Appendices

https://www.energy.gov/eere/water/articles/hydropower-vision-new-chapter-america-s-1st-renewable-electricity-source

Hydropower VISION

A New Chapter for America's 1st Renewable Electricity Source

U.S. DEPARTMENT OF ENERGY

Appendix A: Glossary

This glossary contains terms used in the *Hydropower Vision*. For more information and additional relevant terms, please see the following resources:

U.S. Department of Energy, Glossary of Hydropower Terms	*http://energy.gov/eere/water/glossary-hydropower-terms*
U.S. Bureau of Reclamation, Glossary of Hydropower Terms	*https://www.usbr.gov/power/edu/Glossary%20of%20Hydropower%20Terms.pdf*
U.S. Army Corps of Engineers, Hydropower Abbreviations and Glossary	*http://www.sas.usace.army.mil/About/Divisions-and-Offices/Operations-Division/Hartwell-Dam-and-Lake/Hydropower/Abbreviations-and-Glossary/*
Federal Energy Regulatory Commission, Glossary	*http://www.ferc.gov/resources/glossary.asp*
U.S. Department of Energy, Energy Information Administration, Glossary	*http://www.eia.gov/tools/glossary/*

Term	Definition
adjustable-speed technology	In hydropower, refers to machines that have the ability to enable the power consumed (pumps) or generated (turbines) to be varied, thus providing greater flexibility.
alluvial	Made up of or found in the materials that are left by the water of rivers, floods, etc.
ancillary services	Capacity and energy services (e.g., operating reserve, frequency support, voltage support) provided by power plants that are able to respond on short notice, such as hydropower plants, and are used to ensure stable electricity delivery and optimized grid reliability. Also called *grid services.*
anadromous	Type of fish that is born in fresh water, migrates to the sea for much of its life, and returns to fresh water to spawn (e.g., salmon, sturgeon).
anoxic	Anoxic waters are areas of sea water, fresh water, or groundwater that are depleted of dissolved oxygen.
backstop capacity	Capacity that is purchased or committed in advance and for short periods to supplement overall reserves as needed.
balancing areas	A predefined area within an interconnected transmission grid where a utility, an independent system operator, or a transmission system operator must balance load (electrical demand) and electrical generation, while maintaining system reliability and continuing interchanges with adjoining balancing areas.

Term	Definition
balancing authority	Responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing area, and supports interconnection frequency in real time.
baseload	Minimum energy demand on a given electrical power system over a specific period of time.
basin-scale, basin-wide	Encompassing the activities that occur within the area of land drained by a river and its tributaries.
biogenic	Produced or brought about by living organisms.
biologically-based design	Design of hydropower equipment, such as turbines, that takes into account its direct or indirect biological effects on fish and other aquatic species.
black start	A process of restoring a power station to operation without relying on the external electric power transmission network.
bulk power	Power from generation facilities necessary to maintain reliability of the transmission system reliability.
bypass reach	The portion of a natural waterway between the intake and the tailrace where any and all flow usually comes from the spillway, with smaller amounts of accretion flows.
capacity	Maximum electric output a generator can produce under specific conditions. See also *nameplate capacity.*
capacity factor	Ratio of a power plant's actual output over a period of time to its potential output if it were possible for it to continuously operate at full nameplate capacity over the same period of time.
cavitation	Phenomenon that affects hydropower turbines when vapor bubbles form and implode due to rapid pressure changes, generating shock waves that create cavities on the metal surface.
civil works	Infrastructure of a hydropower project, such as dams, conduits, powerhouses, tunnels, and penstocks.
closed-loop pumped storage hydropower	Projects typically consisting of two reservoirs that are not connected to naturally-flowing sources of water.
condition-based maintenance	A maintenance program that recommends maintenance actions based on information collected from monitoring equipment through its life cycle.
conduit	A manmade structure for conveying water, such as a canals, tunnels, and/or pipelines.
closed-loop pumped storage hydropower	Projects typically consisting of two reservoirs that are not connected to naturally-flowing sources of water.

Term	Definition
critical infrastructure	Assets that are considered vital to the energy, economy, health, and/or safety security of the United States, such as storage reservoirs for water supply and flood management, dams for power production, and the electrical transmission grid.
curtailment	Reduction of output (ramp down or shut down) that is a generation unit's response to a grid operator's request, or to market signals.
curve fit	The empirical determination of a curve or function that approximates a set of data. Also known as linear fit.
day-ahead market	Type of market that allows market participants to secure prices for electric energy the day before the operating day and hedge against price fluctuations that occur in real time.
denitrification	A decrease of dissolved atmospheric nitrogen at a reservoir.
dispatch	The operation of a generating unit within a power system at a designated output level to meet demand for electricity.
distributed generation	Small, grid connected energy generation systems located close to the load they serve.
diversion	A facility that channels a portion of a river through a canal or penstock.
duty cycle	Fraction or percentage of time during which a device or system is operated.
economic dispatch	The operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities.
electrical demand	Rate at which electricity is being consumed, expressed in kilowatts, at a given instant or averaged over a specified period of time.
energy arbitrage	Purchasing (storing) energy when electricity prices are low, and selling (discharging) energy when electricity prices are high.
energy imbalance services (reserves)	A market service provided for the management of unscheduled deviations in individual generator output or load consumption.
entrainment	The non-volitional passage of fish in water flowing into a turbine or cooling water intake at a power plant.
environmental flows	Flows required to protect natural, cultural, and recreational resources.
environmental redispatch	Policy adopted by the Bonneville Power Authority where scheduled generation in their Balancing Authority Area will be replaced, when necessary, with federal hydropower to ensure statutory obligations for environmental stewardship are met.
environmentally-sensitive area	Designation for an agricultural area which needs special protection because of its landscape, wildlife or historical value.

Term	Definition
equivalent availability factor	The fraction of time that a unit is available to generate electricity without any outages.
equivalent forced outage factor	The fraction of time that a unit is not available due to forced outages.
essential reliability services	The grid services of frequency response, ramping, and voltage support designated by the North American Electric Reliability Corporation as being critical to operation of the national power grid.
fish passage structure	Structure on or around a dam to facilitate the movement of migrating fish.
fixed-speed technology	Pump and turbine units that are operated at the constant speed that provides maximum efficiency.
flexibility	The ability of the power system to respond to variations in supply and/or demand.
flow	Volume of water passing a location per unit time.
flow regime	The magnitude, duration, timing, seasonality, and rate of change of flows in a natural waterway.
forebay	Impoundment or reservoir immediately above a dam or intake structure at a hydropower plant.
frequency regulation	Efforts by a balancing authority to maintain scheduled frequency in the grid.
frequency response	Generation ability to increase and decrease output to maintain system frequency.
freshet	Spring thaw, i.e., river flow from heavy rain or melting snow.
fuel	A material or product that can be used to generate electricity.
gas supersaturation	An increase of dissolved atmospheric nitrogen, often resulting from high flow releases from hydropower dams, that is toxic to downstream aquatic organisms, including fish.
generation	Act of producing electrical power from other energy forms (such as thermal, mechanical, chemical or nuclear), or the amount of electrical energy produced; usually expressed in kilowatt-hours or megawatt-hours.
generator	A device for converting mechanical energy to electrical energy.
geotechnical	Referring to the behavior of earth materials considered during the design and construction stages of hydropower development.
grid	A common term that refers to an electricity transmission and distribution system.
grid services	See *ancillary services.*

Term	Definition
gross head	Difference in height between the headwater surface above and tailwater surface below a hydropower plant.
head	Difference in height between the upstream pool and tailwater.
head loss	Energy lost as water flows from the headwater to the tailwater.
hydraulic head	A measure of liquid pressure, expressed in terms of the height of a column of water, which represents the total energy of the water.
hydraulic residence time	Measure of the average length of time that water remains in storage before being released. Also known as hydraulic retention time.
hydroacoustics	Underwater sound; also a technology to monitor fish passage, abundance, and distribution.
hydrologic cycle	Earth's natural water cycle which includes the processes of evaporation, condensation, precipitation, interception, infiltration, percolation, transpiration, runoff, and storage.
impoundment	Body of water created by a structure that obstructs flow, such as a dam.
Independent Power Producer	Any entity that owns or operates an electricity generating facility that is not included in the utility's rate base.
Independent System Operator	Organization that coordinates, controls, and monitors operation of the electrical power system within a specified geographic region.
intake	Structure that diverts water from a natural waterway into the turbine.
interconnection	Major points in the United States electrical grid where large regional grids connect with each other.
Investment Tax Credit	Tax incentive that allows qualifying businesses to deduct a certain amount of money from their taxes based on capital investments in renewable energy projects.
load	The amount of electrical power delivered or required at any specific point or points on a system.
load following, load shifting	Ability of a hydropower plant to adjust its power output as electricity demand changes throughout the day.
load-following reserves	Additional capacity available to accommodate load variability and uncertainty.
mainstem	Primary downstream segment of a river.
marine and river hydrokinetic technologies	Devices that capture energy from waves, tides, ocean currents, the natural flow of water in rivers, and marine thermal gradients.

Term	Definition
market clearing	Process by which, in an economic market, the supply of energy or power is equal to the demand.
market settlement	Price at which electricity is traded in the wholesale market.
nameplate capacity	Indicates the maximum output a generator can produce without exceeding design thermal limits; determined by manufacturer.
non-powered dams	Dams that do not have any electricity generation equipment installed.
non-spinning operating reserves	Additional capacity that is not connected to the system but can be made available to meet demand within a specified time. Also known as supplemental reserves.
Open Access Transmission Tariff	Requirement that the Transmission Service Provider furnish to all shippers of electrical power through the transmission system with non-discriminating service comparable to that provided by Transmission Owners to themselves.
particulate matter	Particulate matter (PM), also known as particle pollution, is a complex mixture of extremely small particles and liquid droplets found in the atmosphere that, when inhaled, can cause serious health effects.
partnership flips	Structure in which a developer and the tax equity investor form a joint venture partnership and the allocation of cash and tax benefits changes or "flips" between both parties over time.
peaking	Operating mode in which power is produced only during periods of peak demand.
peaking power plant	Power plants operated to help balance the fluctuating power requirements of the electricity grid.
penetration	Fraction of energy produced by select generating sources (such as wind and solar) compared with total generation.
penstocks	A closed conduit or pipe for conducting water from the forebay to turbines in the powerhouse.
piezometers	Device used to determine water levels at a dam by measuring hydraulic head.
PME measures	Measures that Protect, Mitigate, or Enhance natural, cultural, and recreational resources affected by hydropower projects.
potential transformer	A conventional voltage transformer.
power	The rate of production or consumption of energy; electric power is the rate at which electrical energy is transferred by an electric circuit.
powerhouse	The structure that houses generators and turbines at a hydropower facility.
practical resource	Portion of the technical resource that is available when other constraints—including economic, environmental, and regulatory—are factored in.

Term	Definition
Production Tax Credit	A U.S. federal, per-kilowatt-hour tax credit for electricity generated by qualified energy resources.
pumped storage hydropower	Type of hydropower project where energy can be stored and generated by moving water between two reservoirs of differing elevations.
ramp rate	Rate at which flows from the powerhouse into the tailwater and downstream into the natural waterway are increased or decreased.
ramping capability	Ability of a power station to change its output over time.
reactive supply	Portion of electricity supposed to sustain the electric and magnetic fields of alternating current (AC) equipment, such as transformers.
Regional Transmission Operator	Organization responsible for moving and monitoring electricity over specific interstate areas.
regulating reserves	Capacity available for providing fast, real-time balancing services.
rehabilitation	Process of expanding, upgrading, and improving efficiency of existing hydropower facilities.
reliable (power generation)	Probability that a generating unit will perform when used under stated conditions.
relicensing period	Period during which a licensee must file notice of intent to declare whether the licensee intends to seek a new license for its project (at least 5 years before a license expires) and during which the licensee must actually file the application for a new license (at least 2 years before a license expires).
reregulating reservoir	Reservoir located downstream from a hydropower peaking plant with the capacity to store fluctuating discharges and release them according to environmental flow needs.
reservoir	Body of water that builds up behind a dam. See also *impoundment*.
resource potential	Amount of power that could be generated from a particular resource; see also *theoretical, technical, and practical potential*.
rotor	Rotating inner portion of a generator consisting of a series of windings that surround the field poles.
rough zone	Part of the range between minimum and maximum output that should be avoided due to deteriorating impacts on plant equipment, e.g., due to vibration.
runoff	Precipitation, snow melt, glacial melt, or irrigation water that appears in uncontrolled surface streams, rivers, drains, or sewers.
run-of-river	Type of hydropower project in which limited storage capacity is available and water is released at roughly the same rate as the natural flow of the river.

Term	Definition
sale-leasebacks or sale-leaseback agreement	Transaction in which the buyer of a facility leases the facility back to the seller at agreed-upon lease terms, thus functioning as a loan with payments taking the form of rent.
salmonid	Any of various fishes of the family Salmonidae, which includes the salmon, trout, grayling, and whitefish.
self-aerating turbines	Turbines that use low pressures created by flows exiting the turbine to induce additional airflows.
sensitivity analyses	Technique used to determine how different values of an independent variable will impact a particular dependent variable under a given set of assumptions.
special protection system	Automatic system designed to detect and correct abnormal or predetermined system conditions to maintain system reliability. Also called Remedial Action Scheme.
spillway	A structure used to provide the release of flows from a dam into a downstream area.
spinning reserves	Additional, rapidly-available capacity available in generating units that are operating at less than their capability.
stakeholder	Individual, group, or organization who may affect, be affected by, or perceive itself to be affected by a decision, activity, or outcome of a project.
stator	Stationary outer portion of a generator often made of a series of magnets and windings that carry heavy currents and high voltages.
storage	The storing of water in a reservoir during periods of high inflow that can be used later to generate electricity.
new stream-reach	Denotes waterways that are previously undeveloped with hydropower.
sustainable hydropower; sustainability	For hydropower, a project or interrelated projects that are sited, designed, constructed, and operated to balance social, environmental, and economic objectives at multiple geographic scales (e.g., national, regional, basin, site) and to internalize all social, environmental, and economic benefits and costs in a manner that provides a long-term net benefit to the public owners of the resource.
tailwater	The water downstream of the powerhouse or dam.
technical resource	Portion of a theoretical resource that can be captured by using a specific technology.
theoretical resource	Annual average amount of physical energy that is hypothetically available.
transformer	A device for changing alternating current (AC) to higher or lower voltages.
transmission	Conveyance of electrical energy from generation facilities to local distribution systems.

Term	Definition
turbidity	Measure of the relative clarity of a fluid, commonly used as a measure of water quality.
turbine	A machine that produces continuous power in which a wheel or rotor revolves by a fast-moving flow of water.
turbine runner	The rotating part of the turbine that converts the energy of falling water into mechanical energy.
variable renewable generation resource	A renewable energy source that fluctuates due to natural circumstances not controlled by the operator, such as wind and solar.
vertically-integrated utility	Utility that provides all aspects of electric service through ownership of the generating plants, transmission system, and distribution lines.
voltage	The amount of electromotive force, measured in volts, between two points.
watershed	Land that water flows across or under on its way to a stream, river, lake, or ocean.
weir	A barrier built across a stream or river to alter its flow characteristics.
wheeling	Delivery of power from one utility to a second utility using the transmission system of a third utility.
wholesale power market	Type of market where any entity that can generate power and connect to the grid can compete to sell their power output; the disposition of such and who is involved varies regionally.
wicket gates	Adjustable elements that control the flow of water to the turbine.

This page is intentionally left blank

Appendix B: Expanded Discussion of Hydropower Technology Assumptions

This appendix is a long-form explanation of the hydropower technology assumptions briefly documented in Section 3.1 of the *Hydropower Vision.* Additional detail on hydropower cost reduction assumptions is included in Appendix C.

B.1 Introduction

To model growth in the *Hydropower Vision,* each type of hydropower potential—upgrades and expansion, Non-Powered Dams (NPDs), New Stream-reach Development (NSD), and Pumped Storage Hydropower (PSH)—is represented separately, and each potential type has its own unique set of cost and performance attributes. This separation allows the model to resolve the key differences in how market and technology factors will influence the growth and operation of each resource class, such as the differing responses of upgrades and NSD to lower technology costs and differences between PSH and NSD when faced with a power system with low-cost variable resource renewable energy technologies.

As noted, the Regional Energy Deployment System (ReEDS) model is limited to simulating capacity expansion and power system operation in the continental United States. As the opportunities for hydropower to play a role in the future of the power system outside of the continental United States cannot be quantified using ReEDS, these topics are not covered in this chapter.

Also absent from the modeled (ReEDS) components of the *Hydropower Vision* is the potential to add power to canals and conduits. The potential for such hydropower exists but is only partially quantified. This resource uncertainty prevents canal and conduit hydropower from being explicitly modeled in ReEDS. The U.S. Bureau of Reclamation (Reclamation) has assessed power potential throughout its existing water resource infrastructure (Reclamation 2012), finding the potential to add 225 megawatts (MW) along its canal system [1]. Some other states and organizations have performed regional resource assessments [2], [3], [4]. These studies place a lower bound on potential from canals and conduits below 500 MW, while extrapolation of state-level assessments and unstudied potential in municipal water systems could push the number into the low gigawatts.

B.2 Existing Hydropower Facilities and Upgrade Potential

The potential for expanding the contributions of the existing hydropower fleet to the power system is the most immediate opportunity for a growing hydropower industry. This additional potential at existing facilities comes in many forms. At individual facilities, investments can be made to improve the efficiency of existing generating units through overhauls, generator rewinds, or turbine replacements; such investments are known collectively as "upgrades." These upgrade activities can increase capacity through higher unit ratings or can increase generation through increased plant efficiencies, even if peak generating capabilities go unchanged. Additional capacity can be constructed either by adding units into existing, unoccupied turbine bays or by constructing an additional powerhouse at an existing power plant (i.e., "expansion"). Even in the absence of major capital projects from upgrades or expansion, significant efficiency and generation increases are possible through the optimized operations of individual units and entire plants. Beyond these optimization activities at individual plants, it is possible to coordinate the operations of multiple plants along a single river system to achieve peak generation potential by timing water releases from all facilities optimally. This coordination can happen within the projects of a single owner, or among multiple owners if allowed by power-market regulations.

Unlike the NPD and NSD resources, however, no single source of information exists from which to estimate the national potential for maximizing the site-specific capabilities of the existing fleet. Instead, the *Hydropower Vision* relies on generalizable information drawn from a series of case studies or owner-specific assessments. Information available to inform the representation of improvements to the existing fleet includes:

1. A systematic, full-fleet assessment of expansion potential at Reclamation projects performed under the Reclamation Hydropower Modernization Initiative [28]
2. Case study reports from the U.S. Army Corps of Engineers (Corps) performed under its Hydropower Modernization Initiative [5]
3. Case study reports combining assessments of upgrade and unit and plant optimization potential from the U.S. Department of Energy/Oak Ridge National Laboratory Hydropower Advancement Project.

The Reclamation expansion study assessed the potential to add up to 50% of capacity at each of its sites, considering the economics of each plant's expansion potential and assigning benefit-cost ratios to expansion potential in increments of 10% (e.g., 10%, 20%, 30%, 40%, and 50%) [6]. While potential up to 50% expansion was studied, this level of capacity increase was generally not considered economically viable: the report found that only 67 MW had a benefit-cost ratio greater than one [6]. For the *Hydropower Vision,* the limitation of the upgrade resource to potential deemed economic under present-day conditions was thought to be overly restrictive. Instead, for each Reclamation facility, the largest capacity-expansion potential with a benefit-cost ratio of more than 0.5 was used. The estimates of expansion potential also included costs estimates, and these were used directly (with appropriate escalation) in the *Hydropower Vision* upgrade and expansion supply curve.

In the Corps' Hydropower Modernization Initiative case studies (, a series of plants were assessed for generation and capacity increases based on upgrade potential alone. No costs were assigned to these opportunities in the study. For use in modeling upgrade and expansion potential in the *Hydropower Vision,* the results from this report—an 8% average increase in generation—have been extrapolated to all Corps and Tennessee Valley Authority projects. The cost assumptions used for modeling Corps and Tennessee Valley Authority upgrade resources are described in Section B.6.

For non-federal upgrade and expansion potential estimates, results from the Hydropower Advancement Project—a 10% average increase from 1,636 facilities—were applied to the remainder of the U.S. fleet.

An additional consideration in the modeling of upgrade and expansion potential is that modifications to existing plants face additional non-cost barriers to their implementation. While it might be possible to upgrade or replace a piece of equipment today, it might not make financial sense to do so if that existing asset is not fully depreciated. Separately, it might again be possible to increase plant generation and capacity today, but doing so could under some circumstances require an amendment to an existing Federal Energy Regulatory Commission (FERC) license—a risk many owners might not be willing to take for incremental gains in power production. In light of these conditions, the availability of upgrade potential to ReEDS was given a time component—that is, some upgrades are not immediately available and are instead delayed to future years. To approximate the concerns with regard to depreciation and licensing risk, the potential to upgrade a plant is given as the lesser of the two following criteria:

1. Expiration of current FERC license (not applicable to federal fleet and select non-federal projects)
2. Turbine age exceeding 50 years.[1]

1. Turbine age is taken from the National Hydropower Asset Assessment Program, "NHAAP FY15 Existing Hydropower Assets Database" 2015 (internal only) [7].

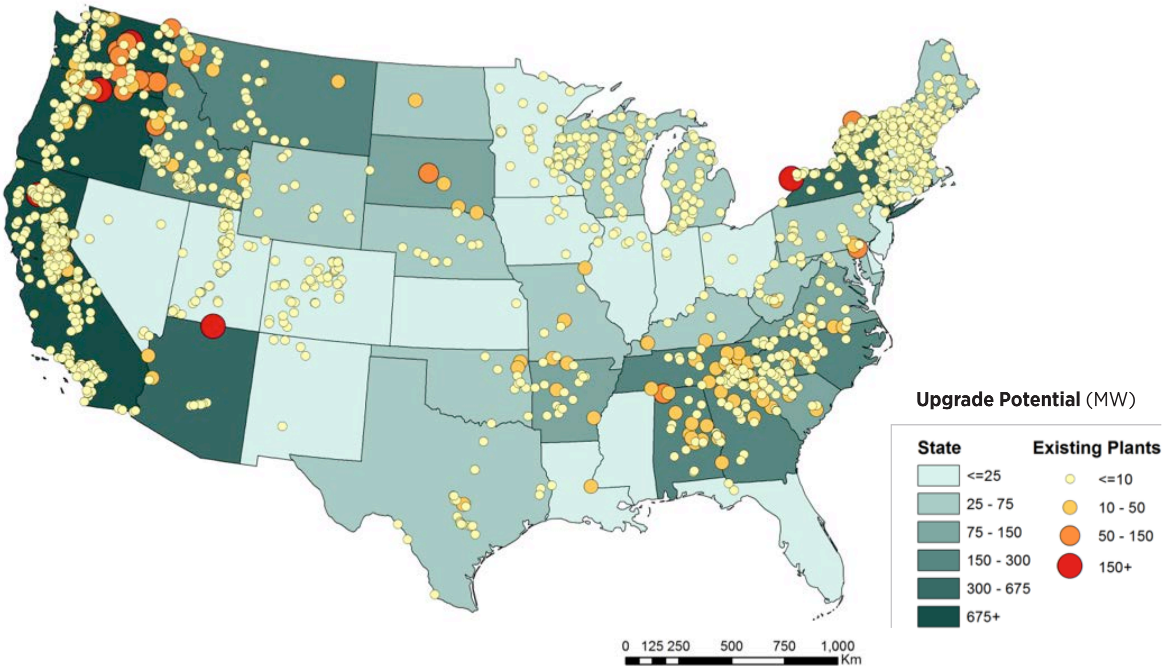


Figure B-1. Modeled upgrade potential at the state- and plant-level in the *Hydropower Vision*

Altogether, the upgrade and expansion resource represents 1,799 plants with 6,856 MW of capacity expansion potential. The ability to upgrade a facility is modeled as being dependent on a plant's regulatory status and/or estimated depreciation of major powertrain components, and subsequently some upgrade resource is not available until later in the Hydropower Vision study period, although the overwhelming majority (>80%) is available to be deployed before 2020. Figure B-1 maps the resource nationally.

Overall, the upgrade and expansion resource is the least certain of those modeled in the *Hydropower Vision.*[2] As it currently exists, the resource potential estimates are an imperfect composite of expansion potential, upgrade potential, and composite upgrade and plant-level optimization. Certain classes of potential have not been explicitly considered, such as increases in dam height to increase hydraulic head and system-level optimization to increase generation across entire river basins. In certain cases, these omissions might be significant,[3] but a lack of concrete data prevents their inclusion in the *Hydropower Vision.*

Additionally, modeling limitations within ReEDS mean that this resource is characterized solely by capacity increases at existing capacity factors, with costs typical of expanding powerhouses. The unique site-specific dynamics of optimizing the value and contributions of any single hydropower asset are readily apparent and present large challenges to national-scale modeling such as that done in ReEDS. Despite these limitations, the current representation of upgrade and expansion potential shows the magnitude of the opportunities available from existing facilities, without the need for construction of new power infrastructure or impoundments.

2. The development of this resource class for analysis also exposed information gaps to be addressed within the *Hydropower Vision* roadmap to support hydropower growth.

3. One significant, known issue is that there have been suggestions made that major gains in generation are possible at Corps projects, potentially in excess of 20% (NRC, 2012); however, these are speculative—if promising—and require further study [27].

B.3 Powering Non-Powered Dams

The modeling of potential from NPDs relies on the resource estimates developed by the U.S. Department of Energy (DOE). The foundation of the NPD resource in the *Hydropower Vision* is the 2012 report, *An Assessment of Energy Potential At Non-Powered Dams,* which quantified hydraulic head[4] and the technical energy potential at 54,391 non-powered dams [8]. This initial report identified 12.1 gigawatts (GW) of capacity available, with an average annual generation potential of 46 terawatt-hours (TWh) per year.

This 2012 DOE assessment estimated the technical upper-bound estimate of capacity and energy potential based on hydropower storage assumptions derived from regional capacity factors, which are typically driven by large-storage hydropower facilities with relatively low utilization rates. While some NPD have storage, they generally operate according to the demands of their water resource purposes—e.g., irrigation, flood control, and recreation[5]. NPD developments that have more recently been developed have generally exhibited lower flexibility but higher overall capacity factors than existing storage hydropower assets. The ReEDS model optimizes capacity expansion based on the competitive economics between technologies. As such, using estimates of technical potential for NPD would overestimate capacity and energy while underestimating cost, which distorts the economics of the NPD in the *Hydropower Vision.*

For the *Hydropower Vision,* the capacity estimates for NPD were revisited using the run-of-river sizing methodology developed for DOE's estimates of resource potential from NSD [9]. In this approach, NPDs are approximately sized so that they operate at maximum hydraulic capacity 30% of the time (often referred to as "30% flow exceedance"). The revised resource estimates generally lower capacity and energy potential—i.e., more water is spilled—but are a more accurate reflection of the economic sizing of new hydropower projects. Under the new methodology, the total NPD potential of the 2012 study drops to 5.7 GW of capacity with an average annual generation potential of 31 TWh per year. Further resource corrections[6]—the addition of previously omitted dams and the exclusions of dams slated for removal or those that have added power generation capabilities since the original resource assessment—bring the resource to 5.5 GW and 30 TWh per year.

For modeling purposes in ReEDS, only hydropower projects with capacities greater than 500 kilowatts (kW) are included. This prevents smaller projects from negatively impacting the deployment of large, more economically competitive facilities (more information about this is discussed in Section B.7). This brings the final NPD resource total available in the *Hydropower Vision* modeling to 5.0 GW (28 TWh per year) from 671 NPD.

The resulting resource is mapped in Figure B-2, with select resource characteristics described in Table B-1.

Additionally, 393 MW across 20 NPD projects are either already under construction or have been approved and are in the near-term pipeline for development. These projects are assumed to be deployed in every *Hydropower Vision* scenario. Of these projects, 11 account for more than 95% of the total capacity.[7] The NPD resource is located primarily along major rivers across the Midwest, extending from the Mississippi River in Minnesota through its tributaries across the South and into the Gulf of Mexico. The Ohio River plays a similar role to the East. These sites are often lock-and-dam infrastructure owned by the Corps and are typically characterized by high-flow, low-head hydrological conditions.

---

4. The hydraulic head, or "head" of a hydropower project, refers to the elevation difference between a project's upstream reservoir and downstream power-generating capabilities. Power potential scales with head—that is, as the elevation difference increases, so too does plant capacity—as do many technical, operational, and economic features of hydropower projects.
5. It is possible that dams in some locales—such as mill dams in New England—are no longer in use at all.
6. R.C. Byrd and Pike Island dams were both omitted from the original resource assessment. The Olmstead Locks and Dam currently under construction was also admitted, because it replaces Ohio River Locks and Dam 52 and Ohio River Locks and Dam 53, which are subsequently slated for removal by the Corps. Both Mahoning Creek and Red Rock dams have been removed from the supply curve, as power capabilities on the former are operational as of 2013 and the latter is under construction. Several smaller Corps and Reclamation dams were also identified by those organizations as unsuitable for power production.
7. B. Everett Jordan hydropower project (North Carolina), Bowersock Mills (Kansas), Cannelton Locks and Dam (Indiana), Dorena Dam (Oregon), Lower St. Anthony Falls Hydroelectric Project (Minnesota), Meldahl Locks and Dam (Ohio), Red Rock Dam (Iowa), Robert V. Trout Hydropower Plant (Colorado), Smithland Locks and Dam (Kentucky), Turnbull Drop Hydroelectric Project (Montana), and Willow Island Locks and Dam (West Virginia).

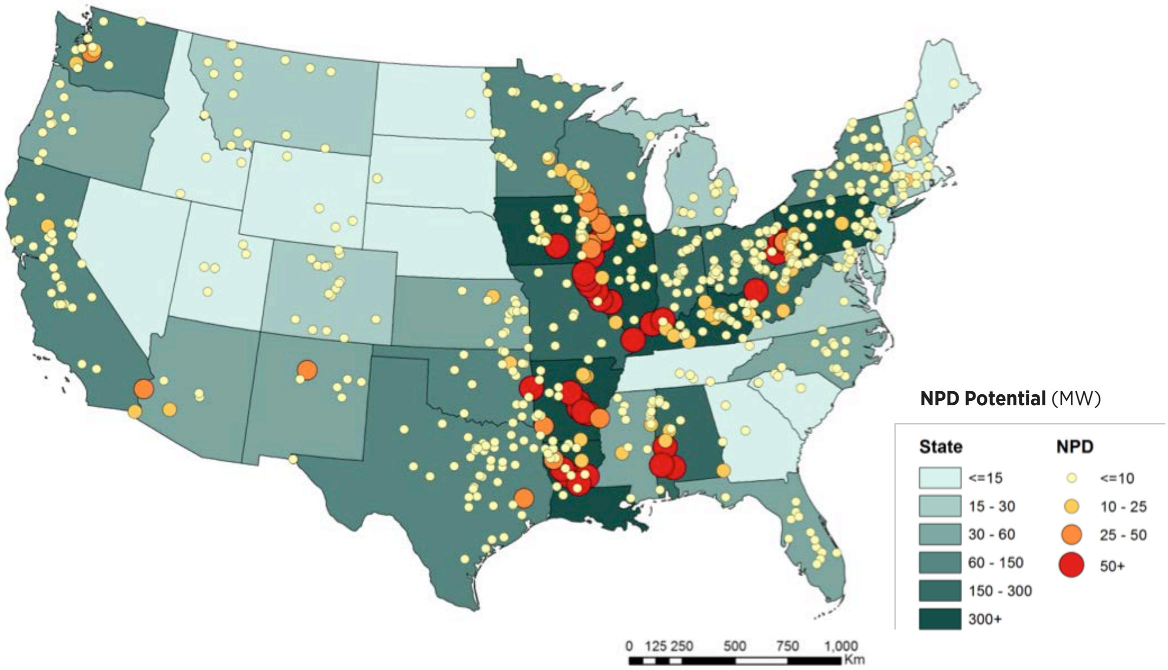


Figure B-2. State- and project-level distribution of NPD potential modeled in the *Hydropower Vision*

Table B-1. NPD Resource Statistics

NPD Resource Statistics	
Total Capacity (MW)	5,047
Number of Projects	671
Average Capacity (MW)	7.6
Median Capacity (MW)	1.6
Minimum Capacity (MW)	0.5
Maximum Capacity (MW)	192

B.4 New Stream-Reach Development

The largest source of potential new hydropower capacity comes from the development of new projects on undeveloped stream reaches— also the most costly and potentially environmentally disruptive, owing to the need for the development of new impoundment structures.

A recent DOE resource assessment forms the basis of the resource estimates used in the *Hydropower Vision* [9]. This report considered the technical resources that would be available for development given the 2014 state of hydropower technology. Unlike previous efforts, this process focused solely on undeveloped stream reaches, omitting streams with pre-existing hydropower facilities or NPDs. Two core assumptions bound the technical characteristics of the potential identified by the NSD report:

1. Inundation from NSD projects was bounded by the 100-year floodplain in an attempt to minimize the physical footprint of new development.
2. The power potential of individual NSD projects was estimated assuming they operate as "run-of-river" hydropower, wherein water is used to generate power as it reaches a facility, which as modeled has little to no power-storage capacity or operational flexibility; by design, none of the NSD potential changes the natural flow regime for power purposes[8].

For the *Hydropower Vision,* three primary modifications were made to the resource described in the 2014 report**.** [9].

1. In the course of developing the inputs for the *Hydropower Vision,* it was found that the resource sizing in select basins required correction to remain consistent with the rest of the continental U.S. resource. This correction regarding the choice of the 30% exceedance flow reduces the total national resource from the 65.5 GW in the published 2014 report to 53.2 GW possible for inclusion in the *Hydropower Vision* supply curves [9].
2. The resource modeled in the *Hydropower Vision* supply curves is limited to potential projects greater than 1 MW. This is done for two reasons. First, given the dynamics of how the NSD resource is transformed into the modeling inputs for ReEDS (see Section B.7), smaller, less-economic NSD potential might artificially disadvantage the larger, more economic remainder. Second, in the course of the NSD resource assessment, potential with capacity greater than 1 MW was given additional quality assurance and quality control and had more sophistication in the application and assessment of environmental attributes. With the exception of a handful of bounding cases, limitations on NSD resource are not reached in the *Hydropower Vision* scenarios.
3. Projects located in areas statutorily barred from development—national parks, wild and scenic rivers, and wilderness areas—have already been excluded from the *Hydropower Vision* supply curves in the original 53.2 GW.

NSD was also subjected to an effort to assign other environmentally and socially relevant characteristics (such as the presence of endangered species) to the resource potential. The environmental characteristics of NSD play an important role in shaping the potential for growth from NSD, and this environmental attribution effort and its application in the development of *Hydropower Vision* modeling scenarios are described in more detail in Section B.10 of this appendix.

Ultimately, 30.7 GW of NSD resource potential[9]—screened for modeling purposes from the original resource assessment and assigned an array of environmental characteristics as described above—is available for deployment in the *Hydropower Vision*. This potential is mapped in Figure B-3, and select resource characteristics are described in Table B-2. Whereas resource potential from upgrades and NPD is mapped at a site-specific level, NSD potential is mapped at an aggregate level (below at the watershed level), given the uncertainties inherent in the estimation of the NSD resource, which is most accurately considered a statistical representation of potential and not a site-specific identification of hydropower projects.

8. As the NSD resource is based on attempting to identify low-impact areas of power potential, some forms of new hydropower development that might be seen in the future—such as the addition of power to large new dams constructed for water supply purposes—cannot be modeled in the *Hydropower Vision*.

9. Additional to the modeled NSD resource, a single project with 7.9 MW of capacity is assumed to deploy for NSD. This project—Snohomish Public Utility District's Youngs Creek—became operational in 2011, but as the ReEDS model begins simulation in 2010, the project's deployment must be prescribed.

The NSD resource is concentrated in the Northwest, interior Mid-Atlantic, Appalachia, and Ozark regions. In general, these regions have a greater likelihood for higher head sites, resulting in a greater generation potential. While many stream reaches with some generation potential exist in the south, those resources tend to be smaller, leaving the region with a high number of sites, but low overall generation potential.

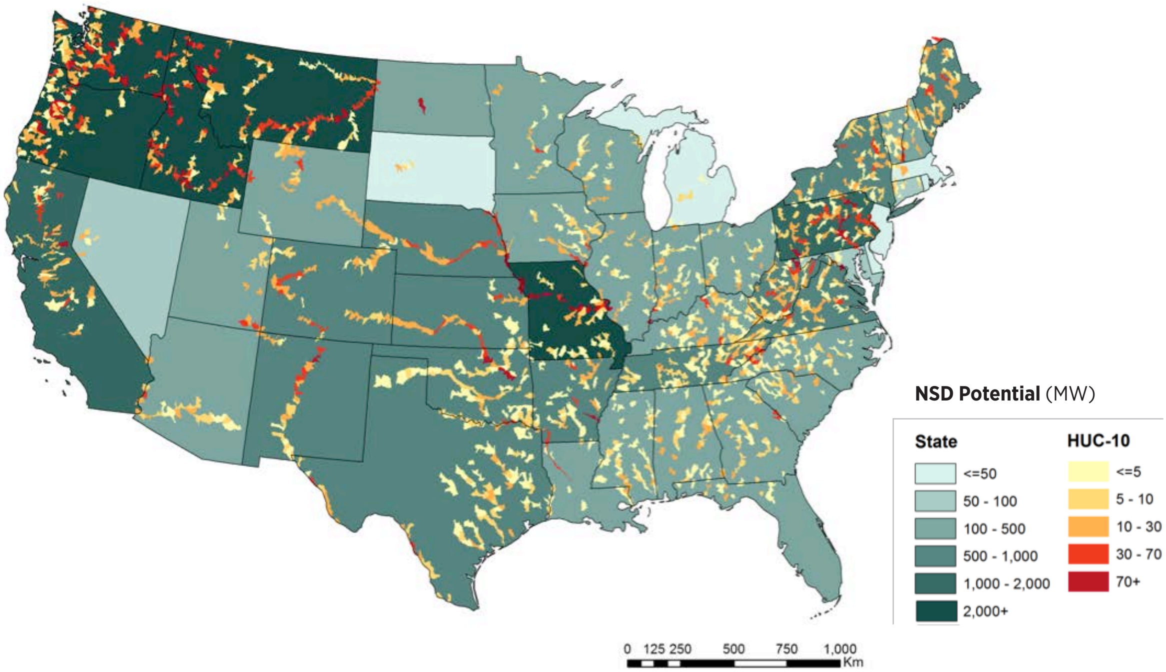


Figure B-3. Distribution of NSD resource potential at the state- and watershed-level

Table B-2. NSD Resource Statistics

NSD Resource Statistics	
Total Capacity (MW)	30,669
Number of Projects	7,977
Average Capacity (MW)	3.8
Median Capacity (MW)	1.9
Minimum Capacity (MW)	1.0
Maximum Capacity (MW)	357

B.5 Pumped Storage Hydropower

Unlike the NPD and NSD resource, no clear process for the identification of the total national resource of pumped storage exists. As an energy storage technology, pumped storage represents an inherently different resource to assess and categorize. PSH capabilities can be added in an "open-loop" configuration at existing dams or at new reservoirs connected to existing waterways. There are also opportunities for "closed-loop" pumped storage configurations—where both reservoirs are disconnected from natural waterbodies. Closed-loop configurations are more flexible, and this flexibility introduces significant uncertainty into the estimation of resource potential. Proposed closed-loop designs include the use of existing open-pit mines, abandoned mine shafts, or two entirely new off-stream reservoirs; additional, less-conventional design proposals also exist for small modular units and the hybridization of pumped storage and compressed air on a distributed-storage scale.

Historical assessments have found potential exceeding 1,051 GW, but these efforts focused on quantifying total regional potential and did not provide site-specific information [10]. Recent assessments of potential have focused on specific open-loop subsets of the potential PSH resource, but still lack the full suite of site-specific details necessary to model hydropower in a capacity-expansion model [11].

As such, local characteristics might make one site more attractive than another, but PSH could technically be built in many geographic locations. As an alternative to national-scale resource assessment, the *Hydropower Vision* uses historical proposed development as a lower bound for resource availability by generating potential PSH projects from more than 200 FERC PSH preliminary-permit applications encompassing all PSH projects proposed to the FERC since 1980. These permits were manually examined and duplicate proposals were removed as a result of overwhelming similarity across permits filed for the same geographic location.[10] Overall, 108.7 GW of permits from 166 sites were used to assign PSH resource potential to the 134 ReEDS balancing areas (BAs).

However, fewer than 50 of the 134 of ReEDS BAs are home to a previously proposed PSH project. This distribution might be the result of a complex set of factors such as local market drivers, geography, power-system topology, and developer interest, rather than an intrinsic limitation on the technical feasibility of developing pumped storage. To avoid overly constraining the potential for PSH development owing to limitations on data availability for the PSH resource, every ReEDS BA is allowed to deploy up to five "artificial" 750 MW closed-loop PSH projects in addition to those identified from FERC permit applications, but only at a very high cost. This high cost typically prevents the ReEDS model from deploying PSH storage in these areas without a powerful economic incentive[11] for the BA. An approximate average of the capacity of PSH projects proposed in the last decade is 750 MW.

Figure B-4 illustrates the distribution of the resource derived from FERC permit applications. Given the uncertainty in the PSH resource, the available supply and deployment results are shown in aggregate at the North American Electric Reliability Corporation (NERC) sub-region level. BAs with only artificial resource available are shaded with diagonal lines.

10. These were recurring permits. As each previous project lapsed, a new application was filed with intent to develop the same site with a similar capacity resource. In these cases, the most recent permit was included.

11. As discussed later, combinations of cost reductions, alternative-valuation perspective and financing mechanisms, as well as power-system conditions such as the cost of fossil fuel or variable renewable energy technologies can create powerful motivators for the development of PSH.

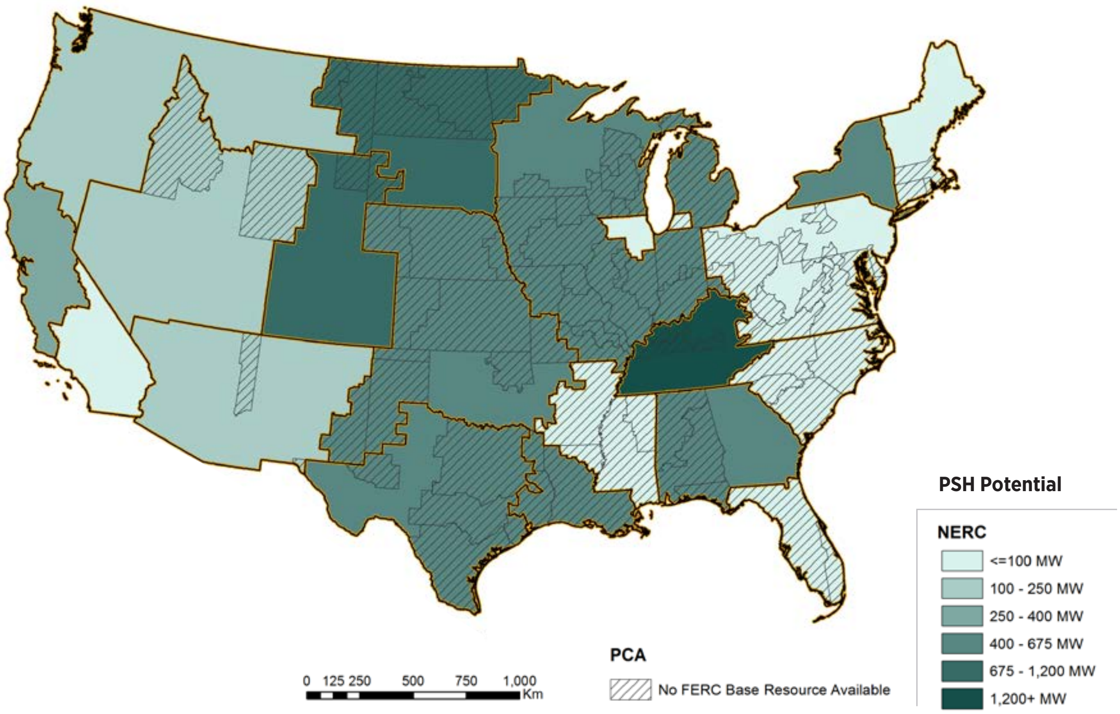


Figure B-4. NERC regional-level PSH resource potential modeled in the *Hydropower Vision* as identified in FERC preliminary permit applications; shaded ReEDS BAs indicate no publically available historical permits

Table B-3. PSH Resource Statistics (from FERC Permit Applications)

PSH Resource Statistics (from FERC permit applications)	
Total Capacity (MW)	108,742
Number of Projects	166
Average Capacity (MW)	655
Median Capacity (MW)	600
Minimum Capacity (MW)	5
Maximum Capacity (MW)	2,000

B.6 Hydropower Costs and Cost Projections

Each of the hydropower resources has individualized cost dynamics that influence its economic competitiveness in the *Hydropower Vision.* In general, the cost of developing and operating a hydropower project is highly site-specific and subject to a number of economies of scale—such as decreasing relative costs (i.e., \$/kW) as project size or other design attributes (such as higher heads) increase. To the extent that economies of scale are quantitatively identifiable from past hydropower industry experience, they inform the distribution of costs between and within resources in the *Hydropower Vision.* Note that all costs are in 2014 dollars.

- **Upgrades** are often the lowest-cost hydropower resource in the *Hydropower Vision,*[12] with the modeled costs for individual projects ranging from \$800/kW to nearly \$20,000/kW. This differential results from significant economies of scale from project size, wherein larger-capacity plants are less expensive to upgrade on a \$/kW basis than smaller projects. While the smallest projects in the United States can be as small as 10 kW to 100 kW, the bulk of upgrade potential is from large facilities. The average cost of the upgrade resource is approximately \$1,500/kW.

  Reclamation's Hydropower Modernization Initiative studies included specific cost estimates for Reclamation plants, and those values were used for that portion of the fleet. Costs at non-Reclamation plants were developed from a 2003 Idaho National Laboratory study[13]. Licensing costs were escalated from 2002 to 2014 dollars using the consumer price index. Construction costs were escalated using Reclamation's composite construction index. The cost formula is:

  $$\text{Cost} = (277 \times \mathit{ExpansionMW}^{-0.3}) + (2230 \times \mathit{ExpansionMW}^{-0.19})$$

- **NPD** costs in the *Hydropower Vision* generally fall between those for Upgrades and NSD, and are based on statistical models derived from U.S. NPD projects constructed over the last 30 years. As modeled in the *Hydropower Vision,* NPD costs range from \$2,700/kW to \$9,000/kW and exhibit weak economies of scale with respect to project capacity, but very strong economies of scale with respect to project head—that is, lower head projects are much more costly than higher head projects. The average cost of a low-head (less than 30 feet) NPD project modeled in the *Hydropower Vision* is \$5,800/kW; the average cost of higher-head projects is \$4,200/kW.

  The equation used to cost each NPD site was sourced from the Hydropower Baseline Cost Modeling report [12]. P is capacity in MW, while H is head in feet. The first term represents the initial capital costs, while the second represents licensing. Figure B-5 shows the project capital costs for NSDs from 1 to 500 MW, across five different head values.

  $$\text{Cost} = (11{,}489{,}245 \times P^{0.976} \times H^{-0.24}) + (310{,}000 \times P^{0.7})$$

12. As discussed earlier, upgrade potential is the most uncertain resource in the *Hydropower Vision.* The costs used to represent upgrade potential in ReEDS are only accurate as a magnitude of order and cannot resolve the differences between types of activities that can increase capacity potential or generation at existing facilities.

13. The use of the Idaho National Laboratory (2003) cost equations implicitly assumes all upgrade and expansion potential is costed equivalently to expansion [26]. Certain upgrade activities such as generator rewinds or turbine replacements have lower costs; however, the cost assumptions were kept conservative given the large resource uncertainties [12].

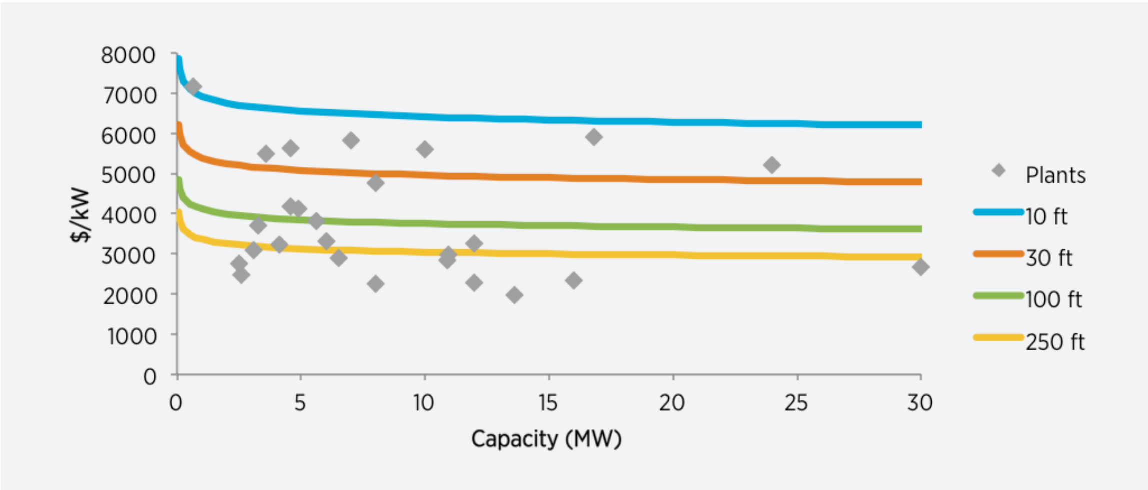


Figure B-5. Visualization of NPD cost equations

- **NSD** costs are generally higher than NPD costs as these projects require the construction of impoundment infrastructure; the cost of NSD in the *Hydropower Vision* ranges from \$5,200/kW to \$15,600. Costs for NSD are also determined statistically based on historical project experience, but the lack of recent U.S. NSD development renders these costs more uncertain. As with NPD, NSD costs are subject to weak economies of scale from project capacity, but scale more strongly with increasing project head, although less so than NPD. The average cost of low-head NSD potential is \$7,000/kW; the average of higher-head potential is \$6,000/kW.

  The equation used to cost each NSD site was sourced from the Hydropower Baseline Cost Modeling report [12]. *P* is capacity in MW, while *H* is head in feet. The first term represents the initial capital costs, while the second represents licensing. Figure B-6 shows the project capital costs for NSDs from 1 MW to 500 MW across five different head values.

$$\text{Cost} = (9{,}605{,}710 \times P^{0.977} \times H^{-0.126}) + (610{,}000 \times P^{0.7})$$

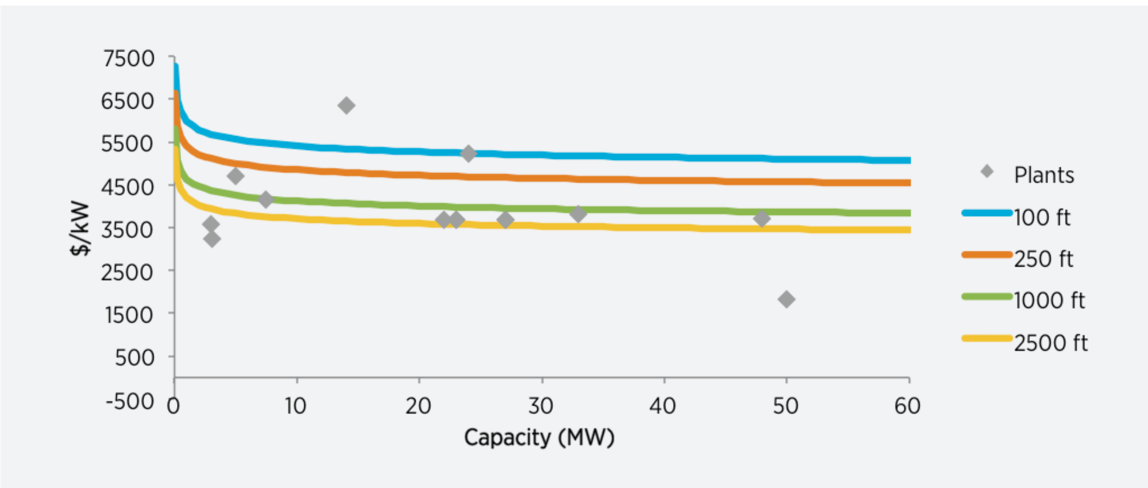


Figure B-6. Visualization of NSD cost equations

- **PSH** costs are unique relative to other new construction from NPDs and NSD, as PSH projects exhibit strong economies of scale with respect to project capacity, but might experience cost savings in cases where existing infrastructure or reservoirs reduce the scope of new construction. Data on existing infrastructure were available for the resource derived from FERC permits, and as such, costs are modeled separately in the *Hydropower Vision* for projects with ($1,750/kW to $2,700/kW) and without existing infrastructure ($1,750/kW to $4,500/kW); the average PSH potential costs are $2,700/kW. The 750 MW artificial projects are costed conservatively at $3,500/kW—$800/kW more than a similarly sized project without existing infrastructure and the high bound of similarly sized projects using the cost formulas described below.

  To cost to the PSH resource, three equations from O'Connor et al. (2015) have been applied [12]. These equations—adapted and escalated from U.S. Army Corps of Engineers (2009)—are available for low-cost, average-cost, and high-cost project types are parametric functions of project capacity—reflecting the economies of scale inherent in PSH development [13]. For projects whose preliminary permit applications indicated the presence of existing infrastructure—such as existing reservoir structures or dams—the low-cost line was applied. For all other projects identified from FERC permit applications, the average-cost project line was used. The high-cost project line was used to assign a cost to the 750 MW artificial plants available in BAs without FERC permit applications. These projects are assigned a cost of $3,500/kW. The three project cost curves are shown below in Figure B-7. For the cost equations, *P* is capacity in MW.

  - Greenfield Initial Capital Cost = $(4{,}882{,}655 \times P \times e^{-0.000776} \times P)$
  - Existing Infrastructure Initial Capital Cost = $(3{,}008{,}246 \times P \times e^{-0.00046} \times P)$

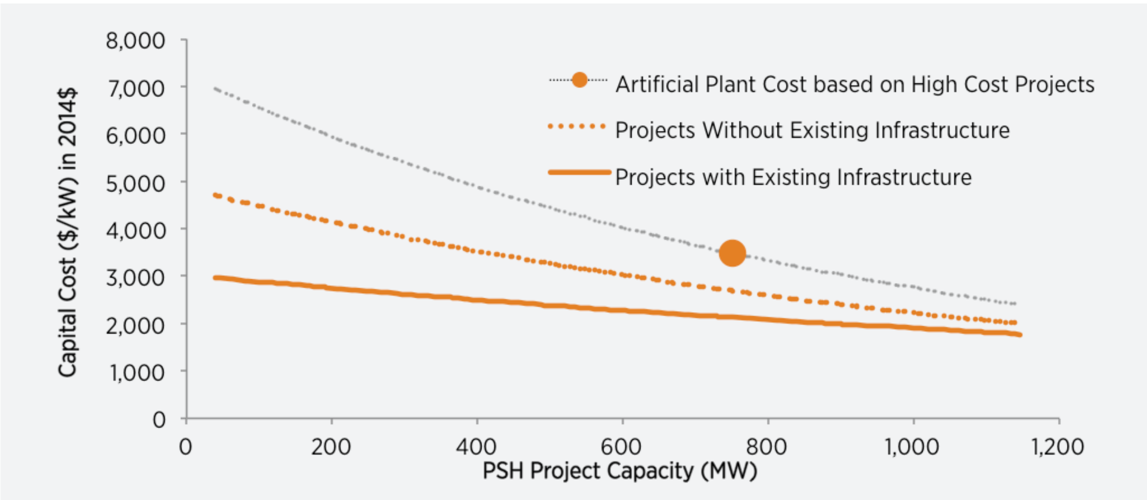


Figure B-7. Visualization of PSH cost equations

- Hydropower **operation and maintenance (O&M)** costs are modeled using equations from O'Connor et al. (2015), which rely on data derived from publically available information from investor-owned and municipal utilities and applied identically for all hydropower resource types [12]. O&M costs exhibit strong economies of scale with respect to project capacity, with the smallest 500-kW NPD costing $180/kW-year to operate versus a modeled cost of $4.2/kW-year to operate the nation's largest hydropower plant—the 6.5 GW Grand Coulee. While the differences in cost can be striking, their magnitude of order is generally consistent with that seen by *Hydropower Vision* participants and in proprietary industry databases.

Figure B-8 illustrates the relative capital costs of the hydropower resources modeled in the *Hydropower Vision.*

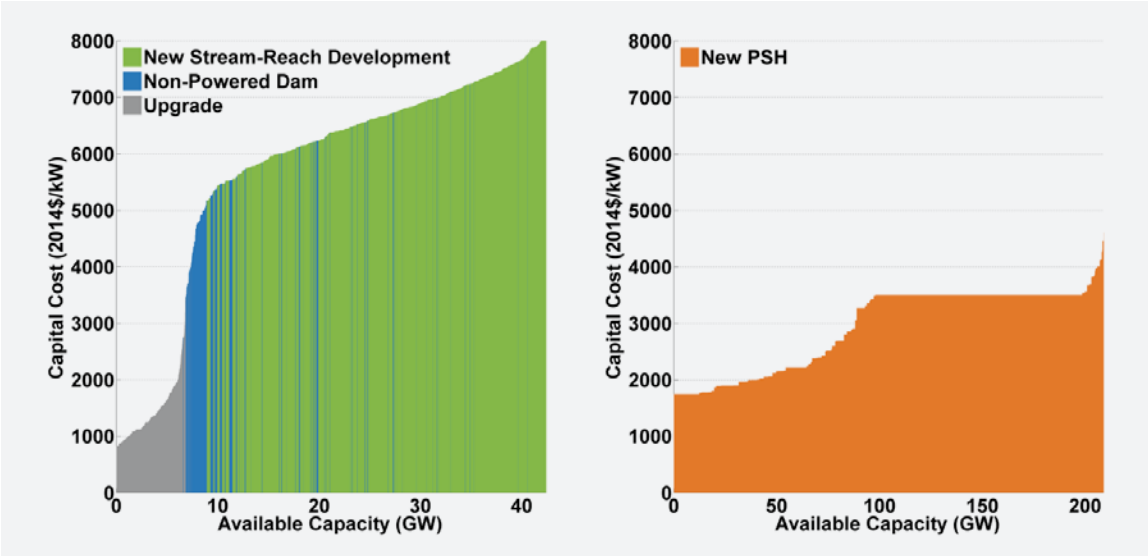


Figure B-8. 2014 Cost of hydropower resources in the *Hydropower Vision*

The *Hydropower Vision* incorporates three potential future cost trajectories to explore how these initial cost assumptions might evolve across the *Hydropower Vision* study period, with differentiated capital and O&M cost scenarios for NSD, high- and low-head NPD, and PSH.

The *Business as Usual* cost conditions assume a low, learning-based capital cost reduction of 5% by 2035, increasing to a total of 9% by 2050 (relative to baseline 2014 levels)[14] for NPD, NSD, and PSH. All O&M costs and capital costs for all other hydropower types remain constant under central assumptions.

Two additional scenarios with increasing levels of cost reduction were also developed based on projections in literature and expert stakeholder input from the *Hydropower Vision* effort:

- The *Evolutionary Technology* assumptions envision a world in which NSD and NPD development is increasingly standardized, while automation and best-practices dissemination reduce the O&M costs for these new projects. NSD and NPD experience capital cost reductions of up to 15% by 2035, increasing up to[15] 18% by 2050. NSD and NPD O&M costs are reduced by 25% in 2035 with minor improvement to 28% reduction in 2050.
- In *Evolutionary Technology,* PSH capital costs also experience modest cost reductions from evolutionary change based on continued process, contracting, design, and technological improvements within the conventional hydropower and dam construction industries. PSH capital costs decrease 7% by 2035 and a total of 11% by 2050.
- Under *Advanced Technology* assumptions, major technology advances in NPD and NSD from modularity and advanced manufacturing further drive down capital costs for these resources. NPD and NSD O&M costs are significantly reduced through modularity and design for reduced O&M in conjunction with smart, data-driven monitoring and maintenance planning. These capital cost reductions are up to 30% in 2035 and a total of 35% in 2050. O&M costs are reduced by 50% in 2035 and 54% in 2050.

14. These learning rates are consistent with the minimum rates used in the U.S. Energy Information Administration's *Annual Energy Outlook* publication

15. These ranges are specified as "up to" because high-head NPD and low-head NPDs have differentiated cost reductions. Low-head costs experience larger declines.

- PSH achieves slightly higher cost reductions in *Advanced Technology* than under *Evolutionary Technology* from the incorporation of new technologies as applicable (e.g., penstock materials), and the leveraging of advancements in other, non-hydropower construction industries such as oil and gas. Capital costs decrease 12% by 2035 and a total of 15% by 2050.

The costs of operating, maintaining, and upgrading the existing fleet are constant in all three scenarios. Extended documentation of the rationale for these assumptions and their comparison relative to forecasts in recent literature is available in Appendix C. Table B-4 summarizes the three cost trajectories modeled in the *Hydropower Vision.*

Table B-4. *Hydropower Vision* Cost Reduction Scenarios

Capital Cost	***Business as Usual*** (relative to 2015)		***Evolutionary Technology*** (relative to 2015)		***Advanced Technology*** (relative to 2015)	
	2035	**2050**	**2035**	**2050**	**2035**	**2050**
NSD			15%	18%	30%	35%
Low-Head NPD	5%	9%	15%	18%	30%	35%
High-Head NPD			10%	13%	25%	3%
Utility-Scale PSH			7%	11%	12%	15%
Upgrades	None		None		None	
O&M Cost						
NPD and NSD	None		25%	28%	50%	54%
Other O&M			None		None	

B.7 Transformation of Hydropower Resource Data into ReEDS Inputs

Hydropower is a complicated resource to represent in the context of the ReEDS model, as the economics, performance, and environmental context of hydropower projects within all classes is highly dependent on site-specific characteristics. The process by which hydropower potential is aggregated from the site-specific level into ReEDS modeling inputs and then disaggregated from ReEDS model output back down to site-specific deployment is important for understanding the limitations and implications of the model results discussed in the *Hydropower Vision* report.

Each resource is represented uniquely in each of the ReEDS model's 134 BAs. Individual projects within the ReEDS BA are aggregated into a series of composite steps in a *"supply curve"* where each step in the supply curve represents a capacity-weighted average cost of the projects underlying it. Figure B-9 illustrates this process for the NPDs in a specific BA.

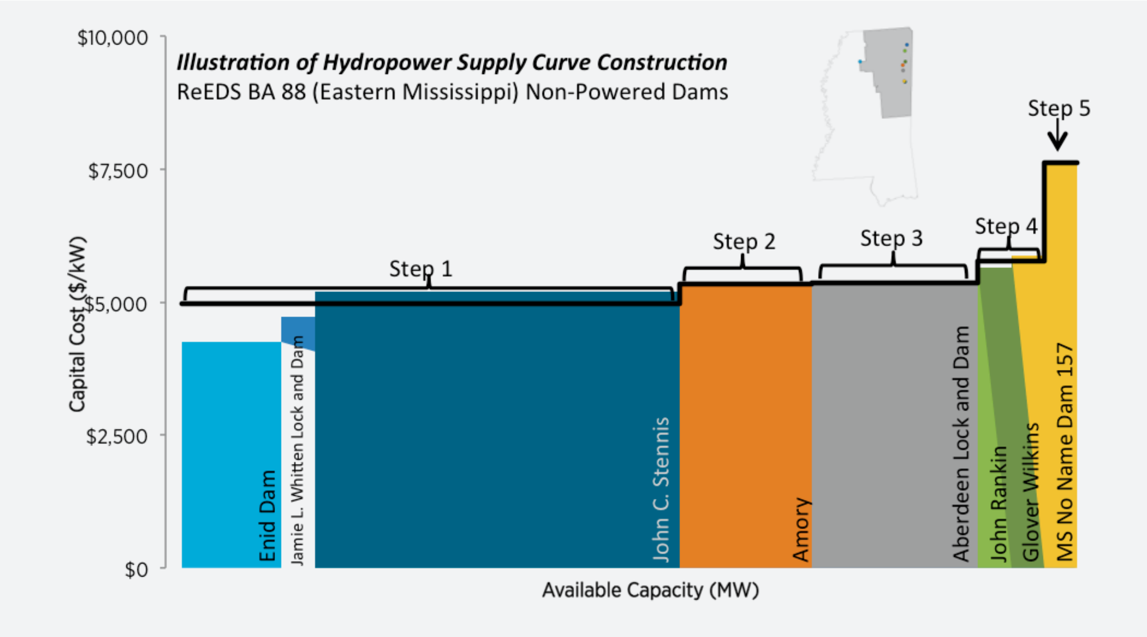


Figure B-9. Example of how *Hydropower Vision* supply curves are constructed

As seen in Figure B-9, there are eight NPDs of varying cost and capacity in ReEDS BA 88 covering eastern Mississippi. These projects are sorted in order of increasing cost and divided into five composite supply-curve steps. The strengths and weaknesses of this necessary approach are evident. In the first "step" of the supply curve, three projects are aggregated into one "block" of capacity that is seen by ReEDS at an average of approximately $5,000/kW. However, the cheapest project in Step 1—Enid Dam at approximately $4,000/kW—might be deployed at an artificially later time (or not at all) owing to its aggregation with the larger but more expensive John C. Stennis project. However, there are many times where individual projects will be assigned their own step in the supply curve, such as Amory Dam and Aberdeen Lock and Dam in the example.

In addition to composite costs at each step in the supply curve, all resources have one set of capacity factors and one aggregated O&M cost for each BA. Both are capacity weighted.

The equation used for the O&M cost of all resources is (from O'Connor et al., 2015) [12]:

$$\text{Lessor of } \begin{cases} \textit{Annual O\&M} \text{ (in 2014\$)} = 225{,}417\ P^{0.547} \\ 2.5\% \text{ of } \textit{CapEx} \end{cases}$$

Both upgrades and NPDs use a single five-step supply curve. Given the large amount of resource, and the potential for more economically competitive projects to be "averaged out" with more expensive ones, NSD uses a 10-step supply curve. The implementation of PSH is slightly different to accommodate the artificial resource. The permit-based resource is separated into up to four steps (if there are four or more projects), and any empty supply-curve steps are populated by artificial 750 MW, $3,500/kW projects.

Identifying deployment at the project level from the aggregated ReEDS results is a simple function of assigning capacity deployed first in a supply-curve step to the underlying project with the lowest capital cost (on a relative $/kW basis).

B.8 Financing Treatment of Hydropower

ReEDS standard and universal financing assumptions include an 8% nominal discount rate and 20-year valuation, based on 20-year economic life. Typically, these assumptions are applied to all technologies. However, it is common for hydropower projects to have feasible lifetime of 30, 50, and even 100 years. To accommodate this difference in the relative asset life for hydropower (as compared to wind, solar, and natural gas plants), an alternative to the standard ReEDS asset valuation treatment is defined and denoted as *Low Cost Finance*.

Low Cost Finance represents an investment environment where the long physical life and stable revenue stream is more highly valued during project financing and decision making than is typical in the industry today. Thorough examination of alternative financing conditions resulted in these input conditions being defined as an effective 40% reduction in the cost of capital. While this reduction is significant, it reflects some of the real-world financing conditions seen when developers and investors—both in the private and public (e.g., municipal or utility district) sectors—value the long life of hydropower assets. Whereas the *Hydropower Vision* cost trajectories phase in through time, the *Low Cost Finance* assumption is applied immediately to all ReEDS solve years.

B.9 Scenarios of Water Availability in a Changing Climate

Future trends in water availability driven by climate change have the potential to alter the economic attractiveness of hydropower projects by altering the nature of the "fuel" needed by hydropower plants. Based on the current scientific understanding (Intergovernmental Panel on Climate Change, 2014), two primary effects can be anticipated [14]:

- **Change in total water availability:** Climate change might alter the distributions of major hydrometeorological variables, such as precipitation, temperature, and evapotranspiration, which will in term affect the amount of runoff generated from natural hydrologic systems that can be utilized for hydropower generation. In other words, climate change might cause certain regions of the United States to receive more or less water on an average annual basis.
- **Change in runoff seasonality:** In addition to the potential change of total amount, the timing and temporal distribution of various major hydrometeorological variables can also change in the projected future climate conditions. For instance, in response to the increasing air temperature, earlier snowmelt can be expected in the near-term and mid-term future [15]. This means that a considerable amount of natural runoff that could be stored in the forms of snow and ice might melt and enter the reservoirs earlier.

The former effect is likely to have a direct influence on the average annual generation expected from new and existing hydropower projects. This theoretical impact has been examined by recent studies [16], [17], which showed that, on a regional basis, the historical annual U.S. federal hydropower generation (1989–2008) had a strong linear relationship with the corresponding regional annual runoff (obtained from the U.S. Geological Survey WaterWatch Program) [18]. Therefore, an increase or decrease in the projected future runoff will likely result in a proportional change of annual hydropower generation.

The latter effect can alter the value of generation depending on whether water is available in seasons with higher water and energy demands—such as summer—or during periods of lesser electricity demand—such as the more temperate seasons of spring and fall. Nevertheless, the potential impact of change in runoff seasonality will be dependent on the type of hydropower project under consideration—more specifically, a project's capabilities to store and manage water for use during high water- and energy-demand seasons. Projects with sufficiently large seasonal storage capabilities (e.g., most of the conventional storage-peaking projects)—or projects downstream that benefit from upstream storage—might be less affected by changes in the timing of runoff. However, hydropower projects without the ability to store water on an interseasonal basis will be forced to generate with the water available to them at the time and/or spill the excess amount of water when exceeding the maximum turbine capacity. This is a particular problem for more recent U.S. hydropower projects that operate in a run-of-river mode, using water only as it is available. As described previously, potential NSD and NPD projects are modeled as run-of-river in the *Hydropower Vision.*

While the types of impacts that are possible from climate change are known, there are large uncertainties as to the magnitude or even direction of changes in water availability on both annual and seasonal bases. To project the future hydroclimate conditions in a 30- to 40-year timeframe (e.g., *Hydropower Vision*), the global climate model (GCM) remains the most scientific defensible approach. A GCM uses physical-based equations to describe processes in the atmosphere, ocean, land surface, and cryosphere and can simulate the time evolution (i.e., centuries long) of temperature, precipitation, atmospheric moisture, sea ice, and other variables describing the state of various climate-system components in time and space. However, given the large modeling and methodological uncertainties, GCM data are not suitable for direct use in regional-scale water resource planning and policy making. Proper downscaling and bias-correction techniques will be needed to translate the global climate signals into regional- and watershed-scale hydroclimate projections. In addition, recognizing the large interannual variability and modeling uncertainty, a large climate ensemble comprising different GCMs, emission scenarios, and downscaling techniques is generally used as a basis to derive possible future scenarios to support decision making (as opposed to relying on the results from only one model/simulation) [19], [20].

To support this *Hydropower Vision* study, 97 sets of future hydroclimate projections from Brekke et al. (2013) and 10 sets from Kao et al. (2016) were collected for scenario development (both studies were based on multiple GCMs from the most recent Intergovernmental Panel on Climate Change Fifth Assessment) [21], [22]. The GCM outputs were downscaled by different methods (i.e., statistical versus dynamical), and a macro-scale variable infiltration capacity hydrologic model was used to simulate the future U.S. runoff by downscaled GCM temperature and precipitation[16] [23], [24]. These two hydroclimate data sets are also used as the scientific basis for the upcoming 2016 Reclamation's SECURE Water Act Section 9503 report to Congress and DOE's SECURE Water Act Section 9505 report to Congress.

These combined 107 hydroclimate projections were used to help bound the uncertainty of water availability for future hydropower development. Two sensitivity scenarios—one focused on a wetter future climate and one on a drier future climate—were developed for the *Hydropower Vision*. The following steps were used to derive one representative *Wet* and one representative *Dry* scenario from the combined ensemble of 107 climate simulations:

1. The projected average annual U.S. runoff change from the 1966–2005 baseline to 2011–2050 future periods was calculated for each ensemble member. Among these 107 possible future annual U.S. runoff change values, those in the lower 10th quantile represented a 4% decrease in the total annual U.S. runoff and those in the higher 90th quantile represented an 11% increase in the total annual U.S. runoff. These -4% and +11% values were then set as the targets of *Dry* and *Wet* scenarios to represent two extreme runoff cases.
2. Similar to the previous step, the projected change of future annual runoff was calculated for each of the 107 ensemble members and in each of the 134 PCA regions. In each PCA region, the quantiles among the 107 ensemble members were identified.
3. To develop the *Dry* scenario, it was identified that the lower 26th quantile in each PCA can jointly make the 4% decrease in the total annual U.S. runoff; therefore, the 26th quantile in each PCA is summarized as the *Dry* scenario. Similarly, it was identified that the higher 75th quantile in each PCA can jointly make the 11% increase in the total annual U.S. runoff and, hence, the 75th quantile in each PCA was summarized as the *Wet* scenario (see both *Dry* and *Wet* scenarios in Figure B-10). While this process seems a bit counterintuitive, it was needed because of the spatial heterogeneity in each climate simulation (i.e., it's unlikely that the entire U.S. runoff will be consistently projected to increase or decrease in all regions). Without this summarization process, the ReEDS simulation for each of the 107 climate projections would need to be repeated, which was not feasible for the scope of *Hydropower Vision*.
4. Similar to step 2, the projected change of future runoff in each season (spring, summer, fall, and winter following ReEDS modeling definition) was calculated for each ensemble member in each PCA region. The multimodel median seasonal runoff change was then identified for each PCA region.

16. A detailed comparison of these downscaled hydroclimate projections can be found in Kao et al. (2016).

5. To assign the projected seasonal runoff change for the *Dry* scenario, the median seasonal runoff changes calculated in step 4 were used as the basis. In each PCA, the seasonal runoff changes (across four seasons) were consistently reduced until they jointly made the annual runoff change set for the *Dry* scenario in step 3. This process was repeated for the *Wet* scenario. The results are shown in figures B-11 and B-12. This process ensures that the projected change in all seasons was consistent with the projected annual change (e.g., to maintain the total runoff mass balance).
6. The average rates of change in the *Wet* and *Dry* scenarios were applied at an annual level in the ReEDS modeling so that each progressive ReEDS solve year and each BA experienced an incrementally wetter (or drier) climate as represented in annual and seasonal capacity factors.

Figures B-10 through B-12 illustrate the resulting magnitude and regionality of changes in water availability in the *Wet* and *Dry* scenarios. Water availability is quantified as the annual rate of change.

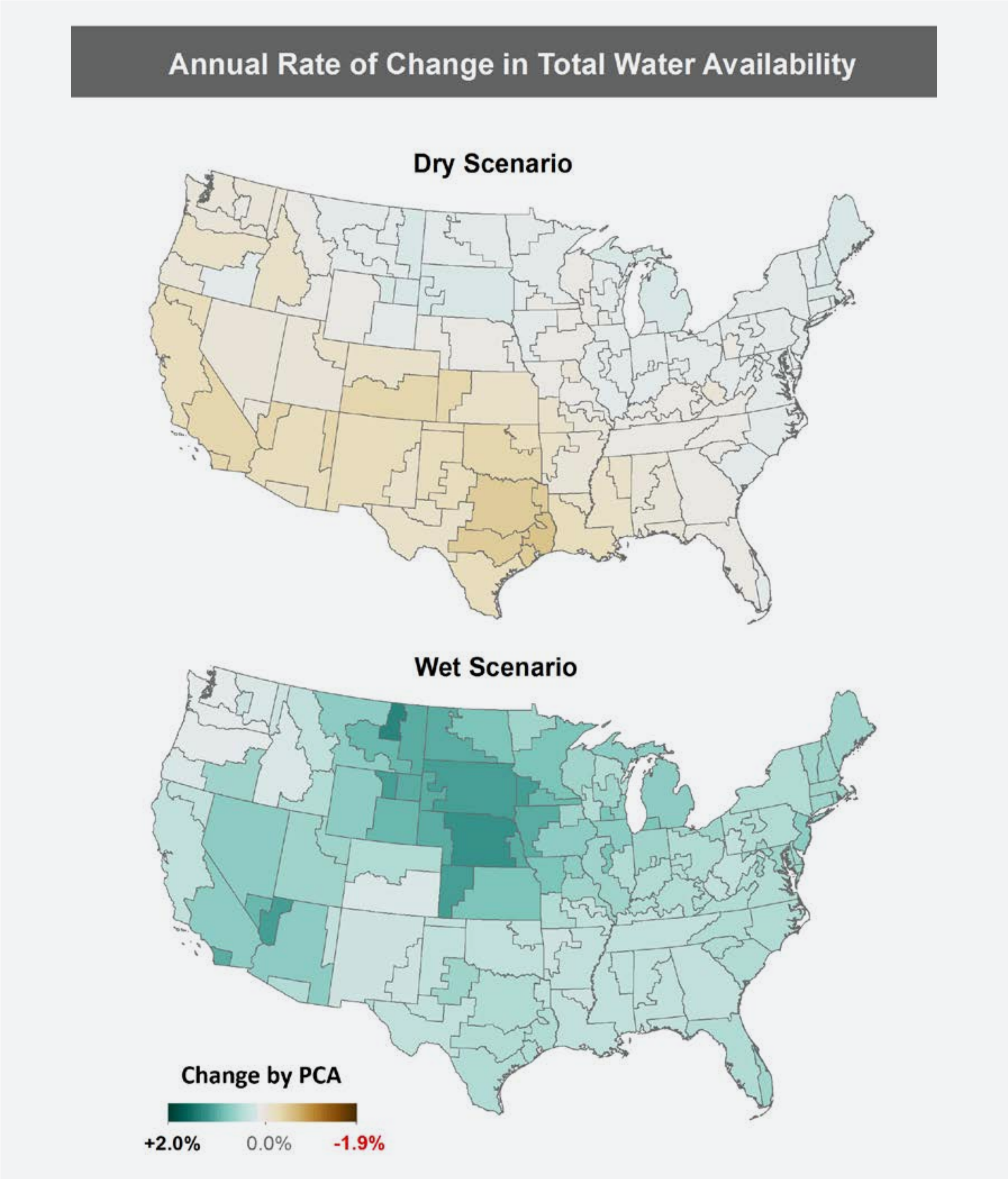


Figure B-10. Average annual change in runoff available for run-of-river hydropower generation by ReEDS balancing area

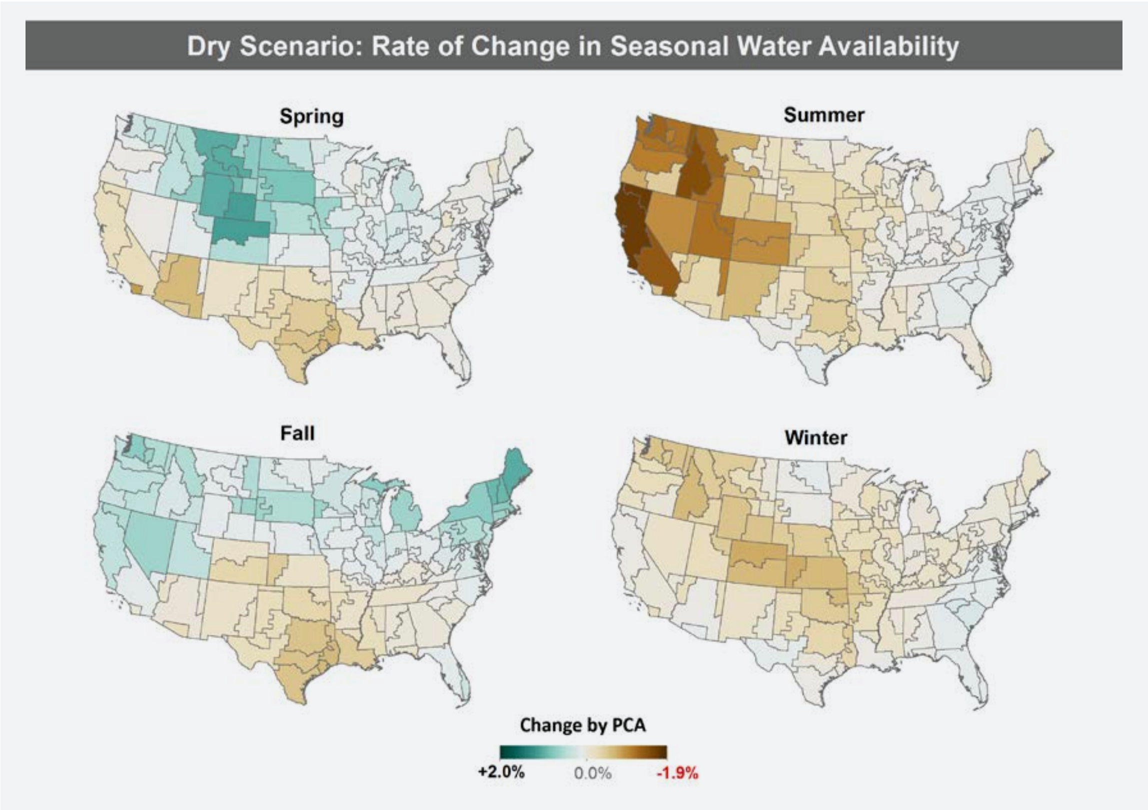


Figure B-11. Average annual change in seasonal runoff available for run-of-river hydropower generation by ReEDS balancing area in *Dry* scenarios

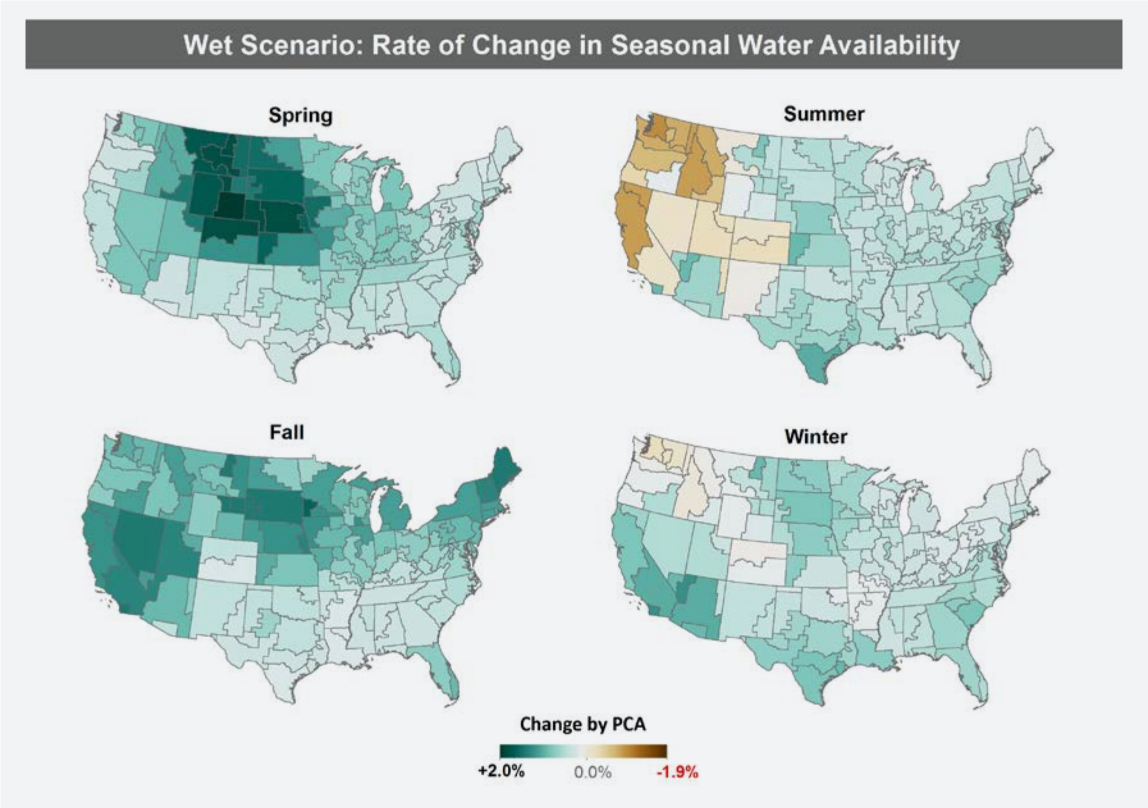


Figure B-12. Average annual change in seasonal runoff available for run-of-river hydropower generation by ReEDS balancing area in *Wet* scenarios

At a national scale, the average rates of change in the *Wet* scenario project an 11% increase in runoff in 2030 and a 22% increase in total runoff in 2050. The *Dry* scenario envisions an average decrease in water availability of 4% in 2030 and 8% in 2050.

The wet conditions see a modest increase in runoff (and subsequently hydropower capacity factor) across the United States, with the largest increases concentrated in the plains states. Under dry conditions, there are small decreases in runoff in the West and Southwest and minimal runoff increases throughout the rest of the country. However, both water-availability scenarios exhibit stark seasonal changes in summer runoff across the West, which will have large negative impacts on the relative value of generation from new projects developed in these regions. In ReEDS, the capacity value of nondispatchable hydropower (including new NSD and NPD deployment and some of the existing fleet) is dependent on summer capacity factor. As changes in average water availability increase through time in the *Hydropower Vision* sensitivity scenarios, the capacity value from these projects decreases accordingly (all else being equal).

These scenarios do not resolve the complex relationship within the existing storage fleet among water-storage capabilities, competing uses, and generation capability. Addressing these important interdependencies to accurately model the true seasonal and annual impact of climate change on the existing fleet will require additional research.

B.10 Hydropower Environmental Attribution

The ReEDS model identifies economically favorable hydropower development under multiple constraints and assumptions; however, these exclude environmental considerations. In conjunction with *Hydropower Vision* stakeholders, nine major types of environmental considerations were identified, five of which could be addressed using spatial data (see Table B-5). The remaining four categories are complex products of site-specific factors. Spatial environmental datasets relevant to hydropower planning were identified by McManamay et al. (2015) and were assigned to each of the spatial environmental consideration categories (see Table B-5) [25]. Figure B-14 features examples of two of the spatial datasets used to explore environmental considerations. Of particular note, the NSD potential was previously screened to remove sites overlapping Wild and Scenic Rivers, National Parks, and Wilderness Areas; thus, those environmental datasets were not included in the analysis, as all potential overlapping them is excluded from the *Hydropower Vision* supply curves.

Table B-5. Environmental Consideration Categories and Data Approximations[a]

Environmental Consideration Category	Geospatial Data Layer
Sensitive Ecological Communities	• Critical Habitat • Species of Concern[b] • Diadromous Fish
High-Value Rivers and Protected Areas	• Gap 1 & 2 Protected Lands[c] • National Rivers Inventory • Northwest Power and Conservation Council Protected Areas • National Fish Habitat Partnership Disturbance Index
Ocean Connectivity	• Connection to Estuary
Additional Spatial Layers Available	
Existing Water Quality Issues	• 303d Impaired Waterbodies
Recreation	• Fishing Access/Boat Ramp • Kayak/Rafting Access
Nonspatial Layers	
Flow Regime	• Resource characteristics
Sediment	• Resource characteristics
Water Quality	• Resource characteristics
Water Footprint	• Resource characteristics

a. Because of uncertainties in the spatial representation of environmental features and the potential for cascading effects of hydropower development across landscapes and riverscapes, spatial buffers of varying sizes were used to associate hydropower development with different environmental characteristics (such as those presented in Table B-5).

b. Includes aquatic species (fish, mussels, and crayfish) that are listed under the Endangered Species Act as endangered, threatened, candidates for listing, proposed for listing, or of concern; or those listed by the International Union for Conservation of Nature as near threatened, vulnerable, endangered, or critically endangered.

c. Missing text for this note.

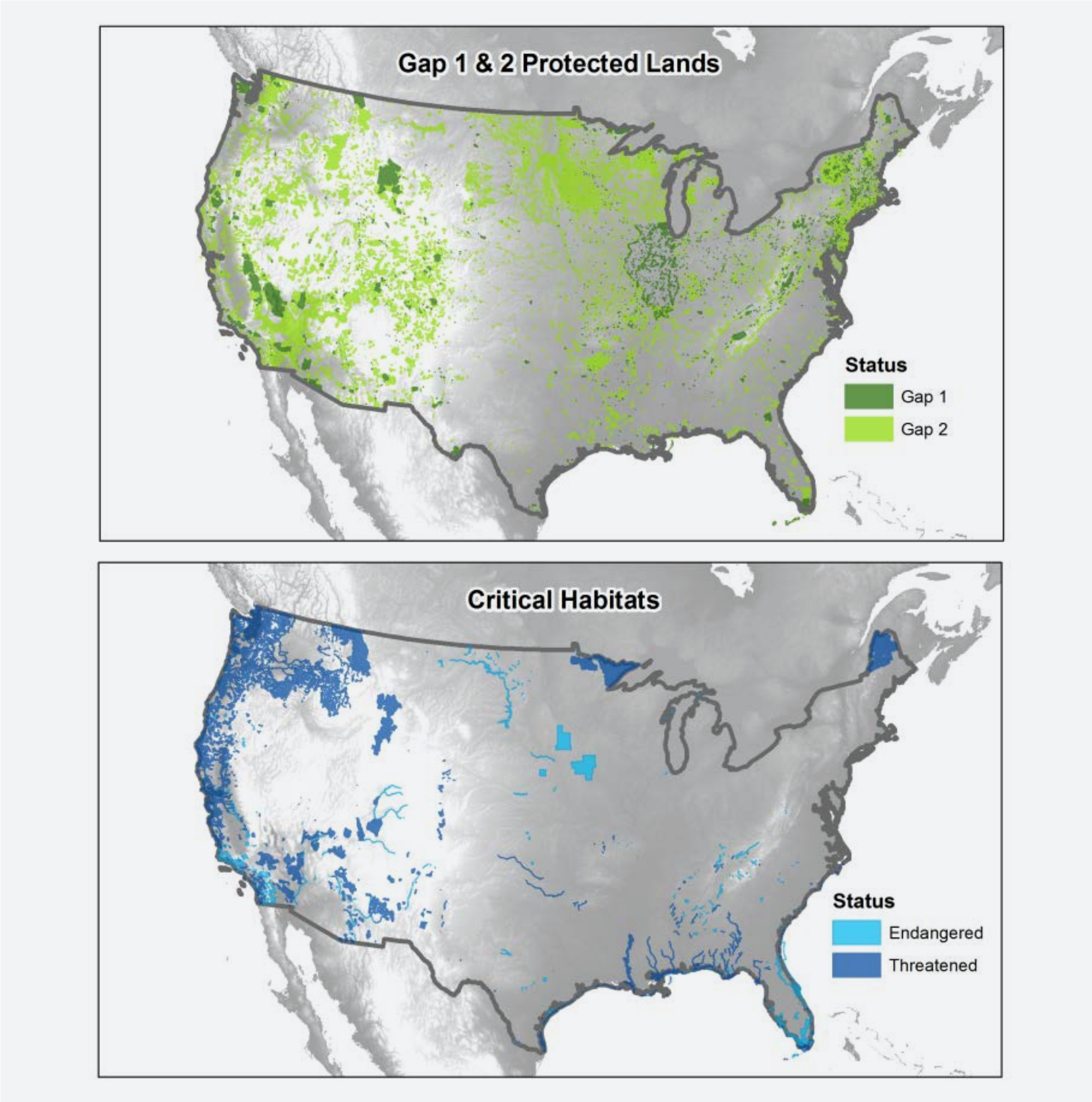


Figure B-14. Spatial distribution of two selected environmental considerations

From the data described in Table B-5, eight ReEDS modeling scenarios were constructed to explore the environmental considerations:

1. **Critical Habitats:** NSD development is avoided in ecologically sensitive areas as defined by their designation as critical habitat. The data for this consideration was provided by the U.S. Fish and Wildlife Service, but also includes species managed by other U.S. agencies.
2. **Ocean Connectivity:** NSD development is avoided at locations where such development would disturb existing river connectivity to the ocean. Connectivity in this context is extended to reaches on which data for artificial downstream passage exists—either through explicit passage technology or implicitly through navigation locks. This layer has been developed uniquely for the *Hydropower Vision* analysis.

3. **Migratory Fish Habitat:** NSD development is avoided on reaches where potamodromous and diadromous fish species are likely to be present, based on ocean connectivity and/or reach characteristics such as length and average annual flow rates. This layer has been developed uniquely for the *Hydropower Vision* analysis.
4. **Species of Concern:** NSD deployment is avoided on reaches where aquatic species (fish, mussels, and crayfish) of concern are known to exist. These species include those listed under the Endangered Species Act as endangered, threatened, candidates for listing, proposed for listing, or of concern; or those listed by the International Union for Conservation of Nature as near threatened, vulnerable, endangered, or critically endangered. This layer has been developed uniquely for the *Hydropower Vision* analysis.
5. **Protected Lands:** Areas with formal protections as designated by U.S. Geological Survey Gap Analysis Program[17] Status 1 or 2 are avoided for development. Gap Analysis Program 1 and 2 designations cover a variety of areas, ranging from state and local parks to formal conservation areas managed explicitly for species preservation.
6. **National Rivers Inventory:** Development on potentially high-value river systems is avoided as approximated by placement on the National Rivers Inventory. Note that potential located along Wild and Scenic Rivers is already excluded in the base *Hydropower Vision* supply curves because of statutory limitations.
7. **Low Disturbance Rivers:** Development on stream reaches that are currently minimally altered from their natural state as categorized by the National Fish Habitat Action Plan as having low or very low levels of disturbance.
8. **Environmental Composite (All Combined):** This scenario explores the combined influence of the prior seven considerations and serves to illustrate that accommodating the wide variety of existing values of uses of reaches with NSD potential is essential for realizing growth.

The intent of these scenarios is not to assert that hydropower development in these areas is not possible. Instead—in light of the modeling limitations outlined in Section 3.1—these scenarios help illustrate the central importance of achieving NSD growth by accommodating and complementing the many other values of rivers.

17. The U.S. Geological Survey Gap Analysis Program is an effort to catalogue and spatially document lands afforded formal protection designations by federal, state, local, and private owners.

Appendix B References

[1] U.S. Bureau of Reclamation. 2012. Site Inventory and Hydropower Energy Assessment of Reclamation Owned Conduits: Supplement to the "Hydropower Resource Assessment at Existing Reclamation Facilities Report." Prepared by United States Department of the Interior, Bureau of Reclamation, Power Resources Office, Denver, Colorado March 2012. Accessed July 5, 2016. *http://www.usbr.gov/power/CanalReport/index.html*.

[2] Kane, M. 2005. California Small Hydropower and Ocean Wave Energy Resources. California Energy Commission. *CEC-500-2005-074.* Accessed July 5, 2016. *http://www.energy.ca.gov/2005publications/CEC-500-2005-074/CEC-500-2005-074.PDF*

[3] Allen, G. S., Fay, C. N., Matys, E. 2013. In-Conduit Hydropower Project—Phase I Report. Alden Research Laboratory. Accessed July 5, 2016. *http://cdnassets.hw.net/2e/fd/58ca4ccf465ab32ebb17ebc4c588/hydrop1.pdf*

[4] Colorado Department of Agriculture. 2013. Recommendations for Developing Agricultural Hydropower in Colorado. Accessed July 5, 2016. *https://www.colorado.gov/pacific/sites/default/files/AgHydroRoadmap.pdf*

[5] Montgomery, Watson, Harza. 2009. Hydropower Modernization Initiative, Phase I, Needs and Opportunities Evaluation and Ranking. Report prepared for the U.S. Army Corps of Engineers Northwest Division Hydroelectric Design Center, Contract No. W9127N-08-D-0003, Task Order 0013.

[6] U.S. Bureau of Reclamation. 2010. Assessment of Potential Capacity Increases at Existing Hydropower Plants—Hydropower Modernization Initiative. Prepared for the U.S. Department of the Interior, Bureau of Reclamation, Denver, Colorado, by MWH. October. Accessed July 5, 2016. *http://www.usbr.gov/power/AssessmentReport/USBRHMICapacityAdditionFinalReportOctober2010.pdf*

[7] NHAAP FY15 Existing Hydropower Assets Database" 2015 (internal only)

[8] Hadjerioua, B., Y. Wei, and S. C. Kao. 2012. An Assessment of Energy Potential at Non-Powered Dams in the United States. GPO DOE/EE-0711. Wind and Water Power Program, Department of Energy, Washington, DC. Accessed July 5, 2016. *http://www1.eere.energy.gov/water/pdfs/npd_report.pdf*.

[9] Kao, S.-C, R. A McManamay, K. M Stewart, N. M Samu, B. Hadjerioua, S. T DeNeale, D. Yeasmin, M. FK Pasha, A. A Oubeidillah, and B. T Smith. 2014. "New Stream-Reach Development: A Comprehensive Assessment Of Hydropower Energy Potential In The United States." Accessed July 5, 2016. *http://nhaap.ornl.gov/sites/default/files/ORNL_NSD_FY14_Final_Report.pdf*.

[10] United States Army Corps of Engineers. 1981. An Assessment of Hydroelectric Pumped Storage. National Hydroelectric Power Resources Study. Vol 13. Accessed July 5, 2016. *http://www.iwr.usace.army.mil/Portals/70/docs/iwrreports/IWR019-000001-000517.pdf*

[11] Hall, D. G., Lee, R. D. 2014. Assessment of Opportunities for New United States Pumped Storage Hydroelectric Plants Using Existing Water Features as Auxiliary Reservoirs. *Idaho National Laboratory* Accessed July 5, 2016. *http://hydropower.inel.gov/resourceassessment/d/pumped-storage-hydro-assessment-report-published-version-20mar14.pdf*

[12] O'Connor, P.W., S.T. DeNeale, D.R. Chalise, A. Maloof (2015). Hydropower Baseline Cost Modeling, Version 2. ORNL/TM-2015/471. Oak Ridge, TN: Oak Ridge National Laboratory. Accessed July 5, 2016. *http://hydropower.ornl.gov/docs/publications/ORNL_Hydropower%20Baseline%20Cost%20Development%202015-01-28_OConnor.pdf*

[13] United States Army Corps of Engineer. 2009. Technical Analysis of Pumped Storage and Integration with Wind Power in the Pacific Northwest. MWH Prepared for U.S. Army Corps of Engineers, Northwest Division, Hydroelectric Design Center. Accessed July 5, 2016. *http://www.hydro.org/wp-content/uploads/2011/07/PS-Wind-Integration-Final-Report-without-Exhibits-MWH-3.pdf*

[14] Intergovernmental Panel on Climate Change. 2014. Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp. Accessed July 5, 2016. *https://www.ipcc.ch/report/ar5/syr/*

[15] Ashfaq, M., S. Ghosh, S.-C. Kao, L. Bowling, P. Mote, D. Touma, S. Rauscher, and N. Diffenbaugh. 2013. Near-term acceleration of hydroclimatic change in the western U.S., J. Geophys. Res. – Atmos., 118, 10,676–10,693, doi:10.1002/jgrd.50816. Accessed July 5, 2016. *http://onlinelibrary.wiley.com/doi/10.1002/jgrd.50816/full*

[16] Sale, M.J., S.-C. Kao, M. Ashfaq, D.P. Kaiser, R. Uría Martínez, C. Webb, and Y. Wei. 2012. Assessment of the Effects of Climate Change on Federal Hydropower, Technical Memorandum 2011/251, Oak Ridge National Laboratory, Oak Ridge, TN. Accessed July 5, 2016. *http://nhaap.ornl.gov/sites/default/files/9505_FY12_Assessment_Report.pdf*

[17] Kao, S.-C., M.J. Sale, M. Ashfaq, R. Uría Martínez, D. Kaiser, Y. Wei, and N.S. Diffenbaugh. 2015. Projecting changes in annual hydropower generation using regional runoff data: an assessment of the United States federal hydropower plants, Energy, 80, 239–250, doi:10.1016/j.energy.2014.11.066. Accessed July 5, 2016. *http://www.sciencedirect.com/science/article/pii/S0360544214013218*

[18] Brakebill, J.W., D.M. Wolock, and S.E. Terziotti. 2011. Digital hydrologic networks supporting applications related to spatially referenced regression modeling, J. Am. Water Resour. Assoc., 47(5), 916-932, doi:10.1111/j.1752-1688.2011.00578.x. Accessed July 5, 2016. *http://www.ncbi.nlm.nih.gov/pmc/articles/PMC3307631/*

[19] Wood, A.W., E.P. Maurer, A. Kumar, and D.P. Lettenmaier. 2002. Long-range experimental hydrologic forecasting for the eastern United States, J. Geophys. Res. – Atmos., 107(D20), 4429, doi:10.1029/2001JD000659. Accessed July 5, 2016. *http://onlinelibrary.wiley.com/doi/10.1029/2001JD000659/full*

[20] Ashfaq, M., L.C. Bowling, K. Cherkauer, J.S. Pal, and N.S. Diffenbaugh. 2010. Influence of climate model biases and daily-scale temperature and precipitation events on hydrological impacts assessment: A case study of the United States. J. Geophys. Res. – Atmos., 115, D14116, doi:10.1029/2009JD012965. Accessed July 5, 2016. *http://onlinelibrary.wiley.com/doi/10.1029/2009JD012965/full*

[21] Brekke, L., B.L. Thrasher, E.P. Maurer, and T. Pruitt. 2013. Downscaled CMIP3 and CMIP5 climate and hydrology projections: Release of downscaled CMIP5 climate projections, comparison with preceding information, and summary of user needs. U.S. Department of the Interior, Bureau of Reclamation, Technical Services Center, Denver, CO. Accessed July 5, 2016. *http://gdo-dcp.ucllnl.org/downscaled_cmip_projections/dcpInterface.html*

[22] Kao, S.-C., M. Ashfaq, B. S. Naz, R. Uría Martínez, D. Rastogi, R. Mei, Y. Jager, N. M. Samu, and M. J. Sale. 2016. The Second Assessment of the Effects of Climate Change on Federal Hydropower. ORNL/TM-2015/357. Oak Ridge National Laboratory, Oak Ridge, Tennessee, pending public release upon the delivery of the companion DOE report to Congress.

[23] Liang, X., D.P. Lettenmaier, S.J. Burges, and E.F. Wood. 1994. A simple hydrologically based model of land surface water and energy fluxes for general circulation models. J. Geophys. Res. – Atmos., 99, 14415–14428, doi:10.1029/94JD00483. Accessed July 5, 2016. *http://onlinelibrary.wiley.com/doi/10.1029/94JD00483/abstract*

[24] Liang, X., D.P. Lettenmaier, and E.F. Wood. 1996. Surface soil moisture parameterization of the VIC-2L model: evaluation and modification. Global Planet. Change, 13, 195–206, doi:10.1016/0921-8181(95)00046-1. Accessed July 5, 2016. *http://www.sciencedirect.com/science/article/pii/0921818195000461*

[25] McManamay, RA, N Samu, SC Kao, MS Bevelhimer, SC Hetrick. 2015. A multi-scale spatial approach to address environmental impacts of small hydropower development. Environmental Management 55: 217-243. Accessed July 5, 2016. *http://link.springer.com/article/10.1007%2Fs00267-014-0371-2*

[26] Hall, D.G., Hunt, R.T., Reeves, K.S., and Carroll, G.R. Estimation of Economic Parameters of U.S. Hydropower Resources. INEEL/EXT-03-00662. Accessed July 5, 2016. *http://www1.eere.energy.gov/wind/pdfs/doewater-00662.pdf*

[27] National Research Council. 2012. "Corps of Engineers Water Resources Infrastructure: Deterioration, Investment, or Divestment?" National Research Council. Washington, DC: The National Academies Press, 2012. Accessed July 5, 2016. *http://dels.nas.edu/Report/Corps-Engineers-Water-Resources-Infrastructure/13508*

[28] U.S. Bureau of Reclamatio). 2011. Hydropower resource Assessment at Existing Reclamation Facilities. U.S. Department of the Interior, Bureau of Reclamation, Power Resources Office. Denver, CO. March 2011. Accessed July 5, 2016. *http://www.usbr.gov/power/AssessmentReport/*

This page is intentionally left blank

Appendix C: *Hydropower Vision* Future Technology Cost Assumptions

C.1 Overview and Introduction

A key step in assessing the potential bounds for the growth of hydropower involved making careful and defensible choices of possible cost trajectories for new development. However, the modeling and projection of hydropower costs is uniquely difficult compared to most other generation technologies. Site- and location-specific factors drive overall $/kW capital costs, particularly the presence of existing infrastructure (such as a non-powered dam), as well as site-specific hydrology and geology. Hydropower projects may also benefit from distinct cost economies of scale for both project size and design factors, such as hydraulic head.

Given these factors, a survey of other studies and existing projections found little agreement and even less certainty in future cost estimates. Many, but not all, studies show that the capital costs for the same hydropower site are essentially flat until 2050 (in constant 2014 dollars), with the remainder predicting both increases and decreases. The largest projected cost decrease is estimated at 15% to 30% by 2030. Because of the limited insight available from other studies and the fact that hydropower is generally considered to be a mature technology, a range of future cost outcomes was developed from the bottom up, based on potential process or technology improvements.

Three scenarios were implemented for the *Hydropower Vision:* a high-cost (reference) case, a medium-cost case, and a low-cost case, each with increasingly aggressive cost-reduction targets for the individual hydropower resource classes modeled in the *Hydropower Vision* project (Non-Powered Dams [NPDs], New Stream-reach Development [NSD], and Pumped Storage Hydropower [PSH]). Each case uses a mix of inputs based on U.S. Energy Information Administration (EIA) technological learning assumptions, input from a technical team of Oak Ridge National Laboratory (ORNL) researchers, and the experience of expert hydropower consultants. The reference case is based entirely on EIA assumptions, while the medium- and low-cost cases reflect 2035 cost targets developed by the technical team. The 2035 targets are only intended to provide magnitude-of-order cost reductions deemed to be at least conceptually possible and are meant to stimulate a broader discussion with the hydropower industry and its stakeholders that will be necessary to the future of cost reduction in the hydropower industry.

This appendix presents the magnitude, timing, and rationale for the future cost assumptions used in the modeling runs of the *Hydropower Vision* project. Section C.2 presents the complete set of future cost assumptions. Section C.3 documents the baseline assumptions and technological or process-improvement pathways to arrive at the 2035 conceptual cost targets. Section C.4 presents the results of a survey of hydropower cost assumptions in alternative studies and analyses to place the *Hydropower Vision* assumptions in the context of the broader assumptions in use by the energy modeling community.

C.2 Summary of Future Cost Assumptions

Figure C-1 illustrates the magnitude and timing of future cost reductions used in the *Hydropower Vision* scenarios. Costs are shown on a 2-year basis consistent with the time steps employed by the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) used to model future *Hydropower Vision* scenarios. The overall reductions are summarized in tables C-1 and C-2.

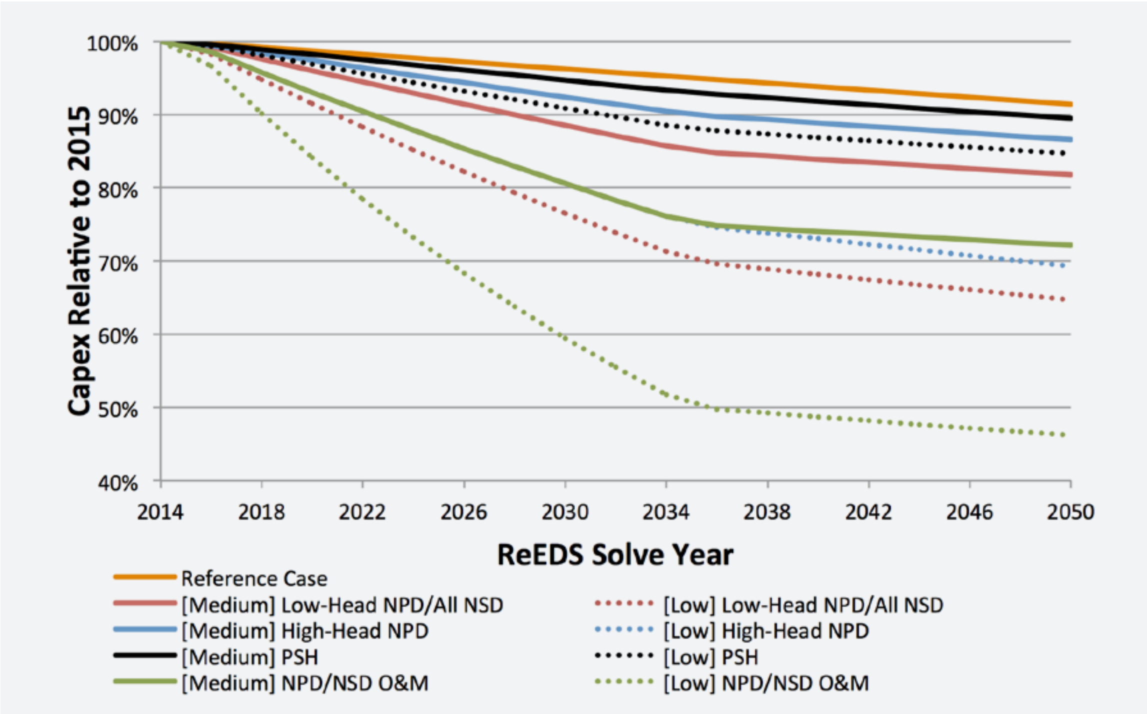


Figure C-1. Visualization of technology cost trajectories

Table C-1. Total Cost Reductions

<table>
<tr><th rowspan="2">Resource/Cost Category</th><th colspan="2">Reference Case (relative to 2015)</th><th colspan="2">Medium-Cost Case (relative to 2015)</th><th colspan="2">Low-Cost Case (relative to 2015)</th></tr>
<tr><th>by 2035</th><th>by 2050</th><th>by 2035</th><th>by 2050</th><th>by 2035</th><th>by 2050</th></tr>
<tr><td>Low-Head NPD/NSD</td><td rowspan="3">5%</td><td rowspan="3">8.6%</td><td>15%</td><td>18.2%</td><td>30%</td><td>35.3%</td></tr>
<tr><td>High-Head NPD</td><td>10%</td><td>13.4%</td><td>25%</td><td>32.7%</td></tr>
<tr><td>Utility-Scale PSH</td><td>7%</td><td>10.5%</td><td>12%</td><td>15.3%</td></tr>
<tr><td>O&M (NPD/NSD)</td><td rowspan="2" colspan="2">None</td><td>25%</td><td>27.8%</td><td>50%</td><td>53.8%</td></tr>
<tr><td>Other O&M</td><td colspan="2">None</td><td colspan="2">None</td></tr>
</table>

Table C-2. Annualized Cost Reductions

Resource/Cost Category	Reference Case	Medium-Cost Case		Low-Cost Case	
	2015–2050	2015–2035	2036–2050	2015–2035	2036–2050
Low-Head NPD/NSD	0.256%	0.809%	0.256%	1.768%	0.525%
High-Head NPD		0.525%	0.256%	1.428%	0.525%
Utility-Scale PSH		0.362%	0.256%	0.637%	0.256%
O&M (NPD/NSD)	None	1.428%	0.256%	3.406%	0.525%

C.2.1 Non-Powered Dams and New Stream-Reaches

The medium-cost cases represent aggressive equipment standardization efforts and the widespread implementation of value engineering and design/construction best practices using generally conventional technology. Evolutionary improvements to the licensing process, such as the alignment of Federal Energy Regulatory Commission (FERC) licensing and the Corps 408 process, are assumed to occur; however, there is no step change in the prevailing licensing paradigm. The operation and maintenance (O&M) reductions are similarly within the realm of existing knowledge, largely the result of achieving operational economies of scale; exploring alternative staffing and contracting mechanisms for a smaller, distributed fleet; and the widespread use of existing automation regimes at new small facilities.

The low-cost cases reflect the gains achievable when pushing new technologies to the limits of potential. Modularity (in both civil structures and power-train design), advanced manufacturing techniques, and materials all come into play in the direct reduction of capital costs. The major O&M reductions are the product of a complete rethinking of how to design, operate, and maintain a hydropower facility with O&M as a key driver. Modularity, advanced materials and components, and the implementation of standardized “smart” automation and remote monitoring systems are the key elements here. Hydropower is typically regularly and preventively maintained—moving to a system with more reliable, advanced-material modular components that can be immediately replaced and remotely serviced only as needed on condition-monitored basis would be a major shift in how O&M is performed. One conceptual example would be “plug-and-play” power-train modules that could easily be removed with a small crane, a replacement dropped in, and the old unit refurbished for use at a different, modular site.

C.2.2 Utility-Scale Pumped Storage

Incremental improvement in utility-scale PSH costs is thought possible, although at nowhere near the magnitude of that available for newer, smaller (and more expensive) conventional hydropower sites. Modular PSH technologies may have more substantial cost-reduction potential, but are not modeled in ReEDS for lack of resource data.

The medium-cost case represents evolutionary change based on continued process, contracting, design, and technological improvements within the conventional hydropower and dam construction industries.

The low-cost case additionally factors in potential cost reductions from the incorporation of new technologies (e.g., penstock materials) where applicable and the leveraging of advancements in other construction industries.

O&M reductions are thought to be minimally impactful in a modeling context for PSH plants given their size, low costs, and the high value of their availability. No PSH O&M cost reductions are proposed, as they are likely independent of a modular or conventional project, and in the early phase of modular development, O&M costs could be slightly higher.

C.2.3 Context for the Reference Case and Post-2035 Cost Reductions

The pre-2035 medium- and high-cost reductions are order-of-magnitude estimates based on industry expertise and identifiable potential future technology and process advancements. This does not foreclose that more modest cost reductions in a reference (business-as-usual) case may occur or, conversely, the potential for further cost reductions post-2035. Instead, generalized assumptions from the EIA are adapted to the reference case and each cost reduction scenario post-2035 .

EIA implements a technological learning framework by which costs are reduced based on the volume of resource deployed to approximate industry improvements from development experience. Unfortunately, given that these costs are determined endogenously within the EIA's National Energy Modeling System (NEMS) capacity-expansion decision, these costs cannot be directly used to estimate potential cost reductions. However, as a backstop, for all technologies, EIA assumes a minimum cost-reduction factor ("minimum total learning") to capture the potential impacts of research and development (R&D) and international development experience. Mature industries, such as hydropower or coal (and even land-based wind), are assumed to experience minimum cost reductions of 5% over a 20-year period. Less-mature technologies, such as geothermal or Generation III+ nuclear are assumed to experience minimum cost reductions of 10% over a 20-year period; even less-mature technologies, such as offshore wind, experience a 20% reduction. These 5% and 10% minimum learning factors are used to account for generalized cost reductions in the *Hydropower Vision* hydropower supply curves.

In the reference case, the minimum technological learning rate is assumed across the entire study period. Consistent with NEMS Electricity Market Module assumptions, no O&M cost reductions are predicted. As the NSD and NPD low-cost cases are predicated on substantial technological advancement, the factor of 10% over 20 years is used. As the NSD and NPD medium-cost and PSH low-cost cases rely on maximizing the use of conventional technologies (a mature industry), a factor of 5% over 20 years is assumed. No additional cost reduction is assumed in the medium-cost PSH case, as any additional reductions would likely be based on the actual demand for modular pumped turbine units (e.g., cost reductions in equipment technology may lag until industry demand is realized). As a general note, actual levels of cost reduction and learning would be influenced by future domestic-demand factors (e.g., monetization of benefits, need for capacity, and energy), but sustained R&D and international growth in the small hydropower and PSH markets could help drive some cost reductions in U.S. projects even beyond 2035.[1]

As EIA learning factors are over a 20-year period, a 15-year equivalent is calculated to determine the cost reduction possible between 2035 and 2050. Consequently, a 5% reduction by 2055 is equivalent to a 3.8% reduction by 2050 (relative to 2035), and a 10% reduction by 2055 is equivalent to a 7.8% reduction by 2050 (relative to 2035). Note that the absolute magnitude of the cost reduction from post-2035 learning and R&D relative to the original cost in 2015 is dependent on the amount of cost reduction achieved by 2035.

C.3 Hydropower Project Opportunities for Cost Reduction

ORNL was tasked to review the knowledge base of hydropower and pumped-storage projects and forecast opportunities to reduce costs for small and modular pumped storage and small hydropower projects that may be built in the next 5 to 20 years. This effort is intended to provide the U.S. Department of Energy (DOE) defensible estimates and trends of potential development cost savings over a mid- to long-term horizon. ORNL, with consultation from industry partners MWH (modular pumped storage) and Knight Piesold (small hydro), has summarized the typical project characteristics and potential future cost-reduction opportunities applicable to various classes of hydropower.

1. *http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf*

C.3.1 Low-Head NPDs (Below 20 m/65.6 ft)

Low-head NPDs are classified as having design heads below 20 m (65.6 ft) and typically exhibit the following characteristics:

- 1 MW to 10 MW
- New/rehabilitated intake structure
- Little, if any, new penstock
- Axial-flow or Kaplan turbines (2-4 units)
- New powerhouse (indoor)
- New/rehabilitated tailrace
- Minimal new transmission line (<5 miles, if required)
- 35% to 60% capacity factor.

Scenarios being planned for near-future installation that demonstrate cost-reduction capability:

- 1 MW to 10 MW (fits recent FERC licensing reforms; <10 MW small-hydro exemption)
- Use of existing intake structure with minimum changes
- Penstock, only where needed; many cases do not need a penstock
- Reduced civil costs may be achieved by eliminating a traditional powerhouse and using modularized components
  - Simple, modular, submerged, reinforced-concrete vault (possibly precast concrete)
  - Turbine units mounted in modular spillway gates or control gates
  - Other modular configurations not requiring major structures
- New electromechanical (E/M) technology
  - Axial flow turbine/generator combinations (with traditional and composite construction)
  - Simplify control system to basic configuration
- Use existing tailrace
- Use existing electrical bus and step-up transformer (only replace if needed)
- Use existing distribution or transmission line (reconductor if needed)
- 35% to 60% capacity factor
- Capital expenditure (CAPEX) $1,800 to $2,300 per kW complete (overall CAPEX reduction between 15% and 30%).

Table C-3 shows the expected CAPEX breakdowns at existing low-head dams. Since April 2004, FERC and federal agencies (such as the U.S. Army Corps of Engineers, U.S. Fish and Wildlife Service, and others) have streamlined some of the licensing costs. This is reflected in the dams' engineering and approvals. As such, recent projects have benefited from reduced licensing costs, while projects developed before 2004 have generally higher FERC licensing costs. In addition, FERC Order 800, issued in October 2014, raised the 5-MW small hydropower exemption to 10 MW for small hydropower projects at existing dams utilizing a natural water feature for hydraulic head, or for existing projects with proposed capacity additions of 10 MW or less. Also, a parallel process has been in place by the U.S. Bureau of Reclamation for streamlining hydropower additions at existing Reclamation facilities.

Table C3. Expected CAPEX Breakdowns for New-Technology Hydropower at Existing Dams

Cost Component	Average	Range
Civil Cost	25%	20% to 30%
E/M Cost	53%	50% to 56%
Transmission	12%	10% to 14%
Engineering & Approvals	10%	8% to 12%

C.3.2 High-Head NPD (Above 20 m/65.6 ft)

High-head NPDs are classified as having design heads above 20 m (65.6 ft) and typically exhibit the following characteristics:

- 5 MW to 30 MW
- New/rehabilitated intake structure
- New penstock
  - <500 ft of steel penstock (typically), if required
- Francis turbines (1-3 units)
- New powerhouse(indoor)
- New/rehabilitated tailrace
- Minimal new transmission line (up to 15 mi, if required)
- 35% to 60% capacity factor.

Scenarios being planned for installation in the near future that demonstrate cost-reduction capability have the following characteristics:

- 5 MW to 30 MW
  - Most achievable market is under 10 MW as a result of FERC licensing reforms
- Rehabilitated existing intake structures
  - Use existing intake structure with minimum changes
  - Use value methodologies that avoid risk and use of expensive cofferdams
  - Use updated low-cost techniques for concrete rehabilitation
- New penstock
  - <500 ft of penstock
  - Consider lower-cost alternatives to steel penstock
- Water-to-wire turbines (look for high efficiency over a range of heads and flows, and increased operational life), which require minimal or alternative civil works
  - Standard Kaplan turbine/generator combinations are limited to the 3-MW to 10-MW range (in some cases, multiple units may be required); powerhouse required is a scaled-down version of a traditional powerhouse
  - Axial-flow turbine/generator combinations are limited to lower capacities (below 5 MW) within the 3-MW to 30-MW range (in some cases, multiple units may be required); a nontraditional powerhouse may be used to reduce the need for excavation and civil works
- Crossflow turbine water-to-wire packages:
- Typically cost 25% less than Francis turbines and are easier to maintain
- Are limited to capacities below 8 MW within the 3-MW to 30-MW range (in some cases, two or more crossflow units are needed)
- Require smaller powerhouse structures
- Are above tailwater elevation
- Do not require tailwater modifications
- Lead to reduced project cost
- Modularize the water-to-wire equipment (install as much as possible in shop rather than field)
- Simplify control system to basic configuration
- Reduce civil costs by eliminating a traditional powerhouse and using modularized components
- Simple, modular, submerged reinforced-concrete vault (possibly precast concrete)
- Value-engineering techniques to lower construction cost
- Use existing tailrace (repair or modify only if needed)
- Use existing or extension of existing electrical bus and step-up transformer (only replace if needed); because all dams have some type of electrical service, it is less costly to rebuild or upgrade than to build completely new
- Use existing distribution or transmission line (reconductor if needed)
- 35% to 60% capacity factor
- CAPEX $1,500 to $3,200 per kW complete (overall CAPEX reduction between 10% and 25%).

Table C4 Expected CAPEX Breakdowns for New-Technology Hydropower at Existing Dams

Cost Component	Average	Range
Civil Cost	34%	25% to 43%
E/M Cost	45%	38% to 52%
Transmission	11%	10% to 13%
Engineering & Approvals	10%	8% to 12%

Table C-4 shows the expected CAPEX breakdowns at existing high-head dams. Since April 2004, FERC and federal agencies (such as the U.S. Army Corps of Engineers and the U.S. Fish and Wildlife Service) have streamlined some of the licensing costs. This is reflected in the dams' engineering and approvals. As such, recent projects have benefited from reduced licensing costs, while projects developed before 2004 have generally higher FERC licensing costs. In addition, FERC Order 800 issued in October 2014 raised the 5-MW small hydropower exemption to 10 MW for small hydropower projects at existing dams utilizing a natural water feature for head or for existing projects with proposed capacity additions of 10 MW or less. Also, a parallel process has been in place by the U.S. Bureau of Reclamation for streamlining hydropower additions at existing Reclamation facilities.

C.3.3 Greenfield/NSD

Greenfield/NSD sites are defined as new hydropower developments along previously undeveloped waterways and typically exhibit the following characteristics:

- 1 MW to 100 MW
- New diversion/intake structure
- New penstock
- Steel with length being head/terrain dependent
- Various turbine selections
- Impulse/Francis are common for recently completed projects
- New powerhouse (indoor)
- New tailrace
- New transmission line
- Up to 15 mi for new projects
- 30% to 80% Capacity Factor.

Scenarios being planned for near-future installation that demonstrate cost-reduction capability have the following characteristics:

- MW to 100 MW
- Most achievable market is under 10 MW as a result of FERC licensing reforms
- Minimize weir and barrage height to enable proper hydraulics at the power intake
- Consider Coanda screen diversion weirs (lower cost than traditional intakes; minimizes affect on river life)
- Modular intake structure
- Avoid use of expensive cofferdams
- Low-impact techniques; minimize riverine impacts
- New penstock
- Use intake canals (canals cost less than penstocks)
- Limit size and length of penstock
- Consider lower-cost alternatives to steel penstock
- Consider alternative water-to-wire turbines (look for high efficiency over a range of heads and flows and increased operational life)
- Consider Pelton/Francis where applicable, but also consider Kaplan, axial flow and crossflow
- Consider a preassembled equipment module
- Shop assembly costs less than field assembly and installation
- It is less expensive to level and align than to assemble many large components
- Standard Pelton water-to-wire arrangements are available with resulting lower cost than custom design machinery
- Standard Kaplan turbine/generator combinations (e.g., Canadian Hydropower Components) are limited to the 3-MW to 10-MW range
- In some cases, multiple units may be required
- Powerhouse required is a scaled-down version of a traditional powerhouse components

- Axial-flow turbine/generator combinations are limited to the lower capacities (below 5 MW) within the 1-MW to 100-MW range
- In some cases, multiple units may be required
- A non-traditional powerhouse may be used
- Crossflow turbine water-to-wire packages:
- Typically cost 25% less than Francis turbines and are easier to maintain
- Are limited to capacities below 8 MW within the 3-MW to 30-MW range (in some cases, two or more crossflow units are needed)
- Require smaller powerhouse structures
- Are above tailwater elevation
- Do not require tailwater modifications
- Lead to reduced project cost
- Simplify control system to basic configuration
- Reduced civil costs may be achieved by eliminating a traditional powerhouse and using modularized
- Simple, modular, submerged, reinforced-concrete vault (possibly precast concrete)
- Value-engineering techniques to lower construction cost
- New tailrace
- Minimize tailrace work
- Consider low-impact tailrace construction techniques
- Avoid expensive cofferdams
- New transmission line
- Up to 15 mi for new projects
- Avoid custom design; use standard modular, predesigned substations and transmission line
- Lower voltage reduces cost
- 30% to 80% capacity factor
- CAPEX $2,200 to $3,600 per kW complete (overall CAPEX reduction between 15% and 30%).

Table C-5 shows the expected CAPEX breakdowns for Greenfield/NSD sites. Since April 2004, FERC and federal agencies (such as the U.S. Army Corps of Engineers and the U.S. Fish and Wildlife Service) have streamlined some of the licensing costs. This is reflected in the dams' engineering and approvals. As such, recent projects have benefited from reduced licensing costs, while projects developed before 2004 have generally higher FERC licensing costs. In addition, FERC Order 800 issued in October 2014 raised the 5-MW small hydropower exemption to 10 MW for small hydropower projects utilizing a natural water feature for hydraulic head, or for existing projects with proposed capacity additions of 10 MW or less.

Table C5 Expected CAPEX Breakdowns for New Technology Hydropower at Greenfield Sites

Cost Component	Average	Range
Civil Cost	43%	35% to 50%
E/M Cost	32%	30% to 35%
Transmission	12%	10% to 14%
Engineering & Approvals	13%	10% to 15%

C.3.4 Utility-Scale PSH (Above 1,000 MW)

A more in-depth exercise was conducted for evaluating the total development and construction costs for an example utility-scale PSH project. While other studies have addressed O&M cost reductions, this assessment instead assumes that the project site has been selected to optimize head: length ratio, reservoir volume, water source for initial charge and makeup, proximity to transmission interconnection, and reduction of technical risks. It also assumes that the project developer has held preliminary discussions with the transmission owner(s) or Independent System Operator/Regional Transmission Organization (ISO/RTO) to confirm that the proposed project has at least one or more transmission points of interconnection (POI). The advantage of early identification of a suggested POI is that project developers could more confidently rank and screen candidate projects and eliminate those with unacceptable transmission interconnection requirements.

Key project costs can typically be broken into the following four categories:

1. Project Development, Planning, Design, and Construction-Supervision Services
2. Permitting and Licensing
3. Civil Construction Cost
4. Electrical, Mechanical, and Hydromechanical Equipment.

Table C-6 shows the expected CAPEX breakdowns and cost reductions associated with utility-scale PSH.

Table C6 Utility-Scale PSH Cost Reduction Breakdown

Project Development Scope Area	Estimated Portion of Total Project Costs	Potential Opportunity for Cost Reduction
Project Development, Planning, Design, and Construction-Supervision Services	5% to 15%	2% to 10%
Permitting and Licensing	3% to 10%	5% to 20%
Civil Construction Cost	40% to 50%	5% to 15%
Electrical, Mechanical, and Hydromechanical Equipment	30% to 40%	5% to 20%
Total Potential Opportunity for Cost Reduction		*7% to 15% (average 11% estimate)*

Considerable opportunities for PSH cost reduction exist and are summarized below:

1. **Project Development, Planning, Design, and Construction Supervision**
   a. Improve and standardize design criteria better adapted to modular projects, resulting in reduced design times.
   b. Use publicly available software and modeling tools as well as online databases and toolboxes that have been recognized by the industry for best practices.
   c. Rank prospective project sites according to key characteristics by regions of the country (i.e., geotechnical characteristics), resulting in optimal site selection based on appropriate risks.
   d. Within regions, rank potential sites according to physical characteristics and quantities, such as hydraulic head, penstock length: head ratio, reservoir volume, open vs. closed system, proximity to existing bulk-power transmission system interconnection for pumping power source and power delivery (not initially included in cost-reduction estimate).
   e. Further time reduction in initial planning and early development phases (not initially included in cost-reduction estimate).
2. **Permitting and Licensing**
   a. Simplify permitting and licensing requirements compared to those required for larger projects.
   b. Work with FERC or other agencies to simplify regulatory compliance processes.
   c. Streamline the scope and time requirements to perform the static and dynamic transmission-voltage and interconnection studies with the transmission owner(s) or ISO/RTO.
   d. Help recognize lower-cost sites to identify and rank prospective project sites according to environmental characteristics regardless of land ownership classification (not initially included in cost-reduction estimate).

3. Civil Construction Cost

a. Use continued technological advancements from dam and hydropower construction industries in concrete mix, compacting methods, and earth-filled dams for reservoirs.

b. Employ water-conductor construction techniques, tunnel boring, standardized tunnel boring machines, and open-cut or surface penstocks (to minimize tunnels).

c. Use advancements from other construction industries such as increased use of 3-D designs, alternative materials (i.e., advanced polyvinyl chloride penstocks for near-surface cut-and-cover conveyance options), and modern anti-corrosion equipment for sea or brackish water.

d. Improve cost estimating and scheduling methods to reduce risks, construction periods, and claims.

4. Electrical, Mechanical, and Hydromechanical Equipment

a. Standardize water-to-wire mechanical and electrical equipment manufacturing, allowing for reduced efficiency with suboptimal hydraulics during the initial phase of the project.

b. Use proven, standard substation and transmission configuration with lower construction costs and a faster installation schedule.

c. Realize cost reductions associated with volume production by standardizing on specific model types, similar to the combustion-turbine industry's use of standard MW ratings to classify generation capacity options.

d. Use simplified design schemes where overall project efficiency may be lower during the initial operation period and a more customized design scheme in 15 to 20 years of operation when the project is paid off. In concept, it would be easier to spend the additional capital for advanced, customized equipment once the project has been online and making money for a period of time.

Table C-7 summarizes the cost-reduction potential associated with each of these areas of opportunity.

In addition to potential reductions in development and construction costs at a specific site, there are other aspects that could further reduce capital costs. For example, the concurrent development and construction of multiple small, modular projects together could generate additional savings. In addition, combining the joint development and construction of modular pumped-storage projects with other renewable energy projects would also bring synergies and savings based on reduced permitting, transmission, and other overlapping needs.

The above suggestions are associated with a traditional way to plan, design, and build projects. Further cost reductions could be achieved under a completely integrated approach. Under this approach, a separate legal entity with a very lean overhead structure composed of a developer/investor, a planner/designer/constructor, and a preferred equipment manufacturer would jointly pursue these small, modular projects. The preferred equipment supplier would have to be able to provide all or most of the E/M equipment at a very competitive price. This integrated approach would help further standardize the complete development process, from planning and licensing through construction, commissioning, and operation.

As civil works are usually designed for a 50- or 100-year economic life and require limited maintenance costs, major civil rehabilitation and E/M replacement costs of a PSH project occur after 15 to 25 years of operation and are typically within 35% to 55% of the original cost. At that time, it would most likely be financially feasible to improve the overall efficiency and performance of the equipment by utilizing the latest technology, increasing reservoir size, and reducing hydraulic losses (e.g., through tunnel lining).

Table C-7. PSH Cost-Reduction Opportunities

Project Development Detailed Scope Area	% of Total Construction Cost	Potential Cost Reduction (% of Item Cost)	
		Low	High
Project Development, Planning, Design, and Construction Supervision			
1.a	5% to 15% (assumed 10%)	2%	10%
1.b		0%	1%
1.c		—	–
1.d		–	–
1.e		–	–
Estimated Average Cost Reduction: 12%			
Regulatory, Permitting, and Licensing			
2.a	3% to 10% (assumed 5%)	10%	15%
2.b		5%	20%
2.c		2%	5%
2.d		–	–
Estimated Average Cost Reduction: 10%			
Civil Construction Cost			
3.a	40% to 50% (assumed 50%)	1%	3%
3.b		2%	5%
3.c		3%	10%
3.d		1%	5%
Estimated Average Cost Reduction: 10%			
Electrical, Mechanical, and Hydromechanical Equipment			
4.a	30% to 40% (assumed 35%)	5%	10%
4.b		1%	3%
4.c		3%	10%
4.d		3%	10%
Estimated Average Cost Reduction: 12%			

C.3.5 Operation and Maintenance Cost Reductions

One additional way to reduce cost is in the expense to operate and maintain a hydropower facility. Unlike thermal stations, which require significant onsite O&M activities, hydropower can often be run remotely, with no onsite O&M staff needed. A central dispatch facility dispatches maintenance workers only when infrequent maintenance is scheduled or required. The tools and spare parts are dispatched with the workers. When a remote-operation alarm is acknowledged, a maintenance worker(s) can be dispatched based on the type of alarm. This reduces time required to diagnose issues. More than 100 stations could be centrally dispatched, resulting in significant O&M cost reductions for a utility. The cost of automation is very small compared to onsite representation of O&M staff.

In the future, the number of small hydropower operators will consolidate, further consolidating O&M activities in an effort to reduce and control operational expenditures. Typically, a cost reduction of >50% can be achieved, with the remote-operation cost often being paid back within 1 year.

C.4 Contemporary Projections of Future Costs for Hydropower Development

For the purposes of electric-sector analysis, hydroelectric power is considered a very mature industry and, in part because of this, many forward-looking studies from organizations including the International Renewable Energy Agency (IRENA), the International Energy Agency (IEA), Rocky Mountain Institute, and Black and Veatch estimate that the capital costs (or levelized $/MWh costs) for a specific type of hydropower site are not expected to decline significantly for 15 to 35 years (from 2012). A number of these studies show that the capital costs ($/kW) for the same hydropower site remain flat until 2050 (in constant 2014 dollars). Some of the studies show increases and a few show potential decreases, with the largest decrease estimated at 15% to 30% by 2030 (depending on capital-cost assumptions).

A complicating factor in estimating future capital-cost changes for hydropower is that the current cost of hydropower facilities varies widely by site and location, as well as by type of facility (very small vs. small vs. large; non-powered dam vs. greenfield vs. pumped storage), and the ranges can be significant (by factor of five or more in some cases). IEA's Energy Technology Systems Analysis Programme and IRENA (IEA – ETSAP and IRENA 2015 hydropower brief gives a sense of the different classifications and the ranges in capital costs used by other analysts today

> ***The investment costs for large hydropower plants (>10 MWe) range from USD 1 050-7 650/kWe (calculated in 2010 USD) and are very site-sensitive. The investment costs of small (1–10 MWe) and very small hydropower plants (VSHP) (≤1 MWe) may range from USD1 000-4 000/ kWe and USD 3 400-10 000/kWe, respectively. Operation and maintenance (O&M) costs of hydropower plants are typically between 1%–4% of annual investment costs. The levelised cost of electricity (LCOE) typically ranges from USD 20-190/MWh for large hydropower plants, from USD 20-100/MWh for small plants and USD 270/ MWh or more for very small plants.***

An additional complicating factor in the tracking of hydropower cost trends and the projection of future costs is that the $/kW capital cost can be expected to rise over time as more attractive sites are utilized first. One difficulty with interpreting cost projections is whether observed increases are due at least in part to supply-curve considerations. As the International Plant Protection Convention (IPCC) (2011) notes, when trying to isolate the historical trends in hydroelectric plants (let alone future costs):

> ***There is relatively little information on historical trends of hydropower cost in the literature. Such information could be compiled by studying a large number of already-implemented projects, but because hydropower projects are so site-specific it would be difficult to identify trends in project component costs unless a very detailed and time-consuming analysis was completed for a large sample of projects. It is therefore difficult to present historical trends in investment costs and LCOE.***

Care must be taken, therefore, when considering cost changes over time to ensure that costs are compared for same plant at the same site (which is not possible in practice, as each plant can be built only once), and also to recognize there will be inherent limits to accuracy in applying percentage or absolute changes to hydropower plants that differ substantially in original cost.

There are published reports and projections that show substantial declines for PV or wind but show no changes whatsoever for hydropower for the same type of facility—though it is sometimes ambiguous as to whether these are in fact deliberate estimates of no change rather than that no estimate has been made. For example a 2012 IRENA study of hydropower stated that when making no estimate of any change over a short period until 2020 (emphasis is bold added to the original):

> *Hydropower is a mature, commercially proven technology and* ***there is little scope for significant cost reductions in the short-to-medium term.*** *Technological innovation could lower the costs in the future,* ***although this will mainly be driven by the development of more efficient, lower cost techniques in civil engineering and works.*** *These improvements and cost reductions in major civil engineering techniques (tunneling, construction, etc.) could help to reduce hydropower investment costs below what they otherwise would be.*
>
> *However, analysis of cost reduction potentials in the literature* ***does not provide a clear picture of any likely trends. Some studies expect slight increases in the range of installed costs, while others expect slight decreases when looking out to 2030 or 2050*** *(EREC/ Greenpeace, 2010; IEA, 2008a; IEA, 2008b; IEA, 2010c; and Krewitt et al., 2009). Part of the problem is that* ***it is difficult to separate out improvements in civil engineering techniques that may reduce costs (which would lower the supply curve) and the fact that the best and cheapest hydropower sites have typically, already been exploited (i.e. we are moving up and along the supply curve).*** *As a consequence of these difficulties, the inconclusive evidence from the literature and the fact that hydropower is a mature technology; no material cost reductions for hydropower are assumed in the period to 2020 in the analysis presented in this paper.*

Costs may also vary widely by country and may be lower in developing countries with lower costs for labor and local construction material. A recent IPCC study commented on the difficulty of knowing whether the cost of hydropower would fall in the future (emphasis is bold added to the original):

> *In the studies included in Box 5.3 and Table 5.7b,* ***there is no consensus on the future cost trend. Some studies predict a gradually lowering cost*** *(IEA, 2008b; Krewitt et al., 2009),* ***some a gradually increasing cost and one no trend*** *(UNDP/UNDESA/WEC, 2004).*
>
> *A reason for this may be the complex cost structure of hydropower plants,* ***where some components may have decreasing cost trends (for example tunneling costs), while others may have increasing cost trends (for example social and environmental mitigation costs).*** *This is discussed, for example, in WEA-2004 (see Box 5.3) where the conclusion is that these factors probably balance each other.*

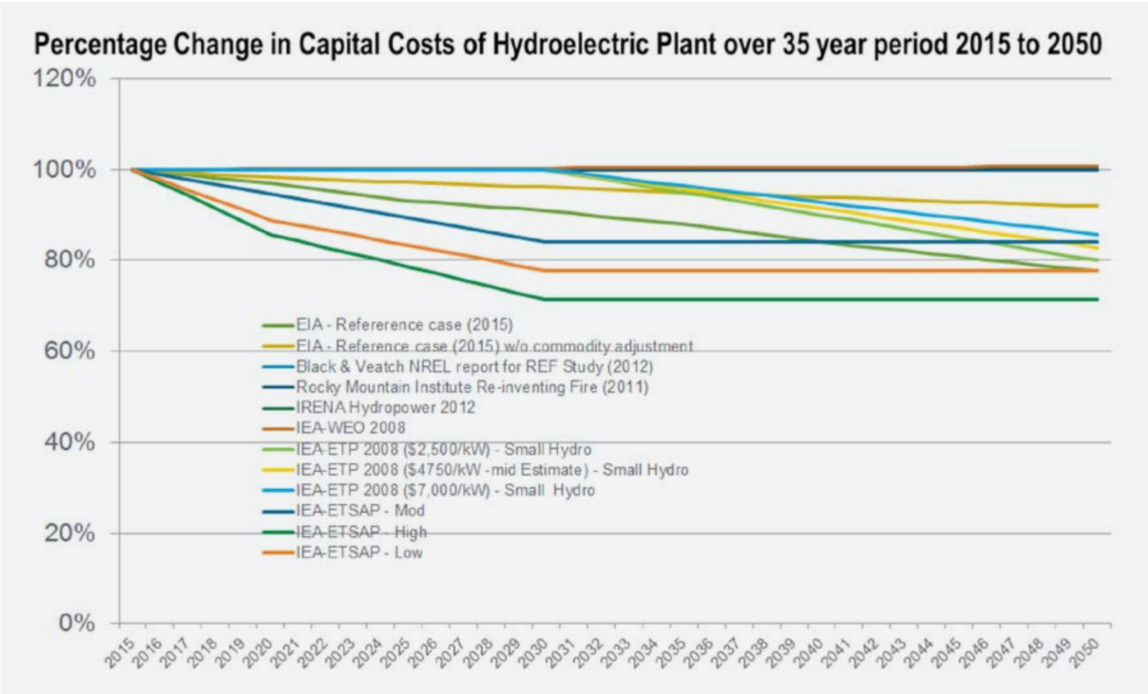


Figure C-2. Range of hydropower cost trajectories from literature

Summary Conclusions

Information from 12 studies or interviews indicated that many showed no decline (or even a slight increase) out to 2050, while a number showed declines in the range of 10% to 30% by 2030 (see Figure C-2). Most studies restrict estimates of substantive cost reductions to 2030, though some go out to 2050. In the case of the U.S. Energy Information Association (EIA), the learning-curve estimates used to 2040 were continued out to 2050 (though the last decade of changes does not reflect EIA actual projections).

It is worth noting that cost reductions are likely to vary with initial capital cost, not scale. Large reductions for moderately expensive sites may not scale to more expensive sites, and similar considerations may apply to less-expensive sites.

Studies Considered (Including cited estimates within some studies)

Data was gathered from 12 sources, which are listed below with comments. Please see C.5 References for full citations for these sources.

1. **EIA/Annual Energy Outlook**
   Hydroelectric investment costs are projected todecline 6% to 8% due to experience curve considerations out to 2040. There is a projected additional 10% decline by 2040 in cost due to EIA estimating that the cost of commodities rises less quickly than inflation (as measured by the Consumer Price Index). Solar and wind costs are also projected to decline.

2. **IEA World Energy Investment Outlook (2014)**
   http://www.iea.org/publications/freepublications/publication/weio2014.pdf
   Hydropower capital costs in 2012 dollars are projected to be flat or rising for Organisation for Economic Co-operation and Development countries including the United States out to 2050. Solar and wind costs are projected to decline.

3. Kumar, A., T. Schei, A. Ahenkorah, R. Caceres Rodriguez, J.-M. Devernay, M. Freitas, D. Hall, A. Killingtveit, and Z. Liu. "Hydropower: IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation." Cambridge University Press, Cambridge, Massachusetts, and New York, New York (US); United Kingdom. 2011 *http://www.ipcc.ch/report/srren/*

Contains current and future hydropower cost-projection estimates out to 2050 from a number of studies in $2005, including:

IEA—World Energy Outlook 2008
IEA—Energy Technology Perspectives (ETP) 2008
EREC/Greenpeace 2010

IEA-WEO 2008, like IEA-WEIO 2014, shows hydropower costs as flat, while EREC/Greenpeace shows costs as rising (where the latter may be due to supply-curve assumptions).
For IEA-ETP 2008, however, hydroelectric capital costs decline by 2050, but less so early on. In small hydropower, estimated costs are unchanged from 2010 to 2030 (ranging between from $2,500 and $7,000/kW). However, by 2050, the estimated range of capital costs is lowered to $2,000/kW to $6,000/kW; this correspond to a reduction in between 2030 and 2050 in estimated capital costs ranging from 20% for the low cost estimate to 14% of the high capital cost estimate.

4. **IEA – Energy Technology Systems Analysis Programme, IEA-ETSAP. 2015. Technology Brief: Hydropower.**
http://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP_Tech_Brief_E06_Hydropower.pdf
Cost estimates for hydropower shown to decline in 2020 and 2030, dropping after 20 years (from 2010 to 2030) to 20% to 30%.

5. **Black and Veatch. 2012. Cost and Performance Data for Power Generation Technologies, Prepared for the National Renewable Energy Laboratory.**
http://bv.com/docs/reports-studies/nrel-cost-report.pdf%E2%80%8E
Hydropower costs will be unchanged out to 2050 ($3,500/kW +/-35%). Similarly, no change for combustion turbines and combined cycle gas turbines at $651 and $1,230/kW per year, respectively. By contrast, there will be roughly a 30% decline in cost for solar PV by 2050, but no decline assumed for land-based wind.

6. **Rocky Mountain Institute— Technology Capital Cost Projections, 2010-2050.**
http://www.rmi.org/RFGraph-technology_capital_cost_projections
Hydropower costs unchanged out to 2050 at about $3,000/kW. Combined cycle gas turbines and nuclear also assumed unchanged. By contrast, onshore wind drops by about 25% from $2,000 to $1,500 and declines for solar are much greater.

7. **IRENA. Renewable Energy Technologies: Cost Analysis Series. Vol. 1: Power Sector, Hydropower. 2012**
http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-HYDROPOWER.pdf
Hydropower costs will be unchanged out to 2020. Argues different factors make it difficult to anticipate whether costs are likely to increase or decrease in future.

8. **European Renewable Energy Council (EREC) and Greenpeace. 2010. Energy [R]evolution: A Sustainable World Energy Outlook.**
http://www.greenpeace.org/seasia/ph/Global/international/publications/climate/2010/fullreport.pdf
Hydropower capital costs will increase $/kW out to 2050 by 20%, but this may be due to resource-constraints assumptions (i.e., moving to less-competitive sites along the supply curve).

Appendix C References

[1] Bulgaria-Serbia IPA Cross-Border Programme. 2014. Comparative Study of Small Hydropower Stations. 2007CB16IPO006 2011-2-229. Accessed June 6, 2016. *http://riversproject.eu/pdf/Comparative%20study.pdf*

[2] Delta-Montrose Electric Association. 2013. "Delta-Montrose adds hydro to renewable mix." Accessed June 6, 2016. *http://www.poweringthewest.org/tag/delta-montrose-electric-association/*

[3] Tri-County Water. "Frequently Asked Questions: What is the Tri-County Water Hydropower Project?" Accessed June 6, 2016. *http://www.tricountywater.org/www/pdf/info/000032/FAQ.pdf*

[4] Federal Energy Regulatory Commission. 2004. Hydroelectric Project Licensing & 5 MW Exemptions from Licensing. Federal Energy Regulatory Commission, Washington, DC (US). Accessed June 6, 2016. *http://www.ferc.gov/industries/hydropower/gen-info/handbooks.asp*

[5] Federal Energy Regulatory Commission. 2001. Hydroelectric Project Handbook for Filings other than Licenses and Exemptions. Federal Energy Regulatory Commission, Washington, DC (US). Accessed June 6, 2016. *http://www.ferc.gov/industries/hydropower/gen-info/handbooks.asp*

[6] Bishop, N., D. Linke. C. Vansant, C. Alsberg, J. Anders, A. Grovue, S. Hill-Nelson, K. Johnson, B. Smith, D. Youlen, and K. Young. 2015. New Pathways for Hydropower: Getting Hydropower Built—What Does It Take? ORNL/TM-2015/48. Oak Ridge National Laboratory, Oak Ridge, TN. Accessed June 6, 2016. *http://hydropower.ornl.gov/docs/publications/ORNL_New%20Pathways%20for%20Hydro_final_ORNLTM2015_48.pdf*

[7] U.S. Department of Energy. 2015. Pumped Storage and Potential Hydropower from Conduits. Report to Congress. U.S. Department of Energy, Washington, DC (US). Accessed June 6, 2016. *http://energy.gov/eere/water/downloads/pumped-storage-and-potential-hydropower-conduits*

[8] Energy Information Administration. 2015. Annual Energy Outlook 2015 with Projections to 2040. DOE/EID-0383(2015). U.S. Department of Energy, Energy Information Administration, Washington, DC. June 13, 2016: *www.eia.gov/forecasts/aeo*.

[9] International Energy Agency. June 2014. World Energy Investment Outlook. Paris, France. Accessed June 13, 2016. *http://www.iea.org/publications/freepublications/publication/weio2014.pdf.*

[10] Kumar, A., T. Schei, A. Ahenkorah, R. Caceres Rodriguez, J.-M. Devernay, M. Freitas, D. Hall, A. Killingtveit, and Z. Liu. 2011. Hydropower: IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. Cambridge University Press, Cambridge, Massachusetts, and New York, New York (US); United Kingdom. Accessed June 13, 2016. *http://www.ipcc.ch/report/srren/*.

[11] International Energy Agency and International Renewable Energy Agency. 2015. Energy Technology Systems Analysis Programme, IEA-ETSAP. Technology Brief: Hydropower. Accessed June 13, 2016. *www.irena.org/Publications*.

[12] Black and Veatch. February 2012. Cost and Performance Data for Power Generation Technologies. Prepared for the National Renewable Energy Laboratory. Accessed June 13, 2016. *http://bv.com/docs/reports-studies/nrel-cost-report.pdf.*

[13] "Technology Capital Cost Projections, 2010-2050," Rocky Mountain Institute, accessed June 13, 2016, *http://www.rmi.org/RFGraph-technology_capital_cost_projections*.

[14] International Renewable Energy Agency. June 2012. Renewable Energy Technologies: Cost Analysis Series. Vol. 1: Power Sector, Hydropower. IRENA Secretariat, Abu Dhabi, United Arab Emirates. Accessed June 13, 2016. *http://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-HYDROPOWER.pdf*.

[15] European Renewable Energy Council (EREC) and Greenpeace. June 2010. Energy [R]evolution: A Sustainable World Energy Outlook. ISBN 978-90-73361-90-4. Accessed June 13, 2016. *http://www.greenpeace.org/international/Global/international/publications/climate/2010/fullreport.pdf.*

Appendix D: Regional Energy Deployment System (ReEDS) Model—Additional Inputs and Assumptions

Section 3.1 summarizes key characteristics of the Regional Energy Deployment System (ReEDS) model, hydropower input assumptions, and scenario variables used in the *Hydropower Vision* analysis. Appendices B and C describe hydropower input data and assumptions in greater detail, while this appendix provides more details about the model and the non-hydropower assumptions for technology cost and performance, electricity market conditions, and policies. Included is a description of the ReEDS model representation and data sources as well as numerical values of key input assumptions used to develop the scenarios contained in the *Hydropower Vision* analysis.

Appendix D is organized as follows:

- An overview of the ReEDS model and list of references to model documentation and other recent studies (Section D.1)
- The cost and performance assumptions of the non-hydropower generation technologies (Section D.2)
- Fuel-price formulations and assumptions (Section D.3)
- Retirement assumptions (Section D.4)
- Central-financing parameters used in ReEDS investment and dispatch decisions (Section D.5)
- Electricity-demand assumptions (Section D.6)
- Transmission cost and modeling assumptions (Section D.7).

D.1 ReEDS Model

The primary analytic tool used for this analysis is the ReEDS electric-sector capacity expansion model [1]. ReEDS is a capacity-expansion model that simulates the construction and operation of generation and transmission capacity to meet electricity demand and system capacity requirements. The model relies on system-wide, least-cost optimization to provide estimates of the type and location of fossil, nuclear, renewable, and storage resource development; the transmission infrastructure expansion requirements of those installations; and the generator dispatch and fuel needed to satisfy regional demand requirements and maintain grid system adequacy. The model also considers technology, resource, and policy constraints. ReEDS models the continental U.S. electricity system with a set of sequential 2-year solve periods out to 2050. In each solve period, the model optimizes the new capacity-expansion requirements and system operation. In the *Hydropower Vision* analysis, ReEDS is used to analyze potential changes in the generation mix of the electricity sector under a wide range of conditions and to generate a set of future scenarios for the U.S. electricity sector from which the range of potential hydropower deployment can be understood and the impacts of the *Hydropower Vision* are assessed. Although ReEDS scenarios are not forecasts or projections, they provide a common framework for understanding the incremental effects associated with specific power-sector changes.

A key ReEDS feature is its focus on representing the unique characteristics of renewable generation—variability, uncertainty, geographic resource constraints, and transmission—and to assess its impacts on the broader electric system. Its high spatial resolution and statistical treatment of the impact of variable wind and solar resources enable representation of the relative value of geographically and temporally constrained renewable power resources. In ReEDS, the continental United States is divided into 356 wind/solar resource regions and 134 model balancing areas (BAs). [1] The resource regions are where wind and solar resource availability and quality are evaluated and capacity expansion is modeled. Hydropower, other renewable resources (geothermal, biopower), and all other generation technologies are represented at the 134 BA level of aggregation, which is where electricity demand and reserves need to be met. Long-distance transmission is represented between interconnected BAs.

ReEDS also uses a supply curve for resource capacity rather than infrastructure investment costs to model the intra-BA, spur-line costs required to interconnect wind and solar capacity from its region to the transmission grid. Capturing the resource cost and quality at such a high geographical granularity enables ReEDS to find the lowest-cost renewable resource expansions by interconnecting high-quality resources through appropriate long-distance inter-BA transmission and intra-BA spur-line expansions. These spur-line costs are not included for hydropower resources. While new hydropower capacity could require spur-line transmission investment to reach the long-distance transmission system, these costs are assumed to be small relative to hydropower construction costs, which are the primary drivers of new hydropower installation decisions.

There are also larger sets of regions within ReEDS: 48 states, 18 curtailment regions that approximate existing regional transmission operator and other reliability regions [2], 13 North American Electric Reliability Corporation (NERC) regions [3], and the three major interconnections—Western, Eastern, and Electric Reliability Council of Texas. The NERC regions are used to model inputs, such as load growth and fuel prices from the U.S. Energy Information Administration (EIA) and the National Energy Modeling System. These higher levels of regional aggregation also facilitate state or regional policy representations.

In each solve period, ReEDS dispatches generation in multiple time slices to capture seasonal and diurnal demand and renewable-generation profiles. Each "solve year" from 2010 to 2050 is divided into 17 time slices that represent four diurnal time slices (morning, afternoon, evening, night) for each of the four seasons (winter, spring, summer, fall) along with a summer peaking time slice (representing the top 40 hours of summer load). While this model time resolution allows the model to capture seasonal and diurnal variations in demand and wind profiles, it is insufficient to capture some of the shorter timescale phenomena associated with high, variable-generation penetration and address the related challenges. The time resolution also precludes representing detailed power-system operating constraints such as ramp rate limits and minimum runtime. To bolster how renewable grid integration might affect investment and dispatch decisions, the ReEDS model includes statistical parameters to address the variability and uncertainty of wind and certain other renewable resources. These parameters include capacity value for planning reserves, forecast error reserves, and curtailment estimates [1, 36].

In addition to modeling generation and pumped storage hydropower technologies, ReEDS includes a full suite of major generation and storage technologies, including coal-fired, natural gas–fired, oil and gas steam, nuclear, biopower, geothermal, land-based and offshore wind, utility-scale solar, compressed-air energy storage, and batteries.[2] To determine competition among the many electricity-generation, storage, and transmission options throughout the contiguous United States, ReEDS chooses the cost-optimal mix of technologies that meet all regional electric-power demand requirements, based on grid-reliability (reserve) requirements, technology resource constraints, and policy constraints. This cost minimization routine is performed for each of 21 two-year periods from 2010 to 2050.

The major outputs of ReEDS include the amount of generator capacity and annual generation from each technology, storage capacity expansion, transmission capacity expansion, total electric-sector costs, electricity price, fuel demand and prices, and direct-combustion carbon dioxide emissions. Through these output metrics, ReEDS is able to provide estimates of the nationwide impact of the *Hydropower Vision.* Greater detail for these

1. While the boundaries of real balancing authority areas helped to inform the design of the model BAs, the ReEDS BAs do not correspond perfectly with real balancing authority areas, where boundaries are dynamic and likely to change in the future.

2. Coal and natural gas with and without carbon capture and storage are included. ReEDS models natural-gas-combined cycle and combustion-turbine technologies independently. Utility-scale solar includes photovoltaic and concentrated solar power with and without TES; rooftop solar deployment is not modeled endogenously but is applied as an exogenous input into the system. Section D.2 and Short et al. [1] describe the array of technologies modeled in ReEDS in greater detail.

model technology categories is provided in the next section. ReEDS applies standardized financing assumptions for investments in all technologies represented in the model (see Section D.6). The exception, where some scenarios use alternative financing assumptions for hydropower, is discussed in Section 3.3.2 and Appendices B and J. Annual electric loads and fuel-price supply curves are exogenously specified to define the system boundaries for each period of the optimization, as discussed in later sections.

The ReEDS documentation [1] provides a more detailed description of the model structure and equations. The *2015 Standard Scenarios Annual Report* developed by the National Renewable Energy Laboratory (NREL) also discusses the ReEDS model inputs and assumptions in detail [36]. Recent publications using ReEDS include the *SunShot Vision Study* [4], the *Renewable Electricity Futures* study [5], other lab reports [6, 7, 8, 9], and journal articles [10, 11, 12, 13].[3] This appendix focuses on the primary data assumptions and model representations that are used specifically for the *Hydropower Vision* analysis, which may differ from assumptions applied in prior studies using ReEDS. The model version described here is largely consistent with the *NREL 2015 Standard Scenarios Annual Report* version [36], with the most substantial deviation being the improved hydropower representation discussed in Appendix B.

While ReEDS represents many aspects of the U.S. electric system, it has certain key limitations. First, ReEDS is a system-wide optimization model and, therefore, does not consider revenue impacts for individual project developers, utilities, or other industry participants. Second, ReEDS does not explicitly model constraints associated with the manufacturing sector. All technologies are assumed to be available up to their technical resource potential. Third, technology cost reductions from manufacturing economies of scale and "learning by doing" are not endogenously modeled for this analysis; rather, current and future cost-reduction trajectories are defined as inputs to the model (see also Appendix C). Fourth, with the exception of future fossil-fuel prices, foresight is not explicitly considered in ReEDS (i.e., the model makes investment decisions based on current conditions, without consideration for how those conditions may evolve in the future). Furthermore, ReEDS is deterministic and has limited considerations for risk and uncertainty. Fifth, while embedded financing assumptions capture a general representation of the relationship between overnight and installed capital costs, the optimization algorithm in ReEDS does not fully represent the prospecting, permitting, and siting hurdles that are faced by project developers for either electricity-generation capacity or transmission infrastructure. Moreover, ReEDS does not include fuel infrastructure or land competition challenges associated with fossil-fuel extraction and delivery. Finally, ReEDS models the power system of the continental United States and does not represent the broader United States or global energy economy. For example, competing uses of resources across sectors (e.g., natural gas) are not dynamically represented in ReEDS, and end-use electricity demand is exogenously input to ReEDS for this study.

One consequence of these model limitations is that system expenditures estimated in ReEDS may be understated, as the practical realities associated with planning electric-system investments and siting new generation and transmission facilities are not fully represented in the model. At the same time, the ReEDS spatial resolution provides much more sophisticated evaluation of the relative economics among generation resources and significant insight into key issues surrounding future hydropower deployment, including locations for future deployment, implications of climate change and local environmental attributes, impacts on planning and operating reserves, and interactions with other renewable resources.

With a system-wide utility-scale optimization outlook, ReEDS is not designed to evaluate distributed-generation scenarios. Accordingly, ReEDS analysis is supported by the Distributed Solar (dSolar) model [14]. dSolar (formerly SolarDS) is used to generate a projection of rooftop solar photovoltaic (PV) deployment, which is then input into ReEDS. The dSolar capacity projections utilized for the *Hydropower Vision* analysis are described in Section D.2. No other distributed-generation technologies are modeled explicitly in the *Hydropower Vision.*

3. See *www.nrel.gov/analysis/reeds* for a list of publications about and further description of ReEDS.

D.2 Generator Assumptions—Technology Cost and Performance

ReEDS models a full suite of generation technologies including renewable, non-renewable, and storage. The technologies modeled in ReEDS represent the existing capacity fleet as well as newer-generation technologies that have not realized commercial deployment in the United States. With the exception of rooftop PV, the existing capacity in ReEDS only includes units that are primarily used to generate and transmit electricity to the grid and excludes facilities that generate electricity primarily for on-site consumption or combined heat and power facilities.[4]

New capacity growth for the following technologies is allowed in ReEDS:

- Natural gas-fired combustion turbine (NGCT)
- Natural gas—combined cycle (NGCC)
- Natural gas with carbon capture and storage (NGCCS)[5]
- Coal with carbon capture and storage (Coal-CCS)[6]
- Nuclear
- Biopower
- Cofired coal and biomass[7]
- Utility-scale solar PV[8]
- Wind (land-based and offshore)
- Concentrated solar power (CSP) with and without thermal energy storage (TES)[9]
- Hydropower (generation and pumped storage)[10]
- Geothermal[11]
- Compressed air energy storage (CAES)
- Utility-scale batteries.

The following technologies are also modeled in ReEDS, but new capacity additions are not allowed:

- Pulverized coal with no carbon capture and storage[12]
- Coal-integrated gasification combined cycle (Coal-IGCC)
- Landfill gas and municipal solid wast[13]
- Oil and gas steam.

4. The treatment of rooftop PV is described in section D.2.2.
5. While CCS technologies are included in the ReEDS model and allowed to be built, none of the modeled scenarios in this report resulted in the deployment of CCS capacity
6. Coal with CCS reflects integrated gasification combined cycle coal (IGCC) technologies.
7. Cofired plants represent new plants that can accommodate coal and biomass fuels as well as cofiring retrofits to existing coal plants. In ReEDS, no more than 15% of the capacity of a cofired coal plant can operate on biomass feedstocks at any time. In Chapter 3, cofired capacity is separated into coal and biomass categories in the reported capacity and generation values. More particularly, the reported cofired coal capacity is split between coal and biomass (85% of the capacity included with coal and 15% included with biomass). The generation from cofired plants is split by the generation from each fuel in the modeled plants with energy from biomass feedstocks included in the biomass category.
8. The cost and performance of utility-scale PV reflect 100-MW single-axis tracking systems.
9. CSP without TES is represented by trough systems with a solar multiple of 1.4. CSP with TES includes trough and tower systems with a solar multiple of at least two and at least 6 hours of storage. ReEDS endogenously optimizes the system configuration of CSP with TES plants within these limits.
10. Section G.2.3 discusses the hydropower resources modeled in ReEDS. No ocean or marine hydrokinetic technologies are included in ReEDS for the present analysis. Canal/conduit development is also not modeled.
11. Section G.2.4 discusses the geothermal resource modeled in ReEDS for the present analysis.
12. New coal-fired plants without CCS, including IGCC, are prohibited by the EPA 111(b) policy. ReEDS does not currently include a representation of coal with partial-CCS that would comply with the 111(b) policy.
13. In Chapter 3, landfill-gas and municipal-solid-waste generation and capacity are included in the biomass values.

In addition to the previously listed technologies, new rooftop PV capacity is exogenously included (see section D.2.2). For energy storage technologies, pumped storage hydropower assumptions are presented in Sections 3.2, 3.3, and Appendix B, while resource, cost, and performance projections for CAES and batteries options are based on those modeled in the *Renewable Electricity Futures Study* [15].

D.2.1 General Technology Assumptions

Each modeled technology is characterized by its regional resource potential, capital cost, O&M costs, and heat rates or capacity factors. Other technology characteristics such as lifetime, reserve capability, and tax credits are also modeled as described in Short et al. [1]. Regional variations and adjustments in some of the technology characteristics are also included and described in the following sections and other ReEDS publications listed in Section D.2. This section presents the capital, fixed O&M, variable O&M, and heat rates for all technologies modeled.

Cost and performance assumptions for all new fossil-based and nuclear technologies and certain renewable technologies (e.g., biopower and geothermal) are largely based on projections from the EIA Annual Energy Outlook (AEO) 2015 Reference scenario [16]. The modeling tool in the AEO 2015 endogenously models technology learning, wherein technology cost and performance parameters are informed by the amount of capacity deployed in a given scenario. As a result, the technology cost assumptions reflect the learning estimated in the AEO 2015 Reference scenario and are directly applied in ReEDS. ReEDS does not include any explicit representation of technology learning in the *Hydropower Vision* analysis. In addition, projected parameters beyond 2040 are assumed to remain flat at the 2040 levels, as the AEO 2015 includes data only through 2040. For some technologies (e.g., geothermal), only O&M costs from the AEO 2015 Reference scenario are used, while capital costs are based on other data sources (see D.2.4). Solar and wind technology assumptions also diverge from the AEO and are described in sections D.2.2 and D.2.3. Assumptions for hydropower technologies and resources (including pumped storage) are described in Appendix B. Storage assumptions are based on those developed for the *Renewable Electricity Futures Study* [15]. Overnight capital, fixed O&M, and variable O&M cost projections are shown in Tables D-1, D-2, and D-3, respectively. Heat-rate assumptions for new capacity are shown in Table D-4. All costs presented in this appendix are in real 2015 dollars unless otherwise noted.

Table D-1. Overnight Capital Cost Projections (2015$/kilowatt [kW])

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
NGCT	853	833	813	801	780	765	751	751	751
NGCC	1,004	978	960	947	926	909	894	894	894
NGCCS	NA	2,096	1,982	1,925	1,844	1,778	1,715	1,715	1,715
Old coal with scrubbers[a]	NA	NA	NA	NA	NA	NA	NA	NA	NA
Old coal without scrubbers[a]	NA	NA	NA	NA	NA	NA	NA	NA	NA
New coal[a]	NA	NA	NA	NA	NA	NA	NA	NA	NA
Coal-IGCC	NA	NA	NA	NA	NA	NA	NA	NA	NA
Coal-CCS	NA	6,547	6,257	6,085	5,879	5,693	5,516	5,516	5,516
Oil/gas steam	NA	NA	NA	NA	NA	NA	NA	NA	NA
Nuclear	4,951	5,364	4,884	4,644	4,528	4,390	4,239	4,239	4,239
Geothermal[b]	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve	Supply curve
Biopower[c]	4,257	3,705	3,618	3,549	3,479	3,411	3,345	3,345	3,345
Cofire retrofit[d]	295	295	295	295	295	295	295	295	295
SO_2 scrubber retrofit[e]	548	548	548	548	548	548	548	548	548
Landfill gas	NA	NA	NA	NA	NA	NA	NA	NA	NA
Battery	NA	3,341	3,255	3,169	3,083	2,997	2,912	2,826	2,740
CAES	NA	994	994	994	994	994	994	994	994

a. Coal plants that existed before 2010 are included in ReEDS and separated into three categories: new coal, old coal without scrubbers, and old coal with scrubbers. Old coal with and without scrubbers comprises plants built before 1995. New coal (post-1995) plants are assumed to have scrubbers. For the reported coal capacity and generation in Chapter 3, all coal technologies are aggregated together (new and old coal, coal-IGCC, and coal-CCS).

b. Geothermal capital costs are represented through regional supply curves. No capital cost reductions are assumed for these technologies. See section D.2.4.

c. The costs under the "biopower" category represent costs for new dedicated biopower plants.

d. The capital cost represents the cost to retrofit any existing coal facilities to be able to cofire with biomass. Biomass cofiring is assumed to be limited to 15% of the total plant capacity. A plant that has been retrofitted to cofire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant. ReEDS includes an option to deploy new facilities that can cofire coal and biomass; however, none of the scenarios discussed in the *Wind Vision* analysis relied on this option.

e. Sulfur dioxide (SO_2) scrubber retrofits upgrade capacity from the "Old Coal without Scrubbers" category to the "Old Coal with Scrubbers" category.

Table D-2. Fixed O&M Costs for New and Existing Generators (2015$/kW-year)

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
NGCT	7.31	7.31	7.31	7.31	7.31	7.31	7.31	7.31	7.31
NGCC	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50	14.50
NGCCS	NA	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30
Old coal with scrubbers	42.20	42.20	42.20	42.20	42.20	42.20	42.20	42.20	42.20
Old coal without scrubbers	38.11	38.11	38.11	38.11	38.11	38.11	38.11	38.11	38.11
New coal	32.17	32.17	32.17	32.17	32.17	32.17	32.17	32.17	32.17
Coal-IGCC	52.22	52.22	52.22	52.22	52.22	52.22	52.22	52.22	52.22
Coal-CCS	NA	7.40	7.40	7.40	7.40	7.40	7.40	7.40	7.40
Oil/gas steam	27.90	27.90	27.90	27.90	27.90	27.90	27.90	27.90	27.90
Nuclear	94.77	94.77	94.77	94.77	94.77	94.77	94.77	94.77	94.77
Geothermal	11.47	11.47	11.47	11.47	11.47	11.47	11.47	11.47	11.47
Biopower	107.33	107.33	107.33	107.33	107.33	107.33	107.33	107.33	107.33
Cofire retrofit[a]	see note	see note	see note	see note	see note	see note	see note	see note	see note
Landfill gas	399.10	399.10	399.10	399.10	399.10	399.10	399.10	399.10	399.10
Battery	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22	5.22
CAES	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81	12.81

a. A plant that has been retrofitted to cofire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant.

Table D-3. Variable O&M Costs for New and Existing Generators (2015$/megawatt-hour [MWh])

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
NGCT	13.12	13.12	13.12	13.12	13.12	13.12	13.12	13.12	13.12
NGCC	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
NGCCS	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89
Old with scrubbers	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
Old coal without scrubbers	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89	1.89
New coal	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70	1.70
Coal-IGCC	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34	7.34
Coal-CCS	8.58	8.58	8.58	8.58	8.58	8.58	8.58	8.58	8.58
Oil/gas steam	4.26	4.70	5.19	5.73	6.33	6.99	7.71	8.51	9.40
Nuclear	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18	2.18
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biopower	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35	5.35
Cofire retrofit[a]	see note	see note	see note	see note	see note	see note	see note	see note	see note
Landfill gas	8.88	8.88	8.88	8.88	8.88	8.88	8.88	8.88	8.88
Battery	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
CAES	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71	1.71

a. A plant that has been retrofitted to cofire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant.

Table D-4. Heat Rates for New and Existing Generators (Million British Thermal Units [Mbtu]/MWh)

Generator	2010	2015	2020	2025	2030	2035	2040	2045	2050
NGCT	10.27	10.01	9.76	9.50	9.50	9.50	9.50	9.50	9.50
NGCC	6.74	6.68	6.62	6.57	6.57	6.57	6.57	6.57	6.57
NGCCS	NA	7.51	7.50	7.49	7.49	7.49	7.49	7.49	7.49
Old coal with Scrubbers	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98
Old coal without Scrubbers	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26	10.26
New coal	8.80	8.78	8.76	8.74	8.74	8.74	8.74	8.74	8.74
Coal-IGCC	8.70	8.28	7.87	7.45	7.45	7.45	7.45	7.45	7.45
Coal-CCS	NA	9.90	9.10	8.31	8.31	8.31	8.31	8.31	8.31
Oil/gas steam	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65	10.65
Nuclear	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48	10.48
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA
Biopower	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50	13.50
Cofire retrofit[a]	see note	see note	see note	see note	see note	see note	see note	see note	see note
Landfill gas	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88	14.88
Battery	NA	NA	NA	NA	NA	NA	NA	NA	NA
CAES	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91	4.91

a. A plant that has been retrofitted to cofire biomass is assumed to retain the existing heat rate and O&M costs of the original coal plant.

D.2.2 Solar Technologies

The *Hydropower Vision* analysis includes three primary solar technologies: utility-scale PV, rooftop PV, and CSP. Solar-power-technology capital costs are benchmarked to cost data reported by Feldman et al. [17] and GTM Research/Solar Energy Industries Association [18]. Performance for all solar technologies varies regionally, with data developed using NREL's System Advisor Model (SAM) [24]. Central capital-cost projections from 2014 to 2020 for CSP and utility-scale PV are aligned with the U.S. Department of Energy (DOE) 62.5% cost-reduction scenario (relative to 2010) documented by the *SunShot Vision Study* [4]. This cost trajectory was subsequently grounded against a sample of cost projections from the EIA [37], International Energy Agency [2,] Bloomberg New Energy Finance [19], Greenpeace/European Photovoltaic Industry Association [20], and GTM Research/ Solar Energy Industries Association [19, 22]. After 2020, costs decline linearly to reach the DOE 75% reduction scenario by 2030 [4]. Costs are assumed to be unchanged (in real terms) from 2030 to 2050.[14] Although literature estimates that emphasize this time period are fewer, this cost trajectory is also generally consistent with an average literature estimate [2, 23, 24].

The *High Variable-Generation (VG) Cost* and *Low VG Cost* scenarios in the *Hydropower Vision* use alternative-capital cost assumptions for PV technologies. Central CSP costs are used for all scenarios because new CSP economically built by ReEDS typically uses thermal storage to allow dispatchability, and the primary behavior of interest in varying renewable energy costs is the system response to VG. The high PV cost trajectory (used for *High Variable Resource Renewable Energy [VRRE] Cost* scenarios) assumes no reductions past 62.5% achieved in 2020, and the low PV cost trajectory (used for *Low VRRE Cost* scenarios) reaches the 75% cost-reduction SunShot target in 2020 with no change thereafter. Figure D-1 shows the three utility-scale PV future-cost trajectories. Cost and performance trajectories for all variations of these technologies are presented in the Annual Technology Baseline spreadsheet [36].

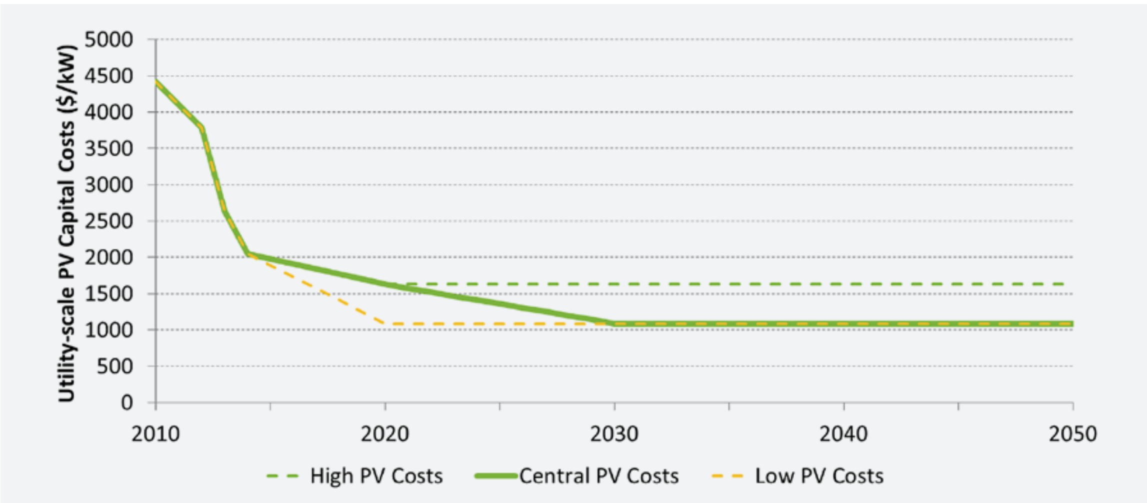


Figure D-1. High, central, and low capital costs projections for utility-scale PV; the mid case is used in the *Central* scenario

14. Potential generation does not remove curtailments, which are estimated internally by ReEDS. Curtailments for variable generation are removed in the generation reported in Chapter 3.

Table D-5 presents the O&M cost assumptions over the model horizon for utility-scale PV, which ReEDS models based on 100-MW single-axis tracking systems. Regional capacity factors are developed from the System Advisor Model's PV module [24] and range from 0.17 to 0.28.[15] The performance characteristics for ReEDS were developed using hourly weather data from the National Solar Radiation Database for 939 sites from 1998 to 2005. The representative PV capacity factor for each model BA reflects the site within each BA with the highest-annual average capacity factor. No changes or improvements in capacity factor are assumed for utility-scale PV.

Table D-5. Technology Cost Assumptions for Utility-Scale PV (2015$)

Cost Type	2010	2015	2020	2025	2030	2035	2040	2045	2050
Fixed O&M ($/kWDC-year)	22.09	16.57	7.73	7.73	7.73	7.73	7.73	7.73	7.73
Variable O&M ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Rooftop PV includes commercial and residential systems. The dSolar model [14], a diffusion model for the continental U.S. rooftop market, is used to develop future scenarios for rooftop PV capacity. Each VG cost scenario has a unique rooftop PV growth projection.

Consistent with utility PV and CSP, the central dSolar scenario reaches the 62.5% cost-reduction scenario from the *SunShot Vision Study* in 2020 and the 75% cost-reduction scenario in 2030 with constant costs thereafter[16] [4]. This scenario reaches 200-GW rooftop PV deployment by 2050. The solar investment tax credit (ITC) policy as of December 18, 2015, is implemented in accordance with the Consolidated Appropriations Act of 2016.[17] All other assumptions are the same as those used in the *SunShot Vision Study* [4]. The *High VG Cost* scenario for rooftop PV uses a more modest deployment pathway that achieves 72 GW in 2050, while the *Low VG Cost* trajectory reaches 245 GW in 2050. Though representative of high and low rooftop PV deployment in 2050, these scenarios do not include the December 2015 ITC extension, which was unavailable for inclusion in the these dSolar simulations. As a result, central 2050 rooftop PV capacity and generation is not substantially lower than in the *Low VG Cost* scenario, and the Central scenario outperforms the *Low VG Cost* scenario in intermediate years.

Figure D-2 shows the resulting capacity and generation trajectories for rooftop PV based on these assumptions and the dSolar modeling. Degradation of the efficiency of solar PV capacity over time is also modeled at 0.5% per year. This degradation is modeled by reducing the capacity of PV that generates energy by 0.5% per year.

Consistent with assumptions around solar PV, assumptions for CSP with TES costs are based on the 62.5% and 75% cost-reduction scenarios from the *SunShot Vision Study* [4]. CSP capital costs are more complicated than other technologies because ReEDS optimizes the CSP system configuration through separate considerations for the turbine, solar field, and storage components of the system. Within its solutions, ReEDS can deploy CSP with TES plants with any configuration of solar multiples and storage capacity within certain limitations [4].

15. Capacity factors for utility-scale PV are based on the system capacity in watts direct current (W_{DC}) and generation in watts alternating current (W_{AC}). The capacity factor includes the conversion from DC to AC power.

16. Similar to other solar technologies, rooftop PV capital costs are linearly interpolated between 2020 and 2030, and the capital costs are held constant at the 75% *SunShot Vision Study* cost reductions in all years after 2030.

17. This assumption differs from the *SunShot Vision Study*, where the ITC was assumed to be eliminated after 2016.

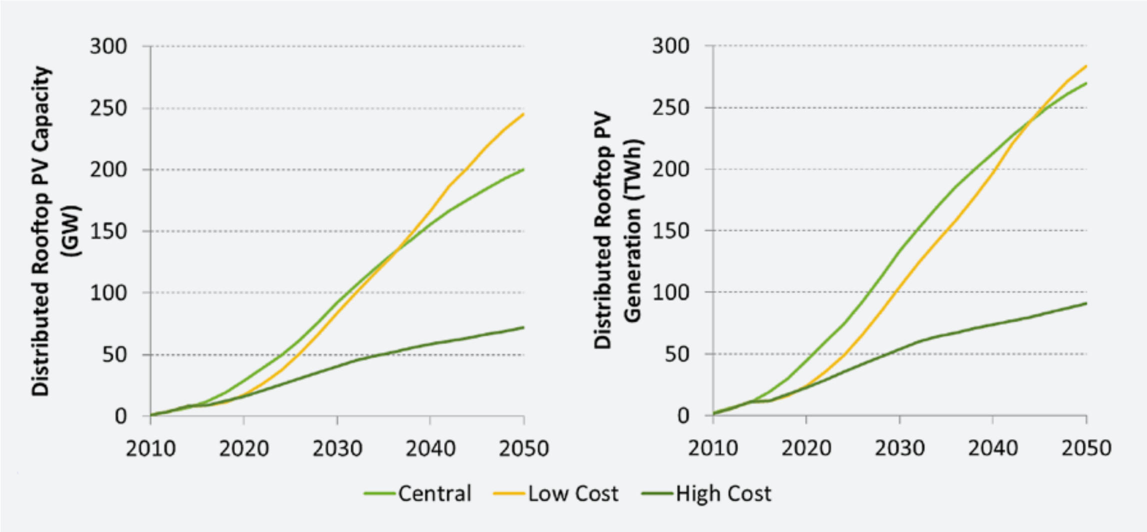


Figure D-2. Capacity gigawatt (GW) and potential generation in terawatt-hours (TWh) of rooftop PV for each VG cost condition[18]

For example, the TES capacity must be between 6 and 12 hours of storage (rated at maximum power output), resulting in a capacity factor between 0.40 and 0.65. While future deployment of CSP systems will likely result in a range of technologies, the cost and performance assumptions in ReEDS assumes that trough systems are deployed prior to 2025 and power towers are deployed subsequently. Further details on CSP modeling in ReEDS can be found in the *SunShot Vision Study* [4]. Table D-6 shows component capital and O&M cost projections for CSP systems modeled in ReEDS.

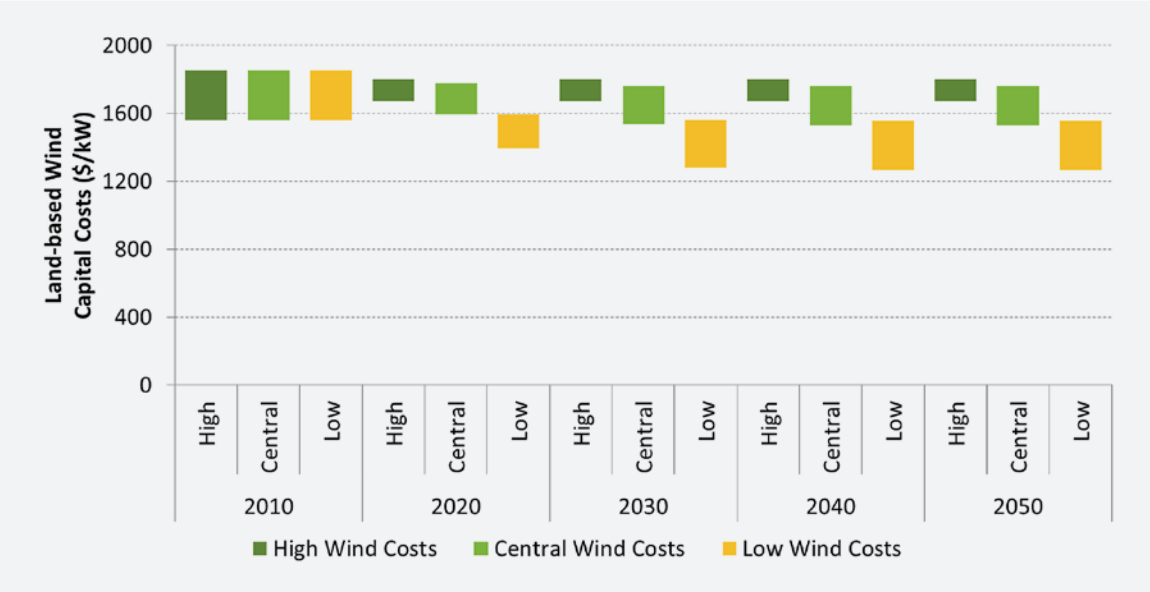
Table D-6. Technology Cost Assumptions for CSP Systems (2015$)

Cost Type	2010	2015	2020	2025	2030	2035	2040	2045	2050
Turbine Capital Cost ($/kW)	1,823	1,823	1,767	1,551	1,336	1,336	1,336	1,336	1,336
Solar Collector Array Capital Cost ($/kW)	2,189	2,189	1,022	960	773	773	773	773	773
TES Capital Cost ($/kWh)	115	115	55	48	41	41	41	41	41
Fixed O&M ($/kW-year)	972	777	583	583	583	583	583	583	583
Variable O&M ($/MWh)	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31	3.31

18. Potential generation does not remove curtailments, which are estimated internally by ReEDS. Curtailments for variable generation are removed in the generation reported in Chapter 3.

D.2.3 Wind

Wind technology inputs match the *Wind Vision* report assumptions (see Appendix B and Section 3.2.1 in the *Wind Vision* report) [38]. Land-based wind input data are grounded in reported costs (such as those in [39]) and modeled performance of currently available technology (as shown in [40]). Land-based wind levelized cost of energy (LCOE) projections through 2050 were developed from a review and analysis of independent literature-based projections (see also [41] and [42]), resulting in identification of three distinct projections: *High Wind Costs* (constant wind LCOEs from 2014 to 2050), *Central Wind Costs* (median 2014 cost reduction of 9% by 2020, 16% by 2030, and 22% by 2050) and *Low Wind Costs* (maximum 2014 cost reduction of 24% by 2020, 33% by 2030, and 37% by 2050). Costs and projections depend on wind speed conditions, so Figure D-3 shows the decadal capital cost ranges at the plant level[19] for each of the three cost projection scenarios. All *Hydropower Vision* scenarios with *High VG Cost* conditions use the *High Wind Costs* projection, while all scenarios with *Low VG Cost* use the *Low Wind Costs* projection. *Central Wind Costs* are assumed elsewhere.



Note: Ranges result from consideration of a broad array of wind-speed conditions. For areas outside the Interior region, capital-cost multipliers are applied, resulting in a broader range of estimated costs for the country as a whole than reflected here. Data shown represent the plant-level LCOE, excluding potential intraregional transmission needed to move the power to the grid and interregional transmission to move the power to load.

Figure D-3. Land-based wind capital-cost projections under high, central, and low wind-cost conditions

Offshore wind inputs were developed in manner similar to their land-based counterparts and are detailed in full in Appendix H in the *Wind Vision* report [38]. Projections through 2050 for offshore wind were developed from a combination of methods, including review and analysis of independent literature [43, 44, and 45] and adopting different learning-rate estimates (5% based on [46], and 10% based on [47] and [48]). Reductions from 2014 LCOEs are 5% by 2020 and 18% by 2050 in the *High Wind Cost* case; 16% by 2020, 32% by 2030, and 37% by 2050 in the *Central Wind Cost* case; and 22% by 2020, 42% by 2030, and 51% by 2050 in the *Low Wind Cost* case. For both land-based and offshore wind, *High Wind Cost* and *Low Wind Cost* cases are used for any scenarios with *High VRRE Costs* or *Low VRRE Costs,* respectively.

19. Values do not include any transmission costs associated with new wind-capacity construction.

D.2.4 Geothermal

Geothermal capital costs in ReEDS are based on regional supply curves developed from Augustine (2011) [28]. This source includes capital costs and resource potential for identified and undiscovered hydrothermal, near-hydrothermal field-enhanced geothermal systems, and deep-enhanced geothermal-system wells including discovered and potentially discovered resources. The geothermal supply curve in ReEDS for the *Hydropower Vision* analysis (Figure D-4) includes only the identified hydrothermal and near-hydrothermal field-enhanced geothermal. These two resource classes total about 11.2 GW of potential new capacity; however, only resources under $14,000/kW are shown in Figure D-4. The *Hydropower Vision* analysis excludes undiscovered hydrothermal, deep and greenfield-enhanced geothermal systems, and other geothermal resources, which could expand the resource potential for geothermal. The set of geothermal resources assumed to be available is consistent with that used in the *NREL 2015 Standard Scenarios Annual Report* Central Scenario [36]. A different set of resource and/or cost assumptions could yield different geothermal deployment levels in the scenarios.

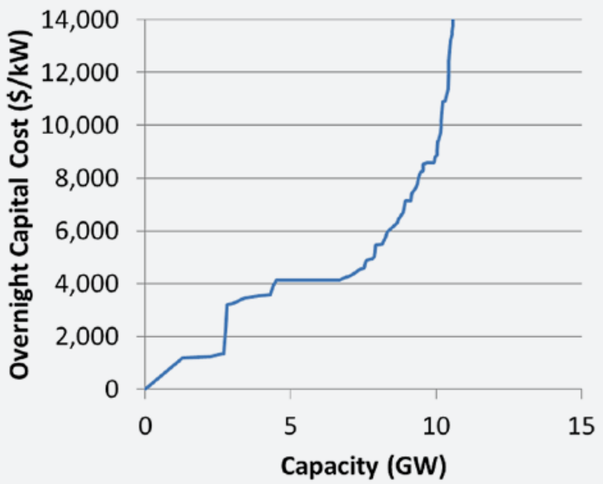
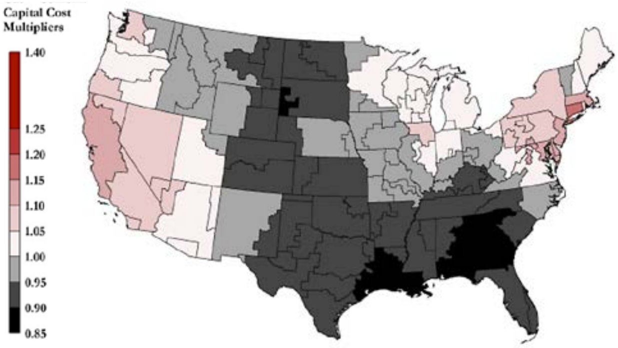


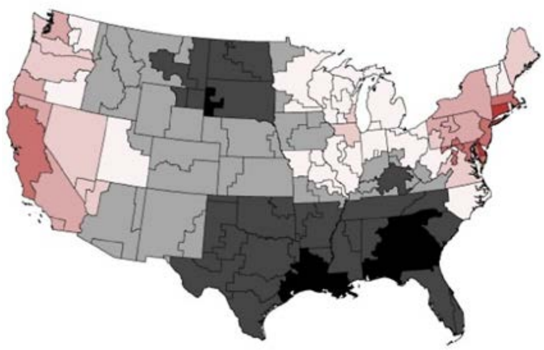
Figure D-4. Geothermal capacity supply curve for new, identified hydrothermal and near-hydrothermal field-enhanced geothermal system resources

D.2.5 Capital Cost Multipliers

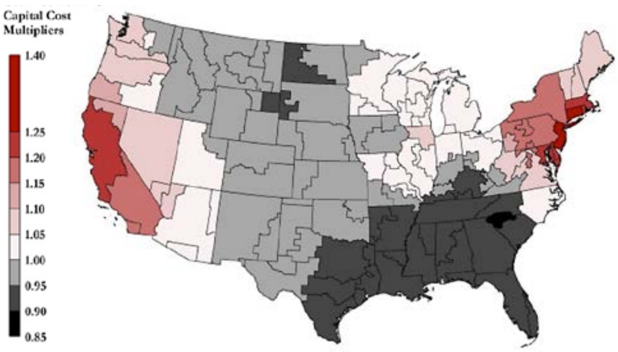
For most generation technologies, regional-cost multipliers are applied to reflect variations in installation costs across the United States. These regional multipliers are applied to the base overnight capital cost of the associated technology presented in earlier sections. The regional multipliers are technology-specific and are derived from Science Applications International Corporation's (SAIC) report for EIA, "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" [29]. While the regional costs presented in the SAIC report are based on particular cities, the regional multipliers for ReEDS are calculated by interpolating among these cities and using the average value over the ReEDS regions for each technology. The multipliers are applied to the base capital cost of each technology within ReEDS. SAIC does not report regional capital-cost multipliers for hydropower, but hydropower costs are region-specific based on the considerations discussed in Appendices B and C. The capital-cost multipliers used in ReEDS are shown in Figure D-5.



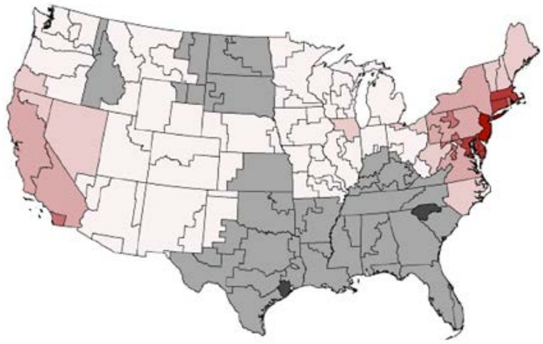
a. Biopower



b. New Coal

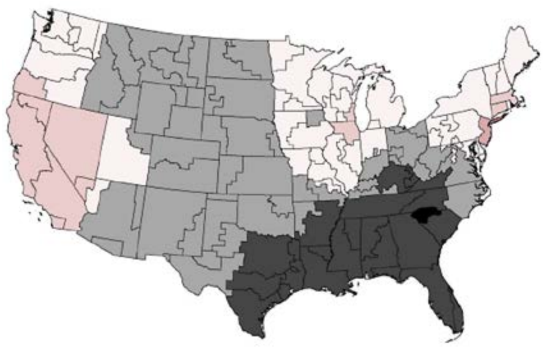


c. Gas—Combined Cycle



d. Gas—Combustion Turbine

e. Nuclear



f. Utility-Scale Photovoltaics

Figure D-5. Maps of regional capital-cost multipliers

D.3 Fuel Prices

The natural gas, coal, and uranium price assumptions used in the *Hydropower Vision* analysis are based primarily on AEO 2015 data [16]. All scenarios rely on the same uranium price trajectory based on the AEO 2015 Reference scenario (Figure D-7), but three fossil fuel cost scenarios are defined for coal and natural gas prices: *Low Fossil Fuel Cost, Central Fossil Fuel Cost,* and *High Fossil Fuel Cost. Central Fossil Fuel Cost* uses AEO 2015 Reference scenario data for coal and natural gas prices. For natural gas prices, *Low Fossil Fuel Cost* is extracted from the High Oil and Gas Resource scenario, while High Fossil Fuel Cost is extracted from the Low Oil and Gas Scenario in AEO 2014 [37].[20] AEO 2015 does not have High Coal Cost or Low Coal Cost scenarios, so coal prices for High Fossil Fuel Cost and *Low Fossil Fuel Cost* conditions are produced by multiplying AEO 2015 Reference coal prices by the coal price ratio of AEO 2014 High and Low Coal Cost scenarios to the AEO 2014 Reference scenario [17, 37]. Because the AEO data extend only through 2040, fossil fuel costs for each specific trajectory (e.g., low, central, high) are assumed to be constant in real dollar terms from 2040 to 2050.[21] Figure D-6 presents the base natural gas and coal price trajectories, respectively, directly from the AEO scenarios.[22]

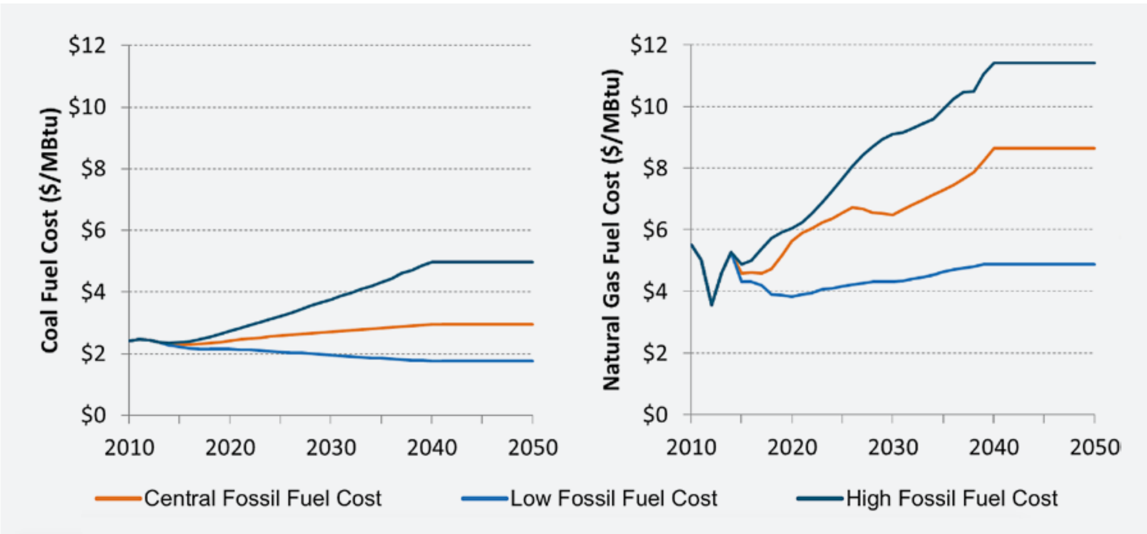


Figure D-6. Fossil fuel cost trajectories applied in the *Hydropower Vision*

Natural gas prices in ReEDS are represented using a combination of national and regional supply curves to take into account the price response to greater electric-sector natural gas consumption. In each year, each census region is characterized by a price-demand set point taken from the AEO Reference scenario, and two elasticity coefficients that model the rate of regional price change with respect to change in the regional gas demand from its set point and the overall change in the national gas demand from the national price-demand set point. These elasticity coefficients are developed through a regression analysis across an ensemble of AEO scenarios (as described in Logan et al. [11], though the numbers have since been updated using more recent AEO scenarios). The supply curves reflect natural-gas resource, infrastructure, and nonelectric-sector demand assumptions embedded within the AEO modeling.

---

20. AEO 2015 does not include a Low Oil and Gas Resource scenario.

21. Prices are assumed to increase with the rate of inflation over this time period.

22. Figure D-6 shows natural gas price trajectories directly from the AEO scenarios. While these trajectories are the basis of the prices observed in ReEDS, as described in this section, ReEDS endogenously conditions changes to natural gas prices based on its own estimates of natural gas consumption by the electricity sector.

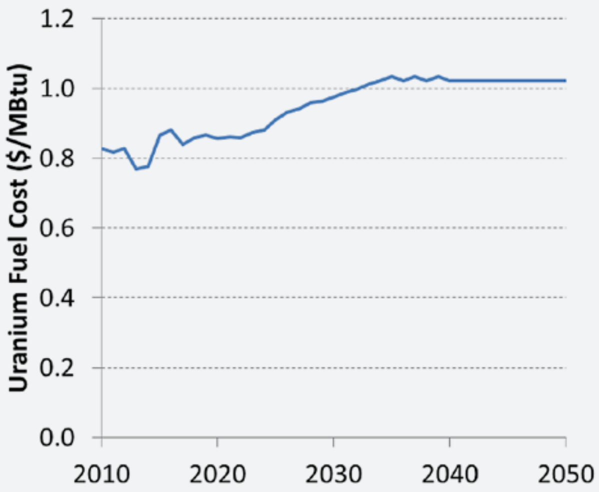


Figure D-7. Uranium prices applied in the *Hydropower Vision* analysis

In addition to the natural-gas supply-curve representation in ReEDS, limited foresight is also included in the model for new natural-gas-capacity investments.[23] In particular, the effective investment cost for new NGCC capacity includes an additional foresight term representing the present value of the difference between flat natural gas prices and expected future natural gas prices. This term is based on the trajectories in the associated AEO Natural Gas scenario.[24] This foresight does not affect the operation of an NGCC plant in a given year, but it does affect the investment decision for new capacity.

D.4 Retirements

Retirements in ReEDS are primarily a function of plant age and assumed lifetimes. Fossil fuel-fired plant ages are derived from data reported by Ventyx [30]. Coal-fired plants less than 100 MW in capacity are retired after 65 years; coal-fired plants greater than 100 MW in capacity are retired after 75 years. Natural-gas and oil-fired capacity is assumed to have a 55-year lifetime. Nuclear plants are assumed to be approved for a single service-life-extension period, giving existing nuclear plants a 60-year life. No refurbishment costs or increased O&M costs are applied to extend the nuclear or fossil plant life. These age-based retirement assumptions result in nearly all of the existing (2014) oil-and-gas steam turbines and existing nuclear units being retired by 2050.[25] By 2050, about half of the existing coal capacity is also retired based solely on the age-based retirement assumptions. Age-based retirements have a lesser impact on natural-gas capacity, with only about 35% of 2013 NGCT capacity and about 10% of 2013 NGCC capacity retired by 2050.

In addition to age-based retirements, other long-term retirements are captured by considering plant utilization. Assumed age-based and announced coal retirements total 67 GW of coal-capacity retirements from 2013 to 2020, 83 GW by 2030, and 192 GW by 2050. Modeled utilization-based coal retirements represent a proxy for economic-based considerations and accelerate coal retirements. This utilization-based retirement is implemented using an annual capacity factor threshold for each model BA. If the capacity factor is beneath the threshold in

23. Foresight terms are not included for other fuel-based technologies, as the slope of the fuel price trajectories for these other fuels is generally shallower than for natural gas.

24. For example, larger foresight terms are found for the Low Oil/Gas Resource scenario than for the Reference scenario because of the more rapid increase in estimated natural gas prices.

25. The age-based retirements result in essentially no nuclear retirements by 2030. However, recent and announced nuclear retirements (e.g., the San Onofre Nuclear Generating Station retirement in 2013) are included in ReEDS.

a given year, an amount of capacity is retired such that the capacity factor of the BA would be equal to that threshold. The utilization-based retirement is not active until 2020 and becomes increasingly stringent over time.[26] The oldest and least-efficient extant coal units are retired preferentially in this scheme. While all generator types retire at the end of their defined equipment lifetimes, the site-specific technologies that have resource-accessibility supply curves (wind, solar, geothermal) require some special consideration. When their capacity retires (e.g., wind capacity retires upon reaching its assumed 24-year life), the freed resource potential in that site is available for new builds—but with a zero-accessibility cost, as the existing spur line and other site infrastructure for any new builds remain available from the prior facility.

As described in Section D.2.2, degradation of the efficiency of solar-PV capacity over time is also modeled at 0.5% per year, which indicates that the capacity of PV that generates energy is reduced by 0.5% every year. For results detailed in this report, however, the total PV capacity does not reflect this degradation and remains at the initial nameplate capacity, while the generation reported from this capacity is reduced, reflecting the efficiency degradation of that capacity over time.

D.5 Financial Assumptions

Aside from alternative financing assumptions for hydropower in all *Low Cost Finance* scenarios, ReEDS uses generalized financial assumptions that are standardized across technologies. While this assumption may not accurately represent project financing today, the standardized method allows for a consistent comparison of technologies without projecting uncertain technology-specific risk profiles into the future. The ReEDS financing assumptions allow for the comparison and competition of different projects and technologies with a long-term decadal perspective and with the spatial resolution of ReEDS.

Table D-7 lists the major financial parameters used in the ReEDS analysis. All costs, including new capital investments, O&M, fuel, and transmission investments, are considered on a 20-year, net-present-value basis. The discount rate used in the present-value evaluation, which is the weighted average cost of capital based on the parameters shown in Table D-7, is 8.1% nominal (5.4% real).[27]

Table D-7. Major Financial Assumptions

Type of Assumption	Value Used
Evaluation period	20 years
Inflation rate	2.5%
Interest rate—nominal	8%
Rate of return on equity—nominal	13%
Debt fraction	60%
Combined state and federal tax	40%
Discount rate—nominal (real)	8.1% (5.4%)
Modified accelerated cost recovery system (MACRS) (non-hydropower renewables)	5 years
MACRS (nuclear, combustion turbines)	15 years
MACRS (other fossil, hydropower, storage)	20 years

26. The capacity factor threshold starts at 0.01% in 2020, increases linearly to 0.5% in 2040, and stays flat at that value until 2050.

27. ReEDS considers all costs in real dollar terms, but the parameters presented in Table D-7 are primarily nominal.

In addition to the general financial assumptions, some technology-specific parameters are used in ReEDS. In particular, technology-specific construction periods yield different construction financing costs. Tax credits and accelerated tax-depreciation rules also yield different financing terms across technologies.

D.6 End-Use Electricity Demand

The end-use electricity demand projection used in ReEDS is exogenously defined. The scenarios presented in Chapter 3 all rely on the same end-use demand projection. The 2010 electricity demand in ReEDS is calibrated from Ventyx (2013) [30] and EIA's Electric Power Annual 2012 [33]. In particular, Ventyx's hourly load data is temporally aggregated to determine the 17 time-slice load profiles for the model BAs. These 2010 profiles are scaled to match the state-level annual load data from EIA's Electric Power Annual 2012 [33]. The load growth factors for years after 2010 are calculated from the AEO 2015 Reference scenario's load projections by census regions [16].[28] For each solve year in ReEDS, the regional load profiles are increased by regional growth factors.[29]

Figure D-8 shows the end-use electricity demand projection for the continental United States as modeled in all scenarios presented in Chapter 3. While regional variations exist, the annual growth rate in this projection is about 0.7% per year from 2014 to 2050. In addition, ReEDS assumes 5.3% of the end-use demand as losses in the distribution system for all years and all regions.

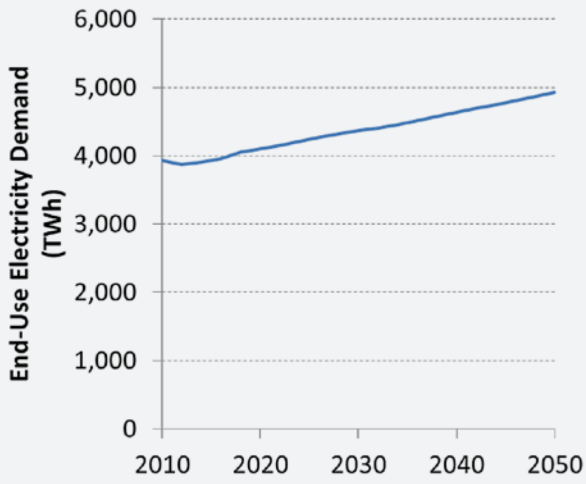


Figure D-8. Continental U.S. end-use electricity demand used in the *Hydropower Vision* analysis

The price-demand elasticity option in ReEDS is not used for the scenarios modeled for this report. Energy efficiency is only modeled indirectly through the embedded results of the AEO 2015 Reference scenario [16]. Similarly, demand response is only included to the extent that it was included in the AEO 2015 Reference scenario; the ReEDS scenarios did not explicitly include demand-side options to support VG integration or, more broadly, grid operations. Demand response is an option to increase grid flexibility through scheduled or fixed changes in electricity demand profiles and can be used to help support renewable grid integration. All things being equal, the absence of demand response likely may lead to overestimates of the incremental cost of certain scenarios since this potentially important flexibility option is not incorporated into the model. Further work is needed to evaluate the costs and benefits of demand response within the scenarios explored in the *Hydropower Vision* analysis.

28. The demand growth factors from AEO's census regions are applied to the ReEDS NERC-level regions. Due to differences in AEO's census regions and the similarly sized NERC regions in ReEDS, the projected national load in ReEDS does not agree exactly with AEO's demand projections, but the differences are small, particularly on the national-level results.

29. For years after 2040, for which AEO does not have projections, the average growth rate projected between 2030 and 2040 is used.

D.7 Transmission Assumptions

For each scenario, ReEDS estimates the amount and location of transmission expansion, including long-distance inter-BA transmission, as well as intra-BA spur-line transmission needs for new wind capacity. Transmission dispatch is modeled for each of the 17 ReEDS time slices through a linearized direct-current (DC) power flow algorithm among the 134 model BAs. This section provides further detail on the transmission assumptions used in modeled scenarios.

D.7.1 Long-Distance Transmission

The existing (2010) long-distance transmission infrastructure is modeled in ReEDS with more than 300 aggregate long-distance transmission lines connecting 134 BAs (shown in Figure D-9). The initial transmission infrastructure is based on data for 2010.[30] The existing transmission network comprises primarily alternating-current (AC) transmission lines. Expansion of the AC network among adjacent BAs is a model decision based on the overall system optimization of the model. Due to the long siting, permitting, and construction lead times needed for transmission projects, ReEDS restricts all pre-2020 transmission expansion to projects already underway (see Table D-8).

ReEDS also considers DC transmission lines, including existing DC lines and any DC interties between the three major interconnections. Expansion of the DC network is limited to the planned DC projects under construction (Table D-9) and the expansion of the cross-interconnection AC-DC-AC interties. It is important to note that, while the system-wide optimization and linear program in ReEDS is intended to consider the transmission needs for remote resources and to provide high-level estimates of transmission expansion and associated costs, it is not designed as a transmission planning tool. As such, the transmission results from and assumptions used in ReEDS are not intended to distinguish among different transmission technologies into the future, including important distinctions between AC and DC lines.

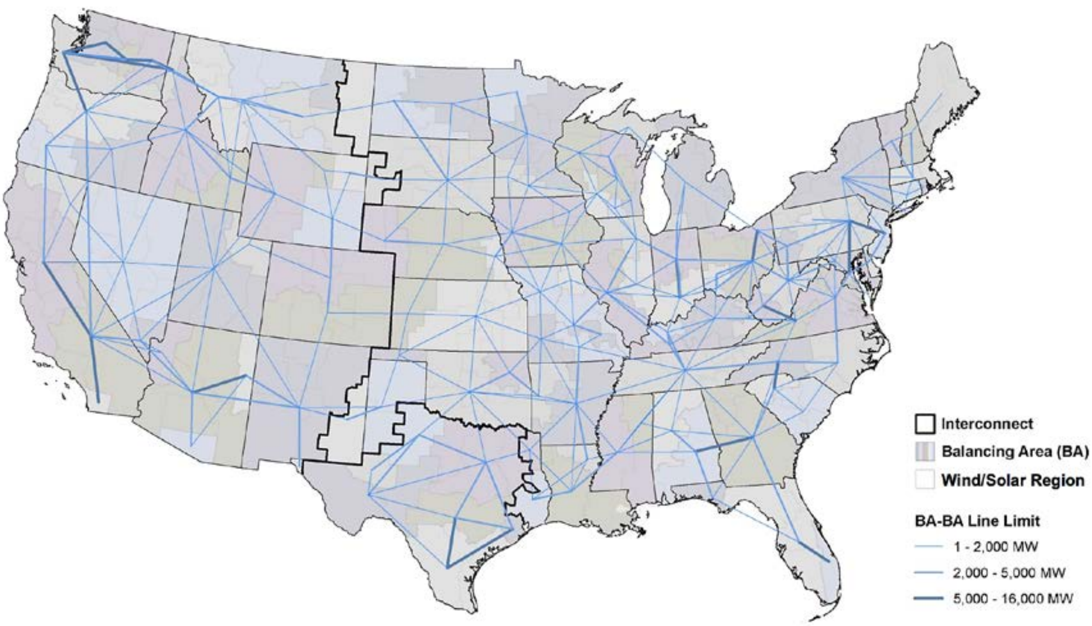


Figure D-9. Existing long-distance transmission infrastructure in ReEDS

30. See Short et al. [1].

Table D-8. Allowed AC Transmission Builds Before 2020

Name—Location (none listed for larger projects spanning multiple areas)	
Adair—Ottumwa	Adair—Palmyra Tap
Big Eddy—Knight	Big Hill—Kendall
Bluff Creek—Brown	Brookings—Hampton
Central Bluff—Bluff Creek	Clear Crossing—Willow Creek
Fargo—St. Cloud	Glenwillow—Bruce Mansfield
Gray—Tesla	Greater Springfield Reliability Project
Greenline	Hampton—La Crosse
High Plains Express	Hitchland—Woodward
I-5 Corridor Reinforcement	Interstate Reliability Project
Kansas Electric Transmission Authority (KETA) Project	Lakefield Junction —Webster
Las Vegas—Los Angeles	McNary—John Day
Midwest Transmission Project	Mountain States Transmission Intertie
North LaCrosse—Cardinal	North Gila—Imperial Valley
Odessa—Bakersfield	One Nevada Transmission Line
Palmyra Tap—Pawnee	Pawnee—Pana
Pioneer Transmission	Pleasant Prairie—Zion Energy Center
Reynolds—Rockport	Riley—Bowman
Riley—Krum West	Reliability Interregional Transmission Extension Line (RITELine)
RS20—Silver King—Coronado	Seminole—Muskogee Project
Southwest Intertie	Sunzia Southwest
Susquehanna—Roseland	Tesla—West Shackelford
Tippet—North McCamey	Toronto—Harmon Star
Trans-Allegheny Interstate Line	TUCO Substation—Texas/Oklahoma Interconnect
Twin Buttes—Brown	Winco—Hazleton
Woodward—Hitchland	

Table D 9. Allowed DC Transmission Builds

Name of Allowed DC Transmission Build	
Zephyr	Southern Cross
Plains and Eastern Clean Line	High Plains Express
Grain Belt Express Clean Line	Northeast Energy Link

D.7.2 Spur-Line Transmission and Geospatial Supply Curves

Because the resources for wind and solar are highly sensitive to location, they are assessed additional costs to represent the needed spur lines, with costs being based on an estimated distance to transmission infrastructure. These supply curves are developed based on geographic-information-system analysis, which estimates the resource accessibility costs in terms of supply curves based on the expected cost of linking renewable resource sites to the high-voltage, long-distance transmission network. The details on the assumptions and methods used to estimate the supply curves for these intraregional spur lines are provided in detail in the *Wind Vision* Appendix H [38].

D.7.3 Transmission Costs

The long-distance and spur-line transmission costs in ReEDS are based on ReEDS line-voltage and regional-multiplier assumptions. For long-distance interregional transmission lines, an assumed voltage (345 kilovolts [kV], 500 kV, or 765 kV) is applied for each region. This voltage assumption for each BA for long-distance transmission is taken from the highest voltage line currently operating in the BA from the Homeland Security Infrastructure Program [34]. For BAs where the highest voltage of currently operating transmission lines is less than 500 kV, the voltage in the future is assumed to be 765 kV; and the associated costs for 765-kV lines are used for all years. For BAs where the highest voltage of currently operating transmission lines is 500 kV, the costs for 500-kV lines are used. The only exceptions to these rules for voltages are in the Eastern Interconnection for BAs in New England (Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine) and New York, which are assumed to use 345-kV transmission lines for all years. A base capital cost is associated with each voltage line from the Phase II Eastern Interconnection Planning Collaborative (EIPC) report [35]. The base transmission costs taken from the EIPC report used in ReEDS are $2,370/MW-mile, $1,370/MW-mile, and $1,420/MW-mile for 345-kV, 500-kV, and 765-kV transmission lines, respectively [35].[31]

All spur-line costs are based on 230-kV line costs, assumed to be $3,730/MW-mile [35].[32] Because the plant envelope used to determine technology capital cost assumptions includes the on-site switchyard, the short spur line, and the relevant upgrades at the substation [29]; technologies that are generally sited close to load incur no additional grid-interconnection cost.

In addition to the base transmission costs for long-distance transmission lines, regional multipliers, largely based on assumptions from the EIPC report [35], are also applied. Regional transmission cost multipliers, which are the average of the EIPC report's high and low multipliers in each North American Electricity and Environmental Model region, are associated with the assumed voltage for the region. BAs in the Electric Reliability Council of Texas and the Western Interconnection (excluding Canada) are assumed to have a regional transmission multiplier of one. Long-distance transmission costs in BAs in the California Independent System Operator are 2.25 times the cost of the other baseline costs for the rest of the Western Interconnection. For long-distance transmission among BAs with different transmission costs, the average cost is used. The same process is applied for wind spur-line costs.

31. The base transmission costs for ReEDS are converted into dollars/MW-mile according to new transmission line cost and capacity assumptions for single-circuit conductors for each voltage in the EIPC report [35]. The costs reported are in 2014 dollars.

32. Spur-line costs are applied within the development of the wind and solar resource supply curves.

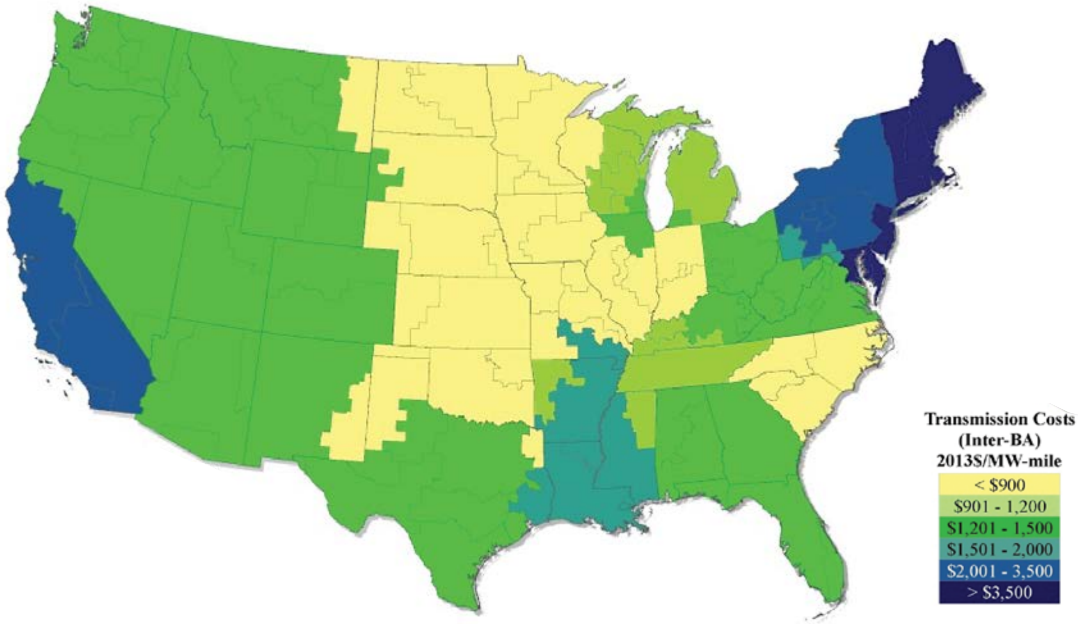


Figure D-10. Map of long-distance transmission costs

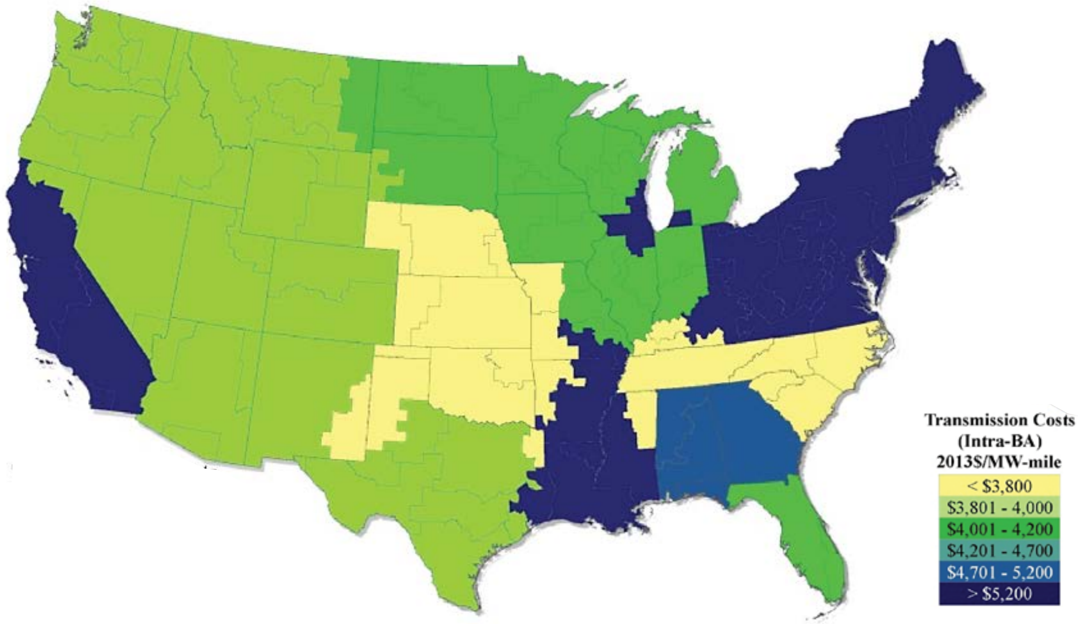


Figure D-11 Map of spur-line transmission costs

Figures D-10 and D-11, respectively, show the regional long-distance and spur-line transmission costs resulting from the previously described steps and assumptions.

D.7.4 Transmission Dispatch

The long-distance transmission dispatch is modeled in ReEDS using a linearized DC power flow algorithm for the AC transmission network [10]. The algorithm approximates Kirchhoff's voltage law by determining the power flow in a network based on injections and withdrawals at each BA, and the line susceptances and carrying capacities. Full flow control is modeled for DC lines in ReEDS. The ReEDS model considers these transmission flow limits when dispatching energy generation in each of the 17 time slices and in contracting firm capacity for system adequacy needs. Adding capacity on a transmission corridor in a particular ReEDS solve year increases that line's susceptance in subsequent years, thus increasing the proportion of a power injection that takes that route. ReEDS does not address the AC-power-flow issues of voltage, frequency, or phase angle. Intra-BA transmission and distribution networks are similarly ignored. However, the transmission dispatch accounts for losses in the long-distance transmission, as well as the distribution networks. Long-distance transmission energy losses are assumed to be 1% per 100 miles. These losses are representative of the losses occurring over the high-voltage bulk transmission system. As mentioned earlier, for losses within a distribution network and between the distribution and transmission networks, a 5.3% loss is assumed for each model BA.

Appendix D References

[1] Short, W., P. Sullivan, T. Mai, M. Mowers, C. Uriarte, N. Blair, D. Heimiller, and A. Martinez. 2001. *Regional Energy Deployment System (ReEDS)* (Technical Report). NREL/TP-6A20-46534. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy12osti/46534.pdf*.

[2] Energy Information Administration. 2013. *Form EID-411 Data: Coordinated Bulk Power Supply and Demand Program Report.* U.S. Department of Energy, Energy Information Administration, Washington, DC. Accessed June 6, 2016. *www.eia.gov/electricity/data/eia411/*.

[3] Energy Information Administration. 2009. *The National Energy Modeling System: An Overview 2009*. DOE/EID-0581 (2009). U.S. Department of Energy, Energy Information Administration, Washington, DC.

[4] U.S. Department of Energy. 2012. *SunShot Vision Study*. DOE/GO-102012-3037. U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, Washington, DC. Accessed June 6, 2016. *www1.eere.energy.gov/solar/pdfs/47927.pdf*.

[5] Mai, T., R. Wiser, D. Sandor, G. Brinkman, G. Heath, P. Denholm, D. Hostick, N. Darghouth, A. Schlosser, and K. Strzepek. 2012. *Renewable Electricity Futures Study: Exploration of High-Penetration Renewable Electricity Futures*, *Vol. 1 of 4* (Technical Report). NREL/TP-6A20-52409. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy12osti/52409-1.pdf*.

[6] Lantz, E., D. Steinberg, M. Mendelsohn, O. Zinaman, T. James, G. Porro, M. Hand, T. Mai, J. Logan, J. Heeter, and L. Bird. 2014. *Implications of a PTC Extension on U.S. Wind Deployment* (Technical Report). NREL/TP-6A20-61663. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy14osti/61663.pdf*.

[7] Eurek, K., P. Denholm, R. Margolis, and M. Mowers. 2013. *Sensitivity of Utility-Scale Solar Deployment Projections in the SunShot Vision Study to Market and Performance Assumptions*. NREL/TP-6A20-55836. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016 *www.nrel.gov/docs/fy13osti/55836.pdf*.

[8] Martinez, A., K. Eurek, T. Mai, and A. Perry. 2013. *Integrated Canada-U.S. Power Sector Modeling with the Regional Energy Deployment System (ReEDS)* (Technical Report). NREL/TP-6A20-56724. National Renewable Energy Laboratory Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy13osti/56724.pdf*.

[9] Logan, J., G. Heath, J. Macknick, E. Paranhos, W. Boyd, and K. Carlson. 2012. *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity* (Technical Report). NREL/TP-6A50-55538. National Renewable Energy Laboratory Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy13osti/55538.pdf*.

[10] Mai, T., D. Mulcahy, M. Hand, and S. Baldwin. "Envisioning a Renewable Electricity Future for the United States." *Energy*; Vol. 65, pp. 374–386, February 2014. doi:10.1016/j.energy.2013.11.029. Accessed June 6, 2016. *http://dx.doi.org/10.1016/j.energy.2013.11.029.*

[11] Logan, J., A. Lopez, T. Mai, C. Davidson, M. Bazilian, and D. Arent. "Natural Gas Scenarios in the U.S. Power Sector." *Energy Economics;* Vol. 40, pp. 183–195, November 2013. doi:10.1016/j.eneco.2013.06.008. Accessed June 6, 2016. *http://www.sciencedirect.com/science/article/pii/S0140988313001217*.

[12] Clemmer, S., J. Rogers, S. Sattler, J. Macknick, and T. Mai. "Modeling low-carbon US electricity futures to explore impacts on national and regional water use." *Environmental Research Letters* (8:1), p. 11, January 2013. doi:10.1088/1748-9326/8/1/015004. Accessed June 6, 2016. *http://iopscience.iop.org/article/10.1088/1748-9326/8/1/015004/pdf*.

[13] Mignone, B.K., T. Alfstad, A. Bergman, K. Dubin, R. Duke, P. Friley, A. Martinez, M. Mowers, K. Palmer, A. Paul, S. Showalter, S. Steinberg, W. Woerman, and F. Wood. "Cost-Effectiveness and Economic Incidence of a Clean Energy Standard." *Economics of Energy & Environmental Policy*, Vol. 1, Number 3, pp. 59–86, 2012. doi:10.5547/2160-5890.1.3.5. Accessed June 6, 2016. *www.iaee.org/en/publications/eeeparticle.aspx?id=32*.

[14] Denholm, P., E. Drury, and R. Margolis. 2009. *The Solar Deployment System (SolarDS) Model: Documentation and Sample Results* (Technical Report). NREL/TP-6A2-45832. National Renewable Energy Laboratory Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy10osti/45832.pdf*.

[15] Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D.; eds. 2012. *Renewable Electricity Futures Study* (Full Technical Report). NREL/TP-6A20-52409. National Renewable Energy Laboratory Golden, CO. Accessed June 6, 2016. *http://www.nrel.gov/analysis/re_futures/*

[16] Energy Information Administration. 2015. *Annual Energy Outlook 2015 with Projections to 2040*. DOE/EID-0383. U.S. Department of Energy, Energy Information Administration, Washington, DC. Accessed June 6, 2016. *www.eia.gov/forecasts/aeo/pdf/0383%282015%29.pdf*

[17] Feldman, D., G. Barbose, R. Margolis, T. James, S. Weaver, N. Darghouth, R. Fu, C. Davidson, S. Booth, and R. Wiser. "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections—2014 Edition" (Presentation). September 2014. NREL/PR-6A20-62558. National Renewable Energy Laboratory Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy14osti/62558.pdf*.

[18] GTM Research and the Solar Energy Industries Association. 2013. *Solar Market Insight 2013 Q3*. Solar Energy Industries Association, Washington, DC. Accessed June 6, 2016. *www.seia.org/research-resources/us-solar-market-insight*.

[19] "Q1 2013 North America Wind Market Outlook." New York: Bloomberg New Energy Finance, 2013.

[20] Global Wind Energy Council, Greenpeace International, and SolarPowerEurope. 2012. *Energy [R]evolution*, 4th ed. Greenpeace, Washington, DC. Accessed June 6, 2016. *www.greenpeace.org/international/en/campaigns/climate-change/energyrevolution/*.

[21] GTM Research and the Solar Energy Industries Association. 2011. *Solar Market Insight 2011 Q4*. Solar Energy Industries Association, Washington, DC: Accessed June 6, 2016: *www.seia.org/research-resources/us-solar-market-insight-report-2011-year-review*.

[22] International Energy Agency. 2013. *Technology Roadmap: 2013 Edition.* International Energy Agency, Paris, France.

[23] "Q4 2013 PV Market Outlook." New York: Bloomberg New Energy Finance, 2013.

[24] Blair, N., A. Dobos, J. Freeman, T. Neises, M. Wagner, T. Ferguson, P. Gilman, and S. Janzou. 2014. *System Advisor Model, SAM 2014.1.14: General Description* (Technical Report). NREL/TP-6A20-61019. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy14osti/61019.pdf*

[25] Hadjerioua, B., S.-C. Kao, R. A. McManamay, M. F. K. Pasha, D. Yeasmin, A. A. Oubeidillah, N. M. Samu, K. M. Stewart, M. S. Bevelhimer, S. L. Hetrick, Y. Wei, and B. T. Smith. 2013. *An Assessment of Energy Potential from New Stream-Reach Development in the United States: Initial Report on Methodology* (Technical Manual), p. 298. Oak Ridge National Laboratory, Oak Ridge, TN (US). Accessed June 6, 2016. *http://nhaap.ornl.gov/nsd*.

[26] Hadjerioua, B., Y. Wei, and S.-C. Kao. 2012. *An Assessment of Energy Potential at Non-Powered Dams in the United States*. GPO DOE/EE-0711. Prepared by Oak Ridge National Laboratory for the U.S. Department of Energy Wind and Water Power Program. Oak Ridge National Laboratory, Oak Ridge, TN (US). Accessed June 6, 2016. *www.worldcat.org/title/assessment-of-energy-potential-at-non-powered-dams-in-the-united-states-report/oclc/842094581*.

[27] Hall, D.G., R. T. Hunt, K. S. Reeves, and G. R. Carroll. 2003. *Estimation of Economic Parameters of U.S. Hydropower Resources*. INEEL/EXT-03-00662. Idaho National Engineering and Environmental Laboratory, Idaho Falls, ID (US). Accessed June 6, 2016. *www1.eere.energy.gov/wind/pdfs/doewater-00662.pdf*.

[28] Augustine, C. 2011. Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input (Technical Report). TP-6A2-47459. National Renewable Energy Laboratory Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy12osti/47459.pdf*.

[29] Beamon, A., and M. Leff. 2013. *EOP III Task 1606, Subtask 3—Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report*, *Appendix B of Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*. Work performed by SAIC Energy, Environment & Infrastructure, McLean, VA, (US). U.S. Department of Energy, Energy Information Administration, Washington, DC. Accessed June 6, 2016. *http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf*.

[30] "Energy Market Intelligence & Forecasting Solutions." Ventyx, 2013.

[32] Energy Information Administration. 2014. *Assumptions to the Annual Energy Outlook 2014. Independent Statistics and Analysis*. U.S. Department of Energy, Energy Information Administration Washington, DC. Accessed June 6, 2016. *http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554%282014%29.pdf*.

[33] Energy Information Administration. 2013. *Electric Power Annual 2012.* U.S. Department of Energy, Energy Information Administration, Washington, DC. Accessed June 6, 2016. *http://www.eia.gov/electricity/annual/*.

[34] U.S. Department of Homeland Security. 2012. "Homeland Security Infrastructure Program." U.S. Department of of Homeland Security, Washington, DC. Accessed June 6, 2016. *https://www.dhs.gov/infrastructure-information-partnerships*.

[35] Eastern Interconnection Planning Collaborative. 2012. *Phase 2 Report: DOE Draft Parts 2–7—Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios.* Washington, DC. Accessed June 16, 2016. *http://www.eipconline.com/phase-ii-documents.html*.

[36] Sullivan, P., W. Cole, N. Blair, E. Lantz, V. Krishnan, T. Mai, D. Mulcahy, and G. Porro. 2015. *2015 Standard Scenarios Annual Report: U.S. Electric Sector Scenario Exploration* (Technical Report). NREL/TP-6A20-64072. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016. *http://www.nrel.gov/docs/fy15osti/64072.pdf*.

[37] Energy Information Administration. 2014. *Annual Energy Outlook 2014 with Projections to 2040*. DOE/EID-0383 (2014). U.S. Department of Energy, Energy Information Administration, Washington, DC. Accessed Jan. 20, 2016. *www.eia.gov/forecasts/AEO/pdf/0383%282014%29.pdf*.

[38] U.S. Department of Energy. 2015. *Wind Vision: A new era for wind power in the United States*. U.S. Department of Energy, Washington, DC. Accessed June 6, 2016. *http://energy.gov/eere/wind/maps/wind-vision*.

[39] Wiser, R. and M. Bolinger. 2014. *2013 Wind Technologies Market Report*. DOE/GO-102014-4459. U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Washington, DC. Accessed June 6, 2016. *www.energy.gov/eere/wind/downloads/2013-wind-technologies-market-report*.

[40] Wiser, R. and M. Bolinger. 2013. *2012 Wind Technologies Market Report*. DOE/GO-102013-3948. U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Washington, DC. Accessed June 6, 2016. *www.energy.gov/indianenergy/downloads/2012-wind-technologies-market-report*.

[41] Lantz, E., R. Wiser, and M. Hand. 2012. *IEA Wind Task 26: The Past and Future Cost of Wind Energy* (Technical Report). NREL/TP 6A20-53510. National Renewable Energy Laboratory, Golden, CO (US). *www.nrel.gov/docs/fy12osti/53510.pdf*.

[42] Tegen, S.; M. Hand, B. Maples, E. Lantz, P. Schwabe, and A. Smith. 2012. *2010 Cost of Wind Energy Review* (Technical Report). NREL/TP-5000-52920. National Renewable Energy Laboratory, Golden, CO (US). *www.nrel.gov/docs/fy12osti/52920.pdf*.

[43] The Crown Estate. 2012. *Offshore Wind Cost Reduction Pathways Study*. London, England. Accessed June 6, 2016. *www.thecrownestate.co.uk/media/5493/ei-offshore-wind-cost-reduction-pathways-study.pdf*

[44] Department of Energy and Climate Change. 2011. *Update of UK Shadow Flicker Evidence Base*. Prepared by Parsons Brinckerhoff for the Department of Energy and Climate Change, London, England. Accessed June 6, 2016. *www.gov.uk/government/publications/update-of-uk-shadow-flicker-evidence-base*.

[45] International Energy Agency. 2013. *World Energy Outlook 2013*. International Energy Agency, Paris, France. Accessed June 6, 2016. *www.worldenergyoutlook.org/publications/weo-2013/*.

[46] van der Zwaan, B., R. Rivera-Tinoco, S. Lensink, and P. van den Oosterkamp. “Cost Reductions for Offshore Wind Power: Exploring the Balance Between Scaling, Learning and R&D.” *Renewable Energy* (41), May 2012: pp. 389–393. doi:10.1016/j.renene.2011.11.014. Accessed June 6, 2016. *www.sciencedirect.com/science/article/pii/S0960148111006161*.

[47] Wiser, R., Z. Yang, M. Hand, O. Hohmeyer, D. Infield, P. H. Jensen, V. Nikolaev, M. O’Malley, G. Sinden, and A. Zervos. “Wind Energy,” Chapter 7 of the *Intergovernmental Panel on Climate Change (IPCC) Special Report on Renewable Energy Sources and Climate Change Mitigation*, edited by Edenhofer, O., R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, et al. Cambridge, UK, and New York, NY: Cambridge University Press, 108 pp., 2011.

[48] Musial, W., and S. Butterfield. 2004. “Future for Offshore Wind Energy in the United States.” Prepared for Energy Ocean 2004 (Preprint). NREL/CP-500-36313. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 6, 2016. *www.nrel.gov/docs/fy04osti/36313.pdf*.

Appendix E: *Hydropower Vision* Scenario Matrix

This appendix complements the scenario framework discussion in Section 3.3 by presenting a full scenario listing in matrix form that enumerates input parameter settings for all parameters varied throughout the Hydropower Vision analysis. This comprehensive list includes all scenarios allowing new hydropower deployment beyond currently announced projects.

Table E-1. *Hydropower Vision* Scenario Matrix

Scenario Name	Hydropower Cost	Hydropower Asset Value	Environmental Attribute Exclusion	Hydropower Water Availability	Fossil Fuel Cost	VG Cost
Business-as-Usual	Cen.	Std.	None	Cen.	Cen.	Cen.
Low Fossil Fuel Cost	Cen.	Std.	None	Cen.	**Low**	Cen.
Low VG Cost	Cen.	Std.	None	Cen.	Cen.	**Low**
High Fossil Fuel Cost	Cen.	Std.	None	Cen.	**High.**	Cen.
High VG Cost	Cen.	Std.	None	Cen.	Cen.	**High**
Advanced Technology, Low Fossil Fuel Cost	**AT**	Std.	None	Cen.	**Low**	Cen.
Advanced Technology, Low VG Cost	**AT**	Std.	None	Cen.	Cen.	**Low**
Advanced Technology	**AT**	Std.	None	Cen.	Cen.	Cen.
Advanced Technology, High Fossil Fuel Cost	**AT**	Std.	None	Cen.	**High**	Cen.
Advanced Technology, High VG Cost	**AT**	Std.	None	Cen.	Cen.	**High**
Low Cost Finance, Low Fossil Fuel Cost	Cen.	**LCF**	None	Cen.	**Low**	Cen.
Low Cost Finance, Low VG Cost	Cen.	**LCF**	None	Cen.	Cen.	**Low**
Low Cost Finance	Cen.	**LCF**	None	Cen.	Cen.	Cen.
Low Cost Finance, High Fossil Fuel Cost	Cen.	**LCF**	None	Cen.	**High**	Cen.
Low Cost Finance, High VG Cost	Cen.	**LCF**	None	Cen.	Cen.	**High**

Continued next page

Key to Abbreviations:

VG = Variable generation renewable resource
Cen. = Central
Std. = Standard
AT = Advanced Technology
ET = Evolutionary Technology
LCF = Low Cost Finance
CH = Critical Habitat
PL = Protected Lands
LDR = Low Disturbance Rivers
NRI = National Rivers Inventory
OC = Ocean Connectivity
SC = Species of Concern
MFH = Migratory Fish Habitat
CSL = Combined Sensitive Lands
CSC = Combined Species Concerns
CE = Combined Environmental

Table E-1. continued

Scenario Name	Hydropower Cost	Hydropower Asset Value	Environmental Attribute Exclusion	Hydropower Water Availability	Fossil Fuel Cost	VG Cost
Evolutionary Technology, Low Cost Finance	**ET**	**LCF**	None	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	**AT**	**LCF**	None	Cen.	**Low**	Cen.
Advanced Technology, Low Cost Finance, Low VG Cost	**AT**	**LCF**	None	Cen.	Cen.	**Low**
Advanced Technology, Low Cost Finance	**AT**	**LCF**	None	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	**AT**	**LCF**	None	Cen.	**High**	Cen.
Advanced Technology, Low Cost Finance, High VG Cost	**AT**	**LCF**	None	Cen.	Cen.	**High**
Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	**AT**	**LCF**	**CH**	Cen.	**Low**	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	**AT**	**LCF**	**CH**	Cen.	Cen.	**Low**
Advanced Technology, Low Cost Finance, Critical Habitat	**AT**	**LCF**	**CH**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	**AT**	**LCF**	**CH**	Cen.	**High**	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	**AT**	**LCF**	**CH**	Cen.	Cen.	**High**
Advanced Technology, Low Cost Finance, Protected Lands	**AT**	**LCF**	**PL**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Low Disturbance Rivers	**AT**	**LCF**	**LDR**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, National Rivers Inventory	**AT**	**LCF**	**NRI**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Ocean Connectivity	**AT**	**LCF**	**OC**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Species of Concern	**AT**	**LCF**	**SC**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Migratory Fish Habitat	**AT**	**LCF**	**MFH**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	**AT**	**LCF**	**CSL**	Cen.	Cen.	Cen.

Table E-1. continued

Scenario Name	Hydropower Cost	Hydropower Asset Value	Environmental Attribute Exclusion	Hydropower Water Availability	Fossil Fuel Cost	VG Cost
Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	**AT**	**LCF**	**CSC**	Cen.	Cen.	Cen.
Advanced Technology, Low Cost Finance, Combined Environmental Considerations	**AT**	**LCF**	**CE**	Cen.	Cen.	Cen.
Dry	Cen.	Std.	None	**Dry**	Cen.	Cen.
Wet	Cen.	Std.	None	**Wet**	Cen.	Cen.
Advanced Technology, Dry	**AT**	Std.	None	**Dry**	Cen.	Cen.
Advanced Technology, Wet	**AT**	Std.	None	**Wet**	Cen.	Cen.
Low Cost Finance, Dry	Cen.	**LCF**	None	**Dry**	Cen.	Cen.
Low Cost Finance, Wet	Cen.	**LCF**	None	**Wet**	Cen.	Cen.
Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	**AT**	**LCF**	**CE**	**Dry**	Cen.	Cen.
Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	**AT**	**LCF**	**CE**	**Wet**	Cen.	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	**AT**	**LCF**	**CH**	**Dry**	Cen.	**Low**
Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	**AT**	**LCF**	**CH**	**Wet**	Cen.	**Low**
Advanced Technology, Low Cost Finance, Critical Habitat, Dry	**AT**	**LCF**	**CH**	**Dry**	Cen.	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, Wet	**AT**	**LCF**	**CH**	**Wet**	Cen.	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	**AT**	**LCF**	**CH**	**Dry**	**High**	Cen.
Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	**AT**	**LCF**	**CH**	**Wet**	**High**	Cen.
Advanced Technology, Low Cost Finance, Dry	**AT**	**LCF**	None	**Dry**	Cen.	Cen.
Advanced Technology, Low Cost Finance, Wet	**AT**	**LCF**	None	**Wet**	Cen.	Cen.
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	**AT**	**LCF**	None	**Dry**	**High**	Cen.
Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	**AT**	**LCF**	None	**Wet**	**High**	Cen.

This page is intentionally left blank

Appendix F: Supplemental Modeling Results

This appendix contains additional figures and tabulated results data to supplement the *Hydropower Vision* analysis discussion in Chapter 3. Figure and table sets are organized as follows.

	Topic	Figures	Tables
Section F.1. Impact of the CPP on the Hydropower Vision Analysis	Installed capacity by technology	F-1	
	Generation by technology	F-2	
	Hydropower capacity deployment	F-3 – F-4	
	Hydropower energy production	F-5	
Section F.2. Supplement to Section 3.4	Hydropower capacity deployment	F-6 – F-13	F-1 – F-5
	Hydropower energy production	F-14 – F-21	F-6
	Existing fleet hydropower energy production in *Wet/Dry* scenarios		F-7
	Hydropower capacity deployment by region	F-22 – F-41	F-8 – F-11
	Overlap of New Stream-reach Development (NSD) with environmental considerations	F-42 – F-43	F-12
Section F.3. Supplement to Section 3.5	Installed capacity by technology	F-44	
	Generation by technology	F-45	
	Incremental electricity price changes		F-13
	Present value of system costs		F-14
	Hydropower costs	F-46	

F.1 Impact of the Clean Power Plan on the Hydropower Vision Analysis

All modeling scenarios presented in Chapter 3 and above assume that the Clean Power Plan (CPP) is active law pending resolution of the February 2016 Supreme Court stay of the policy. This section demonstrates the impact of the CPP on hydropower deployment in the nine selected scenarios elaborated upon in Chapter 3 by simulating those same nine scenarios without the CPP. The results and discussion herein are not a detailed policy analysis of the effects the CPP could have on the U.S. electricity system. Such an analysis is outside the scope of the *Hydropower Vision*. Rather, the purpose of this section is limited primarily to demonstrating the potential differences in hydropower deployment among scenarios with and without a CPP policy.

Figure F-1 compares capacity expansion of each power-generation technology for the *Business-as-Usual Scenario* with and without the CPP, and Figure F-2 does the same for energy generation. Details of the CPP implications on hydropower are explored using figures F-3 through F-5. Under *Business-as-Usual*, the carbon limits imposed by the CPP tend to reduce coal-based generation, which is replaced primarily by a combination of natural gas—combined cycle, wind, and photovoltaic (PV) generation. Differences become smaller in the 2040s as continued renewable energy cost reductions fulfill requirement of the policy. The same trends in behavior occur under other scenarios and market conditions, though differences are smaller with *Low VG Cost* or *High Fossil Fuel Cost* assumptions, which ease CPP compliance by making renewable electricity more attractive relative to fossil fuel-based generation. Compared to other technologies, hydropower capacity and generation are not affected substantially by the existence of the CPP in the modeled scenarios. However, the greenhouse gas and air pollution benefits derived from incremental hydropower deployment would likely be modestly larger without the CPP as a result of greater use of coal in the mid-term (~2030) time period (see also Section 3.5.7).

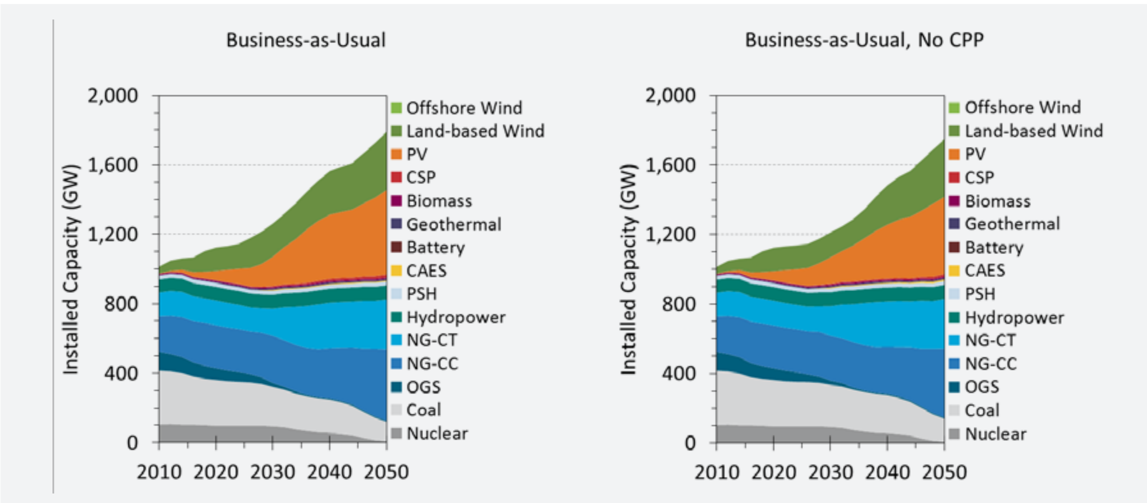


Figure F-1. Installed capacity by technology type and year in the *Business-as-Usual Scenario* with and without the CPP active

Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

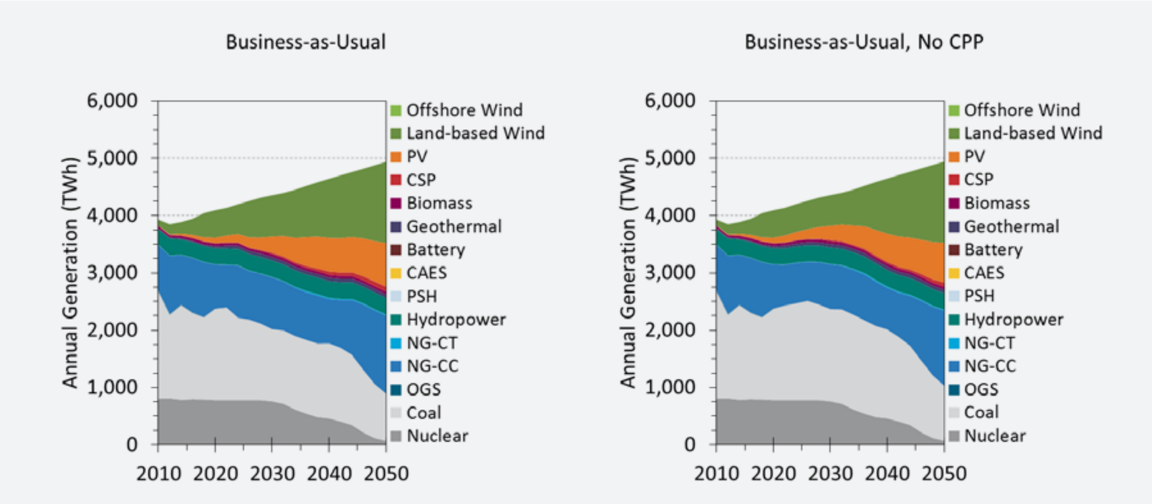


Figure F-2. Annual generation by technology type and year in the *Business-as-Usual Scenario* with and without the CPP active

Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

Figures F-3 and F-4 compare deployment of hydropower generation and Pumped Storage Hydropower (PSH), respectively, with and without the CPP policy in place. Most scenarios demonstrate only small changes in hydropower capacity due to the CPP, with typically a small increase in hydropower capacity with the policy.

The largest impact on hydropower generation capacity is observed for the *Advanced Technology, Low Cost Finance* and *Advanced Technology, Low Cost Finance, Critical Habitat* scenarios in the 2030s, where capacity is 2 gigawatts (GW) (or more) higher with the CPP. This benefit, however, diminishes in later years when significant wind and PV growth ease CPP compliance. The CPP results in no more than a 5% difference in 2050 hydropower generation capacity for all nine scenarios.

The CPP promotes additional PSH deployment for many scenarios during a large portion of the study period, but the differences are small, highly variable, and not always persistent as a result of the complex relationship among PSH, variable renewables, and gas-fired capacity. The CPP results in additional wind and PV deployment, which can support additional PSH growth as a result of the ancillary services provided by PSH capacity. However, the CPP also results in additional gas-based capacity, which provides the same ancillary services as PSH and thus can mitigate the positive correlation between PSH and variable generation. For scenarios with greater than 1 GW PSH deployment by 2050, the CPP results in no more than a 7% difference in 2050 PSH capacity.

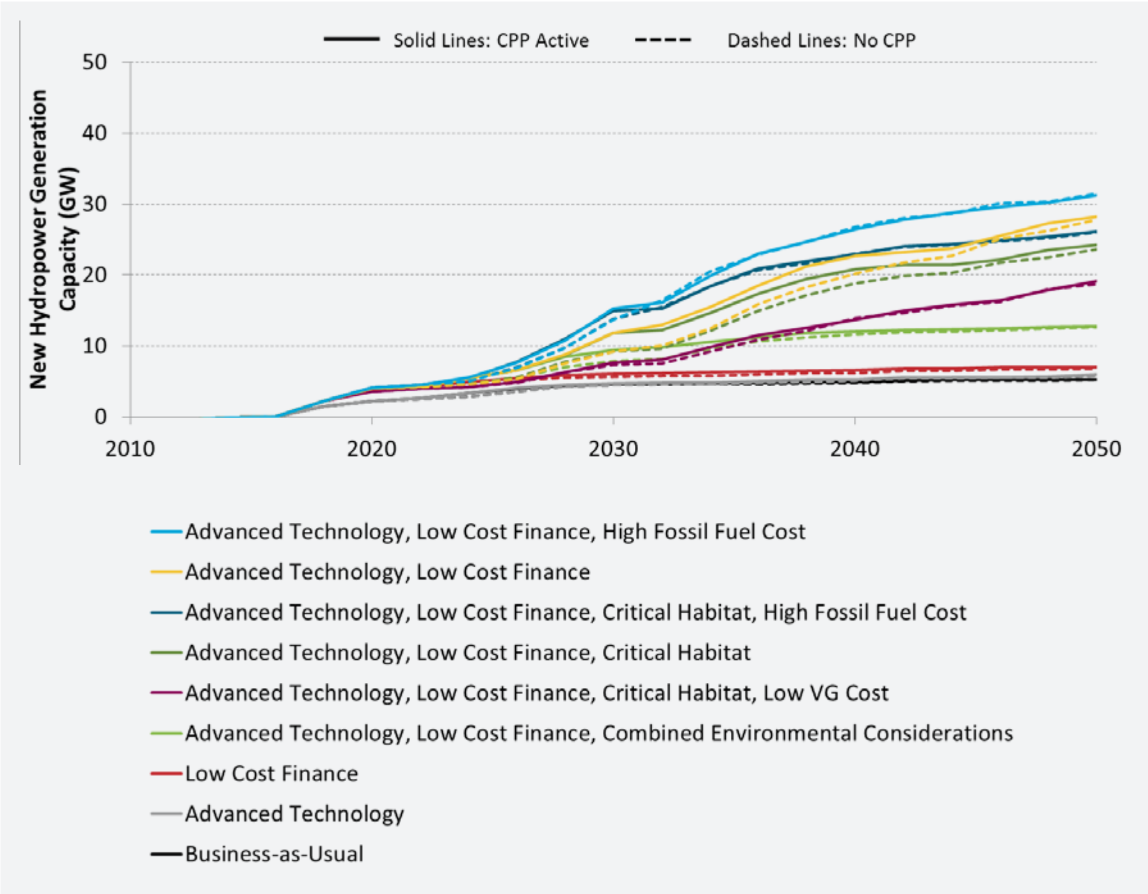


Figure F-3. Capacity growth of hydropower generation in the nine selected deployment scenarios with and without the CPP

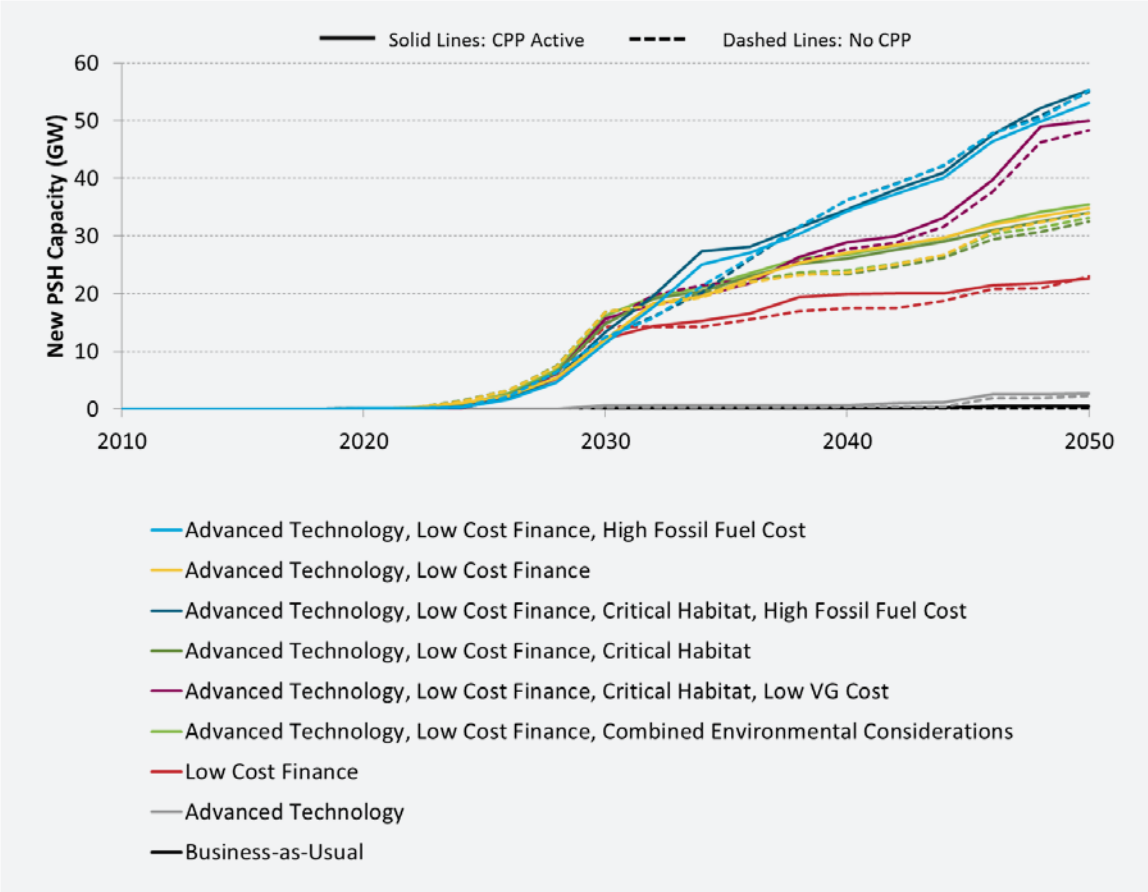


Figure F-4. Capacity growth of pumped storage hydropower in the nine selected deployment scenarios with and without the CPP

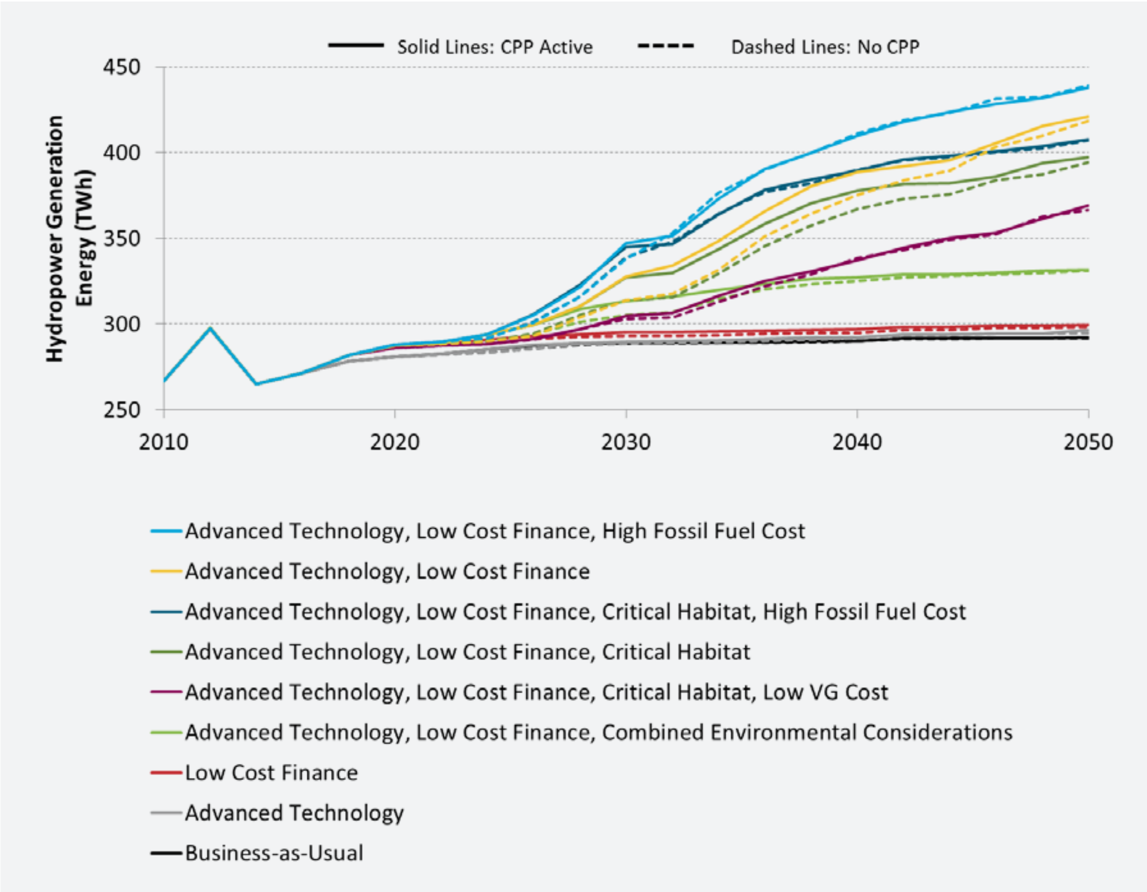


Figure F-5. Electricity generation from the existing hydropower fleet and growth in upgrades, non-powered dams (NPD), and NSD for the nine selected scenarios with and without the CPP (note: y-axis begins at 250TWh and excludes net generation from PSH)

Figure F-5 plots total energy production from all hydropower generation for the selected scenarios with and without the CPP. Trends in this figure reflect those seen for hydropower generation capacity (Figure F-3). There is up to a 5% increase in energy production in the 2030s for the *Advanced Technology, Low Cost Finance* and *Advanced Technology, Low Cost Finance, Critical Habitat* scenarios (up to a 16.6 TWh increase), but differences fall to 1% or less for those and all other scenarios by 2050.

F.2 Supplement to Section 3.4

Figures F-6 through F-13 display cumulative post-2016 new hydropower capacity for all the scenarios modeled in the *Hydropower Vision* analysis.

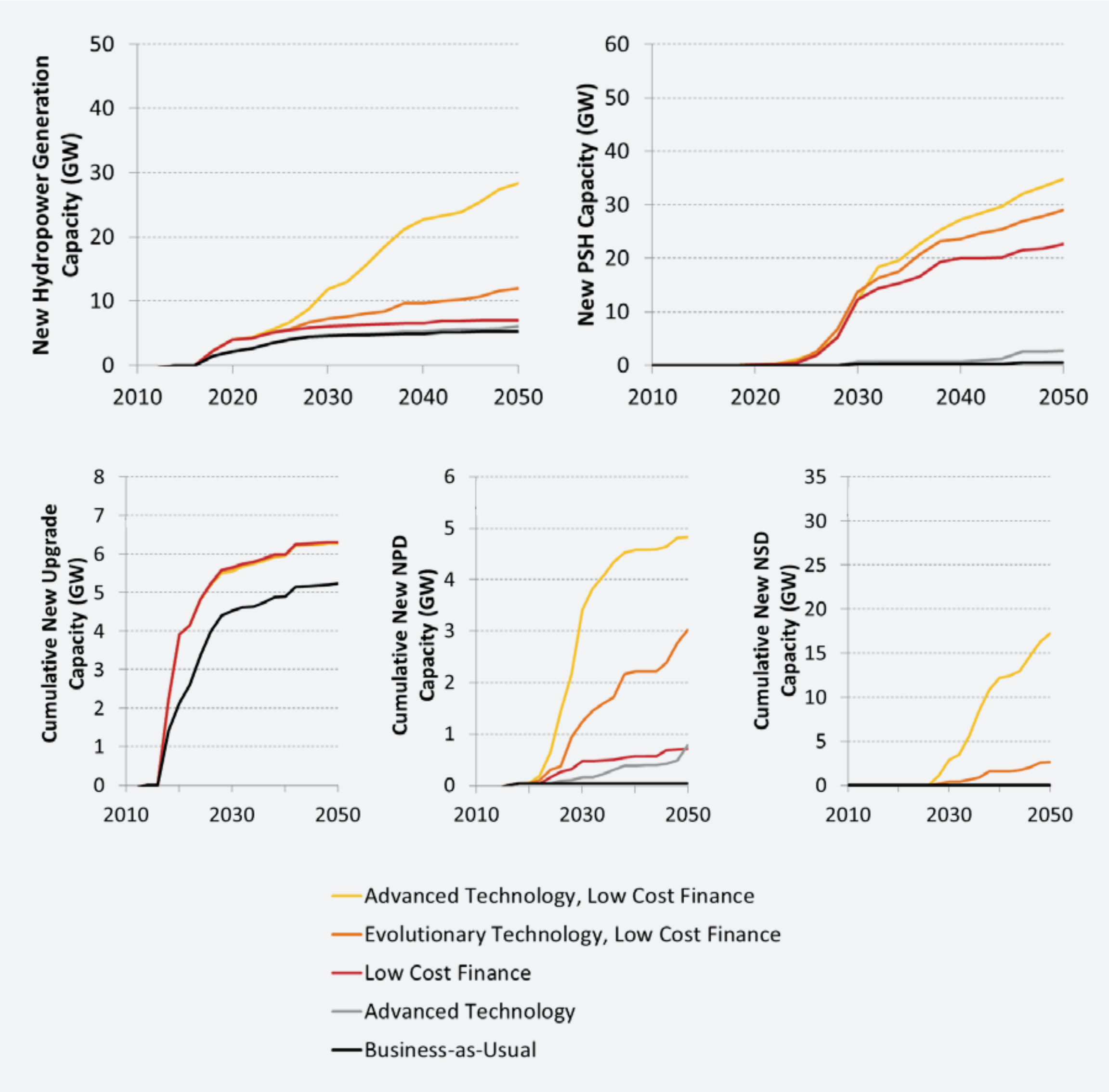


Figure F-6. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in hydropower technology cost scenarios (note: each panel uses a unique y-axis)

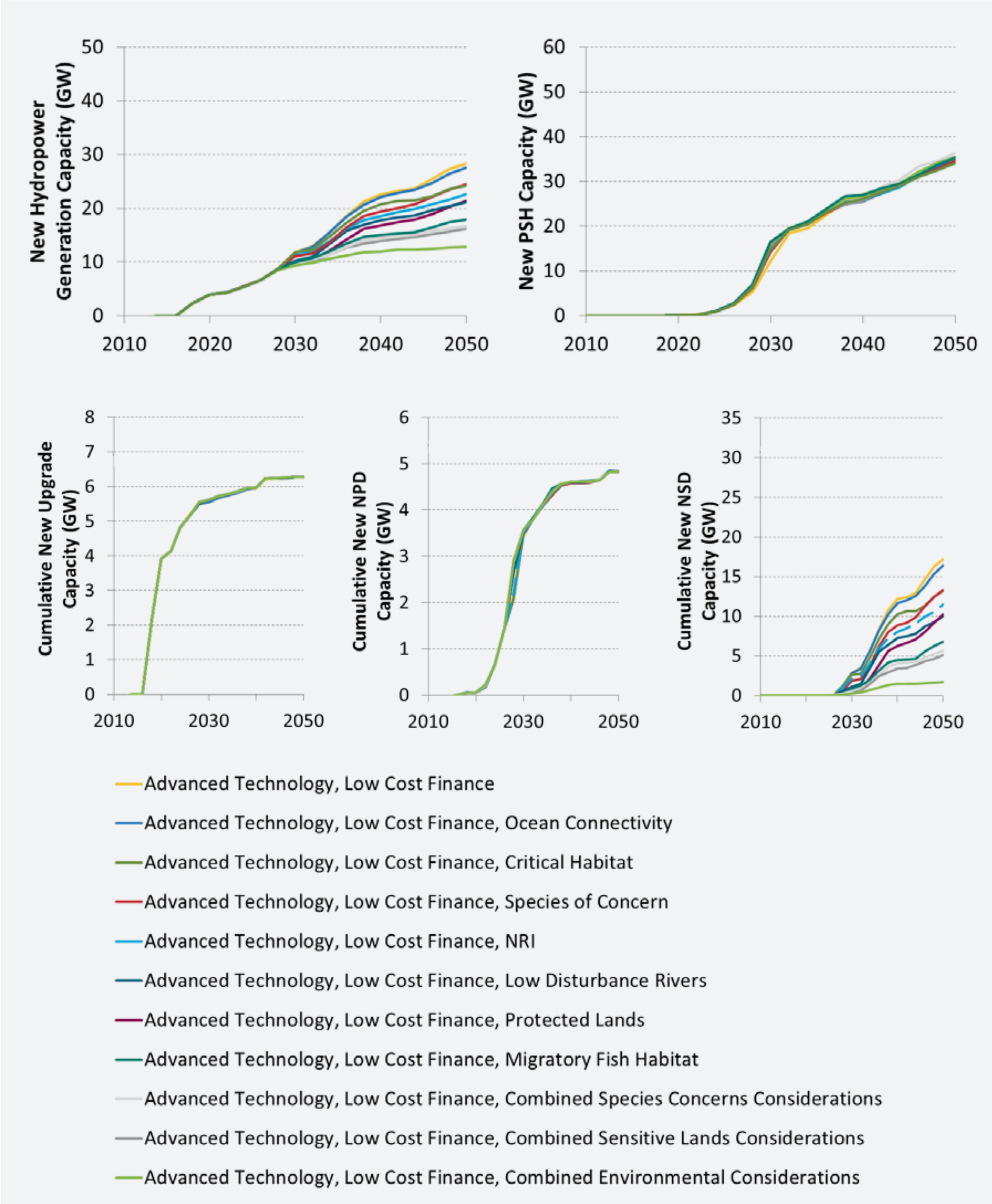


Figure F-7. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in hydropower environmental consideration scenarios (note: each panel uses a unique y-axis)

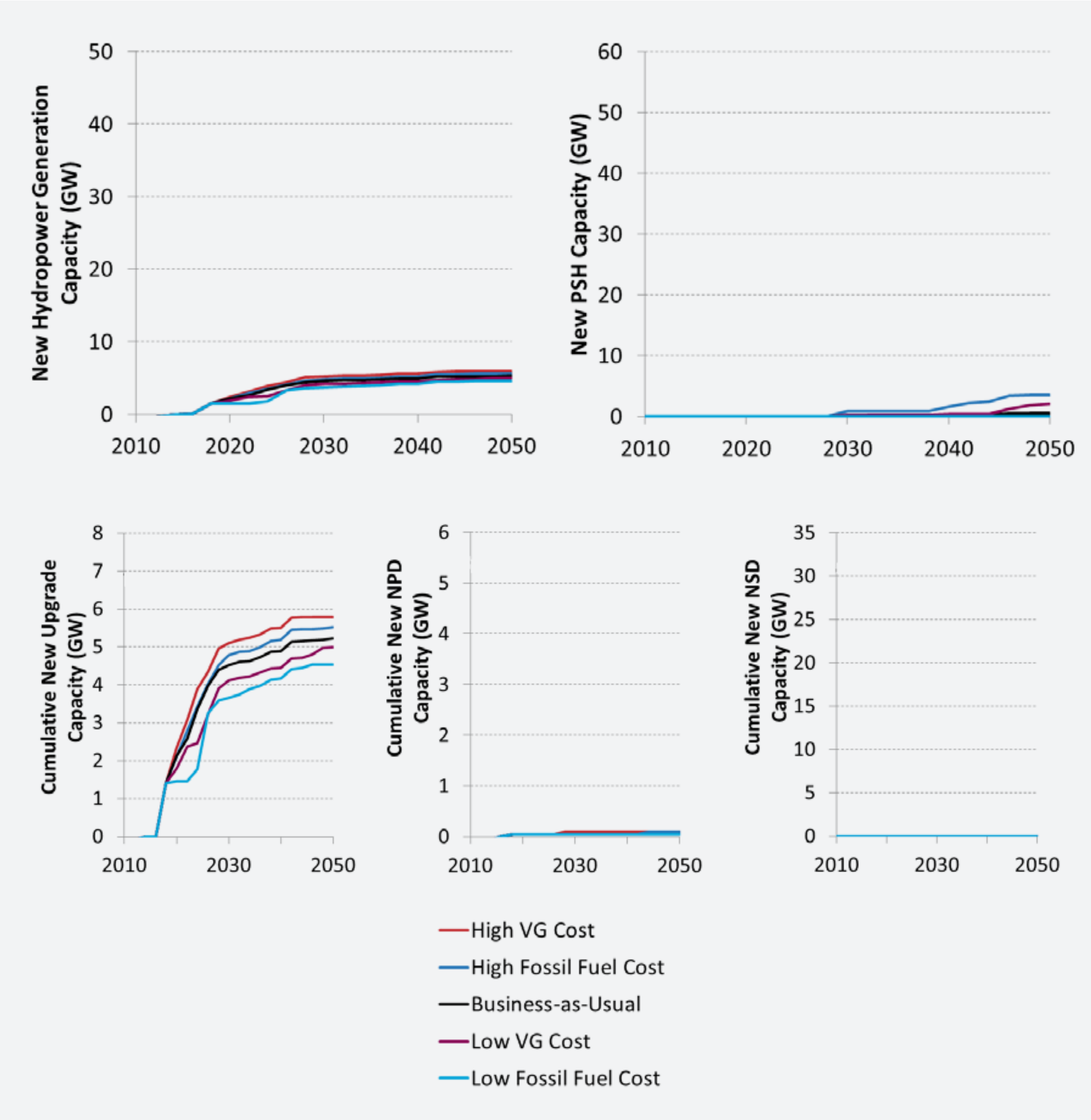


Figure F-8. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in fossil fuel and variable-generation (VG) cost scenarios under reference hydropower assumptions (note: each panel uses a unique y-axis)

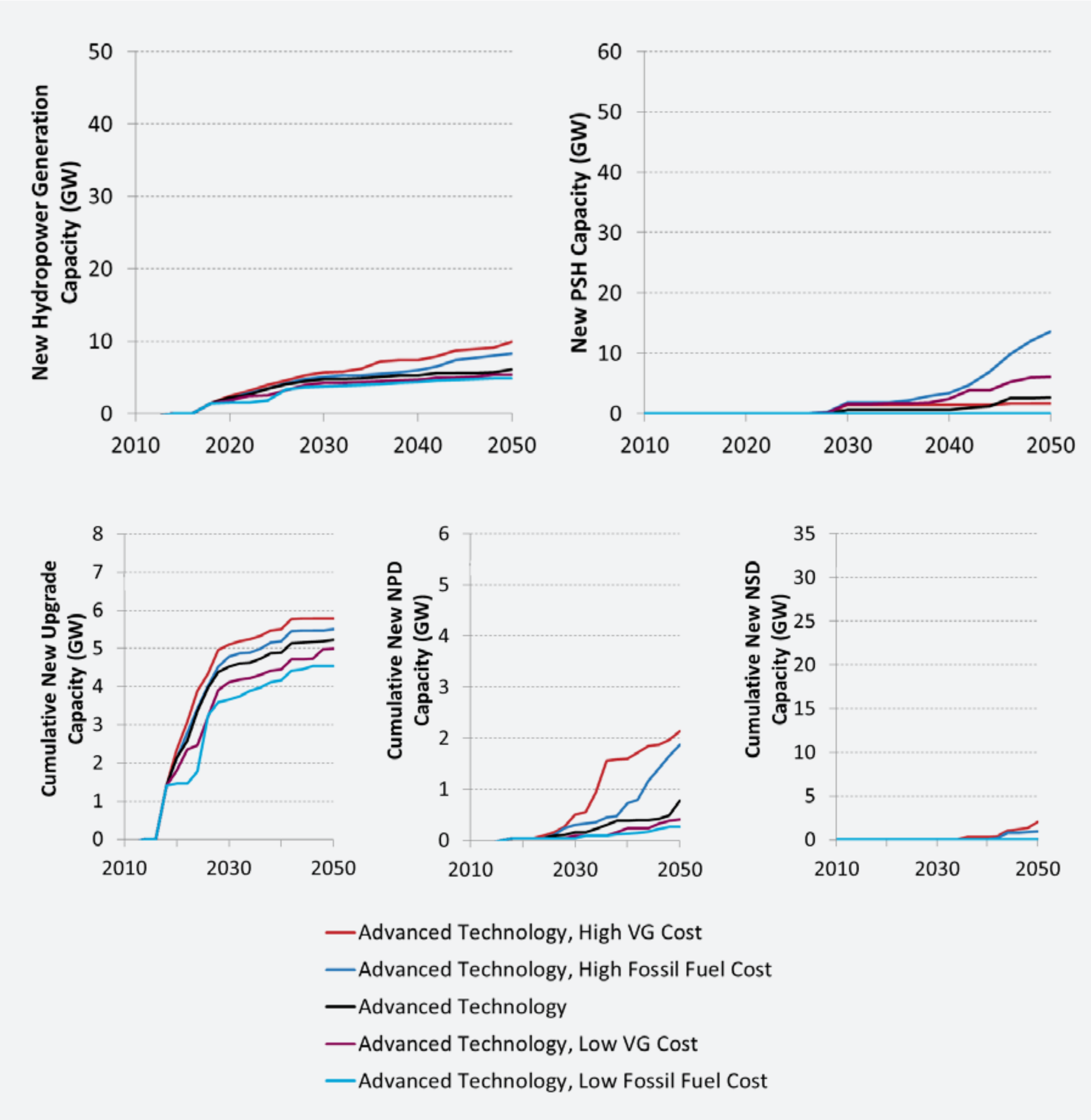


Figure F-9. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in fossil fuel and VG cost scenarios with *Advanced Technology* assumptions (note: each panel uses a unique y-axis)

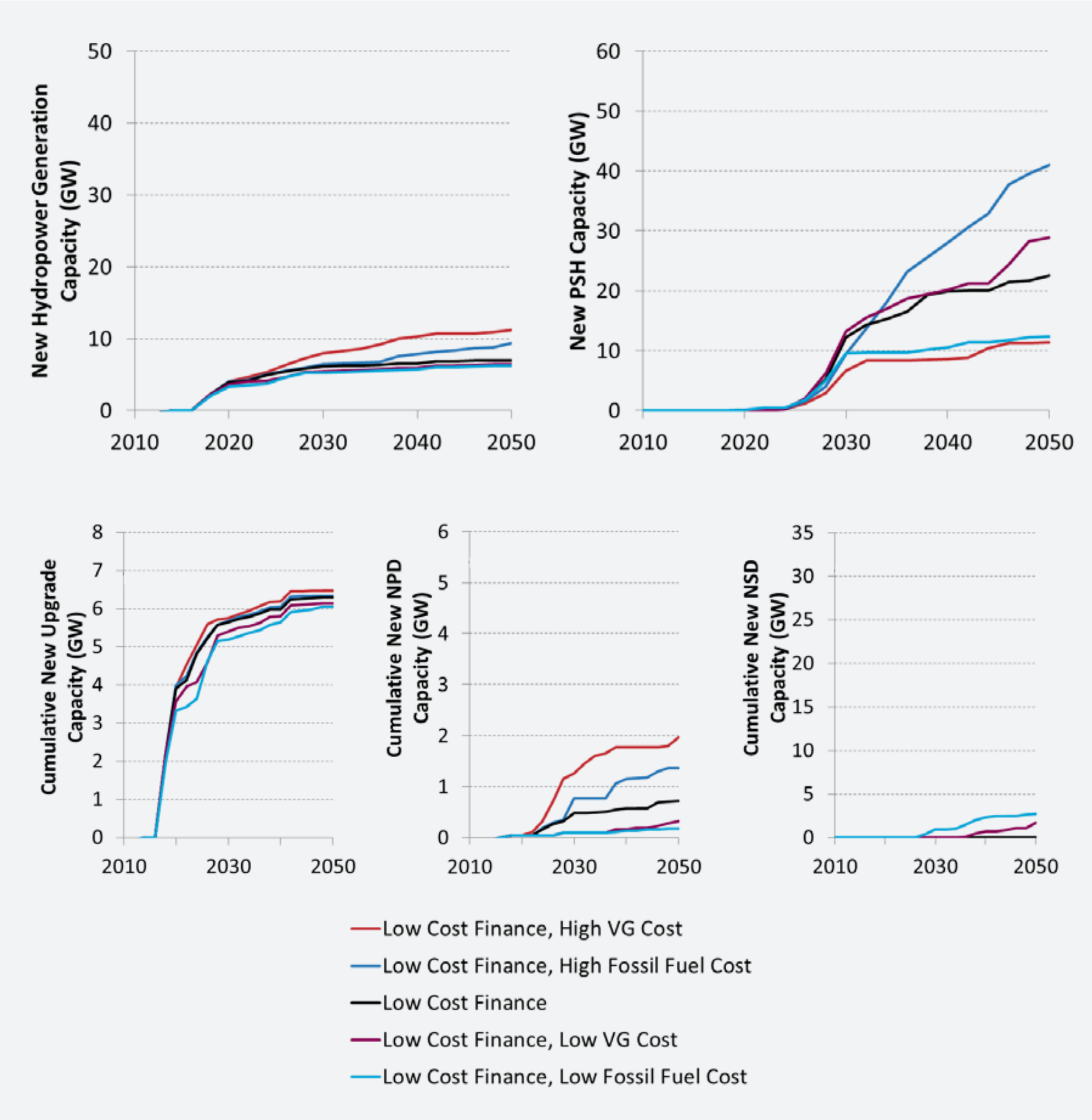


Figure F-10. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in fossil fuel and VG cost scenarios with *Low Cost Finance* assumptions (note: each panel uses a unique y-axis)

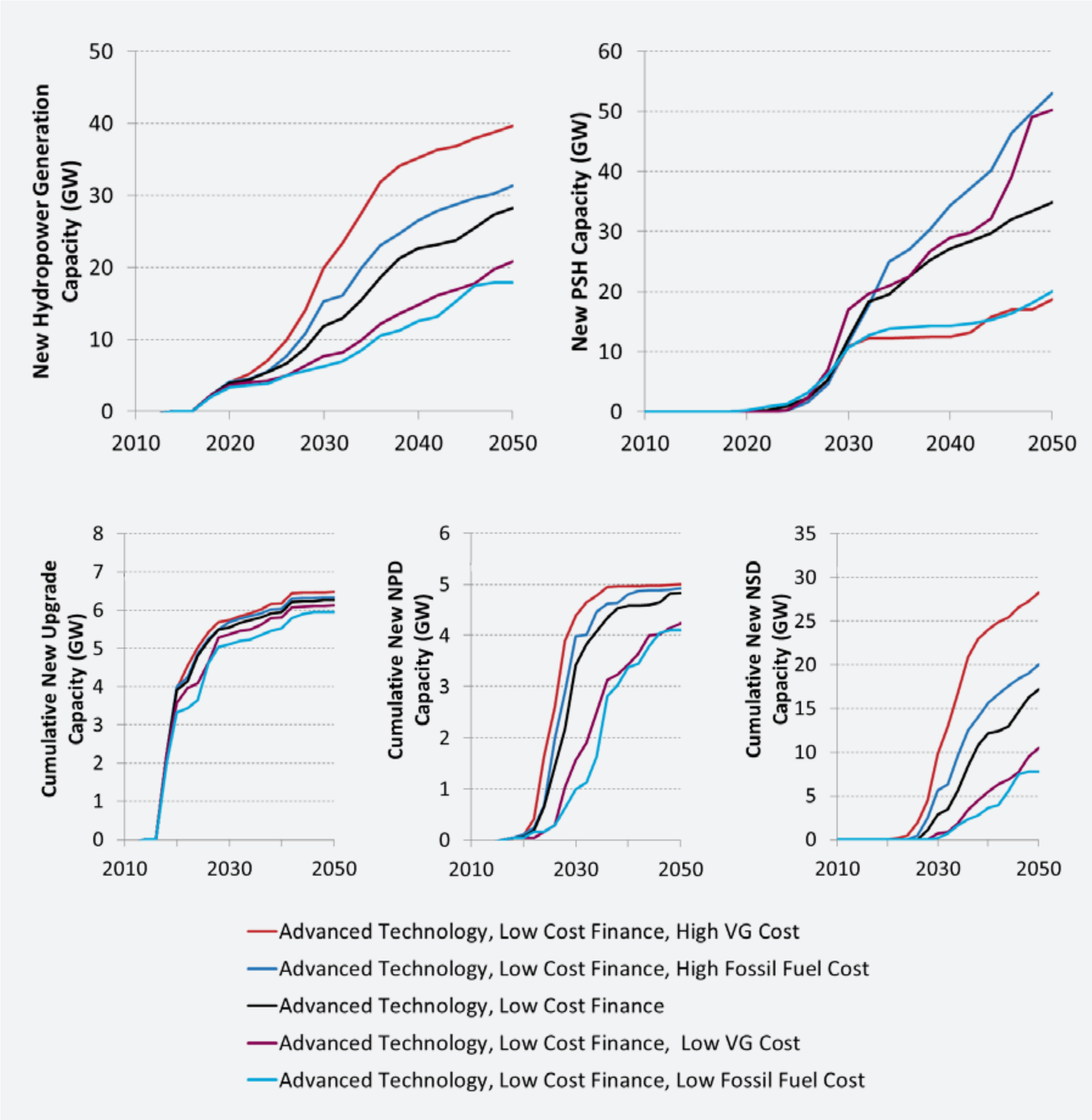


Figure F-11. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in fossil fuel and VG cost scenarios with *Advanced Technology, Low Cost Finance* assumptions (note: each panel uses a unique y-axis)

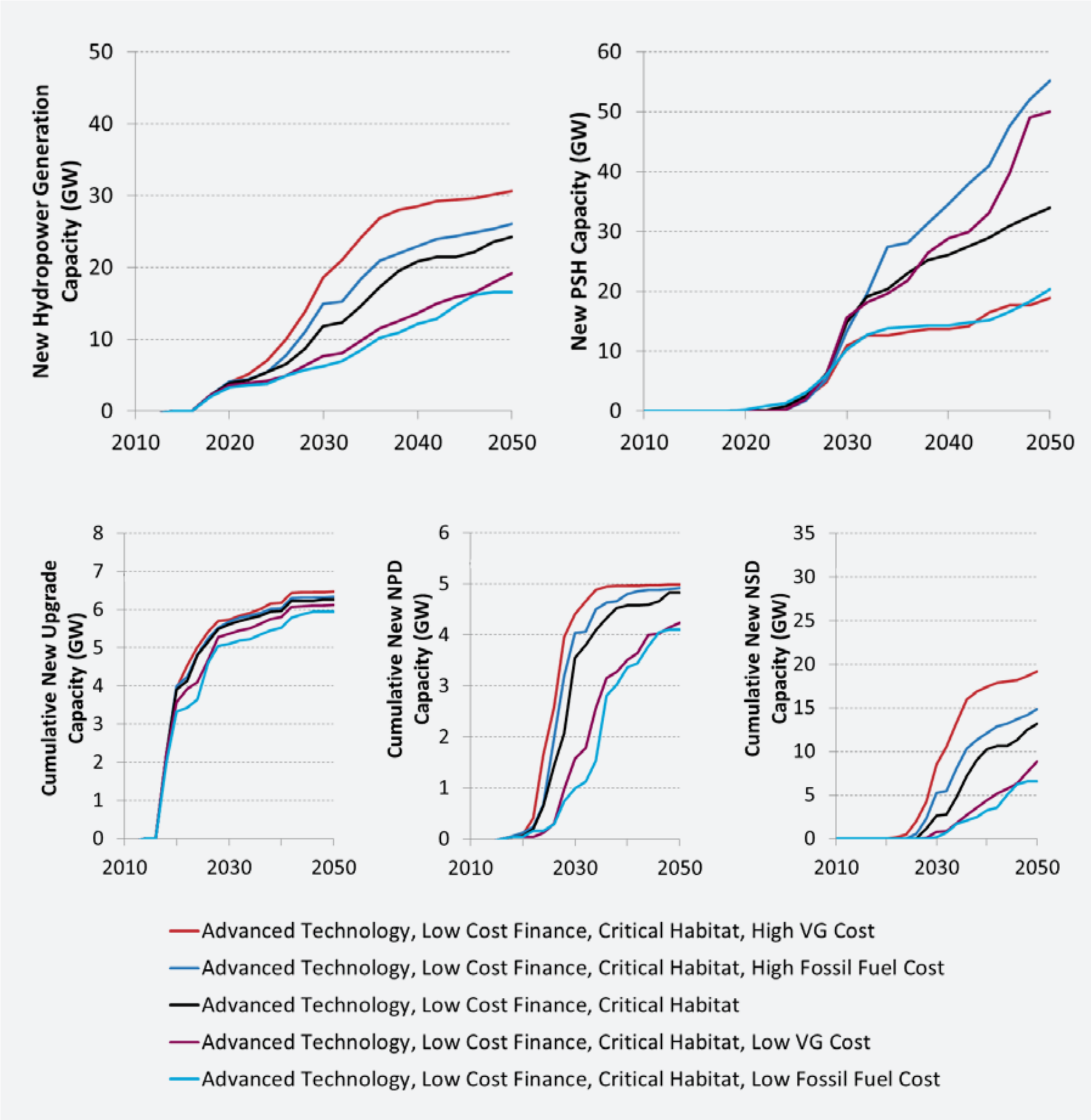


Figure F-12. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in fossil fuel and VG cost scenarios with *Advanced Technology, Low Cost Finance, Critical Habitat* assumptions (note: each panel uses a unique y-axis)

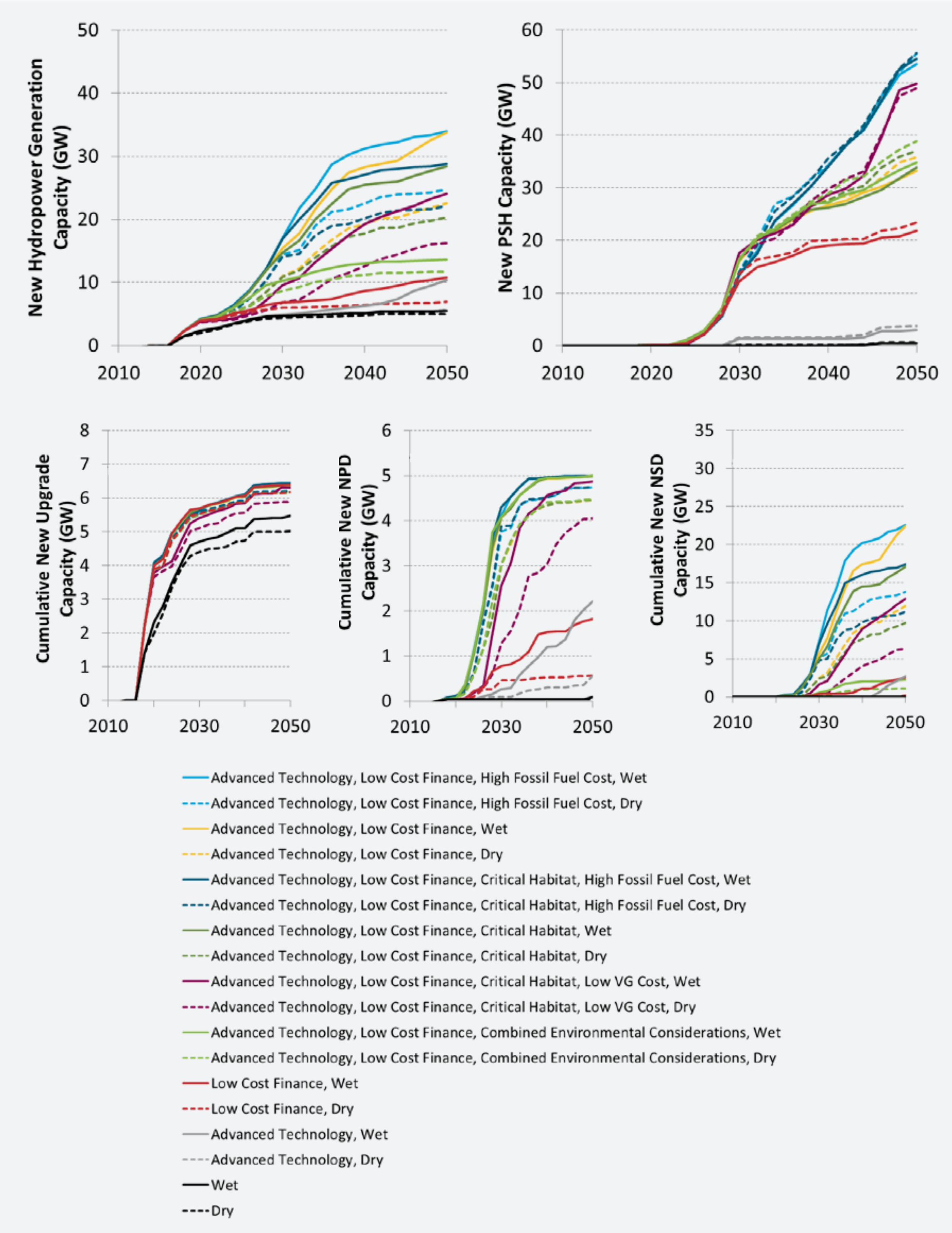


Figure F-13. Cumulative post-2016 capacity growth of total hydropower generation, PSH, and each category of hydropower generation (upgrades, NPD, and NSD) in *Wet* and *Dry* scenario variants for the nine focus scenarios (note: each panel uses a unique y-axis)

Tables F-1 through F-5 display cumulative new post-2016 hydropower capacity in each decade for all the scenarios modeled in the *Hydropower Vision* analysis.

Table F-1. Cumulative New Post-2016 Hydropower Generation Capacity in Each Decade for All *Hydropower Vision* Analysis Scenarios

		Cumulative New Post-2016 Hydropower Generation Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
1	Business-as-Usual	2.2	4.6	4.9	5.3
2	Low Fossil Fuel Cost	1.5	3.7	4.2	4.6
3	Low VG Cost	1.8	4.2	4.5	5.0
4	High Fossil Fuel Cost	2.2	4.8	5.2	5.6
5	High VG Cost	2.4	5.2	5.6	5.9
6	Advanced Technology, Low Fossil Fuel Cost	1.5	3.7	4.3	4.8
7	Advanced Technology, Low VG Cost	1.8	4.2	4.7	5.4
8	Advanced Technology	2.2	4.7	5.3	6.0
9	Advanced Technology, High Fossil Fuel Cost	2.2	5.1	5.9	8.3
10	Advanced Technology, High VG Cost	2.4	5.6	7.4	9.9
11	Low Cost Finance, Low Fossil Fuel Cost	3.4	5.3	5.8	6.2
12	Low Cost Finance, Low VG Cost	3.6	5.5	6.0	6.5
13	Low Cost Finance	3.9	6.1	6.6	7.0
14	Low Cost Finance, High Fossil Fuel Cost	4.0	6.5	7.9	9.4
15	Low Cost Finance, High VG Cost	4.0	8.0	10.3	11.2
16	Evolutionary Technology, Low Cost Finance	3.9	7.2	9.7	11.9
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	3.4	6.3	12.5	17.9
18	Advanced Technology, Low Cost Finance, Low VG Cost	3.6	7.6	14.7	20.8
19	Advanced Technology, Low Cost Finance	4.0	11.8	22.7	28.3
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	4.1	15.3	26.5	31.3
21	Advanced Technology, Low Cost Finance, High VG Cost	4.0	19.9	35.2	39.7
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	3.4	6.3	12.2	16.6
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	3.6	7.7	13.7	19.2
24	Advanced Technology, Low Cost Finance, Critical Habitat	4.0	11.8	20.8	24.3
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	4.1	14.9	22.9	26.1
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	4.0	18.7	28.5	30.7
27	Advanced Technology, Low Cost Finance, Protected Lands	4.0	9.7	16.8	21.4
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	4.0	10.2	17.8	21.1

		Cumulative New Post-2016 Hydropower Generation Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
29	Advanced Technology, Low Cost Finance, NRI	4.0	11.3	18.6	22.6
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	4.0	11.8	22.2	27.5
31	Advanced Technology, Low Cost Finance, Species of Concern	4.0	11.0	19.4	24.5
32	Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	4.0	9.4	14.0	16.2
33	Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	4.0	9.7	14.6	16.7
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	4.0	9.4	12.0	12.8
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	4.0	10.0	15.0	17.9
36	Dry	2.0	4.4	4.8	5.1
37	Wet	2.4	4.7	5.2	5.6
38	Advanced Technology, Dry	2.1	4.5	5.0	5.6
39	Advanced Technology, Wet	2.4	5.0	6.3	10.4
40	Low Cost Finance, Dry	3.9	6.0	6.4	6.9
41	Low Cost Finance, Wet	4.0	6.8	8.7	10.8
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	3.9	8.7	11.2	11.7
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	4.1	10.3	13.0	13.6
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	3.7	6.8	12.6	16.2
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	3.8	9.6	19.3	24.0
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	3.9	10.9	17.8	20.3
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	4.1	14.7	25.5	28.4
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	4.1	14.2	20.2	22.1
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	4.2	17.0	27.1	28.9
50	Advanced Technology, Low Cost Finance, Wet	4.1	15.5	28.4	33.7
51	Advanced Technology, Low Cost Finance, Dry	4.0	11.0	19.3	22.5
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	4.1	14.4	22.5	24.8
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	4.2	17.1	31.2	34.0

Table F-2. Cumulative New Post-2016 PSH Capacity in Each Decade for All *Hydropower Vision* Analysis Scenarios

#	Scenario	Cumulative New Post-2016 PSH Capacity in Year (GW)			
		2020	2030	2040	2050
1	Business-as-Usual	0.0	0.2	0.2	0.5
2	Low Fossil Fuel Cost	0.0	0.0	0.0	0.0
3	Low VG Cost	0.0	0.3	0.4	2.1
4	High Fossil Fuel Cost	0.0	0.8	1.6	3.5
5	High VG Cost	0.0	0.0	0.0	0.0
6	Advanced Technology, Low Fossil Fuel Cost	0.0	0.0	0.0	0.0
7	Advanced Technology, Low VG Cost	0.0	1.6	2.4	6.0
8	Advanced Technology	0.0	0.6	0.6	2.6
9	Advanced Technology, High Fossil Fuel Cost	0.0	1.8	3.3	13.6
10	Advanced Technology, High VG Cost	0.0	1.5	1.5	1.7
11	Low Cost Finance, Low Fossil Fuel Cost	0.2	9.6	10.6	12.4
12	Low Cost Finance, Low VG Cost	0.0	13.2	20.1	28.9
13	Low Cost Finance	0.0	12.2	20.0	22.6
14	Low Cost Finance, High Fossil Fuel Cost	0.1	9.4	28.0	41.0
15	Low Cost Finance, High VG Cost	0.0	6.6	8.6	11.4
16	Evolutionary Technology, Low Cost Finance	0.0	13.7	23.5	29.0
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	0.2	10.7	14.4	20.0
18	Advanced Technology, Low Cost Finance, Low VG Cost	0.0	17.0	29.0	50.2
19	Advanced Technology, Low Cost Finance	0.0	12.1	27.1	34.8
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	0.1	11.5	34.3	53.0
21	Advanced Technology, Low Cost Finance, High VG Cost	0.0	10.9	12.5	18.7
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	0.2	10.2	14.4	20.4
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	0.0	15.6	28.9	50.0
24	Advanced Technology, Low Cost Finance, Critical Habitat	0.1	14.8	26.1	34.0
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	0.1	13.3	34.6	55.2
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	0.0	10.9	13.7	19.0
27	Advanced Technology, Low Cost Finance, Protected Lands	0.1	16.4	26.6	34.2
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	0.1	15.7	26.0	34.6
29	Advanced Technology, Low Cost Finance, NRI	0.0	16.2	25.8	34.1
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	0.1	14.2	25.6	34.5

#	Scenario	Cumulative New Post-2016 PSH Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
31	Advanced Technology, Low Cost Finance, Species of Concern	0.1	14.3	25.9	34.6
32	Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	0.1	15.7	25.7	35.5
33	Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	0.0	16.2	26.4	36.3
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	0.1	16.2	26.7	35.5
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	0.1	16.4	27.0	35.3
36	Dry	0.0	0.1	0.1	0.5
37	Wet	0.0	0.0	0.0	0.4
38	Advanced Technology, Dry	0.0	1.5	1.5	3.7
39	Advanced Technology, Wet	0.0	1.2	1.2	2.9
40	Low Cost Finance, Dry	0.0	13.7	20.1	23.4
41	Low Cost Finance, Wet	0.0	12.2	19.0	21.8
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	0.1	16.3	28.8	38.8
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	0.1	16.4	27.2	34.8
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	0.0	16.6	29.7	49.0
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	0.0	17.6	28.6	49.7
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	0.0	16.2	27.5	37.1
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	0.1	16.4	26.2	33.8
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	0.1	14.0	35.5	55.6
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	0.1	13.4	33.9	54.5
50	Advanced Technology, Low Cost Finance, Wet	0.1	16.0	26.7	33.2
51	Advanced Technology, Low Cost Finance, Dry	0.0	16.3	27.8	35.8
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	0.1	14.1	34.3	55.5
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	0.1	13.5	34.3	53.6

Table F-3. Cumulative New Post-2016 Upgrade Capacity in Each Decade for All *Hydropower Vision* Analysis Scenarios

		Cumulative New Post-2016 Upgrade Capacity in Year (GW)			
#	**Scenario**	**2020**	**2030**	**2040**	**2050**
1	Business-as-Usual	2.1	4.5	4.9	5.2
2	Low Fossil Fuel Cost	1.5	3.7	4.2	4.5
3	Low VG Cost	1.8	4.1	4.4	5.0
4	High Fossil Fuel Cost	2.1	4.8	5.2	5.5
5	High VG Cost	2.3	5.1	5.5	5.8
6	Advanced Technology, Low Fossil Fuel Cost	1.5	3.7	4.2	4.5
7	Advanced Technology, Low VG Cost	1.8	4.1	4.4	5.0
8	Advanced Technology	2.1	4.5	4.9	5.2
9	Advanced Technology, High Fossil Fuel Cost	2.1	4.8	5.2	5.5
10	Advanced Technology, High VG Cost	2.3	5.1	5.5	5.8
11	Low Cost Finance, Low Fossil Fuel Cost	3.3	5.2	5.6	6.0
12	Low Cost Finance, Low VG Cost	3.6	5.4	5.8	6.1
13	Low Cost Finance	3.9	5.6	6.0	6.3
14	Low Cost Finance, High Fossil Fuel Cost	4.0	5.7	6.0	6.3
15	Low Cost Finance, High VG Cost	3.9	5.8	6.2	6.5
16	Evolutionary Technology, Low Cost Finance	3.9	5.6	6.0	6.3
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	3.3	5.1	5.5	5.9
18	Advanced Technology, Low Cost Finance, Low VG Cost	3.6	5.4	5.8	6.1
19	Advanced Technology, Low Cost Finance	3.9	5.6	6.0	6.3
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	4.0	5.7	6.0	6.3
21	Advanced Technology, Low Cost Finance, High VG Cost	3.9	5.7	6.2	6.5
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	3.3	5.1	5.5	5.9
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	3.6	5.4	5.8	6.1
24	Advanced Technology, Low Cost Finance, Critical Habitat	3.9	5.6	6.0	6.3
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	4.0	5.7	6.0	6.3
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	3.9	5.7	6.2	6.5
27	Advanced Technology, Low Cost Finance, Protected Lands	3.9	5.6	6.0	6.3
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	3.9	5.6	6.0	6.3
29	Advanced Technology, Low Cost Finance, NRI	3.9	5.6	6.0	6.3
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	3.9	5.5	6.0	6.3
31	Advanced Technology, Low Cost Finance, Species of Concern	3.9	5.6	6.0	6.3
32	Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	3.9	5.6	6.0	6.3

		Cumulative New Post-2016 Upgrade Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
33	Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	3.9	5.6	6.0	6.3
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	3.9	5.6	6.0	6.3
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	3.9	5.6	6.0	6.3
36	Dry	2.0	4.4	4.7	5.0
37	Wet	2.3	4.7	5.1	5.5
38	Advanced Technology, Dry	2.0	4.4	4.7	5.0
39	Advanced Technology, Wet	2.3	4.7	5.1	5.5
40	Low Cost Finance, Dry	3.9	5.5	5.9	6.2
41	Low Cost Finance, Wet	4.0	5.7	6.1	6.4
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	3.9	5.5	5.9	6.2
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	4.0	5.7	6.1	6.4
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	3.7	5.1	5.6	5.9
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	3.8	5.4	5.8	6.3
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	3.9	5.5	5.9	6.2
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	4.0	5.7	6.0	6.4
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	4.0	5.6	5.9	6.2
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	4.1	5.6	6.1	6.4
50	Advanced Technology, Low Cost Finance, Wet	4.0	5.7	6.0	6.4
51	Advanced Technology, Low Cost Finance, Dry	3.9	5.5	5.9	6.2
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	4.0	5.5	5.9	6.2
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	4.1	5.6	6.1	6.4

Table F-4. Cumulative New Post-2016 NPD Capacity in Each Decade for All *Hydropower Vision* Analysis Scenarios

		Cumulative New Post-2016 NPD Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
1	Business-as-Usual	0.0	0.0	0.0	0.0
2	Low Fossil Fuel Cost	0.0	0.0	0.0	0.0
3	Low VG Cost	0.0	0.0	0.0	0.0
4	High Fossil Fuel Cost	0.0	0.0	0.0	0.1
5	High VG Cost	0.0	0.1	0.1	0.1
6	Advanced Technology, Low Fossil Fuel Cost	0.0	0.0	0.1	0.3
7	Advanced Technology, Low VG Cost	0.0	0.1	0.2	0.4
8	Advanced Technology	0.0	0.2	0.4	0.8
9	Advanced Technology, High Fossil Fuel Cost	0.0	0.3	0.7	1.9
10	Advanced Technology, High VG Cost	0.0	0.5	1.6	2.1
11	Low Cost Finance, Low Fossil Fuel Cost	0.0	0.1	0.1	0.2
12	Low Cost Finance, Low VG Cost	0.0	0.1	0.2	0.3
13	Low Cost Finance	0.0	0.5	0.6	0.7
14	Low Cost Finance, High Fossil Fuel Cost	0.0	0.8	1.2	1.4
15	Low Cost Finance, High VG Cost	0.0	1.2	1.8	2.0
16	Evolutionary Technology, Low Cost Finance	0.0	1.2	2.2	3.0
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	0.0	1.0	3.4	4.1
18	Advanced Technology, Low Cost Finance, Low VG Cost	0.0	1.6	3.4	4.2
19	Advanced Technology, Low Cost Finance	0.0	3.4	4.6	4.8
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	0.1	4.0	4.8	4.9
21	Advanced Technology, Low Cost Finance, High VG Cost	0.1	4.4	5.0	5.0
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	0.0	1.0	3.4	4.1
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	0.0	1.6	3.5	4.2
24	Advanced Technology, Low Cost Finance, Critical Habitat	0.0	3.5	4.6	4.8
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	0.1	4.0	4.8	4.9
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	0.1	4.4	5.0	5.0
27	Advanced Technology, Low Cost Finance, Protected Lands	0.0	3.6	4.6	4.8
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	0.0	3.6	4.6	4.8
29	Advanced Technology, Low Cost Finance, NRI	0.0	3.6	4.6	4.8
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	0.0	3.5	4.6	4.8
31	Advanced Technology, Low Cost Finance, Species of Concern	0.0	3.6	4.6	4.8
32	Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	0.0	3.6	4.6	4.8

		Cumulative New Post-2016 NPD Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
33	Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	0.0	3.6	4.6	4.8
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	0.0	3.6	4.6	4.8
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	0.0	3.6	4.6	4.8
36	Dry	0.0	0.0	0.0	0.0
37	Wet	0.0	0.0	0.0	0.1
38	Advanced Technology, Dry	0.0	0.1	0.3	0.6
39	Advanced Technology, Wet	0.0	0.3	1.2	2.2
40	Low Cost Finance, Dry	0.0	0.5	0.5	0.6
41	Low Cost Finance, Wet	0.0	0.8	1.5	1.8
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	0.1	3.0	4.4	4.5
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	0.1	4.1	4.9	5.0
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	0.0	1.3	3.0	4.1
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	0.0	2.6	4.6	4.9
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	0.1	3.0	4.3	4.5
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	0.1	4.1	4.9	5.0
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	0.1	3.9	4.5	4.7
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	0.1	4.3	5.0	5.0
50	Advanced Technology, Low Cost Finance, Wet	0.1	4.1	4.9	5.0
51	Advanced Technology, Low Cost Finance, Dry	0.1	3.0	4.3	4.5
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	0.1	3.8	4.5	4.7
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	0.1	4.1	5.0	5.0

Table F-5. Cumulative New Post-2016 NSD Capacity in Each Decade for All *Hydropower Vision* Analysis Scenarios

#	Scenario	Cumulative New Post-2016 NSD Capacity in Year (GW)			
		2020	2030	2040	2050
1	Business-as-Usual	0.0	0.0	0.0	0.0
2	Low Fossil Fuel Cost	0.0	0.0	0.0	0.0
3	Low VG Cost	0.0	0.0	0.0	0.0
4	High Fossil Fuel Cost	0.0	0.0	0.0	0.0
5	High VG Cost	0.0	0.0	0.0	0.0
6	Advanced Technology, Low Fossil Fuel Cost	0.0	0.0	0.0	0.0
7	Advanced Technology, Low VG Cost	0.0	0.0	0.0	0.0
8	Advanced Technology	0.0	0.0	0.0	0.0
9	Advanced Technology, High Fossil Fuel Cost	0.0	0.0	0.0	0.9
10	Advanced Technology, High VG Cost	0.0	0.0	0.3	2.0
11	Low Cost Finance, Low Fossil Fuel Cost	0.0	0.0	0.0	0.0
12	Low Cost Finance, Low VG Cost	0.0	0.0	0.0	0.0
13	Low Cost Finance	0.0	0.0	0.0	0.0
14	Low Cost Finance, High Fossil Fuel Cost	0.0	0.0	0.7	1.7
15	Low Cost Finance, High VG Cost	0.0	1.0	2.3	2.7
16	Evolutionary Technology, Low Cost Finance	0.0	0.4	1.5	2.6
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	0.0	0.2	3.6	7.8
18	Advanced Technology, Low Cost Finance, Low VG Cost	0.0	0.7	5.5	10.5
19	Advanced Technology, Low Cost Finance	0.0	2.8	12.1	17.2
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	0.0	5.6	15.6	20.1
21	Advanced Technology, Low Cost Finance, High VG Cost	0.0	9.8	24.0	28.2
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	0.0	0.2	3.3	6.6
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	0.0	0.7	4.4	8.8
24	Advanced Technology, Low Cost Finance, Critical Habitat	0.0	2.6	10.3	13.1
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	0.0	5.2	12.1	14.9
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	0.0	8.5	17.4	19.2
27	Advanced Technology, Low Cost Finance, Protected Lands	0.0	0.6	6.2	10.3
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	0.0	1.1	7.2	10.0
29	Advanced Technology, Low Cost Finance, NRI	0.0	2.1	8.0	11.5

		Cumulative New Post-2016 NSD Capacity in Year (GW)			
#	Scenario	2020	2030	2040	2050
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	0.0	2.7	11.6	16.4
31	Advanced Technology, Low Cost Finance, Species of Concern	0.0	1.9	8.8	13.4
32	Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	0.0	0.3	3.4	5.1
33	Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	0.0	0.6	4.0	5.6
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	0.0	0.2	1.5	1.7
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	0.0	0.8	4.5	6.8
36	Dry	0.0	0.0	0.0	0.0
37	Wet	0.0	0.0	0.0	0.0
38	Advanced Technology, Dry	0.0	0.0	0.0	0.0
39	Advanced Technology, Wet	0.0	0.0	0.0	2.7
40	Low Cost Finance, Dry	0.0	0.0	0.0	0.2
41	Low Cost Finance, Wet	0.0	0.4	1.1	2.6
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	0.0	0.1	0.9	1.1
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	0.0	0.5	2.0	2.2
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	0.0	0.5	4.0	6.3
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	0.0	1.6	8.9	12.8
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	0.0	2.4	7.6	9.7
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	0.0	5.0	14.5	17.1
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	0.0	4.7	9.7	11.2
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	0.0	7.0	16.0	17.4
50	Advanced Technology, Low Cost Finance, Wet	0.0	5.7	17.4	22.4
51	Advanced Technology, Low Cost Finance, Dry	0.0	2.5	9.1	11.9
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	0.0	5.1	12.1	13.8
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	0.0	7.3	20.2	22.5

Figures F-14 through F-21 display hydropower generation energy for all the scenarios modeled in the *Hydropower Vision* analysis.

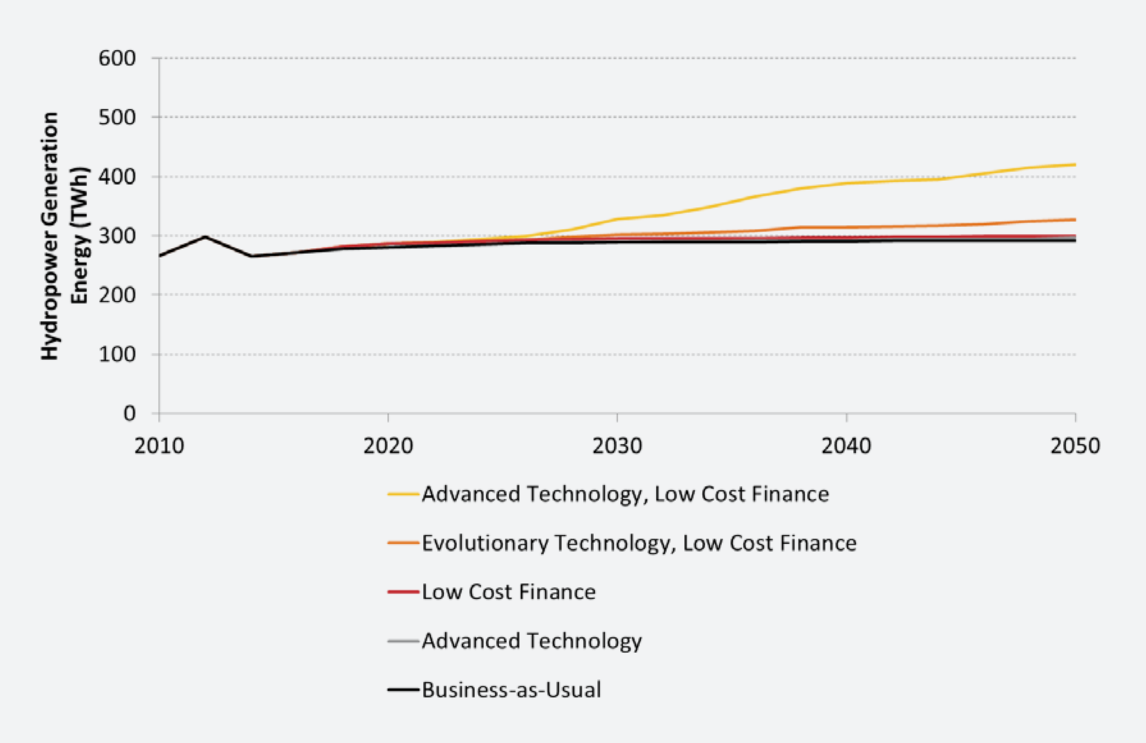


Figure F-14. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in hydropower technology cost scenarios

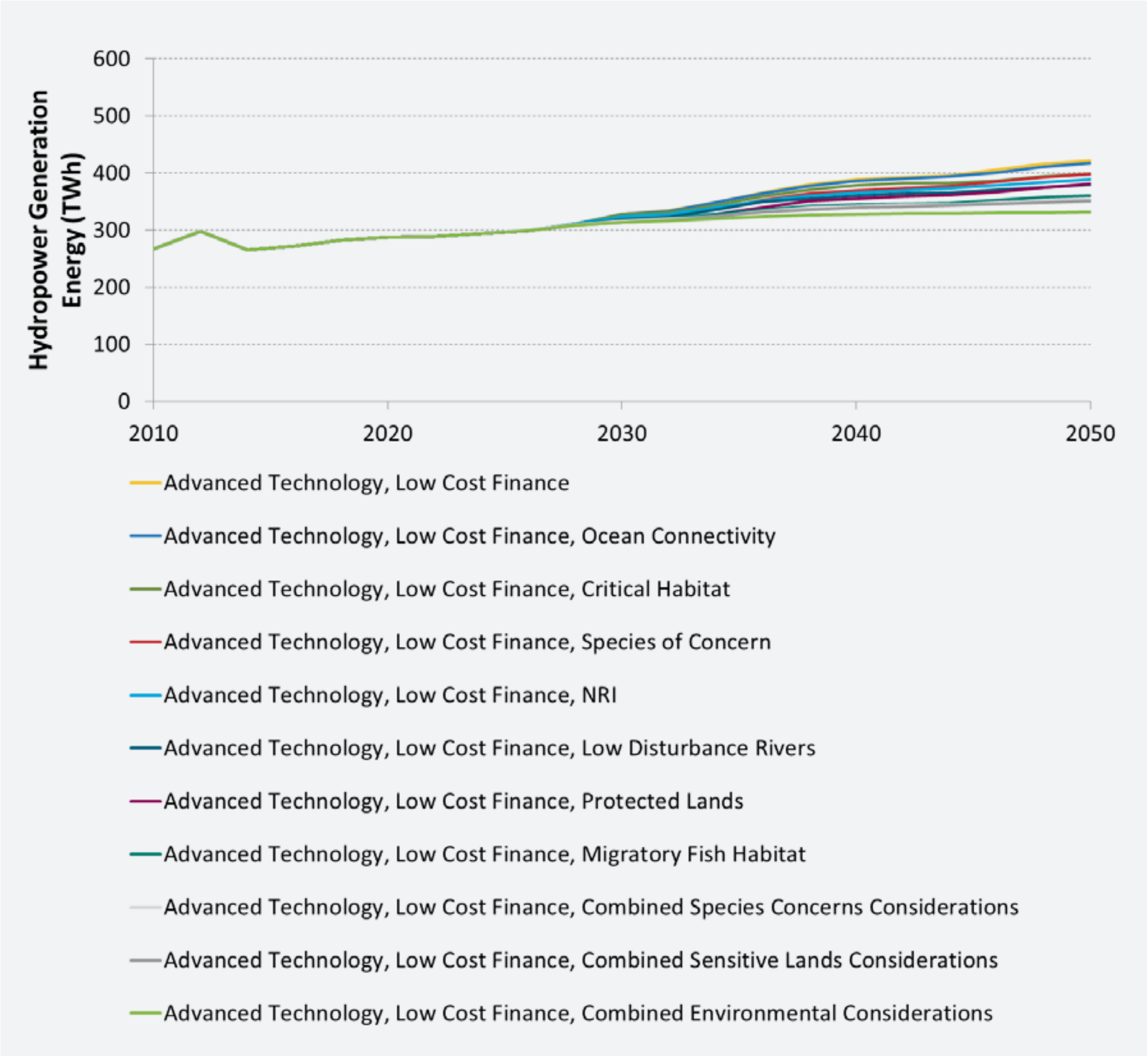


Figure F-15. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in hydropower environmental consideration scenarios

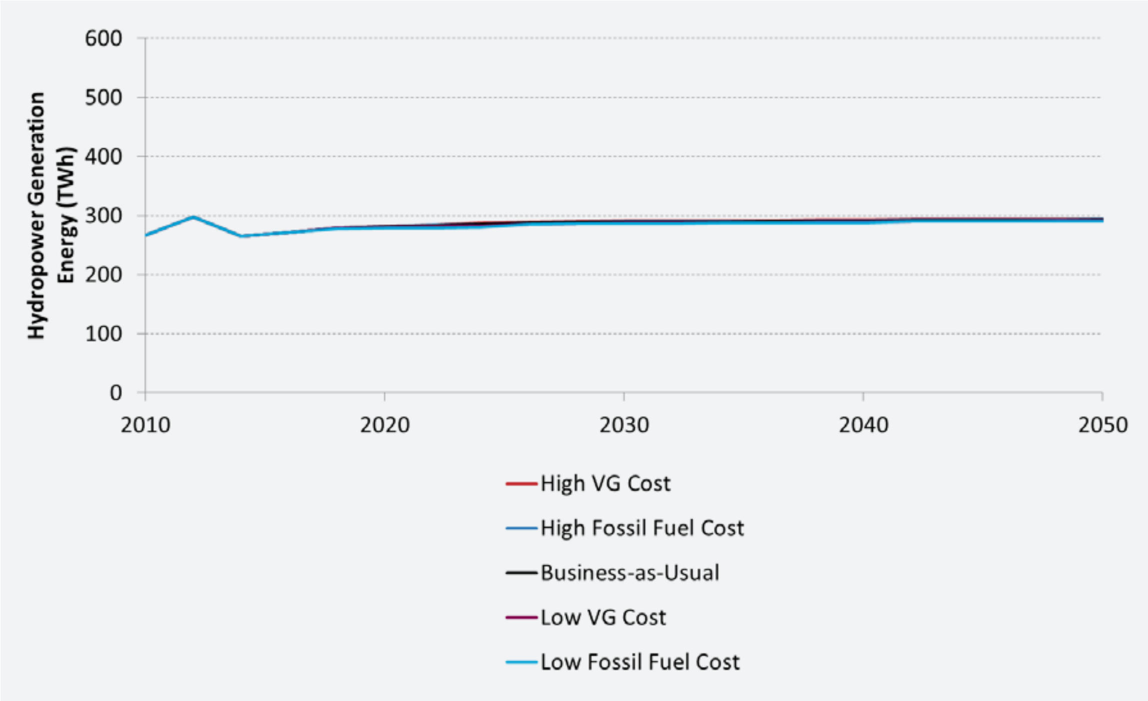


Figure F-16. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in fossil fuel and VG cost scenarios under reference hydropower assumptions

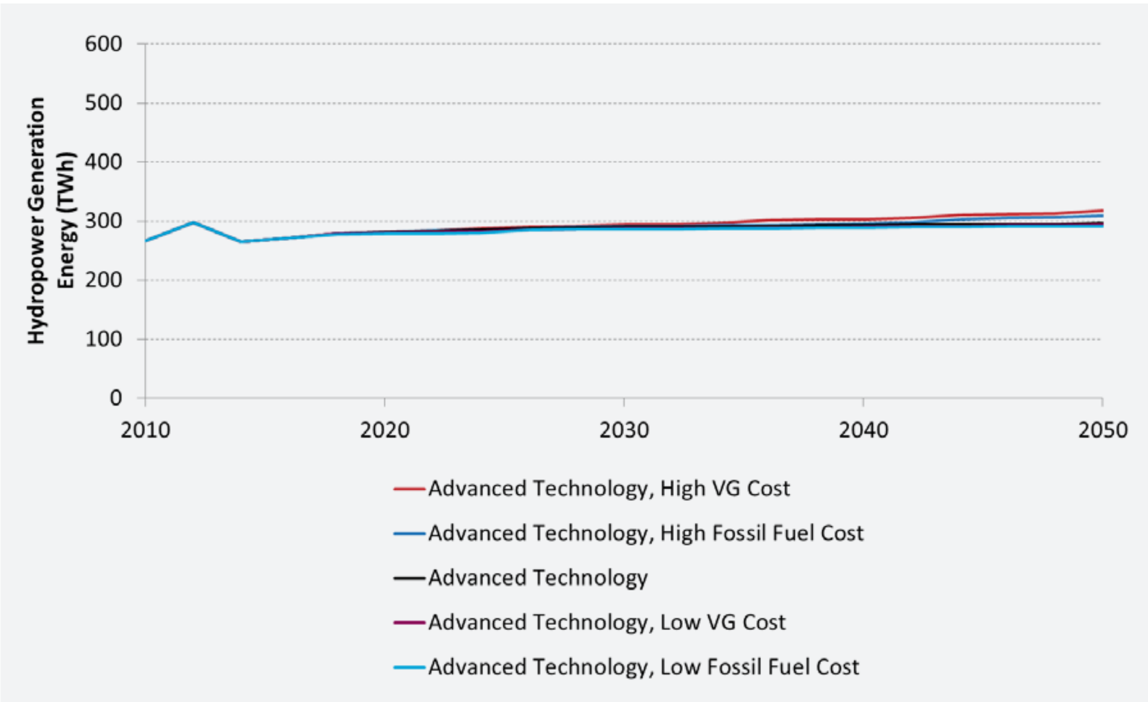


Figure F-17. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in fossil fuel and VG cost scenarios with *Advanced Technology* assumptions

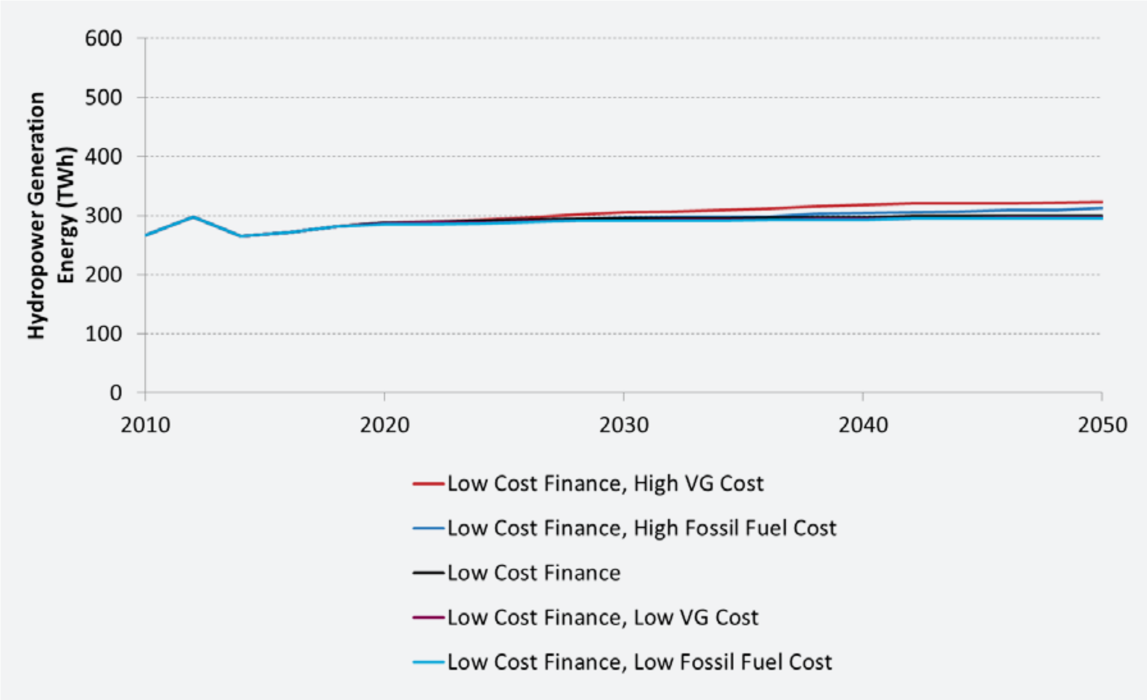


Figure F-18. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in fossil fuel and VG cost scenarios with *Low Cost Finance* assumptions

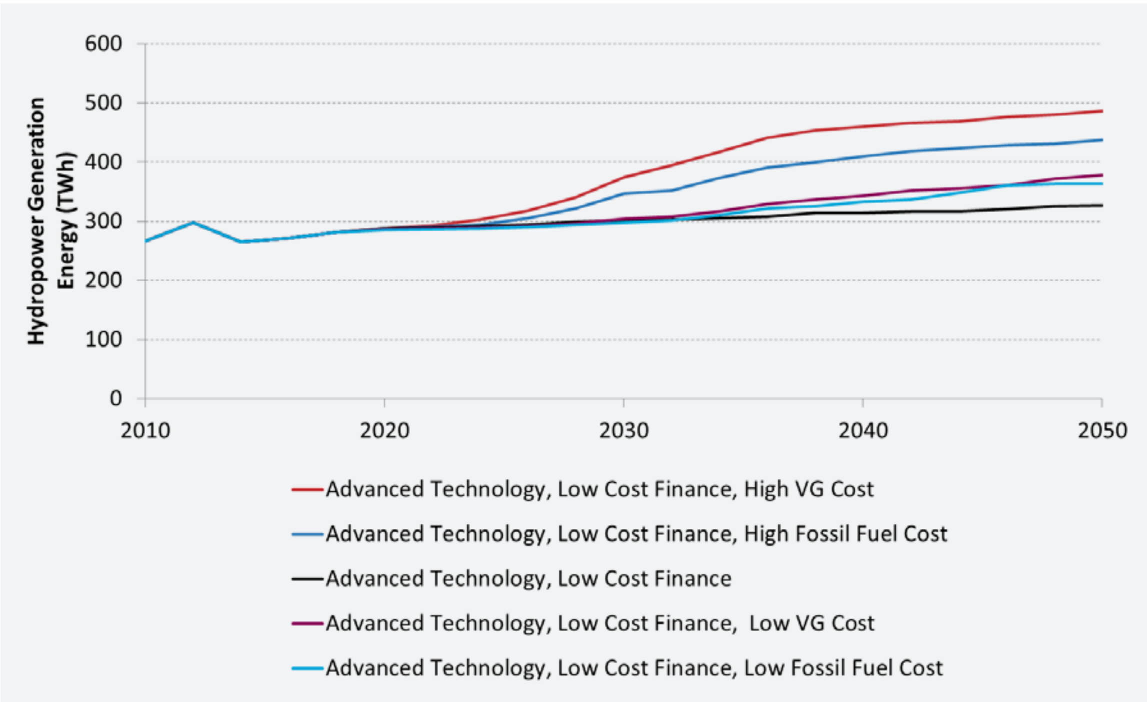


Figure F-19. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in fossil fuel and VG cost scenarios with *Advanced Technology, Low Cost Finance* assumptions

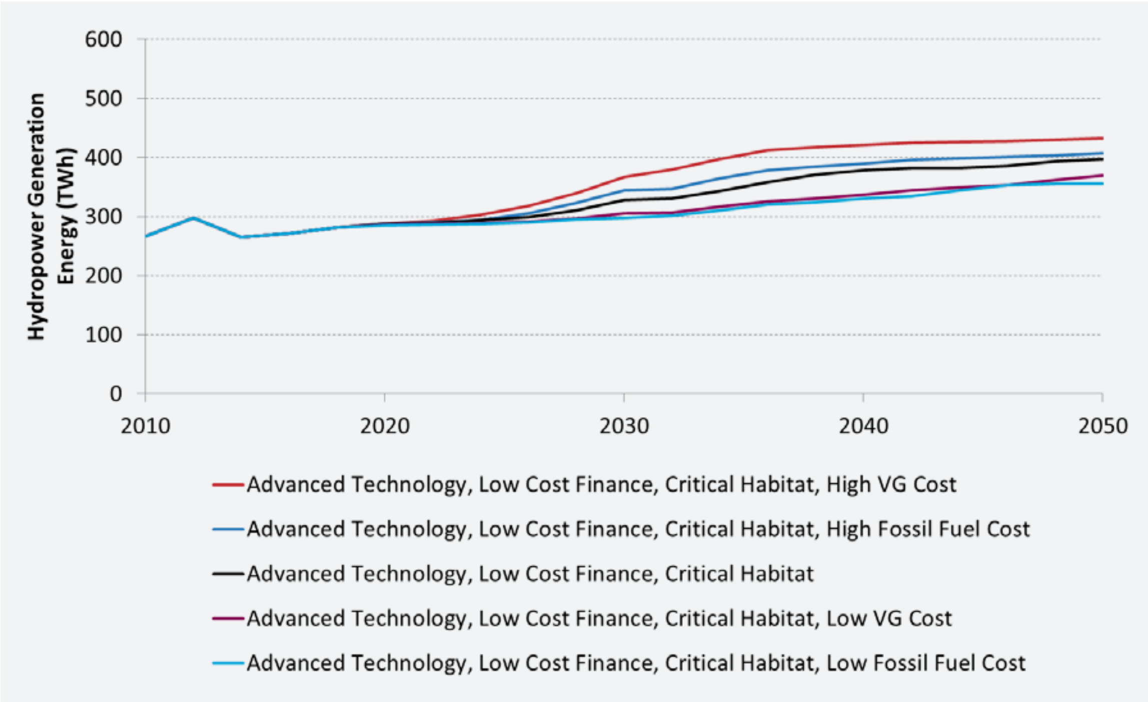


Figure F-20. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in fossil fuel and VG cost scenarios with *Advanced Technology, Low Cost Finance, Critical Habitat* assumptions

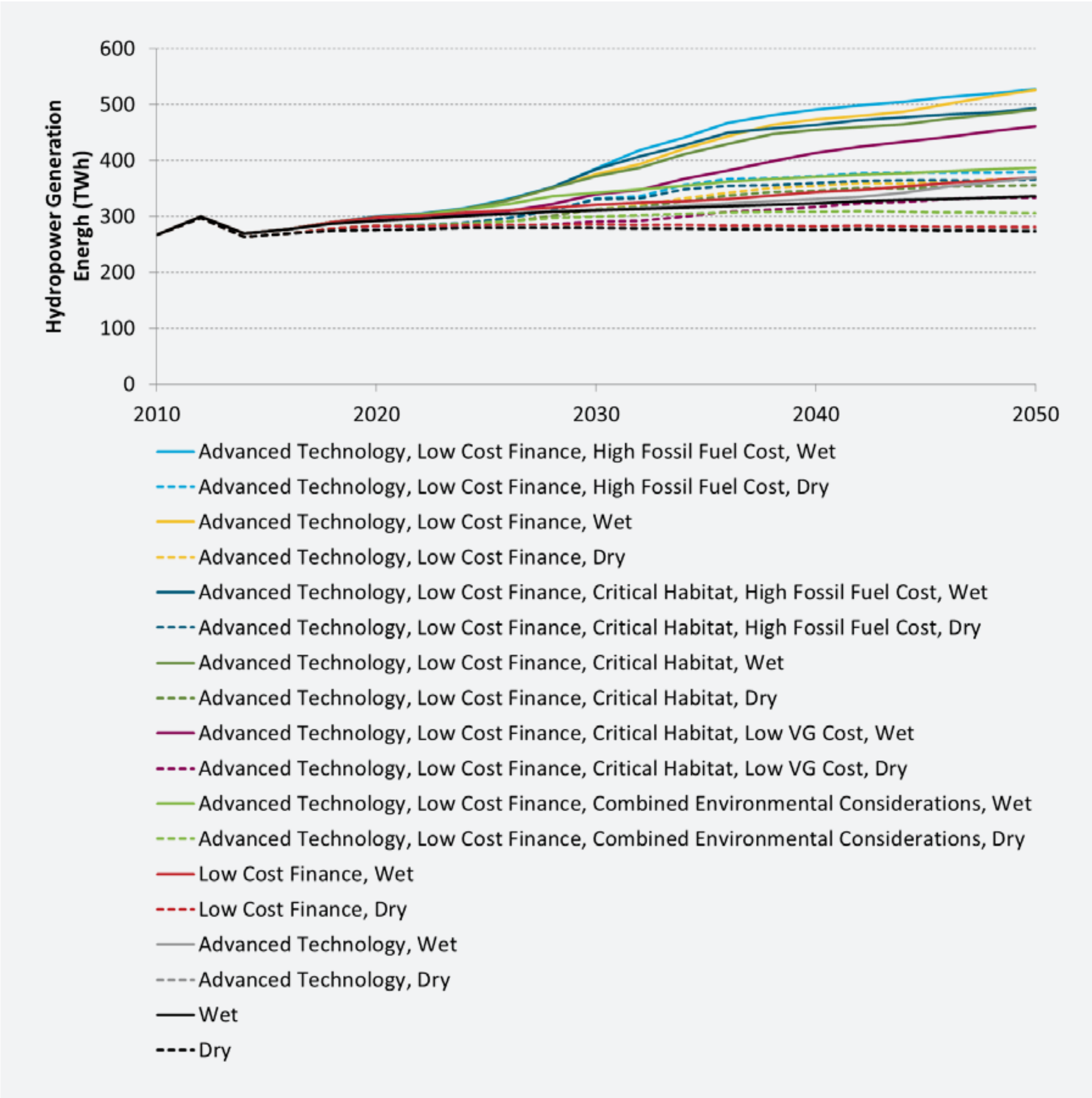


Figure F-21. Electricity generation from the existing hydropower fleet and growth in upgrades, NPD, and NSD (excludes net generation from PSH) in *Wet* and *Dry* scenario variants for the nine focus scenarios

Table F-6 displays total hydropower generation energy in each decade for all the scenarios modeled in the *Hydropower Vision* analysis.

Table F-6. Electricity Generation from the Existing Hydropower Fleet and Growth in Upgrades, NPD, and NSD (Excludes Net Generation from PSH) in Each Decade for All *Hydropower Vision* Analysis Scenarios

		Hydropower Generation Energy in Year (TWh)			
#	Scenario	2020	2030	2040	2050
1	Business-as-Usual	281	289	290	292
2	Low Fossil Fuel Cost	279	286	288	290
3	Low VG Cost	280	287	289	291
4	High Fossil Fuel Cost	281	290	291	293
5	High VG Cost	282	291	293	294
6	Advanced Technology, Low Fossil Fuel Cost	279	286	289	291
7	Advanced Technology, Low VG Cost	280	288	290	293
8	Advanced Technology	281	290	292	296
9	Advanced Technology, High Fossil Fuel Cost	281	291	295	309
10	Advanced Technology, High VG Cost	282	294	303	318
11	Low Cost Finance, Low Fossil Fuel Cost	285	291	293	295
12	Low Cost Finance, Low VG Cost	286	292	294	297
13	Low Cost Finance	287	295	297	299
14	Low Cost Finance, High Fossil Fuel Cost	288	297	304	312
15	Low Cost Finance, High VG Cost	287	306	318	323
16	Evolutionary Technology, Low Cost Finance	287	301	314	327
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	285	298	333	363
18	Advanced Technology, Low Cost Finance, Low VG Cost	286	304	343	378
19	Advanced Technology, Low Cost Finance	287	328	389	421
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	288	347	410	438
21	Advanced Technology, Low Cost Finance, High VG Cost	288	374	460	486
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	285	298	331	356
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	286	305	337	369
24	Advanced Technology, Low Cost Finance, Critical Habitat	287	327	378	397
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	288	345	389	408
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	288	367	421	433
27	Advanced Technology, Low Cost Finance, Protected Lands	287	315	355	381
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	287	318	361	379
29	Advanced Technology, Low Cost Finance, NRI	287	324	365	388
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	287	328	386	417

#	Scenario	Hydropower Generation Energy in Year (TWh)			
		2020	2030	2040	2050
31	Advanced Technology, Low Cost Finance, Species of Concern	287	323	370	399
32	Advanced Technology, Low Cost Finance, Combined Sensitive Lands Considerations	287	314	339	351
33	Advanced Technology, Low Cost Finance, Combined Species Concerns Considerations	287	315	342	353
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	287	313	327	331
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	287	317	344	360
36	Dry	276	279	276	273
37	Wet	292	311	323	336
38	Advanced Technology, Dry	276	280	277	276
39	Advanced Technology, Wet	292	312	331	369
40	Low Cost Finance, Dry	283	285	282	280
41	Low Cost Finance, Wet	298	321	343	369
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	283	300	308	306
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	298	342	370	387
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	282	291	317	334
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	297	339	413	461
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	283	313	346	356
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	298	372	455	491
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	284	331	359	365
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	299	385	464	493
50	Advanced Technology, Low Cost Finance, Wet	298	376	473	526
51	Advanced Technology, Low Cost Finance, Dry	283	314	355	368
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	284	333	372	380
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	299	385	491	527

Table F-7 displays total energy produced by the existing hydropower generation fleet in each decade for the reference, *Wet*, and *Dry* water availability conditions. These results show the change in water availability to the existing fleet under climate uncertainty scenarios.

Table F-7. Electricity Generation from the Existing Hydropower Fleet (Excludes Net Generation from Existing PSH) in Each Decade Under Reference, *Wet*, and *Dry* Water Availability Conditions

	Existing Fleet Hydropower Generation Energy in Year (TWh)			
Scenario	**2020**	**2030**	**2040**	**2050**
Reference	269	269	269	269
Dry	265	261	256	252
Wet	279	289	298	308

Figures F-22 through F-41 show the national distribution of cumulative post-2016 growth in 2050 for each hydropower resource in selected *Hydropower Vision* modeling scenarios and their *Wet* and *Dry* climate change water availability sensitivities. Each column in a figure traces a single scenario from *Dry* (top) to reference (middle) to *Wet* (bottom) water availability conditions for a given scenario.

Figure F-22. National distribution of cumulative post-2016 upgrade capacity in 2050 for the *Business-as-Usual* and *Advanced Technology* scenarios and *Wet* and *Dry* sensitivities

Figure F-23. National distribution of cumulative post-2016 upgrade capacity in 2050 for the *Low Cost Finance* and *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenarios and *Wet* and *Dry* sensitivities

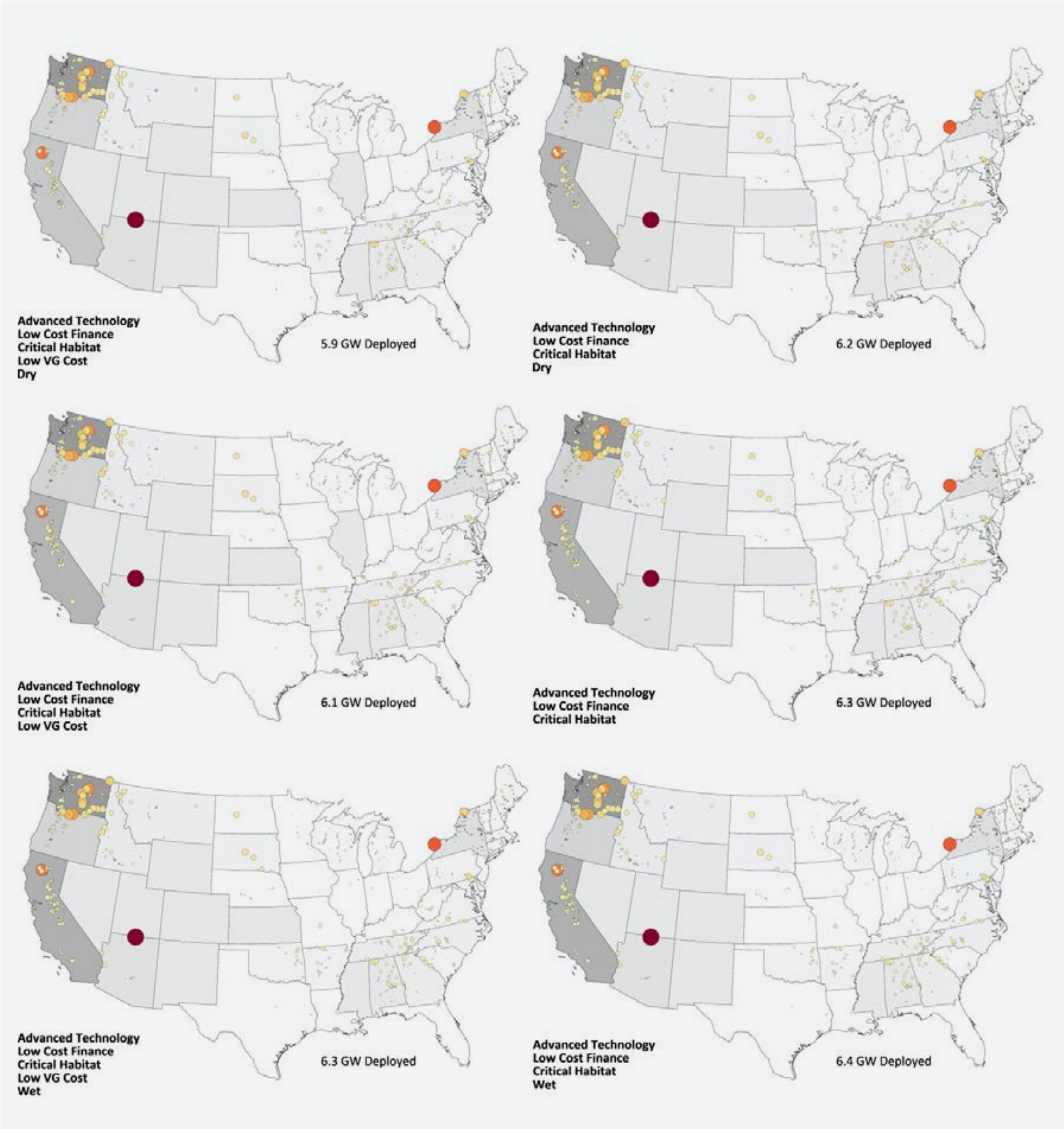


Figure F-24. National distribution of cumulative post-2016 upgrade capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* and *Advanced Technology, Low Cost Finance, Critical Habitat* scenarios and *Wet* and *Dry* sensitivities

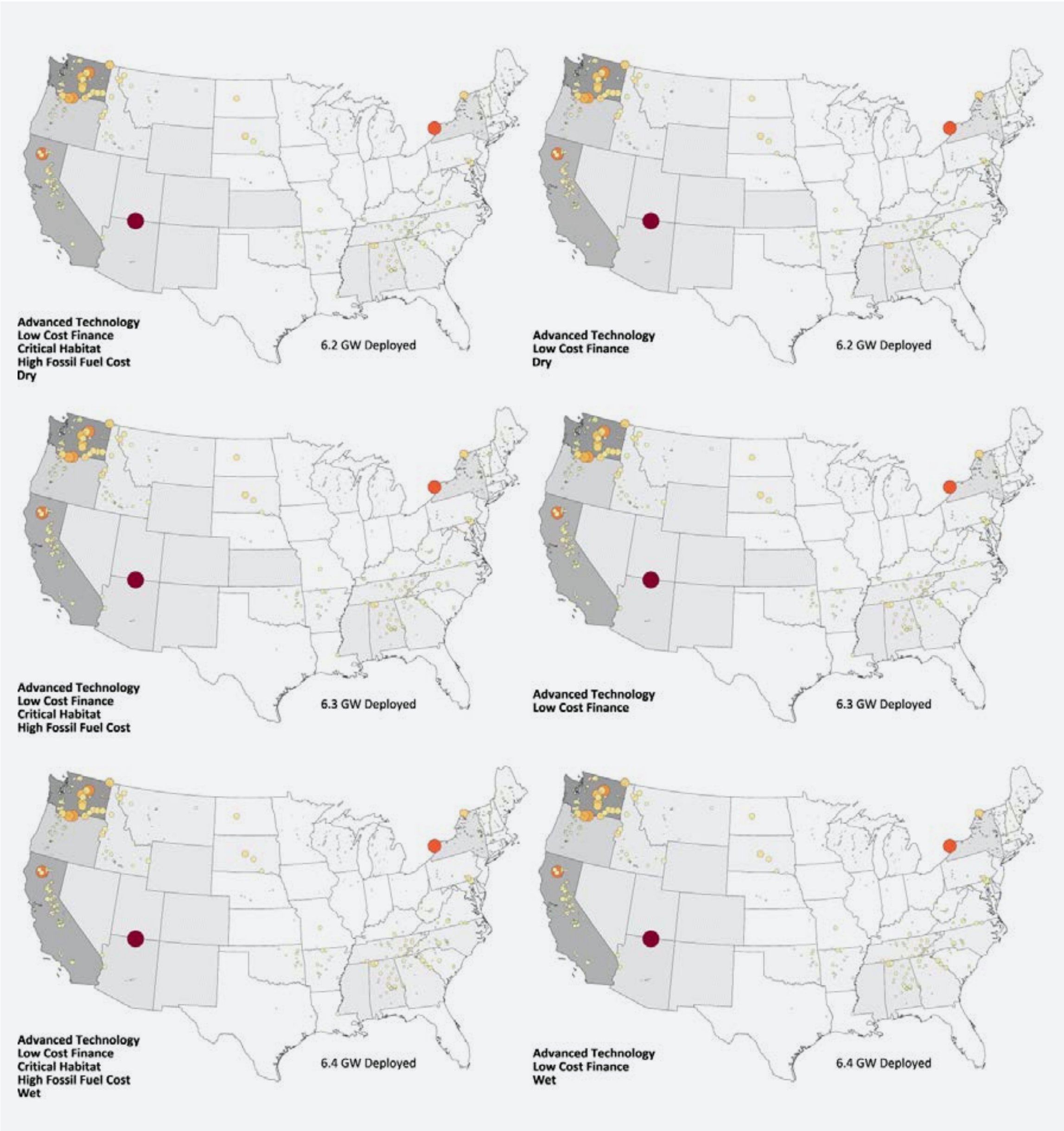


Figure F-25. National distribution of cumulative post-2016 upgrade capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost* and *Advanced Technology, Low Cost Finance* scenarios and *Wet* and *Dry* sensitivities

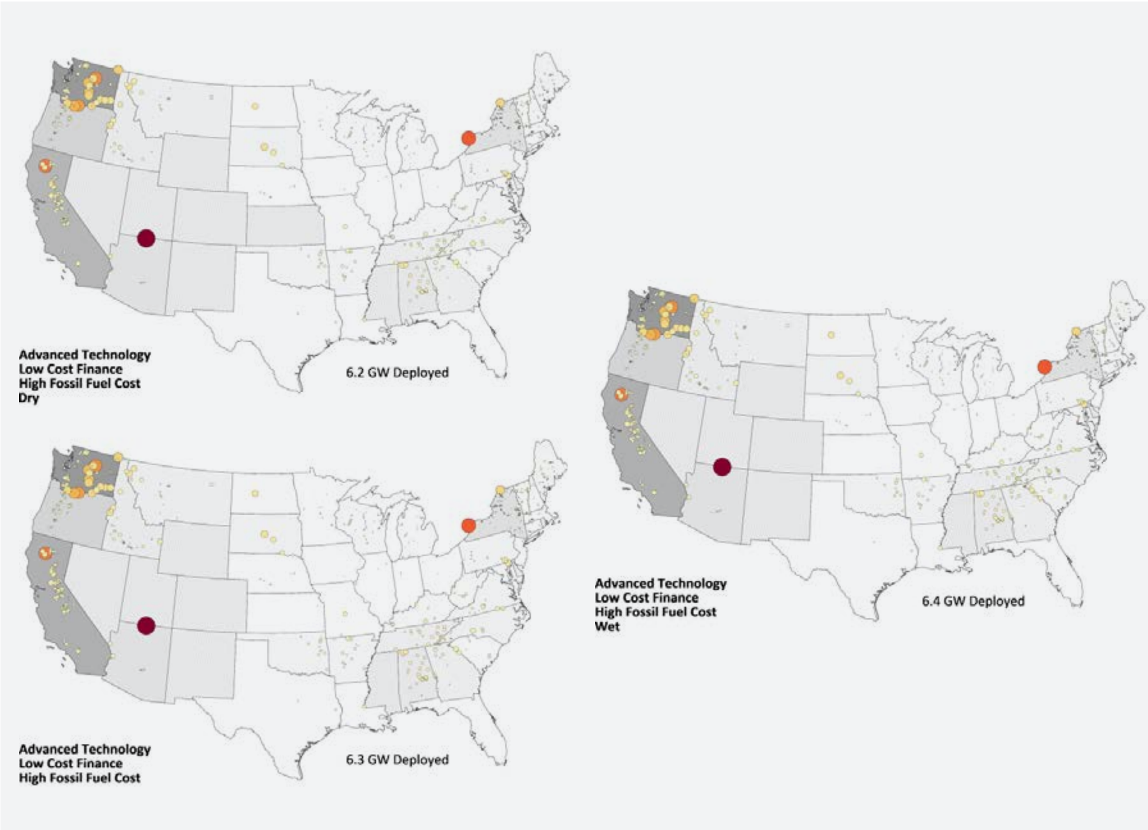


Figure F-26. National distribution of cumulative post-2016 upgrade capacity in 2050 for the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario and *Wet* and *Dry* sensitivities

Figure F-27. National distribution of cumulative post-2016 non-powered dam capacity in 2050 for the *Business-as-Usual* and *Advanced Technology* scenarios and *Wet* and *Dry* sensitivities

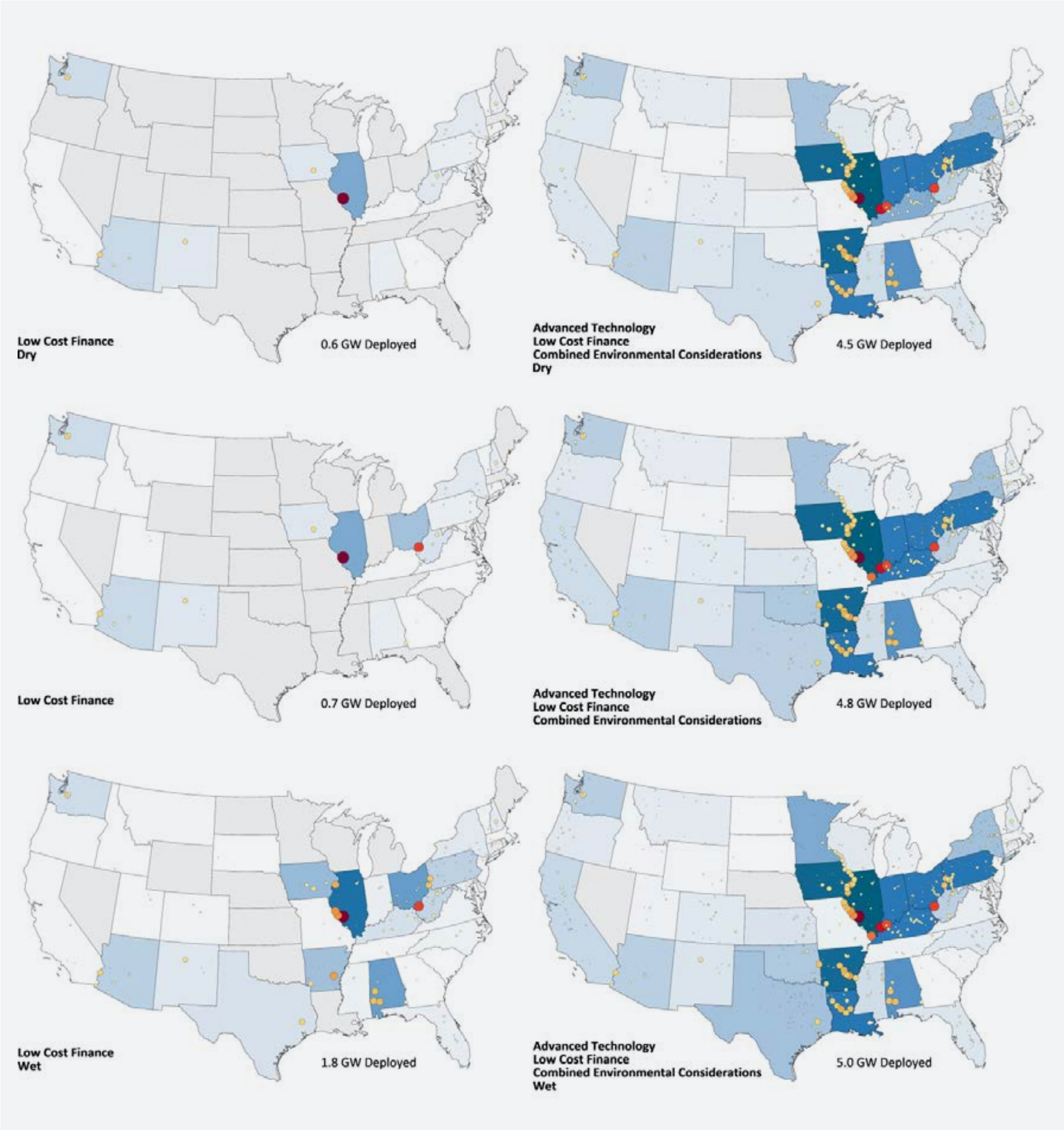


Figure F-28. National distribution of cumulative post-2016 non-powered dam capacity in 2050 for the *Low Cost Finance* and *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenarios and *Wet* and *Dry* sensitivities

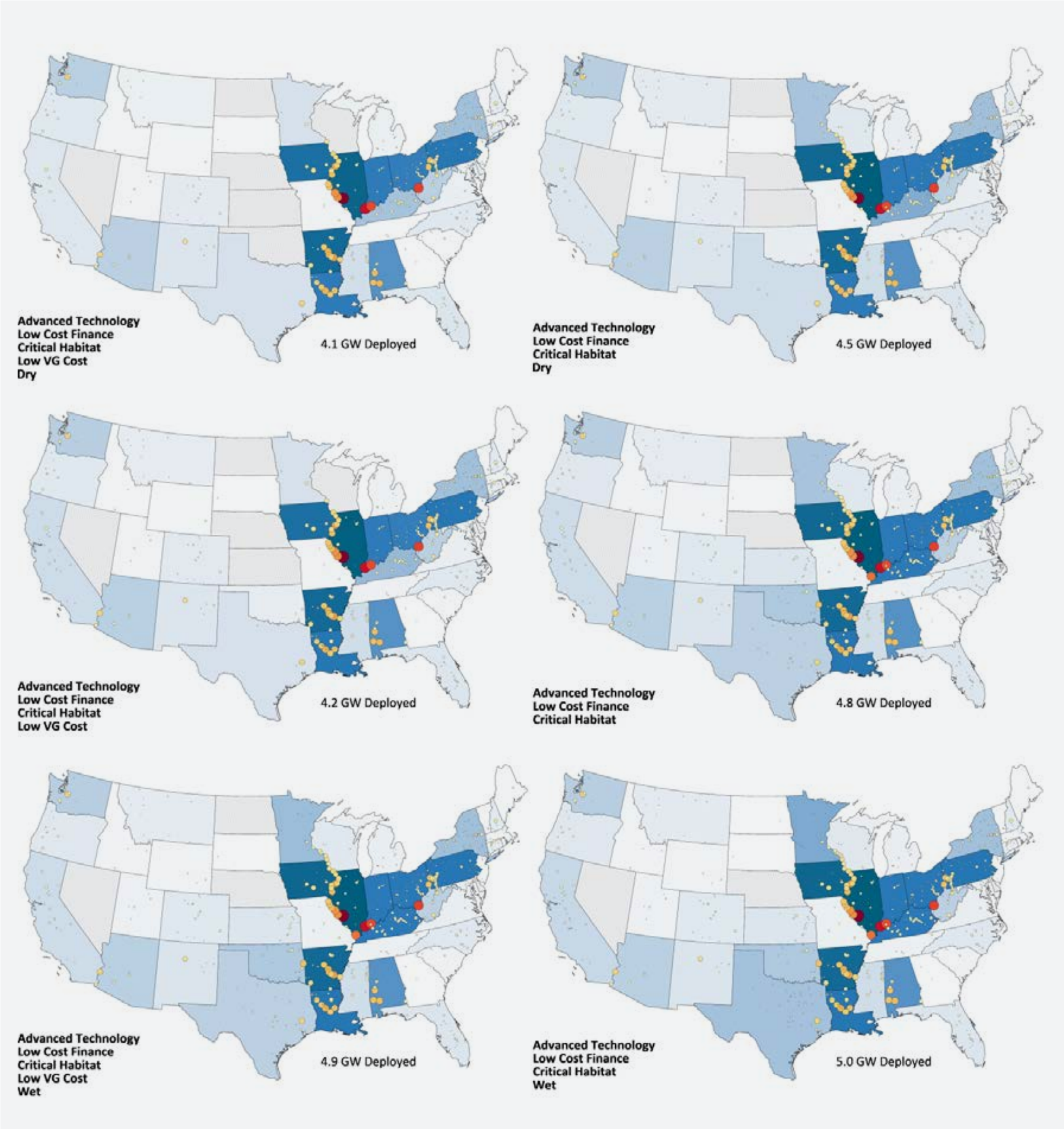


Figure F-29. National distribution of cumulative post-2016 NPD capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost* and *Advanced Technology, Low Cost Finance, Critical Habitat* scenarios and *Wet* and *Dry* sensitivities

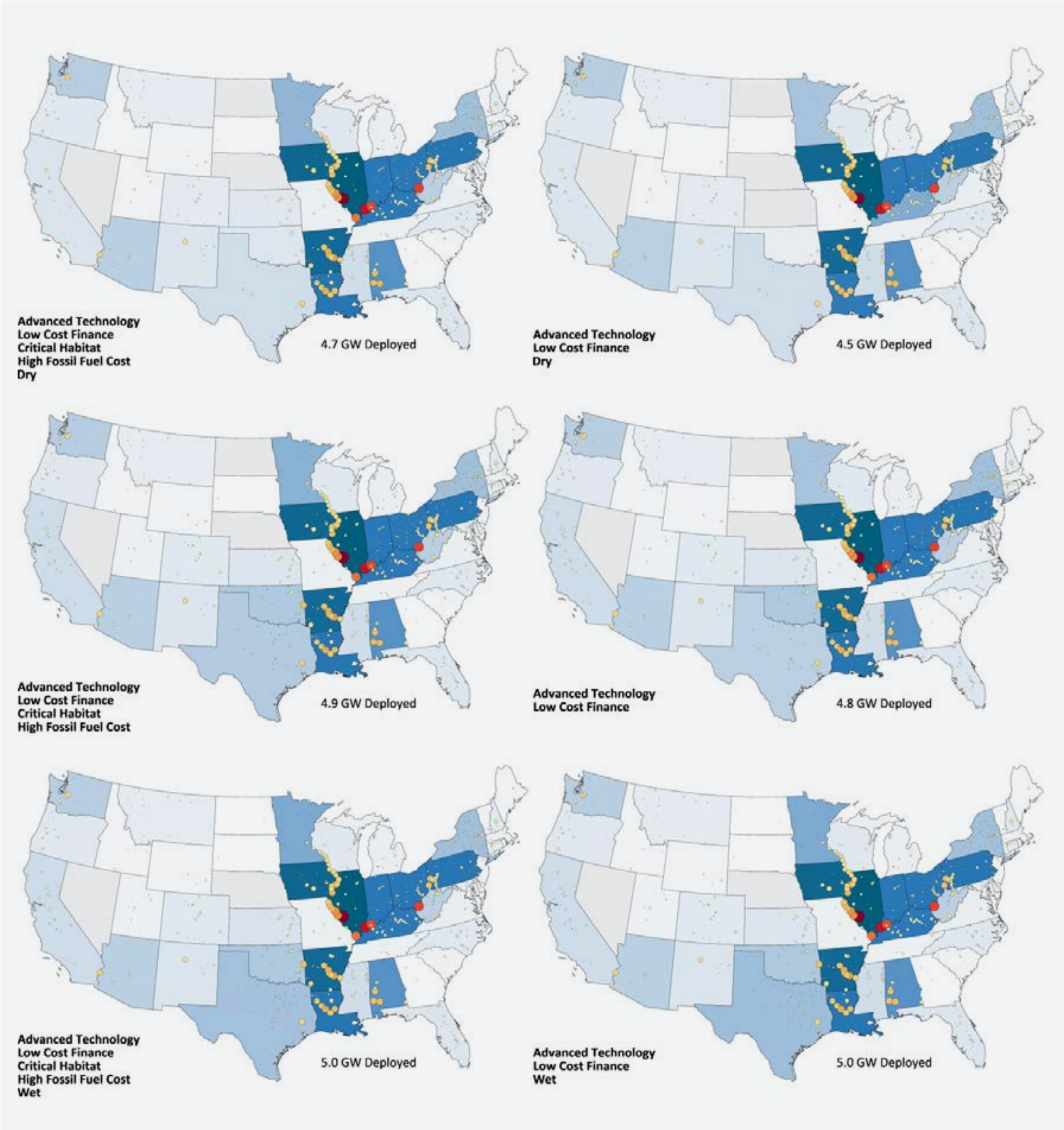


Figure F-30. National distribution of cumulative post-2016 NPD capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost* and *Advanced Technology, Low Cost Finance* scenarios and *Wet* and *Dry* sensitivities

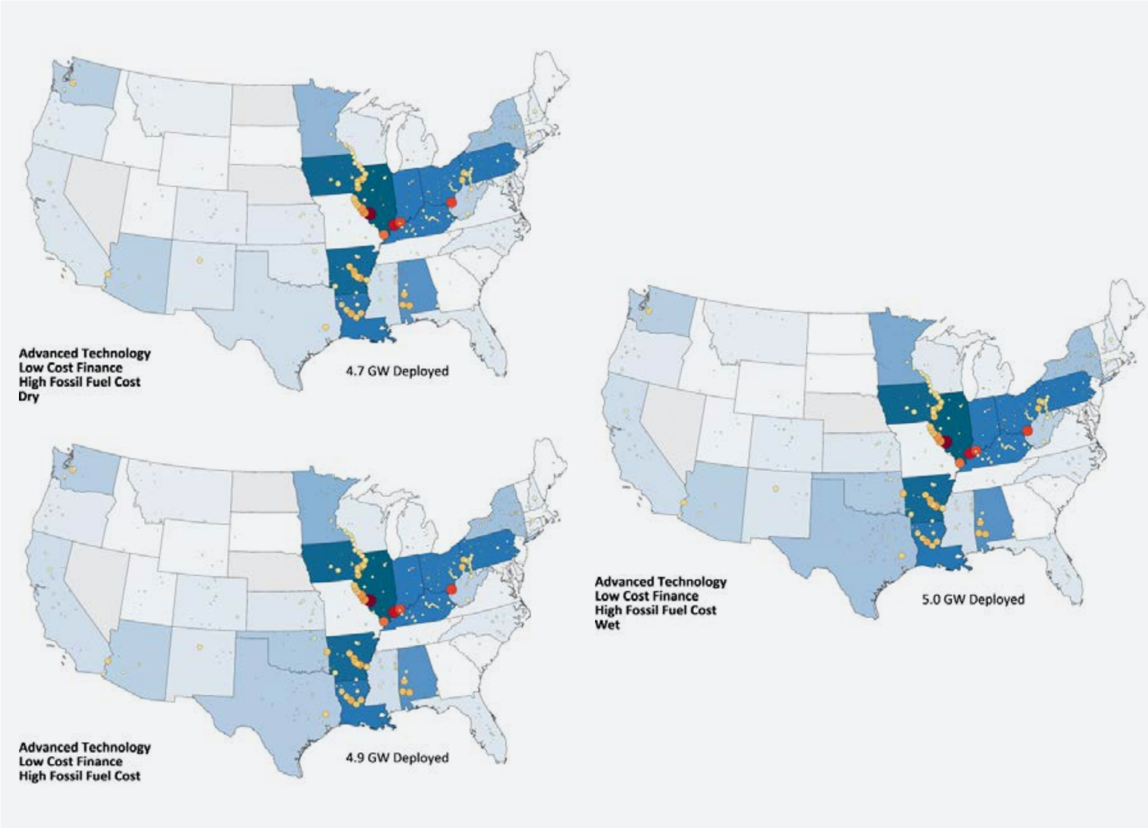


Figure F-31. National distribution of cumulative post-2016 NPD capacity in 2050 for the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario and *Wet* and *Dry* sensitivities

Figure F-32. National distribution of cumulative post-2016 NSD capacity in 2050 for the *Business-as-Usual* and *Advanced Technology* scenarios and *Wet* and *Dry* sensitivities

Figure F-33. National distribution of cumulative post-2016 NSD capacity in 2050 for the *Low Cost Finance* and *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenarios and *Wet* and *Dry* sensitivities

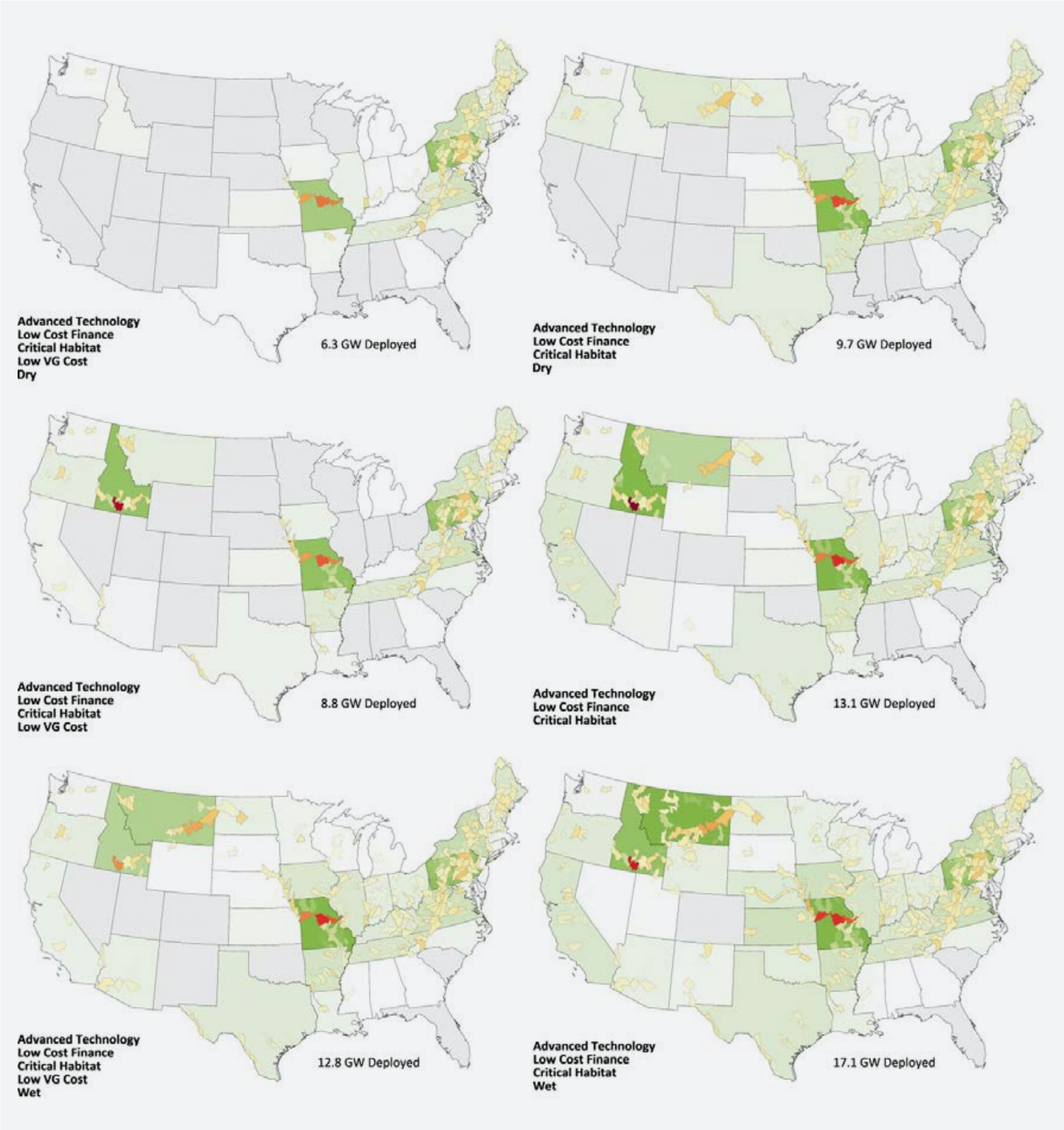


Figure F-34. National distribution of cumulative post-2016 NSD capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost and Advanced Technology, Low Cost Finance, Critical Habitat* scenarios and *Wet* and *Dry* sensitivities

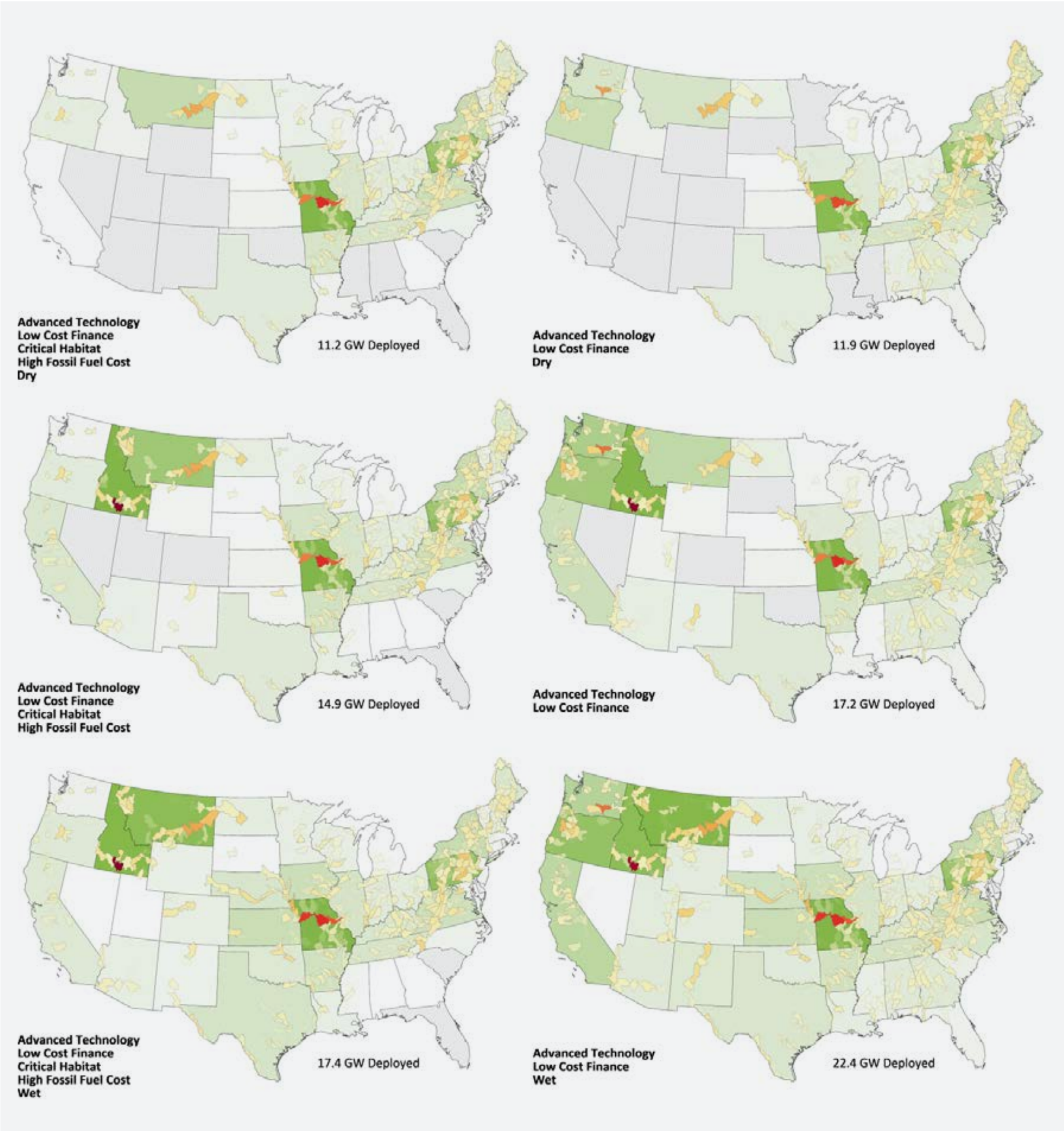


Figure F-35. National distribution of cumulative post-2016 NSD capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost and Advanced Technology, Low Cost Finance* scenarios and *Wet* and *Dry* sensitivities

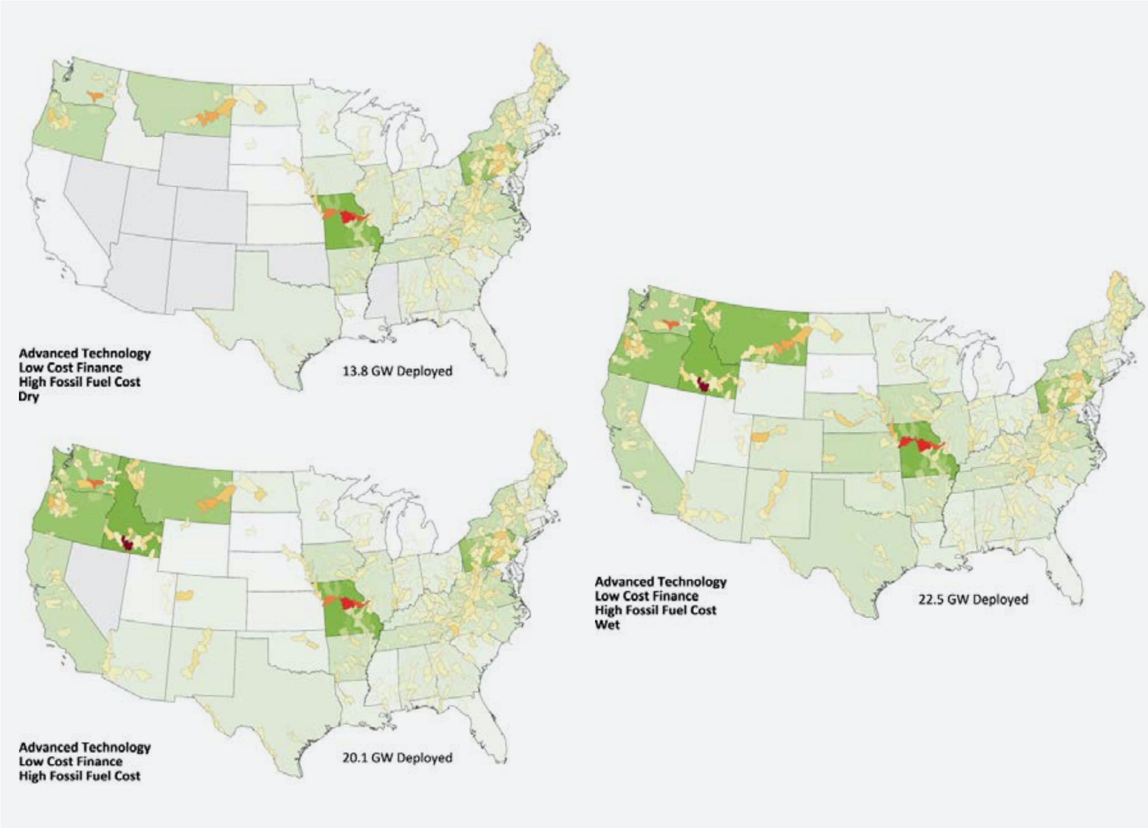


Figure F-36. National distribution of cumulative post-2016 NSD capacity in 2050 for the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario and *Wet* and *Dry* sensitivities

Figure F-37. National distribution of cumulative post-2016 PSH capacity in 2050 for the *Business-as-Usual* and *Advanced Technology* scenarios and *Wet* and *Dry* sensitivities

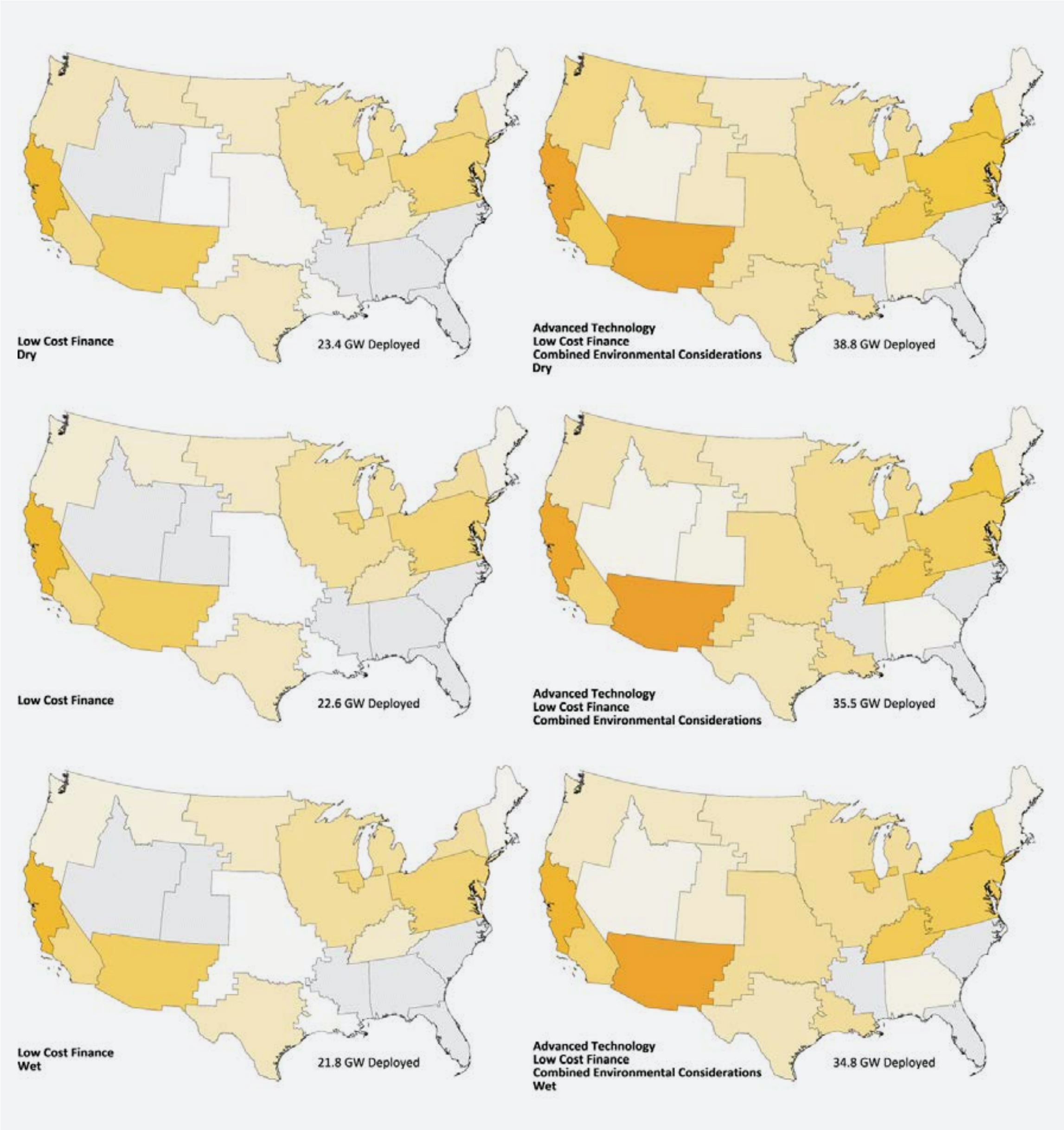


Figure F-38. National distribution of cumulative post-2016 PSH capacity in 2050 for the *Low Cost Finance* and *Advanced Technology, Low Cost Finance, Combined Environmental Considerations* scenarios and *Wet* and *Dry* sensitivities

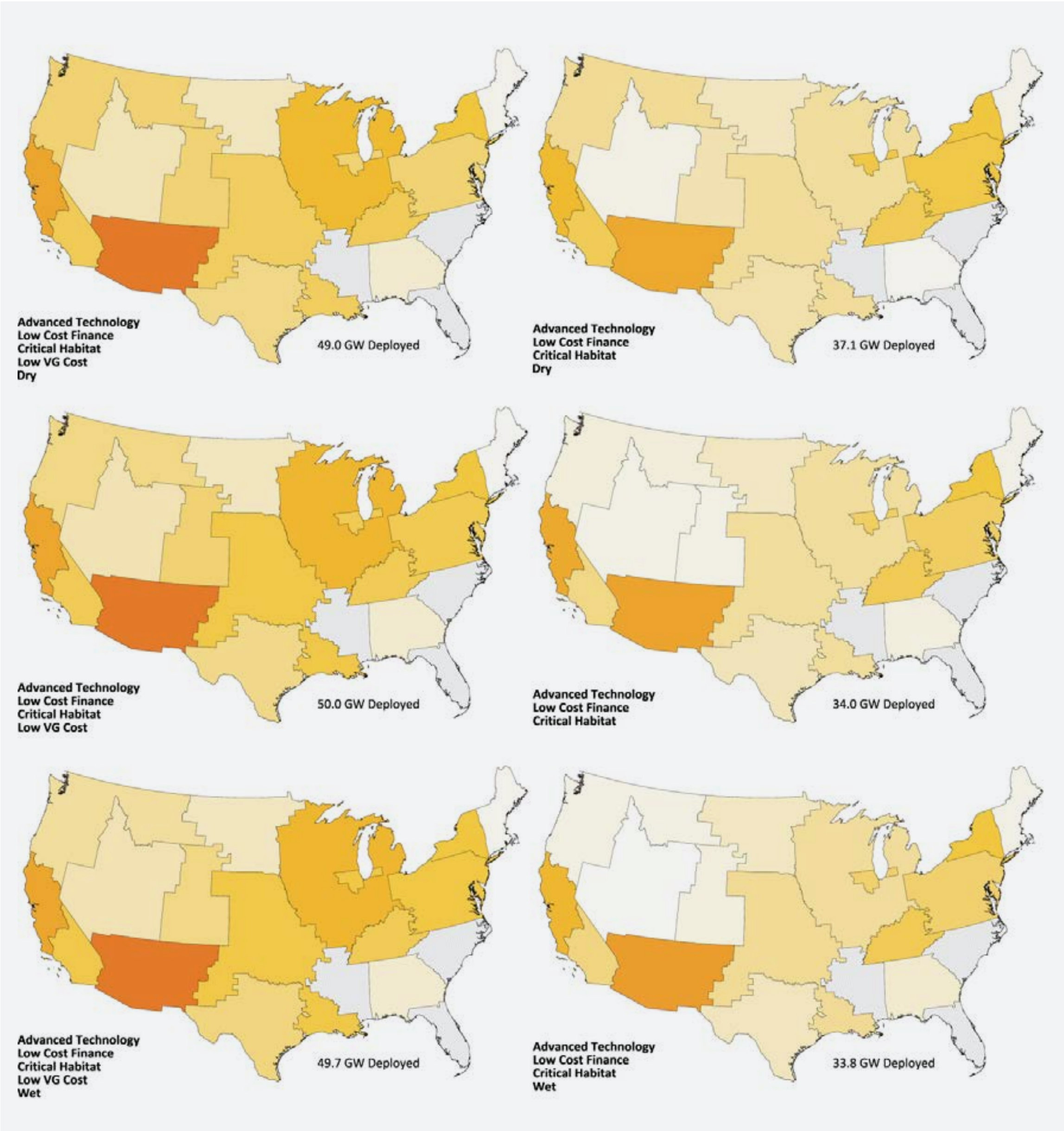


Figure F-39. National distribution of cumulative post-2016 PSH capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost and Advanced Technology, Low Cost Finance, Critical Habitat* scenarios and *Wet* and *Dry* sensitivities

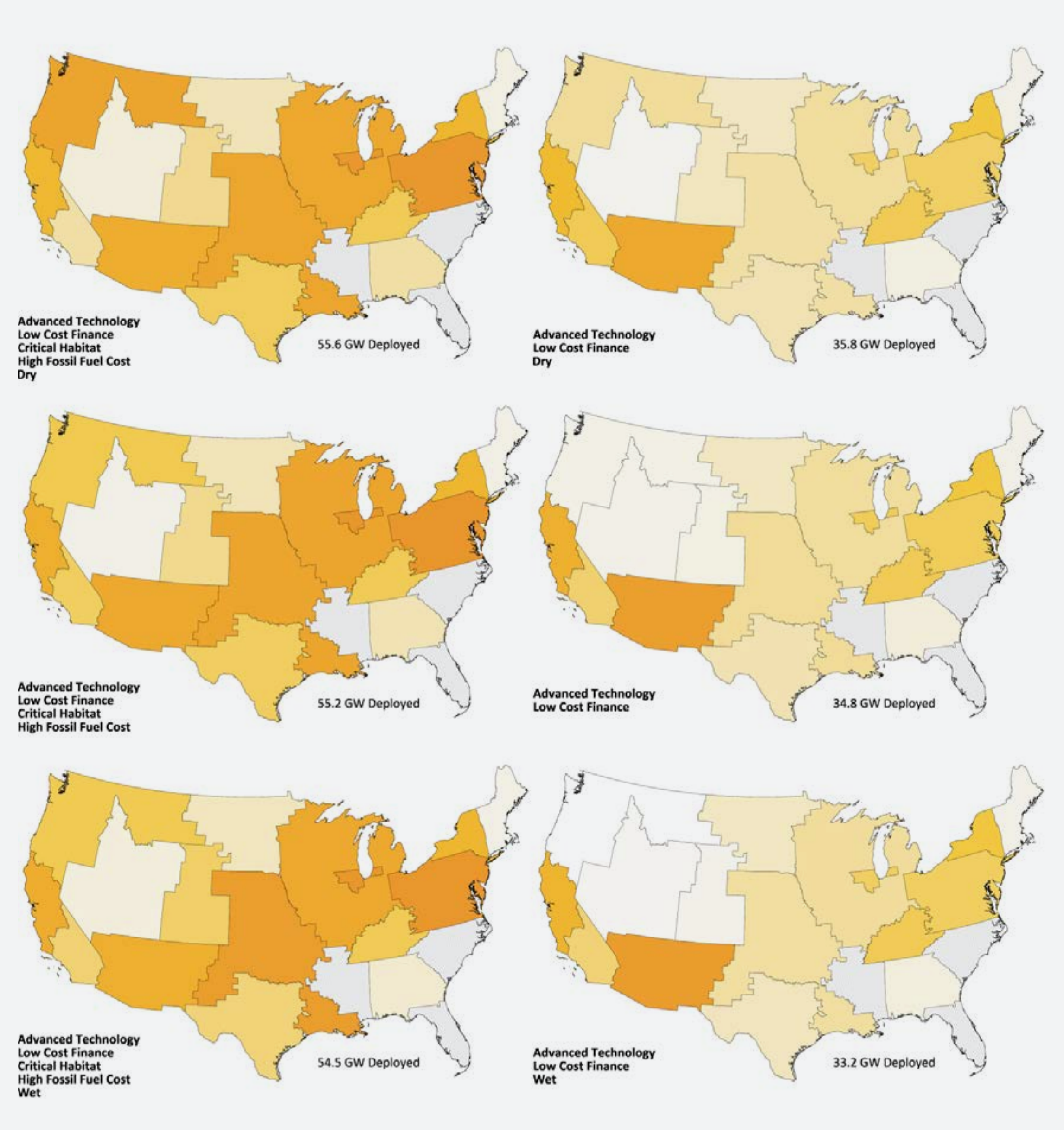


Figure F-40. National distribution of cumulative post-2016 PSH capacity in 2050 for the *Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost and Advanced Technology, Low Cost Finance* scenarios and *Wet* and *Dry* sensitivities

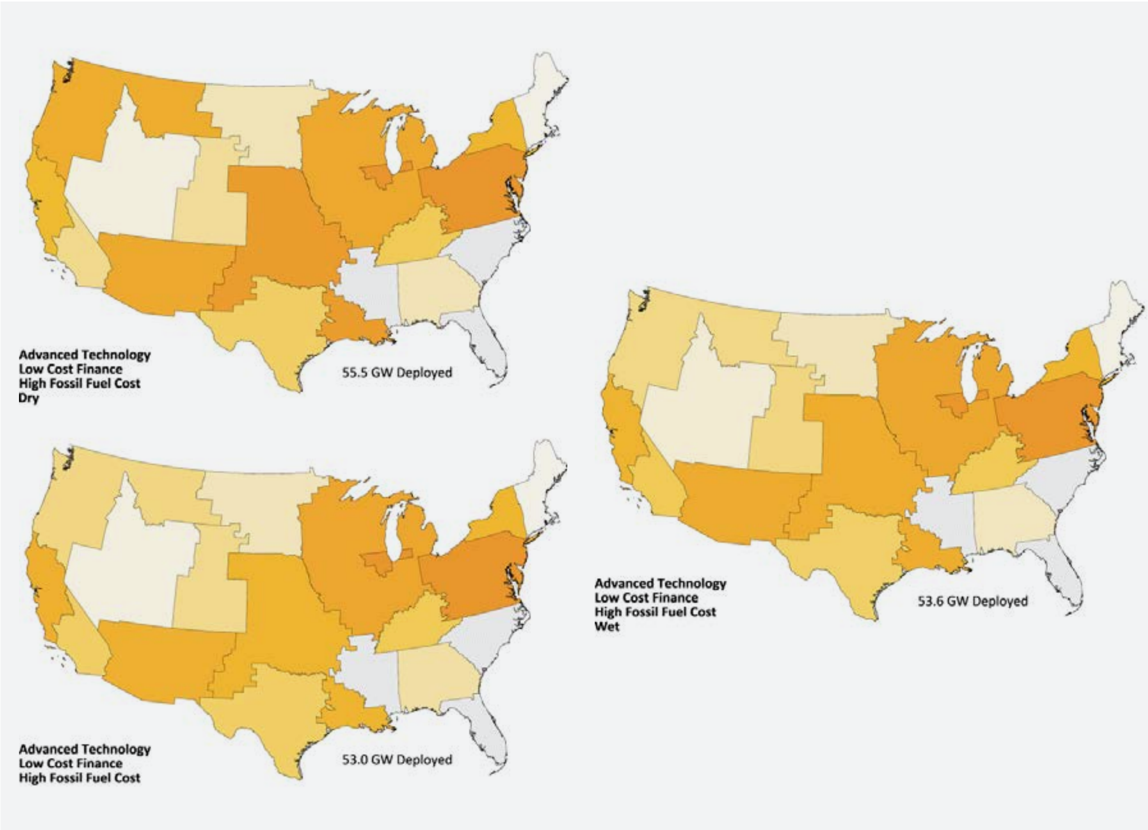


Figure F-41. National distribution of cumulative post-2016 PSH capacity in 2050 for the *Advanced Technology, Low Cost Finance, High Fossil Fuel Cost* scenario and *Wet* and *Dry* sensitivities

Tables F-8 through F-11 display cumulative new post-2016 hydropower capacity by state in 2030 and 2050 for selected scenarios modeled in the *Hydropower Vision* analysis. Given the resource availability considerations discussed in Chapter 3 and Appendix B, Table F-11 displays deployment at the North American Electric Reliability Corporation (NERC) regional scale for PSH instead of the state scale as is done for upgrades, NPD, and NSD.

Table F-8. Cumulative New Post-2016 Upgrade Capacity by State in 2030 and 2050 for Selected *Hydropower Vision* Analysis Scenarios

Cumulative new post-2016 upgrade capacity (MW) by state																		
	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
State	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
AK	Alaska is not directly modeled in National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) in the Hydropower Vision																	
AL	164	172	164	172	264	273	264	273	254	273	264	273	264	279	254	273	264	279
AR	69	79	69	79	79	97	79	97	79	97	79	97	79	98	79	97	79	98
AZ	426	428	426	428	428	430	428	430	428	430	428	430	428	430	428	430	428	430
CA	698	749	698	749	1029	1086	1011	1065	963	1018	1008	1063	1030	1085	1008	1063	1028	1083
CO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT	7	7	7	7	7	10	7	10	7	10	7	10	11	12	7	10	11	12
DE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FL	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
GA	92	116	92	116	142	166	142	166	142	166	142	166	142	166	142	166	142	166
HI	Hawaii is not directly modeled in ReEDS in the Hydropower Vision																	
IA	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	13	13	13
ID	172	183	172	183	244	263	244	263	197	218	244	263	244	263	208	263	244	263
IL	0	0	0	0	2	2	2	2	0	0	2	2	2	2	2	2	2	2
IN	6	6	6	6	9	9	9	9	6	6	8	9	9	9	8	9	9	9
KS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
KY	17	39	17	39	58	64	58	64	49	49	49	64	64	64	49	64	64	66
LA	0	19	0	19	0	19	0	19	0	19	0	19	0	19	0	19	0	19
MA	8	15	8	15	25	25	22	25	22	25	22	25	27	27	25	25	27	27
MD	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53	53
ME	62	65	62	65	68	72	68	72	68	72	68	72	68	72	68	72	68	72
MI	14	18	14	18	33	37	33	36	24	28	33	36	33	37	33	36	33	37
MN	9	9	9	9	17	20	17	20	16	18	17	20	17	21	17	20	17	21
MO	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
MS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MT	166	166	166	166	176	177	176	177	174	177	176	177	176	177	176	177	176	177
NC	70	80	70	80	105	137	105	137	70	115	105	137	127	145	105	137	127	145

Cumulative new post-2016 upgrade capacity (MW) by state

	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
State	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
ND	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49
NE	0	11	0	11	25	25	25	25	16	25	25	25	25	25	25	25	25	25
NH	1	11	1	11	40	41	40	41	12	41	40	41	41	46	40	41	41	46
NJ	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
NM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NY	152	439	152	439	203	470	203	470	194	470	203	470	203	470	203	470	203	470
OH	12	12	12	12	12	13	12	13	12	13	12	13	12	13	12	13	12	13
OK	20	20	20	20	67	70	67	70	58	70	67	70	67	70	67	70	67	70
OR	653	653	653	653	682	687	682	687	682	687	682	687	682	687	682	687	682	687
PA	60	60	60	60	64	74	64	74	64	73	64	74	64	75	64	74	64	75
RI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SC	11	11	11	11	17	24	17	24	17	24	17	24	17	24	17	24	17	24
SD	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128	128
TN	136	172	136	172	204	204	204	204	197	204	204	204	204	204	204	204	204	204
TX	0	0	0	0	12	12	12	12	12	12	12	12	12	12	12	12	12	12
UT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VA	54	54	54	54	70	70	70	70	60	67	70	70	70	72	60	67	70	72
VT	3	7	3	7	14	18	14	18	10	18	14	18	17	21	13	18	17	21
WA	1129	1298	1129	1298	1202	1339	1202	1339	1198	1333	1202	1339	1204	1339	1198	1339	1204	1339
WI	33	33	33	33	52	52	52	52	48	48	52	52	53	53	52	52	53	53
WV	16	32	16	32	21	38	21	38	21	37	21	38	21	38	21	38	21	38
WY	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table F-9. Cumulative New Post-2016 NPD Capacity by State in 2030 and 2050 for Selected *Hydropower Vision* Analysis Scenarios

Cumulative new post-2016 NPD capacity (MW) by state																				
	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
State	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
AK	Alaska is not directly modeled in ReEDS in the Hydropower Vision																			
AL	0	0	0	79	0	19	238	252	215	252	238	252	252	252	238	252	252	252
AR	0	0	0	0	0	0	448	492	134	490	448	492	490	492	383	492	490	492
AZ	0	0	21	69	69	69	93	93	69	93	93	93	93	93	93	93	93	93
CA	0	0	0	18	2	2	40	63	22	63	40	63	53	63	40	63	40	63
CO	0	0	0	7	0	0	27	30	7	27	27	30	27	30	27	30	27	30
CT	0	0	0	7	0	7	7	26	7	26	7	26	26	26	7	26	26	26
DE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FL	0	0	0	7	0	0	29	37	27	37	29	37	33	37	29	37	33	37
GA	0	0	0	1	0	1	2	2	1	2	2	2	2	2	2	2	2	2
HI	Hawaii is not directly modeled in ReEDS in the Hydropower Vision																			
IA	36	36	36	36	36	36	481	514	149	430	481	514	482	527	481	514	481	527
ID	0	0	0	3	3	3	5	6	3	5	5	6	5	6	3	6	5	6
IL	0	0	0	193	193	193	603	624	409	609	603	624	607	627	603	624	607	627
IN	0	0	0	0	0	0	307	312	11	307	307	312	307	315	307	312	307	315
KS	0	0	0	0	0	0	0	38	0	0	0	38	0	38	0	38	0	38
KY	0	0	0	20	0	6	66	314	20	150	54	314	68	314	54	314	68	314
LA	0	0	0	0	0	0	308	345	0	339	308	345	339	345	254	345	339	345
MA	0	0	0	2	0	0	2	8	2	8	2	8	8	8	2	8	8	8
MD	0	0	0	11	0	9	11	20	11	20	11	20	13	20	11	20	13	20
ME	0	0	0	0	0	0	0	6	0	6	0	6	6	6	0	6	6	6
MI	0	0	0	0	0	0	0	15	0	10	0	15	0	15	0	15	0	15
MN	0	0	0	0	0	0	49	125	0	49	49	125	49	174	49	125	49	174
MO	0	0	0	0	0	0	8	13	6	8	8	13	8	13	8	13	8	13
MS	0	0	0	14	0	0	30	57	14	57	25	57	55	59	25	57	55	59
MT	0	0	0	8	6	6	20	21	10	20	20	21	20	20	18	20	20	20
NC	0	0	0	13	0	1	13	32	1	32	13	32	13	34	13	32	13	34
ND	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NH	0	0	0	26	21	25	26	27	26	27	26	27	26	27	26	27	26	27
NJ	0	0	0	2	0	0	2	7	2	7	2	7	7	7	2	7	7	7
NM	0	0	34	35	35	35	39	39	35	39	39	39	39	39	39	39	39	39
NV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Cumulative new post-2016 NPD capacity (MW) by state																		
	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
State	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
NY	0	0	0	28	0	28	28	133	28	133	28	133	116	133	28	133	116	133
OH	0	0	0	31	0	130	229	314	161	300	229	314	259	318	229	314	259	318
OK	0	0	0	0	0	0	18	112	0	18	18	112	18	112	18	112	18	112
OR	0	0	6	14	6	6	29	34	6	32	29	34	32	34	29	34	32	34
PA	0	0	0	29	2	15	153	339	15	339	153	339	275	342	153	339	275	342
RI	0	0	0	0	0	0	0	1	0	1	0	1	0	1	0	1	0	1
SC	0	0	0	1	0	0	3	8	1	8	3	8	8	8	3	8	8	8
SD	0	0	0	1	0	0	1	1	0	1	1	1	1	1	1	1	1	1
TN	0	0	0	4	0	0	4	12	4	11	4	12	4	12	4	12	4	12
TX	0	0	0	0	0	0	48	93	47	49	48	93	53	107	48	93	48	107
UT	0	0	0	4	4	4	10	11	9	10	10	11	10	11	10	11	10	11
VA	0	0	0	9	0	9	11	16	9	16	11	16	11	16	11	16	11	16
VT	0	0	0	5	0	5	5	7	5	7	5	7	7	7	5	7	7	7
WA	0	0	63	63	63	63	87	96	63	96	87	96	91	98	87	96	91	98
WI	0	0	0	0	0	0	0	31	0	0	0	31	26	31	0	31	0	31
WV	0	0	0	34	34	42	77	93	42	91	77	93	91	93	68	93	91	93
WY	0	0	0	0	0	0	0	7	0	4	0	7	0	8	0	7	0	8

Table F-10. Cumulative New Post-2016 NSD Capacity by State in 2030 and 2050 for Selected *Hydropower Vision* Analysis Scenarios

Cumulative new post-2016 NSD capacity (MW) by state																		
	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
State	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
AK	Alaska is not directly modeled in ReEDS in the Hydropower Vision																	
AL	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	272	64	279
AR	0	0	0	0	0	0	0	136	0	345	0	470	199	540	0	470	157	540
AZ	0	0	0	0	0	0	0	57	0	53	0	78	0	154	0	198	0	271
CA	0	0	0	0	0	0	0	27	0	56	0	421	20	416	0	636	20	635
CO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	180
CT	0	0	0	0	0	0	0	6	0	53	0	65	23	68	0	65	23	68
DE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	42	105	83	105
GA	0	0	0	0	0	0	0	5	0	5	0	5	5	5	0	310	132	310
HI	Hawaii is not directly modeled in ReEDS in the Hydropower Vision																	
IA	0	0	0	0	0	0	0	0	0	141	141	297	141	485	106	311	141	502
ID	0	0	0	0	0	0	67	444	0	1503	86	1815	86	1892	86	1873	86	2093
IL	0	0	0	0	0	0	0	0	0	0	0	320	75	431	0	320	0	431
IN	0	0	0	0	0	0	0	3	0	0	0	182	21	236	0	174	0	236
KS	0	0	0	0	0	0	0	0	0	95	95	95	95	95	0	95	95	95
KY	0	0	0	0	0	0	0	14	0	21	0	182	0	322	0	196	0	353
LA	0	0	0	0	0	0	0	0	0	78	0	139	0	180	0	99	0	204
MA	0	0	0	0	0	0	0	16	0	50	0	50	38	50	0	50	29	50
MD	0	0	0	0	0	0	0	1	0	82	0	91	41	95	0	92	42	96
ME	0	0	0	0	0	0	0	27	0	369	0	404	292	404	0	559	383	616
MI	0	0	0	0	0	0	0	0	0	4	0	14	0	42	0	14	0	42
MN	0	0	0	0	0	0	0	32	0	0	0	62	0	137	0	46	0	137
MO	0	0	0	0	0	0	0	0	638	1547	1340	1871	1527	1888	1340	1871	1340	1900
MS	0	0	0	0	0	0	0	0	0	0	0	0	0	50	0	21	0	133
MT	0	0	0	0	0	0	0	0	0	262	0	929	0	1337	0	822	0	1279
NC	0	0	0	0	0	0	6	10	96	133	118	133	133	133	187	426	281	432
ND	0	0	0	0	0	0	0	0	0	0	0	208	0	208	0	208	0	208
NE	0	0	0	0	0	0	0	0	0	0	0	40	0	40	0	40	0	40
NH	0	0	0	0	0	0	0	8	0	237	0	237	224	237	0	237	222	237
NJ	0	0	0	0	0	0	0	0	0	89	27	89	81	89	27	89	81	89
NM	0	0	0	0	0	0	0	0	0	0	0	18	0	73	0	157	0	279
NV	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Cumulative new post-2016 NSD capacity (MW) by state																				
	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
State	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**	**2030**	**2050**
NY	0	0	0	0	0	0	0	120	0	458	0	673	233	744	0	673	233	744
OH	0	0	0	0	0	0	0	36	0	0	0	171	0	227	0	160	0	227
OK	0	0	0	0	0	0	0	0	0	0	0	0	0	46	0	0	0	167
OR	0	0	0	0	0	0	51	51	0	226	0	274	99	274	0	1297	0	1442
PA	0	0	0	0	0	0	0	375	0	1563	548	1579	1193	1591	373	1579	1078	1591
RI	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	68	155	113	155
SD	0	0	0	0	0	0	0	0	0	0	0	0	0	20	0	0	0	20
TN	0	0	0	0	0	0	0	20	0	361	109	438	197	438	116	515	171	515
TX	0	0	0	0	0	0	20	85	0	118	92	302	118	317	57	323	110	323
UT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	79	0	60
VA	0	0	0	0	0	0	72	157	0	535	91	578	336	578	88	667	362	667
VT	0	0	0	0	0	0	0	14	0	61	0	93	28	103	0	93	28	103
WA	0	0	0	0	0	0	0	19	0	74	0	82	0	82	357	1130	357	1365
WI	0	0	0	0	0	0	0	0	0	0	0	89	0	124	0	89	0	124
WV	0	0	0	0	0	0	0	14	0	301	0	594	0	652	0	594	0	652
WY	0	0	0	0	0	0	0	7	0	0	0	61	0	61	0	61	0	61

Table F-11. Cumulative New Post-2016 PSH Capacity by NERC Region in 2030 and 2050 for Selected *Hydropower Vision Analysis* Scenarios

Cumulative new post-2016 PSH capacity (MW) by NERC region																		
	(1) Business-as-Usual		(8) Advanced Technology		(13) Low Cost Finance		(34) Advanced Technology, Low Cost Finance, Combined Environmental Considerations		(23) Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost		(24) Advanced Technology, Low Cost Finance, Critical Habitat		(25) Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost		(19) Advanced Technology, Low Cost Finance		(20) Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	
NERC Region	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
BASN	0	0	0	0	0	0	0	247	0	1530	0	350	0	319	0	319	0	508
CALN	0	0	161	161	1498	4733	1876	5777	2396	6013	1689	5717	839	5462	1058	5415	877	5420
CALS	0	0	0	0	2090	2571	2090	2786	2201	3571	2090	2571	1115	3335	2090	3020	352	3252
DSW	0	0	0	0	1088	3300	1025	6319	1438	8554	932	6138	844	5831	908	6412	835	5380
ERCOT	171	480	284	1271	1271	1271	1271	1422	1271	2471	1271	1358	1271	3372	1271	1557	1271	3254
FRCC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ISO-NE	0	0	0	0	330	330	325	325	192	192	329	329	261	340	329	329	241	323
MAPP	0	0	187	1200	1200	1200	1200	1200	819	1231	1200	1201	1200	1434	1154	1200	1039	1356
MISO-US	0	0	13	16	160	2000	159	2207	533	5032	113	2000	1165	6034	102	2025	268	6009
NORW	0	0	0	0	0	778	2	1530	0	2565	0	623	0	3697	0	370	0	2595
NYISO	0	0	0	0	2046	2046	3731	4000	3589	4000	3306	4000	4000	5007	2387	4000	4000	5000
PJM	0	0	0	0	2500	2850	2500	3337	2500	3631	2500	3258	2500	6946	2500	3448	2500	6944
ROCK	0	0	0	0	0	0	0	452	2	2953	0	373	0	2308	0	428	0	2381
SERC-E	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SERC-N	0	0	0	0	16	1470	2065	3562	695	3562	1369	3562	105	3562	289	3562	104	3562
SERC-SE	0	0	0	0	0	0	0	182	0	900	0	530	0	1482	0	632	0	1848
SERC-W	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SPP	0	0	0	0	0	28	0	2173	0	3826	0	2030	0	6079	0	2120	0	5174

Table F-12 displays the overlap of NSD deployment with the environmental considerations outlined in Chapter 3 and Appendix B. The total NSD resource available for economic competition in the National Renewable Energy Laboratory's Regional Energy Deployment System (ReEDS) is also given for context in the subset of scenarios that avoid deployment where overlap exists.

Table F-12. Overlap of 2050 Cumulative New NSD Capacity with Environmental Considerations for all *Hydropower Vision* Analysis Scenarios

				Overlap of 2050 NSD Capacity with Environmental Considerations (GW)							
#	Scenario	NSD Resource (GW)	2050 NSD Capacity (GW)	Critical Habitat	Protected Lands	Migratory Fish Habitat	Low Disturbance Rivers	National Rivers Inventory	Ocean Connectivity	Species of Concern	No Overlap
1	Business-as-Usual	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	Low Fossil Fuel Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	Low VG Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	High Fossil Fuel Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	High VG Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Advanced Technology, Low Fossil Fuel Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	Advanced Technology, Low VG Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Advanced Technology	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Advanced Technology, High Fossil Fuel Cost	30.7	0.9	0.1	0.5	0.4	0.3	0.5	0.1	0.0	0.0
10	Advanced Technology, High VG Cost	30.7	2.0	0.5	1.6	1.5	1.4	0.9	0.0	0.9	0.1
11	Low Cost Finance, Low Fossil Fuel Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	Low Cost Finance, Low VG Cost	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	Low Cost Finance	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	Low Cost Finance, High Fossil Fuel Cost	30.7	1.7	0.0	1.2	1.0	0.8	0.7	0.1	0.6	0.1
15	Low Cost Finance, High VG Cost	30.7	2.7	0.4	2.3	2.3	1.9	0.9	0.0	1.3	0.1
16	Evolutionary Technology, Low Cost Finance	30.7	2.6	0.5	2.0	1.8	1.5	1.2	0.1	0.9	0.1
17	Advanced Technology, Low Cost Finance, Low Fossil Fuel Cost	30.7	7.8	1.3	4.2	5.9	3.3	2.6	0.2	3.0	0.6

#	Scenario	NSD Resource (GW)	2050 NSD Capacity (GW)	Overlap of 2050 NSD Capacity with Environmental Considerations (GW)							
				Critical Habitat	Protected Lands	Migratory Fish Habitat	Low Disturbance Rivers	National Rivers Inventory	Ocean Connectivity	Species of Concern	No Overlap
18	Advanced Technology, Low Cost Finance, Low VG Cost	30.7	10.5	2.3	4.8	5.8	4.8	4.2	0.8	2.7	1.1
19	Advanced Technology, Low Cost Finance	30.7	17.2	4.2	7.2	10.5	7.4	6.6	1.4	4.3	1.6
20	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost	30.7	20.1	5.2	8.0	12.9	8.6	7.3	1.7	4.8	1.8
21	Advanced Technology, Low Cost Finance, High VG Cost	30.7	28.2	9.1	9.9	19.4	12.3	9.8	3.1	7.0	2.3
22	Advanced Technology, Low Cost Finance, Critical Habitat, Low Fossil Fuel Cost	21.2	6.6	0.0	3.5	4.9	2.7	1.5	0.1	2.6	0.6
23	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	21.2	8.8	0.0	3.8	4.6	4.0	2.6	0.3	2.5	1.3
24	Advanced Technology, Low Cost Finance, Critical Habitat	21.2	13.2	0.0	5.5	7.4	5.8	4.2	0.4	3.2	1.7
25	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	21.2	14.9	0.0	6.1	8.6	6.3	4.6	0.4	3.4	1.9
26	Advanced Technology, Low Cost Finance, Critical Habitat, High VG Cost	21.2	19.2	0.0	7.2	11.5	8.1	5.6	0.8	4.6	2.3
27	Advanced Technology, Low Cost Finance, Protected Lands	20.3	10.3	2.6	0.0	5.4	3.3	3.6	0.8	2.0	1.7
28	Advanced Technology, Low Cost Finance, Low Disturbance Rivers	17.3	10.0	2.6	3.1	6.3	0.0	3.2	0.9	2.4	1.7
29	Advanced Technology, Low Cost Finance, National Rivers Inventory	20.4	11.5	2.2	4.5	7.6	4.6	0.0	0.9	3.4	1.7
30	Advanced Technology, Low Cost Finance, Ocean Connectivity	27.1	16.4	3.4	6.7	9.6	7.1	6.0	0.0	4.3	1.7

#	Scenario	NSD Resource (GW)	2050 NSD Capacity (GW)	Overlap of 2050 NSD Capacity with Environmental Considerations (GW)							
				Critical Habitat	Protected Lands	Migratory Fish Habitat	Low Disturbance Rivers	National Rivers Inventory	Ocean Connectivity	Species of Concern	No Overlap
31	Advanced Technology, Low Cost Finance, Species of Concern	23.2	13.4	3.5	4.9	7.0	5.7	5.4	1.3	0.0	1.7
32	Advanced Technology, Low Cost Finance, Combined Species Considerations	8	5.6	0.0	1.6	0.0	2.6	2.3	0.0	0.0	1.7
33	Advanced Technology, Low Cost Finance, Combined Land Considerations	9.3	5.1	0.8	0.0	3.0	0.0	0.0	0.3	1.1	1.8
34	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	2.6	1.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7
35	Advanced Technology, Low Cost Finance, Migratory Fish Habitat	9.9	6.8	1.0	1.8	0.0	3.1	2.8	0.1	0.3	1.7
36	Dry	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
37	Wet	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
38	Advanced Technology, Dry	30.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
39	Advanced Technology, Wet	30.7	2.7	0.3	1.9	1.7	1.4	1.1	0.2	1.0	0.1
40	Low Cost Finance, Dry	30.7	0.2	0.0	0.2	0.0	0.2	0.0	0.0	0.0	0.0
41	Low Cost Finance, Wet	30.7	2.6	0.2	1.9	1.7	1.4	0.9	0.1	1.0	0.1
42	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Dry	2.6	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1
43	Advanced Technology, Low Cost Finance, Combined Environmental Considerations, Wet	2.6	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2
44	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Dry	21.2	6.3	0.0	3.3	2.8	3.2	2.4	0.2	1.3	0.8
45	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost, Wet	21.2	12.8	0.0	5.6	7.3	5.6	4.1	0.4	2.9	1.6

#	Scenario	NSD Resource (GW)	2050 NSD Capacity (GW)	Overlap of 2050 NSD Capacity with Environmental Considerations (GW)							
				Critical Habitat	Protected Lands	Migratory Fish Habitat	Low Disturbance Rivers	National Rivers Inventory	Ocean Connectivity	Species of Concern	No Overlap
46	Advanced Technology, Low Cost Finance, Critical Habitat, Dry	21.2	9.7	0.0	4.8	5.1	4.7	3.5	0.3	2.0	1.1
47	Advanced Technology, Low Cost Finance, Critical Habitat, Wet	21.2	17.1	0.0	6.7	10.3	7.4	5.1	0.5	3.8	2.0
48	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Dry	21.2	11.2	0.0	5.3	6.1	5.2	3.8	0.3	2.3	1.3
49	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost, Wet	21.2	17.4	0.0	6.8	10.6	7.5	5.1	0.6	4.1	2.1
50	Advanced Technology, Low Cost Finance, Dry	30.7	11.9	2.3	5.6	6.7	5.8	5.0	0.8	2.4	1.1
51	Advanced Technology, Low Cost Finance, Wet	30.7	22.4	5.0	8.7	14.4	9.6	7.8	1.8	5.3	2.1
52	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Dry	30.7	13.8	2.5	6.3	8.0	6.5	5.5	0.9	2.8	1.3
53	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost, Wet	30.7	22.6	5.0	8.8	14.5	9.6	7.8	1.9	5.5	2.1

Figures F-42 and F-43 display the national-scale NSD results of scenarios that avoid development in areas overlapping the environmental considerations. Both figures include the *Advanced Technology, Low Cost Finance* scenario as a reference point. Chapter 3 and Appendix B describe assumptions underlying these scenarios.

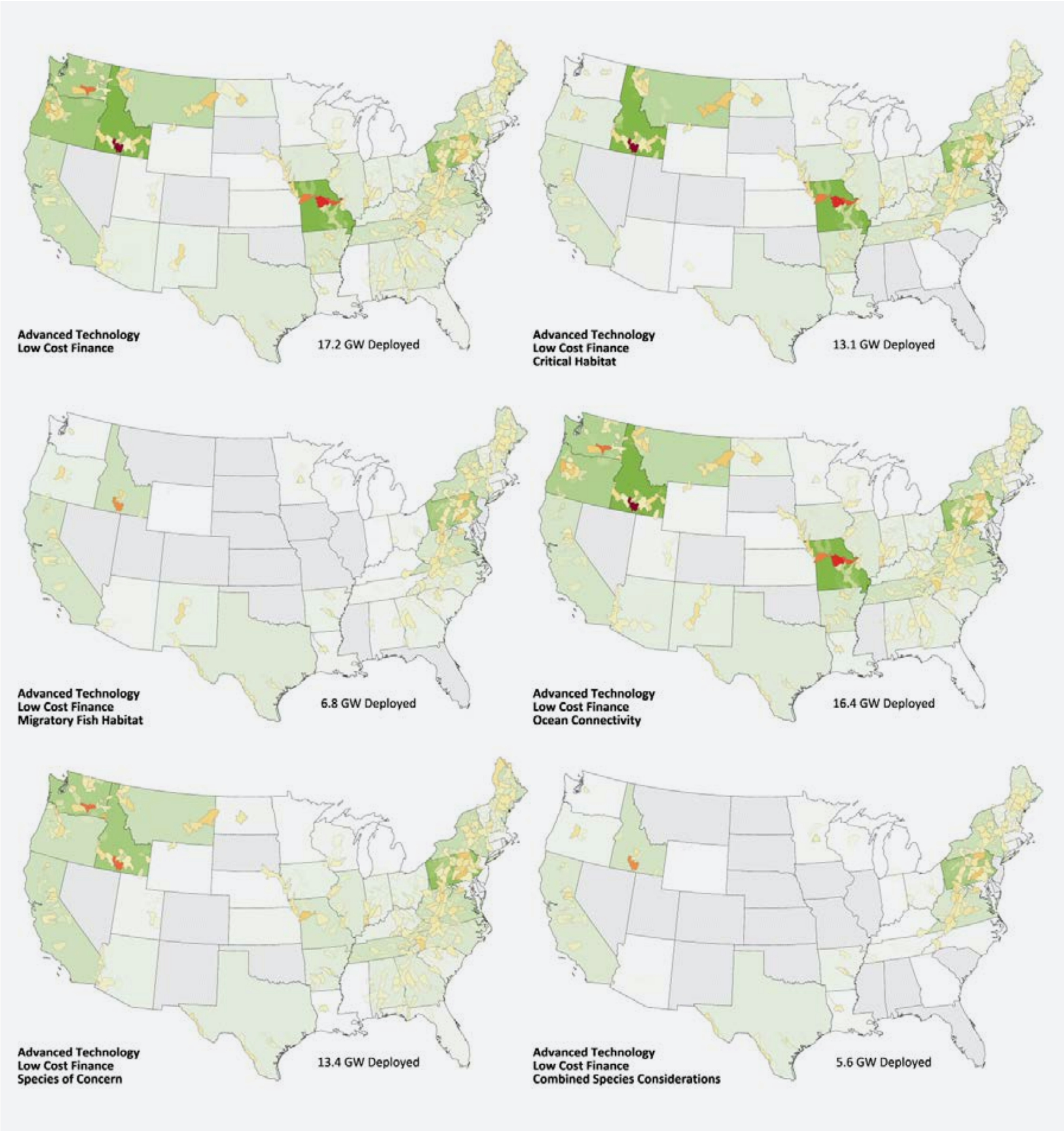


Figure F-42. National distribution of cumulative post-2016 NSD capacity in 2050 for selected environmental considerations scenarios under *Advanced Technology, Low Cost Finance* conditions

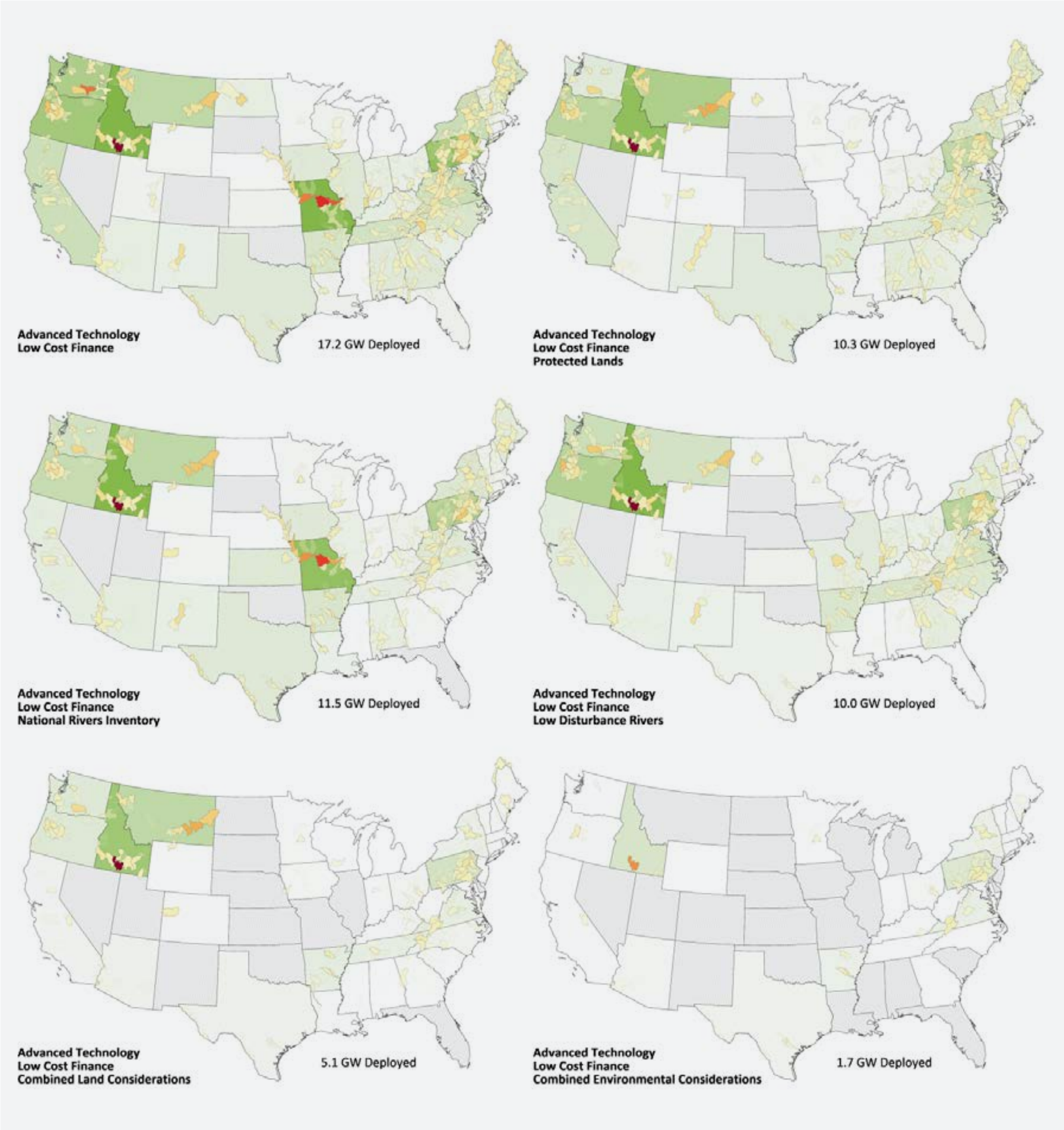


Figure F-43. National distribution of cumulative post-2016 NSD capacity in 2050 for additional selected environmental considerations scenarios under *Advanced Technology, Low Cost Finance* conditions

F.3 Supplement to Section 3.5

Figure F-44 displays installed capacity by technology for each of the nine selected scenarios, while Figure F-45 shows generation by technology. These figures supplement the four scenarios shown in figures 3-30 and 3-31 in Chapter 3.

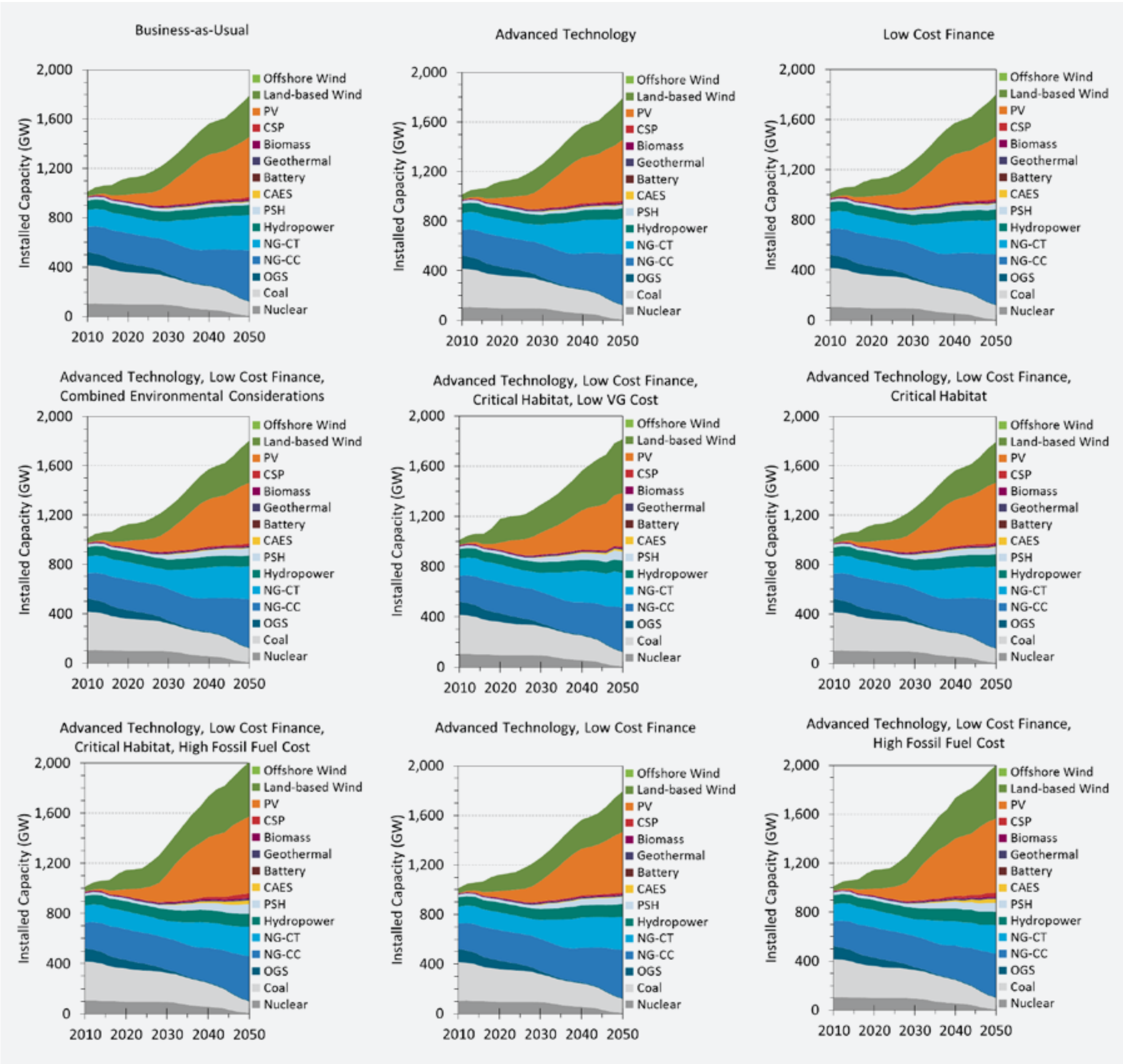


Figure F-44. Installed capacity by technology type and year in the nine selected scenarios

Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

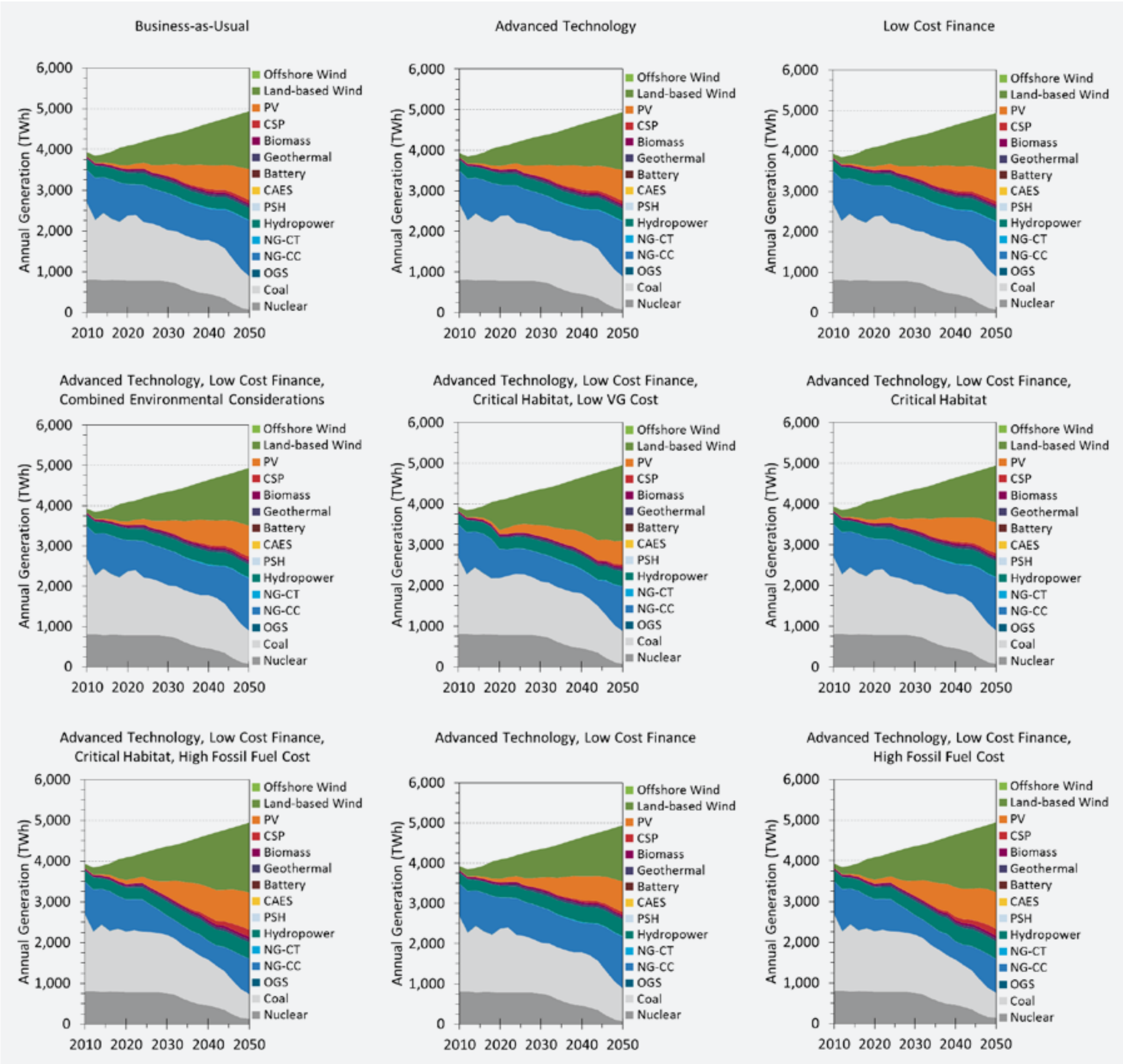


Figure F-45. Annual generation by technology type and year in the nine selected scenarios

Note: Solar Photovoltaics (PV), Concentrating Solar Power (CSP), Compressed Air Energy Storage (CAES), Pumped Storage Hydropower (PSH), Combustion Turbine Natural Gas (NG-CT), Combined Cycle Natural Gas (NG-CC), Oil-Based Generators and Gas-Steam Boilers (OGS).

Table F-13 displays the incremental national average electricity price relative to the baseline for each solve year in the nine selected scenarios, supplementing Figure 3-35 in Chapter 3. The baseline is a reference scenario with no new hydropower development; therefore, incremental prices indicate the change induced by the incremental new hydropower growth in the scenario.

Table F-13. Incremental Average Electricity Prices in the Nine Selected Scenarios Relative to Their Corresponding Baseline Scenarios

Year	Business-as-Usual	Advanced Technology	Low Cost Finance	Advanced Technology, Low Cost Finance	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost
2018	-0.03	-0.03	-0.03	-0.03	-0.01
2020	-0.02	-0.02	-0.02	-0.02	-0.02
2022	-0.17	-0.17	-0.16	-0.17	-0.02
2024	-0.11	-0.12	-0.12	-0.12	-0.13
2026	-0.09	-0.09	-0.08	-0.10	-0.15
2028	-0.06	-0.06	-0.05	-0.06	-0.03
2030	-0.08	-0.08	-0.09	-0.09	-0.04
2032	-0.11	-0.11	-0.13	-0.13	-0.04
2034	-0.07	-0.07	-0.09	-0.11	-0.06
2036	-0.06	-0.05	-0.06	-0.11	-0.04
2038	-0.04	-0.04	-0.04	-0.10	-0.04
2040	0.00	-0.01	-0.01	-0.08	-0.01
2042	-0.01	-0.01	-0.04	-0.13	0.00
2044	0.02	0.02	-0.02	-0.05	-0.06
2046	0.00	0.00	-0.04	-0.07	-0.09
2048	-0.01	-0.02	-0.07	-0.09	-0.14
2050	-0.01	-0.02	-0.06	-0.10	-0.12

Year	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost	Advanced Technology, Low Cost Finance, Critical Habitat	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	Advanced Technology, Low Cost Finance, Combined Environmental Considerations
2018	-0.02	-0.03	-0.01	-0.03
2020	0.00	-0.02	-0.02	-0.02
2022	-0.01	-0.18	-0.02	-0.18
2024	-0.13	-0.12	-0.13	-0.12
2026	-0.13	-0.10	-0.15	-0.10
2028	-0.05	-0.07	-0.03	-0.07
2030	0.00	-0.10	-0.05	-0.09
2032	-0.03	-0.14	-0.04	-0.13
2034	-0.01	-0.11	-0.06	-0.10
2036	-0.02	-0.11	-0.04	-0.08
2038	-0.01	-0.09	-0.03	-0.07
2040	-0.01	-0.08	-0.01	-0.03
2042	0.00	-0.13	0.00	-0.10
2044	0.02	-0.06	-0.06	-0.04
2046	-0.02	-0.09	-0.06	-0.07
2048	-0.01	-0.10	-0.11	-0.08
2050	-0.05	-0.10	-0.09	-0.08

Table F-14 displays the 2017–2050 present value of electricity system costs by cost category for each of the nine selected scenarios, supplementing Figure 3-36 in Chapter 3.

Table F-14. Category-Specific 2017–2050 Present Value of Total System Cost for the Selected Scenarios (Billion $)

Category	Business-as-Usual	Advanced Technology	Low Cost Finance	Advanced Technology, Low Cost Finance, Combined Environmental Considerations	Advanced Technology, Low Cost Finance, Critical Habitat, Low VG Cost
Conventional Capital	203	203	187	179	162
Conventional O&M	726	726	719	715	698
Conventional Fuel	1,973	1,971	1,965	1,950	1,729
Renewable Capital	620	620	622	630	646
Renewable O&M	351	352	352	354	385
Renewable Fuel	22	22	22	22	20
Storage Capital	7	8	26	34	40
Storage O&M	4	4	6	7	7
All Transmission	55	55	56	55	70
Water	0	0	0	0	0
TOTAL	**3,962**	**3,961**	**3,955**	**3,946**	**3,758**

Category	Advanced Technology, Low Cost Finance, Critical Habitat	Advanced Technology, Low Cost Finance, Critical Habitat, High Fossil Fuel Cost	Advanced Technology, Low Cost Finance	Advanced Technology, Low Cost Finance, High Fossil Fuel Cost
Conventional Capital	177	144	178	147
Conventional O&M	715	687	715	687
Conventional Fuel	1,942	2,097	1,940	2,094
Renewable Capital	634	902	634	900
Renewable O&M	354	427	354	427
Renewable Fuel	22	24	22	24
Storage Capital	32	56	32	54
Storage O&M	7	9	7	9
All Transmission	54	85	53	85
Water	0	0	0	0
TOTAL	**3,937**	**4,431**	**3,936**	**4,427**

Figure F-46 plots capital and operating costs for hydropower generation and PSH for the nine selected scenarios.

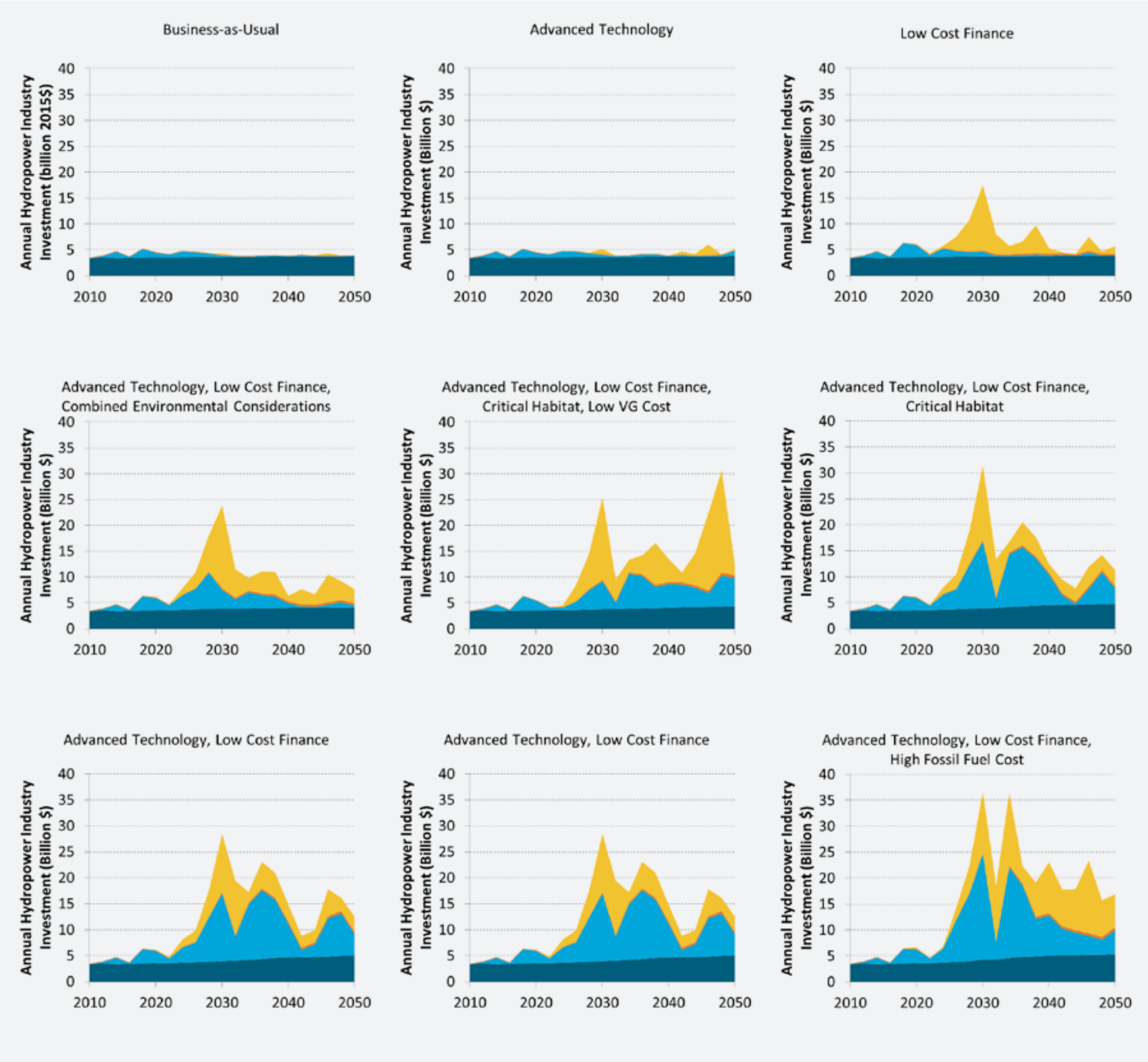


Figure F-46. Hydropower industry investments by market segment in selected deployment scenarios

This page is intentionally left blank

Appendix G: Life Cycle Greenhouse Gas Emissions and Net Energy Metrics

Greenhouse gas (GHG) emissions reduction estimates rely on the National Renewable Energy Laboratory's (NREL's) Life Cycle Assessment Harmonization project, which was an extensive meta-analysis of the life cycle literature. This appendix contains details about study results and how they were applied and is associated with Section 3.5.6 of the main report. This appendix also provides high-level information on how life cycle GHG emissions were estimated for different hydropower technologies, characteristics such as capacity factors, and geographical locations.

G.1 Life Cycle GHG Emissions

Aggregate GHG emissions estimates leverage both output from NREL's Regional Energy Deployment System (ReEDS) model and literature estimates of life cycle GHG emissions. The life cycle assessment (LCA) literature typically reports GHG emissions normalized per kilowatt hour (kWh) of electricity generation (for emissions related to plant operations, or "ongoing") or per kilowatt (kW) of installed capacity (for emissions related to plant construction, or "upstream," and decommissioning, or "downstream"). Both normalization metrics, applied to different life cycle phases, were used to estimate the contribution of each energy source to total life cycle GHG emissions for all scenarios.

NREL's LCA Harmonization project conducted an exhaustive literature search, extracting normalized life cycle GHG emission estimates from published LCA literature. All collected literature was first categorized by content (recording key information from every collected reference) and added to a bibliographic database. Then, screens were applied to select only those references that met stringent quality and relevance criteria. This screening procedure has been described by Heath and Mann 2012 [1].

The estimates of life cycle GHG emissions by energy source used in the *Hydropower Vision Study* are similar to those reported by Mai et al. (2012) [2]. This literature was updated by removing duplicate life cycle GHG emission estimates and completing a more exhaustive literature search for the latest literature on water technologies following the same procedures as in Heath and Mann (2012) [1].

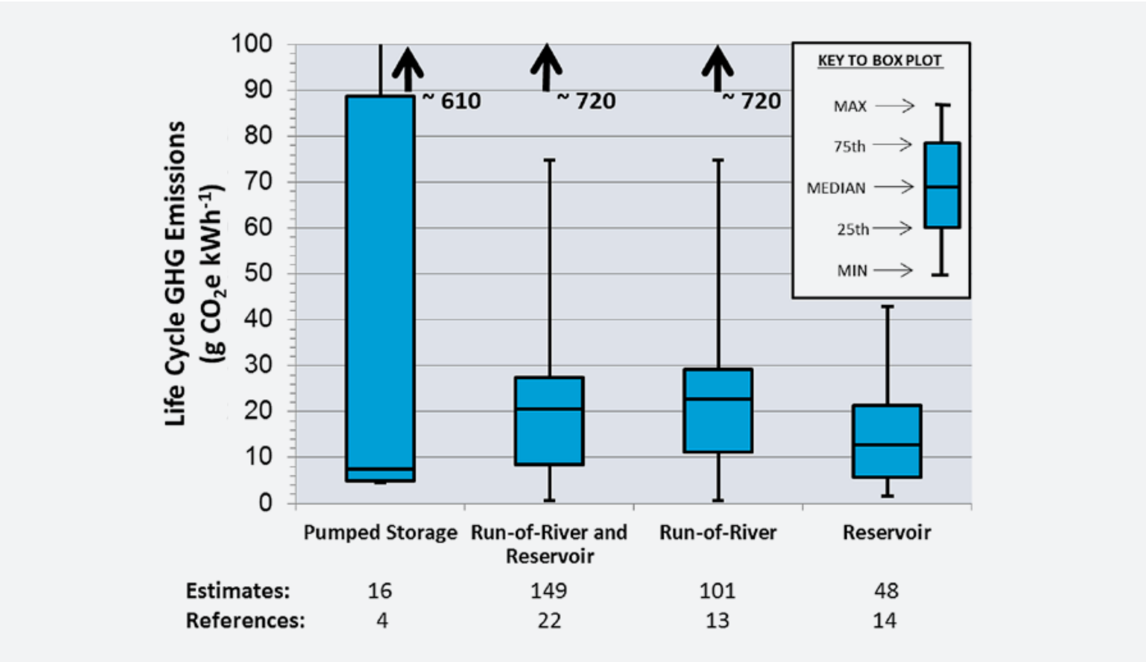
Life cycle GHG emissions from hydropower were not included in the ReEDS analysis [2]. The *Hydropower Vision Study* updated LCA literature collected for the Intergovernmental Panel on Climate Change Special Report on Renewable Energy [3]. The only additional screen for hydropower added to screens documented in Heath and Mann (2012) [1] was the exclusion of life cycle GHG emission estimates that did not report biogenic GHG emissions separately from other sources of emissions. Biogenic GHG emissions from hydropower were not within the scope of *Hydropower Vision*, but are instead discussed in the report's text box 4.5-1.

The life cycle GHG emission estimates for reservoir, run-of-river, and pumped-storage hydropower that are used in the *Hydropower Vision Study* are reported in Table G-1. To align with ReEDS output in the *Hydropower Vision Study,* the combined reservoir and run-of-river results are used rather than the individual technology estimates. The life cycle emissions for these technologies are similar, but run-of-river hydropower ongoing non-combustion emissions are higher and reservoir hydropower construction and decommissioning emissions are higher. The life cycle GHG emission estimates in Table G-1 are median estimates whose distribution of total life cycle GHG emissions is visualized in Figure G-1.

Table G-1. Median Estimates of GHG Emissions by Life Cycle Stage Wind

Water Technology	Upstream Emissions (kg CO_2e MW^{-1})	Ongoing Non-Combustion Emissions (g CO_2e kWh^{-1})	Downstream Emissions (kg CO_2e MW^{-1})
Reservoir and Run-of-River	1,100	1.9	0
Reservoir	1,300	0.55	0.84
Run-of-River	1,100	1.9	0
Pump Storage	310	1.8	7.2

Note: Hydropower does not have ongoing combustion emissions. kg = kilogram; g = grams; MW = megawatt; g = gram; kWh = kilowatt hour; CO_2e = carbon dioxide equivalent.



Note: GHG = greenhouse gas; g = gram; CO_2e = carbon dioxide equivalent; kWh = kilowatt hour.

Figure G1. Distribution of estimates of reported GHG emissions (g CO_2e kWh^{-1}) for pumped storage, combined run-of-river and reservoir, run-of-river, and reservoir.

Again, for all other energy sources, see the documentation in Mai et al. (2012) [2]. As more studies are conducted, the estimates of life cycle GHG emissions may change from the current median estimates reported here, based on the available literature through 2014. Table G-2 describes characteristics of the hydropower studies included. It should be noted that there are many fewer life cycle GHG emission estimates for pumped storage than reservoir or run-of-river hydropower. Pumped storage is a storage technology and not a technology intended for net-energy generation, so GHG emissions per kWh of output are highly variable and could be as high as natural gas (i.e., ~600 g CO_2e kWh^{-1}). Other hydropower technologies exhibit life cycle GHG emissions on par with other renewable technologies and nuclear energy, but substantially lower than those found for fossil-based systems.

One run-of-river outlier estimate of ~720 g CO_2e kWh^{-1} from Pascale et al. (2011) [4] represents a small-scale pessimistic case where electricity generation is about 40 times lower than the base case (1.5 kW) for the same hydropower system that generates 40 g CO_2e kWh^{-1}.

To estimate total GHG emissions for all scenarios, GHG emissions estimates were assembled into four general life cycle stages that correspond to ReEDS output, as follows:

- One-time upstream emissions, which include emissions resulting from raw materials extraction, materials manufacturing, component manufacturing, transportation from the manufacturing facility to the construction site, and on-site construction. Emissions for this life cycle stage used in the analysis were median estimates taken from the LCA literature.
- Ongoing non-combustion emissions during the operating phase, which include fuel-cycle emissions (i.e., emissions associated with extraction, processing, and transportation of fuels, where applicable) and emissions resulting from non-combustion-related operation and maintenance activities. Emissions for this life cycle stage used in the analysis were median estimates taken from the LCA literature.
- Ongoing combustion emissions[1] resulting from combustion at the power plant (where applicable) for the purpose of electricity generation. Emissions for this life cycle stage used in the analysis are outputs of ReEDS, based on generation technology, electricity generation, heat-rate assumptions, and the carbon content of the fuel.
- One-time downstream emissions, which include emissions resulting from project decommissioning, disassembly, transportation to a waste site, and ultimate disposal and/or recycling of the equipment and other site materials. Emissions for this life cycle stage used in the analysis were median estimates taken from the LCA literature.

One-time emissions (upstream and downstream) are related to the embodied emissions of the facility, which are largely determined by the capacity of the technology deployed. ReEDS reports capacity by technology installed or decommissioned in a given year. The analysis further assumes that ReEDS-estimated rebuilds (i.e., repowering) are approximately equivalent to new construction for the purposes of GHG emission accounting[2] and so sums these two ReEDS outputs (new build and repowering) into one "installed" category. Multiplying literature-estimated, one-time upstream GHG emissions normalized per kW of installed capacity by ReEDS-estimated installed capacity yields an estimate of GHG emissions associated with the addition of that technology's capacity in that year. An analogous method was used to estimate GHG emissions associated with facility retirements in a given year.

Ongoing emissions are mainly related to the production of electricity. ReEDS explicitly reports combustion-related CO_2 emissions by technology each year. In the case of biomass, combustion produces GHG emissions. However, because the carbon emitted during combustion was absorbed during photosynthesis in biomass feedstock production, these emissions were assumed to cancel when summed over the life cycle in the long term.

ReEDS also reports electricity generation by each technology in a given year. Estimates of GHG emissions associated with the fuel cycle and other non-combustion-related ongoing activities were derived by multiplying literature-estimated, ongoing non-combustion-related GHG emissions normalized per kWh by ReEDS-estimated generation.

Summing year- and technology-specific GHG emissions associated with the four life cycle phases over all years of the period studied in the *Hydropower Vision* (2013–2050) and all technologies yielded estimates of cumulative life cycle GHG emissions for each scenario. The GHG benefits of variable renewable generation may be eroded to a degree by the increased cycling, ramping, and partial loading required of conventional generators. Partial loading of fossil generators, for example, means operating those plants at less-efficient output levels. This creates a penalty to fuel efficiency and GHG emissions relative to optimally loaded plants. Though the analysis discussed here does not capture these effects, the difference implied by this omission is, in this case, expected to be modest.

1. Hydropower does not have ongoing combustion emissions.
2. ReEDS modeling includes hydropower retrofits. No LCA literature could be found on hydropower retrofits. Retrofits in this analysis are assumed to impact GHG emissions from ongoing non-combustion activities.

Table G2. Characteristics of Studies Included in the *Hydropower Vision*[3]

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Denholm 2004 [5]	PS	1,000	60	20%	Salem, SC	Empirical		9.9
Denholm 2004 [5]	PS	200	60	20%	Shaver Lake, CA	Empirical		4.5
Denholm 2004 [5]	PS	2,100	60	20%	Warm Springs, VA	Empirical		5.5
Denholm 2004 [5]	PS	31	60	20%	Center, MO	Empirical		4.8
Denholm 2004 [5]	PS	512	60	20%	Jenkinsville, SC	Empirical		4.5
Denholm 2004 [5]	PS	1,206	60	20%	Shaver Lake, CA	Empirical		53
Denholm 2004 [5]	PS	200	60	20%	Leadville, CO	Empirical		5.9
Denholm 2004 [5]	PS	1,530	60	20%	Chattanooga, TN	Empirical		8.9
Denholm 2004 [5]	PS	760	60	20%	Armuchee, GA	Empirical		4.5
Dones 2007 [6]	R	9,130	132	24%	Switzerland	Empirical		3.8
Dones 2007 [6]	R	NR	NR	NR	Finland	Empirical		4.2
Dones 2007 [6]	R	NR	NR	NR	Europe	Empirical		4.1
Dones 2007 [6]	RR	NR	NR	NR	Switzerland	Empirical		2.9
Dones 2007 [6]	RR	NR	NR	NR	Europe	Empirical		3.1
Flury 2012 [7]	RR	0.2	70	57%	EU	Empirical		6.1
Flury 2012 [7]	RR	1	70	57%	EU	Empirical		4.3
Flury 2012 [7]	RR	50	70	57%	EU	Empirical		3.9
Flury 2012 [7]	R	1,000	120	34%	EU	Empirical		7.4
Flury 2012 [7]	PS	500	120	34%	EU	Empirical		5.0
Flury 2012 [7]	R	95	150	23%	Switzerland	Empirical	w/ pumps	9.4
Flury 2012 [7]	R	95	150	23%	Switzerland	Empirical	w/o pumps	4.1
Flury 2012 [7]	R	95	150	23%	EU	Empirical		4.5
Flury 2012 [7]	PS	95	150	1%	Switzerland	Empirical		150
Flury 2012 [7]	PS	95	150	1%	EU	Empirical		610
Flury 2012 [7]	RR	8.6	80	51%	Switzerland	Empirical		3.6
Flury 2012 [7]	RR	8.6	80	51%	EU	Empirical		3.8
Hondo 2005 [8]	RR	10	30	45%	Japan	Empirical		11
Hondo 2005 [8]	RR	10	10	45%	Japan	Empirical		30

3. The comments in the table provide details that are not covered in the other columns and/or information to distinguish different scenarios from the same author. Blank cells in the table indicate that no information was available. Empirical studies are those based on recorded performance data, while theoretical studies are based on detailed analyses of projected performance.

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Hondo 2005 [8]	RR	10	20	45%	Japan	Empirical		16
Hondo 2005 [8]	RR	10	50	45%	Japan	Empirical		7.5
Hondo 2005 [8]	RR	10	100	45%	Japan	Empirical		4.7
Hondo 2005 [8]	RR	10	30	35%	Japan	Empirical		14
Hondo 2005 [8]	RR	10	30	40%	Japan	Empirical		12
Hondo 2005 [8]	RR	10	30	50%	Japan	Empirical		10
Hondo 2005 [8]	RR	10	30	55%	Japan	Empirical		9.6
Hung 2010 [9]	PS	NR	NR	NR	EU	Empirical		190
Hung 2010 [9]	R	NR	NR	NR	EU	Empirical		5.4
Hung 2010 [9]	RR	NR	NR	NR	EU	Empirical		3.5
IEA 1998 [10]	RR	40.8	40	45%	WA	Empirical		8.6
IEA 1998 [10]	RR	390	100	38%	India	Empirical	optimistic	2.3
IEA 1998 [10]	RR	390	100	38%	India	Empirical	pessimistic	1.4
IEA 1998 [10]	R	1,600	100	64%	Africa	Empirical	optimistic	5.9
IEA 1998 [10]	R	1,600	100	64%	Africa	Empirical	pessimistic	3.8
IEA 1998 [10]	R	12,600	100	68%	Brazil/Paraguay	Empirical	optimistic	2.6
IEA 1998 [10]	R	12,600	100	68%	Brazil/Paraguay	Empirical	pessimistic	1.6
Lenzen 2008 [11]	RR	100	40	50%	Australia	Meta-analysis	base	14
Lenzen 2008 [11]	RR	100	25	35%	Australia	Meta-analysis	pessimistic	40
Lenzen 2008 [11]	RR	100	55	65%	Australia	Meta-analysis	optimistic	6.3
ORNL 1994 [12]	RR	5	40	50%	Skagit River Basin, WA	Empirical		7.4
ORNL 1994 [12]	RR	5	40	57%	Skagit River Basin, WA	Empirical		6.2
ORNL 1994 [12]	RR	7.5	40	30%	Skagit River Basin, WA	Empirical		7.9
ORNL 1994 [12]	RR	3.8	40	45%	Skagit River Basin, WA	Empirical		13

Continued next page

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
ORNL 1994 [12]	RR	6.5	40	46%	Skagit River Basin, WA	Empirical		6.6
ORNL 1994 [12]	RR	13	40	47%	Skagit River Basin, WA	Empirical		10
Pacca 2002 [13]	R	1296	20	49%	Page, AZ	Empirical		6.2
Pascale 2011 [4]	RR	0.0015	20	85%	Thailand	Empirical		40
Pascale 2011 [4]	RR	0.003	40	95%	Thailand	Empirical		8.0
Pascale 2011 [4]	RR	0.0003	10	45%	Thailand	Empirical		720
Pehnt 2006 [14]	RR	3.1	NR	NR	Germany	Empirical		11
Pehnt 2006 [14]	RR	0.3	NR	NR	Germany	Empirical		14
Rentizelas 2014 [15]	R	170	100	43%	Greece	Empirical		2.5
Rhodes 2000 [16]	R	50	100	86%	Chelan County, WA	Empirical		1.6
Ribeiro 2010 [17]	R	14,000	100	73%	Brazil/Paraguay	Empirical		5.5
SECDA 1994 [18]	RR	10	20	95%	Saskatchewan, Canada	Empirical		0.6
SECDA 1994 [18]	R	330	40	60%	Saskatchewan, Canada	Empirical		8.4
Suwanit 2011 [19]	RR	2.25	50	45%	Thailand	Empirical	Mae Thoei	23
Suwanit 2011 [19]	RR	2.5	50	45%	Thailand	Empirical	Mae Pai	16
Suwanit 2011 [19]	RR	1.15	50	45%	Thailand	Empirical	Mae Ya	16
Suwanit 2011 [19]	RR	6	50	45%	Thailand	Empirical	Nam San	23
Suwanit 2011 [19]	RR	5.1	50	45%	Thailand	Empirical	Nam Man	11
Suwanit 2011 [19]	RR	3.4	50	45%	Thailand	Empirical	average	18
Torres 2011 [20]	PS	960	100	0.4%	Norway	Empirical	electricity from wind	4.7
Torres 2011 [20]	PS	960	100	0.4%	Norway	Empirical	electricity from grid	67
Torres 2011 [20]	PS	960	100	0.4%	Norway	Empirical	electricity from gas	370
Varun 2010 [21]	RR	0.05	30	76%	India	Empirical	Karmi III	75
Varun 2010 [21]	RR	0.1	30	76%	India	Empirical	Jakhana	55

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Varun 2010 [21]	RR	3	30	76%	India	Empirical	Rayat	35
Varun 2012 [22]	R	0.4	30	76%	India	Empirical	Lower Ghagri MHP	34
Varun 2012 [22]	R	15	30	76%	India	Empirical	Bhatsa	24
Varun 2012 [22]	R	1.5	30	76%	India	Empirical	Nugu MHS-I	26
Varun 2012 [22]	R	10	30	76%	India	Empirical	Somasili SHP	17
Varun 2012 [22]	R	1.5	30	76%	India	Empirical	Nugu MHS-II	27
Varun 2012 [22]	R	2	30	76%	India	Empirical	Mid Pennar MHS	21
Varun 2012 [22]	R	15	30	76%	India	Empirical	Singoor	15
Varun 2012 [22]	R	2.4	30	76%	India	Empirical	Malaprabha SHP	18
Varun 2012 [22]	R	9	30	76%	India	Empirical	Harangi SHP	16
Varun 2012 [22]	R	16	30	76%	India	Empirical	Hemawathi	15
Varun 2012 [22]	R	2.4	30	76%	India	Empirical	Bhincrarh	22
Varun 2012 [22]	R	16	30	76%	India	Empirical	Warna	13
Varun 2012 [22]	R	16	30	76%	India	Empirical	Bhatgar	11
Varun 2012 [22]	R	1.3	30	76%	India	Empirical	Perunchani	28
Varun 2012 [22]	R	2.5	30	76%	India	Empirical	Aliyar	19
Varun 2012 [22]	R	0.7	30	76%	India	Empirical	Mukurthy	31
Varun 2012 [22]	R	2	30	76%	India	Empirical	Pyakra	24
Varun 2012 [22]	R	9	30	76%	India	Empirical	Veer	14
Varun 2012 [22]	R	1.5	30	76%	India	Empirical	Vaitarna	26
Varun 2012 [22]	R	1.5	30	76%	India	Empirical	Aanveri Mini Hydel	21
Varun 2012 [22]	R	3	30	76%	India	Empirical	Yeleru Reser SHP	21
Varun 2012 [22]	R	8	30	76%	India	Empirical	TB. Dam SHP	14

Continued next page

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Varun 2012 [22]	RR	5	30	76%	India	Empirical	Suringad SHP – Stage-II	25
Varun 2012 [22]	RR	8	30	76%	India	Empirical	Pein SHP Phase-II	21
Varun 2012 [22]	RR	2	30	76%	India	Empirical	Manglay SHP	29
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Ham mangarh MHP	28
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Rungyard MHP	34
Varun 2012 [22]	RR	5	30	76%	India	Empirical	Lngli-I SHP	24
Varun 2012 [22]	RR	9	30	76%	India	Empirical	Mukto SHP	21
Varun 2012 [22]	RR	2	30	76%	India	Empirical	Dom Khorong MHP	28
Varun 2012 [22]	RR	6	30	76%	India	Empirical	Nuranang SHP	21
Varun 2012 [22]	RR	0.9	30	76%	India	Empirical	Bogdong Mini HEP	31
Varun 2012 [22]	RR	4	30	76%	India	Empirical	Mandi Baragran SHP	19
Varun 2012 [22]	RR	2	30	76%	India	Empirical	Kullu Phulga MHP	23
Varun 2012 [22]	RR	0.2	30	76%	India	Empirical	Kinnour Charag MHP	48
Varun 2012 [22]	RR	4.5	30	76%	India	Empirical	Sirmour Bhand SHP	20
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Ringali MHP	38
Varun 2012 [22]	RR	2	30	76%	India	Empirical	Mounday CHP	29
Varun 2012 [22]	RR	4.5	30	76%	India	Empirical	Maujhi CHP	25
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Solang	31

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Varun 2012 [22]	RR	0.9	30	76%	India	Empirical	Titang MHS	33
Varun 2012 [22]	RR	0.8	30	76%	India	Empirical	Raskat MHP	34
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Dehar SHP	29
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Chandini SHP	24
Varun 2012 [23]	RR	3	30	76%	India	Empirical	Manal SHP	23
Varun 2012 [22]	RR	5	30	76%	India	Empirical	Brahmagana SHP	24
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Baragran SHP	21
Varun 2012 [22]	RR	1.8	30	76%	India	Empirical	Kotlu SHP	27
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Jiwa MHS	27
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Manjhal SHP	31
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Ching SHP	29
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Timbi SHP	22
Varun 2012 [22]	RR	21	30	76%	India	Empirical	Kuthugal	14
Varun 2012 [22]	RR	2	30	76%	India	Empirical	Gaurikund HEP	25
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Lagrasu MHP	21
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Badayar MHP	21
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Pali Gad MHP	22
Varun 2012 [22]	RR	1	30	76%	India	Empirical	Ringali MHP	28
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Hanumana MHP	22
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Haumana Ganga MHP	27
Varun 2012 [22]	RR	6	30	76%	India	Empirical	Pan SHP	27
Varun 2012 [22]	RR	0.3	30	76%	India	Empirical	Tangtac MHP	49

Continued next page

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Varun 2012 [22]	RR	0.6	30	76%	India	Empirical	Lahaul Spiti kaga MHP	43
Varun 2012 [22]	RR	6	30	76%	India	Empirical	East Siang SHP	29
Varun 2012 [22]	RR	0.75	30	76%	India	Empirical	Ganga MHP	43
Varun 2012 [22]	RR	0.75	30	76%	India	Empirical	Sikku MHP	42
Varun 2012 [22]	RR	6	30	76%	India	Empirical	Parng SHP	26
Varun 2012 [22]	RR	0.05	30	76%	India	Empirical	Kuawari MHP	60
Varun 2012 [22]	RR	0.1	30	76%	India	Empirical	Jagthana MHP	63
Varun 2012 [22]	RR	0.2	30	76%	India	Empirical	Lamba Pagar MHP	49
Varun 2012 [22]	RR	4	30	76%	India	Empirical	Kanhar	22
Varun 2012 [22]	RR	25	30	76%	India	Empirical	Kolab SHP-I	16
Varun 2012 [22]	RR	12	30	76%	India	Empirical	Kolab SHP	18
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Motighat SHP	27
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Tanga SHP	27
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Kailganga SHP	23
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Peni SHP Phae-I	32
Varun 2012 [22]	RR	2	30	76%	India	Empirical	Liromoba MHP	75
Varun 2012 [22]	RR	3	30	76%	India	Empirical	Gangani SHP	35
Varun 2010 [23]	R	30	30	76%	India	Empirical	Dhukwan	12
Varun 2010 [23]	R	2	30	76%	India	Empirical	Devara-belakere	19
Varun 2010 [23]	R	1	30	76%	India	Empirical	Sadani	31
Wall 2013 [24]	R	0.73	100	56%	Austria	Empirical		7.0
Zhang 2007 [25]	R	44	50	26%	China	Empirical		43

Table G-2. continued

Source Study	Technology Type	Turbine Capacity (MW)	Lifetime (yr)	Capacity Factor	Location	Study Type	Comments	Total (g CO_2e kWh^{-1})
Zhang 2007 [25]	R	3600	100	50%	China	Theoret-ical		5.9
Zhang 2015 [26]	R	5850	44	47%	Southwest China	Theoret-ical	earth-core rock-fill dam	11
Zhang 2015 [26]	R	5850	44	47%	Southwest China	Theoret-ical	concrete-gravity dam	8.4

Notes: (1) The comments in the table provide details that are not covered in the other columns and/or information to distinguish different scenarios from the same author. Blank cells in the table indicate that there is no amplifying information or that it is the base case for the author. Empirical studies are those based on recorded performance data, while theoretical studies are based on detailed analyses of projected performance.

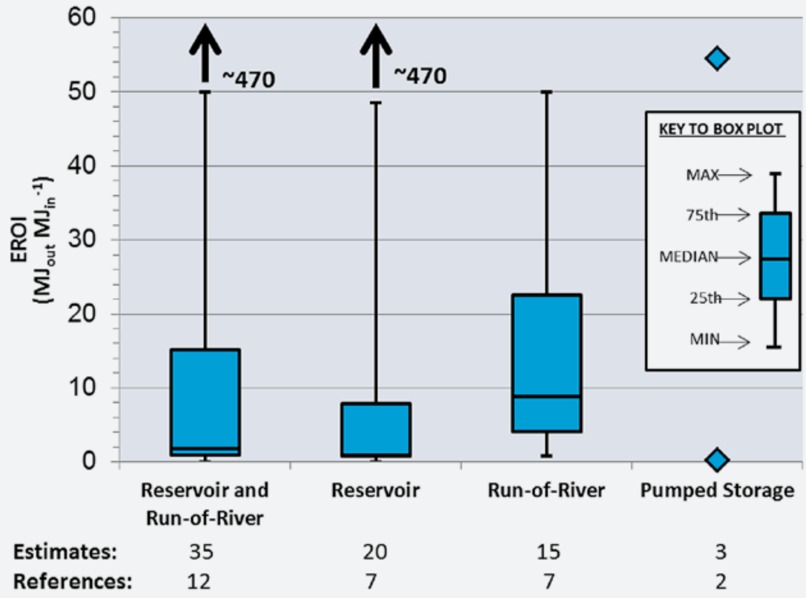
(2)MW = megawatt; yr = year; g = grams; CO_2e = carbon dioxide equivalent; kWh = kilowatt-hour; PS = pumped storage, R = reservoir, RR = run-of-river; NR = not reported; HEP = hydroelectric power; MHP = micro hydroelectric power; MHS = micro-hydropower system; SHP = small hydropower.

G.2 Net-Energy Metrics

The review of energy metrics for hydropower technologies started by extracting estimates from literature collected for Moomaw et al. (2011) [3]. That literature was then updated, in a similar fashion as the GHG review. Estimates of energy metrics, such as energy return on investment (EROI), net-energy ratio, and energy payback time, were collected and screened using the same screening criteria as for the GHG evaluation. Fourteen references with almost 40 estimates passed the *Hydropower Vision Study* review screens and provided energy metrics. When compared to the screened GHG emission references, the only notable addition is Varun (2008) [27], whose GHG emission results duplicate Varun (2012) [23].

Figure G-2 displays the results of the collected energy metrics converted to a common metric, EROI, for combined reservoir and run-of-river, reservoir, run-of-river, and pumped storage hydropower technologies. Table G-3 lists the individual studies and their results. Only three estimates for pumped storage hydropower were found in the literature. Run-of-river and reservoir hydropower technologies were relatively well studied.

The results shown in Figure G-2 and Table G-3 reflect the conditions analyzed in each study, which sometimes exercised results across a wide range of conditions, producing widely varying results. For instance, results from Lenzen (2008) [11] represent the results of a high, low, and base set of hydropower conditions from a literature review and meta-analysis of hydropower GHG emissions. The low and high cases represent a set of optimistic and pessimistic hydropower project conditions for capacity factor (35%–65%), efficiency (77%–87%), lifetime (25–55 years), and other assumptions found in the literature Lenzen (2006) [11] reviewed. Most estimates of EROI fall within the optimistic and pessimistic results from Lenzen (2008) [11]. One outlier EROI, which was about 470 $MJ_{out}\ MJ_{in}^{-1}$ from Rhodes (2000) [16], estimated a low annual energy use relative to energy production.



Note: EROI = energy return on investment; MJ = megajoule.

Figure G2. Distribution of estimates of reported EROI (MJ_{out} MJ_{in}^{-1}) for combined reservoir and run-of-river, reservoir, run-of-river, and pumped storage.

Table G3. Estimates of EROI (MJ_{out} MJ_{in}^{-1}) for Literature Considered in This Study[4]

Author	Technology Type	Lifetime (yr)	EROI (MJ_{out} MJ_{in}^{-1})
Denholm 2004 [5]	PS	60	55
Dones 2007 [6]	R	150	0.77
Dones 2007 [6]	R	150	0.77
Dones 2007 [6]	R	150	0.77
Dones 2007 [6]	R	150	0.77
Dones 2007 [6]	RR	80	0.81
Dones 2007 [6]	RR	80	0.81
Flury 2012 [7]	R	150	0.84
Flury 2012 [7]	R	150	0.94
Flury 2012 [7]	R	150	0.94
Flury 2012 [7]	R	150	0.94

4. Blank cells in the table indicate that no information was available. Results are reporting directly from literature and not harmonized.

Table G-3. continued

Author	Technology Type	Lifetime (yr)	EROI ($MJ_{out}\ MJ_{in}^{-1}$)
Flury 2012 [7]	R	70	0.94
Flury 2012 [7]	R	70	0.94
Flury 2012 [7]	R	70	0.94
Flury 2012 [7]	R	70	0.94
Flury 2012 [7]	PS	150	0.28
Flury 2012 [7]	PS	150	0.27
Flury 2012 [7]	RR	80	0.94
Flury 2012 [7]	RR	80	0.94
Lenzen 2008 [11]	RR	40	22
Lenzen 2008 [11]	RR	25	7.3
Lenzen 2008 [11]	RR	55	50
Pehnt 2006 [14]	R	NR	36
Pehnt 2006 [14]	RR	NR	26
Rhodes 2000 [16]	R	100	470
Ribeiro 2010 [17]	R	100	1.7
Varun 2008 [27]	RR	30	11
Varun 2008 [27]	RR	30	15
Varun 2008 [27]	RR	30	23
Varun 2010 [21]	R	30	24
Varun 2010 [21]	R	30	15
Varun 2010 [21]	R	30	9.3
Varun 2010 [21]	RR	30	8.0
Varun 2010 [21]	RR	30	8.9
Varun 2010 [21]	RR	30	8.4
Wall 2013 [24]	RR	100	25
Zhang 2007 [25]	R	50	7.4
Zhang 2007 [25]	R	100	48

Note: yr = year; EROI = energy return on investment; MJ = megajoule; PS = pumped storage; R = reservoir; RR = run-of-river; NR = not reported.

Appendix G References

[1] Heath, G.A., and M. K. Mann. 2012. "Background and Reflections on the Life Cycle Assessment Harmonization Project." *Journal of Industrial Ecology* (16:s1); pp. S8–S11. Accessed June 8, 2016. *http://onlinelibrary.wiley.com/doi/10.1111/j.1530-9290.2012.00478.x/abstract*.

[2] Mai, T., R. Wiser, D. Sandor, G. Brinkman, G. Heath, P. Denholm, D. Hostick, N. Darghouth, A. Schlosser, and K. Strzepek. 2012. *Renewable Electricity Futures Study Vol. 1: Exploration of High-Penetration Renewable Electricity Futures* (Technical Report). NREL/TP-6A20-52409-1. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 8, 2016. *www.nrel.gov/docs/fy12osti/52409-1.pdf*.

[3] Moomaw, W., et al. 2011. "Annex II: Methodology." *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*. Accessed June 8, 2016. *www.ipcc.ch/report/srren/*.

[4] Pascale, A., T. Urmee, and A. Moore. 2011. "Life cycle assessment of a community hydroelectric power system in rural Thailand." *Renewable Energy* (36:11); pp. 2799-2808. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0960148111001959*.

[5] Denholm, P. 2004. "Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems." *Energy Conversion and Management* (45:13); pp. 2153-2172. Accessed June 8, 2016. *www.researchgate.net/publication/223663980_Life_cycle_energy_requirements_and_greenhouse_gas_emissions_from_large_scale_energy_storage_systems_Energy_Convers_Manage_45_2153-2172*.

[6] Dones R., Bauer C., Bolliger R., Burger B., Faist Emmenegger M., Frischknecht R., Heck T., Jungbluth N., Röder A., Tuchschmid M. 2007. "Life Cycle Inventories of Energy Systems: Results for Current Systems in Switzerland and other UCTE Countries."Accessed June 8, 2016. *http://ecolo.org/documents/documents_in_english/Life-cycle-analysis-PSI-05.pdf*

[7] Flury, K., and R. Frischknecth. 2012. Life Cycle Inventories of Hydroelectric Power Generation. ESU Services, commissioned by Öko-Institute e.V. Accessed June 8, 2016. *www.esu-services.ch/fileadmin/download/publicLCI/flury-2012-hydroelectric-power-generation.pdf*.

[8] Hondo, H. 2005. "Life cycle GHG emission analysis of power generation systems: Japanese case." *Energy* (30:11–12); pp. 2042–2056. International Symposium on CO_2 Fixation and Efficient Utilization of Energy (CandE 2002) and the International World Energy System Conference (WESC-2002). Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0360544204003652*.

[9] Hung, C. *Environmental Impacts of Renewable Energy: An Overview of Life Cycle Results*. (Master thesis, Institutt for energi- og prosessteknikk, 2010.) Accessed June 8, 2016. *https://brage.bibsys.no/xmlui//handle/11250/234089*.

[10] International Energy Agency. 1998. *Benign energy? The environmental implications of renewables.*

[11] Lenzen, M. 2008. "Life cycle energy and greenhouse gas emissions of nuclear energy: A review." *Energy Conversion and Management* (49:8); pp. 2178-2199. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0196890408000575*.

[12] Oak Ridge National Laboratory. 1994. "Estimating Externalities of the Hydro Fuel Cells." Oak Ridge National Laboratory and Resources for the Future. Accessed June 16, 2016. *http://www.osti.gov/scitech/servlets/purl/757384*

[13] Pacca, S., and A. Horvath. 2002. "Greenhouse Gas Emissions from Building and Operating Electric Power Plants in the Upper Colorado River Basin." *Environmental Science & Technology* (36:14); pp. 3194-3200. Accessed June 8, 2016. *http://pubs.acs.org/doi/abs/10.1021/es0155884*.

[14] Pehnt, Martin. 2006. "Dynamic life cycle assessment (LCA) of renewable energy technologies." *Renewable Energy* (31:1); pp. 55-71. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0960148105000662*.

[15] Rentizelas, A., and D. Georgakellos. 2014. "Incorporating life cycle external cost in optimization of the electricity generation mix." *Energy Policy* Vol. 65; pp. 134-149. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0301421513010458*.

[16] Rhodes, S., Apfelbaum, S., L. Brown, G. Carrington, C. Chaffee, F. Kommonen, and J. Wazlaw. 2000. *A Study of the Lake Chelan Hydroelectric Project Based on Life-Cycle Stressor-Effects Assessment*. Prepared for the Public Utility District No. 1 of Chelan County, Washington. Accessed June 8, 2016. *http://clio.chelanpud.org/relicense/study/refer/4841_1.PDF*.

[17] de Miranda Ribeiro, F., and G. Anderi da Silva. 2010. "Life-cycle inventory for hydroelectric generation: a Brazilian case study." *Journal of Cleaner Production* (18:1); pp. 44-54. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0959652609002777*.

[18] Saskatchewan Energy Conservation Development Authority. 1994. *Levelized Cost and Full Fuel Cycle Environmental Impacts of Saskatchewan's Electric Supply Options*. SECDA Publication No: T800-94-004.

[19] Suwanit, W., and S. H. Gheewala. 2011. "Life cycle assessment of mini-hydropower plants in Thailand." *The International Journal of Life Cycle Assessment* (16: 9); pp. 849-858. Accessed June 8, 2016. *http://link.springer.com/article/10.1007/s11367-011-0311-9*.

[20] Torres, O. "Life cycle assessment of a pumped storage power plant." (Student thesis, Norwegian University of Science and Technology, Faculty of Engineering Science and Technology, Department of Energy and Process Engineering, 2011). Accessed June 8, 2016. *www.diva-portal.org/smash/record.jsf?pid=diva2%3A455355&dswid=-5938*.

[21] Varun, R. P., and I. K. Bhat. 2010. "Life Cycle Energy and GHG Analysis of Hydroelectric Power Development in India." *International Journal of Green Energy* (7:4); pp. 361-375. Accessed June 8, 2016. *http://www.tandfonline.com/doi/abs/10.1080/15435075.2010.493803*.

[22] Varun, Prakash, R., and I. K. Bhat. 2012. "Life cycle greenhouse gas emissions estimation for small hydropower schemes in India." *Energy* (44:1); pp. 498-508. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0360544212004495*.

[23] Varun, R. Prakash, and I. K. Bhat. 2010. "Life Cycle Energy and GHG Analysis of Hydroelectric Power Development in India." *International Journal of Green Energy* (7:4); pp. 361-375. Accessed June 8, 2016. *www.tandfonline.com/doi/abs/10.1080/15435075.2010.493803#.V1iS6JfG8Xg*.

[24] Wall, J and Passer, A. 2013. *Harvesting factor in hydropower generation.* Institute of Technology and Testing of Building Materials, Working Group Sustainability Assessment Graz University of Technology, Graz, Austria. ISBN 978-0-415-62126-7. Accessed June 16, 2016. *https://online.tugraz.at/tug_online/voe_main2.getvolltext?pCurrPk=79272*.

[25] Zhang, Q., B. Karney, H. L. MacLean, and J. Feng. 2007. "Life-Cycle Inventory of Energy Use and Greenhouse Gas Emissions for Two Hydropower Projects in China." *Journal of Infrastructure Systems* (13:4); pp. 271-279. Accessed June 8, 2016. *http://ascelibrary.org/doi/abs/10.1061/%28ASCE%291076-0342%282007%2913:4%28271%29*.

[26] Zhang, S., B. Pang, and Z. Zhang. 2015. "Carbon footprint analysis of two different types of hydropower schemes: comparing earth-rockfill dams and concrete gravity dams using hybrid life cycle assessment." *Journal of Cleaner Production,* Vol. 103; pp. 854-862. Accessed June 8, 2016. *www.sciencedirect.com/science/article/pii/S0959652614006416*.

[27] Varun, R. Prakash, and I. K. Bhat. 2008. "Life Cycle Analysis of Run-of River Small Hydro Power Plants in India." The Open Renewable Energy Journal , 2008, 1: 11-16. DOI: 10.2174/1876387100901010011. Accessed June 16, 2016. *http://benthamopen.com/ABSTRACT/TOREJ-1-11*.

This page is intentionally left blank

Appendix H: The Conventional Hydropower Jobs and Economic Development Impacts (JEDI) Model

This appendix contains further information about the Jobs and Economic Development Impacts (JEDI) model, which is used in section 3.5.9 to estimate jobs, earnings, gross domestic product, and output impacts associated with hydropower construction and operation and maintenance (O&M). It provides information on the model methodology, defines metrics that are reported, and lists important details about model limitations and how results should be interpreted.

The JEDI suite of models includes publicly available tools that can be used to estimate potential gross economic impacts from energy or energy-related projects. As of 2012, JEDI models had been cited in more than 70 published studies. In the same year, there were approximately 3,000 unique downloads [1]. Unique downloads are counts of one person downloading one model and do not count one person downloading the same model several times.

H.1 About JEDI

The JEDI model is an input-output (I-O) model designed to analyze gross economic impacts from the construction and operation of energy projects. I-O models are commonly used analytical tools to estimate economy-wide economic impacts (such as spillovers or ripple effects) from specified changes in expenditures for goods and services. The version of JEDI used in this analysis uses the IMPLAN I-O model.[1]

The Conventional Hydropower JEDI (CH-JEDI) differs from many other I-O models because it is designed specifically to analyze hydropower projects. In a typical I-O analysis, an analyst must specify which commodities are purchased or which industries produce purchases. Hydropower construction and O&M are typically not among the industries or commodities listed as options in these models, so estimating impacts from hydropower activities is not straightforward.[2] JEDI represents projects in terms of expenditures for specific inputs such as labor, materials, services, manufactured components, project development activities, and finance. The model uses labor expenditures to estimate onsite impacts and allocates other expenditures to relevant industries to estimate supply chain and induced impacts. Aside from the advantage of simply allowing analysis of hydropower, this also allows the model to account for diversity in how costs are distributed from project to project. CH-JEDI has several different project types: new construction, non-powered dams, and pumped storage. Costs are also distributed differently for small projects than they are for large projects. Construction of a larger project, for example, might have a greater portion of expenditures in materials compared to labor than a small project would have.

H.2 Input-Output Methodology

I-O models represent transactions among different sectors in an economy at a point in time. These sectors include businesses, workers/households, and governments. These transactions are simultaneously inputs and outputs. Inputs are purchases. At a business level, these could be commodities necessary for production. Households spend money for commodities such as housing, transportation, and food. All of these purchased commodities must also be sold, and these sales are outputs. A motor-manufacturing business that purchases copper as an input, for example, must purchase that copper from a copper producer. Copper is output for the copper producer.

This representation of purchases and sales, or inputs and outputs, in an economy allows for a detailed analysis of ripple effects that could occur as a result of an initial expenditure. A purchase of a motor in the previous example would result in economic activity for the motor manufacturer as well as the copper supplier. This activity would also support wages paid to workers at the motor manufacturer and the copper supplier. These workers, in turn, would use these wages to make purchases in the economy, supporting further economic activity.

1. Further information about IMPLAN can be found at *http://www.implan.com*.
2. Hydroelectric power generation is classified in the most detailed (6-digit) codes under the North American Industry Classification System (NAICS). However, hydropower is not included in the most detailed I-O tables produced by the Bureau of Economic Analysis or IMPLAN.

H.3 JEDI Results

JEDI displays impacts as they relate to projects separately. These are onsite, supply chain, and induced. Onsite impacts are those that directly arise as a result of an expenditure and ignore all other economic activity down the supply chain. In the previous example, this would solely occur in the motor-manufacturing industry. For hydropower, these are the impacts directly at hydropower sites and could be construction activity or onsite operations. Supply-chain impacts occur as a result of inputs purchased by operators. This is the copper supplier in the previous example. Supply-chain impacts can be manufactured components such as generators, material inputs as well as services such as engineering consulting, accounting, finance, and legal services. Induced effects arise as a result of onsite and supply-chain workers spending their earnings.

JEDI only produces results within a specified region of analysis and therefore does not capture all impacts from a scenario. In the project scenario, the portion of local content is specified. This local content is the percentage of expenditures that are paid to producers within the region of analysis. The local content of transformers imported from Korea, for example, would be zero while concrete sourced within the United States (the region of analysis) would be 100%. The IMPLAN I-O model also accounts for economic activity that occurs outside of the region throughout the supply chain. An operator might purchase a generator that is manufactured in the United States, for example, but that manufacturer might import 25% of the materials that go into the generator. The results from IMPLAN do not include economic activity from the imported materials because they occur outside of the region of analysis.

JEDI produces three metrics: jobs, earnings, and gross output. Jobs are expressed as full-time equivalent (FTE). One FTE is the equivalent of one person working 40 hours per week for one year. Someone who works 20 hours per week for one year, for example, would be 0.5 FTE. Someone who is employed full time for three months would be 0.25 FTE. Earnings are all income from work. These include wages as well as employer-provided supplements such as health insurance and retirement benefits. Gross output is a measure of overall economic activity. This is the value of production as well as inputs used in production. Gross output is not the same as gross domestic product (GDP)—GDP is solely the value of production and does not include expenditures on inputs.

This report covers results in two time periods: construction and O&M. Construction-phase results are the equivalent of one year. A project that supports 60 jobs and takes three years to complete, for example, would support an average of 20 jobs annually throughout the construction period. O&M results are ongoing and assumed to exist for the life of the facility.

H.4 Limitations of JEDI and Interpretation of Results

As with all economic models, there are limitations to JEDI and specific ways that results should be interpreted.

JEDI results are gross, not net. JEDI impacts presented in this report are solely those that are associated with the specified hydropower scenario. They do not account for far-reaching economic impacts such as those caused by displaced investment, changes in utility rates, and changes in taxes.

The I-O model used by JEDI is static, meaning that relative prices and technology remains fixed. As relative prices changes, producers might decide to substitute one input for another. As technology and productivity change, some inputs might be used more extensively than others. JEDI does not account for these changes.

The model also assumes that inputs necessary for a specified scenario will be available. It does not account for production shortages or price changes that might be associated with goods or services that are in short supply.

JEDI estimates should be interpreted as economic activity supported by hydropower construction and O&M. A manufacturing job supported by hydropower construction, for example, may have existed prior to that construction. It might only be temporarily supported by construction, but not necessarily created by that construction.

H.5 Use of ReEDS Capacity Expansion Data in JEDI

The Regional Energy Deployment System (ReEDS) provides capacity and cost data for 134 regions in the continental United States that are separated into five resource classes.[3] Construction and O&M cost estimates by line item were obtained by scaling JEDI default costs to match ReEDS cost totals. In other words, ReEDS cost estimates were distributed according to JEDI costs for each line item.

The Hydropower JEDI model incorporates economies of scale when it estimates costs for different goods and services. As such, estimates of economic impacts need to be as close to the site level as possible. Because results at the power-control-area level are not necessarily single projects, this was accomplished by disaggregating ReEDS results using the site-level data that was used to develop ReEDS supply curves.[4] ReEDS capacity and cost data for each power control area and resource class were disaggregated to match individual site cost, capacity, capacity factor, rated generator speed, and net head. Impacts were estimated for all sites and aggregated to the national level. Onsite impacts were aggregated to the state and national level.

H.6 JEDI Domestic Content Estimates

Domestic content percentages for different items are manually specified domestic-content percentages in JEDI for different items. JEDI does not estimate economic impacts outside of the region of analysis, so the portion of expenditures that goes toward domestically produced products influences impact estimates.

Domestic-content estimates come from several different sources. The jobs, workforce, and economic development task force made significant contributions by reaching out to manufacturers and other companies along the hydroelectric supply chain to supply information about where they operate. In addition, Oak Ridge National Laboratory surveyed hydroelectric operators in 2013 and included questions about where components are purchased.

Table H-1 shows estimates of 2013 domestic content, which is used in estimates of existing hydropower construction jobs as well as estimates of supply chain and induced jobs from hydropower operations

Table H-1. Domestic Content Percentages Used to Calculate 2013 Hydropower U.S. Employment

Phase	Category	Percent Domestic
Construction	Land/Water Rights and Right of Way	100%
	Civil Works—Structures	90%
	Turbines, Generators, and Balance of Plant	50%
	Transformers and Related Components	0
	Installation Labor	90%
	Engineering and Other Professional Services	30%
	Other Costs	75%
O&M	Onsite Labor	100%
	Replacement Parts	50%
	Regulatory Compliance and Rents/Leases	90%

3. ReEDS documentation is in Appendix D.

4. Further information about these data is in Appendix I.

Appendix H References

[1] Billman, L. and D. Keyser. 2013. *Assessment of the Value, Impact, and Validity of the Jobs and Economic Development Impacts (JEDI) Suite of Models* (Technical Report). NREL/TP-6A20-56390. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 7, 2016. *http://www.nrel.gov/docs/fy13osti/56390.pdf*

Appendix I: Workforce

This appendix is associated with the current workforce estimates contained in Section 2.8 and Section 3.5.9.

I.1 Detailed Classification Scheme

Section 3.5.9 presents several occupational categories that can be disaggregated into further refined Standard Occupation Classification (SOC) codes. The Bureau of Labor Statistics maintains and uses SOC codes to organize occupational data such as employment and wages. Tables I-1 through I-3 show each general labor category with more specific descriptions of what wrkers do within each category.

Table I-1. Craft Occupation Descriptions

General Category	Specific Category	SOC Code	SOC Description
Craft—Unskilled	Construction Labor	47-2061	Construction Laborers
	Manufacturing Labor	51-9198	Helpers—Production Workers
Craft—Skilled	Electrician	47-2111	Electricians
		49-2095	Electrical and Electronics Repairers; Powerhouse, Substation, and Relay Electricians
	Heavy Civil Construction	47-2000	Construction Trades Workers
	Instrumentation Technicians	49-2094	Electrical and Electronics Repairers; Commercial and Industrial Equipment Technicians
	Mechanic	49-9041	Industrial Machinery Mechanics
	Operator	51-8013	Power Plant Operators
	Production/Technician	51-1011	First-Line Supervisors of Production and Operating Workers
		51-2000	Assemblers and Fabricators
		51-4000	Metal Workers and Plastic Workers
	Resource Assessment/Surveying	17-1022	Surveyors
Craft—Supervisory	Maintenance Manager/ Superintendent	11-9021	Superintendents, Construction
	Manufacturing Managers	11-3050	Industrial Production Managers
	Operations Manager/ Superintendent	11-9199	Managers, All Other
	Shift Supervisor	11-3051	Industrial Production Managers

Source: DOE forthcoming 2016, DOE/EE-1400, "United States Hydropower Workforce Assessment and Future Scenarios"

Table I-2. Managerial, Engineering, and Administrative Occupation Descriptions

General Category	Specific Category	SOC Code	SOC Description
Managerial	Development Management	11-9041	Architectural and Engineering Managers
	General Management	11-1021	General and Operations Managers
	Project & Program Manager	11-9021	Construction Managers
		11-3051	Industrial Production Managers
	Supply Chain & Purchasing Management	11-3061	Purchasing Managers
Engineering	Civil	17-2051	Civil Engineers
	Electrical	17-2071	Electrical Engineers
	Environmental (Water Management)	17-2081	Environmental Engineers
	Manufacturing	17-2110	Industrial Engineers
	Mechanical	17-2141	Mechanical Engineers
Administrative	Accounting/Finance	13-2010	Accountants and Auditors
		13-2050	Financial Analysts and Advisors
	Clerical	43-0000	Office and Administrative Support Occupations
	Customer Service Representative	43-4050	Customer Service Representatives

Source: DOE forthcoming 2016, DOE/EE-1400, "United States Hydropower Workforce Assessment and Future Scenarios

Table I-3. Professional Occupation Descriptions

General Category	Specific Category	SOC Code	SOC Description
Professional	Attorney	23-1011	Lawyers
	Environmental Scientists	19-2040	Environmental Scientists and Geoscientists
	Fish/Wildlife Scientists	19-1020	Zoologists and Wildlife Biologists
	Health and Safety	19-2040	Environmental Scientists and Specialists, Including Health
		17-2110	Health and Safety Engineers, Except Mining Safety Engineers and Inspectors
	Human Resources	13-1070	Human Resources Workers
	Information System Specialists	15-1150	Computer Occupations
	Land-Leasing Agents	43-4171	Receptionists and Information Clerks
		13-2021	Appraisers and Assessors of Real Estate
		11-9141	Property, Real Estate, and Community Association Managers
	Sales	41-4010	Wholesale and Manufacturing Sales Representatives
		41-9099	Other Sales and Related Workers
	Security	33-9030	Protective Service Occupations

Source: DOE forthcoming 2016, DOE/EE-1400, "United States Hydropower Workforce Assessment and Future Scenarios"

This page is intentionally left blank

Appendix J: The Value of Hydropower as a Long-Lived Asset

An important source of value for hydropower comes from its long operational life compared to other generation assets. Hydropower plants typically operate for well over 40 years without major refurbishments, and with careful refurbishment and modernization planning, can run reliably for 100 years or more [1]. This long asset life may significantly affect the cost of energy (i.e., $/MWh) for consumers over the operational life of the plant as well as the overall competitiveness of hydropower technology investment decisions. As discussed in Section 2.3, the financial perspectives and objectives may vary significantly among the diverse group of entities that own hydropower assets and that span the public and private spectrum. These differences may in turn influence the extent and degree to which hydropower's expected long operational lifetime is valued in economic decision making of investments. For these reasons, the modeling scenarios documented in Chapter 3 of this report include a range of sensitivities intended to better capture the potential economic attributes of this long operational life.

This appendix discusses the two sets of financial modeling assumptions associated with these sensitivities—the *Reference* assumptions and the *Low Cost Finance (LCF)* assumptions. The Reference assumptions present a more conservative take on the financing of electric-sector projects, which requires full capital recovery over the first 20 years and may be more typical of some short-term focused, Independent Power Producer (IPP)-type development, particularly when the price of power may be influenced by the wholesale price of energy and capacity. In contrast, LCF uses a lower weighted average cost of capital (WACC) and more explicit accounting for the longer-term life and value of hydropower projects, which results in a decrease of relative annualized capital recovery costs of 40% over the first 20 years compared to the financial Reference case assumptions. The LCF scenario is in many ways aspirational for some hydropower investments, but it reflects a potential future in which more appropriate financing mechanisms exist to better reflect the value of hydropower across its entire useful lifetime. Section 4.3 of the Roadmap provides some suggested actions that would help make the LCF perspective more applicable to a broader cross section of the hydropower industry.

The Reference conditions assume WACC = 8.1%, and financial life t = 20 years, and that the residual value (RV) in year 20 is zero (RV_f = 0%).[1] These parameters correspond to an annual capital recovery factor (CRF) of 10.2%. The relationship between these factors and the CRF is discussed in detail in Section 2. In contrast to the Reference conditions, the LCF conditions are not derived from a single combination of these three Regional Energy Deployment System (ReEDS) financial variables, but instead are intended to represent alternative combinations of these factors that can lead to a 40% reduction in the annual CRF over Reference conditions during the first 20 years. There are many different combinations that may lead to this effect, and some of these are shown and discussed in Tables 2 and 3 in Section 2. For example, if the RV is excluded, projects with a WACC of 4%–5% over 30–50 years could represent LCF conditions (See Table J-2). The inclusion of RV allows the 40% target to be met with a higher WACC and/or a shorter financial life. In Table J-3, for example, the combination of reducing WACC from 8% to 5%, extending the financial life from 20 years to 30 years, and incorporating the effect of the present value of an RV of 60% at the end of the financial life also meets the LCF scenario conditions. Similarly, a greater WACC of 6%, the same financial life of 30 years, and a larger RV of 100% after 30 years, also meets the LCF assumptions. (See Table J-2 and Table J-3 in Section J.2)

1. The RV is assumed zero when estimating the net present value over 20 years in order to make investment decisions. However, RV is an important consideration with respect to actual cost to consumers, in that the existence of the sale/acquisition of hydropower assets is indicative of actual RV.

The rest of this appendix is structured as follows: Section J.1 discusses the long-term value of hydropower in the context of the industry's more than 100-year (and counting) existence in the United States. Section J.2 briefly introduces the reader to some of the key financial "levers" available to the ReEDS model and how these levers result in the assumptions underlying the Reference conditions and how they can work in combination to inform the development of the alternative LCF scenario, which better reflects some of hydropower's unique long-term benefits. Section J.3 explores the role of assumptions regarding project financial life and the WACC in driving the economics of hydropower, including discussions of real-world examples from recent successfully financed hydropower projects and acquisitions of existing assets that lend support to and illustrate LCF-like financing arrangements. An important driver in understanding the value of hydropower is that it may have substantial RV 20 or 30 years (or more) beyond the reference 20-year financial life. Section J.4 explores the economic value of hydropower's *operational* life beyond typical assumptions of *financial* life, demonstrating how the consideration of the RV of operations beyond the financial life can change the value proposition of hydropower.

J.1 The Long Lifetime of Hydropower Assets

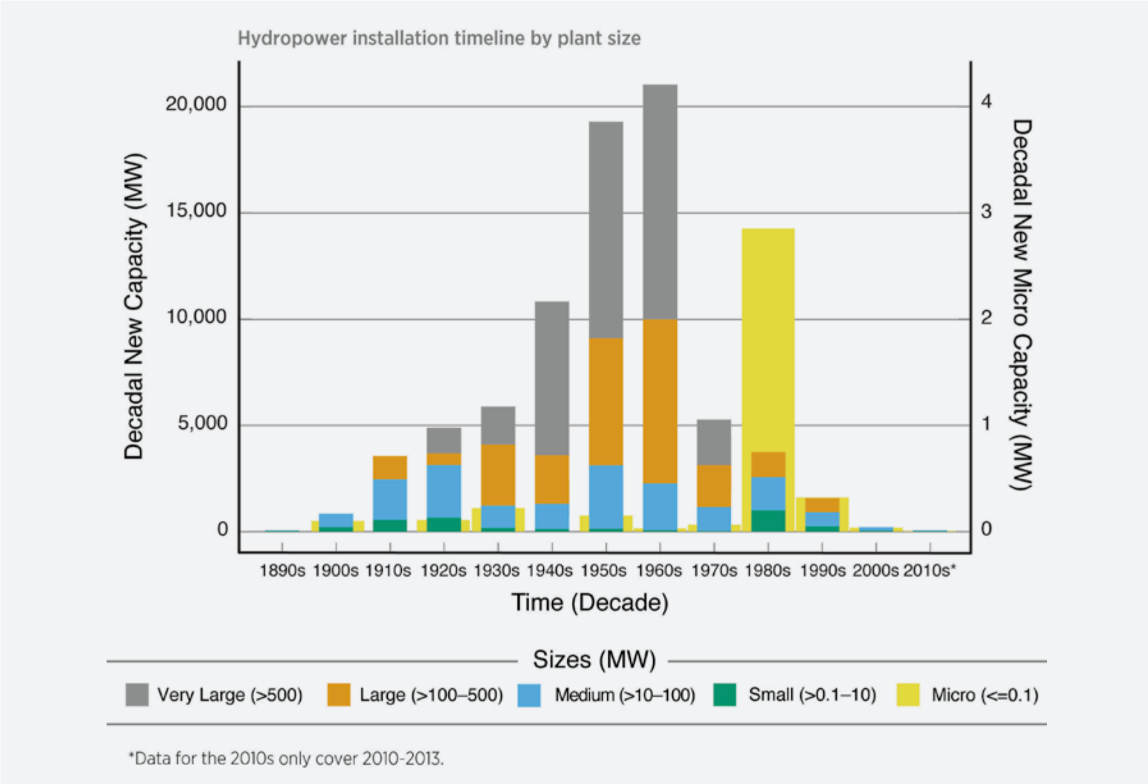
Hydropower plants can and often do have operational lives exceeding 100 years.[2] This period exceeds the operational lives of many other electricity-generation technologies by a wide margin. When comparing life-cycle costs of electricity-generation technologies, the long operational life may be an important determinant. In contrast, the financial life (the period over which initial capital investment is recovered) is typically determined over a much shorter period.

More than half of hydropower capacity installed in the United States is more than 50 years old, and more than 10% of that capacity exceeds 80 years of age (see Figure J-1). The Hoover Dam, for example, is more than 70 years old, with its first 11 turbines installed between 1936 and 1939 and the last of 19 turbines installed in 1969. Activities such as turbine refurbishment and generator rewinds allow hydropower assets to be continually extended at relatively low capital cost (compared with full replacement); even when replacement is needed, it will likely be limited to the turbines and electrical equipment and not the dam itself. In addition, refurbishment is typically accompanied by significant improvements as a result of modernization that can substantially increase the nameplate capacity and efficiency of the hydropower plant available from the same head of water [2]. For example, in the case of the Hoover Dam, most of the 17 original Francis turbines were 82.5 MW each, and the overall capacity of the hydropower plant 45 years ago was 1,344 MW. From 1986 to 1993, the main turbines were uprated from 82.5 MW to 130 MW, and the Hoover Dam's total capacity was increased by more than 50% to 2,080 MW.[3] This type of refurbishment is not uncommon [1]. The Hoover Dam, as with a number of other similar large hydroelectric dams and dam complexes in the United States, arose as part of President Franklin D. Roosevelt's New Deal initiative designed to bring low-cost power to rural areas while providing work. Today, these dams and dam complexes continue to provide large sources of low-cost power as well as a variety of other benefits including water control, irrigation, and recreation.

The Bonneville Power Administration (BPA), for example, was created in 1938 and now markets power in the Pacific Northwest region from 31 federally-owned hydroelectric plants with a total nameplate capacity of more than 22,000 GW. This system delivers "power worth $4.4 billion annually…in addition to providing protection, mitigation, and enhancement of fish and wildlife…[and] also provides avoided carbon dioxide emission benefits of $1.4 billion annually by displacing fossil-fired generation…" [3]. The average age of BPA's hydropower infrastructure at this point is nearly 50 years, with BPA's goal to have the system run for at least another 75 years [4]. Part of that strategy is ongoing capital investment in the existing infrastructure up to and including turbine replacements. BPA estimates that annual capital investments of approximately $340 million per year are needed

2. In the United States, 243 plants (2.7 GW) first became operational more than 100 years ago; 1,160 plants (64.7 GW) entered operations more than 40 years ago [19].

3. Two 2.4-MW Pelton turbines were also added for the dam's own operation requirements.



Source: Martinez, O'Connor, and Johnson [1]

Figure J-1. Timeline for hydropower capacity additions in the United States

to maintain the existing hydroelectric generating system on an on-going basis [22].[4] For a system of roughly 22,500 MW, that is equivalent to spending about $15/kW per year.. The sustainable peaking capability for hydropower will be substantially less than this due to water constraints, and can depend on how firm capacity is defined. A conservative measure would be the sustained 120 hour peak capacity in January under low water conditions.[5] This figure of 10,108 MW increases the annualized cost of maintaining BPA hydropower generation capacity on an on-going basis to $34/kW per year [22]. This dollars-per-kW-per-year capital cost is significantly less than the annualized capital required for a new combustion turbine[6] (without counting the cost of natural gas consumed), which can be $100/kW per year or more [5][7]. In addition, unlike traditional peaking capacity the average energy output of the system (aMW) associated with this firm capacity is estimated to be nearly 8,900 MW with no fuel costs (for a utilization of nearly 90% relative to the 10,100 MW 120-hour peak MW capacity used here). This cost for capacity is also significantly less than the annualized auction prices for capacity in restructured markets, which often range from $40/kW to $100/kW per year, though can be less in markets that have a large amount of excess capacity [6], [7].

4. This is based on BPA's forecast capital spending over the 8 year period 2016 and 2023, that includes an average annual expenditure of $292 million for the federal hydro system, $33 million on capital expenditure for fish and wildlife related investments, and about $17 million per year for the allowance for funds used in construction (AFDUC). Transmission capital investments are excluded as this estimate is for generation related costs [22].
5. This "January 120-Hour Peak MW Capacity" corresponds to the ability to provide 6 hours of peak generation 5 days a week for 4 weeks under low water flow conditions (based on 1937) when loads are typically highest.
6. Assuming a utilization of approximation 40%, this is equivalent to roughly $10/MWh to $13/MWh.
7. The impact on the cost of energy would be less than $5/MWh assuming year round median average energy (aMW) estimate of 8873MW in 2017 [22].

Recent acquisitions of existing hydropower plants also provide evidence of the long life and long-term value of these assets. NorthWestern Energy, for example, recently purchased 11 hydropower plants with more than 600 MW of capacity; all but one of these plants was originally built on or before 1930 (Table J-1) [8]. Most of these plants now have Federal Energy Regulatory Commission (FERC) license expirations that extend to 2040. The planned capital expenditure for the 10 hydropower facilities totaling 443 MW (and excluding Kerr) between 2015 and 2020 is capped at $58.1 million, which is $26/kW per year. Even though this annualized cost would need to be adjusted upward to reflect the lower peak capacity available, this cost is, again, significantly less than the annualized cost of building a combustion turbine (CT) to provide this capacity or the recent auction prices for capacity in many, though not all, restructured markets [6], [7].

Table J-1. Age, Capacity, and Capacity Factor for NorthWestern Energy Transaction

Plant	Net Capacity (MW)	Ownership%	COD	River Source	FERC License Expiration	5-Yr. Avg. Capacity Factor
Black Eagle	21	100%	1927	Missouri	2040	73.6%
Cochrane	69	100%	1958	Missouri	2040	49.1%
Hauser	19	100%	1911	Missouri	2040	79.3%
Holter	48	100%	1918	Missouri	2040	72.4%
Kerr	194	100%	1918	Flathead	2035	64.5%
Madison	8	100%	1906	Madison	2040	89.2%
Morony	48	100%	1930	Missouri	2040	63.8%
Mystic	12	100%	1925	West Rosebud Creek	2050	48.2%
Rainbow	60	100%	1910/2013	Missouri	2040	77.5%
Ryan	60	100%	1915	Missouri	2040	79.8%
Thompson Falls	94	100%	1915	Clark Fork	2025	60.1%
Total	633					66.1%

Source: NorthWestern Energy (2014) [8], [20]

Longer operational life lowers the annualized payment required to recover the original capital investment. A recent study by the International Energy Agency (IEA) and the Organisation for Economic Co-operation and Development's Nuclear Energy Agency (NEA) compared the levelized cost of energy (LCOE) of different technologies across 21 countries (including the United States) using 80 years for both the financial and the operational life of hydropower [9]. In a similar manner, a study on hydropower by the International Renewable Energy Agency used 40 years for its base case in estimating LCOE and 80 years as a sensitivity case [10]. The IEA/NEA project harmonized the expected lifetimes for different technologies across countries and recommended [9]:

- **Wave and tidal plants** — **20 years**
- **Wind and solar plants** — **25 years**
- **Gas-fired power plants** — **30 years**
- **Coal-fired power and geothermal plants** — **40 years**
- **Nuclear power plants** — **60 years**
- **Hydropower** — **80 years.**

Hydropower assets have much longer than the 20- to 25-year ranges suggested by IEA/NEA for variable renewable energy and the 30-year lifespan for gas-fired power plants. While the operational lifetimes for conventional technologies such as nuclear and coal plants are also much longer than 20 years, they are also much shorter than hydropower—both in this IEA/NEA study and in practice.[8] On the other hand, many economic assessments separate the idea of the financial life from the operational life. The U.S. Energy Information Administration (EIA), for example, uses 30 years as the financial life for all generation technologies (which is the life that would be used to estimate cost of energy), but then allows all generation to continue with an operational life of 50 years or more [11].[9,10] Related to this assumption, some investors in electricity-generation assets typically expect capital recovery over shorter time periods, typically 20–35 years (sometimes even less). Differences in modeled lifetime can have significant impact on how electric-sector models view the relative competitiveness/attractiveness of different generating technologies. Section J.2 of this appendix addresses this in the context of the ReEDS model used for the *Hydropower Vision.*

J.2 Introduction of Financial Modeling Scenarios

Three variables that have a significant effect on the cost of energy and investment decisions are:

1. The financial life (t) over which debt is repaid and/or equity investors receive their returns, e.g., 20 to 50 to 80 years[11].
2. The cost of capital that investors require for a given project (WACC). Lower WACCs are typically associated with public-sector investments that may also more closely reflect the hydropower plant's operational asset life.
3. The fraction of the original capital investment, or RV (RV_f) that remains at the end of a 20- or 30-year project financial life. This RV is uncertain, but it can be very significant. This RV may be estimated in a number of ways including the use of the remaining book value (i.e., original investment cost less depreciation); prices of recent comparable sales transactions; and estimated after-tax net cash flows from future electricity sales. If factored into project valuation, the RV can reduce the LCOE compared to the case where no RV is assumed. It is important to recognize that the RV and the financial life may be dependent on each other (e.g., the RV of a hydropower asset may be much greater in year 20 than in year 80).

Collectively, these variables are the mechanism by which the ReEDS model can be used to illustrate the impact of lower discount rates and hydropower's long asset life on economic competitiveness[12]. The effect of these three variables can be reflected in a modified CRF given by Eq. 1.

1)

$$CRF = \frac{WACC}{\left(1 - \frac{1}{(1+WACC)^t}\right)} \times \left(1 - \frac{RV_f}{(1+WACC)^t}\right)$$

The CRF determines what fraction of the original investment needs to be recovered on an annual basis. Dividing this number by the MWh/MW gives the $/MWh cost of energy associated with capital recovery. The first term on the right-hand side is the traditional CRF that determines what fraction of the investment needs to be repaid each year. This term will be greater than the WACC because it includes both the rate of return and the repayment

8. There are differences in agreement over what the financial life should be. A recent comparative LCOE analysis by Lazard [21] tended to be more conservative than IEA/NEA in most but not all cases, with 20 years for wind (5 years less), 20 to 30 years for solar (similar), 20 years for natural gas CTs and CCGT (10 years lower), 25 years for geothermal (15 years lower), 40 years for coal thermal (no difference), and 40 years for nuclear (20 years less), with no estimate for hydropower.

9. Strictly speaking, EIA could handle upgrades to the point of rebuilding using fixed operation and maintenance (O&M) charges.

10. Similarly, the ReEDS model uses a 20-year financial life for all electricity-generation investments with operational lives that vary by technology (Appendix D). Upon capital recovery after 20 years, the plant continues to produce electricity with annual O&M expenditures until the operational life is reached.

11. The financial life may be interpreted a number of ways. It might refer to the length of the debt (e.g., 20 or 30 years), or a longer period over which investors will make an equity return, which may be closer the operational life of the plant. Complicating these definitions is that after the first 40 or 50 years, a significant investment may be needed to allow the plant to operate for another 40 to 50 years.

12. The LCOE associated with capital recovery is given by the product of the initial capital investment and the CRF divided by the annual energy generated.

of principal. This CRF is very sensitive to the financial asset life (as can be seen in Table J-2). The second term reflects the effect of the present value of the RV per dollar invested on the original investment. Effectively, it discounts the size of the investment that the first term is applied to because it recognizes the present value of the RV does not need to be paid off over time *t* (see Table J-3).

The CRF can be reduced in three ways: 1) increase the financial life of the asset; 2) reduce the WACC; 3) include the RV remaining at the end of the financial life. As mentioned, the effects of 1 and 3 may partially offset each other, though this is not always true. Lowering the CRF will reduce the annual cost in terms of $/kW required return and the cost of energy $/MWh, which can increase the likelihood of deployment or investment in new generation assets.

This study used two sets of a mptions of combinations of WACC, financial life, and inclusion of RV that span the range of capital recovery outcomes. These are the ReEDS Reference Project Finance conditions (which are applied to all electricity-generation technologies including hydropower, wind, solar, fossil, nuclear, and other technologies) and the LCF conditions.

The Reference conditions assume a WACC = 8.1%, and financial life t = 20 years, and that the RV in year 20 is zero (RV_f = 0%).[13] While broadly applicable to a wide range of electricity-sector investments, for hydropower, this approach without explicit consideration of RV is particularly conservative and leads to a higher associated LCOE over the first 20 years than would be the case if any of the three factors discussed above were considered. Following Eq. 1, the CRF under Reference conditions is 10.2%.

In contrast to the Reference conditions, the LCF conditions are not derived from a single combination of the three ReEDS financial variables, but instead represent a magnitude of reduction in the annual CRF over Reference conditions during the first 20 years that are attributable to using a lower WACC and incorporating hydropower's long asset life and long-term value in the economic decision process. This reduction in CRF, chosen to be 40% for the first 20 years, is intended to reflect a combination of the use of a lower WACC and specific accounting for the longer asset life either by directly extending the financial life of the asset or by including the effect of the RV—and ideally by some combination of all three ReEDS financial variables.

Some specific real-world examples that might achieve this relative reduction in CRF are discussed in Section 3, but Tables 2 and 3 illustrate in a generic way how assumptions related to the CRF can result in project investment conditions that reflect the LCF scenario assumptions that are 40% lower relative to the ReEDS Reference Project Finance conditions (shaded grey cells on the right side). The $/MWh impact on the cost of energy can be estimated by multiplying the original or modified capital recovery factor by the investment and dividing this by total MWh of electricity generated in the year. The table is intended to be illustrative and to demonstrate how the consideration of different variations of WACC, financial life, and RV are consistent with the LCF project finance conditions.

If the RV is excluded, projects with a WACC of 4%–5% over 30–50 years could represent LCF conditions (See Table J-2). Table J-3 shows the effect of including the RV value, which can reduce the degree to which the financial life needs to be extended or the WACC reduced to meet the 40% target reduction. In Table J-3, we see, for example, the combination of reducing WACC from 8% to 5%, extending the financial life from 20 years to 30 years, and reflecting an RV of 60% at the end of the financial life also meets the LCF scenario conditions. The LCF assumptions are similarly reflected if the WACC is 6%, the financial life is 30 years, and the RV is 100% (See Table J-3).

While each hydropower plant investment is unique, there are a number of examples that suggest the LCF project finance conditions may be met, but these examples are not widespread. For example, several FERC license applications show projects with debt financing of 5% or less over periods of 30 years or more. American Municipal Power plans to build three facilities on the Ohio River with bonds rated at 5% over 35 years. NorthWestern Energy

13. Strictly speaking, the RV is assumed to be zero when estimating the net present value over 20 years in order to make investment decisions. However, RV is an important consideration with respect to actual cost to consumers in that the existence of the sale/acquisition of hydropower assets is indicative of actual RV.

Table J-2. Impact on Annual Capital Recovery Due to Impact of Extending Financial Life and/or Lowering WACC

WACC (nominal)	CRF alternatives to Reference Project Finance* Conditions—for changes to financial life and WACC (RV_f = 0%)				Percent Reduction from Reference Project Finance Conditions—for changes to financial life and WACC (RV_f = 0%)			
	20	30	50	80	20	30	50	80
8.0%	10.2%	8.9%	8.2%	8.0%	0.0%	12.8%	19.7%	21.3%
7.0%	9.4%	8.1%	7.2%	7.0%	7.3%	20.9%	28.9%	31.0%
6.0%	8.7%	7.3%	6.3%	6.1%	14.4%	28.7%	37.7%	40.5%
5.0%	8.0%	6.5%	5.5%	5.1%	21.2%	36.1%	46.2%	49.9%
4.0%	7.4%	5.8%	4.7%	4.2%	27.8%	43.2%	54.3%	58.9%
3.0%	6.7%	5.1%	3.9%	3.3%	34.0%	49.9%	61.8%	67.5%

*Reference Project Finance Conditions: RV_f = 0%, WACC = 8.1%, financial life = 20 years)

Shaded cells illustrate conditions that reflect LCF project finance scenarios.

Table J-3. Impact on Annual Capital Recovery Due to Impact of Extending Financial Life and/or Lowering WACC

WACC (nominal)	CRF alternatives to Reference Project Finance* Conditions—for changes to Residual Value and WACC (financial life = 30 years)				Percent Reduction from Reference Project Finance Conditions—for changes to Residual Value and WACC (financial life = 30 years)			
	RV_f of 0%	RV_f of 60%	RV_f of 80%	RV_f of 100%	RV_f of 0%	RV_f of 60%	RV_f of 80%	RV_f of 100%
8.0%	8.9%	8.4%	8.2%	8.0%	12.8%	18.0%	19.7%	21.5%
7.0%	8.1%	7.4%	7.2%	7.0%	20.9%	27.1%	29.2%	31.3%
6.0%	7.3%	6.5%	6.3%	6.0%	28.7%	36.1%	38.6%	41.1%
5.0%	6.5%	5.6%	5.3%	5.0%	36.1%	45.0%	48.0%	50.9%
4.0%	5.8%	4.7%	4.4%	4.0%	43.2%	53.7%	57.2%	60.7%
3.0%	5.1%	3.8%	3.4%	3.0%	49.9%	62.3%	66.4%	70.5%

*Reference Project Finance Conditions: RV_f = 0%, WACC = 8.1%, financial life = 20 years)

Shaded cells illustrate conditions that reflect LCF project finance scenarios.

recently purchased hydropower assets for more than the book value, and estimated the RV of these assets in 20 years will be greater than the current acquisition price (RV > 100%). A complicating factor is there may also be risk premium for new build over the WACC used for the acquisition of existing assets.

Increasing the financial life and reflecting RV are complementary ways of viewing the long-term value of hydropower plants. Increasing financial life would be attractive to investors who are able to spread capital recovery over a long period. Reflecting RV is likely to be a preferred alternative to investors who require a shorter capital recovery period. The degree to which the RV is incorporated into investment pricing and the methods for estimating RV vary greatly with each hydropower project.

J.3 Impact of Financial Life and the Weighted Average Cost of Capital

Generic private-sector investment in all electricity-generation technologies has been represented in ReEDS using a financial life of 20 years, WACC of 8.1%, and no RV[14]. This short recovery period can lead to high LCOE for the first 20 years, which makes many otherwise economically attractive projects too expensive.[15] As described above, hydropower is unique in that its operational life far exceeds this typical financial life. In addition, the hydropower sector's historic growth has been driven by public-sector investments by publicly owned utilities and municipalities, as well as regulated utilities with long investment horizons—organizations that are likely better able to appreciate and account for the benefits associated with hydropower's long asset life [1]. Together with the ability of the public sector to finance their investments using debt rather than equity, the resulting use of a longer financial life and lower WACC is a "win-win" in terms of reducing the CRF and the cost of energy to consumers. Some examples that demonstrate the variability of alternative WACC and financial asset lives include:

- **American Municipal Power, Inc.:** Proposed to build three run-of-river hydropower facilities on Ohio River. With capacity of 208 MW, these facilities are to be financed with $2 billion in debt with a true interest cost (TIC) of 5% and final maturity date in 2050 (or 35 years) [12].
- **Western Minnesota Municipal Power Agency (owner) and Missouri River Energy Services (operator):** Issued a $351 million bond for 55 MW on an existing dam. Features security- and long-term member contracts through 2046 and a maximum maturity of 31 years [13]. The true interest cost of the bonds was 4.05% and the average maturity is 21 years. The final maturity on the bonds is January 1, 2046 [14].
- **NorthWestern Energy:** Purchased 439 MW of existing hydropower facilities that were included in a 40-year-rate base, with the long-term debt separated from specific assets. Used a WACC of 7.14%, with an estimated cost of debt of 4.5% and equity of 10% [15].
- **BPA:** Hydropower generation assets are 100% funded by debt, and use a WACC of less than 5% based on the average cost of outstanding debt ,and asset depreciation for often over 40 years or more. May use a higher risk-adjusted rate of return to prioritize between alternative investments. .
- **Other:** DOE/NREL examined the financing plans of the 19 FERC license applications active as of the writing of this document and found a wide range of estimates and value for debt and financial life, including some consistent with debt financing of 5% to 6% or less over 30 years or more for some municipally financed projects. Other projects had repayment terms of 15 years or less. A number of these also had cash grants.

More generally, Bloomberg New Energy Finance estimates the WACC for utilities for existing investments in the range of 4% to 6%, though this may be 0.5% to 1% higher for newer assets [16].[16] Bloomberg also indicates that the cost of debt and return on equity for small hydropower used in their estimates is similar to those used for onshore wind and solar PV. On the other hand, Aquila Group suggests that there may be a premium of 1% to 2% in the WACC for a new hydropower build compared to existing assets including acquisition, though this may be expected to vary significantly by project and country [17].

Table J-2 illustrates the impact of increased financial life and lower WACC in reducing the capital recovery factor. Reductions of 40%, consistent with the LCF scenario assumptions, are achieved under conditions similar to some of the examples above. For example, projects with financial life of 30–50 years that can obtain debt/equity funding with the WACC between 4% and 6% represent the LCF conditions. However, shorter periods and higher WACCs are also viable when hydropower RV is included (discussed in the next section). Understanding and incorporating the RV allows projects to be attractive with smaller reductions of WACC or extension in financial life. The next section discusses how to estimate the RV and its impact in more detail.

---

14. It should be noted that unlike a typical private-sector investment, ReEDS actually assumes that, after the first 20 years, the asset continues to provide low-cost power over its remaining operational life. This assumption is equivalent to the case where the ownership of the fully paid-off asset is transferred to the consumers after 20 years.
15. Because hydropower plants are not then retired, this may lead to much lower cost of energy over the operational life of the asset.
16. One caveat about low WACCs in the range of 4% to 6% is that they may reflect low values for use going forward, as these values in part reflect current very low cost of debt, which in turn is a result of government intervention. However, the same argument also applies to the upper WACC estimate of 8%, which might also be expected to rise if interest rates rise in the future. Given we are interested largely in the relative investment differences between the two cases, the effect of this may be partially mitigated by the correlation of all WACCs to the underlying cost of debt.

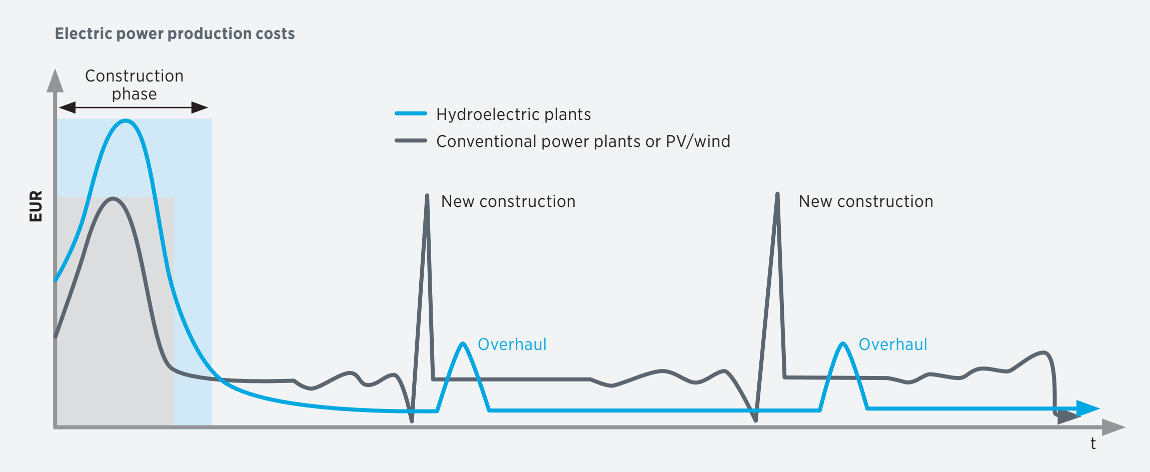
J.4 Estimation and Impact of Residual Value Considerations

The RV after 20 or 30 years for a hydropower asset may be significant because a hydropower plant is then typically only a small fraction of the way through its actual operational life. The specific source of value can be estimated in three ways:

1. The calculated discounted value of future net cash flow that may come from:
   a. The present value of future after-tax sales for energy and/or capacity sales into the wholesale market and via auctions
   b. Follow-on contracts for energy and/or energy and capacity
   c. Some combination of a) and b).
2. The potential value from the sale of a hydropower asset that may have retained most, if not all, of its original financial value in a restructured market.
3. The book value of the asset. After 20 years, a hydropower asset may have a significant fraction of its book value remaining in a regulated environment.

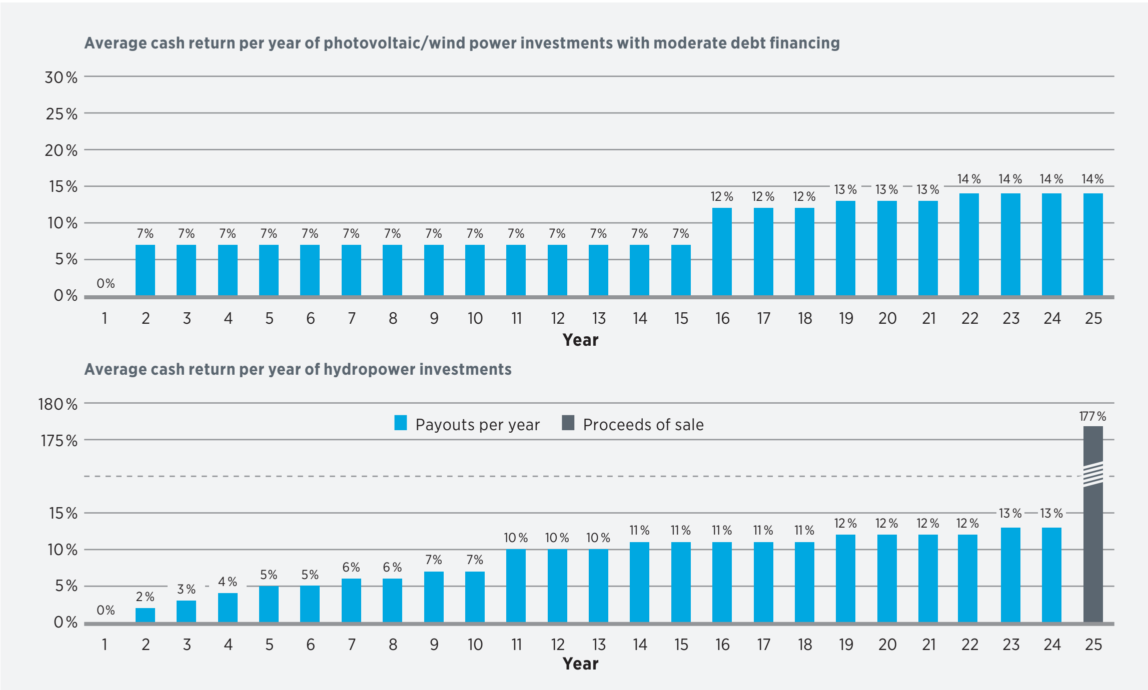
Figures J-2 and J-3, by the Aquila Group (2015), illustrate the financial effect of the estimated hydropower RV in two ways [17]. First, Figure J-2 shows that while solar, wind, and (some) conventional power plant investment may need complete replacement every 20 or 30 years, the corresponding hydropower asset is likely to require refurbishment, not replacement. The additional fixed capital costs for refurbishment (denoted by the term "overhaul" in Figure J-2) are much lower (Option 3 above). Second, Figure J-3 illustrates the RV if the hydropower plant was sold after 20 or 30 years (Option 2 above). The estimated RV in this example is well in excess of the original cost of the hydropower investment (177%) in nominal terms, and it is likely to still be slightly above the original cost in real terms; this valuation is very different from conventional, solar, and wind plants, which may have relatively little RV at this point and/or require new construction.

As the Aquila Group notes, *"The key differences can be seen at the end of the observation period: due to the long service life of the technology, the 'residual' value is generally significantly higher than at purchase (the amount depending largely on the movement of the price of electricity).* The residual value of photovoltaic and wind plants, by contrast tends to be low." [Italics added] [17].



Source: Aquila Capital Investment GmbH, Real Assets—Hydropower Investments, June 2015. [17]

Figure J-2. Illustrative figure of cash-flow outlay over time for hydropower plants compared to conventional, PV, or wind power plants.



Source: Aquila Capital Investment GmbH, Real Assets—Hydropower Investments, June 2015. [17]

Figure J-3. Illustrative figure of cash-flow returns over time for hydropower plants compared to conventional, PV, or wind power plants.

In other words, the RV of hydropower after 20 or 30 years may be substantial, but may not always be higher than the original purchase price, especially if adjusted for inflation. In part, this uncertainty is because the RV may be driven by the expectations of the future market price of power, which are likely to be highly uncertain and may vary by location.[17]

Table J-3 illustrates the impact of various combinations of WACC, financial life, and RV that result in the LCF project-finance conditions. These combinations include increasing the financial life from 20 to 30 years, having RV_f > 60%, and lowering the WACC to 5% or 6%.

Inclusion of the RV is equivalent to reducing the original capital investment (I) by the present value of the estimated expected future RV. Where t is the financial life in years when the RV is estimated, the adjusted investment value (I’) becomes:

2)

$$I' = I - \frac{RV}{(1 + WACC)^t}$$

If this RV is redefined as the fraction of the original investment in year t (RV_f), then the adjusted fraction of the original capital investment is given by I/I’.

3)

$$\frac{I'}{I} = \left(1 - \frac{RV_f}{(1+WACC)^t}\right) \text{ where } RV_f = \frac{RV}{I}$$

17. The RV reflects conceptually the sum of the individual RV subcomponents, which may differ substantially in anticipated or remaining life. For example, while a turbine might be replaced after 40 or 50 years, the dam infrastructure, which can be a substantial component of the original costs, may have much longer life.

Discounted cash-flow analysis is then performed on this adjusted investment cost. This approach is similar to how the original investment cost might be reduced through a cash grant. Unlike a cash grant available at project initiation, the RV represents an uncertain future cash flow and must be estimated and discounted. As discussed at the start of this section, there are three different methods of estimating the RV. These are based on based on (1) future net revenue from after-tax energy and/or capacity sales, (2) possible asset sale prices based on comparable transactions, and (3) use of the depreciated book value (which may be more applicable in regulated markets than in competitive markets).

Table J-4 shows illustrative estimates of the RV, the present value of the RV (PV of RV), and the adjusted capital investment (I') using each of the three methods described above. The analysis is shown for hydropower assets under two hydropower cost assumptions of $2,500/kW and $5,000/kW.

Table J-4. Residual Value Estimates under Alternative Approaches and Impact on Capital Investment

	Nominal Residual Value in Future Year (RV)	Nominal Residual Value Fraction (RV_f)	Present Value of Nominal Residual Value	Present Value Fraction of Nominal Residual Value	Present Value Capital Investment (I')	Present Value Fraction of Capital Investment (I'/I)
Original Capital Investment of $2500/kW						
Option 1: Future market power prices, $60/MWh	$2,424	97%	$914	37%	$1,586	63%
Option 1: Future market power prices, $30/MWh	$970	39%	$365	15%	$2,135	85%
Option 2: Market value of recent sales	$2,000	80%	$754	30%	$1,746	70%
Option 3: Book value depreciation after 20 years (based on 50 year life)	$1,500	60%	$565	23%	$1,935	77%
RV Adder due to Avoided CO_2 emissions at $26/MWh (with SCC $52/ton) for 3%SDR	$2,679	107%	$1,483	59%	$1,017	41%
Original Capital Investment of $5000/kW						
Option 1: Future market power prices, $60/MWh	$2,424	48%	$914	18%	$4,086	82%
Option 1: Future market power prices, $30/MWh	$970	19%	$365	7%	$4,635	93%
Option 2: Market value of recent sales	$2,000	40%	$754	15%	$4,246	85%
Option 3: Book value depreciation after 20 years (based on 50 year life)	$3,000	60%	$1,131	23%	$3,869	77%
RV Adder due to Avoided CO_2 emissions at $26/MWh (with SCC $52/ton) for 3%SDR	$2,679	54%	$1,483	30%	$3,517	70%

Note: Estimates based on discount rate for years 1-50 = WACC = 5% real and 7.5% nominal; discount rate for years after financial life of 20 years could be altered to reflect lower risk. For Option 1, utilization = 60%, O&M = 10$/MWh, Tax rate = 40%

The information in the table can be understood in the following manner, using Option 3 as an example. In this case, for a plant with an original investment cost (I) of $2,500/kW, a 60% RV in year 20 is $1,500/kW. The present value of this RV when discounted at 5% is $565/kW or 23% of the original investment (I). Finally, Table J-4 shows that the net investment to which the capital recovery is applied over the financial life (I') is the original investment less the present value of the RV. This is $1,935/kW ($2,500/kW - $565/kW), or 77% of the original investment (100% - 23%).

Option 1: Estimate future market power prices (and capacity, where relevant) to determine the present value of after-tax sales of power, or follow-on power purchase agreement (PPA) contracts.
This approach involves estimating present value of after-tax net revenue for years 21 to 50 (or longer), assuming utilization and operation and maintenance (O&M) costs and then discounting that value back to the present. This approach may also be used to estimate the prices of a new or follow-on PPA contract. In either case, the RV estimate depends on expectations about future electricity prices, which will be highly uncertain and will vary by location. In Table J-4, for the high and low capital investment choices, two scenarios for future electricity prices are considered ($60/MWh and $30/MWh). In these cases, the present value of the RV after 20 years is 37% and 15% respectively under the high and low electricity price assumptions for the $2,500/kW investment. Halving the electricity prices has a greater effect on reducing the RV because the variable O&M assumptions are the same in both cases. When the capital investment price is doubled, the fractional present value of the RV is cut in half to 18% and 7% respectively.

Option 2: Use recent market transaction of sales of 50-plus-year-old hydropower assets.
The market value of hydropower assets can be significant after 20 years, or even after 50 or more years. For example, today's present value of selling a hydropower plant for $2,000/kW in 20 years (in real terms) is (assuming a 5% real discount rate (7.5% nominal)) roughly $750/kW. Recent transactions for hydropower acquisitions provide strong evidence that 50-plus-year-old hydropower assets often have value in this range (or higher), even if largely depreciated (though the value may vary significantly by location). For example, in 2014, NorthWestern Energy paid approximately $2,000/kW for 10 hydropower assets (excluding the Kerr facility) with a total capacity of 439 MW. These facilities ranged in age from 57 years to more than100 years old, with a system average age of more than 90 years. The valuation methods included a number of scenarios using a discounted cash-flow approach over 20 years, but with a terminal value of 7.5 times the earnings before taxes, interest, depreciation, and amortization. Under this approach, the estimated terminal value results in an estimated RV in 20 years of more than 100% of the target purchase price of roughly $2,000/kW. As part of the process to justify this price, NorthWestern Energy and its financial advisors identified a number of other transactions for hydropower acquisitions by other companies in the last 5 years that showed comparable $/kW prices. In 2015, Brookfield Renewable announced its acquisition of 292 MW of hydropower generation for $860 million (or $2,945 per kW) in the northeastern United States. This is a premium of nearly 50% over the NorthWestern Energy acquisition, suggesting the importance of local market conditions [18].

Option 3: Estimate and use depreciated-asset value. A hydropower asset with a 50-year depreciable asset life will still have 60% of its value remaining after 20 years. For hydropower assets with capital costs of $2,500/kW and $5,000/kW, the RV in 20 years will be $1,500/kW and $3,000/kW respectively, while the present value when discounted at 5% will be $565/kW and $1,131/kW. In both of these cases, and unlike the market-based estimates under options 1 and 2, this corresponds to a fixed fraction of the original investment value (23% in this example). As indicated above, the market-value purchase price may be higher than the book value. For example, the recent payment of $2,000/kW by NorthWestern Energy represented a 55% premium over the book value of the assets. Furthermore, this new purchase will be depreciated anew in the rate base over a 40 year period [15].

While estimates for RV are uncertain, it is also clear none of them is close to zero—and they may represent significant value. The RV discussion and analysis may also be oversimplified in some ways. A hydropower asset comprises many different components that can have very different asset lives, all of which together contribute to the RV. A fuller analysis would separate components with extremely long asset lives (>50 years), such as the physical infrastructure of the dam, from components with slightly shorter lives (<50 years; >20 years), such as the turbines and generators, from those with much shorter lives (<20 years).

The estimates given above are conservative and may underestimate the value of hydropower because the estimated RV is based on years 21 to 50. In practice, these assets may often last 100 years or more, though some incremental investment will also be required (as discussed in Section J.2). In addition, given the debt will have been paid off after 20 or 30 years, the risk (and, hence, discount rate) associated with the hydropower asset might be substantially lower in years 21 or 31 onward. This situation may be particularly true for societal or public-sector investments and treatment of the social cost of carbon, where real social discount rates of 3% or lower may be appropriate. The use of lower discounts and the inclusion of the benefits of avoided carbon emission may have a large incremental effect on the value of the asset over its lifetime. For example, even without allowing for a life beyond 50 years or the social cost of carbon, the use of 2.5% rather than 5% discount rate under Option 1 would increase the present value of the RV by over 80% to $1,711 and $684 under the high and low future electricity price scenarios.

In addition to benefits associated with the sale of energy and capacity, the present value of benefits associated with carbon dioxide abatements after 20 years leads to a very large source of RV. In Table J-4, the RV of these benefits for years 20 to 50 (estimated using the International Working Group social cost of carbon estimates together with a 3% social discount rate) are over $2,500/kW. This is equivalent to a present value today of nearly $1,500/kW. This source of value is additive and greater than almost every other estimate of RV in Table J-4. For example, internalizing the effects of the benefits of avoided carbon-dioxide emissions would increase the present value of the RV (based on estimated future energy and capacity sales estimated illustratively to be between $1,000/kW and $2,400/kW) by 100% to 200% or more—to between $2,600/kW to $5,000/kW, respectively.

Appendix J References

[1] Uría-Martínez, R., P.W. O'Connor, and M. M. Johnson. 2015. *2014 Hydropower Market Report*. DOE/EE-1195. U.S. Department of Energy, Wind and Water Power Technologies Office, Washington, DC (US). Accessed June 5, 2016. *http://nhaap.ornl.gov/HMR/2014*.

[2] Appleyard, David. "Refurbishing Hydropower to Increase Project Life and Boost Capacity." *Renewable Energy World*, September 24, 2013. Accessed June 5, 2016. *http://www.renewableenergyworld.com/articles/2013/09/refurbishing-hydropower-to-increase-project-life-and-boost-capacity.html*.

[3] Bonneville Power Administration. 2014. "2016 Hydro Asset Strategy." Federal Columbia Rivers Power System. Accessed June 5, 2016. *https://www.bpa.gov/Finance/FinancialPublicProcesses/CapitalInvestmentReview/2014CIRDocuments/*.

[4] Bonneville Power Administration. 2013. "Reinvesting in assets" (Fact Sheet). DOE/BP-4530. Accessed June 5, 2016. *https://www.bpa.gov/news/pubs/Pages/FactSheets.aspx*.

[5] Newell, S., J. Hagerty, K. Spees, J. Pfeifenberger, Q. Liao, C. Ungate, and J. Wrable. 2014. "Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM." Prepared for PJM Interconnection Ltd. Accessed June 5, 2016. *https://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-cone-study.ashx*.

[6] Ela, E., M. Milligan, A. Bloom, A. Botterud, A. Townsend, and A. Levin. 2014. *Evolution of Wholesale Electricity Market Design with Increasing Levels of Renewable Generation* (Technical Report). NREL/TP-5D00-61765. National Renewable Energy Laboratory, Golden, CO (US). Accessed June 5, 2016. *http://www.nrel.gov/docs/fy14osti/61765.pdf*.

[7] Pfeifenberger, J., S. Newell, K. Spees, A. Murray, and I. Karkatsouli. 2014. *Third Triennial Review of PJM's Variable Resource Requirement Curve*. The Brattle Group, Cambridge, MA (US). Accessed June 5, 2016. *http://www.pjm.com/~/media/documents/reports/20140515-brattle-2014-pjm-vrr-curve-report.ashx*.

[8] NorthWestern Energy. 2013. "Application for Approval to Purchase and Operate PPL Montana's Hydroelectric Facilities, for Approval of Inclusion of Generation Assets Cost of Service in Electricity Supply Rates, for Approval of Issuance of Securities to Complete the Purchase, and for Related Relief" (Docket No. D2013.12.85). Before The Public Service Commission of the State of Montana. Accessed June 5, 2016. *http://www.northwesternenergy.com/docs/default-source/documents/hydro/application/d2013-12-85_supplemental_testimony_efile.pdf*.

[9] International Energy Agency and OECD Nuclear Energy Agency. 2010. *Projected Costs of Generating Electricity 2010 Edition*. OECD Publication, ISBN 978-92-64-08430-8. Accessed June 5, 2016. *https://www.iea.org/publications/freepublications/publication/projected_costs.pdf*.

[10] International Renewable Energy Agency. 2012. *Renewable Energy Technology: Cost Analysis Series, Hydropower*. Volume 1: Power Sector, Issue 3/5. IRENA Secretariat, Abu Dhabi, United Arab Emirates. Accessed June 5, 2016. *http://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf*.

[11] U.S. Energy Information Administration. 2015. *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015*. Accessed June 5, 2016. *https://www.eia.gov/forecasts/aeo/electricity_generation.cfm*.

[12] Meyers, Edward P. "Tax-advantaged financing for hydroelectric facilities" (Presentation). June 2013.

[13] Sawyer, Merlin. "Red Rock hydroelectric project" (Presentation). Missouri River Energy Services, October 2, 2014.

[14] Red Rock Hydroelectric Project. 2014. "Completion of $351 million bond issue." Accessed June 5, 2016. *http://redrockhydroproject.com/news/completion-of-351-million-bond-issue/*

[15] NorthWestern Energy. 2014. "A Once-in-a-Lifetime Opportunity for Montana PPL Hydro Acquisition" (Fact Sheet). Accessed June 5, 2016. *https://www.northwesternenergy.com/docs/default-source/documents/hydro/project-factsheet-2014.pdf*.

[16] Shurey, Dan. "LCOE, Finance and Investment Update." Presentation by Dan Shurey at BNEF Analyst Day, Department of Energy, Washington DC, April 14 2016.

[17] Aquila Group. 2015. "Real Assets: Hydropower Investment." Aquila Group, Hamburg, Germany. Accessed June 5, 2016. *http://www.aquila-capital.de/en/alternative-investments/real-assets*.

[18] Brookfield Renewable Partners. 2015. "Brookfield Renewable To Acquire 292 MW Hydroelectric Portfolio in Pennsylvania." Accessed June 5, 2016. *https://www.brookfieldrenewable.com/content/2015/brookfield_renewable_to_acquire_292_mw_hydroelectr-43022.html*.

[19] National Hydropower Asset Assessment Program. 2016. "Existing Hydropower Assets Assessment." Oak Ridge National Laboratory. Accessed June 5, 2016. *http://nhaap.ornl.gov*

[20] NorthWestern Energy. 2014. "Application of NorthWestern Energy for Hydro Assets Purchase" (Regulatory Division Docket No. D2013.12.85, Order No. 7323k, Final Order). Department of Public Service Regulation Before the Public Service Commission of the State of Montana. Accessed June 5, 2016. *http://psc.mt.gov/Docs/ElectronicDocuments/pdfFiles/D2013-12-85_7323k.pdf.*

[21] Lazard. 2015. "Levelized Cost of Energy Analysis 9.0." Accessed June 5, 2016. *https://www.lazard.com/perspective/levelized-cost-of-energy-analysis-90/*.

[22] Bonneville Power Administration. 2016. "2016 AB Energy Northwest Official Statement." Appendix A—The Bonneville Power Administration, March 23, 2016. Accessed June 16, 2016. *https://www.bpa.gov/news/Investor/Pages/default.aspx*.

This page is intentionally left blank

Appendix K: Contributors

The U.S. Department of Energy (DOE) acknowledges the authors, reviewers, and various contributors listed below, all of whom assisted in this project since its inception in early 2014. More than 300 individuals, representing more than 150 organizations, contributed technical knowledge, draft text or review comments. The DOE Wind and Water Power Technologies Office managed the project in collaboration with the National Hydropower Association. Together, these organizations invited participation of individuals representing a broad range of hydropower stakeholder sectors including, but not limited to, trade organizations, equipment manufacturers, project developers, independent power producers, technical consultants, non-governmental environmental organizations, electric utilities, state organizations, national laboratories and federal agencies. Expert input from these sectors was provided through active participation in ten Task Forces, a Senior Peer Review Group comprised of senior executives and administrators, or an External Review Group of experts who had not previously been involved in preparation of the report. Contributions and support from all these participants were incorporated throughout the development of this report.

Various offices within DOE and other federal agencies also provided counsel and review throughout the effort. The DOE's Office of Energy Efficiency and Renewable Energy was a principal internal adviser. DOE's Office of Energy Policy and Systems Analysis, Office of Electricity Delivery and Energy Reliability, Power Marketing Administration, and Energy Information Administration also provided valuable input. DOE also coordinated with other federal agencies, such as the Department of the Interior, Federal Energy Regulatory Commission, Army Corps of Engineers, and the National Oceanic and Atmospheric Administration.

The final version of this document was prepared by DOE.

Lead authors and main advisors within each group of contributors below are shown in **bold.**

Overall Direction

Hydropower Vision Project Management

Jose Zayas (DOE Lead)	**U.S. Department of Energy**
Gary Norton (Team Lead)	**CSRA Inc.**
Dave Culligan	HDR, Inc. / National Hydropower Association
Coryne Tasca	CSRA Inc.
T.J. Heibel	Pacific Northwest National Laboratory
Ryan Hoesly	formerly CSRA Inc.

Report Lead Editors and Coordinators

Gary Norton (Co-Lead)	**CSRA Inc.**
Coryne Tasca (Co-Lead)	**CSRA Inc.**
Ed Eugeni (Co-Lead)	**CSRA Inc.**
Alexsandra Lemke (Communications Lead)	**National Renewable Energy Laboratory**
John Frenzl (Art Director)	**National Renewable Energy Laboratory**
Marisol Bonnet	Allegheny Science and Technology
Dave Culligan	HDR, Inc. / National Hydropower Association
Gary Johnson	Pacific Northwest National Laboratory
Eric Lantz	National Renewable Energy Laboratory
Carol Laurie	National Renewable Energy Laboratory
Lauren Peterson	Allegheny Science and Technology
Sandyn Skudneski	CSRA Inc.

Senior Peer Review Group

The Senior Peer Review Group played an important role by reviewing key findings of the report during its development, and providing important constructive comments and strategic guidance as the work progressed.

Jose Zayas (DOE Lead)	**U.S. Department of Energy**
Linda Church-Ciocci	National Hydropower Association
Marc Gerken	American Municipal Power
Jo-Ellen Darcy	Army Corp of Engineers
William Irvin	American Rivers
Tom Iseman	U.S. Department of Interior
Herbie Johnson	Southern Company
Kristina Johnson	Enduring Hydro
Randy Livingston and David Moller	Pacific Gas and Electric
John McCormick	Tennessee Valley Authority
Ann Miles	Federal Energy Regulatory Commission
Rick Miller	HDR, Inc.
Debbie Mursch	Alstom Power
Lynn Scarlett	The Nature Conservancy
Gia Schneider	Natel Energy
David Terry	National Association of State Energy Officials
Dave Youlen	Eagle Creek Renewable Energy

Lead Authors and Contributors

Executive Summary: Chapter Key Findings

Jose Zayas	**U.S. Department of Energy**
Fred Beck (Lead)	**CSRA Inc.**
Gary Norton	CSRA Inc.
Dave Culligan	HDR, Inc. / National Hydropower Association
Richard Tusing	Allegheny Science and Technology
Tim Welch	U.S. Department of Energy

Chapter 1: The *Hydropower Vision*

Fred Beck (Lead)	**CSRA Inc.**
Gary Norton	**CSRA Inc.**
Dave Culligan	HDR, Inc. / National Hydropower Association
Richard Tusing	Allegheny Science and Technology

Chapter 2: State of Hydropower in the United States

Gary Johnson (Lead)	**Pacific Northwest National Laboratory**
Boualem Hadjerioua	**Oak Ridge National Laboratory**
Kenneth Ham	**Pacific Northwest National Laboratory**
David Keyser	**National Renewable Energy Laboratory**
Vladimir Koritarov	**Argonne National Laboratory**
Michael Milligan	**National Renewable Energy Laboratory**
Patrick O'Connor	**Oak Ridge National Laboratory**
Brennan Smith	**Oak Ridge National Laboratory**
Marisol Bonnet	Allegheny Science and Technology
Eduardo Ibanez	GE Energy Connections
Todd Levin	Argonne National Laboratory
Jim Miller	Oak Ridge National Laboratory
Bo Saulsbury	Oak Ridge National Laboratory
Suzanne Tegen	National Renewable Energy Laboratory
Connor Waldoch	Oak Ridge National Laboratory

Chapter 3: Assessment of National Hydropower Potential

Eric Lantz (Lead)	**National Renewable Energy Laboratory**
Stuart Cohen	**National Renewable Energy Laboratory**
Maureen Hand	**National Renewable Energy Laboratory**
David Keyser	**National Renewable Energy Laboratory**
Patrick O'Connor	**Oak Ridge National Laboratory**
Garvin Heath	National Renewable Energy Laboratory
Thomas Jenkin	National Renewable Energy Laboratory
Shih-Chieh Kao	Oak Ridge National Laboratory
Venkat Krishnan	National Renewable Energy Laboratory
Ryan McManamay	Oak Ridge National Laboratory
Jordan Macknick	National Renewable Energy Laboratory
Dev Millstein	Lawrence Berkeley National Laboratory
Nicole Samu	Oak Ridge National Laboratory
Suzanne Tegen	National Renewable Energy Laboratory
Connor Waldoch	Oak Ridge National Laboratory
Ethan Warner	National Renewable Energy Laboratory

Chapter 4: The *Hydropower Vision* Roadmap: A Pathway Forward

Marisol Bonnet (Lead)	**Allegheny Science and Technology**
Dave Culligan	**HDR, Inc./National Hydropower Association**
T.J. Heibel	**Pacific Northwest National Laboratory**
Gary Norton	**CSRA Inc.**
Edward Eugeni	CSRA Inc.
Boualem Hadjerioua	Oak Ridge National Laboratory
Kenneth Ham	Pacific Northwest National Laboratory
Gary Johnson	Pacific Northwest National Laboratory
Vladimir Koritarov	Argonne National Laboratory
Jim Miller	Oak Ridge National Laboratory
Patrick O'Connor	Oak Ridge National Laboratory
Bo Saulsbury	Oak Ridge National Laboratory
Brennan Smith	Oak Ridge National Laboratory
Suzanne Tegen	National Renewable Energy Laboratory
Connor Waldoch	Oak Ridge National Laboratory
Timothy Welch	U.S. Department of Energy

Appendices

Appendix A: Glossary

Coryne Tasca	**CSRA Inc.**

Appendix B: Expanded Discussion of Hydropower Technology Assumptions

Connor Waldoch	**Oak Ridge National Laboratory**

Appendix C: *Hydropower Vision* Future Technology Cost Assumptions

Connor Waldoch	**Oak Ridge National Laboratory**

Appendix D: Regional Energy Deployment System (ReEDS) Model— Additional Inputs and Assumptions

Stuart Cohen	**National Renewable Energy Laboratory**

Appendix E: *Hydropower Vision* Scenario Matrix

Stuart Cohen	**National Renewable Energy Laboratory**

Appendix F: Supplemental Results

Stuart Cohen	**National Renewable Energy Laboratory**

Appendix G: Life cycle GHG Emissions and Net Energy Metrics

David Keyser	**National Renewable Energy Laboratory**

Appendix H: The Conventional Hydropower Jobs and Economic Development Impacts (JEDI) Model

Suzanne Tegen	**National Renewable Energy Laboratory**

Appendix I: Workforce

Suzanne Tegen	**National Renewable Energy Laboratory**

Appendix J: The Operational and Economic Value of Hydropower as a Long Lived Asset

Thomas Jenkin	**National Renewable Energy Laboratory**
Maureen Hand	**National Renewable Energy Laboratory**
T.J. Heibel	**Pacific Northwest National Laboratory**
Patrick O'Connor	Oak Ridge National Laboratory

Contributing Task Force Members

Markets Task Force

Patrick O'Connor (Lead)	**Oak Ridge National Laboratory**
Connor Waldoch (Deputy)	**Oak Ridge National Laboratory**
Gary Norton (Project Coordinator)	**CSRA Inc.**
Gordon Ashby	Bonneville Power Administration
Bob Barksdale	Keycor Consulting
Jeff Bishop	Brookfield Renewable Energy Partners
Marisol Bonnet	Allegheny Science and Technology
Audun Botterud	Argonne National Laboratory
Gregg Carrington	Chelan County PUD
Thomas Dautel	Federal Energy Regulatory Commission
Jamil Farbes	Pacific Gas and Electric Company
Alisha Fernandez	McKeown and Associates
Francisco Flores-Espino	National Renewable Energy Laboratory
Suzanne Grassell	Chelan County PUD
Dana Hall	Low Impact Hydropower Institute
David Harpman	U.S. Bureau of Reclamation
Eduardo Ibanez	General Electric
Vibhu Kaushik	Southern California Edison
Vladimir Koritarov	Argonne National Laboratory
Joe Lawlor	Pacific Gas and Electric Company
Jaclynn Lukach	PJM Interconnection
David H. Mangold	DHM/University of Akron
Mike McElhany	Western Area Power Administration
Rick Miller	HDR, Inc.
Michael Milligan	National Renewable Energy Laboratory
Jim Reilly	New West Technologies, LLC
Ken Schuyler	PJM Interconnection
Brian Shenk	U.S. Army Corp of Engineers
Ryan Stewart	Bonneville Power Administration
Brennan Smith	Oak Ridge National Laboratory
Christina Stotesbury	PJM Interconnection
Gene Therriault	Alaska Energy Authority
Rocio Uria-Martinez	Oak Ridge National Laboratory
Brad Vickers	Southwestern Power Administration

Modeling and Analysis Task Force

Maureen Hand (Co-Lead)	**National Renewable Energy Laboratory**
Eric Lantz (Co-Lead)	**National Renewable Energy Laboratory**
Stuart Cohen (Deputy)	**National Renewable Energy Laboratory**
T.J. Heibel (Project Coordinator)	**Pacific Northwest National Laboratory**
Phillip Beiter	National Renewable Energy Laboratory
Clark Bishop	U.S. Bureau of Reclamation
Norman Bishop	Knight Piesold Consulting
Nate Blair	National Renewable Energy Laboratory
Michelle Bowman	U.S. Energy Information Administration
Alberta Carpenter	National Renewable Energy Laboratory
James Clune	Bonneville Power Administration
Dave Culligan	HDR, Inc./National Hydropower Association
Elise DeGeorge	National Renewable Energy Laboratory
Robert Deibel	U.S. Forest Service
Richard Fisher	Consultant
Bo Hadjerioua	Oak Ridge National Laboratory
Kenneth Ham	Pacific Northwest National Laboratory
Garvin Heath	National Renewable Energy Laboratory
Jory Hecht	Tufts
Shelaine Hetrick	Oak Ridge National Laboratory
Shih-Chieh Kao	Oak Ridge National Laboratory
Ken Kemp	Eagle Creek Renewable Energy
Eduardo Ibanez	National Renewable Energy Laboratory
Thomas Jenkin	National Renewable Energy Laboratory
David Keyser	National Renewable Energy Laboratory
Ian Kraukunas	Pacific Northwest National Laboratory
Venkat Krishnan	National Renewable Energy Laboratory
Vladimir Koritarov	Argonne National Laboratory
Todd Levin	Argonne National Laboratory
Jordan Macknick	National Renewable Energy Laboratory
Stephanie Maggard	Pacific Gas and Electric Company
Patrick March	Hydro Performance Processes Inc.
Erik Martin	The Nature Conservancy
Ryan McManamay	Oak Ridge National Laboratory
Jim Miller	Oak Ridge National Laboratory
Thomas Miller	Pacific Gas and Electric Company
Michael Milligan	National Renewable Energy Laboratory
Tara Moberg	The Nature Conservancy

Modeling and Analysis Task Force *(continued)*

Christopher Namovicz	U.S. Energy Information Administration
Patrick O'Connor	Oak Ridge National Laboratory
David Raff	U.S. Bureau of Reclamation
Bo Saulsbury	Oak Ridge National Laboratory
Rick Skaggs	Pacific Northwest National Laboratory
Brennan Smith	Oak Ridge National Laboratory
Suzanne Tegen	National Renewable Energy Laboratory
Matthew Troia	Oak Ridge National Laboratory
Rocio Uria-Martinez	Oak Ridge National Laboratory
Thomas Veselka	Argonne National Laboratory
Ethan Warner	National Renewable Energy Laboratory
Connor Waldoch	Oak Ridge National Laboratory

Economic Development Task Force

David Keyser (Lead)	**National Renewable Energy Laboratory**
Suzanne Tegen (Deputy)	**National Renewable Energy Laboratory**
T.J. Heibel (Project Coordinator)	**Pacific Northwest National Laboratory**
Bob Barksdale	Keycor Consulting
Phillip Beiter	National Renewable Energy Laboratory
Bill Bunker	Pacific Gas and Electric Company
Matt Crane	MWH Global Inc.
Jeanne Hilsinger	Mavel
Francisco Flores-Espino	National Renewable Energy Laboratory
Pat McCarty	Tacoma Public Utilities
Mike Meko	Pacific Gas and Electric Company
Courtenay O'Mara	Southern Company
Jay Paidipati	Navigant
Chris Porse	Mavel
David Sanna	U.S. Army Corps of Engineers
Karina Saslow	New York Power Authority
Max Spiker	U.S. Bureau of Reclamation
John Suloway	New York Power Authority
Phillip Toia	New York Power Authority
Rocio Uria-Martinez	Oak Ridge National Laboratory
Brenna Vaugn	Hydro Foundation

Technology Task Force

Boualem Hadjerioua (Lead)	**Oak Ridge National Laboratory**
Marisol Bonnet (Deputy)	**Allegheny Science and Technology**
Dave Culligan (Project Coordinator)	**HDR, Inc. / National Hydropower Association**
Brian Eyler	Stimson Center
Greg Allen	Alden Research Laboratory, Inc
Norman Bishop	Knight Piesold Consulting
Paul Blaszczyk	MWH Global, Inc.
Merlyn Bender	U.S. Bureau of Reclamation
Kearon Bennett	Ottawa Engineering
David Brown	Lock 7 Hydro Partners
Roger Clarke-Johnson	American Governor Company
Daniel Deng	Pacific Northwest National Laboratory
Donald Erpenbeck	MWH Global Inc.
John Etzel	U.S. Army Corps of Engineers
Dick Fisher	Consultant
Scott Flake	Sacramento Municipal Utility District
William (Bill) French Sr.	French Development Enterprises
Erin Foraker	U.S. Bureau of Reclamation
Russ Fostiak	Institute of Electrical and Electronics Engineers
Jason Foust	Voith
Kim Hansen	Kleinschmidt
Jeanne Hilsinger	Mavel
Chuck Hutton	Consultant
Bruno Kaelin	Alstom
Greg Lewis	Duke Energy
Peter Ludewig	New York Power Authority
James Mearns	Pacific Gas and Electric Company
Egil Opsahl	CleanPower
Jim Ruane	Reservoir Environmental Management, Inc
Abe Schneider	Natel
Darryl Stevenson	Voith
Kelly Tilford	McMillen, LLC
Eric Van Deuren	Pacific Gas and Electric Company

Project Development Task Force

Bo Saulsbury (Lead)	**Oak Ridge National Laboratory**
Dave Culligan (Project Coordinator)	**HDR, Inc. / National Hydropower Association**
Hoyt Battey	U.S. Department of Energy
Paul Bernhardt	Hatch
Clark Bishop	U.S. Bureau of Reclamation
Marisol Bonnet	Allegheny Science and Technology
Peter Brown	Preti Flaherty
Craig Collar	Snohomish County Public Utilities District
Bob Dach	Bureau of Indian Affairs
Peter Drown	Contractor
Wayne Dyok	Alaska Energy Authority
John Ferguson	U.S. Army Corps of Engineers
Simon Geerlofs	Pacific Northwest National Laboratory
Joan Harn	National Parks Service
Tom Heller	Missouri River Energy Services
Nick Jayjack	Federal Energy Regulatory Commission
Kurt Johnson	Telluride Energy/Colorado Small Hydro Association
Jed Jorgensen	Energy Trust of Oregon
Ken Kemp	Eagle Creek Renewable Energy
Michael Kerr	New England Hydropower
Jan Lee	Northwest Hydroelectric Association
Kevin Mendik	National Parks Service
Amy Newsock	The Nature Conservancy
Patrick O'Connor	Oak Ridge National Laboratory
David Sinclair	Advanced Hydro Solutions
Brennan Smith	Oak Ridge National Laboratory
Debbie Stone	Knight Piesold Consulting
Nick Tackett	Federal Energy Regulatory Commission
Eric Van Deuren	Pacific Gas and Electric Company
Tim Welch	U.S. Department of Energy
Vince Yearick	Federal Energy Regulatory Commission

Operations and Maintenance Task Force

Brennan T. Smith (Lead)	**Oak Ridge National Laboratory**
Jim Miller (Deputy)	**Oak Ridge National Laboratory**
Gary Norton (Project Coordinator)	**CSRA Inc.**
Marisol Bonnet	Allegheny Science and Technology
Dave Brown	Eagle Creek Renewable Energy
Alisha Fernandez	U.S. Department of Energy
Jim Gill	Pacific Gas and Electric Company
Bruce Hamilton	Navigant
Chris Hayes	Centre for Energy Advancement through Technological Innovation
Jeremy Jessup	Federal Energy Regulatory Commission
Kyle Jones	U.S. Army Corp of Engineers
Greg Lewis	Duke Energy
Matthew Mahalik	Argonne National Laboratory
Pat Maher	Avista Corporation
Patrick March	Hydro Performance Processes Inc.
Lisa Martindale	Southern Company
Richard Mickwee	Southern Company
Pat McCarty	Tacoma Public Utilities
Patrick O'Connor	Oak Ridge National Laboratory
Ken Poletti	Exelon
Nora Rosemore	Minnesota Power
Stan Rosinski	Electric Power Research Institute
John Shucknecht	Pacific Gas and Electric Company
Stephen Signore	Oak Ridge National Laboratory
Andrew Warner	The Nature Conservancy
Steve Wenke	Avista Corporation
Alastair Wilson	Centre for Energy Advancement through Technological Innovation
Warren Witt	Ameren Missouri
Eric Wolfe	Southeast AK Power

Sustainability, Environmental and Regulatory Considerations Task Force

Simon Geerlofs (Lead)	**Pacific Northwest National Laboratory**
Kenneth Ham (Deputy)	**Pacific Northwest National Laboratory**
Dave Culligan (Project Coordinator)	**HDR, Inc. / National Hydropower Association**
Mark Bevelhimer	Oak Ridge National Laboratory
Mary Josie Blanchard	U.S. Department of Interior
Tim Brush	Normandeau
David Coughlan	Normandeau
Elise DeGeorge	National Renewable Energy Laboratory
Robert Deibel	U.S. Forest Service
John Devine	HDR, Inc.
Steve Edmondson	NOAA—National Marine Fisheries Service
Lara Fowler	Penn State University
Gary Franc	Franc Logic
Julie Smith Galvin	Brookfield Renewable Partners
Dave Geist	Pacific Northwest National Laboratory
Kirby Gilbert	MWH Global Inc.
Frankie Green	U.S. Fish and Wildlife Service
Joan Harn	National Park Service
Melanie Harris	NOAA—National Marine Fisheries Service
John Hayse	Argonne National Laboratory
Jory Hecht	Tufts University
Shelaine Hetrick	Oak Ridge National Laboratory
Tim Hogan	Alden
Paul Jacobsen	Electric Power Research Institute
Nick Jayjack	Federal Energy Regulatory Commission
Gary Johnson	Pacific Northwest National Laboratory
Jason Kapelina	WEG/Electric Machinery
Julie Keil	Retired
Katie Kennedy	The Nature Conservancy
Jereme Klassy	Eagle Creek Renewable Energy
Karen Klosowski	GEI Consultants. Inc.
Mona Koerner	U.S. Forest Service
Jeff Leahey	National Hydropower Association
Jan Lee	Northwest Hydroelectric Association
Diane McMahon	Bechtel
Kevin Mendik	National Park Service
Kate Miller	Trout Unlimited
Tara Moberg	The Nature Conservancy

Sustainability, Environmental and Regulatory Considerations Task Force *(continued)*

David Moller	Pacific Gas and Electric Company
Lisa Morales	U.S. Army Corps of Engineers
Tam Nguyen	Bechtel
Tim Oakes	Kleinschmidt
Thomas O'Keefe	American Whitewater
Ian Ochs	Eureka Software
Kim Ogren	Oregon State University/Hydro Research Foundation
Fritha Ohlson	Southwestern Power Administration
Rebecca O'Neill	Oregon U.S. Department of Energy
Jeff Opperman	The Nature Conservancy
Cherise Oram	Stoel Rives
Brenda Pracheil	Oak Ridge National Laboratory
Jeremy Pratt	GEI Consultants, Inc.
Andy Qua	Kleinschmidt
Marshall Richmond	Pacific Northwest National Laboratory
Richard Roos-Collins	Water and Power Law Group
James Ruane	Reservoir Environmental Management, Inc.
Mike Sale	Low Impact Hydropower Institute
Bo Saulsbury	Oak Ridge National Laboratory
John Seebach	American Rivers
Angela Segars	Southern Company
Chuck Sensiba	Van Ness Feldman
Frank Simms	American Electric Power
Heather Snow	U.S. Bureau of Land Management
Alan Stuart	Duke Energy
Tom Sullivan	Gomez and Sullivan
Nicholas Tackett	Federal Energy Regulatory Commission
Brad Vickers	Southwestern Power Administration
Richard Vogel	Tufts University
Hiedi Wahto	McMillen LLC
Anna West	Kearns and West
John Whittaker	Winston & Strawn LLP
Kellie Whitton	U.S. Forest Service
Vince Yearick	Federal Energy Regulatory Commission
Edie Zagona	Center for Advanced Decision Support for Water and Environmental Systems
David Zayas	National Hydropower Association

Pumped Storage Hydro (PSH) Task Force

Vladimir Koritarov (Lead)	**Argonne National Laboratory**
Todd Levin (Deputy)	**Argonne National Laboratory**
T.J. Heibel (Project Coordinator)	**Pacific Northwest National Laboratory**
Norman Bishop	Knight Piesold Consulting
Audun Botterud	Argonne National Laboratory
John Brewer	Glenfield America
Brandon Cherry	Federal Energy Regulatory Commission
Stefano Chioetto	Toshiba
Charlton Clark	U.S. Department of Energy
Paul Denholm	National Renewable Energy Laboratory
Douglas Divine	Eagle Crest Energy (Eagle Mt.)
Peter Donalek	MWH Global Inc.
Joe Eberhardt	EDF Renewable Energy
Erik Ela	National Renewable Energy Laboratory
Klaus Engels	Leiter Wasserkraft (Prokurist)
Donald Erpenbeck	MWH Global Inc.
Alisha Fernandez	U.S. Department of Energy
Dick Fisher	Hydro Insights
Scott Flake	Sacramento Municipal Utility District
Ginger Gillin	GEI Consultants
Bo Hadjerioua	Oak Ridge National Laboratory
Keith Heimbach	Pacific Gas and Electric Company
Jennifer Hill	Federal Energy Regulatory Commission
Rob Hovsapian	Idaho National Laboratory
Eduardo Ibanez	National Renewable Energy Laboratory
Teruyuki Ishizuki	Toshiba
Michael Jones	Pacific Gas and Electric Company
Michael Kintner-Meyer	Pacific Northwest National Laboratory
Jeff Leahey	National Hydropower Association
Mike Manwaring	MWH Global Inc.
Patrick March	Hydro Performance Processes Inc.
John McCormick	Tennessee Valley Authority
Steven Zuretti	Brookfield
Rick Miller	HDR, Inc.
Michael Milligan	National Renewable Energy Laboratory
Aleksandar Mitreski	Brookfield
Debbie Mursch	National Hydropower Association
Swami Nathan Subramanian	Eaton

Pumped Storage Hydro Task Force *(continued)*

Osamu Nagura	Hitachi-Mitsubishi Hydro
Ali Nourai	DNV GL
Patrick O'Connor	Oak Ridge National Laboratory
Ken Odom	Southern Company
Charlie Post	Pacific Gas and Electric Company
Michael Pulskamp	U.S. Bureau of Reclamation
Jim Reilly	U.S. Department of Energy
Kamau Sadiki	U.S. Army Corp of Engineers
Nathan Sandvig	MWH Global Inc.
Devesh Sharma	Tomlin Investments
Douglas Spaulding	Missouri River Energy Services
Olivier Teller	Alstom
Kelly Tilford	McMillen LLC
Bruno Trouille	MWH Global Inc.
Thomas Veselka	Argonne National Laboratory
Xiaobo Wang	California Independent System Operator
Warren Witt	Ameren Missouri

Grid Integration Task Force

Michael Milligan (Lead)	**National Renewable Energy Laboratory**
Eduardo Ibanez (Deputy)	**National Renewable Energy Laboratory**
Gary Norton (Project Coordinator)	**CSRA Inc.**
Tom Acker	Northern Arizona U.
Antonio Alvarez	Pacific Gas and Electric Company
Steve Beuning	Xcel
Caitlin Callaghan	U.S. Department of Energy
Tom Chisholm	U.S. Army Corp of Engineers
Charlton Clark	U.S. Department of Energy
Tom Dautel	Federal Energy Regulatory Commission
Vikas Dawar	New York Independent System Operator
Peter Donalek	MWH Global Inc.
Alisha Fernandez	BCS, Incorporated)
Rob Hovsapian	Idaho National Laboratory
David Jacobson	Manitoba Hydro
Landis Kannberg	Pacific Northwest National Laboratory
Vladimir Koritarov	Argonne National Laboratory
Joe Kysely	American Transmission Company

Grid Integration Task Force *(continued)*

Todd Levin	Argonne National Laboratory
Clyde Loutan	California Independent System Operator
Tim Magee	Center for Advanced Decision Support for Water and Environmental Systems
Jim McCalley	Iowa State University
Thomas Miller	Pacific Gas and Electric Company
Patrick O'Connor	Oak Ridge National Laboratory
Michael Starkey	Oak Ridge National Laboratory
Debbie Stone	Knight Piesold Consulting
Aidan Tuohy	Electric Power Research Institute
Edie Zagona	Center for Advanced Decision Support for Water and Environmental Systems

Communications, Outreach, and Production

Alexsandra Lemke (Lead)	**National Renewable Energy Laboratory**
John Frenzl (Art Director)	**National Renewable Energy Laboratory**
Gary Norton	**CSRA Inc.**
David Anderson	Southern Company
Dean Armstrong	National Renewable Energy Laboratory
Marla Barns	Pennwell
Josh Bauer	National Renewable Energy Laboratory
Bryan Bechtold	National Renewable Energy Laboratory
Angela Becker-Dippmann	Pacific Northwest National Laboratory
Stacy Buchanan	National Renewable Energy Laboratory
LeRoy Coleman	National Hydropower Association
Liz Craig	National Renewable Energy Laboratory
John De La Rosa	National Renewable Energy Laboratory
Liz Hartman	U.S. Department of Energy
T.J. Heibel	Pacific Northwest National Laboratory
Shelaine Hetrick	Oak Ridge National Laboratory
Alfred Hicks	National Renewable Energy Laboratory
Carol Laurie	National Renewable Energy Laboratory
Todd Levin	Argonne National Laboratory
Matthew Nocella	National Hydropower Association
Sheldon Reiffenstein	Maga Design, Inc.
Joelynn Schroeder	National Renewable Energy Laboratory
Randall Stearnes	Tacoma Public Utilities
Mark Swisher	Independent Contractor
Sarah Wagoner	Hannon Group

External Peer Reviewers

Although feedback on the draft report was provided by these individuals, DOE is ultimately responsible for content in this report.

Roger Ballentine	**Green Strategies Inc.**
Nicolas Bossé	**Brookfield Renewable Energy Group**
Margaret Bowman	**Bowman Environmental Consulting, LLP**
Chuck Coutant	**Technical Consultant, Coutant Aquatics**
John Devine	**HDR, Inc.**
Brian Fitzgerald	**Vermont Natural Resources Council**
Bob Gallo	**Voith Hydro**
Mark Garner	**Voith Hydro (Retired); Enduring Hydro**
Frank Hamill	**Bechtel Corporation**
Jane Hannuksela	**NOAA—Office of General Counsel, Northwest Section**
Chris Hayes	**Centre for Energy Advancement through Technological Innovation**
Bill Holmes	**K&L Gates LLP**
Michael Kerr	**New England Hydropower Company LLC**
Roy Kuga	**Pacific Gas and Electric Company**
Jeff Lineberger	**Duke Energy**
Deborah Linke	**Hydro Research Foundation**
Dave Smith	**Wartsila Defense**
Cassie Thomas	**National Park Service**
Maria Tome	**State of Hawaii, Public Utilities Commission**
Rollie Wilson	**Fredericks, Peebles and Morgan, LLP**

A New Chapter for America's 1ST Renewable Electricity Source

This first-of-its-kind analysis builds on the historical importance of hydropower and establishes a roadmap to usher in a new era of growth in sustainable domestic hydropower.

U.S. DEPARTMENT OF ENERGY

DOE/GO-102016-4869 • July 2016
Cover photos from iStock 55486650, 83494953, 28045480, 1946803