Enhanced Hydropower Database

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Enhanced Hydropower Database

Final Report

Prepared for:

New York State Energy Research and Development Authority

Albany, NY

Prepared by:

Gomez and Sullivan Engineers, D.P.C

Utica, NY

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Acronyms and Abbreviations

7Q10	A low flow occurring over seven consecutive days that has a 10% chance of occurring in each year
ATB	Annual Technology Baseline
AWWA	American Water Works Association
CapEx	capital expenditure
CES	Clean Energy Standard
Cf/s	cubic feet per second
cf/sm	cubic feet per second per square mile
CREB	Clean Renewable Energy Bonds
QECB	Qualified Energy Conservation Bonds
DEC	New York State Department of Environmental Conservation
DOE	United States Department of Energy
DOI	United States Department of the Interior
DOT	United States Department of the Treasury
DPS	New York State Department of Public Service
EIA	United States Energy Information Administration
ENR	Engineering News Record
FERC	Federal Energy Regulatory Commission
Fps	feet per second
Gomez and Sullivan	Gomez and Sullivan Engineers, D.P.C.
IDF	inflow design flood
INL	Idaho National Laboratory
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
LCOE	Levelized Cost of Energy
LSR	Large Scale Renewables
MGD	million gallons per day
MW	megawatts
MWh	megawatt-hour
NA	not applicable
NAVD88	North American Vertical Datum of 1988
NGO	non-governmental organization
NID	National Inventory of Dams
NPV	net present value
NREL	National Renewable Energy Laboratory
NYGATS	New York Generation Attribute Tracking System

NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSET	New York Streamflow Estimation Tool
O&M	operation and maintenance
OPCC	opinion of probable construction costs
ORNL	Oak Ridge National Laboratory
PINY	Polytechnic Institute of New York
PLC	Programmable Logic Controller
PAD	pre-application document
PTC	production tax credit
REC	renewable energy certificate
RES	Renewable Energy Standard
RFP	request for proposals
SCADA	Supervisory Control and Data Acquisition
USACE	United States Army Corps of Engineers
USEPA	United States Environmental Protection Agency
USFWS	United States Fish and Wildlife Service
USGS	United States Geological Survey

Conversions

1 meter	=	3.281 feet
1 foot	=	0.3048 meters
1 MGD	=	1.55 cf/s
1 cf/s	=	0.646 MGD
1 MW	=	1,000 kW

Executive Summary

The New York State Energy and Research Development Authority (NYSERDA) seeks to foster the development of large-scale renewables to achieve the State's goal of obtaining 100% clean power by 2040. Understanding current and future hydropower generation in New York State is necessary to achieve this goal.

Previous studies examining the status and potential of hydropower in New York State largely focused on publicly owned hydropower sites. The current study provides both an updated database of all hydropower sites in New York State and more detailed generation and cost analyses for 40 privately owned sites which are likely to experience changes in annual power generation within the next 20 to 30 years.

For the 40 privately owned hydropower sites examined, the potential net change in average annual generation is approximately 270,000 megawatts-hours (MWh), a 0.2% increase in renewable energy generation in New York State. The potential net change in average annual generation includes both proposed powerhouse and minimum flow turbine upgrades, as well as generation losses for projects with no upgrade potential. The total capital expenditure cost associated with the proposed upgrades is approximately $767 million.

1 Introduction

1.1 Background

In conjunction with the development of large-scale renewables (LSR) included in the State Energy Plan, an LSR supply curve model was built to analyze available renewable energy technology costs, resource availability, and resource constraints for renewable energy, including hydropower. The LSR analysis included detailed modeling of small-scale hydropower generation potential based on publicly available data. However, due to the site-specific and size-sensitive nature of potential hydropower costs and resources, the model only attempted to represent the central tendency of hydropower development based on historical data. A comprehensive site screening analysis using project-specific data was recommended to accurately capture the potential for private sector hydropower resource development in New York.

At non-powered dams and greenfield (potential developments without existing dams) sites, it is difficult to assess the validity of the data presented in the hydropower resource assessments unless dam safety reports or previous feasibility studies have been developed about those sites. A subset of non-powered dams with significant hydropower potential in the State are well known and, in some cases, have been the subject of feasibility studies. However, available feasibility studies are typically limited to publicly owned sites and do not include the 159 privately owned, licensed, or exempted by the Federal Energy Regulatory Commission (FERC), projects in New York, consisting of 190 individual sites. Therefore, there was a need to assess these privately-owned sites and, specifically, privately owned sites with FERC licenses or exemptions.[1]

To accomplish this, NYSERDA contracted Gomez and Sullivan Engineers, D.P.C. (Gomez and Sullivan) in November 2016 to evaluate the status and potential of private sector hydropower generation in New York State to support the LSR supply curve modeling. The detailed assessment will serve as the new baseline for future hydropower studies to accurately predict energy generation growth or reduction for existing privately-owned hydropower sites over the next 20 to 30 years. The anticipated generation estimates provided for each site will make it possible for others to develop detailed LSR curves for use in further analyzing the status of hydropower in New York State.

1 Out of the 1,900 sites in New York, 213 are regulated by FERC.

1.2 Project Objectives

The purpose of this study is to evaluate the current status and potential growth or reduction in private sector hydropower generation at existing sites regulated by the Federal Energy Regulatory Commission (FERC). This study included the following goals. For a detailed discussion see specific section.

- Summarize the status of hydropower in New York State (section 2).
- Develop an updated database of hydropower sites in New York State (section 3).
  Identify private sector hydroelectric sites with the greatest potential for change in generation (section 4).
- Calculate generation for these screened hydroelectric sites under existing and possible future configurations (section 5).
- Examine the costs of private sector hydropower development (section 6).
- Make recommendations for additional analyses to refine the results and further assess the potential for hydropower in the State (section 7).

1.3 Previous Studies

Between 1978 and 1980, the Polytechnic Institute of New York (PINY) constructed a hydropower database of over 1,500 existing and potential dams in New York State. The database provided conceptual Levelized Cost of Energy (LCOE)[2] values for additional hydropower at existing and potential hydro developments for over 600 sites. This baseline study served as a guide for developers looking to modify existing or construct new hydropower projects (Brown and Goodman 1980).

In 2003, the Idaho National Laboratory (INL) developed a database of potential hydropower sites and prepared an accompanying report titled, “Estimation of Economic Parameters of U.S. Hydropower Resources.” The database was developed by further evaluating 352 potential projects identified in New York State in a previous (1998) study by INL. The 2003 report identified 89 sites with hydropower potential over 1 megawatt (MW) in New York State. The potential projects included “greenfield” sites (i.e., potential development sites without existing dams), existing non-powered dams, and sites with hydroelectric equipment that may have the potential to be upgraded (Hall, et al. 2003).

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2 LCOE is a metric for comparing project revenue requirements with the value of electricity produced.

In 2016, Gomez and Sullivan prepared an updated New York State hydropower database for the New York Power Authority (NYPA), which included a list of over 1,900 dams, conduits, locks, and greenfield sites. Data were compiled from multiple sources, including nationwide FERC hydropower databases and several previous nationwide and regional studies. At existing hydropower sites, the data was vetted against FERC dockets, U.S. Geological Survey (USGS) flow records, GIS imagery, and internal dam data maintained by Gomez and Sullivan (Gomez and Sullivan 2016).

In 2016, the U.S. Department of Energy (DOE) published a report on the state of hydropower in the United States. The report described the hydropower market in America, its history, as well as its generation capacity. A preliminary assessment of hydropower potential estimated that up to 48.3 GW of additional capacity could be added between 2017 and 2050 at a cost of $71 billion. The report also summarized potential changes to the regulatory process and financial incentives hydropower developers might be able to utilize to facilitate the development of hydropower.

NYSERDA’s LSR supply curve was developed using publicly available data from the United States Army Corps of Engineers (USACE), National Dam Inventory (NID), INL, the Oak Ridge National Laboratory (ORNL), and the DOE. The curve included two types of hydropower sites: upgrades to existing sites and non-powered existing dams (DPS 2016). The focus of the current Gomez and Sullivan study was to enhance the existing database of private sector hydropower potential with site-specific data that can be used to refine future LSR supply curve modeling.

2 Status of Hydropower in New York State

2.1 Types of Hydropower Sites

According to the U.S. Army Corps of Engineers' (USACE) National Inventory of Dams (NID), there are over 1,900 dams in New York State, which includes both hydropower dams as well as non-powered dams. In 2017, New York produced more hydroelectric power than any state east of the Rocky Mountains and was the 4th largest generator of hydroelectric power of all 50 states (EIA 2017). In 2016, hydropower produced 19% of New York State's electricity (NYISO 2017). Hydropower potential exists at several different types of sites, including existing hydropower dams (where there is the potential for site upgrades and capacity expansions), existing non-powered dams, as well as undeveloped greenfield sites.[3] These three types of sites are described in more detail below.

2.1.1 Existing Hydropower Dams

There are 228 FERC-regulated sites (i.e., individual dams and/or conduits) in the State. Of those, 190 are privately owned and are regulated under 159 FERC licenses or exemptions.[4] The total FERC nameplate capacity[5] for the hydropower plants in New York is approximately 6,085 MW. By the year 2030 (the year in which 70% of the State's electricity should be generated by renewables per the CES), 49 privately owned sites and approximately 272 megawatts (MW) of hydropower capacity are anticipated to be due for relicensing. Figure 1 provides a breakdown of capacity up for relicensing by five-year periods up to the year 2030.[6] The average age of the dams at these 49 FERC sites is approximately 91 years old.

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3 Hydropower potential also exists for instream/in-conduit sites, which were not included in this study as they have been addressed in previous studies.

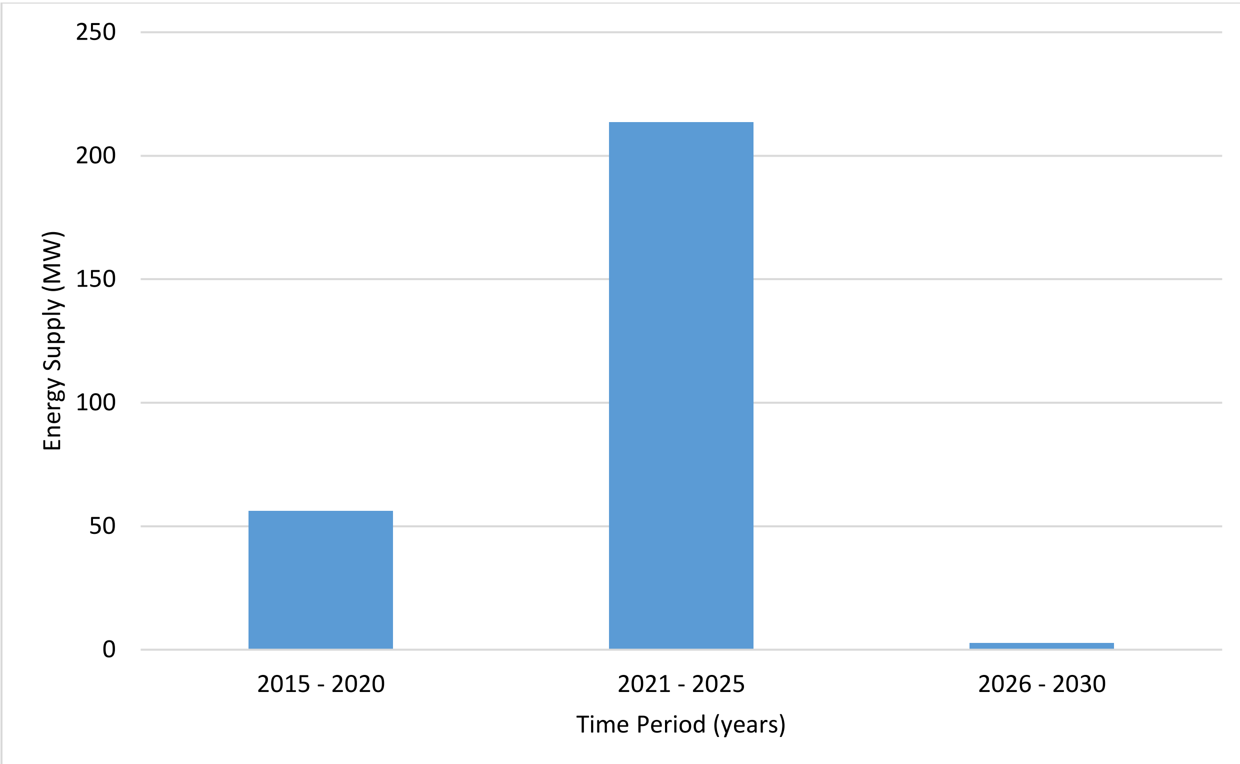
4 FERC license exemptions may be granted for projects utilizing an existing dam and generating less than 10 MW, projects utilizing natural water features for head, or projects utilizing existing conduits and generating less than 40 MW.

5 Nameplate capacity refers to the capacity labeled on the turbine-generator assembly.

6 All figures and tables are provided at the end of this report.

Figure 1. Privately Owned FERC Sites Due for Relicensing by 2030

Data source: (FERC 2015)



2.1.2 Existing Non-Powered Dams

The NID contains over 1,700 non-powered dams in New York State. These dams serve a variety of purposes, including recreation, water supply, flood protection, navigation, and fire suppression. New hydropower developments at existing dams benefit from being able to utilize the infrastructure to assist with access and water control during construction, and these types of projects are generally less capital-intensive than greenfield sites where no dam or infrastructure is present. However, adding a new powerhouse and transmission line or substation to a site does require significant initial capital investment in addition to new short- and long-term operation and maintenance costs (section 6.2 provides a more detailed description of these costs.)

2.1.3 Greenfield Sites

Greenfield sites do not have any existing dams or hydropower sites. The 2003 INL study included a list of 43 greenfield sites in New York State with a potential generating capacity of approximately 731 MW. Over half of that predicted capacity (408 MW) was expected to be generated from a single site on the Niagara River.[7] Greenfield sites require more capital expenditures than existing hydropower sites and non-powered dams, as they involve consideration of many factors prior to construction, including engineering design, FERC licensing and dam safety approvals, as well as permitting and other regulatory reviews. Initial licensing efforts at greenfield sites are also expected to receive greater scrutiny from federal and state resource agencies concerned with the potential for adverse environmental or other impacts during the construction and operation of the project.

2.2 Regulatory Issues, Impediments, and Opportunities

The Federal Energy Regulatory Commission (FERC) and other federal and state resource agencies regulate hydropower projects to ensure the safety and reliability in their construction and operation as well as to limit their impact on natural resources and habitats. The 1986 Electric Consumers Protection Act established that equal consideration must be given to power and non-power (e.g., environmental, recreational, cultural) values during the FERC licensing process (Uría-Martínez, O'Connor and Johnson 2015). New requirements are often issued as projects undergo relicensing, which typically occurs every 30 to 50 years. Environmental factors play a large role in these requirements and can have a significant impact on project operations. However, there may be opportunities to minimize the impacts of requirements imposed during relicensing on generation, as discussed in the following section.

2.2.1 Operating Regime

Most hydropower sites operate in one of two general modes: run-of-river or peaking operations. Run-of-river operations require project outflows to equal project inflows on an instantaneous basis. This mode of operation is generally favored by federal and state resource agencies involved in the FERC licensing process because the aquatic habitat surrounding the projects is typically more stable. Peaking hydropower sites operate in response to the demand for power. These sites store water behind

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7 Gomez and Sullivan investigated the validity of this generation prediction using known flow regulations on the Niagara River and the 60-foot height of the proposed dam. It is anticipated that the project would be located downstream of Niagara Falls but would not affect the Robert Moses Niagara Power Plant tailrace. Project costs would have to include altering or establishing a new treaty with Canada because the Niagara River forms a border between Canada and the United States. The generation benefits would likely be divided between the two countries (204 MW each).

their dams until it is passed downstream for generation when the price of power is higher. Requiring such sites to convert to a run-of-river mode of operation, as is often the case during relicensing of a peaking project, generally results in approximately the same generation but less revenue. However, there may be opportunities to upgrade sites that have been converted from peaking to run-of-river operation to take advantage of the lower flows typically seen by run-of-river projects and maximize generation for the new operating regime.

2.2.2 Minimum Flow Requirements

Hydropower owners may encounter additional lost generation due to an increase in the minimum flow requirements for a project during relicensing. In the 1980s, many hydropower sites were mandated to pass a minimum flow equal to a low-flow parameter known as the 7Q10[8] flow or project inflow, whichever is less, through their bypass reach[9] (if one is present) for fish passage and aquatic habitat requirements. The passage of the 1986 Electric Consumers Protection Act has forced some projects with licenses issued before 1986 to increase their bypass flows. Some projects in the northeastern United States have been required to pass flows in the range of 0.5 cubic feet per second per square mile (cf/sm)[10] based on the project drainage area, which generally produces a higher minimum flow than the 7Q10 flow. Increases in minimum flows generally reduce a hydropower site's generation as water is typically spilled over the dam. However, there is often an opportunity to install new turbine equipment that is sized smaller to generate power from the minimum flows. The impacts of minimum flow requirements on generation are highly site-specific.

2.2.3 Fish Passage and Protection Requirements

Another regulatory challenge for hydropower is the requirement to provide passage and protection sites for resident and migratory fish species. All projects in New York State require intake protection and downstream passage sites for fish species to maintain aquatic habitats. Most projects already have steel

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8 The 7Q10 is a low flow occurring over seven consecutive days that has a 10% chance of occurring each year. Historically, this is the river design flow upon which wastewater discharge amounts are determined.

9 A bypass reach is the reach of a river between a dam (or other diversion structure) and the powerhouse. When the project is generating, most of the flow may be diverted to the powerhouse. Minimum flows are often specified in the bypass reach for fish passage and aquatic habitat requirements.

10 This is based on the New England Flow Policy established by the U.S. Fish and Wildlife Service (USFWS). Typical bypass flow requirements in New York based on recent FERC licensing have been slightly lower, between 0.2 cf/sm to 0.3 cf/sm, but still typically higher than the 7Q10.

trash racks to prevent debris from entering the turbine, which may also protect many species of resident and migratory fish from entering the intakes. Many sites are now required to install trash racks with smaller, three-quarter to one-inch clear spacing to prevent entrainment. In some cases, projects are also required to install automated trash rakes to protect fish during spawning seasons.

Upstream passage structures for migratory fish species may also be required for hydropower projects located in rivers that drain to the ocean or the Great Lakes. For these structures, water must be diverted to the passage structure to attract fish to its entrance and facilitate their upstream movement around the dam. The diverted flow, which is typically unusable for generation, can be up to 3 to 5% of the station's maximum hydraulic capacity. However, for the American eel, the predominant migratory species requiring upstream passage in New York State, the upstream passage sites are smaller, less expensive, and require significantly less attraction and transport flow.

2.3 Key Stakeholders

Key stakeholders that are typically involved with FERC-regulated, private sector, hydropower projects in New York include the dam owners, FERC, the New York State Department of Environmental Conservation (DEC), the U.S. Fish and Wildlife Service (USFWS), Office of Parks, Recreation and Historic Preservation, and the public. Each of these entities is discussed in more detail below.

2.3.1 Dam Owners

Figure 2 presents the breakdown of public versus private ownership for FERC-regulated sites in New York, whereas Figure 3 presents the total nameplate capacity for public versus private sites. These two charts indicate that although only 17% of hydropower sites are publicly owned, 80% of New York State's nameplate capacity is derived from public/municipal sites. The large nameplate capacity is primarily due to several dominate sites—the Robert Moses Niagara Power Plant, the St. Lawrence-FDR Power Plant, and the Blenheim-Gilboa Pumped Storage Project—that are owned and operated by the New York Power Authority (NYPA), which is the largest public power authority in the United States. These three projects have nameplate ratings of 2,755 MW, 912 MW, and 1,160 MW, respectively. If these large public projects are not considered, approximately 92% of the State's hydropower supply is provided by privately owned sites, and the nameplate capacity of public sites is reduced to only 105 MW as shown in Figure 4.

Figure 2. Public versus Private Hydropower Ownership in New York

Data source: (FERC 2016a and 2016b)

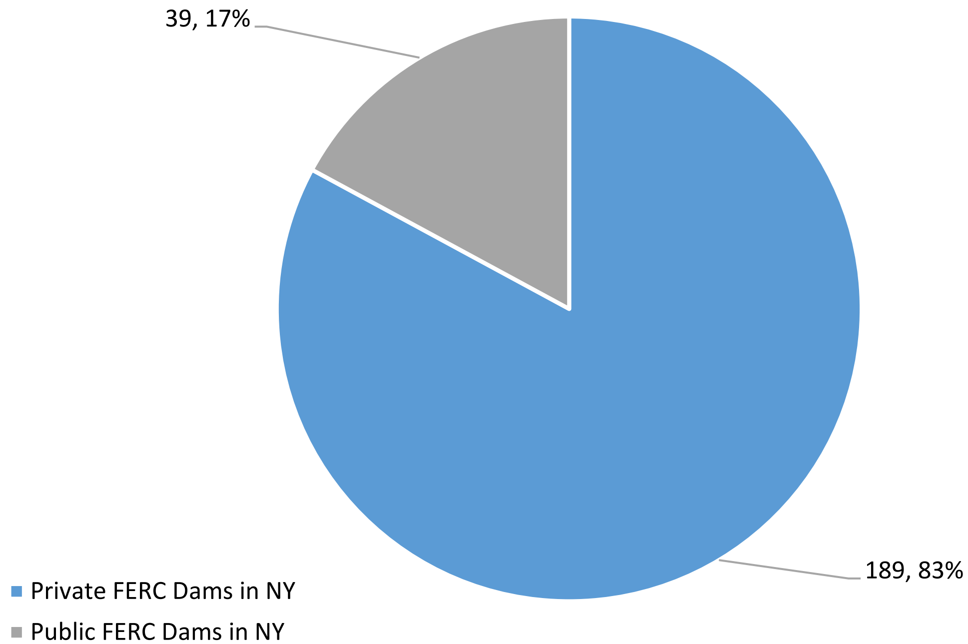


Figure 3. Public versus Private Hydropower Nameplate Capacity in New York

Data source: (FERC 2015)

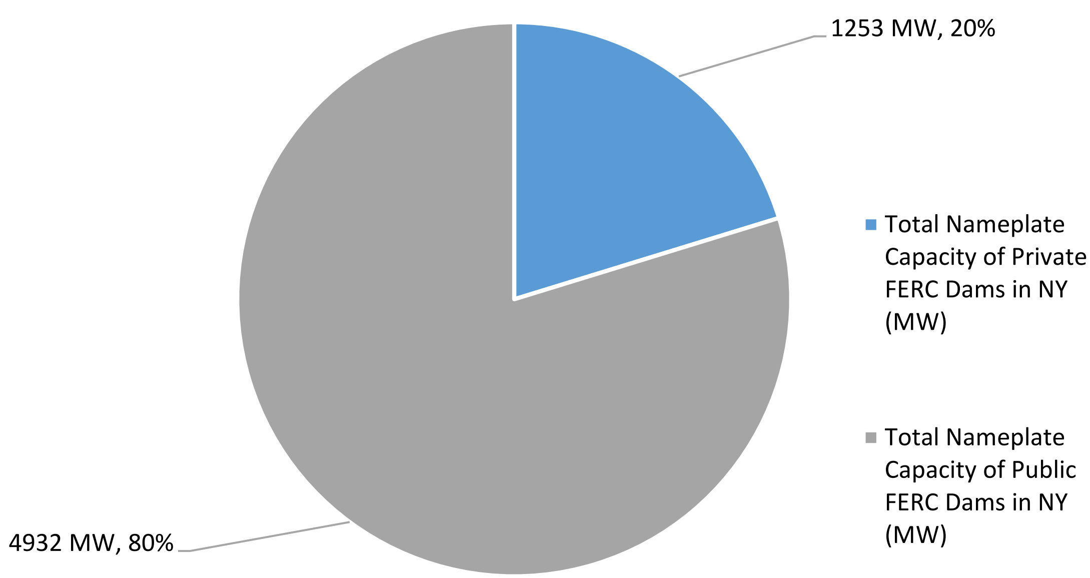
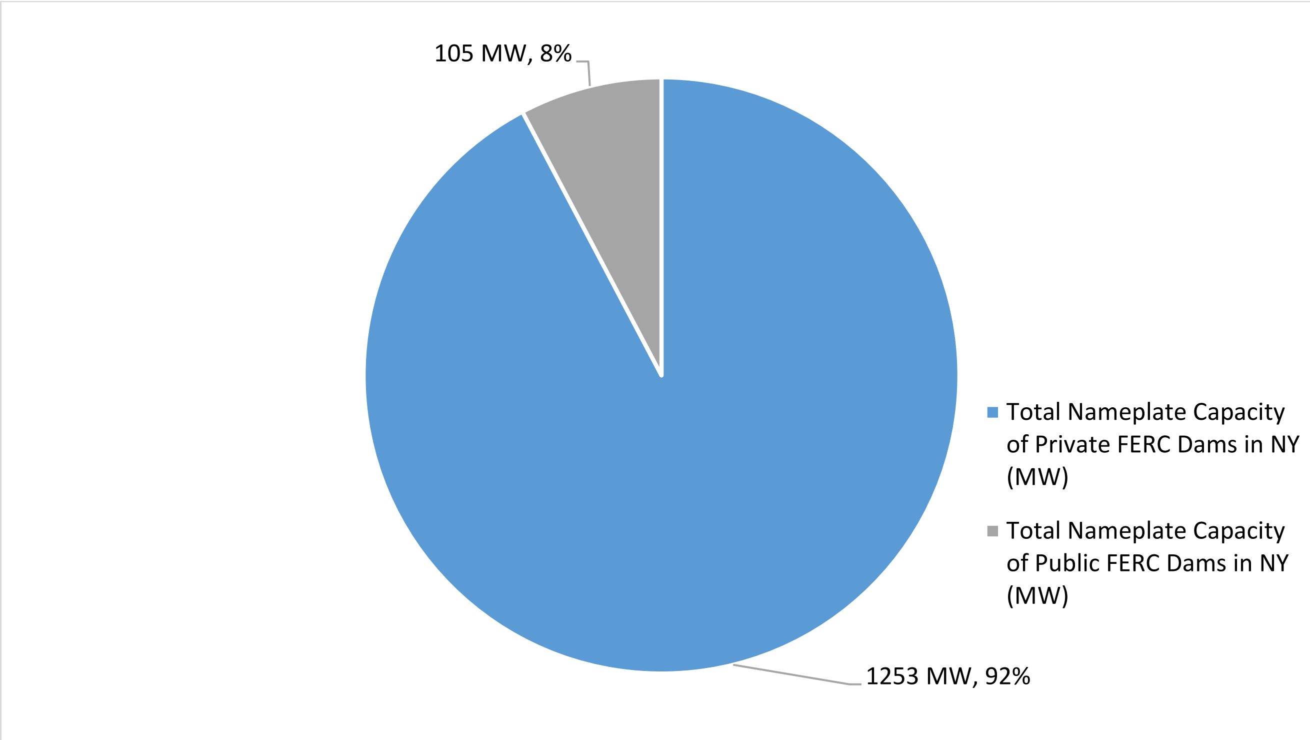


Figure 4. Public versus Private Hydropower Nameplate Capacity in New York—Adjusted

Note: Chart excludes the Niagara, St. Lawrence, and Blenheim-Gilboa Projects owned by NYPA, the largest public power authority in the US. Data source: (FERC 2016a and 2016b).



2.3.2 Federal Energy Regulatory Commission

All existing and proposed hydropower projects are required to obtain or renew a license from FERC every 30 to 50 years unless the project has obtained a license exemption. Additionally, FERC must approve any construction of or modifications to hydropower sites, such as powerhouse alterations, turbine-generator equipment replacement, or dam safety improvements. FERC-regulated projects must comply with FERC dam safety guidelines, which could lead to extensive capital costs for dam repair/rehabilitation at new hydropower projects if the dam wasn't originally designed based on FERC guidelines. Initial licensing efforts at greenfield sites are expected to receive greater scrutiny from federal and state resource agencies concerned with the potential for adverse environmental or other impacts during the construction and operation of the project.

2.3.3 New York State Department of Environmental Conservation

The DEC establishes water quality requirements, including minimum bypass flow requirements for projects through Water Quality Certificates under Section 401 of the federal Clean Water Act as a part of FERC licensing. Initial bypass flow estimates are sometimes determined using the Natural Flow Regime Method (NFRM), which is based on an analysis of monthly hydrological patterns and flow exceedance curves. For streams or rivers with existing dams, which are usually considered "altered,"[11] bypass flow requirements are ultimately determined by DEC staff using site-specific studies and professional judgement. Bypass flows are chosen to emulate the natural hydrological patterns and habitat within a river or stream (DEC 2015). Bypass flow requirements in New York State based on recent FERC licensing have been in the range of 0.2 to 0.3 cf/sm.

2.3.4 United States Fish and Wildlife Service

The USFWS advises FERC and other resource agencies on recommended environmental protections and operating regimes that hydropower owners should be responsible for implementing as a part of a project licensing or exemption. Topics of expertise include upstream and downstream fish passage, minimum flows, and sediment stabilization and aggradation upstream of the dam. As a part of the licensing process, the USFWS may develop a fish passage prescription under Section 18 of the Federal Power Act.

2.3.5 The Public

Public groups, including non-governmental organizations (NGOs), are invited to take part in FERC licensing process as well. Issues that are commonly raised by residents near a project include maintaining or enhancing recreation amenities as well as reducing the impacts of the project on aesthetic factors (e.g., noise, real estate values).

11 Altered drainage areas have over 25% of the drainage area upstream of a dam, weir, bypass, or other artificial flow modification.

2.4 Financing Incentives

Owners of larger hydropower projects may be more likely to take advantage of low-cost financing or incentives since their payback period is relatively long, whereas small, private, owners often take advantage of preferential loan arrangements and individual state incentives (Uría-Martínez, O'Connor and Johnson 2015). Several economic incentives are available to developers for improvements made at qualified hydropower sites through federal and state government programs, as discussed in more detail in the following sections.

2.4.1 Federal Tax Credits

The U.S. government encourages investment in alternative energy through federal tax subsidies such as tax credits. Some renewable technologies such as wind and solar have made significant use of federal tax incentives to justify project economics, particularly the production tax credit (PTC) and the investment tax credit (ITC). However, the hydropower industry has different eligibility requirements than other renewable industries and has experienced less of a benefit from tax credits (Uría-Martínez, O'Connor and Johnson 2015).

The production tax credit (PTC), governed by Section 45 of the Internal Revenue Code, is based on the actual production of electricity from renewable resources. Qualified hydropower projects include upgrades or efficiency improvements made to an existing hydropower dam, or new hydropower sites installed at existing non-powered dams[12]. The rebate applies to the first 10 years of a plant's operation. Existing hydropower projects can only claim credits on the incremental generation attributed to the upgrade or improvements. The PTC is only available for electricity sold to an unrelated third party. The 2005 Energy Policy Act established the eligibility of hydropower for the PTC, however only at a half value (compared to wind and geothermal) rate of $0.011 per kilowatt-hour (kWh) (Ernst & Young 2011).

The 2009 American Reinvestment and Recovery Act gave taxpayers the option to take the Section 48 business energy investment tax credit in lieu of the PTC. The ITC is a one-year tax credit based on the initial investment made in qualified renewable energy products. This is different than the PTC, which is a 10-year credit based on the production of electricity. The same eligibility rules apply to both the ITC and PTC, with the exception that the electricity does not need to be sold to a third party to be eligible for the

[12] Existing hydropower dams must have been placed into service prior to August 8, 2005 and existing non-powered dams must have been built prior to the same date, when the Energy Policy Act of 2005 was enacted.

ITC. The ITC is entirely taken up front. Since the PTC spans a 10-year period and is based on actual production, it is more volatile, which can be beneficial or detrimental depending on generation. The ITC is equal to 30% of the eligible project cost claimed in the year the site is placed into service (Ernst & Young 2011).

Federal tax credit policy has required frequent and irregular renewals, leading to uncertainty given the long lead times for hydropower project developments (Uría-Martínez, O'Connor and Johnson 2015). Most recently, the 2015 Consolidated Appropriations Act extended the expiration date of PTCs for hydropower sites to December 31, 2016 and applied it retroactively to January 1, 2015. Members of the National Hydropower Association have been lobbying the United States Congress to extend the PTCs again, but Congress has not yet approved any such measure for 2017.

2.4.2 Federal Grants and Other Incentives

Section 1603 of the 2009 American Reinvestment and Recovery Act established a grant program that provides cash grants in lieu of energy tax credits. The eligibility requirements are the same as for the PTC and ITC. Under this program, renewable energy sites can elect to take a lump sum cash payment from the U.S. Department of the Treasury (DOT) in the amount of 30% of the eligible project cost in lieu of taking the PTC or ITC. Payments issued under Section 1603 are subject to sequestration. Currently, Section 1603 grants issued between October 1, 2016 and September 30, 2017 will be reduced by 6.9% (DOT n.d.).

The 2005 Energy Policy Act established another nontax-based incentive in the form of the Section 242 hydroelectric production incentive. This incentive applies only to the installation of new generating equipment at existing dams or conduits—not efficiency or capacity upgrades. Eligible sites may receive up to 1.8 cents/kWh (indexed for inflation) with maximum payments of $750,000 per year for hydroelectric energy generated by the site during the incentive period. The program was authorized in 2005, but funding (in the amount of $3.6 million) was not allocated until fiscal year 2014. The program is contingent on continued appropriation of adequate funding by Congress, as opposed to other incentives that are administered by the U.S. Treasury. Given the relative magnitude of the Section 242 payments and their reliance on funding through annual appropriations, they are unlikely to promote substantial new development (Uría-Martínez, O'Connor and Johnson 2015).

2.4.3 Federal Bond Subsidies

Tax credits have been relatively effective in promoting private hydropower development, but do not provide incentives for public entities, which account for most of the existing hydropower capacity (over 80% in New York State and 73% nationally). However, public hydropower owners have made significant use of federal bond subsidies in lieu of their ability to leverage direct tax credits (Uría-Martínez, O'Connor and Johnson 2015).

Clean Renewable Energy Bonds (CREBs) and Qualified Energy Conservation Bonds (QECBs) are two means by which public entities can fund renewable projects at federally subsidized interest rates. Although they existed previously, the 2009 American Recovery and Reinvestment Act significantly expanded their availability. In addition to renewable energy specialty bonds, the general-use Build America Bonds created by the American Recovery and Reinvestment Act were instrumental in helping public entities finance the development of hydropower (Uría-Martínez, O'Connor and Johnson 2015). However, new applications for these bonds are no longer being accepted, as all $2.4 billion of the original bonds have been issued. CREBs may be available again in the future if some of the funds currently allocated go unused or if additional bonds are made available (DOE n.d.).

2.4.4 Renewable Energy Certificates

Renewable energy certificates (RECs) have provided some additional incentive for hydropower development. In New York State, RECs are managed under the Renewable Energy Standard (RES), which is one of two mechanisms enacted by the CES to help the State reach its clean energy goals. The RES requires utilities to procure RECs, which are produced by generators using new renewable energy resources such as hydropower—known as "Tier 1" in New York State. To meet RES load serving entity obligations, eligible generators can produce Tier 1 RECs in the New York Generation Attribute Tracking System (NYGATS). These credits can be used by load serving entities to demonstrate Tier 1 compliance (NYSERDA 2017a).

Hydropower projects eligible for participation in Tier 1 of the RES include (1) new low-impact, run-of-river developments or (2) incremental upgrades. The project must not involve any constructed new storage impoundments (NYSERDA 2017b).

For upgrade projects, only the production resulting from the incremental upgrade will be considered eligible for the RES, measured as the percentage over the historic generation baseline of average annual production. The upgrades must be significant and not simply the result of normal capital and/or operation and maintenance activities. Specifically, an upgrade project must directly result in one of the following conditions (NYSERDA 2017b):

- A material increase in the efficiency of its generation process, resulting in an increase in annual energy production of at least 5% under normal operating conditions and normal resource availability, relative to the weather-normalized annual energy production prior to the upgrade.
- An increase to the generator's nameplate capacity of at least 10% also resulting in a minimum 5% increase in annual energy production under normal operating conditions and normal resource availability, relative to the weather-normalized annual energy production prior to the upgrade.

NYSERDA issues an annual request for proposals (RFP) for Tier 1 RECs under long-term contracts. If the designated target of RECs outlined is not met, a second RFP will be issued in the same year. NYSERDA offered 56,142 Tier 1 RECs for sale in the 2017 compliance year at a cost of $21.16/MWh (NYSERDA 2017a).

3 Database Development

The first step in this project was to develop an enhanced database of all hydropower sites in New York State that includes public, private, and greenfield sites. The comprehensive database of over 1,900 sites was compiled from (1) the NID maintained by the USACE, (2) lists of hydropower projects maintained by FERC, and (3) the INL's 2003 Hydropower Resource Economic Database, as described in more detail in the following section. Information was added or updated as needed where missing or incorrect. Table 1 provides a summary of the parameters from the comprehensive database that are used in the tables throughout this report along with a description of the source of the data for each field. See associated Excel file for additional information (Comprehensive_Hydro_Database_NYS).

3.1 USACE National Inventory of Dams

The NID is a nationwide database of existing dams that is maintained by the USACE. It was most recently updated in 2016. It includes over 1,900 dams in New York State, which were used to populate the initial list of sites. This database is organized by individual dams or other water retaining structures, as opposed to overall developments or hydropower projects. The NID database provides the following parameters for each dam:

- Project Name
- Stream Name
- Owner Name
- Drainage Area
- Dam Height
- Latitude/Longitude
- Dam Purpose (hydropower, recreation, flood control, etc.)
- Dam Hazard Status
- Date Constructed

Table 1. Definitions of Hydropower Database Parameters

Parameter		Definition	Data Source	Date Accessed
No.		Site number arbitrarily assigned for this study.	N/A	N/A
Project Name		Name of the project.	FERC hydropower databases (FERC 2016)	Dec-16
FERC ID		FERC identification number.		Dec-16
Project Owner		Name of project owner.		Dec-16
Waterway		Name of the river or other waterway on which the project is located.		Dec-16
Latitude		Latitude of project.	National Inventory of Dams (USACE 2016)	Dec-16
Longitude		Longitude of project.		Dec-16
FERC Licensing Status		FERC projects are either licensed, exempt from licensing, or issued preliminary permits prior to hydropower operation.	FERC hydropower databases (FERC 2016)	Dec-16
FERC License Expiration Date		Date the FERC license or preliminary permit expires.		Dec-16
Drainage Area (mi^2)		The total area of land from which all surface water drains to the dam.	National Inventory of Dams (USACE 2016)	Dec-16
Net Head (ft)		The sum of all pressures within a hydropower facility including static pressure, friction losses, and headlosses due to miscellaneous fittings (this pressure is used to spin the hydropower equipment and generate electricity).	FERC eLibrary docket search	Dec-16
FERC Nameplate Capacity (MW)		The existing plant capacity as labeled on the turbine-generator assembly.	FERC hydropower databases (FERC 2016)	Dec-16
NYISO Zone		The designated New York Independent System Operator (NYISO) zone (1-12), which are areas of similar historical load and weather characteristics used to develop regression models and generate energy forecasts for the State.	NYISO zone maps (NYISO 2017)	Dec-16
Plant Discharge (cf/s)	*Existing*	Approximate existing hydraulic capacity for the plant based on existing documentation.	FERC hydropower databases (FERC 2016)	Dec-16
	Proposed	Approximate hydraulic capacity for the plant with proposed upgrades.	Based on flow duration analyses performed by Gomez and Sullivan using available USGS daily average streamflow data (USGS 2017)	Apr-17
Capacity (MW)	*Existing*	Existing FERC nameplate generating capacity.	FERC hydropower databases (FERC 2016)	Dec-16
	Proposed	Existing FERC nameplate generating capacity plus potential incremental capacity that could be gained by proposed upgrades.	Computed by Gomez and Sullivan	Apr-17
Average Annual Generation (MWh)	*Existing*	Average annual generation under existing conditions.		Apr-17
	Proposed	Average annual generation with proposed upgrades (also considering any losses due to anticipated increases in minimum bypass flow requirements).		Apr-17
Plant Factor (%)	*Existing*	The ratio of actual generation per year to theoretical generation per year (based on 8,760 hours of generation at nameplate capacity per year) for existing conditions.		Apr-17
	Proposed	The ratio of actual generation per year to theoretical generation per year (based on 8,760 hours of generation at nameplate capacity per year) with proposed upgrades (also considering any anticipated increases in minimum bypass flow requirements).		Apr-17
Capital Expenditure (CapEx) Costs	*2017 $/kW*	Total opinion of probable construction cost (OPCC) for proposed project upgrades per kW of incremental generation capacity.		Apr-17
	2017 $/kWh	Total OPCC for proposed project upgrades per kWh of incremental generation capacity.		Apr-17
Fixed O&M Costs (2015 $/kW)	*Existing*	Includes operation, supervision, maintenance, and engineering of associated reservoirs, appurtenant structures, waterways, and miscellaneous hydropower facilities for the site under existing conditions.	Computed by Gomez and Sullivan using the formula shown on slide 174 of the Clean Energy Standard White Paper—Cost Study (DPS 2016). Equation was based on 2015 dollars.	Apr-17
	Proposed	Includes operation, supervision, maintenance, and engineering of associated reservoirs, appurtenant structures, waterways, and miscellaneous hydropower facilities for the site with proposed upgrades.		Apr-17
Variable O&M Costs (2015 $/MWh)	*Existing*	Includes cost of water power, hydraulic expenses, electric expenses, and rents for the site under existing conditions.		Apr-17
	Proposed	Includes cost of water power, hydraulic expenses, electric expenses, and rents for the site with proposed upgrades.		Apr-17
Interconnection Construction Costs (2017 $)		OPCC for required interconnection facilities associated with proposed upgrades, if applicable.	Computed by Gomez and Sullivan	Apr-17

3.2 FERC Project Lists

The FERC maintains a list of hydropower projects for which licenses, exemptions, or preliminary permits have been issued. These lists were used to supplement and refine the NID data for existing hydropower sites. In particular, owner names were confirmed, and nameplate capacities were added to the database. Data was accessed in December 2016. The FERC lists are organized by FERC project numbers, each of which may include several individual developments and/or dams (as opposed to the NID which is organized by individual dam). The following parameters are included for each project number:

- Project Name
- Stream Name
- Owner Name
- FERC ID
- License Issued Date (if applicable)
- License Expiration Date (if applicable)
- Nameplate Power Capacity

3.3 INL Hydropower Resource Economics Database

The INL database was compiled in 2003 by further evaluating 352 potential New York projects identified in a previous (1998) INL study. The database includes greenfield sites, existing non-powered dams, and sites with hydroelectric equipment that may have the potential to be upgraded. Several sites from the INL database were included in the list of 40 upgrade sites identified by Gomez and Sullivan. The INL database provided estimates of upgrade potential (MW) and provided a check on the Gomez and Sullivan estimates of generation capacity. INL database parameters include the following:

- Project Name
- Stream Name
- Owner Name
- Latitude/Longitude
- Additional Generation Capacity
- Owner Classification (federal, municipality, private utility, etc.)
- Potential Issues (wetland protection, cultural, fish habitat, threatened and endangered wildlife areas, recreational, etc.)
- Probability of Site Development
- Estimated Costs Associated with Development (licensing and construction)
- Annual Plant Factors

4 Site Screening

Following the compilation of existing information on all hydropower sites into a single comprehensive database, additional screening (described in following passage) was performed to select the privately owned, FERC-regulated, hydropower sites with the most potential to experience a change in generation over the next 20 to 30 years.

Because the current study focuses on privately owned, FERC-regulated, hydropower sites, public hydropower sites, non-powered dams, and greenfield projects were eliminated. Eliminating these sites narrowed the initial list of over 1,900 sites down to 228 privately owned FERC-regulated sites.

The hydropower market in New York State is expected to fluctuate in part due to upcoming FERC relicensing of existing projects. FERC relicensing can have significant impacts on projects, including future minimum flow requirements, operating regime changes, required resource enhancements, and other regulatory impediments, which in turn could have significant impacts on generation in the State. For this reason, sites with licenses or exemptions expiring by the year 2030 were prioritized.[13]

Preliminary generation analyses were then conducted to evaluate projected gains or losses in average annual generation of these sites under future conditions. This information was computed using average daily average flow data from USGS gages. The preliminary analysis considered whether a site may be required to pass higher bypass and/or fish passage flows in the future, which would limit flow availability for generation purposes. Sites with predicted reductions in generation and no upgrade potential were included, whether there was potential additional generation capacity or not, to predict future trends in the existing private hydropower market more accurately.

[13] Several of the sites selected for the database have license expiration dates beyond 2030. Of these sites, projects with the largest drainage areas were prioritized, as these sites are more likely to have higher generation flows (depending on available head), and, in turn, have a greater effect on the State’s energy supply. License expiration dates for the final 40 sites selected for analysis ranged from 2019 to 2047.

In summary, sites were screened and prioritized as follows:

1. Selected only existing hydropower sites (i.e., eliminate non-powered dams and greenfield sites).
2. Selected only privately-owned sites (i.e., eliminated publicly owned sites).
3. Prioritized sites with FERC licenses or exemptions expiring by the year 2030 (though several sites have licenses expiring beyond that date, up to the year 2047).
4. Selected only sites with projected gains or losses in average annual generation under anticipated future conditions.

Following this screening process, the initial, comprehensive, database was reduced to 40 privately owned, FERC-regulated, hydropower sites with the highest potential for upgrade or expansion. These 40 sites were used to refine future LSR supply curve modeling and are collectively referred to as the LSR database. The final selection of prioritized sites is presented in Figure 5 and Table 2. These sites were advanced to the detailed generation analysis as discussed in section 5. See associated Excel file for additional information (Selected40_Hydro_Database_NYS).

Figure 5. Map of Private Sector Hydropower Sites Selected for Analysis

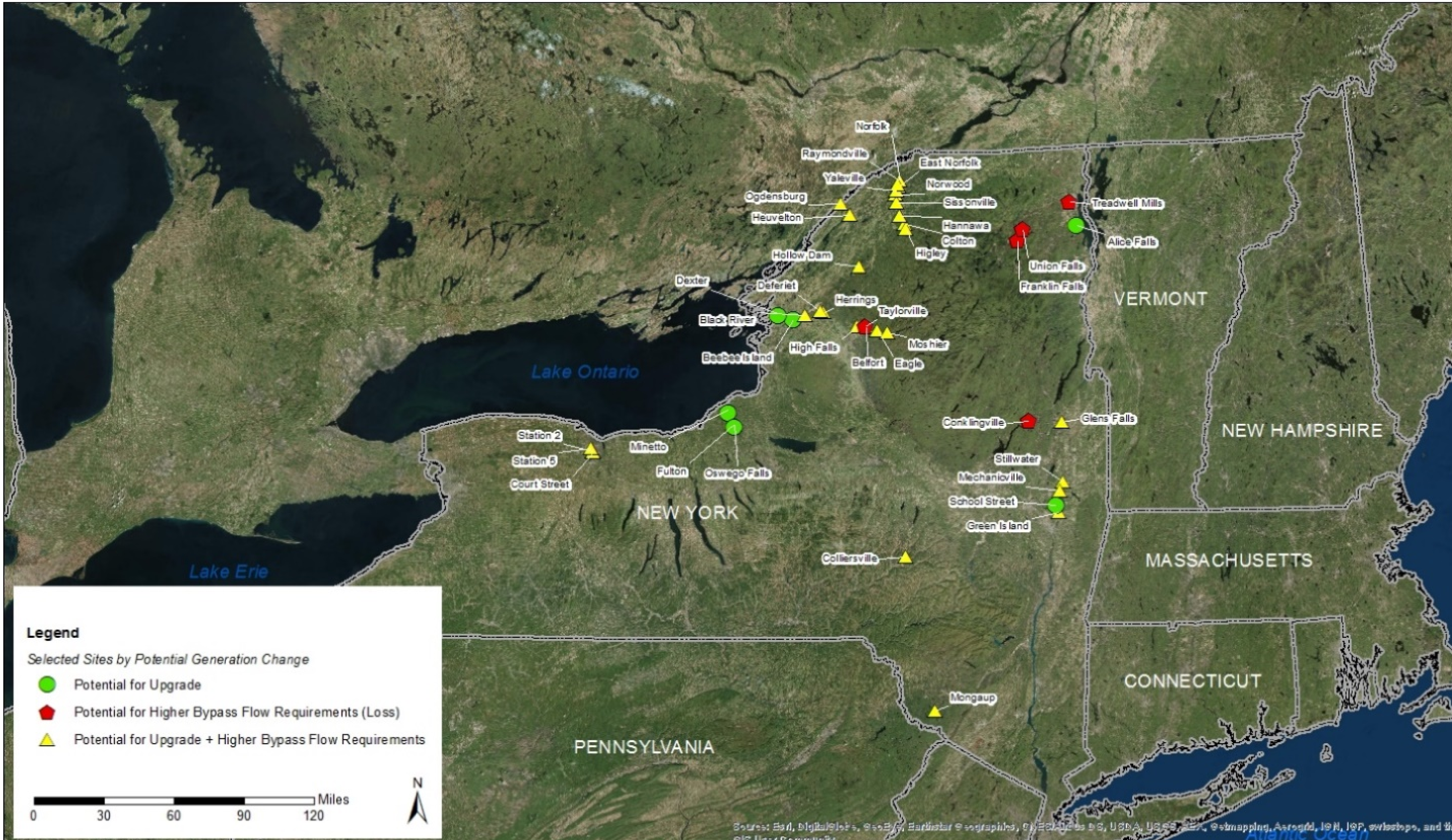


Table 2. Private Sector Sites Selected for Hydropower Generation Analysis

No.	Project Name	FERC ID[a]	Project Owner[a]	Waterway[a]	Latitude[a]	Longitude[a]	FERC Licensing Status[a]	FERC License Expiration Date[a]	Drainage Area (mi^2)[a]	Net Head (ft)[a]	FERC Nameplate Capacity (MW)[a]	NYISO Zone[b]
POTENTIAL MAIN POWERHOUSE UPGRADE PROJECTS												
1	Alice Falls[c]	5867	Alice Falls Hydro LLC	Ausable River	43.4403	-75.2064	License Issued	9/30/2023	448	50	1.9	D
2	Belfort	2645	Brookfield Renewable Energy	Beaver River	43.9267	-75.2883	License Issued	7/31/2026	252	48	2.0	E
3	Eagle	2645	Brookfield Renewable Energy	Beaver River	44.6694	-73.5075	License Issued	7/31/2026	224	132	6.1	E
4	Moshier	2645	Brookfield Renewable Energy	Beaver River	43.2853	-75.1531	License Issued	7/31/2026	182	196	8.0	E
5	High Falls	2645	Brookfield Renewable Energy	Beaver River	43.0864	-73.4956	License Issued	7/31/2026	267	100	4.8	D
6	Dexter	2695	Enel Green Power North America	Black River	44.0061	-76.0458	Exemption Issued	Exempt	1900	14	4.3	E
7	Beebee Island[c]	2538	Brookfield Renewable Energy	Black River	44.6694	-73.5075	License Issued	11/30/2026	1876	32	8.0	E
8	Herrings	2569	Brookfield Renewable Energy	Black River	43.4825	-73.7986	License Issued	11/30/2026	1810	20	5.4	E
9	Black River	2569	Brookfield Renewable Energy	Black River	43.0525	-74.9865	License Issued	11/30/2026	1856	33	6.0	E
10	Court Street	2584	Rochester Gas & Electric Corp.	Genesee River	43.1522	-77.6097	License Issued	9/30/2037	2450	25	3.0	B
11	Station 2	2582	Rochester Gas & Electric Corp.	Genesee River	43.1603	-77.6132	License Issued	1/31/2036	2467	86	14.8	B
12	Station 5	2583	Rochester Gas & Electric Corp.	Genesee River	43.1763	-77.6282	License Issued	1/31/2036	2467	130	45.7	B
13	Stillwater	4684	Gravity Renewables	Hudson River	44.5156	-75.7893	License Issued	4/30/2027	3745	9	3.5	F
14	Glens Falls	2385	Niagara Mohawk Power Corp. & Finch, Pruyn And Co.	Hudson River	43.3058	-73.6410	License Issued	10/31/2041	2807	16	12.1	F
15	Mechanicsville	6032	Albany Engineering	Hudson River	42.8800	-73.6767	License Issued	5/31/2043	4572	23	4.5	E
16	Green Island	13	Green Island Power Authority	Hudson River	42.7517	-73.6867	License Issued	7/31/2062	8090	18	6.0	F
17	School Street[c]	2539	Brookfield Renewable Energy	Mohawk River	42.7967	-73.7150	License Issued	1/31/2047	3456	92	38.8	F
18	Mongaup	10481	Eagle Creek Renewable Energy	Mongaup River	43.3044	-75.1431	License Issued	3/31/2022	180	110	4.0	G
19	Colliersville	2788	Enel Green Power North America	N. Br. Susquehanna River	43.8867	-75.1086	License Issued	2/28/2019	351	35	1.5	E
20	Heuvelton	2713	Brookfield Renewable Energy	Oswegatchie River	44.6178	-75.4050	License Issued	12/31/2052	995	14	1.0	E
21	Ogdensburg	9821	Algonquin Power	Oswegatchie River	42.5036	-74.9850	License Issued	5/31/2027	1592	19	3.7	E
22	Minetto	2474	Brookfield Renewable Energy	Oswego River	43.4000	-76.4725	License Issued	10/31/2044	5092	15	8.0	F
23	Oswego Falls	5984	Brookfield Renewable Energy	Oswego River	43.3147	-76.4158	License Issued	2/29/2036	5121	17	7.4	E
24	Fulton	2474	Brookfield Renewable Energy	Oswego River	43.3241	-76.4198	License Issued	10/31/2044	5018	15	1.3	E
25	Sissonville	9260	Albany Engineering	Raquette River	43.9261	-75.3739	License Issued	4/30/2028	1025	16	2.3	E
26	Yaleville	9222	Brookfield Renewable Energy	Raquette River	44.7667	-74.9983	License Issued	1/31/2022	1046	13	0.7	E
27	Raymondville	2330	Brookfield Renewable Energy	Raquette River	44.8339	-74.9806	License Issued	12/31/2033	1077	22	2.5	E
28	Norwood	2330	Brookfield Renewable Energy	Raquette River	44.7433	-75.0053	License Issued	12/31/2033	1045	21	2.0	E
29	Higley	2320	Brookfield Renewable Energy	Raquette River	44.5303	-74.9319	License Issued	12/31/2033	979	43	6.3	E
30	Hannawa	2320	Brookfield Renewable Energy	Raquette River	44.6119	-74.9750	License Issued	12/31/2033	993	72	7.2	E
31	Colton	2320	Brookfield Renewable Energy	Raquette River	44.5550	-74.9400	License Issued	12/31/2033	981	262	30.1	E
32	Hollow Dam	6972	Hollow Dam Power Co.	W. Br. Oswegatchie River	44.8457	-74.2807	License Issued	4/30/2026	276	21	1.1	E
POTENTIAL MINIMUM FLOW UNIT UPGRADE PROJECTS *(in response to anticipated bypass flow requirements)*												
33	Deferiet	2569	Deferiet Corp.	Black River	43.9783	-75.6150	License Issued	11/30/2026	1817	46	10.8	E
34	Norfolk	2330	Brookfield Renewable Energy	Raquette River	44.8022	-74.9906	License Issued	7/31/2026	1063	41	5.6	E
35	East Norfolk	2330	Brookfield Renewable Energy	Raquette River	44.7947	-74.9864	License Issued	12/31/2033	1063	29	4.0	E
PROJECTS WITH NO UPGRADE POTENTIAL *(only losses due to anticipated bypass flow requirements)*												
36	Taylorville	2645	Brookfield Renewable Energy	Beaver River	43.0933	-73.4950	License Issued	7/31/2026	251	97	4.8	E
37	Conklingville	2318	Brookfield Renewable Energy	Sacandaga River	43.3175	-73.9242	License Issued	8/31/2042	1044	53	20.0	F
38	Franklin Falls	4472	Union Falls Hydropower & Erie Boulevard Hydropower	Saranac River	43.6167	-75.3056	License Issued	6/30/2024	291	53	2.3	E
39	Treadwell Mills	4114	Lower Saranac Hydro Partners LP	Saranac River	44.7667	-74.9983	License Issued	5/31/2027	604	70	9.3	D
40	Union Falls	4472	Union Falls Hydropower & Erie Boulevard Hydropower	Saranac River	44.5189	-73.4647	License Issued	6/30/2024	329	60	3.0	E

Table notes on the next page

(a) Data obtained from previously developed databases. See metadata (Table 3-1) for more details.

(b) Data obtained from NYISO. See metadata (Table 3-1) for more details.

(c) No new minimum bypass flow requirements are anticipated for these sites. Sites were selected by prioritizing privately owned, FERC-regulated hydropower projects with licenses or exemptions expiring primarily by 2030 and with projected gains or losses in average annual generation under anticipated future conditions.

5 Generation Analysis

A spreadsheet-based energy generation model was developed to assess the power capacity and average annual generation of each of the 40 selected privately owned, FERC-regulated, sites under existing and anticipated future conditions. The model was used to compare the existing (termed “baseline”) versus potential future generation estimates to determine which factors contributed to the generation totals. The model was developed on a daily time-step using various inputs as described below.

5.1 Model Inputs

5.1.1 Flow

Hydrology for each site was based on daily average streamflow data from nearby USGS gages. Flow data was prorated by a ratio of the dam drainage area to the USGS gage drainage area for each project.[14] USGS gages with less than 30 years[15] were avoided to develop more accurate hydrology and limit the effects of extreme weather patterns, which could cause the model to either overestimate or underestimate potential hydropower generation.

The analysis considered existing or potential future requirements for minimum bypass flows, which include flows for aquatic habitat as well as fish passage, if applicable. To be conservative, these flows were deemed unavailable for generation purposes. For the existing conditions analysis, project minimum bypass flow requirements were researched through the FERC eLibrary. If requirements were not clear from available documents, bypass flow requirements from nearby FERC sites were prorated using the dam drainage areas. For projects with no bypasses, fish passage flow requirements were increased to 5% of the powerhouse discharge capacity. For projects with bypasses, year-round bypass flow requirements were increased to 0.4 cf/sm (the average of the typical New York State and New England maximum requirements).[16]

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[14] The New York Streamflow Estimation Tool (NYSET) software developed by the USGS and NYSERDA may be required for more detailed hydrology estimates as part of future feasibility studies of individual sites.

[15] The current Bulletin 17B guidelines recommend using a minimum of 10 years of systematic stream flow data to perform statistical analyses (USGS 1982).

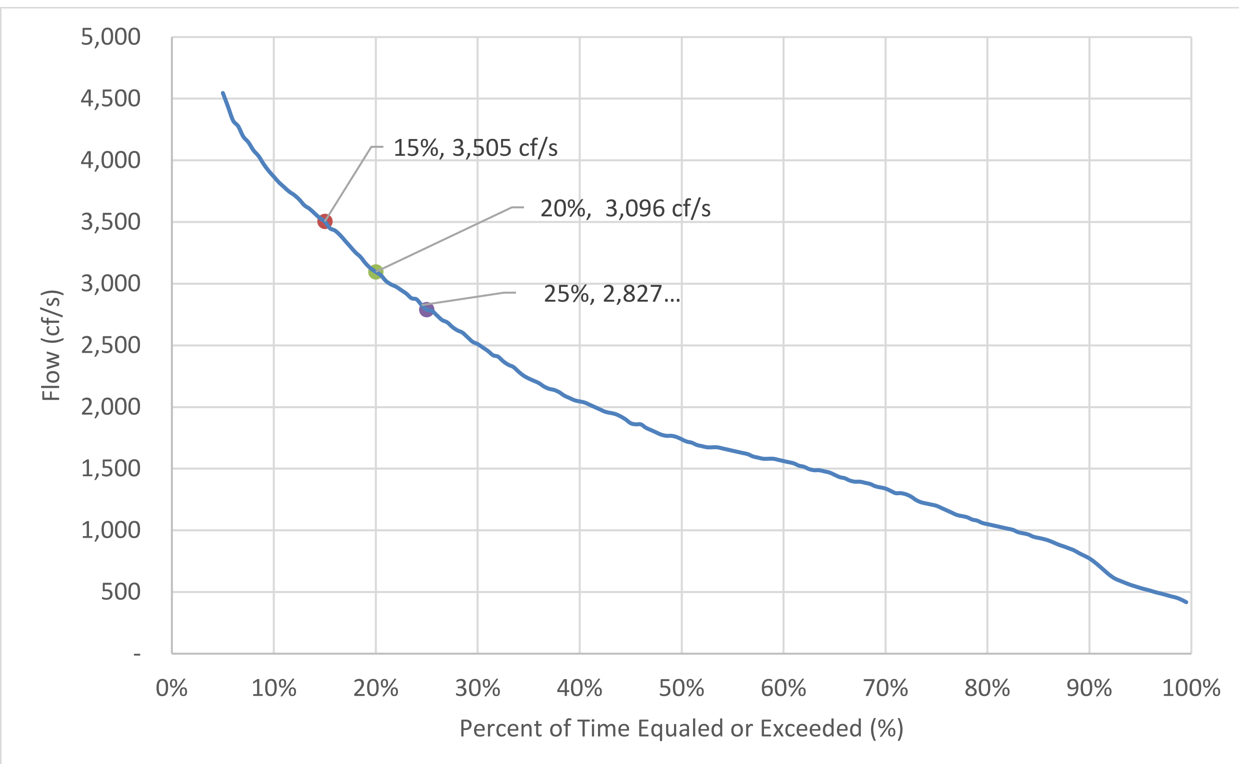
[16] The bypass flow reduction was used alone rather than adding in any potential fish passage flows as well because fish passage flows typically count toward bypass flows in most cases.

5.1.2 Turbine Discharge

The existing and proposed turbine discharges (or hydraulic capacities) for each site were based on annual flow duration curves developed using the prorated average daily flow datasets for the period of the streamflow gage's record. For this study, it was assumed the maximum hydraulic capacity for each plant was equal to the inflow into the project that is equaled or exceeded 20% of the time. Hydropower projects typically have maximum hydraulic capacities in the range of the 15 to 25% exceedance values on the annual flow duration curve. An example annual flow duration curve for a generic site is provided in Figure 6 to demonstrate this method. The 20% exceedance value was applied in all generation analyses unless previous FERC filings for that particular project suggested that other hydraulic capacities are possible.

Figure 6. Example of Flow Duration Curve Analysis

Note: This curve represents inflow into an entire project, not just flow into the powerhouse. Data source: (USGS 2017)



Determining the optimum design discharge for a hydropower site requires a detailed analysis of the site's flow duration curve. Larger units with higher maximum hydraulic capacity also typically have higher minimum hydraulic capacity. A larger turbine has a higher nameplate generating capacity (MW) but it may generate less energy on an annual basis (megawatt-hours, MWh) than it would with a smaller turbine. This is because the turbine will not operate continuously, as flows may drop below the turbine's minimum flow capacity. This is particularly the case if low flows below the turbine's minimum flow capacity occur frequently. For this reason, larger turbines are not always preferable from a total energy perspective.

Minimum flows for turbines also depend on the type of turbine. For planning purposes, minimum flows for Francis turbines are approximately 40% of their maximum hydraulic capacity, whereas Kaplan turbines can have minimum flows as low as 20% of their hydraulic capacity. For example, both turbines at a plant can discharge a maximum of 100 cf/s but the Francis unit will only operate at acceptable efficiencies under flows between 40 to 100 cf/s whereas the Kaplan unit will operate between 20 to 100 cf/s. The actual low end of the operating range will depend on turbine design characteristics and maintenance. Standard operating procedures advise against running Francis and Kaplan turbines below 40 and 20% of their maximum hydraulic capacity, respectively, due to extremely low efficiencies and the potential for issues with vibrations and/or cavitation.[17]

5.1.3 Net Head

Net head is typically provided in FERC licenses or other FERC filings. If no net head information was available, the gross head was used in its place. For these cases, headloss computations are recommended for future studies to determine the effects of minor and friction headlosses on a project's generation capability.

5.1.4 Efficiency

Francis and Kaplan turbine efficiency curves from previous engineering studies and vendor data maintained by Gomez and Sullivan were used in the energy model to calculate the theoretical generation at a given site more accurately. The efficiency of a turbine varies depending on the head at the project[18] and the percentage of hydraulic capacity passed. Francis turbines have steeper

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[17] Cavitation refers to the formation of bubbles in the water flowing through a turbine which can lead to pitting and damage of the turbine parts.

[18] These curves were based on the maximum design head values for projects.

efficiency curves and much lower efficiencies at lower flows. Kaplan turbines have a flatter efficiency curve and are efficient over a wider range of flows. The corresponding discharge at the high point of the efficiency curve (peak efficiency) is referred to as “best gate” discharge. For flows below or above the best gate discharge, the efficiency of the turbine decreases.

To produce electricity, turbines that are turned by water spin the generators to which they are connected. Turbine vendors provide some generator information, although they do not often provide generator efficiencies. For the energy model, a constant 95% generator efficiency was applied over the range of flows to all power calculations.

The efficiency curves for this study were incorporated in the calculations as if each site only had one turbine. For more detailed analyses in the future, composite efficiency curves could be developed to optimize the use of flow at sites with multiple turbines.

5.2 Generation

The following equation was used along with the input parameters described above to calculate daily power generation for each site under existing and proposed conditions:

Equation 1 $$P = (H_{net} \times Q \times E)/11.8$$

where:

- P = Power Generation (kilowatts, kW)
- H_{net} = Net Head (feet, ft), or Reservoir Elevation—Tailwater Elevation—Headlosses (ft)
- Q = Flow Available for Generation up to Turbine Discharge (cubic feet per second, cf/s)
- E = Composite Turbine/Generator Efficiency (%)
- 11.8 = Conversion Factor

Specifically, for each site, an annual flow duration curve was developed based on average daily flows, as described in section 5.1.1. The area under the flow duration curve was then calculated within the plant’s maximum and minimum turbine discharge range, accounting for any flows not available due to minimum bypass flow requirements. The resulting area was then converted to energy using the equation above and the net head and efficiency.

The resulting daily power generation was used to calculate annual generation for each site under existing and proposed conditions using the following equation:

Equation 2 $$G = P \times D \times H \times (1 - T)$$

where:

- G = Generation (kWh)
- P = Power Generation (kW)
- D = Number of Days Operating per Year (assumed 365 days per year)
- H = Number of Hours Operating per Day (assumed 24 hours per day)
- T = Percentage of Time Powerhouse is Inoperable (%) (assumed 5%)[19]

5.3 Data Verification

The existing flow, net head, and efficiency for each site were evaluated and verified using publicly available FERC filings such as licenses/exemptions, pre-application documents (PADs),[20] and/or license/exemption amendments.[21]

The flow, net head, and efficiency data obtained through site-specific sources was used to calibrate the energy model for the existing or baseline condition by trying to match the published FERC nameplate generation capacity. Then, average annual generation estimates obtained from FERC documents were used to check the model's flow allocation for accuracy. Once these two values were verified, the model was ready for modification based on anticipated future operations.

19 All generation totals assume that the powerhouses will be inoperable 5% of the time due to scheduled (maintenance) and unscheduled (unforeseen) outages.

20 A PAD is a document prepared by project owners undergoing relicensing to summarize existing information on the project.

21 Licensees or exemptees must file for approval of any changes to the existing license or exemption between relicensing periods.

5.4 Upgrade Alternatives

If the flow duration curves demonstrated that additional flow could be allocated for generation purposes, three upgrade alternatives were considered: (1) the expansion of existing powerhouses and the installation of an additional turbine, (2) the replacement of existing turbine components and intakes to increase discharge capacity for the existing powerhouse, or (3) the installation of a minimum flow turbine at projects with bypasses where flow requirements may increase due to future environmental regulations. These alternatives are discussed in more detail in the following passages.

5.4.1 Powerhouse Expansions

The expansion of existing powerhouses was considered for sites where there appeared to be sufficient space to accommodate the larger footprint of an expanded powerhouse. FERC dams are required to pass a certain flood flow over their spillways (the inflow design flood [IDF]), and since spillway capacity is a function of spillway length, any encroachment on an already short spillway within a narrow valley could cause dam safety issues for a project. Spillway capacities were not calculated as part of this study, but a qualitative assessment was performed to evaluate whether each site might be able to accommodate a powerhouse expansion.

For projects with ample space, the type of additional turbine (e.g., Francis or Kaplan) to be added was chosen based on the types of turbines currently installed. Similar turbine types and sizes were proposed where possible, since multiple turbines of the same size and model can offer benefits such as limiting the spare parts required at the powerhouse for miscellaneous equipment maintenance. Future analyses could involve evaluating the suitability of various turbine types at each site and selecting the best fit.

5.4.2 Runner Replacements/Intake Modifications

For powerhouses with potential incremental capacity, the increase in discharge for the existing turbines was limited to 15% of current discharge capacity. Typically, hydropower sites maintain flow velocities in the range of 10 to 12 feet per second (fps)[22] (DOI 1987). This prevents significant headlosses and vibration from occurring within the conduits, manifolds, and appurtenant sites. Increasing the discharge

[22] Not all penstocks are designed for flow velocities of 10 to 12 fps.

approximately 33%. It was assumed that for increases over 15%, significant intake modifications would be required to lower headlosses and flow velocities in the system; therefore, the increase in discharge at these sites was limited to 15%.

5.4.3 Minimum Flow Turbines

Minimum flow turbines were investigated for projects where there was additional hydraulic capacity or where bypass flows might increase significantly in the future. At projects where minimum flow turbines had been recently installed it was assumed that FERC had recently mandated minimum flows at the site and that no additional flows could be captured. No generation analysis was performed at these sites.

5.5 Results

Figure 7 and Figure 8 present the range and magnitude of anticipated incremental capacities and incremental average annual generation. Table 3 and Table 4 provide the detailed capacity and generation statistics for the 40 selected sites.

One of the statistics used to measure the efficiency of a project is the plant factor. Plant factors describe how much generation is actually being produced in comparison to the theoretical generation at a site based on its nameplate capacity and the amount of time it should be operational. Typical plant factors for hydropower sites vary between approximately 0.4 and 0.6. Outliers were checked for validity.

Figure 7. Range of Potential Incremental Capacities for Sites Studied

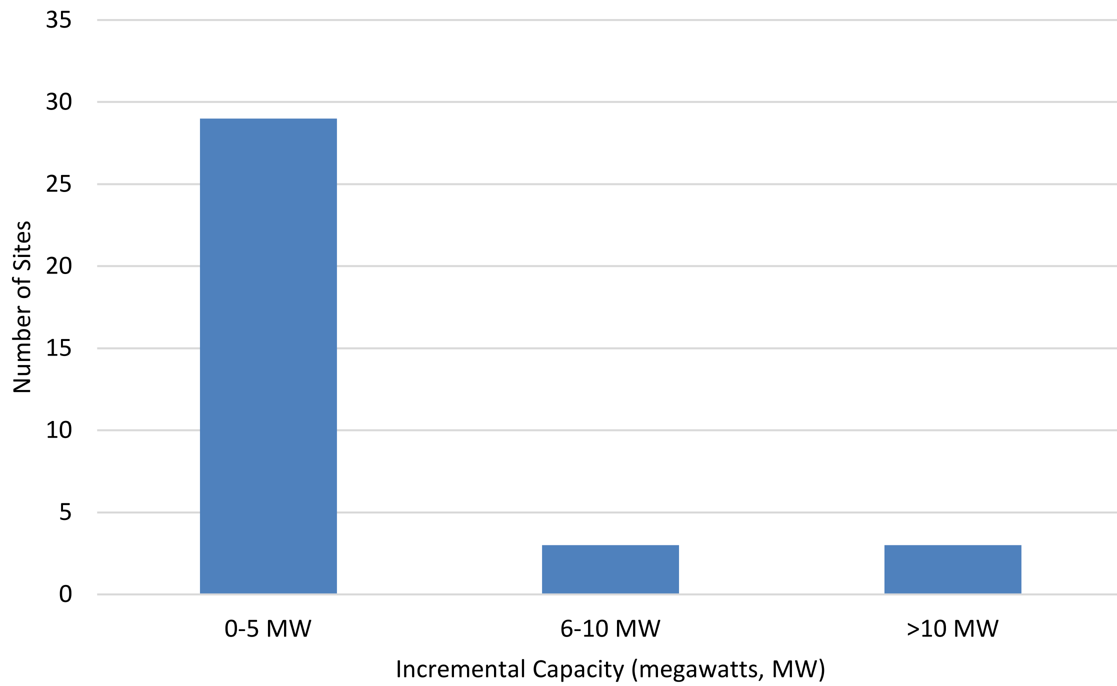


Figure 8. Range of Potential Incremental Generation for Sites Studied

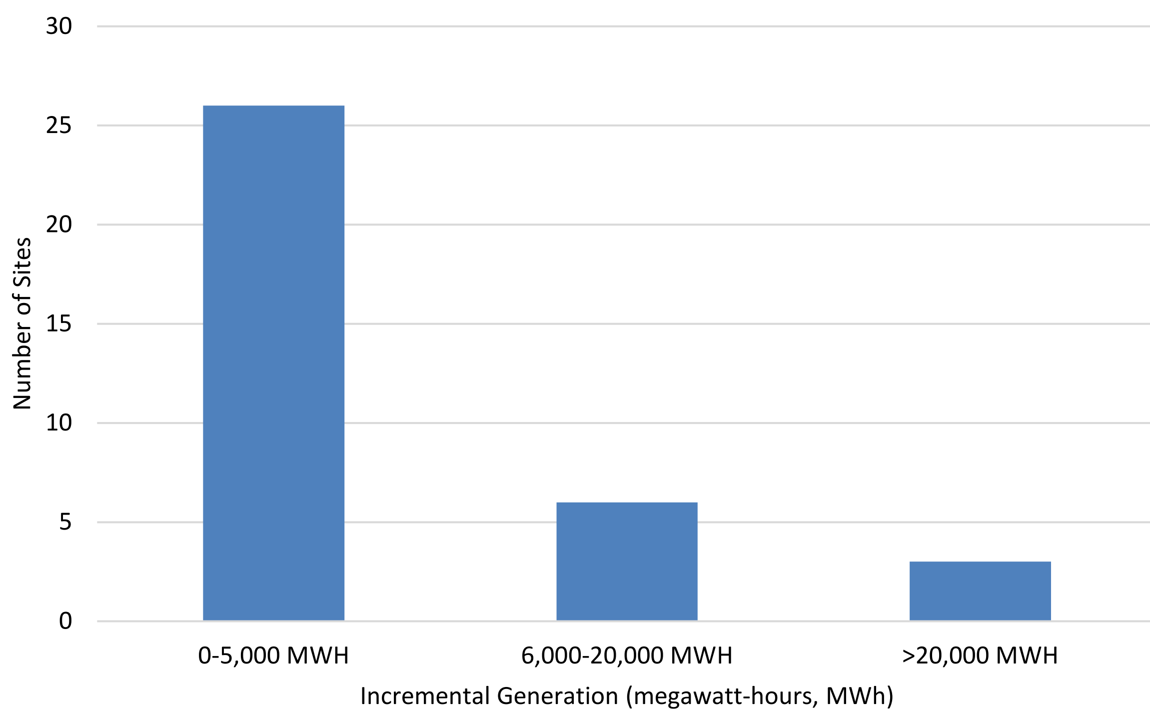


Table 3. Existing and Proposed Plant Capacities of Selected Private Sector Hydropower Sites

No.	Project Name	Net Head (ft)[a]	Plant Discharge (cf/s)		Capacity (MW)	
			Existing[a]	*Proposed*[b,c]	*Existing*[a]	*Proposed*[b]
POTENTIAL MAIN POWERHOUSE UPGRADE PROJECTS						
1	Alice Falls[d]	50	530	610	1.9	2.2
2	Belfort	48	590	690	2.0	2.4
3	Eagle	132	630	680	6.1	6.6
4	Moshier	196	560	660	8.0	9.4
5	High Falls	100	660	900	4.8	6.5
6	Dexter[d]	14	4,250	4,700	4.3	4.8
7	Beebee Island[d]	32	3,440	4,140	8.0	9.6
8	Herrings	20	3,810	5,080	5.4	7.2
9	Black River	33	2,500	3,340	6.0	8.0
10	Court Street	25	1,650	2,750	3.0	5.0
11	Station 2	86	2,370	3,490	14.8	21.8
12	Station 5[d]	130	4,840	5,720	45.7	54.1
13	Stillwater[d]	9	5,600	7,800	3.5	4.9
14	Glens Falls	16	10,410	12,260	12.1	14.3
15	Mechanicsville	23	2,690	12,870	4.5	21.5
16	Green Island	18	4,490	35,920	6.0	48.0
17	School Street[d]	92	5,810	7,450	38.8	49.8
18	Mongaup	110	500	620	4.0	5.0
19	Colliersville[e]	35	570	870	1.5	2.2
20	Heuvelton	14	1,020	1,530	1.0	1.6
21	Ogdensburg[d]	19	2,660	3,730	3.7	5.1
22	Minetto[d]	15	7,470	8,630	8.0	9.2
23	Oswego Falls[d]	17	5,960	9,220	7.4	11.4
24	Fulton	15	1,150	5,300	1.3	5.8
25	Sissonville	16	1,980	2,970	2.3	3.5
26	Yaleville	13	740	2,290	0.7	2.2
27	Raymondville	22	1,630	3,190	3.1	5.0
28	Norwood	21	1,340	3,090	2.0	4.6
29	Higley[d]	43	2,020	3,010	6.3	9.4
30	Hannawa	72	1,380	2,070	7.2	10.8
31	Colton[d]	262	1,580	2,010	30.1	38.3
32	Hollow Dam[d]	21	700	890	1.1	1.4
POTENTIAL MINIMUM FLOW UNIT UPGRADE PROJECTS *(in response to anticipated bypass flow requirements)*						
33	Deferiet	46	3,230	4,377	10.8	12.8
34	Norfolk	41	2,000	2,425	5.6	6.5
35	East Norfolk	29	2,000	3,146	4.0	4.6
PROJECTS WITH NO UPGRADE POTENTIAL (only losses due to anticipated bypass flow requirements)						
36	Taylorville	97	680	NA	4.8	NA
37	Conklingville	53	3,030	NA	20.0	NA
38	Franklin Falls	53	580	NA	2.3	NA
39	Treadwell Mills	70	1,830	NA	9.3	NA
40	Union Falls	60	690	NA	3.0	NA

(a) Data obtained from previously developed databases. See metadata (Table 3-1) for details.

(b) Data generated by Gomez and Sullivan based on preliminary research and desktop investigations.

(c) Approximate hydraulic capacities based on existing project documentation and flow duration analyses performed by Gomez and Sullivan using available USGS average daily streamflow data (USGS 2017).

(d) No new minimum bypass flow requirements are anticipated for these sites.

(e) Colliersville includes both the installation of a new 770 kW turbine at the main powerhouse and a new 200 kW minimum flow turbine.

Table 4. Generation Analysis Results of Selected Private Sector Hydropower Sites

No.	Project Name	Capacity (MW)		Main Powerhouse Energy Gains and Losses Average Annual Generation (MWh)			Bypass Energy Losses and Gains Average Annual Generation (MWh)			Total Energy Gain or (Loss) (MWh) A + B	Plant Factor (%)	
		Existing[a]	*Proposed*[b]	*Existing Energy*	*Proposed Energy*	***A - Net Energy Gain @ Main PH***	*Energy Loss Due to Increase in Bypass Flow*	*Energy Gain due to Bypass Flow Unit*[d]	***B - Net Energy Gain (or Loss) due to Increase in Bypass Flow***[e]		*Existing*[b]	*Total*[b,f]
POTENTIAL MAIN POWERHOUSE UPGRADE PROJECTS												
1	Alice Falls	1.9	2.2	12,120	13,384	1,264	0	0	0	1,264	71%	68%
2	Belfort	2.0	2.4	12,287	13,511	1,224	(1,899)	0	(1,899)	(675)	69%	50%
3	Eagle	6.1	6.6	30,966	31,201	235	(3,467)	0	(3,467)	(3,232)	58%	48%
4	Moshier	8.0	9.4	33,707	34,955	1,248	(3,457)	0	(3,457)	(2,209)	48%	38%
5	High Falls	4.8	6.5	26,223	29,347	3,124	(3,956)	0	(3,956)	(832)	62%	43%
6	Dexter	4.3	4.8	24,073	25,301	1,228	0	0	0	1,228	64%	60%
7	Beebee Island	8.0	9.6	54,580	60,256	5,676	0	0	0	5,676	78%	72%
8	Herrings	5.4	7.2	32,902	36,093	3,191	(1,173)	0	(1,173)	2,018	70%	58%
9	Black River	6.0	8.0	41,666	48,273	6,607	(6,327)	0	(6,327)	280	79%	63%
10	Court Street	3.0	5.0	19,131	28,530	9,399	(2,708)	0	(2,708)	6,691	73%	55%
11	Station 2	14.8	21.8	81,941	103,783	21,842	(11,950)	0	(11,950)	9,892	63%	47%
12	Station 5	45.7	54.1	201,883	220,968	19,085	0	0	0	19,085	50%	47%
13	Stillwater	3.5	4.9	26,788	29,230	2,442	0	0	0	2,442	87%	69%
14	Glens Falls	12.1	14.3	54,200	58,157	3,957	(4,393)	0	(4,393)	(436)	51%	42%
15	Mechanicsville	4.5	21.5	36,518	88,536	52,018	(917)	0	(917)	51,101	93%	44%
16	Green Island	6.0	48.0	39,368	147,362	107,994	(271)	0	(271)	107,723	75%	34%
17	School Street	38.8	49.8	188,551	212,477	23,926	0	0	0	23,926	55%	49%
18	Mongaup	4.0	5.0	9,096	9,667	571	(150)	0	(150)	421	26%	22%
19	Colliersville[c]	1.5	2.2	6,601	8,204	1,603	(1,359)	1507	148	1,751	52%	43%
20	Heuvelton	1.0	1.6	7,204	9,071	1,867	(303)	0	(303)	1,564	79%	63%
21	Ogdensburg	3.7	5.1	16,440	19,469	3,029	0	0	0	3,029	51%	43%
22	Minetto	8.0	9.2	41,095	43,724	2,629	0	0	0	2,629	59%	54%
23	Oswego Falls	7.4	11.4	41,879	55,597	13,718	0	0	0	13,718	65%	56%
24	Fulton	1.3	5.8	4,139	13,686	9,547	(698)	0	(698)	8,849	38%	22%
25	Sissonville	2.3	3.5	11,930	15,389	3,459	(1,448)	0	(1,448)	2,011	59%	45%
26	Yaleville	0.7	2.2	5,653	12,286	6,633	(568)	0	(568)	6,065	92%	52%
27	Raymondville	3.1	5.0	17,994	24,300	6,306	(987)	0	(987)	5,319	66%	44%
28	Norwood	2.0	4.6	14,884	21,061	6,177	(2,111)	0	(2,111)	4,066	85%	44%
29	Higley	6.3	9.4	37,217	42,989	5,772	0	0	0	5,772	67%	52%
30	Hannawa	7.2	10.8	50,009	60,464	10,455	(905)	0	(905)	9,550	79%	62%
31	Colton	30.1	38.3	187,034	210,541	23,507	0	0	0	23,507	71%	63%
32	Hollow Dam	1.1	1.4	5,056	5,488	432	(867)	0	(867)	(435)	54%	46%
POTENTIAL MINIMUM FLOW UNIT UPGRADE PROJECTS *(in response to anticipated bypass flow requirements)*												
33	Deferiet	10.8	12.8	64,084	64,084	0	(14,046)	16,523	2,477	2,477	68%	59%
34	Norfolk	5.6	6.5	37,226	37,226	0	(6,332)	7,415	1,083	1,083	76%	67%
35	East Norfolk	4.0	4.6	26,074	26,074	0	(4,063)	5,111	1,048	1,048	74%	67%
PROJECTS WITH NO UPGRADE POTENTIAL *(only losses due to anticipated bypass flow requirements)*												
36	Taylorville	4.8	NA	24,500	24,500	0	(2,257)	0	(2,257)	(2,257)	59%	53%
37	Conklingville	20.0	NA	46,494	46,494	0	(8,926)	0	(8,926)	(8,926)	27%	21%
38	Franklin Falls	2.3	NA	8,964	8,964	0	(3,159)	0	(3,159)	(3,159)	45%	29%
39	Treadwell Mills	9.3	NA	33,312	33,312	0	(8,141)	0	(8,141)	(8,141)	41%	31%
40	Union Falls	3.0	NA	14,857	14,857	0	(4,147)	0	(4,147)	(4,147)	57%	41%

Table notes are on the next page

(a) Data obtained from previously developed databases. See metadata (Table 3-1) for details.

(b) Data generated by Gomez and Sullivan based on preliminary research and desktop investigations.

(c) Colliersville includes both the installation of a new 770 kW turbine at the main powerhouse and a new 200 kW minimum flow turbine.

(d) Sites with increases in nameplate capacity (MW) and losses in net generation were deemed unsuitable for new minimum flow units due to preliminary investigations of constructability issues based on available aerial imagery, elevation, and flow data.

(e) All of the minimum flow turbine upgrades achieved net energy gains by capturing more available flows at the higher end of their respective flow duration curves.

6 Cost Analysis

An analysis was conducted to examine the costs of hydropower development at each of the 40 sites. The analysis included the estimation of (1) opinions of probable construction costs (OPCCs) and (2) operation and maintenance (O&M) costs, which consist of both fixed and variable costs. Each of these metrics are discussed in more detail in the following passages.

6.1 Opinions of Probable Construction Cost

6.1.1 Methodology

Opinions of probable construction costs (OPCCs) were developed for all sites in the LSR database except for those with anticipated future reductions in generation only. The OPCCs were based on feasibility study cost estimates and construction costs for projects previously completed by Gomez and Sullivan. In some cases, where proposed upgrades were discussed in previous FERC license applications, cost data provided in Exhibit D (Costs and Financing) of the license application were escalated using the Engineering News Record (ENR) historical construction cost index.[23] Costs for runner replacements and proposed turbines and generators were based on data obtained from equipment vendors for previous studies. Intake structure, powerhouse, substation, and transmission line costs were based on internal information and R.S. Means Construction Cost Data. All OPCCs are provided in Appendix A included the following factors:

- Ten percent of construction costs for mobilization/demobilization costs.
- Forty percent of the sum of construction and mobilization/demobilization costs for contingencies.
- Ten percent of the total cost (including contingencies) for engineering and administration.
- Five percent of the total cost (including contingencies) for full-time construction management.

The OPCCs did not consider costs to acquire land or land rights, licensing fees, dam safety capital expenditures, or legal fees. For project upgrades, it was assumed that the improvements would be constructed within the site owner's property. Capital costs associated with implementing and maintaining required improvements related to fish passage, recreation, aesthetics, or other resources were also not included in the OPCCs.

[23] The ENR historical indices combine historical construction costs for cement, lumber, steel, and labor rates into single numbers which can be used to approximate escalation rates for construction costs between two dates occurring since 1908.

Interconnection costs were not included in every OPCC. These costs were only assumed to be required for upgrade projects where the proposed total nameplate capacity of a plant increased and exceeded one of the existing electrical load thresholds presented in Table 5. For example, a site being upgraded from 1 MW to 4.5 MW would not require transmission line upgrades or associated costs, but a plant upgrading from 4.5 MW to 5.1 MW would incur interconnection costs. The relationship between the kilovolt and power ratings in Table 5 is described by a set of average values for projects equal to or less than 20 MW.[24] For projects exceeding 20 MW, additional information would be required to estimate transmission needs.

Table 5. Required Transmission Line Rating Based on Project Size

Maximum Electrical Load / Project Nameplate Capacity (MW)[a,b]	**Required Transmission Line Rating** (kV)
0.55	2.40
1.00	4.16
5.00	13.80
15.00	34.50
20.00	46.00

(a) Without single-line electrical drawings and extensive electrical background on the 40 selected sites, it was assumed that the projects have a single transmission line and feeder. Electrical loads can vary depending on the number and length of lines.

(b) The values in the table assume the connection is made on the main line of a circuit, not a branch.

6.1.2 Capital Expenditure Costs

The OPCCs and the generation estimates from the generation analysis were used to compute capital expenditure, or "CapEx," costs to assess the economic viability of the proposed upgrades. CapEx costs were calculated in two different forms: (1) capital expenditures cost per installed capacity ($/kW) and (2) capital expenditures cost per kilowatt-hour of generation ($/kWh).

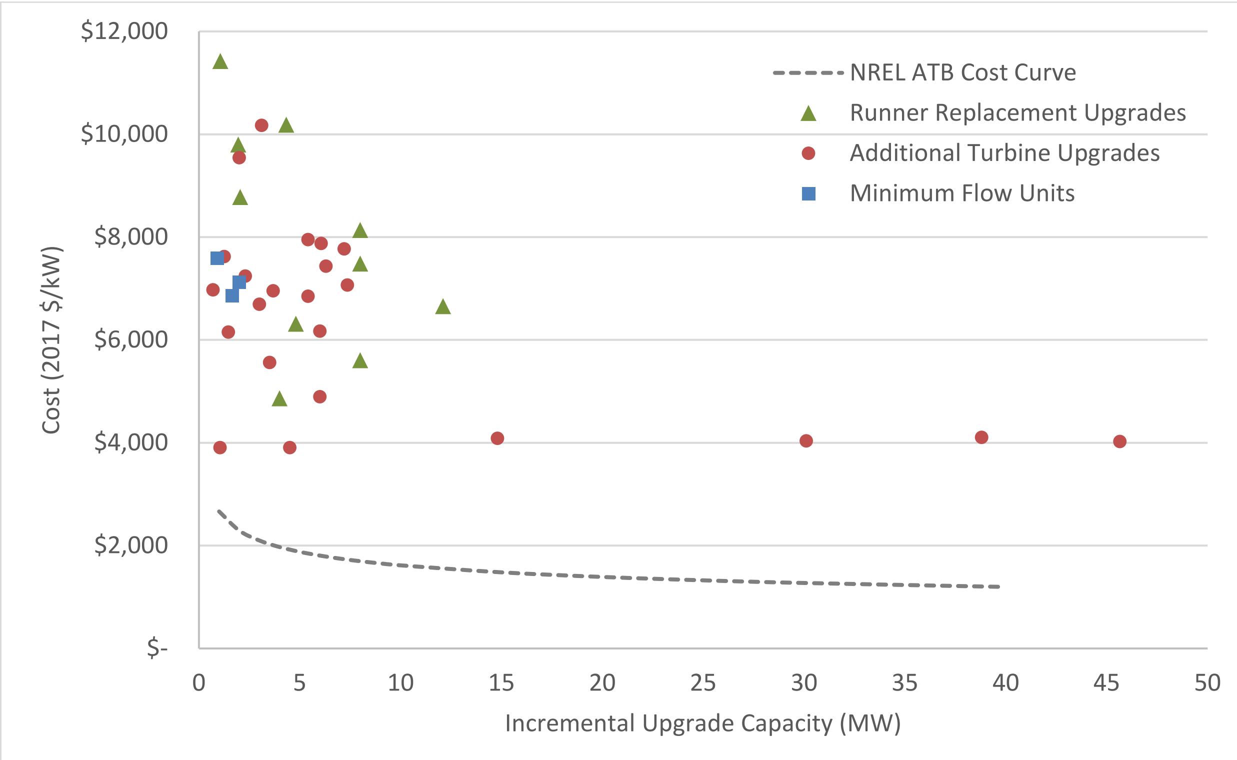
Values of capital expenditures cost per installed capacity calculated for the 40 sites in the LSR database are plotted in Figure 9. The costs range from $3,900 to $11,400/kW (2017 dollars). Developers typically consider investing in projects with capital expenditures between $2,000 and $6,000/kW (Uría-Martínez, O'Connor and Johnson 2015). There are nine sites within this range shown in Figure 9 and in the LSR database. According to the 2017 Annual Energy Outlook provided by the U.S. Energy Information

[24] The table assumes that the connection is made on the main line of a circuit, not a branch.

Administration (EIA), the overnight cost[25] to develop a 500-MW hydropower plant in Upstate New York and in the United States in general are $2,639/kW and $2,442/kW, respectively.

Figure 9. Installed Cost ($/kW) of Proposed Upgrades as a Function of Project Size

Data source for NREL ATB Cost Curve: (DPS 2016)

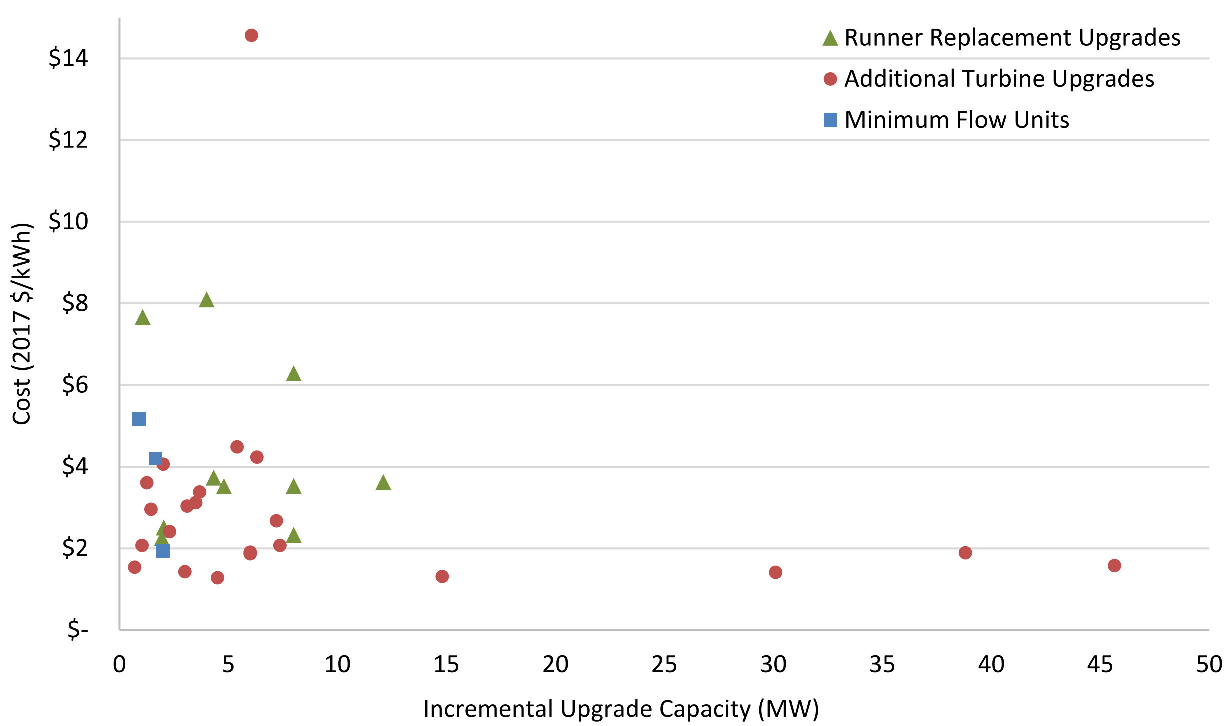


Values of capital expenditures cost per kilowatt-hour of generation calculated for the 40 sites in the LSR database are plotted in Figure 10. The costs range from $1.28 to $56.41/kWh (2017 dollars). Economically feasible projects typically have capital costs less than $1.00/kWh. There are 11 sites between $1.00 and $2.00/kWh shown in Figure 10 and in the LSR database. There doesn't appear to be a pattern to the relationship between the upgrade capacity and the cost per kilowatt-hour. The lack of a relationship is typical, as the generation for two projects of the same size can vary considerably based on the net head and flow availability at each project.

25 Overnight cost is the cost of a construction project if no interest was incurred during construction, as if the project was completed "overnight."

The OPCCs were compared to results from the National Renewable Energy Laboratory (NREL), which prepared an Annual Technology Baseline (ATB) study in 2015. The ATB study provided a cost curve, which is also plotted in Figure 9 along with the capital expenditures costs per installed capacity for the LSR hydropower sites. The ATB curve included costs for turbine equipment installation, interconnection, labor, and financing. Figure 9 shows that costs based on the ATB curve were, at a minimum, $2,000/kW less than the corresponding OPCCs. Since each project is significantly different from the others, no equation could be developed to represent the trend of the OPCC costs. The OPCCs and ATB curve do follow a similar pattern in that it generally costs less per kilowatt to develop larger upgrade projects. Projects with runner upgrades cost more since the upgrade in nameplate capacity was generally smaller.

Figure 10. Installed Cost ($/kWh) of Proposed Upgrades as a Function of Project Size



6.2 Operation and Maintenance Costs

NYSERDA provided formulas used to determine fixed and variable operation and maintenance (O&M) costs based on previous analyses using data developed by the INL.

6.2.3 Fixed Costs

Fixed O&M costs include operation, supervision, maintenance, and engineering of associated reservoirs, appurtenant structures, waterways, and miscellaneous hydropower facilities. Fixed O&M costs include major capital maintenance costs to including generator rewinds and turbine overhauls every 25 – 30 years. These costs can vary between $300,000 to $500,000 for each turbine/generator package. The equation for fixed O&M costs is provided below.[26] Costs for fixed O&M in the LSR database range from approximately $12/kw to $30/kw[27].

Equation 6.2.1-1 Fixed O&M Costs (2017 $/kW) = $(29.263 \times P^{-0.247}) \times 1.04^2$

Source: (DPS 2016)

where:

- P = Daily Power Generation (MW)

6.2.4 Variable Costs

Variable O&M costs include the cost of water power, hydraulic expenses, electric expenses, and rents. The equation for variable costs is provided below.[23] Costs for variable O&M in the LSR database range from approximately $2.81/kw to $5.91/kw[28].

Equation 6.2.2-1 Variable O&M Costs (2017 $/kW) = $(6.2817 \times P^{-0.202}) \times 1.04^2$

Source: (DPS 2016)

where:

- P: Daily Power Generation (MW)

The economic analysis results for the 40 LSR database sites are presented in Table 6.2-1.

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26 The provided fixed cost equation was based on the use of 2015 dollars, so the cost was escalated at an inflation rate of 4% per year to 2017 dollars.

27 The EIA energy outlook uses the reported generation in MWh to measure fixed O&M costs at hydropower projects. The EIA energy outlook for 2017 indicates that the fixed O&M costs for a 500-MW conventional hydropower plant would be approximately $15/MWh. Based on correspondence with dam owners, it seems that small or remote hydro facilities can have fixed O&M costs between $10/MWh and $55/MWh.

28 The EIA energy outlook uses the reported generation in MWh to measure variable O&M costs at hydropower projects. The EIA energy outlook for 2017 indicates that the variable O&M costs for a 500-MW conventional hydropower plant would be approximately $3/MWh.

Table 6. Cost Analysis Results

No.	Project Name	Capital Expenditure (CapEx) Costs[a]		Fixed O&M Costs (2015 $/kW)[b]		Variable O&M Costs (2015 $/MWh)[b]		Interconnection Construction Costs (2017 $)[a]
		2017 $/kW	*2017 $/kWh*	*Existing*	*Proposed*	*Existing*	*Proposed*	
POTENTIAL POWERHOUSE UPGRADE PROJECTS								
1	Alice Falls[c]	$9,797	$2.25	$24.84	$24.00	$5.49	$5.34	$0.00
2	Belfort	$8,780	$2.51	$24.54	$23.60	$5.44	$5.27	$0.00
3	Eagle	$6,848	$14.57	$18.76	$18.40	$4.37	$4.30	$0.00
4	Moshier	$5,606	$6.29	$17.51	$16.83	$4.13	$3.99	$0.00
5	High Falls	$6,314	$3.52	$19.86	$18.40	$4.58	$4.30	$212.64
6	Dexter	$10,187	$3.73	$20.38	$19.89	$4.67	$4.58	$0.00
7	Beebee Island[c]	$8,140	$2.32	$17.51	$16.73	$4.13	$3.98	$0.00
8	Herrings	$7,952	$4.49	$19.29	$17.97	$4.47	$4.22	$0.00
9	Black River	$6,168	$1.87	$18.80	$17.51	$4.37	$4.13	$0.00
10	Court Street	$6,692	$1.42	$22.31	$19.66	$5.03	$4.54	$50.00
11	Station 2	$4,084	$1.31	$15.04	$13.67	$3.64	$3.37	$14.29
12	Station 5	$4,025	$1.77	$11.39	$10.92	$2.90	$2.81	$0.00
13	Stillwater	$5,559	$3.12	$21.48	$19.79	$4.88	$4.56	$0.00
14	Glens Falls	$6,659	$3.62	$15.81	$15.18	$3.80	$3.67	$0.00
15	Mechanicsville	$3,906	$1.28	$20.18	$13.72	$4.64	$3.38	$5.88
16	Green Island	$4,896	$1.90	$18.80	$11.25	$4.37	$2.87	$2.38
17	School Street[c]	$4,102	$1.89	$11.85	$11.15	$3.00	$2.85	$0.00
18	Mongaup	$4,864	$8.10	$20.78	$19.71	$4.75	$4.55	$0.00
19	Colliersville	$7,990	$4.49	$26.70	$24.03	$5.83	$5.35	$100.00
20	Heuvelton	$7,431	$2.07	$28.98	$26.22	$6.23	$5.74	$0.00
21	Ogdensburg	$6,956	$3.38	$21.22	$19.53	$4.83	$4.51	$68.03
22	Minetto	$7,486	$3.53	$17.51	$16.90	$4.13	$4.01	$0.00
23	Oswego Falls	$7,066	$2.07	$17.87	$16.05	$4.20	$3.84	$0.00
24	Fulton	$7,618	$3.61	$27.69	$18.98	$6.00	$4.41	$22.12
25	Sissonville	$7,241	$2.41	$23.82	$21.55	$5.31	$4.89	$0.00
26	Yaleville	$6,973	$1.53	$31.96	$24.19	$6.75	$5.38	$68.49
27	Raymondville	$10,175	$3.03	$22.13	$19.68	$5.00	$4.54	$0.00
28	Norwood	$9,541	$4.06	$24.66	$20.04	$5.46	$4.61	$0.00
29	Higley	$7,875	$4.23	$18.57	$16.83	$4.33	$3.99	$0.00
30	Hannawa	$7,769	$2.68	$17.97	$16.26	$4.22	$3.88	$0.00
31	Colton	$4,033	$1.41	$12.62	$11.89	$3.16	$3.01	$0.00
32	Hollow Dam	$11,424	$7.67	$28.84	$27.17	$6.21	$5.91	$0.00
POTENTIAL MINIMUM FLOW UNIT UPGRADE PROJECTS *(in response to anticipated bypass flow requirements)*								
33	Deferiet	$7,119	$1.94	$16.26	$15.59	$3.88	$3.75	$31.25
34	Norfolk	$7,589	$6.31	$19.10	$18.42	$4.43	$4.30	$0.00
35	East Norfolk	$8,468	$4.85	$20.78	$20.07	$4.75	$4.62	$166.67
PROJECTS WITH NO UPGRADE POTENTIAL *(only losses due to anticipated bypass flow requirements)*								
36	Taylorville	NA	NA	$21.52	NA	$4.96	NA	NA
37	Conklingville	NA	NA	$15.10	NA	$3.71	NA	NA
38	Franklin Falls	NA	NA	$25.88	NA	$5.76	NA	NA
39	Treadwell Mills	NA	NA	$18.25	NA	$4.33	NA	NA
40	Union Falls	NA	NA	$24.13	NA	$5.44	NA	NA

Table notes are on the next page

a) Data generated by Gomez and Sullivan based on preliminary research and desktop investigations.

b) O&M costs computed using the formula shown on slide 174 of the Clean Energy Standard White Paper - Cost Study (DPS 2016). Equation was based on using 2015 dollars; cost was raised at an inflation rate of 4% to 2017 dollars.

c) No new minimum bypass flow requirements are anticipated for these sites.

7 Summary & Recommendations

Table 7 presents a summary of the generation and cost analyses for all sites combined. The table shows that for the 40 sites included in this study, the potential net change in average annual generation is approximately 270,000 MWh. This includes both proposed powerhouse and minimum flow turbine upgrades as well as generation losses for projects with no upgrade potential that are anticipated to have a future increase in minimum bypass flow requirements. The total capital expenditure cost associated with the proposed upgrades is approximately $767 million. In 2015 New York State generated approximately 139 million MWh. The potential increase in generation from developing these sites would increase the State's renewable energy generation by approximately 0.2% (EIA 2017).

Table 7. Summary of Generation and Cost Analysis Results for Selected Private Sector Sites

Scenario	Average Annual Generation (MWh)	Capital Expenditure Costs (2017 $)
Existing Conditions	1,628,693	$0
Powerhouse Upgrade Projects[a]	360,165	$734,484,100
Minimum Flow Turbine Upgrade Projects[a]	30,556	$33,338,800
Projects with No Upgrade Potential[b]	-100,985	$0
NET CHANGE	1,918,382	$766,856,900

(a) Incremental gain in generation.

(b) Incremental loss in generation due to new bypass flow requirements.

The hydropower fleet in New York State includes a wide variety of infrastructure, owners, and stakeholders. The goal of this report was to provide a more accurate depiction of what the future may hold for the private hydropower industry in the State based on generation and cost analyses for the 40 privately owned, FERC-regulated, sites which are most likely to experience changes in annual generation within the next 20 to 30 years. The results from this study do not include publicly owned hydropower sites or sites that have not yet been developed, and therefore do not necessarily correlate directly to other segments of the New York State hydropower market other than privately owned, existing hydropower sites.

7.1 Potential Additional Analysis

Although project-specific data was obtained for each site, it was beyond the scope of this study to determine the feasibility of hydropower development at each location. If a site-specific feasibility study of one or more sites is pursued, the following recommendations for further analysis should be considered.

- **Previous Feasibility Studies**—To evaluate the potential for future powerhouse expansions or upgrades, private utility owners should be contacted to verify and update project data and provide any previous feasibility studies, if available. Previous studies could identify fatal flaws regarding upgrade or expansion projects and limit the amount of work spent on projects with minimal potential.
- **Regulatory Review**—Potential regulatory requirements that may be imposed by FERC for project development should be evaluated in more detail based on current license/exemption requirements and surrounding project licenses/exemptions. Areas in which additional regulatory requirements could be imposed may include fish passage, public recreation, historical/archeological resources, and dam safety.
- **Dam Safety**—For detailed site assessments, an attempt should be made to obtain dam safety records that are not publicly available in the FERC eLibrary, as potential dam safety issues may preclude a site from development. Supporting Technical Information Documents (STIDs) or FERC Part 12 inspection documentation may indicate whether a project has any fatal flaws. In particular, spillway capacity should be analyzed if a proposed powerhouse layout would expand further into a waterway. The results of these calculations may limit the alternatives for redevelopment at a site based on a project's ability to safely pass large flood events.
- **Conceptual Drawings**—Conceptual project drawings are recommended for future studies. Drawings developed from publicly available topographic data and powerhouse dimensions provide a basis for hydropower equipment selection and OPCCs at the conceptual level. Using conceptual schematics, turbine manufacturers can determine the appropriate equipment for a given site and develop preliminary quotes. The quotes are then used to develop OPCCs, which play a significant role in estimating capital costs associated with the powerhouse upgrades or expansions. Sources utilized to develop powerhouse schematics may include FERC Exhibit F Drawings,[29] tape/survey measurements from site visits, and FERC one-line electrical diagrams to assess current powerhouse interconnection sites.
- **Economic Analyses—**To assess the economic viability of hydropower projects, a net present value (NPV) cash flow analysis may be warranted to consider the time-value of money. These analyses include engineering and capital costs, energy generated, price of power, annual O&M, O&M capital expenditures such as generator rewinds and turbine repairs, escalation rates, and discount rates. Other potential factors to consider in NPV cash flow analyses include potential equipment salvage values and REC prices. Salvage values are applied at the end of an object's expected useful life (i.e., a turbine or generator). For turbines and generators, the useful life is commonly assumed to be 50 years. As mentioned above, REC prices aren't always available, but they can help to shorten the payback period for a project. The length of the NPV analysis may vary between 30 to 50 years depending on developer cash flows.

[29] Exhibit F drawings contain Critical Energy Infrastructure Information (CEII) and are not publicly available but may be made available to developers with a dam owner's permission.

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Appendix A. Opinions of Probable Construction Cost

Beebee Island - Opinion of Probable Construction Cost - Replacement of Two Vertical Kaplan Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$744,500	**$744,500**
331	**Powerplant Structures and Improvements**[4]	1	LS	$1,198,000	**$1,198,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$5,772,000	**$5,772,000**
334	**Accessory Electric Equipment**[4]	1	LS	$475,000	**$475,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$0	**$0**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$8,189,500**
Contingencies (40%)[5]	$3,276,000
Total Direct Cost[6]	**$11,466,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$1,147,000
Full Time Construction Management (5%)[8]	$573,000
Total	**$13,186,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of two vertical Kaplan runners rated at 9.62 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Belfort - Opinion of Probable Construction Cost - Replacement of Three Horizontal Francis Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$173,500	**$173,500**
331	**Powerplant Structures and Improvements**[4]	1	LS	$190,000	**$190,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$1,434,000	**$1,434,000**
334	**Accessory Electric Equipment**[4]	1	LS	$111,000	**$111,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$0	**$0**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$1,908,500**
Contingencies (40%)[5]	$763,000
Total Direct Cost[6]	**$2,672,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$267,000
Full Time Construction Management (5%)[8]	$134,000
Total	**$3,073,000**

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of three horizontal Francis runners rated at 2.39 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Black River - Opinion of Probable Construction Cost - One New Vertical Francis Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$696,500	**$696,500**
331	**Powerplant Structures and Improvements[4]**	1	LS	$1,479,000	**$1,479,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$1,678,000	**$1,678,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$2,772,000	**$2,772,000**
334	**Accessory Electric Equipment[4]**	1	LS	$586,000	**$586,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$0	**$0**

Subtotal Direct Cost	**$7,661,500**
Contingencies (40%)[5]	$3,065,000
Total Direct Cost[6]	**$10,727,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$1,073,000
Full Time Construction Management (5%)[8]	$536,000
Total	**$12,336,000**

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis turbine rated at 2.82 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Colliersville - Opinion of Probable Construction Cost - One New Vertical Francis Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$267,370	**$267,370**
331	**Powerplant Structures and Improvements**[4]	1	LS	$418,000	**$418,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$287,000	**$287,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$1,274,700	**$1,274,700**
334	**Accessory Electric Equipment**[4]	1	LS	$244,000	**$244,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$2,941,070**
Contingencies (40%)[5]	$1,176,000
Total Direct Cost[6]	**$4,117,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$412,000
Full Time Construction Management (5%)[8]	$206,000
Total	**$4,735,000**

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis turbine rated at 0.77 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Colliersville - Opinion of Probable Construction Cost - One New Horizontal Kaplan Turbine (Minimum Flow Unit)					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$147,720	**$147,720**
331	**Powerplant Structures and Improvements[4]**	1	LS	$100,000	**$100,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$100,000	**$100,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$627,200	**$627,200**
334	**Accessory Electric Equipment[4]**	1	LS	$100,000	**$100,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$1,524,920**
Contingencies (40%)[5]	$610,000
Total Direct Cost[6]	**$2,135,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$214,000
Full Time Construction Management (5%)[8]	$107,000
Total	**$2,456,000**

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new minimum flow vertical Kaplan turbine rated at 0.2 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Colton - Opinion of Probable Construction Cost - One New Horizontal Francis

Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,865,180	**$1,865,180**
331	**Powerplant Structures and Improvements**[4]	1	LS	$4,720,000	**$4,720,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$2,691,000	**$2,691,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$9,803,800	**$9,803,800**
334	**Accessory Electric Equipment**[4]	1	LS	$607,000	**$607,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$20,516,980**
Contingencies (40%)[5]	$8,207,000
Total Direct Cost[6]	**$28,724,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,872,000
Full Time Construction Management (5%)[8]	$1,436,000
Total	**$33,032,000**

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis unit rated at 8.2 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Deferiet - Opinion of Probable Construction Cost - One New Horizontal Francis Turbines (Minimum Flow PH)					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$815,300	**$815,300**
331	**Powerplant Structures and Improvements[4]**	1	LS	$1,479,000	**$1,479,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$2,361,000	**$2,361,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$2,772,000	**$2,772,000**
334	**Accessory Electric Equipment[4]**	1	LS	$586,000	**$586,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$125,000	**$125,000**

Subtotal Direct Cost	**$8,843,300**
Contingencies (40%)[5]	$3,537,000
Total Direct Cost[6]	**$12,380,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$1,238,000
Full Time Construction Management (5%)[8]	$619,000
Total	**$14,237,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new horizontal Francis units rated at 2 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Eagle - Opinion of Probable Construction Cost - One New Horizontal Francis					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$193,300	**$193,300**
331	**Powerplant Structures and Improvements[4]**	1	LS	$271,000	**$271,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$186,000	**$186,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$868,000	**$868,000**
334	**Accessory Electric Equipment[4]**	1	LS	$158,000	**$158,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$0	**$0**

Subtotal Direct Cost	**$2,126,300**
Contingencies (40%)[5]	$851,000
Total Direct Cost[6]	**$2,977,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$298,000
Full Time Construction Management (5%)[8]	$149,000
Total	**$3,424,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis unit rated at 0.5 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

East Norfolk- Opinion of Probable Construction Cost - One New Horizontal Francis Turbine (Minimum Flow PH)					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$295,960	**$295,960**
331	**Powerplant Structures and Improvements**[4]	1	LS	$444,000	**$444,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$708,000	**$708,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$1,081,600	**$1,081,600**
334	**Accessory Electric Equipment**[4]	1	LS	$176,000	**$176,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$3,155,560**
Contingencies (40%)[5]	$1,262,000
Total Direct Cost[6]	**$4,418,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$442,000
Full Time Construction Management (5%)[8]	$221,000
Total	**$5,081,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new horizontal Francis unit rated at 1.65 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Hannawa - Opinion of Probable Construction Cost - One New Horizontal Francis					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,579,360	**$1,579,360**
331	**Powerplant Structures and Improvements**[4]	1	LS	$4,276,000	**$4,276,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$4,702,000	**$4,702,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$4,589,600	**$4,589,600**
334	**Accessory Electric Equipment**[4]	1	LS	$1,396,000	**$1,396,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$17,372,960**
Contingencies (40%)[5]	$6,949,000
Total Direct Cost[6]	**$24,322,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,432,000
Full Time Construction Management (5%)[8]	$1,216,000
Total	**$27,970,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new horizontal Francis unit rated at 3.6 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Herrings - Opinion of Probable Construction Cost - One New Vertical Kaplan Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$808,180	**$808,180**
331	**Powerplant Structures and Improvements**[4]	1	LS	$1,937,000	**$1,937,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$2,351,000	**$2,351,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$2,544,800	**$2,544,800**
334	**Accessory Electric Equipment**[4]	1	LS	$799,000	**$799,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$8,889,980**
Contingencies (40%)[5]	$3,556,000
Total Direct Cost[6]	**$12,446,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$1,245,000
Full Time Construction Management (5%)[8]	$622,000
Total	**$14,313,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Kaplan unit rated at 1.8 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Heuvelton - Opinion of Probable Construction Cost - One New Vertical Francis Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$218,170	**$218,170**
331	**Powerplant Structures and Improvements[4]**	1	LS	$282,000	**$282,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$194,000	**$194,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$1,090,700	**$1,090,700**
334	**Accessory Electric Equipment[4]**	1	LS	$165,000	**$165,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$0	**$0**

Subtotal Direct Cost	**$2,399,870**
Contingencies (40%)[5]	$960,000
Total Direct Cost[6]	**$3,360,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$336,000
Full Time Construction Management (5%)[8]	$168,000
Total	**$3,864,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis unit rated at 0.52 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

High Falls - Opinion of Probable Construction Cost - Replacement of Three Vertical Francis Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$654,000	**$654,000**
331	**Powerplant Structures and Improvements**[4]	1	LS	$1,286,000	**$1,286,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$3,924,000	**$3,924,000**
334	**Accessory Electric Equipment**[4]	1	LS	$510,000	**$510,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$370,000	**$370,000**

Subtotal Direct Cost	**$6,824,000**
Contingencies (40%)[5]	$2,730,000
Total Direct Cost[6]	**$9,554,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$955,000
Full Time Construction Management (5%)[8]	$478,000
Total	**$10,987,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of three existing vertical Francis runners rated at 1.74 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Higley - Opinion of Probable Construction Cost - Two New Horizontal Kaplan Turbines					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,378,460	**$1,378,460**
331	**Powerplant Structures and Improvements**[4]	1	LS	$3,682,000	**$3,682,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$4,049,000	**$4,049,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$4,021,600	**$4,021,600**
334	**Accessory Electric Equipment**[4]	1	LS	$1,202,000	**$1,202,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$15,163,060**
Contingencies (40%)[5]	$6,065,000
Total Direct Cost[6]	**$21,228,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,123,000
Full Time Construction Management (5%)[8]	$1,061,000
Total	**$24,412,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Two new horizontal Kaplan units rated at 3.1 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Hollow Dam - Opinion of Probable Construction Cost - Replacement of Two Turbine Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$187,100	**$187,100**
331	**Powerplant Structures and Improvements**[4]	1	LS	$157,000	**$157,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$342,000	**$342,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$810,000	**$810,000**
334	**Accessory Electric Equipment**[4]	1	LS	$112,000	**$112,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$2,058,100**
Contingencies (40%)[5]	$823,000
Total Direct Cost[6]	**$2,881,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$288,000
Full Time Construction Management (5%)[8]	$144,000
Total	**$3,313,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of two turbine runners rated at 1.35 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Alice Falls - Opinion of Probable Construction Cost - Replacement of One Turbine Runner					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$160,400	**$160,400**
331	**Powerplant Structures and Improvements**[4]	1	LS	$214,000	**$214,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$855,000	**$855,000**
334	**Accessory Electric Equipment**[4]	1	LS	$85,000	**$85,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$1,764,400**
Contingencies (40%)[5]	$706,000
Total Direct Cost[6]	**$2,470,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$247,000
Full Time Construction Management (5%)[8]	$124,000
Total	**$2,841,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of one turbine runner rated at 2.25 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Mechanicsville - Opinion of Probable Construction Cost - Two New Horizontal Francis Turbines					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$3,758,500	**$3,758,500**
331	**Powerplant Structures and Improvements**[4]	1	LS	$5,798,000	**$5,798,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$8,862,000	**$8,862,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$20,812,000	**$20,812,000**
334	**Accessory Electric Equipment**[4]	1	LS	$140,000	**$140,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$1,873,000	**$1,873,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$41,243,500**
Contingencies (40%)[5]	$16,497,000
Total Direct Cost[6]	**$57,741,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$5,774,000
Full Time Construction Management (5%)[8]	$2,887,000
Total	**$66,402,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Two new horizontal Francis units rated at 17 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Mongaup Falls - Opinion of Probable Construction Cost - Replacement of Four Vertical Francis Turbine Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$260,900	**$260,900**
331	**Powerplant Structures and Improvements**[4]	1	LS	$0	**$0**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$1,881,000	**$1,881,000**
334	**Accessory Electric Equipment**[4]	1	LS	$278,000	**$278,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$2,869,900**
Contingencies (40%)[5]	$1,148,000
Total Direct Cost[6]	**$4,018,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$402,000
Full Time Construction Management (5%)[8]	$201,000
Total	**$4,621,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of four vertical Francis turbine runners rated at 4.95 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Moshier - Opinion of Probable Construction Cost - Replacement of Two Vertical Francis Turbine Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$443,200	**$443,200**
331	**Powerplant Structures and Improvements**[4]	1	LS	$0	**$0**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$3,572,000	**$3,572,000**
334	**Accessory Electric Equipment**[4]	1	LS	$410,000	**$410,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$4,875,200**
Contingencies (40%)[5]	$1,950,000
Total Direct Cost[6]	**$6,825,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$683,000
Full Time Construction Management (5%)[8]	$341,000
Total	**$7,849,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of two vertical Francis turbine runners rated at 9.4 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Norfolk - Opinion of Probable Construction Cost - Minimum Flow Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$385,660	**$385,660**
331	**Powerplant Structures and Improvements**[4]	1	LS	$665,000	**$665,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$2,477,600	**$2,477,600**
334	**Accessory Electric Equipment**[4]	1	LS	$264,000	**$264,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$4,242,260**
Contingencies (40%)[5]	$1,697,000
Total Direct Cost[6]	**$5,939,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$594,000
Full Time Construction Management (5%)[8]	$297,000
Total	**$6,830,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Minimum flow turbine rated at 0.90 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Norwood - Opinion of Probable Construction Cost - Replacement of Existing Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,416,870	**$1,416,870**
331	**Powerplant Structures and Improvements[4]**	1	LS	$3,124,000	**$3,124,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$3,435,000	**$3,435,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$5,759,700	**$5,759,700**
334	**Accessory Electric Equipment[4]**	1	LS	$1,020,000	**$1,020,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$0	**$0**

Subtotal Direct Cost	**$15,585,570**
Contingencies (40%)[5]	$6,234,000
Total Direct Cost[6]	**$21,820,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,182,000
Full Time Construction Management (5%)[8]	$1,091,000
Total	**$25,093,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of existing turbine rated at 4.63 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Ogdensberg - Opinion of Probable Construction Cost - One New Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$587,290	**$587,290**
331	**Powerplant Structures and Improvements**[4]	1	LS	$1,087,000	**$1,087,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$1,735,000	**$1,735,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$2,069,900	**$2,069,900**
334	**Accessory Electric Equipment**[4]	1	LS	$431,000	**$431,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$6,360,190**
Contingencies (40%)[5]	$2,544,000
Total Direct Cost[6]	**$8,904,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$890,000
Full Time Construction Management (5%)[8]	$445,000
Total	**$10,239,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new turbine rated at 1.47 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Raymondville - Opinion of Probable Construction Cost - Replacement of Existing Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,401,830	**$1,401,830**
331	**Powerplant Structures and Improvements**[4]	1	LS	$2,898,000	**$2,898,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$3,187,000	**$3,187,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$6,157,300	**$6,157,300**
334	**Accessory Electric Equipment**[4]	1	LS	$946,000	**$946,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$15,420,130**
Contingencies (40%)[5]	$6,168,000
Total Direct Cost[6]	**$21,588,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,159,000
Full Time Construction Management (5%)[8]	$1,079,000
Total	**$24,826,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new turbine rated at 4.98 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

School Street - Opinion of Probable Construction Cost - One New Fish Friendly Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$2,547,800	**$2,547,800**
331	**Powerplant Structures and Improvements**[4]	1	LS	$3,801,000	**$3,801,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$5,671,000	**$5,671,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$13,996,000	**$13,996,000**
334	**Accessory Electric Equipment**[4]	1	LS	$1,180,000	**$1,180,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$28,025,800**
Contingencies (40%)[5]	$11,210,000
Total Direct Cost[6]	**$39,236,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$3,924,000
Full Time Construction Management (5%)[8]	$1,962,000
Total	**$45,122,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new fish friendly turbine rated at 11 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Sissonville - Opinion of Probable Construction Cost - One New Vertical Francis Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$470,140	**$470,140**
331	**Powerplant Structures and Improvements**[4]	1	LS	$850,000	**$850,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$1,358,000	**$1,358,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$1,706,400	**$1,706,400**
334	**Accessory Electric Equipment**[4]	1	LS	$337,000	**$337,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$0	**$0**

Subtotal Direct Cost	**$5,171,540**
Contingencies (40%)[5]	$2,069,000
Total Direct Cost[6]	**$7,241,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$724,000
Full Time Construction Management (5%)[8]	$362,000
Total	**$8,327,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis turbine rated at 1.15 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Yaleville - Opinion of Probable Construction Cost - One New Horizontal Kaplan Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$583,960	**$583,960**
331	**Powerplant Structures and Improvements[4]**	1	LS	$1,079,000	**$1,079,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$1,724,000	**$1,724,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$2,058,600	**$2,058,600**
334	**Accessory Electric Equipment[4]**	1	LS	$428,000	**$428,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$6,323,560**
Contingencies (40%)[5]	$2,529,000
Total Direct Cost[6]	**$8,853,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$885,000
Full Time Construction Management (5%)[8]	$443,000
Total	**$10,181,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new horizontal Kaplan turbine rated at 1.46 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Court Street- Opinion of Probable Construction Cost - One New Vertical Kaplan Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$764,800	**$764,800**
331	**Powerplant Structures and Improvements**[4]	1	LS	$1,479,000	**$1,479,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$2,361,000	**$2,361,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$2,672,000	**$2,672,000**
334	**Accessory Electric Equipment**[4]	1	LS	$586,000	**$586,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$8,312,800**
Contingencies (40%)[5]	$3,325,000
Total Direct Cost[6]	**$11,638,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$1,164,000
Full Time Construction Management (5%)[8]	$582,000
Total	**$13,384,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Kaplan unit rated at 2 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Minetto - Opinion of Probable Construction Cost - Replacement of Five Vertical Francis Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$524,120	**$524,120**
331	**Powerplant Structures and Improvements**[4]	1	LS	$917,000	**$917,000**
332	**Reservoirs, Dams, and Waterways**[4]	0	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$3,511,200	**$3,511,200**
334	**Accessory Electric Equipment**[4]	1	LS	$363,000	**$363,000**
335	**Miscellaneous Power Plant Equipment**[4]	0	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	0	LS	$0	**$0**

Subtotal Direct Cost	**$5,765,320**
Contingencies (40%)[5]	$2,306,000
Total Direct Cost[6]	**$8,071,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$807,000
Full Time Construction Management (5%)[8]	$404,000
Total	**$9,282,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of five vertical Francis turbine runners rated at 9.24 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Station 2 - Opinion of Probable Construction Cost - One New Vertical Francis Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,623,500	**$1,623,500**
331	**Powerplant Structures and Improvements[4]**	1	LS	$4,034,000	**$4,034,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$2,300,000	**$2,300,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$8,452,000	**$8,452,000**
334	**Accessory Electric Equipment[4]**	1	LS	$519,000	**$519,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$17,758,500**
Contingencies (40%)[5]	$7,103,000
Total Direct Cost[6]	**$24,862,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,486,000
Full Time Construction Management (5%)[8]	$1,243,000
Total	**$28,591,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis turbine rated at 7 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Station 5 - Opinion of Probable Construction Cost - One New Vertical Francis Turbine					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,909,540	**$1,909,540**
331	**Powerplant Structures and Improvements[4]**	1	LS	$4,841,000	**$4,841,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$2,760,000	**$2,760,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$10,042,400	**$10,042,400**
334	**Accessory Electric Equipment[4]**	1	LS	$622,000	**$622,000**
335	**Miscellaneous Power Plant Equipment[4]**	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors[4]**	1	LS	$0	**$0**

Subtotal Direct Cost	**$21,004,940**
Contingencies (40%)[5]	$8,402,000
Total Direct Cost[6]	**$29,407,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,941,000
Full Time Construction Management (5%)[8]	$1,470,000
Total	**$33,818,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. One new vertical Francis turbine rated at 8.4 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Oswego Falls - Opinion of Probable Construction Cost - Replacement of Three Vertical Francis Turbine Runners and Two New Horizontal Quadruplex Turbines					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$0	**$0**
331	**Powerplant Structures and Improvements**[4]	0	LS	$0	**$0**
332	**Reservoirs, Dams, and Waterways**[4]	0	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$17,192,000	**$17,192,000**
334	**Accessory Electric Equipment**[4]	0	LS	$0	**$0**
335	**Miscellaneous Power Plant Equipment**[4]	0	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	0	LS	$0	**$0**

Subtotal Direct Cost	**$17,642,000**
Contingencies (40%)[5]	$7,057,000
Total Direct Cost[6]	**$24,699,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,470,000
Full Time Construction Management (5%)[8]	$1,235,000
Total	**$28,404,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Cost based on proposed development cost in 1996 License escalated to 2017 dollars.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Fulton - Opinion of Probable Construction Cost - Replacement of Two Turbines					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$1,363,200	**$1,363,200**
331	**Powerplant Structures and Improvements**[4]	1	LS	$5,345,000	**$5,345,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$5,612,000	**$5,612,000**
334	**Accessory Electric Equipment**[4]	1	LS	$1,745,000	**$1,745,000**
335	**Miscellaneous Power Plant Equipment**[4]	1	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$830,000	**$830,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$14,895,200**
Contingencies (40%)[5]	$5,998,000
Total Direct Cost[6]	**$20,893,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$2,089,000
Full Time Construction Management (5%)[8]	$1,045,000
Total	**$24,027,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of two turbines rated at 4.5 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Stillwater - Opinion of Probable Construction Cost - Replacement of Existing Horizontal Kaplan Turbines					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$430,070	**$430,070**
331	**Powerplant Structures and Improvements[4]**	1	LS	$795,000	**$795,000**
332	**Reservoirs, Dams, and Waterways[4]**	1	LS	$453,000	**$453,000**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$2,067,700	**$2,067,700**
334	**Accessory Electric Equipment[4]**	1	LS	$535,000	**$535,000**
335	**Miscellaneous Power Plant Equipment[4]**	0	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	0	LS	$0	**$0**

Subtotal Direct Cost	**$4,730,770**
Contingencies (40%)[5]	$1,892,000
Total Direct Cost[6]	**$6,623,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$662,000
Full Time Construction Management (5%)[8]	$331,000
Total	**$7,616,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of two horizontal Kaplan turbines rated at 4.88 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Glens Falls - Opinion of Probable Construction Cost - Replacement of Five Horizontal Francis Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$808,400	**$808,400**
331	**Powerplant Structures and Improvements**[4]	1	LS	$1,589,000	**$1,589,000**
332	**Reservoirs, Dams, and Waterways**[4]	0	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$5,415,000	**$5,415,000**
334	**Accessory Electric Equipment**[4]	1	LS	$630,000	**$630,000**
335	**Miscellaneous Power Plant Equipment**[4]	0	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors**[4]	0	LS	$0	**$0**

Subtotal Direct Cost	**$8,892,400**
Contingencies (40%)[5]	$3,557,000
Total Direct Cost[6]	**$12,449,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$1,245,000
Full Time Construction Management (5%)[8]	$622,000
Total	**$14,316,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of five horizontal Francis turbine runners rated at 14.25 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Dexter - Opinion of Probable Construction Cost - Replacement of Eleven Turbine Runners					
Item No.	Item	Quantity	Unit	Unit Price	**Cost (2015)**
330	**Land and Land Rights[1]**	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$258,850	**$258,850**
331	**Powerplant Structures and Improvements[4]**	1	LS	$259,000	**$259,000**
332	**Reservoirs, Dams, and Waterways[4]**	0	LS	$0	**$0**
333	**Waterwheels, Turbines and Generator[3,4]**	1	LS	$1,776,500	**$1,776,500**
334	**Accessory Electric Equipment[4]**	1	LS	$103,000	**$103,000**
335	**Miscellaneous Power Plant Equipment[4]**	0	LS	$0	**$0**
353	**Substation and Switching Station Equipment[4]**	1	LS	$450,000	**$450,000**
355/356	**Transmission Poles and Conductors[4]**	0	LS	$0	**$0**

Subtotal Direct Cost	**$2,847,350**
Contingencies (40%)[5]	$1,139,000
Total Direct Cost[6]	**$3,986,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$399,000
Full Time Construction Management (5%)[8]	$199,000
Total	**$4,584,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of turbine runners rated at 4.67 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost. Rounded to $1000.

Green Island - Opinion of Probable Construction Cost - Replacement of Four Turbines					
Item No.	Item	Quantity	Unit	Unit Price	Cost (2015)
330	**Land and Land Rights**[1]	1	LS	$0	**$0**
	Mobilization/Demobilization (assume 10%)[2]	1	LS	$11,617,400	**$11,617,400**
331	**Powerplant Structures and Improvements**[4]	1	LS	$31,049,000	**$31,049,000**
332	**Reservoirs, Dams, and Waterways**[4]	1	LS	$25,020,000	**$25,020,000**
333	**Waterwheels, Turbines and Generator**[3,4]	1	LS	$55,030,000	**$55,030,000**
334	**Accessory Electric Equipment**[4]	1	LS	$347,000	**$347,000**
335	**Miscellaneous Power Plant Equipment**[4]	0	LS	$0	**$0**
353	**Substation and Switching Station Equipment**[4]	1	LS	$4,628,000	**$4,628,000**
355/356	**Transmission Poles and Conductors**[4]	1	LS	$100,000	**$100,000**

Subtotal Direct Cost	**$127,691,400**
Contingencies (40%)[5]	$51,117,000
Total Direct Cost[6]	**$178,808,000**
Engineering, Admin. and Part Time Constr. Services (10%)[7]	$17,881,000
Full Time Construction Management (5%)[8]	$8,940,000
Total	**$205,629,000**

Notes

1. Assumed there are no land costs.
2. The mobilization and demobilization costs are 10% of Item Nos. 331-356.
3. Replacement of four turbines rated at 48 MW total.
4. Cost developed by Gomez and Sullivan based on internal cost review.
5. The contingency is 40% of all items. Rounded to $1000.
6. The sum of subtotal direct costs and contingencies. Rounded to $1000.
7. Engineering costs are 10% of the total direct cost. Rounded to $1000.
8. Full-time construction costs are 5% of the total direct cost

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New York State
Energy Research and
Development Authority

17 Columbia Circle
Albany, NY 12203-6399

toll free: 866-NYSERDA
local: 518-862-1090
fax: 518-862-1091

info@nyserda.ny.gov
nyserda.ny.gov

State of New York
Andrew M. Cuomo, Governor

New York State Energy Research and Development Authority
Richard L. Kauffman, Chair | Alicia Barton, President and CEO