

Run-of-River Hydropower in Connecticut: Opportunities and Challenges for Developers, and Recommendations for CCEF Support



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Executive Summary

The Connecticut Clean Energy Fund (“CCEF” or “the Fund”) requested this study to evaluate both the potential for small hydropower development in Connecticut and the best means for supporting that development. The report focuses on the potential for producing new hydropower capacity that would qualify as a renewable energy source in the state, particularly capacity that would qualify as a Class I renewable energy source. The report analyzes the challenges facing small hydropower developers and evaluates the resource potential that could be developed through support from the Fund. The report also considers innovative hydropower technologies capable of providing new generating capacity without the environmental impacts and consequent regulatory challenges associated with traditional hydropower as well as new applications of these technologies capable of providing Class I renewable energy capacity.

The most straightforward sites for development¹ in the state are four inactive, licensed hydropower sites with the potential nameplate capacity of approximately 2.2 megawatts. Other inactive hydropower sites could be re-licensed as well. The process of procuring a license for a hydropower facility can be arduous and expensive, however, and CCEF should be wary of supporting projects before they have obtained a license from the Federal Energy Regulatory Commission (“FERC” or “the Commission”). Finally, CCEF could help bring additional Class I hydropower online by supporting efficiency upgrades at existing Class I or Class II facilities, and by supporting the conversion of existing facilities to run-of-river operation, through use of newer, more innovative hydropower technologies.

The report concludes that the potential for developing additional megawatts of run-of-river hydropower in the state is somewhat limited. Consequently, CCEF should primarily support hydropower through an extension of its existing programs rather than through entirely new programs focused exclusively on hydropower. Given Connecticut’s current need to mitigate federally mandated congestion charges, CCEF should particularly consider supporting hydropower facilities located in areas that have the potential to contribute to congestion cost mitigation.

The Fund should also consider supporting innovative hydropower technologies, both by making the technologies eligible for demonstration funding and by funding a resource assessment study of the technologies’ potential in the state. Innovative hydropower technologies that do not require dams or impoundments could provide a significant amount of energy in the future from rivers and streams, tidal flows, industrial wastewater streams and municipal water systems. A goal of the Fund should also be to establish a program to support grid

¹ In this report, the term *development*—when used in relation to a hydropower facility—is intended to describe the process of refurbishing an existing hydropower site for the purpose of generating power at that facility. While this process may sometimes better be described as “redevelopment,” the term *development* will be used throughout for the sake of simplicity.

connected hydropower which is eligible for net metering in addition to the onsite distributed generation program.

Introduction

CCEF requested this study to evaluate both the potential for developing small hydropower in Connecticut and the best means for supporting the industry. The impetus for the study was a legislative amendment passed in 2003 that added “run-of-the-river hydropower” facilities to the state’s definition of Class I renewable energy under the Renewable Portfolio Standard, provided that such facilities “began operation” after July 1, 2003, and had a generating capacity of less than five megawatts. See *Conn. Gen. Stat. 16-1(26) & (27)*. The report analyzes the challenges facing small hydropower developers and evaluates the resource potential that could be unleashed through support from the Fund. The report also considers new, innovative forms of hydropower capable of providing new generating capacity at a reasonable cost without the environmental impacts and consequent regulatory challenges associated with traditional hydropower.

The total hydropower production capacity in Connecticut currently amounts to approximately 150 MW of electricity. Most of the state’s hydropower capacity, however, does not qualify as a Class I or Class II renewable energy source according to the state’s Renewable Portfolio Standard (“RPS”). This report focuses exclusively on the potential for developing hydropower-generating capacity that meets the Connecticut RPS definition of renewable energy.

According to the Connecticut statute (Conn. Gen Stat. § 16 245n[a]), a hydropower facility must meet two requirements in order to qualify as a renewable energy source under the Connecticut Renewable Portfolio Standards. The facility must (1) have a production capacity of less than five megawatts and (2) must “not cause an appreciable change in river flow.” Additionally, in order to qualify as a *Class I* renewable energy source, the facility must be one that “began operation” as a run-of-river facility after July 1, 2003 (the statutory date). If the facility “began operation” before July 1, 2003, then it can still qualify as a Class II facility if it meets the other two statutory requirements. These statutory requirements—and the regulations that interpret them—are discussed in greater detail below.

As per the Final DPUC Decision in Docket No. 04-02-07 dated September 10, 2004, which interprets the “run-of-river” language in the state’s RPS, there are four different potential sources of Class I renewable energy from hydropower in Connecticut (not including innovative forms of hydropower on which the DPUC has not yet been asked to decide). These include:

- 1) inactive, FERC-licensed facilities,
- 2) inactive, unlicensed facilities,
- 3) upgrades to existing Class I or Class II facilities (as long as the resulting facility is still less than 5 MW, and
- 4) conversions of pond-and-release facilities to run-of-river mode.

Developing hydropower facilities in Connecticut is a challenging endeavor, in large part because of public policy challenges and environmental concerns. Unlike many renewable energy sources, most forms of hydropower come with significant environmental liabilities. Environmentalists particularly object to hydropower's impact on migrating fish populations and downstream water quality.

Environmental regulations are a major component of the larger regulatory review process imposed by the Federal Regulatory Energy Commission. Interconnection review and environmental studies are all considered for FERC licensing.

Closely linked to the environmental challenges is the challenge of resource availability. Due to the stringent environmental restrictions in the state, relatively few sites exist that are viable for development.

Finally, the development of hydropower sites is constrained by the current lack of financial incentives and the difficulty of securing long-term power purchase agreements for the sale of power. Without the availability of the power purchase agreements, developers find it difficult to secure private financing to develop a site.

The challenges facing new development however should not be a deterrent for CCEF support. With careful planning, guided program participation, and project review, CCEF should take a serious look at supporting hydropower in an effort to bring more Class I renewable energy online in the state.

Public Policy Challenges

FERC Licensing Requirements

FERC has plenary authority over the regulation of hydroelectric facilities in the United States. Every facility in the country must have a FERC license to operate. Specifically, Section 23(b)(1) of the Federal Power Act (“FPA”) requires a non-federal hydroelectric project (unless it has a still-valid pre-1920 federal permit) to be licensed if it:

- 1) is located on a navigable water of the United States;
- 2) occupies lands of the United States;
- 3) utilizes surplus water or waterpower from a government dam; or
- 4) is located on a body of water over which Congress has Commerce Clause jurisdiction, project construction has occurred on or after August 26, 1935, and the project affects the interests of interstate or foreign commerce.

This definition is broad enough as to encompass most, if not all, non-federal hydropower sites in the state.

The FERC licensing process has traditionally been long and arduous for developers, in some cases taking as long as ten years to complete. The length and expense of the licensing process is a significant impediment to the development of new sites, and should discourage the Fund from supporting the development of sites that are not already far along in the process or do not already have their FERC license in place.

Under the traditional FERC licensing process, a developer had to complete and document a pre-filing consultation process even to apply for a FERC license. This pre-filing process consisted of three stages, with steps that included FERC issuing an initial stage consultation document, conducting a joint agency/public meeting and site visit, and submission of written comments by the relevant resource agencies and tribes. The developer-applicant was then required to complete “reasonable and necessary studies” and to provide a draft application and study results to relevant resource agencies and tribes for their review. After all appropriate parties had the opportunity to comment on the draft application, a meeting was held between the relevant parties if substantive disagreements existed. And only then did the developer-applicant file the application with the Commission.

In contrast to the traditional licensing process, developer-applicants can now apply for a FERC license through the Commission’s alternative licensing process. Through this process, a developer-applicant can: tailor the pre-filing consultation process to the circumstances of the particular site; combine the pre-filing consultation process and environmental review processes into a single process; and have a preliminary draft environmental assessment or

environmental impact statement (depending on which is required) prepared by a contractor chosen by the Commission and funded by the applicant.

Finally, FERC put in place a third, and even further improved, licensing process called the Integrated Licensing Process (“ILP”), which is gradually replacing the other two processes. The developer-applicants can use the new ILP or the traditional systems. According to FERC, the ILP offers: increased public participation in pre-filing consultation; development by the potential applicant of a Commission-approved study plan; better coordination between the Commission’s and other agencies’ processes; and encouragement of informal resolution of study disagreements followed by a formal dispute resolution.

These improved processes may eventually bring about a somewhat less time-consuming process for FERC licensing approvals. Nonetheless, the licensing process is likely to remain a substantial impediment to the development of new hydroelectric facilities into the foreseeable future.

In certain circumstances, a project may qualify for an exemption from licensing. The Commission issues two types of exemptions, one of which is for small hydropower projects, which are defined as those generating five megawatts or less of power built at an existing dam. Part I of the Federal Power Act does not apply to those projects receiving an exemption. Exempted projects remain subject, however, to mandatory terms and conditions set by federal and state fish and wildlife agencies and by the Commission. Developers often express a reluctance to apply for an exemption because the process can be as burdensome as applying for a license, and more importantly, the terms and conditions remain subject to alteration by the Commission.

Environmental Review by Agencies

The FERC license application process includes consultation with resource and environmental agencies at the state, regional, and federal levels. These agencies subject prospective projects to rigorous environmental review.

One of the most important gatekeepers for environmental review is the state environmental agency, which ultimately must issue a water quality certification under Section 401 of the Federal Clean Water Act in order for the license to be completed. FERC may not issue a license for a hydroelectric project unless the state water quality certifying agency either has issued a water quality certification (“WQC”) for the project or has waived certification by failing to act on a request in a timely fashion. The state certification then becomes a condition of the FERC license. See 33 U.S.C. §1341(d). In Connecticut, the Department of Environmental Protection (“DEP”) is responsible for issuing the WQC.

The DEP conducts a comprehensive review of license (and re-license) applications, considering four major issues: (1) downstream flows; (2) flows in the dam bypass reach; (3) upstream fish passage; and, (4) downstream fish

passage. Depending on the dam, other issues such as dam safety, wetlands, and the natural diversity database may also be considered. The predominant resource concern, however, is fisheries. (See Appendix B for more detail on the DEP approach to fish passage.)

The FPA also specifically requires that FERC include license conditions for the protection, mitigation, and enhancement of fish and wildlife resources based upon the recommendations of the appropriate federal and state agencies. This statutory requirement ensures that the U.S. Fish & Wildlife Service and any local fish and wildlife management agencies will be involved in the regulation of fish-related issues in addition to DEP.

Other provisions of the FPA require FERC to consider a variety of other impacts, such as navigational issues, coastal zone management issues, and others. While FERC is the ultimate arbiter of the hydropower license, recent court decisions have determined that FERC does not have the authority to overrule other agencies with specific regulatory mandates. The result of these court rulings, along with a confluence of a few other factors to be discussed below, has been to ensure that a project receiving a FERC license is reasonably certain to have undergone rigorous environmental scrutiny and to have met meaningful environmental standards.

Other Environmental Considerations

While the FERC licensing process clearly includes a significant focus on environmental issues, the mere possession of a FERC license does not ensure that the environmental community will support a particular hydropower development. Many environmental groups have traditionally opposed any type of hydropower development. Many of these groups, while increasingly willing to support hydropower in limited circumstances, would like to see the Fund limit its support to projects with an independent environmental certification.

The most widespread environmental certification process for hydropower projects is run by the Low Impact Hydropower Institute (“LIHI”), a national environmental nonprofit organization established in 1999 that seeks to reduce the environmental impacts of hydropower dams through market incentives. LIHI runs a voluntary certification program called the Low Impact Hydropower Certification Program, the goal of which is to ensure “that the certified dam adequately protects or mitigates its impacts in eight key resource areas: river flows, water quality, fish passage and protection, watersheds, threatened and endangered species, cultural resources, and public access and recreation opportunities.” See LIHI Web site at <http://www.lowimpacthydro.org>. In order to be certified, the dam also needs to be one that has not been recommended for removal by the relevant state agency.

LIHI describes its certification process as FERC-centric, in that it uses the FERC licensing process as a baseline from which to evaluate projects. Most run-of-river

facilities that have received a FERC license in recent years, and that are located in states such as Connecticut that have state level environment and resource agencies that take a strong stand on protection of river resources, would probably meet LIHI standards. The FERC process has evolved over time, and agencies have recently taken a more active role in ensuring that the licensing process approves only those projects that truly meet high environmental standards since the passage of the Federal Electric Consumers Protection Act in 1986. In particular, within the past five to seven years FERC has come to defer to state regulators on a more regular basis. Where the developer-applicant obtains a full settlement agreement, there is very little difference in LIHI certification requirements from FERC license requirements.

As to why a project developer or operator would apply for LIHI certification despite the improved value of the FERC licensing procedure, the LIHI certification requires that operators sign an affidavit on an annual basis affirming that they are in compliance with their certification, a step that the organization argues is an important compliance guarantee with high environmental standards. In addition, some certified facilities have found that LIHI certification has provided a marketing boost, with green power brokers seeking them out after seeing them listed on the LIHI Web site.

Public Policy Opportunities

Renewable Portfolio Standard

The Connecticut legislation establishing the state's Renewable Portfolio Standard ("RPS") initially created two classes of renewable energy (Classes I and II) and required that all electricity suppliers in the state include a certain percentage of each class in their electricity mix. Subsequent to the original legislation stipulating Class I and Class II requirements the Legislature enacted Public Act 05-01, June Special Session, An Act Concerning Energy Independence, which created a Class III requirement focused on electricity efficiency. See *Conn. Gen. Stat. 16-245a*. In July 2003, the Connecticut legislature amended the RPS statute to include certain types of "run-of-the-river" hydropower as both a Class I and a Class II source. See *Conn. Gen. Stat. 16-1(26) & (27)*. In order to qualify as a Class I renewable energy source, a hydropower operation must be a "run-of-the-river hydropower facility" that has a "generating capacity of not more than five megawatts, does not cause an appreciable change in the river flow, and began operation after the effective date of this section [July 1, 2003]." If the hydropower facility did not begin operation after July 1, 2003, then the facility can still qualify as a Class II facility if it meets the other statutory requirements.

A hydropower facility that the Connecticut Department of Public Utility Control ("DPUC") approves as a Class I or Class II renewable energy resource is eligible to receive not only the market price for its power, but also a Renewable Energy Credit ("REC") for every megawatt-hour ("MWh") of renewable electricity produced. The statutory requirements imposed on Connecticut energy suppliers by the RPS have created a willingness to pay for RECs among suppliers to the extent that those suppliers need them to avoid paying the \$55 per MWh statutory penalty. Class II RECs are not very valuable, but Class I RECs are currently valuable enough to make projects economical that would not otherwise be. The economic significance of this subsidy will be discussed in greater detail below.

On September 10, 2004, the DPUC issued a Final Decision interpreting the July 2003 statute's "run-of-the-river" definition. The decision, Docket No. 04-02-07, "DPUC Declaratory Ruling Concerning 'Run-of-the-River Hydropower' as that Term Is Used in the Definitions of Class I and Class II Renewable Energy Source in C.G.S. § 16-1(A)(26) & (27)" ("DPUC Decision") addressed four major issues.

First, the DPUC Decision addressed the question of what constitutes a "facility" under the statute. Northeast Utility Services Company ("NUSCO") originally raised the question, seeking a ruling that would allow operations with multiple operating units of less than five megawatts, but which total more than five megawatts, to qualify individually as renewable sources under the statute. The DPUC rejected this argument and held that the legislature clearly intended the term *facility* to mean the entire operation at a particular site, including all of the generating units associated with a particular impoundment. See DPUC Final Decision Docket No. 04-02-07 dated September 10, 2004.

Secondly, the DPUC addressed the statutory five-megawatt capacity limitation. The DPUC dismissed the contention by NUSCO that a facility's capacity should be evaluated based on average operating capacity as opposed to nameplate capacity. The DPUC noted that the nameplate capacity of a facility is the industry standard for determining that facility's maximum capacity, and therefore the legislature must have intended that figure to be the relevant one in determining whether a particular facility exceeds the five-megawatt limit.

The DPUC also addressed the question of a facility with a generating capacity of under five megawatts that upgrades or otherwise increases its capacity. The DPUC held that the total generating capacity of the facility after the upgrade must still be less than five megawatts for the facility to continue qualifying as a Class I or Class II renewable source. The DPUC did not accept the argument that the incremental, additional capacity should be viewed separately from the existing capacity. Furthermore, the DPUC made a special point of noting that any producer that reduced a facility's production capacity in order to qualify as a renewable source would be stripped of its renewable designation. A number of parties took exception to the DPUC's Draft Decision on incremental capacity, but the DPUC maintained its position in the Final Decision.

Thirdly, the DPUC considered the term *run-of-the-river* and effectively adopted the FERC definition, which holds that "run-of-the-river" means "no utilization of headpond storage and that outflow from the facility is equal to inflow to the pond on an instantaneous basis." DPUC Decision, 7 (citing Citizens Utilities Company, 105 F.E.R.C. P62, 119 [2003]). The DPUC effectively ceded determination of run-of-river status to FERC, holding that:

the comprehensive scope of a FERC-approved run-of-river compliance plan would effectively and satisfactorily protect and safeguard the rivers and environment as intended and desired by the legislature in enacting C.G.S. §16-1. As such . . . for a hydroelectric facility to qualify as Class I or II renewable energy source . . . the facility must show a current FERC license or exemption that requires the facility to operate in run-of-river mode. . . . A facility that is not required to operate in run-of-river mode but does so voluntarily may also qualify as Class I or II, provided that it can show an amended FERC license or exemption providing for the run-of-river operation. (DPUC Final Decision at 10)

Finally, with regard to the "began operation" language, the DPUC noted that the language is clear with regard to a newly constructed facility, but less so with regard to an existing facility that is restarted as, or converted to, a run-of-river facility. The DPUC considered each of these issues, as well as whether an upgrade at a Class II run-of-river facility could qualify as Class I power.

With regard to the restarting of a previously inactive facility, the DPUC concluded that the restarted facility had to be essentially “new” after July 1, 2003, in order to qualify as a Class I facility. Though the DPUC indicated that the determination of what constitutes a “new” facility would be made on a case-by-case basis, with no one factor conclusive, the DPUC did indicate that a facility would only be able to qualify as new if it can “show that it has been abandoned or destroyed, rebuilt and began operations after July 1, 2003. At minimum . . . such facility must have been abandoned for at least two consecutive years (with limited exceptions set forth in this section) and the facility’s owners must demonstrate a capital investment in equipment and associated structures for any refurbishment of greater than 50% of the total value of the equipment and associated structures at the facility” (DPUC Final Decision at 14).

Though the DPUC’s Decision with respect to restarted facilities was somewhat restrictive, the Decision applies only to facilities that had previously operated in run-of-river mode. *Facilities that convert from pond-and-release to run-of-river are treated separately, since the converted facility is understood to have “begun operation” as a run-of-river facility on the date that the facility is converted.* The DPUC Decision creates the possibility that an existing facility operating in pond-and-release mode could convert to run-of-the-river mode and receive Class I certification, assuming that its generating capacity was less than five megawatts. The same is true for an inactive facility that was operated in pond-and-release mode before it ceased activity.

The DPUC also held that capacity improvements at an existing Class II facility could qualify as Class I power as long as the resultant facility still had a capacity of less than five megawatts. The DPUC Decision held that “it is reasonable to afford Class I status to a portion of an existing facility’s output, provided the increased capacity was added after July 1, 2003, and the total nameplate capacity of the facility does not exceed five megawatts” (DPUC Final Decision, at 15). An upgraded facility will be eligible to receive Class I renewable energy credits as a percentage of the facility’s total production, with the percentage equaling the amount that the upgrade increased the original facility’s production capacity. In other words, a three-megawatt, Class II hydropower facility that added one megawatt of generation capacity after July 1, 2003, through an upgrade would henceforth receive Class I renewable energy credits for one-fourth of its total production.

Parties’ Written Exceptions to the Draft Decision criticized the DPUC for effectively denying renewable status to a facility that post-upgrade has a capacity of greater than five megawatts, but the Final Decision confirmed that the legislature had made its intentions clear to exclude such facilities.

Key Elements of DPUC Draft Decision Interpreting “Run-of-River” statute	
“Facility”	All of the generating units associated with a single hydroelectric site are part of one single facility. Individual generating units that

	are less than five megawatts cannot qualify separately for renewable status.
“Five Megawatts”	The five-megawatt maximum is measured based on nameplate capacity, not based on average actual generation.
“Run-of-River”	The DPUC adopted the FERC definition for run-of-river and determined that a facility can only qualify as a Class I or II renewable source in Connecticut if the facility is required to operate in run-of-river mode as per its FERC permit.*
“Began Operation”	A facility must be abandoned and then substantially improved to qualify as a new facility. A facility that converts from pond-and-release to run-of-river, however, can receive a new “began operation” date when it begins in run-of-river mode. Incremental capacity added to a Class II facility after the statutory date will be considered Class I power.

* Subsequently in Docket No. 04-05-16, the Department expanded the definition of a run-of-river facility to include those facilities that voluntarily operate in run-of-river mode and that can demonstrate that the operation does not cause an appreciable change in the river flow.

100 MW Goal

As mentioned above, in addition to the requirements of the Renewable Portfolio Standard, the legislature passed a 100 MW requirement requiring electric distribution companies in the state to contract for at least 100 MW of Class I power in the form of long-term power purchase agreements, from projects funded by CCEF. See *Conn. Gen. Stat. 16-244c*. CCEF plays an important role in the process by running a competitive solicitation to select those projects with the best opportunity to help meet the goals of the legislation.

This opportunity is potentially significant to hydropower developers because the lack of availability of long-term power purchase agreements is a major impediment to the development of new hydropower sites in the state. An important drawback of the legislation from the perspective of small hydropower developers, however, is the requirement that projects be at least one megawatt in size in order to participate. This requirement might effectively exclude most of the sites in the state since a majority of them have a potential capacity of less than one megawatt. While aggregation will be allowed, the DPUC has interpreted the statute to require that any aggregation must take place under one contract with the utility, with a single contract price.

Alternative Transitional Standard Offer (“ATSO”)— CT Clean Energy Optionssm (“CCEO”)

In 2003, recognizing the factors hindering the growth of a clean energy marketplace, the legislature enacted an Alternative Transitional Standard Offer

² CCEF Project 100 was expanded to 150 MWs in Public Act 07-242, An Act Concerning Electricity and Energy Efficiency

(“ATSO”) through PA 03-135. See *Conn. Gen. Stat. 16-244(c)(d)*. The legislation requires the state’s electric distribution companies, CL&P and UI, to offer clean energy product(s) to Transitional Standard Offer (“TSO”) ratepayers. The CCEO includes an option(s) that exceeds the amount of clean energy mandated under the RPS.

The DPUC selected the two CCEO suppliers, and one of those suppliers’ offering included 33% hydropower from the Northeast region. To the extent that the ATSO offerings include Connecticut hydropower producers in their mix, the program may bring extra revenue to producers through these voluntary RECs. Currently, all Green-e certified hydropower producers qualify under the CCEO program, which includes not only all Class I and Class II facilities, but all hydropower facilities under 30 MW.³

³ Green-e is a program of an independent nonprofit organization called the Center for Resource Solutions. The Green-e Program certifies renewable electricity products that meet the environmental and consumer protection standards established by the Program.

Economic Challenges and Opportunities

The costs associated with feasibility analysis and, particularly, with FERC licensing for hydropower projects can be quite high. As described above, FERC licensing can take as long as ten years to complete for a particular site. During that timeframe, the annual expenditures on required studies and other activities can be quite expensive. Other activities might include local permitting and siting issues. Not only are these expenses quite large, but the costs are often difficult to finance due to the uncertain nature of their extent, especially for licensing.

While the FERC licensing process and associated costs perhaps represent the biggest challenge to the development of hydropower sites in Connecticut (and nationwide for that matter), the Clean Energy Fund should be very wary of committing to provide support for FERC licensing activities. Because the FERC licensing process is extensive and uncertain, the Fund would be putting ratepayer funds at substantial and extended risk by supporting FERC licensing activities. These ratepayer dollars would be better spent supporting projects that are already licensed, are substantially far enough along in the process, or for which only license modifications are required. With regard to other feasibility and permitting activities, the Fund could support these efforts by making hydropower projects eligible for the Pre-Development Program.

In terms of the capital costs to develop a hydropower site, the costs vary widely depending on site-specific characteristics. Some of the characteristics that might drive the costs of development include the following:

- the physical characteristics of the site;
- the state of the current physical plant (if any) on site;
- the state of the transformers and connection lines necessary for interconnection into the grid;
- environmental factors that might require remediation expenditures, such as guaranteed flow-throughs, or expensive fish ladders; and,
- various other factors.

According to Connecticut hydropower developers, re-powering a hydropower facility in Connecticut tends to range in cost from \$1,000–\$3,000 per installed kilowatt. These numbers are consistent with the estimates that Arthur D. Little provided to the Massachusetts Technology Cooperative in their report on hydropower. That report estimated that capital costs for installing a small hydropower facility—which they define as between 1 and 30 megawatts in size—as \$1,000–\$2,500 per kilowatt. For mini hydropower facilities, defined as between 0.1 and 1 megawatt, the report estimated the capital costs as \$1,000–\$1,800.

As an example, one Connecticut developer estimates that it would cost him approximately \$300,000 to re-power a 250 kW facility on the Quinebaug River for

which he already has a FERC license in place, and for which little or no fish-related remediation measures would be required. This estimate suggests an installed cost of approximately \$1,200 per kW, which is in the lower part of the cost estimate range for start-up capital costs. On the other hand, this same developer estimates that rehabilitating a 1 MW facility might cost him upwards of \$2 million, or over \$2,000 per installed kW, due to the more primitive state of the current infrastructure on site and the requirements for fish remediation measures at that site. Installing the required infrastructure to accommodate fish passage at the site could cost as much as \$600,000.

On an ongoing basis, the operating and maintenance costs of hydropower facilities are relatively low. The developer looking to re-power the 250 kW site described above suggests that the operation and maintenance (“O&M”) costs for the facility would be approximately \$25,000 per year, depending on the debt load that the project was carrying. The main operating expenses include equipment upkeep, labor costs, insurance, lease costs, general administration, and interest payments. The A. D. Little report estimates average O&M costs for hydropower facilities to be even significantly lower. For small hydro facilities, the report estimates O&M costs of \$20–\$25 per kilowatt per year. For mini hydropower facilities, the estimate is \$3–\$19 per kilowatt per year.

The capital and ongoing maintenance costs are low enough that many hydropower projects with a FERC license should be able to succeed without much governmental assistance beyond the incentives provided by the RPS mandates. The wildcard issue is the amount of remediation required at a particular site—the development costs may become prohibitive for those sites requiring fish ladders or other extensive remediation. The other key issue is the availability of secure, long-term power purchase agreements (“PPAs”). These power purchase agreements provide the type of assured long-term cash flow necessary to secure financing for a project in the first instance.

Hydropower projects over 1 MW in size are eligible for Project 100 and would therefore be able to take advantage of the legislation’s guarantee of a ten-year contract for the average wholesale price plus up to five and a half cents. The positive impact of the legislation on the small hydropower industry, however, is significantly limited by the exclusion of sites of under one megawatt. The DPUC decision on the Project 100 docket allows aggregation to reach the one-megawatt threshold under certain circumstances, but most facilities will still be unable to take advantage of the long-term contracts because they will not be able to offer a single contract price (either because they are not under common ownership or because they will not be delivering power to a single pricing node). If CCEF wants to see hydropower projects of less than 1 MW be developed, it may need to develop a financing initiative targeted at projects not eligible for Project 100.

With regard to capacity upgrades at Class II facilities (where the incremental capacity would count as Class I power), developers of these projects would probably not face the same financing challenges as developers of new projects.

Resource Assessment

There are over thirty operational hydropower facilities of 10 kW or more in the state of Connecticut, capable of producing approximately 150 MW of power (see Appendix A). The largest facilities in the state are along the Housatonic River, operated by Northeast Generation Services.

Environmental considerations in Connecticut render the construction of new dams extremely unlikely. Connecticut rivers are already highly developed, and the environmental opposition to a new dam could be strong. Every developer interviewed for this report indicated his or her skepticism regarding the potential for new dam construction.

Despite the difficulty of permitting and licensing a new dam, there are a significant number of existing dam impoundments that were used at one time for hydroelectric generation. Due to the difficulty of obtaining a new FERC license, the most attractive sites for development are those that already possess such a license.

There are four inactive hydropower facilities in Connecticut for which a current FERC license exists (see Table 1). These four dams constitute a total potential nameplate capacity of approximately 2.2 MW, and Summit Hydropower owns the licenses for all four sites.

Table 1. Connecticut non-operational dam sites with an existing FERC license

Plant Name	Location (Town)	River	Capacity (kW)	Owner / Licensee	License Issued– Expires	FERC #
Hale	Putnam	Quinebaug	440	Summit Hydropower	10/27/97– 9/30/37	11547
Upper Collinsville	Collinsville	Farmington	373	Summit Hydropower	2/23/01– 1/31/41	10822
Lower Collinsville	Collinsville	Farmington	1130	Summit Hydropower	2/23/01– 1/31/41	10823
Glen Falls	Moosup	Moosup	250	Summit Hydropower	3/2/92– 2/29/32	11143

In addition to these sites already possessing a FERC license, there are a large number of former hydropower sites in the state that do not currently have a FERC license. Table 2 presents a modified version of a list produced by a Department of Energy study team in 1995 as part of a national survey. The DOE team did not evaluate the likelihood of developing individual sites, but did discount potential hydropower capacity based on a complicated formula that rated different sites depending on a variety of factors. The DOE, for example, included undeveloped sites (i.e., sites with no impoundment) in their estimates and generally discounted such sites by 90%. This report does not even consider such sites based on the overwhelming consensus that new dam building in Connecticut is a virtual impossibility. However, as new technologies are being

developed, turbines that can operate within bypass channels without an impoundment, may unlock these sites for low impact small hydro. As for developed sites that are currently inactive, this report does not adopt the DOE discounting method (generally about 50% for such sites) because it seems highly inexact and thereby virtually meaningless to the purposes of this study. **The list is merely a collection of sites that at one time generated power and that therefore represent the best potential for future redevelopment of hydropower resources in the state.**

*Table 2. Connecticut non-operational dam sites without a FERC license**

Plant Name	Location (County)	River	Capacity (kW)	Owner or Prelim Permit Holder (as of 1995)	FERC #
Old Pistol Shop Dam	Middlesex	Coginchaug	60	FSR Realty	CT009
Slocomb	Hartford	Roaring Brook (Connecticut River)	22	JT Slocomb Co.	06498
Union Pond	Hartford	North Brook (Hockanum River)	144	Catalyst Energy Dev Corp	08778
Burnside	Hartford	Hockanum	150	Joint Venturers	09630
Farmington F12	Hartford	Farmington	270	Helen Winter	CT020
Nepaug	Litchfield	Nepaug	100	Metro District Comm	07663B
Richards Corner	Litchfield	East Brook (Farmington River)	150	Metro District Comm	07663A
Barkhamsted	Litchfield	East Brook (Farmington River)	750	Metro District Comm	CT023
Somersville	Hartford	Scantic	330	Springborn Lab Inc	CT024
Enfield Dam	Hartford	Connecticut	755	Dexter C H and Sons	CT025
Windsor Locks	Hartford	Windsor Locks Canal (Connecticut River)	2800	Windsor Locks Canal Co.	08404
Hammonasset Dam	Middlesex	Hammonasset	250	New Haven Water Co	CT027
Rimmon Pond	New Haven	Naugatuck	1275	Southern New Hampshire Hydro	08794
Housatonic Wire	New Haven	Little River (Naugatuck)	100	McCallum Hydro	09396
Thomaston	Litchfield	Naugatuck	2750	Water Power Dev Corp	03425
Pomperaug	Litchfield	Pomperaug	30	Andrew Peklo III	09523
Shepaug	Litchfield	Shepaug	382	Waterbury Water Dept	CT032
Kimberly Clark Dam	Litchfield	Housatonic	1570	Kimberly Clark Corp	CT014
Spooner Dam	Litchfield	Housatonic	1425	NUSCO	CT013
North Canaan	Litchfield	Blackberry	228	Northwest Electric	04513

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				Power Co.	
Bunnells Pond	Fairfield	Pequonnock	200	Southern Connecticut Hydro	10118
Easton	Fairfield	Mill	230	Bridgeport Hydraulic	CT017
Saugatuck	Fairfield	Saugatuck	675	Bridgeport Hydraulic	10680
Pemberwick	Fairfield	Byram	100	McCallum Hydro	09609
Aspetuck Tunnel	Fairfield	Saugatuck	200	Bridgeport Hydraulic	11091
Still River	Fairfield	Still	75	Windsor Machinery	11341
Falls Mill	New London	Yantic	1000	Summit Hydropower	08263
Fitchville	New London	Yantic	135	Summit Hydropower	09283
Slater	New London	Pachaug	300	Borough of Jewett City	09230A
Ashland	New London	Pachaug	190	Borough of Jewett City	09230B
Pachaug 4	New London	Pachaug	71	Richard D. Ely	08190
Pachaug 3	New London	Pachaug	86	Richard D. Ely	08189
Pachaug 2	New London	Pachaug	40	Richard D. Ely	08166
Pachaug 1	New London	Pachaug	110	Richard D. Ely	08165
Blackwell	Windham	Blackwell Brook (Quinebaug R)	30	Ralph S RouschWin	09864
Goodyear	New London	Quinebaug	530	Rogers Paper Mfg	CT003
Cargill Falls	Windham	Quinebaug	1200	Summit Hydro	10038
North Grosvenordale	Windham	French	500	McCallum Hydro	09141
Wilsonville	Windham	French	150	Wilsonville Hydro	09269
West Thompson	Windham	Quinebaug	2260	Thompson Assoc	08033
Willimantic	Windham	Natchaug	520	Willimantic Water Works	CT036
Mansfield Hollow	Tolland	Natchaug	1220	Mansfield Hydro	11395
Willimantic 3	Windham	Willimantic	390	Summit Hydro	09731
Eagleville	Tolland	Willimantic	350	Bowers Hydro	09815
Oneco Pond	Windham	Moosup	60	JH McCann, Jr.	10003
Total Potential Capacity			24,163		

*(Some sites may have attained a FERC license since the DOE study was completed)

This list encompasses only those sites in Connecticut that generated hydroelectric power at one time in the past. The list has not been vetted to determine whether the sites are likely to be developed. Indeed, it is more likely than not that *most* of the sites on this list face significant challenges to development that might make re-powering unlikely even with meaningful subsidies from the Fund. In some cases, local interest groups might be vigorously opposed to re-powering the dam; in other cases, the dam might now be in use for another purpose such as flood control. Nonetheless, developing even a modest percentage of these sites would add meaningful renewable megawatts to the state's electricity mix.

Another potential source of Class I hydropower capacity in Connecticut would stem from the capacity upgrades at active hydroelectric facilities. To some extent, this option was limited by the DPUC Decision that explicitly rejected the notion that efficiency upgrades at facilities of greater than five megawatts could qualify as Class I renewable power. Nonetheless, there may be opportunities for existing Class II facilities to upgrade their capacity, and the resulting additional power would be considered Class I renewable power, assuming that the resultant capacity of the facility did not exceed five megawatts. This approach would have the advantage of bringing more power online without greatly increasing the environmental impact of any site, or bringing any new facility online.

Table 3 presents a complete list of hydropower facilities that have received approval as Class II renewable facilities from the DPUC (as of April 2007). Any upgrade at these Class II facilities would be considered a Class I renewable energy source, as long as the resultant facility did not exceed five megawatts of capacity. Class I RECs will be awarded to an upgraded facility as a percentage of the facility’s total production, with the percentage equaling the amount that the upgrade increased the original facility’s production capacity. In other words, a 3-MW, Class II hydropower facility that added 1 MW of power after July 1, 2003, through an upgrade would henceforth receive Class I RECs for one-fourth of its total production.

Table 3. Class II facilities in Connecticut

Project Name	Location (Town / River)	Renewable Status	Capacity (kW)	Owner / Licensee	License Issued–Expires	FERC #
Greenville Dam (Second Street Hydro)	Norwich / Shetucket R	Class II	500	CT Municipal Electric Energy Coop	3/31/93–12/31/43	02441
Tenth Street Hydro	Norwich / Shetucket R	Class II	1750	CT Municipal Electric Energy Coop	3/31/93–12/31/43	02441
Quinebaug-Five Mile Pond	Windham / Five Mile R	Class II	2,630	Quinebaug Associates, LLC	3/19/87–2/28/27	05062
Putnam	Windham / Quinebaug R	Class II	575	Putnam Hydropower	7/6/82 (exempt)	05645
Toutant (M.S.C.)	Putnam / Quinebaug R	Class II	400	Toutant Hydropower	8/30/84–7/31/24	05679
Kinneytown A	Seymour / Naugatuck R	Class II	850	Kinneytown Hydro Co.	5/20/83 (exempt)	06985
Kinneytown B	Seymour / Naugatuck R	Class II	1,500	Kinneytown Hydro Co.	5/20/83 (exempt)	06985
Willimantic 1	Willimantic / Willimantic R	Class II	700	Willimantic Power Corp	10/17/85–9/30/25	08047
Willimantic 2	Willimantic / Willimantic R	Class II	700	Willimantic Power Corp	12/10/85–11/30/25	08051
Mechanicsville	North Grosvenordale / French R	Class II	275	Saywatt Hydro Assoc.	1/27/88 (exempt)	09611

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Dayville Pond	Windham / Five Mile R	Class II	100	Summit Hydropower	6/29/92–5/31/32	11168
Occum	Norwich / Shetucket R	Class II	800	City of Norwich	9/29/99–8/31/39	11574
Total Generating Capacity			10,780			

An efficiency improvement of 20% at approximately half of the approved Class II facilities would represent only slightly more than one megawatt of new Class I renewable energy in the state. Even if all of the pending Class II applications were approved, a 20% improvement at half of all Class II sites would still yield only slightly more than two megawatts of Class I renewable energy. These scenarios demonstrate that while CCEF should not disregard efficiency improvements at Class II facilities altogether as a source of new Class I renewable energy in Connecticut, the Fund should also not expect too much from this source of new Class I renewable energy. The Fund should be additionally cautious about the potential to generate Class I renewable power from upgrades due to the fact that even relatively minor upgrades may cause FERC or other agencies at the state or federal level to require additional studies to measure potential environmental impacts. Also, it is unclear that these capacity upgrades would be eligible for Project 100, even if they were greater than 1 MW, because Project 100 is geared toward projects begun after July 2003.

Finally, the DPUC determined that pond-and-release hydropower facilities with a generating capacity of less than five megawatts that convert to run-of-river mode after the statutory date are considered Class I renewable energy facilities (DPUC Final Decision, at 14). There are eight such facilities in the state with a total generating capacity of 16.4 MW (see Table 4). If 20% of these sites were encouraged, through CCEF or other support, to convert to run-of-river mode, an additional 3.3 MW of Class I renewable energy would be brought online.

Table 4. Non-Class I or Class II facilities under five megawatts in Connecticut

Project Name	Location (Town / River)	Renewable Status	Capacity (kW)	Owner / Licensee	License Issued– Expires	FERC #
Bantam	Litchfield	n/a	500	Northeast Generation		
Scotland	Windham / Shetucket R	n/a	2,200	Northeast Generation	10/5/82–8/31/12	02662
Colebrook	Colebrook / W Brook, Farmington R	n/a	3,000	Metro District of Hartford	3/27/84–2/28/34	04117
Goodwin Dam	Hartland / W Brook, Farmington R	n/a	3,294	Metro District of Hartford	9/30/81 (exempt)	04297
Taftville	Norwich	n/a	2,000	Northeast Generation		
Robertsville	Colebrook	n/a	600	Northeast Generation		
Tunnel	Preston	n/a	2,100	Northeast		

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				Generation		
Wyre-wynd	New London / Quinebaug R	n/a	2,780	Summit Hydropower	5/19/82– 4/30/22	03472
	Total Generating Capacity		16,474			

Summary Table

Options for new Class I renewable energy from hydroelectric dams in Connecticut

Option	Assessment	Potential Capacity (kW)	Comments / Assumptions
Re-powering existing dam <i>With current FERC license</i>	Represents straightforward way to bring new Class I power generation on-line.	~ 2,200	This number assumes that all four inactive sites with FERC licenses could be developed.
Re-powering existing dam <i>Without current FERC license</i>	Acquiring FERC license can be extremely time intensive.	0	Due to length and expense of FERC licensing process, CCEF should not count on capacity from unlicensed facilities
Upgrades / efficiency Improvements	Only upgrades and efficiency improvements at facilities of less than five megawatts qualify as renewable power.	~ 1,100	Assumes 20% upgrades at half of sites with current Class II status.
Conversion of facilities to run-of-river Mode	As per DPUC Draft Hydro Decision, as long as a facility begins operation as <i>a run-of-river facility</i> after the statutory date it qualifies as a Class I renewable energy facility.	~3,280	Assumes 20% of eligible sites are converted to run-of-river mode, thereby becoming Class I eligible.
Implementation of new hydropower technology	Most promising option in the long term, but the technology is still in a demonstration mode.	0	It is premature to expect specific numbers since this technology is in demonstration mode).
Potential capacity		~6,580	This number is based on the highly theoretical scenarios outlined above.

New Hydropower Technologies

A number of companies are currently developing hydropower technologies that generate electric power from flowing water without requiring a dam or impoundment. These technologies—generally referred to as Instream Energy Generation Technologies, or “kinetic” and “free-flow hydropower”—offer a promising new horizon for the hydropower industry. CCEF should monitor the development of these technologies and consider supporting resource assessment activities in Connecticut that might benefit the development of the industry.

The common feature of free-flow hydropower technologies is that they do not require a dam or impoundment to generate power. A free-flow hydropower facility simply captures the kinetic energy of flowing water—whether unidirectional river flow or bidirectional tidal flow—and converts the water’s energy into electricity. In this manner, these systems are in many ways more akin to underwater wind farms than to traditional hydroelectric generating systems. Many of the leading technologies in this area in fact borrow heavily from the wind power industry’s thirty years of experience.

There are a large number of companies worldwide—twenty six by one estimate as of September 2007 (Ocean Renewable Energy Council) —developing free-flow hydropower technology and projects. The most advanced companies from a commercialization standpoint are two European companies called Marine Current Turbines of the U.K. and Hammerfest Strøm of Norway. Both of these companies have received significant support from their respective federal governments and are fairly far along in the commercialization process, with working prototypes in place. The focus of these companies seems to be on building large-scale, capital-intensive plants that work within a centralized power production model.

The leading U.S. companies are slightly behind on the path toward commercialization, but are focused on developing technology that can both function on a distributed generation model or scale up to a larger, more capital-intensive model. The leading U.S. firm is Verdant Power, based in Virginia. Founded in 1998, Verdant is one of the few U.S. companies in the sector that is approaching the business as a systems integrator and not merely a technology developer. Verdant’s flagship project is an installation in the East River off Manhattan, which the company is implementing with the support of NYSERDA.⁴

⁴ At the East River demonstration project, Verdant is implementing a set of axial flow propeller turbines with 3-bladed, 6-pitch rotors, a technology that the company developed in-house. Each turbine will have a blade diameter of 16 feet and is rated at between 25–30 kW. A passive yaw system allows the system to pivot with the changing tides and capture energy flowing in both directions. The company is planning to put in up to six turbines in staggered configuration once they obtain the proper permits (which they claim to be on the verge of achieving). If this initial demonstration is successful, then the company plans to expand the East River installation to a generating capacity of as much as ten megawatts.

The biggest regulatory hurdle that Verdant, and ostensibly every free-flow or hydro-kinetic hydropower installation, faces is the concern regarding impacts on marine life. Navigation and water-quality issues seem not to have presented as much of a challenge for Verdant with federal and state regulators. In any case, the East River project will undoubtedly serve as a testing ground for other permitting efforts since the project is fairly high profile and has received a great deal of attention from a broad swath of regulatory agencies. If the demonstration project receives the proper permitting and proves to have negligible or low impacts on marine life, then future projects should also be able to succeed in receiving regulatory approval.

GCK Technology, Inc. which developed the Gorlov helical turbine pursued a demonstration project in the Merrimack River in Massachusetts. The Gorlov turbine rotates in the same direction regardless of water flow. The Massachusetts Renewable Energy Trust provided support for this four (4) turbine demonstration project through the Trust's emerging technology demonstration program. The program provides grants of up to \$500,000 for demonstrations of near-commercial technologies. In addition, a company called Natural Currents has conducted its own demonstration project in New York State, which also received funding from NYSERDA and another at a test site in Florida. Natural Currents has utilized the Gorlov Helical Turbine for generation of power from tidal flows. A demonstration project was completed off Long Island in 2005, in the north fork by Shelter Island in cooperation with GCK, Inc and LIPA. The Gorlov Helical Turbine has been demonstrated worldwide, including one project in the Uldolmok Strait by the government of South Korea where tidal flows reach as high as 12 knots. The Korean government has plans for a national tidal energy program with estimates for power generation potential as high as several thousand MW.

Free-flow hydropower has many similarities to wind power, as mentioned above, though the technology has certain advantages over wind power technology and faces some additional challenges. As opposed to wind, free-flow hydropower does not face the challenge of adjusting to gusts or the accumulation of ice on the blades. The flows of water are actually quite predictable and run relatively constantly in one direction or the other. Consequently, the systems have a very high capacity factor, which is a big advantage in relation to wind power and in relation to many other forms of renewable power, for that matter. The companies expect the power from free-flow hydro systems to be almost 100% dispatchable. In addition, the siting issues, while somewhat complicated, are not nearly what they would be if one were to try to place a wind turbine in such close proximity to New York City.

On a final note, free-flow hydropower systems and traditional low-head systems do not necessarily need to operate exclusively in natural bodies of water. Various companies in the industry are investigating water streams that might prove much

less complicated from a regulatory point of view. Verdant mentioned the outflows from nuclear power plant cooling towers as a high-velocity, high-volume system that could be tapped to generate power. Verdant is also exploring water transport and irrigation canals in California; these canals are of uniform size and structure, and have a total lack of protected marine life. While an installation in an irrigation canal would be less dramatic than the East River project, it might be more practical from a regulatory and technical point of view. Another company called e3 (a partner of Natural Currents) is considering tapping the kinetic energy of the runoff streams from wastewater treatment plants.

In addition to free-flow technologies, The CCEF has funded a local Connecticut Company, Windham Automated Machines, to develop a low head hydro turbine for more traditional riparian installations. The new operational demonstration project will test the new Kaplan style turbine for its technological and low impact attributes. The turbine units are designed for low head installations (less than 20 feet) and are rated at 100 KW each. The modular and cost effective design is well suited for existing facility upgrades as well as small undeveloped sites. The technology has the ability to operate in both impounded installations and non impounded bypass channels.

Free-flow Hydropower Potential in Connecticut

Free-flow hydropower facilities are likely to qualify as Class I renewable energy sources under the Connecticut Renewable Portfolio statute, most logically qualifying as a form of run-of-the-river hydropower or under the category of “a low emission advanced renewable energy conversion technology”. The RPS statute does not actually define hydropower beyond requiring that hydropower facilities be operated in run-of-the-river mode and not exceed five megawatts in order to qualify as a renewable energy resource. As to whether free-flow hydropower is run-of-the-river hydropower, the DPUC Decision, in interpreting what the legislature intended by the term *run-of-the-river*, held that, as per FERC, a run-of-the-river facility involves “no utilization of headpond storage and . . . outflow from the facility is equal to inflow to the pond on an instantaneous basis” (*Citizens Utilities Company*, 105 F.E.R.C. P62, 119 [2003]). Based on this definition, it would seem reasonable to expect free-flow hydropower to qualify as a run-of-the-river hydropower facility. Free-flow hydropower facilities do not, of course, utilize headpond storage, and the outflow from the facility is always equal to the inflow on an instantaneous basis. The dispositive issue, though, as per the DPUC Decision is whether FERC recognizes the installations as run-of-river hydropower.

FERC officials have unofficially indicated that they are looking at free-flow hydropower as a form of hydropower at the present time. To date, however, FERC has not received an actual standard application from a free-flow hydropower facility for a FERC license since none of the projects are yet at the stage where they are ready to apply for a full-fledged permit. Up until now, the

various free-flow hydropower demonstration projects have been operating on FERC pre-permits.

As for Connecticut resource potential for free-flow hydropower, Verdant and Natural Currents have made some initial inquiries into sites in Connecticut, including the mouth of the Connecticut River and “the race” in Long Island Sound, but has not looked at the sites in depth. CCEF should consider funding a resource assessment study of the potential in Connecticut to determine whether there are sites with promise for development. The Long Island Power Authority is anticipating release of its own study which should provide valuable information for potential sites within Long Island Sound. Free-flow hydropower companies claim that a major impediment to the growth of the industry is the difficulty of obtaining funding for site assessment work, which can be quite expensive. CCEF funding for site scoping could therefore provide a significant boost to the industry, and ensure that the state plays a leading role in helping to bring this promising new technology online.

Appendix A: Active Hydropower Facilities in Connecticut

Project Name	Location (Town / River)	Renewable Status	Capacity (kW)	Owner / Licensee	License Issued– Expires	FERC #
Greenville Dam (Second Street Hydro)	Norwich / Shetucket R	Class II	500	CT Municipal Electric Energy Coop	3/31/93–12/31/43	02441
Tenth Street Hydro	Norwich / Shetucket R	Class II	1,750	CT Municipal Electric Energy Coop	3/31/93–12/31/43	02441
Housatonic	Litchfield County / Housatonic R		114,900	Northeast Generation	6/23/04–5/31/44	02576
Scotland	Windham / Shetucket R		2,200	Northeast Generation	10/5/82–8/31/12	02662
Taftville	Norwich /		2,000	Northeast Generation		
Robertsville	Colebrook		600	Northeast Generation		
Bantam	Litchfield		320	Northeast Generation		
Tunnel	Preston		2,100	Northeast Generation		
Wyre-wynd	New London / Quinebaug R		2,780	Summit Hydropower	5/19/82–4/30/22	03472
Colebrook	Colebrook / W Brook, Farmington R		3,000	Metro District of Hartford	3/27/84–2/28/34	04117
Goodwin Dam	Hartland / W Brook, Farmington R		3,294	Metro District of Hartford	9/30/81 (exempt)	04297
Quinebaug-Five Mile Pond	Windham / Five Mile R	Class II	2,630	Quinebaug Associates, LLC	3/19/87–2/28/27	05062
Putnam	Windham / Quinebaug R	Class II	575	Putnam Hydropower	7/6/82 (exempt)	05645
Toutant (M.S.C.)	Putnam / Quinebaug R	Class II	400	Toutant Hydropower	8/30/84–7/31/24	05679
Indian-Derby	Shelton / Housatonic R		6,160	McCallum Enter Ltd Partnership	3/25/86–2/28/26	06066
Kinneytown A	Seymour / Naugatuck R	Class II	850	Kinneytown Hydro Co.	5/20/83 (exempt)	06985
Kinneytown B	Seymour / Naugatuck R	Class II	1,500	Kinneytown Hydro Co.	5/20/83 (exempt)	06985
Willimantic 1	Willimantic / Willimantic R	Class II	700	Willimantic Power Corp	10/17/85–9/30/25	08047
Willimantic 2	Willimantic / Willimantic R	Class II	700	Willimantic Power Corp	12/10/85–11/30/25	08051
Mechanicsville	North Grosvenordale / French R	Class II	275	Saywatt Hydro Assoc.	1/27/88 (exempt)	09611

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Rocky Glen	Fairfield / Pootatuck R		110	Rocky Glen Hydro Limited Partnership	2/11/87 (exempt)	09984
Condgon	New London / Oxoboxo Brook		60	William Faye	12/9/87 (exempt)	10200
Gaillard	New Haven / Great Hill Tunnel Conduit		300	South Central Connecticut Regional Water Authority	11/15/89 (exempt)	10720
Dayville Pond	Windham / Five Mile R	Class II	100	Summit Hydropower	6/29/92–5/31/32	11168
Still River	Windham / Still R		37	Mackowiak, Richard G.	11/18/92–10/31/32	11217
Occum	Norwich / Shetucket R	Class II	800	City of Norwich	9/29/99–8/31/39	11574
			Total Generating Capacity	148,641		

Appendix B: DEP Approach to Fish Passage at Hydroelectric Dams

The DEP gives three different levels of priority to fish passage. The first level is for those barriers to fish passage that represent a direct barrier to the passage of anadromous fishes (such as trout and salmon) from Long Island Sound. This level applies when that dam is the first on a particular river system, or all dams downstream currently provide fish passage (or will provide passage after currently scheduled dam removals). Another factor for consideration within this priority level is whether the subject dam is a historic barrier to fish passage.

The second priority for fish remediation measures is for dams that are on watersheds for which the DEP has developed an anadromous fisheries plan that includes, as part of its long-term agenda, a plan to provide fish passage upstream but where there is not currently potential passage. Often in such instances, the DEP will not require that the dam site provide for fish passage immediately, but will nonetheless condition the 401 certification with the requirement that the dam operator will have to add fish passage if it ever becomes relevant.

The third priority goes to other dams located such that the health of inland fish communities requires that there be fish passage. It is worth noting, however, that the DEP has never required a hydropower facility to put in fish ladders exclusively for the benefit of inland fish communities.

There are different types of fish passage that the DEP might require, and each of these measures comes with an associated cost that depends largely on the particular features of the site. The four major types of remediation measures are rough and ramp systems; bypass channels; fish lifts (watered elevator); and fish ladders (usually poured concrete or prefabricated aluminum; operate twenty-four hours a day). Further discussion of these various remediation measures is beyond the scope of this report, except to note that different dam sites might be required to undertake different levels of fish remediation, at widely varying cost to the developer. Because of these remediation measures, licensing dams on rivers with anadromous fish populations can become very costly.