the entire life of the plant (NETL, 2010). LCC calculations were performed using NETL's Power Systems Financial Model (PSFM), which calculates the capital charge factors necessary for apportioning capital costs per unit of production.

Cash flow is affected by several factors, including cost (capital, O&M, replacement, and decommissioning or salvage), book life of equipment, Federal and state income taxes, tax and equipment depreciation, interest rates, and discount rates. For NETL LCC assessments, modified accelerated cost recovery system (MACRS) depreciation schedules are used. O&M costs are assumed to be consistent over the study period except for the cost of energy and feedstock materials determined by EIA.

Capital investment costs are defined as equipment, materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Capital costs are assumed to be "overnight costs" (not incurring interest charges) and are expressed in 2007 dollars. Accordingly, all cost data are normalized to 2007 dollars, which is consistent with NETL's other LCCs of power systems. **Table 5-1** summarizes the LCC economic parameters that were applied to both pathways.

Table 5-1: Economic Parameters for LCC of Conventional Hydropower

Scenario	Greenfield	Power Addition	Power Upgrade	Existing
Financial Structure Type	Low Risk Investor-Owned Utility			
Debt Fraction (1 - Equity)	50%			N/A
Interest Rate	4.5%			N/A
Debt Term (Years)	15			N/A
Plant Lifetime (Years)	80			
Depreciation Period (MACRS)	20			N/A
Tax Rate	38%			N/A
O&M Escalation Rate	3%			
Capital Cost Escalation During the Capital Expenditure Period	3.6%			N/A
Base Year	2007			
Required Internal Rate of Return on Equity (IRROE)	12%			N/A

The boundaries of the LCC are consistent with the boundaries of the environmental portion of the LCA, ending with the delivery of 1 MWh of electricity to a consumer. The capital costs for the hydropower facilities account for all upstream economic activities related to the extraction, processing, and delivery of construction materials. The O&M costs of hydropower do not require the purchase of a primary fuel (which, in the case of hydropower, is water), but do account for labor and maintenance costs. Finally, all costs at the hydropower facility are scaled according to the delivery of 1 MWh of electricity to the consumer, which includes a 7 percent transmission and distribution loss between the power facility and the consumer.

5.2 Hydropower Cost Data

The capital and operating costs data for this analysis are based on a 2003 report by Idaho National Engineering and Environmental Laboratory (INEEL) (Hall, Hunt, Reeves, & Carroll, 2003), which uses data collected by FERC and EIA. In 2005, INEEL was renamed the Idaho National Laboratory (INL).

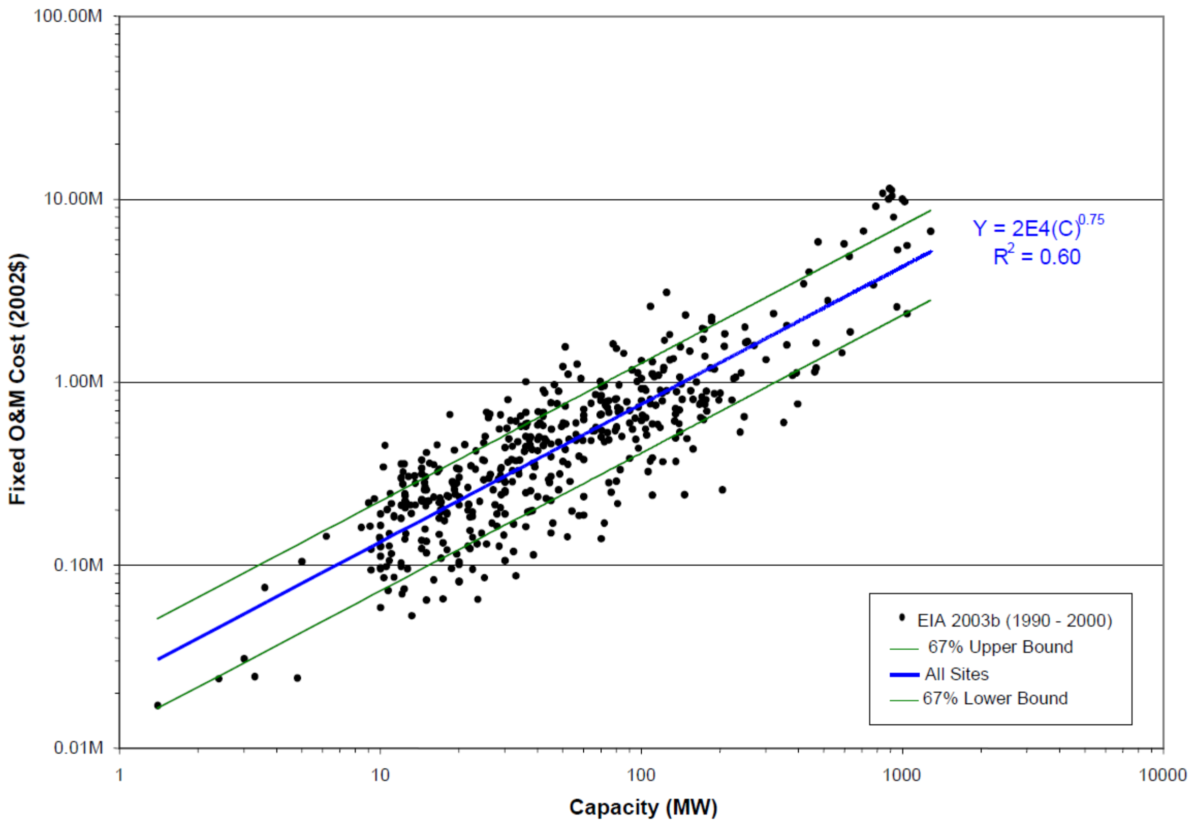
The authors of the INEEL report (Hall, et al., 2003) filtered the capital cost data to exclude small facilities (those with capacities less than 1 MW) and pumped hydro storage. They also separated capital costs into two categories: site preparation and hydropower facility construction. The site preparation costs are based on FERC data and include licensing, fish and wildlife mitigation, historical and archeological mitigation, and water quality monitoring; these data are representative of 226 facilities that reported data from 1980 through 1997. The construction costs of hydropower facilities are based on EIA data and include land and land rights, structures and improvements, reservoirs, equipment, roads, and bridges. The hydropower facility construction costs are representative of over 700 facilities that reported construction costs from 1990 through 2000.

The INEEL report also accounts for the fixed and variable O&M costs reported by U.S. facilities from 1990 through 2001. The original sample included 819 facilities, but was filtered by the authors of the INEEL report to exclude zero and negative O&M values as well as facilities that reported fixed costs outside the range of 0.5 to 5.5 $/MWh and variable costs outside the range of 1.5 to 8.0

$/MWh. The fixed O&M costs are representative of 384 facilities and the variable O&M costs are representative of 421 facilities (Hall et al., 2003).

Figure 5-1 is a plot from an INEEL report (Hall, et al., 2003) that shows the correlation between O&M costs and hydropower capacity. The majority of samples are representative of 10 MW to 200 MW installations. However, to be consistent with the environmental portion of this analysis, a 2,080 MW hydroelectric facility is used as a basis for calculating operating costs. The cost data shown in **Figure 5-1**, as well the variable O&M and capital cost data compiled by INEEL, demonstrate strong linear relationships[1], so on the basis of 1 MWh of produced electricity, the COE of for a 2,080 MW hydroelectric facility will be similar to the COE for a smaller facility.

Figure 5-1: Fixed O&M Costs for Hydropower Facilities Adapted from (Hall, et al., 2003)



Capital and operating costs for conventional hydropower are highly variable. The variability for conventional hydropower largely reflects specific location conditions, as well as regional costs of labor and materials, which can vary substantially when considering data from different global regions.

[1] The authors of the INEEL report on hydropower costs (Hall, et al., 2003) use power curves to develop cost correlations from scatter plots; however, the patterns shown by INEEL's cost data could also be fit with straight lines having high coefficients of determination (R^2).

The capital costs for conventional hydropower installations include three scenarios. The first scenario is an undeveloped site, which requires full site preparation and construction; the site development and construction costs for this scenario are $3,600 and $2,700/kilowatt, respectively, for a total capital cost of $6,300/kilowatt. The second scenario is representative of an existing dam that does not have hydropower; it has site preparation costs of $2,000/ kilowatt, construction costs of $1,200/kilowatt, and a total capital cost of $3,200/ kilowatt. The third scenario is an existing hydropower facility that undergoes equipment upgrading; it has site preparation costs of $1,200/kilowatt, construction costs of $700/kilowatt, and a total capital cost of $1,900/ kilowatt. These costs are in 2002 dollars, and were scaled to a 2007 base year before they were imported to the LCC model using an annual escalation rate of 3 percent. This escalation rate is consistent with the assumptions of the NETL bituminous baseline and is based on the Department of Labor's Producer Price Index for Finished Goods. (The price index for the electric power sector does not date back to 2003, and thus is not adequate for scaling between 2002 and 2007.)

Table 5-2 shows the capital costs for the three conventional hydropower scenarios. To allow comparability between the INEEL report (Hall, et al., 2003) and this analysis, **Table 5-2** shows cost data in terms of 2002 dollars. However, the cost model of this analysis converts all input data to a 2007 dollar basis before performing any calculations.

Table 5-2: Capital Costs for Conventional Hydropower, 2002$/kW

Scenario	Site Development	Construction	Total
Greenfield	3,600	2,700	6,300
Power Addition	2,000	1,200	3,200
Power Upgrade	1,200	700	1,900
Existing	N/A	N/A	N/A

Fixed operating and maintenance (O&M) costs are based on power equations developed by INEEL (Hall, et al., 2003). The power equation for the fixed O&M costs is shown below.

$$Fixed\ O\&M = 24{,}000 * Capacity^{0.75} \qquad \textbf{(Equation 1)}$$

Variable operating and maintenance (O&M) costs are based on power equations developed by INEEL (Hall, et al., 2003). The power equation for the fixed O&M costs is shown below.

$$Variable\ O\&M = 24{,}000 * Capacity^{0.80} \qquad \textbf{(Equation 2)}$$

Where,

Fixed O&M and *Variable O&M* = $/year (in 2002 dollars)

Capacity = MW

This analysis divides the O&M costs calculated by the above equations by the annual quantity of MWh produced to determine the fixed and variable O&M costs per MWh of production. For instance, a 2,080 MW facility with a 37 percent capacity factor produces 6.74 million MWh per year. All costs are converted to 2007 dollars before they are imported into the LCC model.

Other attributes of the LCC analysis of hydropower are as follows:

- The capacity of the hydropower facility is 2,080 MW, and the expected capacity factor is 37 percent.
- Conventional hydropower has an operating life of 80 years.
- Other capital costs include the power trunkline, which connects the hydropower facility to the electricity grid. A 160 km trunkline is modeled for conventional hydropower, and a 40 km trunkline is modeled for hydrokinetic power. The trunkline modeled in NETL's previous LCAs of power generation is a 80 km system with capital costs of $45.6 million. The capital costs for a trunkline for conventional hydropower are estimated at $91.2 million, which is twice the capital cost of the 50-mile trunkline used by NETL's previous LCAs. The capital cost of a trunkline that serves a hydrokinetic installation is estimated at $9.12 million.
- The cost model calculated the COE at the busbar of the power plant, which was then scaled by 7 percent to account for the transmission loss between power plant and consumer.
- Decommissioning costs are not accounted for in this analysis. There are some examples of the decommissioning of small (<50 MW) hydropower facilities in northern California, but the upgrading of an existing hydropower facility is more likely than the decommissioning of a hydropower facility.

The capital and operating costs of the four LCC scenarios are summarized in the following table.

Table 5-3: Cost and Other Parameters for LCC of Hydropower

Parameter	Greenfield	Power Addition	Power Upgrade	Existing
Operating Life (Years)	80			N/A
Construction Period (Years)	4	3	2	N/A
Plant Output (MW)	2,080			
Capacity Factor	37%			
Capital Costs of Energy Conversion Facility (Million 2007$)	$15,200	$7,720	$4,580	N/A
Total Fixed O&M Costs (2007$/MW-yr.)	$4,120			
Total Variable O&M Costs (2007$/MWh)	$1.86			
Capital Costs of Trunkline (Million 2007$)	$91.2		N/A	

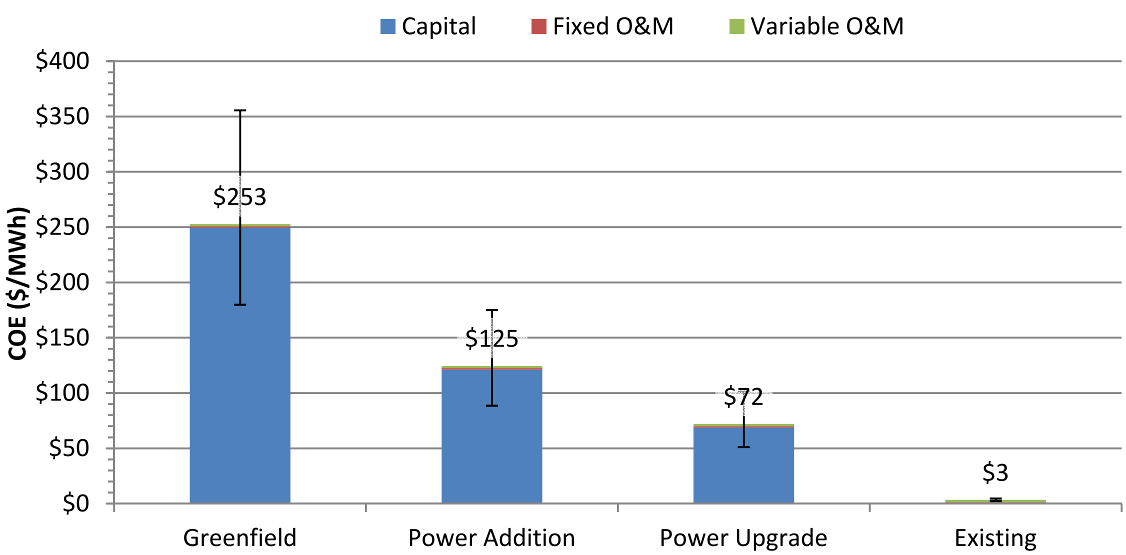
5.3 LCC Results

The COE of the four hydropower scenarios range from $3 to $275 /MWh (in 2007 dollars). Existing hydropower does not have any capital expenditures, so it has the lowest COE. The greenfield scenario has the highest capital expenditures, so it has the highest COE. These results are shown in **Table 5-4** and **Figure 5-2**.

Table 5-4: LCC Results for Hydropower, Cost of Electricity (2007$/MWh)

Parameter	Greenfield	Power Addition	Power Upgrade	Existing
Capital	249	121	68.7	0.00
Fixed O&M	1.37	1.37	1.37	1.37
Variable O&M	2.00	2.00	2.00	2.00
Fuel O&M	0	0	0	0
Total COE	253	125	72.1	3.37

Figure 5-2: LCC Results for Hydropower, COE (2007$/MWh)



Capital costs are the key component of the greenfield, power addition, and power upgrade scenarios. hydropower account for the majority of the COE. For these three scenarios, between 95 and 99 percent of the total COE is due to capital costs. As a renewable energy technology, hydropower does not require the purchase of fuel for operation, and other operating and maintenance costs are small in comparison to the annualized capital costs. Thus, the COE of the existing scenario is particularly low because it does not have any capital burdens.

An important aspect of the LCC results is that the conventional hydropower scenarios are assigned the full capital costs of site preparation and dam construction. However, in addition to power generation, conventional dams also provide irrigation, navigability, flood control, and recreation, each of which has a large economic value. The metrics for measuring the value of these other purposes are different from the metric for measuring power output (i.e., MW), and thus it is difficult to develop a fair scheme for apportioning cost burdens among the services provided by a conventional dam. The greenfield conventional case of this analysis overstates the cost burdens

($253/MWh) that should be assigned to a MWh of delivered electricity because it includes all site preparation and construction costs that could be partly allocated to other services. On the other hand the power upgrade scenario ($72/MWh) is representative of equipment costs that are solely attributable to power generation, but may underestimate site preparation costs that could be allocated to power production. The existing scenario represents a hydroelectric facility that does not have any capital burdens.

Additionally, many of the large scale hydropower facilities in the United States were not financed by traditional utility investors, but rather by the Federal government, so there was no need to manage risk with an expected return on the investment.

The error bars shown in **Figure 5-2** represent the uncertainty in COE caused by a range of capacity factors. The expected capacity factor for conventional hydropower is 37 percent, but the low and high values range from 26.3 percent to 52.0 percent. There is an inverse relationship between capacity factor and COE; as the capacity factor increases, the COE decreases because capital and fixed O&M costs are divided by a greater output of electricity. Capacity factor was the only uncertainty modeled for the cost analysis of hydropower.

6 Barriers to Implementation

Conventional hydropower is considered a mature technology. It has been implemented widely across the United States and globally. When properly designed and engineered, conventional hydropower can provide reliable power production over the lifetime of the facility, which may be 50 years or longer (Pew Center on Global Climate Change, 2009). Drawbacks to conventional hydropower include its dependence on natural flow and water storage volumes. In drought years, the total volume of water is reduced, and therefore the effective generation capacity of the reservoir is also reduced. Water availability for power generation is also affected by various other factors, including competing uses for water supply and flood control. Climate change is also expected to alter natural weather patterns in many regions, including net reductions in the Western and Southeast. Potential reductions in water storage that could result from climate change could reduce the effective generation capacity of conventional hydropower reservoirs. Conventional hydropower also suffers from a lack of available sites that are suitable for very large developments. Most of the very large hydropower sites in the U.S. have already been developed. However, many smaller conventional hydropower sites, such as those with capacities up to 400 MW, are still available (California Energy Commission, 2008).

In contrast, hydrokinetic technologies have recently emerged as viable electricity production technologies. Although substantial new installations are in process along the Mississippi River system, hydrokinetic technologies have not been extensively field tested. While their lifetime is anticipated to range from 20 to 30 years, the extent of required maintenance and replacement is somewhat more difficult to predict. Because they are installed into flowing rivers, hydrokinetic technologies may be subject to substantial damage from debris or washout, especially during high flow or flood events. These concerns could potentially increase the lifetime cost of hydrokinetic installations substantially, depending upon turbine design and site selection. Like conventional hydropower, hydrokinetic technologies are also subject to variation in river flows and water availability. Installations located immediately downstream of a conventional hydropower facility may be further affected by the operation of that facility.

Installation of a new conventional facility results in the submersion of large tracts of land. This characteristic has proved to be highly unpopular from a public perspective, especially among environmental groups. Further, the filling of a reservoir destroys terrestrial vegetation and habitats. Conventional hydropower plants also block the passage of fish and alter river flows, such that substantial in-river ecosystem changes occur following installation of a large conventional hydropower facility (U.S. Bureau of Reclamation, 2011). Long-term issues include reservoir sedimentation, wherein sediment carried into a reservoir settles out. Over time, the sediment builds up and can reduce reservoir capacity. Blockage by sediment also affects downstream habitat and geomorphic processes, which can range from reduced sediment loads downstream of a reservoir, to depleted sand on ocean beaches (U.S. Bureau of Reclamation, 2006).

7 Risks of Implementation

Environmental review and permitting of large conventional hydropower in the U.S. is difficult. Conventional hydropower facilities may be subject to permitting under the National Environmental Policy Act (NEPA), Clean Water Act (CWA), and Endangered Species Act (ESA), as well as environmental compliance and permitting efforts required at the state level. Environmental review and acquisition of needed permits can take 5 to 10 years or more (Contra Costa Water District, 2011). These issues substantially slow conventional hydropower development in the United States.

In contrast to large conventional hydropower, environmental review and permitting for hydrokinetic installations have proven to be much less arduous. FERC has initiated programs to streamline the permitting process for these types of installations (FERC, 2010). The systems are low profile and turbines are installed underwater without the need for a dam or other impoundment. As a result, projects to date have not realized the same level of public scrutiny as large conventional hydropower installations. In terms of environmental issues, hydrokinetic installations do not result in the blocking of waterways, and therefore do not have the same effects on hydrology or fisheries that occur with conventional hydropower. However, hydrokinetic turbines are expected to interfere with fish migration and passage, as fish could become trapped in turbine blades. Additionally, depending upon their configuration, some hydrokinetic facilities could act as partial barriers to fish passage along a waterway. Finally, hydrokinetic facilities may partially restrict the movement of river-borne vessels, and may reduce the suitability of some areas for recreational purposes.

The high maintenance costs of older hydropower facilities hinder the performance of the U.S. hydropower fleet. Hydropower assets are split almost evenly on a capacity basis between federal and non-federal ownership with the federal owners being the U.S. Army Corps of Engineers (USACE), the Department of Interior’s Bureau of Reclamation, and the Tennessee Valley Authority (TVA). The 75 USACE hydropower assets have a median age of 47 years, which, due to unplanned maintenance outages, has made it increasingly difficult to meet the industry goal of 95 percent unit availability (U.S. Army Corps of Engineers, 2011). Since 1999, the number of hours for forced outages for USACE hydropower assets has more than doubled. The USACE has recently established the Hydropower Modernization Initiative (HMI) to identify the assets that are in most need of rehabilitation and that offer the highest potential return on investment. Preliminary assessments of the HMI focused on six plants where an 8 percent increase in electricity production output could be realized with an investment of approximately $600 million (U.S. Army Corps of Engineers, 2011). However, federal funding for even the most promising rehabilitation projects is difficult to secure because of competing priorities. In addition to modernization, another challenge for USACE hydropower assets is the desire to remove dams in order to restore ecosystems and reestablish migratory patterns for species that are protected by the endangered species act. One specific controversial example are the four USACE hydropower assets on the Snake River in Washington state, which together have a rated capacity of 3.0 GW (U.S. Army Corps of Engineers, 2011).

8 Expert Opinions

The National Hydropower Association (NHA), an industry trade organization, projects that modernizing existing conventional hydropower could yield an additional 9 GW of capacity, while converting the most promising non-powered dams could yield 10 GW of additional capacity (National Hydropower Association, 2011). The NHA also projects that 15 GW of capacity could be added by implementing river, tidal, and wave hydrokinetic assets. In order to spur development of these projects, the NHA is lobbying to extend the same level of tax credits to hydropower that are available to other renewable sources. Currently, new hydropower electricity generation, either by upgrades at conventional facilities or new hydrokinetic installations, qualifies for half of the value of the renewable electricity production tax credit (IRS, 2010).

The Electric Power Research Institute (EPRI) has estimated that the potential for hydropower capacity expansion based on modernization of existing facilities, conversion of non-powered dams, and installation of hydrokinetic plants can achieve a total capacity addition of 23 GW by the year 2025 (EPRI, 2007). EPRI contends that the estimates could be further increased up to 85 or 90 GW based on the implementation of new economic and regulatory policies for the hydropower industry. EPRI compares the potential expansion of hydropower, particularly hydrokinetics, to the expansion of wind energy that has taken place over the last 10 years. According to EPRI’s analysis, the expansion in wind energy is due to public- and private-sector commitments to research, development, demonstration, and deployment as well as extensions to the production tax credit and clean renewable energy bond programs.

The Departments of the Army, Energy, and the Interior were tasked by the Energy Policy Act of 2005 with conducting a joint study to assess both the potential of capacity increases at existing federally owned hydropower facilities and the potential for adding electricity generation facilities at other federally owned dams. The report concluded that federal sites owned by the USACE and the Bureau of Reclamation could yield 1.2 GW of new capacity and modernization of existing sites could yield 1.3 GW of additional capacity (U.S. Department of Energy, U.S. Department of the Army, & U.S. Department of the Interior, 2007).

9 Summary

This analysis provides insight into the role of hydropower as a future energy source in the U.S. The criteria used for evaluating the role of hydropower are as follows:

- Resource Base
- Growth
- Environmental Profile
- Cost Profile
- Barriers to Implementation
- Risks of Implementation
- Expert Opinions

Key conclusions for these criteria are summarized below.

The **resource base** for very large hydropower sites in the U.S. has already been developed. However, many smaller conventional hydropower sites, such as those with capacities up to 400 MW, are still available. In 2009, conventional hydropower in the U.S. produced 253 terawatt hours of electricity, equivalent to 72 percent of total renewable power generation and approximately 7 percent of total power generation. The capacity of installed hydropower has remained relatively flat since 2000 near 77 GW.

The average annual **growth** of hydropower as forecasted by the AEO 2011 (EIA, 2011) is 0.5 percent per year from 2.53 to 3.09 quadrillion Btu for hydropower production between 2008 and 2035 and a 0.1 percent capacity increase for the same period (EIA, 2011). The AEO increase in hydropower capacity is substantially smaller than the projected capacity increase based on the issued and pending preliminary FERC permits for new hydropower, which total to a potential of 22.5 GW of additional capacity on top of the existing capacity of 77 GW.

The **environmental profile** of hydropower is based on an LCA of four hydropower scenarios, including the construction of a greenfield hydropower facility, power addition to an existing dam, upgrading of an existing hydropower facility, and an existing facility with no modifications. The expected value for all scenarios falls within range from 27.7 to 43.8 kg CO_2e/MWh. Carbon dioxide and methane emissions from the reservoir during hydropower operations dominate the life cycle GHG emissions and range from 56 to 88 percent of total GHG emissions. GHG emissions from land use account for 22 percent of the GHG from greenfield hydropower (the greenfield scenario is the only scenario that includes land use emissions). Land use GHG emissions increase the total GHG emissions from 34.4 to 43.8 kg CO_2e/MWh.

The **cost profile** of hydropower shows that capital costs are the key component of the greenfield, power addition, and power upgrade scenarios; the total COE for these scenarios are $253, $125, and $72 per MWh, respectively. For these three scenarios, between 95 and 99 percent of the total COE is due to capital costs. As a renewable energy technology, hydropower does not require the purchase of fuel for operation, and other operating and maintenance costs are small in comparison to the annualized capital costs. Thus, the COE of the existing scenario is particularly low ($3/MWh) because it does not have any capital burdens. An important aspect of the cost results is that the conventional hydropower scenarios are assigned the full capital costs of site preparation and dam construction. In addition to power generation, conventional dams also provide irrigation control and recreation. The metrics for measuring irrigation control and recreation are different from the metric for measuring power output (i.e., MW), and thus it is difficult to develop a fair scheme for apportioning cost burdens among the services provided by a conventional dam.

The **barriers to implementation** of conventional hydropower include its dependence on natural flow and water storage volumes. In drought years, the total volume of water is reduced, and therefore the effective generation capacity of the reservoir is also reduced. Water availability for power generation is also affected by various other factors, including competing use for water supply and flood control. Climate change is also expected to alter natural weather patterns in many regions. Because they are installed into flowing rivers, hydrokinetic technologies may be subject to substantial damage from debris or washout, especially during high flow or flood events. These concerns could potentially increase the lifetime cost of hydrokinetic installations substantially, depending upon turbine design and site selection. Like conventional hydropower, hydrokinetic technologies are also subject to variation in river flows and water availability.

The **risks of implementation** of hydropower include the characteristically difficult environmental review and permitting of large conventional hydropower in the United States. Environmental review and acquisition of needed permits can take 5 to 10 years or more, which has substantially slowed development of new hydropower in the U.S. In contrast with large conventional hydropower, environmental review and permitting for hydrokinetic installations have proven to be much less arduous based on streamlining initiatives implemented by FERC.

Expert opinions include the experience of USACE, EPRI projections, and NHA interests; these three organizations agree that, given policies that enact favorable financial incentives, there is potential for hydropower capacity growth. EPRI compares the potential expansion of hydropower, particularly hydrokinetics, to the expansion of wind energy that has taken place over the last 10 years. The expansion in the case of wind installations appears to be a combination of the commitment to research, development, demonstration, and deployment by the public and private sectors along with extensions to the production tax credit and clean renewable energy bond programs. In order to spur development of these projects, the NHA is lobbying to extend the same level of tax credits to hydropower that are available to other renewable sources.

Hydropower is a proven technology that represents approximately 7 percent of U.S. electricity generation, but the resource base for large hydropower facilities has been fully developed and the growth potential for hydrokinetic hydropower is limited by the small capacities of hydrokinetic installations. There is potential for growth in the upgrading of existing power generation facilities and the addition of generation capability to existing dams. The GHG emissions of hydropower are low, but there are ecological impacts of hydropower that are outside the boundaries of the LCA performed. Further, the benefits that dams provide with respect to flood control, irrigation, and navigability are difficult to compare on the same basis as hydroelectric power generation, complicating the calculation of the costs of hydropower.

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Appendix A: Constants and Unit Conversion Factors

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Table A-1: Common Unit Conversions

Category	Input			Output	
	Value	Units		Value	Units
Mass	1	lb.	=	0.454	kg
	1	Short Ton	=	0.907	Tonne
Distance	1	Mile	=	1.609	km
	1	Foot	=	0.305	m
Area	1	$ft.^2$	=	0.093	m^2
	1	Acre	=	43,560	$ft.^2$
Volume	1	Gallon	=	3.785	L
	1	$ft.^3$	=	28.320	L
	1	$ft.^3$	=	7.482	Gallons
Energy	1	Btu	=	1,055.056	J
	1	MJ	=	947.817	Btu
	1	kWh	=	3,412.142	Btu
	1	MWh	=	3,600	MJ

Table A-2: IPCC Global Warming Potential Factors (Forester, et al., 2007)

IPCC GWP Factor	Vintage	20 Year	100 Year	500 Year
CO_2	2007	1	1	1
CH_4	2007	72	25	7.6
N_2O	2007	289	298	153
SF_6	2007	16,300	22,800	32,600
CO_2	2001	1	1	1
CH_4	2001	62	23	7
N_2O	2001	275	296	156
SF_6	2001	15,100	22,200	32,400

Appendix B:
Data for Hydropower Modeling

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B.1 Conventional Hydropower

The LCA of conventional hydropower was based on two unit processes, one for construction and another for operations:

- Conventional Hydropower Dam Construction (Earthen or Concrete)
- Conventional Hydropower Operations

B.2 Conventional Hydropower Dam Construction

Data for conventional hydropower dam construction account for construction materials and air emissions from construction equipment. The unit process is an 80/20 mix of concrete and earthen dams, respectively, which was based by taking of sample of the conventional hydropower facilities in EPA's eGRID database, followed by a determination of the sample's ratio of concrete to earthen dams.

Data for construction of the concrete dam was taken from available documentation on Hoover Dam, located along the Colorado River on the Nevada/Arizona border. Hoover Dam was selected as a representative dam due to its intermediate to large size. The construction materials are comprised mostly of concrete, steel plate, and cold rolled steel (U.S. Bureau of Reclamation, 2005). The emissions from construction equipment used for concrete dam construction are based on data for reservoir, water intake, and electrical equipment installation and include carbon dioxide, carbon monoxide, nitrogen oxides, and particulate matter (California Department of Water Resources, 2005; Contra Costa Water District, 2009).

NETL's review of available data indicated that construction of earthen dams typically relies on earthen materials that are sourced locally to the dam construction site, such as within the reservoir basin for the new dam. To that end, application of a materials profile, for instance as is done within this unit process for concrete in support of the concrete dam, was determined to be not applicable to an earthen dam construction. Instead, earthen dam construction was evaluated based on construction emissions required for the movement of clay and other soils from the newly formed reservoir bottom to the dam, for dam construction. Emission values were based on data available for the construction of the Los Vaqueros Reservoir, an earthen dam that was constructed in the 1990s, that is currently undergoing expansion (Contra Costa Water District, 2009). The earthen dam is assumed to be constructed entirely of dirt/clay aggregate, extracted near the dam's site.

Capacity factor is a key adjustable parameter in support of this unit process, because it strongly influences the amount of electricity that is generated over a hydropower facility's lifetime, thus influencing the amount of construction burdens assigned to each MWh of electricity produced. Capacity factor was calculated based on regional average capacity factors for the U.S. West, Southwest, South, Midwest, and Northeast. Location and capacity factor were queried for approximately 150 U.S. reservoirs, having nameplate capacities of at least 100 MW. Data were acquired for 2002 through 2010, and average capacity factors were generated for each U.S. region (Ventyx, 2011). These are as follows: Northeast, 52.0 percent; West, 42.7 percent; Midwest, 41.9 percent; Alaska, 36.3 percent; South, 29.5 percent; and Southwest, 26.3 percent.

Hydropower facility lifetime is also included as an adjustable parameter. All hydropower scenarios in this analysis are modeled using an expected lifetime of 80 years. The LCA uses sensitivity analysis to test the affect that lifetime has on study results.

Dams often serve other uses in addition to power generation, such as irrigation control and recreation. There is not a common basis for apportioning construction burdens among multiple dam uses. This unit process assigns all construction burdens to power generation.

Upstream emissions from the production of raw materials used for the construction of the turbine and associated components (e.g., steel plate, cold rolled steel, and concrete) are calculated outside the boundary of this unit process, based on steel profiles developed by the International Iron and Steel Institute and concrete data developed by NETL.

Table B-1 shows the inputs and outputs for the construction of conventional hydropower facilities.

Table B-1: Construction and Installation of a 2,080 MW Conventional Hydropower Facility

Inputs	Greenfield	Power Addition	Upgrade	Units
Steel Cold Rolled (St) (Metals)	3.43E+07	1.80E+07	8.16E+06	kg
Steel Plate, BF (85% Recovery Rate) (Metals)	4.54E+07	4.54E+07	2.40E+06	kg
Concrete, Ready Mix, R-5-0 (Concrete_Cement)	6.13E+09	0.00E+00	0.00E+00	kg
Outputs	**Greenfield**	**Power Addition**	**Upgrade**	**Units**
Hydropower Facility Construction	1	1	1	piece
Carbon Dioxide (Inorganic Emissions to Air)	1.22E+09	5.29E+08	2.65E+08	kg
Nitrogen Oxides (Inorganic Emissions to Air)	4.21E+06	4.41E+05	2.45E+04	kg
Carbon Monoxide (Inorganic Emissions to Air)	3.63E+06	2.45E+05	1.23E+04	kg

Table B-2 shows the inputs and outputs for the construction of conventional hydropower facilities, expressed on the basis of 1 MWh of power production. The reference facility has a capacity of 2,080 MW, a capacity factor of 37 percent, and a lifetime of 80 years.

Table B-2: Construction and Installation of a 2,080 MW Conventional Hydropower Facility (per MWh of Electricity Production)

Inputs	Greenfield	Power Addition	Upgrade	Units
Steel Cold Rolled (St) (Metals)	6.36E-02	3.34E-02	1.51E-02	kg
Steel Plate, BF (85% Recovery Rate) (Metals)	8.42E-02	8.42E-02	4.45E-03	kg
Concrete, Ready Mix, R-5-0 (Concrete_Cement)	1.14E+01	0.00E+00	0.00E+00	kg
Outputs	**Greenfield**	**Power Addition**	**Upgrade**	**Units**
Hydropower Facility Construction	1.85E-09	1.85E-09	1.85E-09	piece
Carbon Dioxide (Inorganic Emissions to Air)	2.26E+00	9.81E-01	4.91E-01	kg
Nitrogen Oxides (Inorganic Emissions to Air)	7.81E-03	8.18E-04	4.54E-05	kg
Carbon Monoxide (Inorganic Emissions to Air)	6.73E-03	4.54E-04	2.28E-05	kg

B.3 Conventional Hydropower Operations

The scope of this process encompasses power generated from a conventional hydropower facility. The unit process considers water consumption associated with evaporation from the reservoir, and carbon dioxide and methane emissions from the reservoir surface that occur during operation of the reservoir.

Reservoir surface area is a key factor used for calculating carbon dioxide and methane emissions from the reservoir. Literature values for these emission factors are provided based on emissions from a single square meter during one day (U.S. Bureau of Reclamation, 2005; Aleseyed, 2003). Therefore, the surface area parameter scales these emission factors to account for reservoir surface area.

To complete the calculation of reservoir surface area, the mean amount of water in the reservoir must also be calculated. The volume of water contained in a reservoir varies based on a combination of water inflow to the reservoir, evaporation, and outflow from the reservoir. Most large reservoirs only reach full capacity during limited periods, such as near the end of the annual wet season or snowmelt season. During prolonged drought, large western reservoirs used for water supply may be reduced to 40 percent capacity or less. However, reservoirs located in the south and Midwest, where water is more consistently available and there are not prolonged dry seasons, may have substantially less variability, operating at 70 to 90 percent capacity most of the time. Therefore, based on a preliminary review of reservoir storage data, boundary values of 35 percent to 85 percent capacity have been selected for mean aquifer volume, with a best estimate value of 70 percent.

Evaporation occurs as a natural process along rivers and other waterways. When water is held in a reservoir that would otherwise have been allowed to pass downstream, additional evaporation occurs within the reservoir, during the time period when the water is withheld. Presumably, following release from the reservoir, water would travel down the remainder of the river, where evaporation rates would be similar to natural baseline values. NREL (2002) quantified water evaporation rates from reservoirs, in support of power generation. NREL's data include reservoirs across five U.S. regions, with evaporation rates varying from approximately 23,300 (Northeast) to 340,000 kg/MWh (Southwest) of power generated. These values were calculated based on data from individual reservoirs within each region.

Capacity factor is a key parameter in for this process because it strongly influences the amount of electricity that can be generated over any given period. The calculation of capacity factor is described in **Section B.2** above.

Dams often serve other uses in addition to power generation, such as irrigation control and recreation. There is not a common basis for apportioning reservoir emissions and evaporation among multiple dam uses. This unit process assigns all operating burdens to power generation.

This analysis accounts for the emissions from land use change for the greenfield scenario, but land use GHG emissions are calculated separately from other emissions and are not included in the boundaries of this unit process.

Table B-3 shows the inputs and outputs for the operation of conventional hydropower facilities. These inputs and outputs are a function of operating parameters (reservoir characteristics and capacity factor) and do not vary among the four scenarios (greenfield, power addition, upgrade, and existing) of this analysis.

Table B-3: Inputs and Outputs for Conventional Hydropower Operations

Inputs	Greenfield	Power Addition	Upgrade	Existing	Units
Water (Surface Water) (Water)	6.81E+04	6.81E+04	6.81E+04	6.81E+04	kg/MWh
Outputs	**Greenfield**	**Power Addition**	**Upgrade**	**Existing**	**Units**
Electricity (Electric Power)	1	1	1	1	MWh
Carbon Dioxide (Inorganic Emissions to Air)	16.9	16.9	16.9	16.9	kg/MWh
Methane (Organic emissions to air [group VOC])	0.233	0.233	0.233	0.233	kg/MWh

Appendix B: References

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Appendix C:
Detailed Results for Hydropower

List of Tables

Table C-1: Detailed Results for Conventional Greenfield Hydropower

Category (Units)	Material or Energy Flow	ECF										PT	Total
		Hydro Trunkline Construction				Dam and Hydropower Facility Construction					Operation	T&D	
		Electricity	Cold Rolled Steel	Concrete	Aluminum Sheet	Electricity	Cold Rolled Steel	Concrete	Construction	Steel Plate			
GHG (kg/MWh)	CO_2	2.85E-03	1.77E-02	2.28E-03	1.81E-02	2.11E+00	1.26E-01	1.69E+00	2.42E+00	1.04E-01	1.81E+01	0.00E+00	2.46E+01
	N_2O	4.50E-08	1.15E-07	0.00E+00	3.92E-07	3.34E-05	8.22E-07	0.00E+00	0.00E+00	5.43E-06	0.00E+00	0.00E+00	4.02E-05
	CH_4	8.62E-06	2.07E-05	0.00E+00	2.87E-05	6.39E-03	1.48E-04	0.00E+00	0.00E+00	7.92E-05	2.51E-01	0.00E+00	2.57E-01
	SF_6	6.00E-10	1.28E-13	0.00E+00	2.29E-12	4.45E-07	9.17E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	3.09E-03	1.82E-02	2.28E-03	1.89E-02	2.29E+00	1.30E-01	1.69E+00	2.42E+00	1.08E-01	2.44E+01	3.27E+00	3.44E+01
Other Air (kg/MWh)	Pb	1.89E-11	3.19E-08	0.00E+00	2.40E-09	1.40E-08	2.28E-07	0.00E+00	0.00E+00	2.07E-07	0.00E+00	0.00E+00	4.83E-07
	Hg	5.27E-11	4.08E-11	0.00E+00	1.68E-10	3.91E-08	2.92E-10	0.00E+00	0.00E+00	1.30E-08	0.00E+00	0.00E+00	5.26E-08
	NH_3	2.69E-09	5.74E-08	0.00E+00	7.98E-08	2.00E-06	4.11E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.55E-06
	CO	5.53E-07	1.68E-04	2.94E-06	1.67E-04	4.09E-04	1.20E-03	2.18E-03	7.21E-03	8.81E-04	0.00E+00	0.00E+00	1.22E-02
	NOX	4.37E-06	3.35E-05	6.96E-06	2.47E-05	3.24E-03	2.39E-04	5.16E-03	8.38E-03	1.75E-04	0.00E+00	0.00E+00	1.73E-02
	SO_2	9.12E-06	2.45E-05	5.30E-06	6.78E-05	6.76E-03	1.75E-04	3.93E-03	0.00E+00	2.38E-04	0.00E+00	0.00E+00	1.12E-02
	VOC	7.72E-07	2.52E-06	0.00E+00	3.31E-06	5.72E-04	1.80E-05	0.00E+00	0.00E+00	-4.05E-13	0.00E+00	0.00E+00	5.97E-04
	PM	1.17E-07	1.08E-05	6.79E-06	3.29E-05	8.65E-05	7.71E-05	5.03E-03	0.00E+00	2.50E-05	0.00E+00	0.00E+00	5.27E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	1.88E-05	3.03E-08	0.00E+00	8.07E-08	1.39E-02	2.17E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.39E-02
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	9.90E-02	4.06E-02	9.77E-04	1.04E-01	7.34E+01	2.91E-01	7.24E-01	0.00E+00	5.52E-01	7.33E+04	0.00E+00	7.33E+04
	Discharge	9.14E-02	3.73E-02	0.00E+00	7.40E-02	6.77E+01	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.82E+01
	Consumption	7.63E-03	3.31E-03	9.77E-04	2.95E-02	5.66E+00	2.37E-02	7.24E-01	0.00E+00	5.52E-01	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	4.04E-10	0.00E+00	0.00E+00	0.00E+00	3.00E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.00E-07
	Arsenic (+V)	4.39E-09	1.42E-10	0.00E+00	6.24E-10	3.25E-06	1.02E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.26E-06
	Copper (+II)	5.22E-09	5.45E-10	0.00E+00	1.14E-09	3.87E-06	3.90E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.88E-06
	Iron	8.75E-08	7.92E-07	0.00E+00	4.04E-06	6.48E-05	5.67E-06	0.00E+00	0.00E+00	3.37E-06	0.00E+00	0.00E+00	7.88E-05
	Lead (+II)	2.14E-10	2.94E-10	0.00E+00	2.05E-09	1.59E-07	2.10E-09	0.00E+00	0.00E+00	4.30E-08	0.00E+00	0.00E+00	2.06E-07
	Manganese (+II)	6.72E-09	7.35E-09	0.00E+00	9.04E-09	4.98E-06	5.26E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.06E-06
	Nickel (+II)	2.00E-07	8.27E-10	0.00E+00	6.97E-10	1.48E-04	5.92E-09	0.00E+00	0.00E+00	5.84E-09	0.00E+00	0.00E+00	1.49E-04
	Strontium	1.46E-10	3.50E-08	0.00E+00	1.31E-08	1.08E-07	2.51E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.07E-07
	Zinc (+II)	5.58E-08	8.00E-10	0.00E+00	8.73E-10	4.13E-05	5.72E-09	0.00E+00	0.00E+00	2.57E-08	0.00E+00	0.00E+00	4.14E-05
	Ammonium/ammonia	4.67E-07	3.62E-08	0.00E+00	6.13E-08	3.46E-04	2.59E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.47E-04
	Hydrogen chloride	3.42E-14	1.50E-13	0.00E+00	1.19E-12	2.53E-11	1.08E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.78E-11
	Nitrogen (as total N)	1.41E-09	0.00E+00	0.00E+00	0.00E+00	1.05E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.05E-06
	Phosphate	1.67E-11	1.89E-08	0.00E+00	3.74E-09	1.24E-08	1.35E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.70E-07
	Phosphorus	3.15E-09	2.39E-10	0.00E+00	6.26E-10	2.34E-06	1.71E-09	0.00E+00	0.00E+00	3.51E-07	0.00E+00	0.00E+00	2.69E-06
Resource Energy (MJ/MWh)	Crude oil	1.02E-03	1.99E-02	0.00E+00	6.48E-02	7.59E-01	1.42E-01	0.00E+00	0.00E+00	2.29E-01	0.00E+00	0.00E+00	1.22E+00
	Hard coal	9.01E-03	1.81E-01	0.00E+00	4.92E-02	6.67E+00	1.29E+00	0.00E+00	0.00E+00	9.99E-01	0.00E+00	0.00E+00	9.21E+00
	Lignite	4.74E-06	4.53E-03	0.00E+00	2.41E-02	3.52E-03	3.24E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.46E-02
	Natural gas	1.28E-02	2.65E-02	0.00E+00	5.85E-02	9.46E+00	1.89E-01	0.00E+00	0.00E+00	1.99E-01	0.00E+00	0.00E+00	9.95E+00
	Uranium	1.74E-05	5.30E-03	0.00E+00	5.43E-02	1.29E-02	3.79E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.10E-01
	Total resource energy	2.28E-02	2.37E-01	0.00E+00	2.51E-01	1.69E+01	1.70E+00	0.00E+00	0.00E+00	1.43E+00	0.00E+00	0.00E+00	2.05E+01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	175: 1

Table C-2: Detailed Results for Conventional Hydropower Addition

Category (Units)	Material or Energy Flow	ECF								PT	Total
		Hydropower Facility Construction			Hydro Trunkline Construction				Operation	T&D	
		Construction	Cold Rolled Steel	Steel Plate	Aluminum Sheet	Concrete	Electricity	Cold Rolled Steel			
GHG (kg/MWh)	CO_2	1.05E+00	6.62E-02	1.04E-01	1.81E-02	2.28E-03	2.85E-03	1.77E-02	1.81E+01	0.00E+00	1.94E+01
	N_2O	0.00E+00	4.31E-07	5.43E-06	3.92E-07	0.00E+00	4.50E-08	1.15E-07	0.00E+00	0.00E+00	6.41E-06
	CH_4	0.00E+00	7.76E-05	7.92E-05	2.87E-05	0.00E+00	8.62E-06	2.07E-05	2.51E-01	0.00E+00	2.51E-01
	SF_6	0.00E+00	4.81E-13	0.00E+00	2.29E-12	0.00E+00	6.00E-10	1.28E-13	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.05E+00	6.83E-02	1.08E-01	1.89E-02	2.28E-03	3.09E-03	1.82E-02	2.44E+01	3.27E+00	2.90E+01
Other Air (kg/MWh)	Pb	0.00E+00	1.19E-07	2.07E-07	2.40E-09	0.00E+00	1.89E-11	3.19E-08	0.00E+00	0.00E+00	3.61E-07
	Hg	0.00E+00	1.53E-10	1.30E-08	1.68E-10	0.00E+00	5.27E-11	4.08E-11	0.00E+00	0.00E+00	1.34E-08
	NH_3	0.00E+00	2.15E-07	0.00E+00	7.98E-08	0.00E+00	2.69E-09	5.74E-08	0.00E+00	0.00E+00	3.55E-07
	CO	4.87E-04	6.29E-04	8.81E-04	1.67E-04	2.94E-06	5.53E-07	1.68E-04	0.00E+00	0.00E+00	2.33E-03
	NOX	8.77E-04	1.25E-04	1.75E-04	2.47E-05	6.96E-06	4.37E-06	3.35E-05	0.00E+00	0.00E+00	1.25E-03
	SO_2	0.00E+00	9.17E-05	2.38E-04	6.78E-05	5.30E-06	9.12E-06	2.45E-05	0.00E+00	0.00E+00	4.36E-04
	VOC	0.00E+00	9.45E-06	-4.05E-13	3.31E-06	0.00E+00	7.72E-07	2.52E-06	0.00E+00	0.00E+00	1.60E-05
	PM	0.00E+00	4.04E-05	2.50E-05	3.29E-05	6.79E-06	1.17E-07	1.08E-05	0.00E+00	0.00E+00	1.16E-04
Solid Waste (kg/MWh)	Heavy metals to industrial soil	0.00E+00	1.14E-07	0.00E+00	8.07E-08	0.00E+00	1.88E-05	3.03E-08	0.00E+00	0.00E+00	1.90E-05
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	0.00E+00	1.52E-01	5.52E-01	1.04E-01	9.77E-04	9.90E-02	4.06E-02	7.33E+04	0.00E+00	7.33E+04
	Discharge	0.00E+00	1.40E-01	0.00E+00	7.40E-02	0.00E+00	9.14E-02	3.73E-02	0.00E+00	0.00E+00	3.43E-01
	Consumption	0.00E+00	1.24E-02	5.52E-01	2.95E-02	9.77E-04	7.63E-03	3.31E-03	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.04E-10	0.00E+00	0.00E+00	0.00E+00	4.04E-10
	Arsenic (+V)	0.00E+00	5.34E-10	0.00E+00	6.24E-10	0.00E+00	4.39E-09	1.42E-10	0.00E+00	0.00E+00	5.69E-09
	Copper (+II)	0.00E+00	2.04E-09	0.00E+00	1.14E-09	0.00E+00	5.22E-09	5.45E-10	0.00E+00	0.00E+00	8.95E-09
	Iron	0.00E+00	2.97E-06	3.37E-06	4.04E-06	0.00E+00	8.75E-08	7.92E-07	0.00E+00	0.00E+00	1.13E-05
	Lead (+II)	0.00E+00	1.10E-09	4.30E-08	2.05E-09	0.00E+00	2.14E-10	2.94E-10	0.00E+00	0.00E+00	4.67E-08
	Manganese (+II)	0.00E+00	2.76E-08	0.00E+00	9.04E-09	0.00E+00	6.72E-09	7.35E-09	0.00E+00	0.00E+00	5.07E-08
	Nickel (+II)	0.00E+00	3.10E-09	5.84E-09	6.97E-10	0.00E+00	2.00E-07	8.27E-10	0.00E+00	0.00E+00	2.11E-07
	Strontium	0.00E+00	1.31E-07	0.00E+00	1.31E-08	0.00E+00	1.46E-10	3.50E-08	0.00E+00	0.00E+00	1.80E-07
	Zinc (+II)	0.00E+00	3.00E-09	2.57E-08	8.73E-10	0.00E+00	5.58E-08	8.00E-10	0.00E+00	0.00E+00	8.61E-08
	Ammonium/ammonia	0.00E+00	1.36E-07	0.00E+00	6.13E-08	0.00E+00	4.67E-07	3.62E-08	0.00E+00	0.00E+00	7.01E-07
	Hydrogen chloride	0.00E+00	5.64E-13	0.00E+00	1.19E-12	0.00E+00	3.42E-14	1.50E-13	0.00E+00	0.00E+00	1.94E-12
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.41E-09	0.00E+00	0.00E+00	0.00E+00	1.41E-09
	Phosphate	0.00E+00	7.09E-08	0.00E+00	3.74E-09	0.00E+00	1.67E-11	1.89E-08	0.00E+00	0.00E+00	9.36E-08
	Phosphorus	0.00E+00	8.96E-10	3.51E-07	6.26E-10	0.00E+00	3.15E-09	2.39E-10	0.00E+00	0.00E+00	3.56E-07
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	7.47E-02	2.29E-01	6.48E-02	0.00E+00	1.02E-03	1.99E-02	0.00E+00	0.00E+00	3.90E-01
	Hard coal	0.00E+00	6.79E-01	9.99E-01	4.92E-02	0.00E+00	9.01E-03	1.81E-01	0.00E+00	0.00E+00	1.92E+00
	Lignite	0.00E+00	1.70E-02	0.00E+00	2.41E-02	0.00E+00	4.74E-06	4.53E-03	0.00E+00	0.00E+00	4.56E-02
	Natural gas	0.00E+00	9.92E-02	1.99E-01	5.85E-02	0.00E+00	1.28E-02	2.65E-02	0.00E+00	0.00E+00	3.96E-01
	Uranium	0.00E+00	1.99E-02	0.00E+00	5.43E-02	0.00E+00	1.74E-05	5.30E-03	0.00E+00	0.00E+00	7.94E-02
	Total resource energy	0.00E+00	8.90E-01	1.43E+00	2.51E-01	0.00E+00	2.28E-02	2.37E-01	0.00E+00	0.00E+00	2.83E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1273: 1

Table C-3: Detailed Results for Power Upgrade to Conventional Hydropower

Category (Units)	Material or Energy Flow	ECF				PT	Total
		Hydropower Facility Construction			Operation	T&D	
		Construction	Cold Rolled Steel	Steel Plate			
GHG (kg/MWh)	CO_2	5.26E-01	3.00E-02	5.54E-03	1.81E+01	0.00E+00	1.87E+01
	N_2O	0.00E+00	1.95E-07	2.88E-07	0.00E+00	0.00E+00	4.83E-07
	CH_4	0.00E+00	3.52E-05	4.20E-06	2.51E-01	0.00E+00	2.51E-01
	SF_6	0.00E+00	2.18E-13	0.00E+00	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	5.26E-01	3.10E-02	5.73E-03	2.44E+01	3.27E+00	2.82E+01
Other Air (kg/MWh)	Pb	0.00E+00	5.42E-08	1.10E-08	0.00E+00	0.00E+00	6.52E-08
	Hg	0.00E+00	6.93E-11	6.89E-10	0.00E+00	0.00E+00	7.58E-10
	NH_3	0.00E+00	9.77E-08	0.00E+00	0.00E+00	0.00E+00	9.77E-08
	CO	2.44E-05	2.85E-04	4.67E-05	0.00E+00	0.00E+00	3.56E-04
	NOX	4.87E-05	5.69E-05	9.27E-06	0.00E+00	0.00E+00	1.15E-04
	SO_2	0.00E+00	4.16E-05	1.26E-05	0.00E+00	0.00E+00	5.42E-05
	VOC	0.00E+00	4.29E-06	-2.15E-14	0.00E+00	0.00E+00	4.29E-06
	PM	0.00E+00	1.83E-05	1.33E-06	0.00E+00	0.00E+00	1.97E-05
Solid Waste (kg/MWh)	Heavy metals to industrial soil	0.00E+00	5.15E-08	0.00E+00	0.00E+00	0.00E+00	5.15E-08
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	0.00E+00	6.91E-02	2.93E-02	7.33E+04	0.00E+00	7.33E+04
	Discharge	0.00E+00	6.35E-02	0.00E+00	0.00E+00	0.00E+00	6.35E-02
	Consumption	0.00E+00	5.64E-03	2.93E-02	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Arsenic (+V)	0.00E+00	2.42E-10	0.00E+00	0.00E+00	0.00E+00	2.42E-10
	Copper (+II)	0.00E+00	9.28E-10	0.00E+00	0.00E+00	0.00E+00	9.28E-10
	Iron	0.00E+00	1.35E-06	1.79E-07	0.00E+00	0.00E+00	1.53E-06
	Lead (+II)	0.00E+00	5.00E-10	2.28E-09	0.00E+00	0.00E+00	2.78E-09
	Manganese (+II)	0.00E+00	1.25E-08	0.00E+00	0.00E+00	0.00E+00	1.25E-08
	Nickel (+II)	0.00E+00	1.41E-09	3.09E-10	0.00E+00	0.00E+00	1.72E-09
	Strontium	0.00E+00	5.96E-08	0.00E+00	0.00E+00	0.00E+00	5.96E-08
	Zinc (+II)	0.00E+00	1.36E-09	1.36E-09	0.00E+00	0.00E+00	2.72E-09
	Ammonium/ammonia	0.00E+00	6.16E-08	0.00E+00	0.00E+00	0.00E+00	6.16E-08
	Hydrogen chloride	0.00E+00	2.56E-13	0.00E+00	0.00E+00	0.00E+00	2.56E-13
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Phosphate	0.00E+00	3.22E-08	0.00E+00	0.00E+00	0.00E+00	3.22E-08
	Phosphorus	0.00E+00	4.06E-10	1.86E-08	0.00E+00	0.00E+00	1.90E-08
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	3.39E-02	1.21E-02	0.00E+00	0.00E+00	4.60E-02
	Hard coal	0.00E+00	3.08E-01	5.29E-02	0.00E+00	0.00E+00	3.61E-01
	Lignite	0.00E+00	7.71E-03	0.00E+00	0.00E+00	0.00E+00	7.71E-03
	Natural gas	0.00E+00	4.50E-02	1.06E-02	0.00E+00	0.00E+00	5.56E-02
	Uranium	0.00E+00	9.01E-03	0.00E+00	0.00E+00	0.00E+00	9.01E-03
	Total resource energy	0.00E+00	4.04E-01	7.56E-02	0.00E+00	0.00E+00	4.79E-01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	7511: 1

Table C-4: Detailed Results for Existing Conventional Hydropower

Category (Units)	Material or Energy Flow	ECF Operation	PT T&D	Total
GHG (kg/MWh)	CO_2	1.81E+01	0.00E+00	1.81E+01
	N_2O	0.00E+00	0.00E+00	0.00E+00
	CH_4	2.51E-01	0.00E+00	2.51E-01
	SF_6	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	2.44E+01	3.27E+00	2.77E+01
Other Air (kg/MWh)	Pb	0.00E+00	0.00E+00	0.00E+00
	Hg	0.00E+00	0.00E+00	0.00E+00
	NH_3	0.00E+00	0.00E+00	0.00E+00
	CO	0.00E+00	0.00E+00	0.00E+00
	NOX	0.00E+00	0.00E+00	0.00E+00
	SO_2	0.00E+00	0.00E+00	0.00E+00
	VOC	0.00E+00	0.00E+00	0.00E+00
	PM	0.00E+00	0.00E+00	0.00E+00
Solid Waste (kg/MWh)	Heavy metals to industrial soil	0.00E+00	0.00E+00	0.00E+00
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	7.33E+04	0.00E+00	7.33E+04
	Discharge	0.00E+00	0.00E+00	0.00E+00
	Consumption	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00
	Arsenic (+V)	0.00E+00	0.00E+00	0.00E+00
	Copper (+II)	0.00E+00	0.00E+00	0.00E+00
	Iron	0.00E+00	0.00E+00	0.00E+00
	Lead (+II)	0.00E+00	0.00E+00	0.00E+00
	Manganese (+II)	0.00E+00	0.00E+00	0.00E+00
	Nickel (+II)	0.00E+00	0.00E+00	0.00E+00
	Strontium	0.00E+00	0.00E+00	0.00E+00
	Zinc (+II)	0.00E+00	0.00E+00	0.00E+00
	Ammonium/ammonia	0.00E+00	0.00E+00	0.00E+00
	Hydrogen chloride	0.00E+00	0.00E+00	0.00E+00
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00
	Phosphate	0.00E+00	0.00E+00	0.00E+00
	Phosphorus	0.00E+00	0.00E+00	0.00E+00
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00
	Hard coal	0.00E+00	0.00E+00	0.00E+00
	Lignite	0.00E+00	0.00E+00	0.00E+00
	Natural gas	0.00E+00	0.00E+00	0.00E+00
	Uranium	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	0.00E+00	0.00E+00	0.00E+00
Energy Return on Investment		N/A	N/A	--

Table C-5: Detailed Results for Conventional Greenfield Hydropower (Alternate Units)

Category (Units)	Material or Energy Flow	ECF										PT	Total
		Hydro Trunkline Construction				Dam and Hydropower Facility Construction					Operation	T&D	
		Electricity	Cold Rolled Steel	Concrete	Aluminum Sheet	Electricity	Cold Rolled Steel	Concrete	Construction	Steel Plate			
GHG (lb/MWh)	CO_2	6.283E-03	3.894E-02	5.025E-03	3.990E-02	4.657E+00	2.785E-01	3.725E+00	5.329E+00	2.303E-01	4.001E+01	0.000E+00	5.43E+01
	N_2O	9.924E-08	2.534E-07	0.000E+00	8.642E-07	7.355E-05	1.811E-06	0.000E+00	0.000E+00	1.196E-05	0.000E+00	0.000E+00	8.85E-05
	CH_4	1.900E-05	4.565E-05	0.000E+00	6.322E-05	1.408E-02	3.264E-04	0.000E+00	0.000E+00	1.747E-04	5.524E-01	0.000E+00	5.67E-01
	SF_6	1.323E-09	2.827E-13	0.000E+00	5.049E-12	9.804E-07	2.021E-12	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.160E-04	3.17E-04
	CO_2e (IPCC 2007 100-yr GWP)	6.818E-03	4.016E-02	5.025E-03	4.174E-02	5.053E+00	2.872E-01	3.725E+00	5.329E+00	2.382E-01	5.382E+01	7.204E+00	7.58E+01
Other Air (lb/MWh)	Pb	4.162E-11	7.027E-08	0.000E+00	5.285E-09	3.085E-08	5.024E-07	0.000E+00	0.000E+00	4.560E-07	0.000E+00	0.000E+00	1.06E-06
	Hg	1.163E-10	8.989E-11	0.000E+00	3.706E-10	8.617E-08	6.427E-10	0.000E+00	0.000E+00	2.864E-08	0.000E+00	0.000E+00	1.16E-07
	NH_3	5.935E-09	1.266E-07	0.000E+00	1.760E-07	4.398E-06	9.054E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	5.61E-06
	CO	1.218E-06	3.698E-04	6.476E-06	3.676E-04	9.028E-04	2.644E-03	4.800E-03	1.590E-02	1.942E-03	0.000E+00	0.000E+00	2.69E-02
	NOX	9.626E-06	7.376E-05	1.534E-05	5.448E-05	7.134E-03	5.274E-04	1.137E-02	1.848E-02	3.854E-04	0.000E+00	0.000E+00	3.80E-02
	SO_2	2.011E-05	5.392E-05	1.168E-05	1.496E-04	1.490E-02	3.856E-04	8.660E-03	0.000E+00	5.238E-04	0.000E+00	0.000E+00	2.47E-02
	VOC	1.703E-06	5.555E-06	0.000E+00	7.296E-06	1.262E-03	3.972E-05	0.000E+00	0.000E+00	-8.928E-13	0.000E+00	0.000E+00	1.32E-03
	PM	2.574E-07	2.378E-05	1.497E-05	7.243E-05	1.908E-04	1.700E-04	1.109E-02	0.000E+00	5.519E-05	0.000E+00	0.000E+00	1.16E-02
Solid Waste (lb/MWh)	Heavy metals to industrial soil	4.137E-05	6.677E-08	0.000E+00	1.778E-07	3.066E-02	4.774E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.07E-02
	Heavy metals to agricultural soil	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.00E+00
Water Use (gal/MWh)	Withdrawal	2.615E-02	1.073E-02	2.581E-04	2.735E-02	1.938E+01	7.675E-02	1.913E-01	0.000E+00	1.458E-01	1.935E+04	0.000E+00	1.94E+04
	Discharge	2.414E-02	9.859E-03	0.000E+00	1.955E-02	1.789E+01	7.049E-02	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.80E+01
	Consumption	2.016E-03	8.753E-04	2.581E-04	7.801E-03	1.494E+00	6.259E-03	1.913E-01	0.000E+00	1.458E-01	1.935E+04	0.000E+00	1.94E+04
Water Quality (lb/MWh)	Aluminum	8.917E-10	0.000E+00	0.000E+00	0.000E+00	6.609E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	6.62E-07
	Arsenic (+V)	9.669E-09	3.140E-10	0.000E+00	1.376E-09	7.166E-06	2.245E-09	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	7.18E-06
	Copper (+II)	1.151E-08	1.202E-09	0.000E+00	2.505E-09	8.534E-06	8.598E-09	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	8.56E-06
	Iron	1.929E-07	1.747E-06	0.000E+00	8.915E-06	1.430E-04	1.249E-05	0.000E+00	0.000E+00	7.439E-06	0.000E+00	0.000E+00	1.74E-04
	Lead (+II)	4.716E-10	6.479E-10	0.000E+00	4.511E-09	3.495E-07	4.633E-09	0.000E+00	0.000E+00	9.481E-08	0.000E+00	0.000E+00	4.55E-07
	Manganese (+II)	1.482E-08	1.621E-08	0.000E+00	1.994E-08	1.099E-05	1.159E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.12E-05
	Nickel (+II)	4.416E-07	1.824E-09	0.000E+00	1.536E-09	3.273E-04	1.304E-08	0.000E+00	0.000E+00	1.286E-08	0.000E+00	0.000E+00	3.28E-04
	Strontium	3.210E-10	7.727E-08	0.000E+00	2.884E-08	2.379E-07	5.525E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	8.97E-07
	Zinc (+II)	1.229E-07	1.763E-09	0.000E+00	1.925E-09	9.110E-05	1.261E-08	0.000E+00	0.000E+00	5.666E-08	0.000E+00	0.000E+00	9.13E-05
	Ammonium/ammonia	1.030E-06	7.985E-08	0.000E+00	1.350E-07	7.636E-04	5.710E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	7.65E-04
	Hydrogen chloride	7.532E-14	3.318E-13	0.000E+00	2.632E-12	5.582E-11	2.372E-12	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	6.12E-11
	Nitrogen (as total N)	3.119E-09	0.000E+00	0.000E+00	0.000E+00	2.312E-06	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	2.32E-06
	Phosphate	3.677E-11	4.173E-08	0.000E+00	8.254E-09	2.725E-08	2.984E-07	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.76E-07
	Phosphorus	6.950E-09	5.269E-10	0.000E+00	1.381E-09	5.151E-06	3.767E-09	0.000E+00	0.000E+00	7.749E-07	0.000E+00	0.000E+00	5.94E-06
Resource Energy (Btu/MWh)	Crude oil	9.712E-01	1.889E+01	0.000E+00	6.146E+01	7.198E+02	1.350E+02	0.000E+00	0.000E+00	2.171E+02	0.000E+00	0.000E+00	1.15E+03
	Hard coal	8.535E+00	1.717E+02	0.000E+00	4.660E+01	6.326E+03	1.227E+03	0.000E+00	0.000E+00	9.467E+02	0.000E+00	0.000E+00	8.73E+03
	Lignite	4.495E-03	4.298E+00	0.000E+00	2.283E+01	3.332E+00	3.073E+01	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	6.12E+01
	Natural gas	1.210E+01	2.509E+01	0.000E+00	5.544E+01	8.968E+03	1.794E+02	0.000E+00	0.000E+00	1.888E+02	0.000E+00	0.000E+00	9.43E+03
	Uranium	1.648E-02	5.022E+00	0.000E+00	5.143E+01	1.221E+01	3.591E+01	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	1.05E+02
	Total resource energy	2.163E+01	2.250E+02	0.000E+00	2.377E+02	1.603E+04	1.608E+03	0.000E+00	0.000E+00	1.353E+03	0.000E+00	0.000E+00	1.95E+04
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	175: 1

Table C-6: Detailed Results for Conventional Hydropower Addition (Alternate Units)

Category (Units)	Material or Energy Flow	ECF								PT	Total
		Hydropower Facility Construction			Hydro Trunkline Construction				Operation	T&D	
		Construction	Cold Rolled Steel	Steel Plate	Aluminum Sheet	Concrete	Electricity	Cold Rolled Steel			
GHG (lb/MWh)	CO_2	2.321E+00	1.460E-01	2.303E-01	3.990E-02	5.025E-03	6.283E-03	3.894E-02	4.001E+01	0.000E+00	4.280E+01
	N_2O	0.000E+00	9.497E-07	1.196E-05	8.642E-07	0.000E+00	9.924E-08	2.534E-07	0.000E+00	0.000E+00	1.413E-05
	CH_4	0.000E+00	1.711E-04	1.747E-04	6.322E-05	0.000E+00	1.900E-05	4.565E-05	5.524E-01	0.000E+00	5.529E-01
	SF_6	0.000E+00	1.060E-12	0.000E+00	5.049E-12	0.000E+00	1.323E-09	2.827E-13	0.000E+00	3.160E-04	3.160E-04
	CO_2e (IPCC 2007 100-yr GWP)	2.321E+00	1.505E-01	2.382E-01	4.174E-02	5.025E-03	6.818E-03	4.016E-02	5.382E+01	7.204E+00	6.383E+01
Other Air (lb/MWh)	Pb	0.000E+00	2.634E-07	4.560E-07	5.285E-09	0.000E+00	4.162E-11	7.027E-08	0.000E+00	0.000E+00	7.950E-07
	Hg	0.000E+00	3.369E-10	2.864E-08	3.706E-10	0.000E+00	1.163E-10	8.989E-11	0.000E+00	0.000E+00	2.955E-08
	NH_3	0.000E+00	4.747E-07	0.000E+00	1.760E-07	0.000E+00	5.935E-09	1.266E-07	0.000E+00	0.000E+00	7.832E-07
	CO	1.074E-03	1.386E-03	1.942E-03	3.676E-04	6.476E-06	1.218E-06	3.698E-04	0.000E+00	0.000E+00	5.147E-03
	NOX	1.934E-03	2.765E-04	3.854E-04	5.448E-05	1.534E-05	9.626E-06	7.376E-05	0.000E+00	0.000E+00	2.749E-03
	SO_2	0.000E+00	2.021E-04	5.238E-04	1.496E-04	1.168E-05	2.011E-05	5.392E-05	0.000E+00	0.000E+00	9.612E-04
	VOC	0.000E+00	2.082E-05	-8.928E-13	7.296E-06	0.000E+00	1.703E-06	5.555E-06	0.000E+00	0.000E+00	3.538E-05
	PM	0.000E+00	8.914E-05	5.519E-05	7.243E-05	1.497E-05	2.574E-07	2.378E-05	0.000E+00	0.000E+00	2.558E-04
Solid Waste (lb/MWh)	Heavy metals to industrial soil	0.000E+00	2.503E-07	0.000E+00	1.778E-07	0.000E+00	4.137E-05	6.677E-08	0.000E+00	0.000E+00	4.186E-05
	Heavy metals to agricultural soil	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
Water Use (gal/MWh)	Withdrawal	0.000E+00	4.024E-02	1.458E-01	2.735E-02	2.581E-04	2.615E-02	1.073E-02	1.935E+04	0.000E+00	1.936E+04
	Discharge	0.000E+00	3.696E-02	0.000E+00	1.955E-02	0.000E+00	2.414E-02	9.859E-03	0.000E+00	0.000E+00	9.051E-02
	Consumption	0.000E+00	3.281E-03	1.458E-01	7.801E-03	2.581E-04	2.016E-03	8.753E-04	1.935E+04	0.000E+00	1.936E+04
Water Quality (lb/MWh)	Aluminum	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	8.917E-10	0.000E+00	0.000E+00	0.000E+00	8.917E-10
	Arsenic (+V)	0.000E+00	1.177E-09	0.000E+00	1.376E-09	0.000E+00	9.669E-09	3.140E-10	0.000E+00	0.000E+00	1.254E-08
	Copper (+II)	0.000E+00	4.507E-09	0.000E+00	2.505E-09	0.000E+00	1.151E-08	1.202E-09	0.000E+00	0.000E+00	1.973E-08
	Iron	0.000E+00	6.549E-06	7.439E-06	8.915E-06	0.000E+00	1.929E-07	1.747E-06	0.000E+00	0.000E+00	2.484E-05
	Lead (+II)	0.000E+00	2.429E-09	9.481E-08	4.511E-09	0.000E+00	4.716E-10	6.479E-10	0.000E+00	0.000E+00	1.029E-07
	Manganese (+II)	0.000E+00	6.076E-08	0.000E+00	1.994E-08	0.000E+00	1.482E-08	1.621E-08	0.000E+00	0.000E+00	1.117E-07
	Nickel (+II)	0.000E+00	6.838E-09	1.286E-08	1.536E-09	0.000E+00	4.416E-07	1.824E-09	0.000E+00	0.000E+00	4.646E-07
	Strontium	0.000E+00	2.896E-07	0.000E+00	2.884E-08	0.000E+00	3.210E-10	7.727E-08	0.000E+00	0.000E+00	3.961E-07
	Zinc (+II)	0.000E+00	6.610E-09	5.666E-08	1.925E-09	0.000E+00	1.229E-07	1.763E-09	0.000E+00	0.000E+00	1.899E-07
	Ammonium/ammonia	0.000E+00	2.993E-07	0.000E+00	1.350E-07	0.000E+00	1.030E-06	7.985E-08	0.000E+00	0.000E+00	1.545E-06
	Hydrogen chloride	0.000E+00	1.244E-12	0.000E+00	2.632E-12	0.000E+00	7.532E-14	3.318E-13	0.000E+00	0.000E+00	4.283E-12
	Nitrogen (as total N)	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	3.119E-09	0.000E+00	0.000E+00	0.000E+00	3.119E-09
	Phosphate	0.000E+00	1.564E-07	0.000E+00	8.254E-09	0.000E+00	3.677E-11	4.173E-08	0.000E+00	0.000E+00	2.064E-07
	Phosphorus	0.000E+00	1.975E-09	7.749E-07	1.381E-09	0.000E+00	6.950E-09	5.269E-10	0.000E+00	0.000E+00	7.857E-07
Resource Energy (Btu/MWh)	Crude oil	0.000E+00	7.079E+01	2.171E+02	6.146E+01	0.000E+00	9.712E-01	1.889E+01	0.000E+00	0.000E+00	3.692E+02
	Hard coal	0.000E+00	6.435E+02	9.467E+02	4.660E+01	0.000E+00	8.535E+00	1.717E+02	0.000E+00	0.000E+00	1.817E+03
	Lignite	0.000E+00	1.611E+01	0.000E+00	2.283E+01	0.000E+00	4.495E-03	4.298E+00	0.000E+00	0.000E+00	4.324E+01
	Natural gas	0.000E+00	9.404E+01	1.888E+02	5.544E+01	0.000E+00	1.210E+01	2.509E+01	0.000E+00	0.000E+00	3.755E+02
	Uranium	0.000E+00	1.883E+01	0.000E+00	5.143E+01	0.000E+00	1.648E-02	5.022E+00	0.000E+00	0.000E+00	7.529E+01
	Total resource energy	0.000E+00	8.432E+02	1.353E+03	2.377E+02	0.000E+00	2.163E+01	2.250E+02	0.000E+00	0.000E+00	2.680E+03
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1273: 1

Table C-7: Detailed Results for Power Upgrade to Conventional Hydropower (Alternate Units)

Category (Units)	Material or Energy Flow	ECF				PT	Total
		Hydropower Facility Construction			Operation	T&D	
		Construction	Cold Rolled Steel	Steel Plate			
GHG (lb/MWh)	CO_2	1.160E+00	6.624E-02	1.220E-02	4.001E+01	0.000E+00	4.125E+01
	N_2O	0.000E+00	4.309E-07	6.340E-07	0.000E+00	0.000E+00	1.065E-06
	CH_4	0.000E+00	7.765E-05	9.256E-06	5.524E-01	0.000E+00	5.525E-01
	SF_6	0.000E+00	4.807E-13	0.000E+00	0.000E+00	3.160E-04	3.160E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.160E+00	6.831E-02	1.262E-02	5.382E+01	7.204E+00	6.227E+01
Other Air (lb/MWh)	Pb	0.000E+00	1.195E-07	2.417E-08	0.000E+00	0.000E+00	1.437E-07
	Hg	0.000E+00	1.529E-10	1.518E-09	0.000E+00	0.000E+00	1.671E-09
	NH_3	0.000E+00	2.154E-07	0.000E+00	0.000E+00	0.000E+00	2.154E-07
	CO	5.371E-05	6.289E-04	1.029E-04	0.000E+00	0.000E+00	7.855E-04
	NOX	1.074E-04	1.255E-04	2.043E-05	0.000E+00	0.000E+00	2.533E-04
	SO_2	0.000E+00	9.171E-05	2.776E-05	0.000E+00	0.000E+00	1.195E-04
	VOC	0.000E+00	9.448E-06	-4.732E-14	0.000E+00	0.000E+00	9.448E-06
	PM	0.000E+00	4.045E-05	2.925E-06	0.000E+00	0.000E+00	4.337E-05
Solid Waste (lb/MWh)	Heavy metals to industrial soil	0.000E+00	1.136E-07	0.000E+00	0.000E+00	0.000E+00	1.136E-07
	Heavy metals to agricultural soil	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
Water Use (gal/MWh)	Withdrawal	0.000E+00	1.826E-02	7.729E-03	1.935E+04	0.000E+00	1.935E+04
	Discharge	0.000E+00	1.677E-02	0.000E+00	0.000E+00	0.000E+00	1.677E-02
	Consumption	0.000E+00	1.489E-03	7.729E-03	1.935E+04	0.000E+00	1.935E+04
Water Quality (lb/MWh)	Aluminum	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
	Arsenic (+V)	0.000E+00	5.340E-10	0.000E+00	0.000E+00	0.000E+00	5.340E-10
	Copper (+II)	0.000E+00	2.045E-09	0.000E+00	0.000E+00	0.000E+00	2.045E-09
	Iron	0.000E+00	2.971E-06	3.942E-07	0.000E+00	0.000E+00	3.366E-06
	Lead (+II)	0.000E+00	1.102E-09	5.025E-09	0.000E+00	0.000E+00	6.127E-09
	Manganese (+II)	0.000E+00	2.757E-08	0.000E+00	0.000E+00	0.000E+00	2.757E-08
	Nickel (+II)	0.000E+00	3.103E-09	6.818E-10	0.000E+00	0.000E+00	3.784E-09
	Strontium	0.000E+00	1.314E-07	0.000E+00	0.000E+00	0.000E+00	1.314E-07
	Zinc (+II)	0.000E+00	2.999E-09	3.003E-09	0.000E+00	0.000E+00	6.002E-09
	Ammonium/ammonia	0.000E+00	1.358E-07	0.000E+00	0.000E+00	0.000E+00	1.358E-07
	Hydrogen chloride	0.000E+00	5.643E-13	0.000E+00	0.000E+00	0.000E+00	5.643E-13
	Nitrogen (as total N)	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
	Phosphate	0.000E+00	7.097E-08	0.000E+00	0.000E+00	0.000E+00	7.097E-08
	Phosphorus	0.000E+00	8.961E-10	4.107E-08	0.000E+00	0.000E+00	4.196E-08
Resource Energy (Btu/MWh)	Crude oil	0.000E+00	3.212E+01	1.151E+01	0.000E+00	0.000E+00	4.363E+01
	Hard coal	0.000E+00	2.920E+02	5.018E+01	0.000E+00	0.000E+00	3.421E+02
	Lignite	0.000E+00	7.309E+00	0.000E+00	0.000E+00	0.000E+00	7.309E+00
	Natural gas	0.000E+00	4.267E+01	1.001E+01	0.000E+00	0.000E+00	5.268E+01
	Uranium	0.000E+00	8.542E+00	0.000E+00	0.000E+00	0.000E+00	8.542E+00
	Total resource energy	0.000E+00	3.826E+02	7.169E+01	0.000E+00	0.000E+00	4.543E+02
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	7511: 1

Table C-8: Detailed Results for Existing Conventional Hydropower (Alternate Units)

Category (Units)	Material or Energy Flow	ECF	PT	Total
		Operation	T&D	
GHG (lb/MWh)	CO_2	4.001E+01	0.000E+00	4.001E+01
	N_2O	0.000E+00	0.000E+00	0.000E+00
	CH_4	5.524E-01	0.000E+00	5.524E-01
	SF_6	0.000E+00	3.160E-04	3.160E-04
	CO_2e (IPCC 2007 100-yr GWP)	5.382E+01	7.204E+00	6.103E+01
Other Air (lb/MWh)	Pb	0.000E+00	0.000E+00	0.000E+00
	Hg	0.000E+00	0.000E+00	0.000E+00
	NH_3	0.000E+00	0.000E+00	0.000E+00
	CO	0.000E+00	0.000E+00	0.000E+00
	NOX	0.000E+00	0.000E+00	0.000E+00
	SO_2	0.000E+00	0.000E+00	0.000E+00
	VOC	0.000E+00	0.000E+00	0.000E+00
	PM	0.000E+00	0.000E+00	0.000E+00
Solid Waste (lb/MWh)	Heavy metals to industrial soil	0.000E+00	0.000E+00	0.000E+00
	Heavy metals to agricultural soil	0.000E+00	0.000E+00	0.000E+00
Water Use (gal/MWh)	Withdrawal	1.935E+04	0.000E+00	1.935E+04
	Discharge	0.000E+00	0.000E+00	0.000E+00
	Consumption	1.935E+04	0.000E+00	1.935E+04
Water Quality (lb/MWh)	Aluminum	0.000E+00	0.000E+00	0.000E+00
	Arsenic (+V)	0.000E+00	0.000E+00	0.000E+00
	Copper (+II)	0.000E+00	0.000E+00	0.000E+00
	Iron	0.000E+00	0.000E+00	0.000E+00
	Lead (+II)	0.000E+00	0.000E+00	0.000E+00
	Manganese (+II)	0.000E+00	0.000E+00	0.000E+00
	Nickel (+II)	0.000E+00	0.000E+00	0.000E+00
	Strontium	0.000E+00	0.000E+00	0.000E+00
	Zinc (+II)	0.000E+00	0.000E+00	0.000E+00
	Ammonium/ammonia	0.000E+00	0.000E+00	0.000E+00
	Hydrogen chloride	0.000E+00	0.000E+00	0.000E+00
	Nitrogen (as total N)	0.000E+00	0.000E+00	0.000E+00
	Phosphate	0.000E+00	0.000E+00	0.000E+00
	Phosphorus	0.000E+00	0.000E+00	0.000E+00
Resource Energy (Btu/MWh)	Crude oil	0.000E+00	0.000E+00	0.000E+00
	Hard coal	0.000E+00	0.000E+00	0.000E+00
	Lignite	0.000E+00	0.000E+00	0.000E+00
	Natural gas	0.000E+00	0.000E+00	0.000E+00
	Uranium	0.000E+00	0.000E+00	0.000E+00
	Total resource energy	0.000E+00	0.000E+00	0.000E+00
Energy Return on Investment		N/A	N/A	--