Understanding the Upfront Costs:
An Economic Feasibility Study of Increased Hydroelectricity Generation at Existing Dam Sites in Vermont

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Project Overview

In our climate-altered and energy-hungry world, hydropower has often been cited as critical for future energy portfolios. In Vermont, policymakers, environmental advocates, and citizens alike have looked towards hydropower as a potential energy solution; however, current regulations and public opinion on environmental issues make the construction of new dams in Vermont unlikely. As such, hydropower advocates are examining the potential for upgrading generation at existing hydroelectric sites and installing turbines at existing dam sites not currently used for electricity generation. Beyond possessing preliminary interest, however, many of these stakeholders are uninformed about the economic costs and benefits associated with upgrading or retrofitting existing dam sites.

We seek to provide a guide through which interested Vermonters can gain a better understanding of how to approach the costs and benefits of a variety of retrofits and upgrades of hydropower generation facilities. For the purposes of our study, an *upgrade* is considered a project in which existing generation capacity is augmented, and a *retrofit* involves the construction of generation facilities at non-hydropower dams. In addition to drawing on existing literature from a variety of scales (international, national, regional and local), we present ranges of Vermont-specific costs identified through local case sites. Finally, we designed a decision-making framework that allows a developer to determine when it is cost effective to upgrade or retrofit a hydroelectric site. This document should be read in conjunction with the findings of "Planning for Hydrologic Resilience: an environmental policy framework evaluating existing

dams in Vermont," in which our colleagues investigated the ecological impacts of these dam upgrades and retrofits versus the impacts of dam removal.[1]

In our framework we address two important concerns seen in our research: how to compare costs across varying projects of different scales and how to account for future energy price uncertainty. First, we find when assessing economic viability, one should consider cost per kilowatt of generational capacity rather than total project costs. Second, we concluded that in order to account for future energy price uncertainty, a developer should determine when to move forward with a project based on the energy price that will provide desired payback. Through a close examination of our five case studies, we saw that acquisition of upfront capital is a considerable obstacle to small-scale hydropower development, despite initial beliefs. However, economics are not the only barrier to development. Although a project may be economically desirable, its success also depends on other factors not captured in our analysis, such as the time required to negotiate agreements with stakeholders.

Vermonters deserve to be informed about the potential for new hydropower generation that is both economically feasible and environmentally safe. Our work is step towards that goal.

[1] Available from Middlebury College ENVS 0401 project archive:
http://www.middlebury.edu/academics/es/work/communityconnectedlearning/envs0401/archive

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Introduction

With climate change's impacts already being felt worldwide and an entrenched dependence on fossil fuels, governments and communities across the globe must work together to implement clean, renewable energy systems that protect our communities. Vermont Governor Peter Shumlin states,

> *"I believe there is no greater challenge and opportunity to Vermont and our world than the challenge to change the way we use and produce energy. The challenge is not unique to Vermont, but Vermont does have a tremendous opportunity to serve as a leader"* (Vermont Department of Public Service, 2011).

Vermont has the lowest total electricity consumption of any state in the U.S. and is one of only two states without a coal-fired power plant (U.S. Energy Information Administration, 2010). On the other hand, it is also one of only six states to use nuclear power as its primary source of electrical generation (U.S. Energy Information Administration, 2010). The Vermont Yankee nuclear plant currently provides over thirty percent of Vermont's electrical generation (U.S. Energy Information Administration, 2010). Vermont Yankee's contract with the state's utilities is slated to end in March 2012, giving the state of Vermont the opportunity to fill this impending electricity gap with a diverse set of renewable energy resources (Vermont Department of Public Service, 2011).

On August 12th 2010, Vermont renewed its contract with Hydro-Quebec, a deal that will help shrink this energy gap by securing approximately one quarter of the state's electric supply for the next 26 years. Hydro-Quebec will likely become Vermont's primary source of electricity, especially after the predicted closure of Vermont Yankee (Dillon, 2010). Vermont is the only state in New England to designate large-scale hydroelectric as a renewable energy resource (Barlow, 2010). This designation gives large-scale hydro such as Hydro-Quebec access to special

energy incentives. However, Hydro-Quebec may not be carbon neutral and as a large-scale hydropower developer, it is responsible for environmental degradation and fragmentation of river ecosystems in Northern Quebec, as well as the deterioration of the cultural heritage of the Cree people located in the area (Carlson, 2007). The negative impacts of Hydro-Quebec should encourage Vermonters to shift their focus to small-scale, in-state hydropower projects as a means of increasing clean, socially responsible generating capacity.

On September 13th, 2011, the Shumlin Administration released the Public Review Draft of the Vermont Comprehensive Energy Plan (CEP) to address the state's energy security and independence. As of 2008, Vermont had cut aggregate greenhouse gas (GHG) output by 10% since 2005 (Vermont Emissions, 2011). Even at this rate, the state is not on track to achieve the original goals for cutting greenhouse gas emissions of "25% below 1990 levels by 2012 and 50% below 1990 levels by 2028" (Vermont Emissions, 2011). In response to this shortcoming, the CEP introduces new GHG reduction strategies, such as transitioning from the voluntary Sustainably Priced Energy Enterprise Development (SPEED) program to a mandatory, streamlined Renewable Portfolio Standard (RPS) program. The CEP also espouses a bold new goal: 90% of electricity produced by renewable energy by 2050 (Vermont Department of Public Service, 2011).

Small-scale hydroelectric projects, defined for our purposes as facilities with a capacity of 5 MW or less, represent a viable option for producing renewable energy in Vermont. Small-scale hydroelectric power has the potential to provide more (and more reliable) energy than other renewable sources such as wind, solar, and biomass, and can do so with fewer operational risks than nuclear power plants (ENVS 0401A Fall 2011Project Statement). These small hydro generators also provide much needed jobs and tax revenue to towns across the state.

Furthermore, small-scale hydro has the ability to buffer Vermont's power supply from the price swings associated with buying energy from regional energy markets**.**

Recently, Vermonters' interest has been piqued by in-state electricity generation from small-scale hydro systems. Five years ago, the U.S. Department of Energy (DOE) established 1,201 Vermont locations as potential sites for micro-hydro, ranking Vermont fourth amongst all other states in "total hydropower potential density of feasible low power and small hydro projects" (Hall, 2006). Estimates for Vermont's additional hydropower generating potential vary widely depending on the considerations made when evaluating specific potential sites. The DOE estimates that these potential sites represent a total untapped capacity of 217 MWa (average megawatt hours per year) of mean annual power (Hall, 2006). Other estimates from in-state sources suggest the actual capacity may be as low as 20-25 MW (Warshow, 2011a).

Since 1993, the State of Vermont has denied all proposed new dams on the basis of environmental considerations (ENVS 0401A Fall 2011Project Statement). Retrofits and upgrades, on the other hand, are widely accepted as positive steps that can be taken towards increased power generation without causing external environmental harm (Fitzgerald, 2011a). As such, the State favors projects that involve upgrading the generation capacity of an existing hydrogeneration dam. Another option, though less appealing in the eye of the ANR, is to retrofit existing dams to begin hydroelectric generation for the first time (Fitzgerald, 2011b). The licensing requirements to retrofit or upgrade an existing site are equivalent to those for proposing a new generation site. They are, however, easier to comply with because the impacts of building at an existing site are much less drastic than the impacts caused by the construction of an entirely new dam structure (Fitzgerald, 2011b). In this way, developers across Vermont can tap into

previously untouched hydropower potential without undertaking the expensive, time consuming, and environmentally harmful process of building new dams.

Our statewide study examines existing Vermont dams that could either be retrofitted to become hydroelectric systems, or could be upgraded to increase efficiency on existing generating facilities. Case studies of completed sites and sites in-progress informed our analysis of the criteria that must be taken into account when considering dam upgrading and retrofitting. These case studies represent a variety of approaches and outcomes, thus providing concrete examples that are applicable to a wide audience.

As a result, this report offers a framework for economic feasibility assessments that could be applied to small-scale hydro projects across the state and throughout the greater New England region. This framework will help provide an accessible yet robust guide to inform potential developers of small-scale hydropower about the economic viability of their projects. We intend this guide to be a widely-distributable document, one that is accessible to a broad audience, and one that will aid Vermonters and New Englanders in the analysis of the cost-effectiveness of potential dam upgrades and retrofits.

Figure 1. Map of the existing hydropower sites in Vermont as well as potential sites suitable for retrofits and/or upgrades.

Research Design

A basic understanding of the economics of hydropower generation across multiple scales presents a foundation on which we can build a comprehensive examination of the costs associated with upgrades and retrofits in Vermont. While international examples may differ greatly from Vermont in regards to size, cost, regulation, and cultural considerations, there are a number of lessons that can be applied to Vermont and specifically to our framework. Chief among these lessons is the use of a multi-criteria analysis when evaluating potential hydropower sites. As multi-criteria analyses traditionally focus on studies of environmental, economic, and social considerations, this document is strategically paired with our colleagues' work, "Planning for Hydrologic Resilience."[2] Together, these two papers provide a complete analysis of the viability of a potential site. Multi-criteria analyses and historical examples in the literature present a diversity of methods used to evaluate the economic potential of hydropower development, with no one definitive method (Aggidis et al., 2010; Rojanamon et al., 2009). We include important lessons from each of these studies, such as warnings about the volatility of labor and energy markets or points about common obstacles like upfront costs, in our report. This combination of tips and clues informed both our research design and our policy framework. By examining multiple Vermont-based projects that were developed at different times, we hoped to capture economic data that extend beyond periods of labor price volatility. Furthermore, by looking at projects that have yet to be developed, we identified how developers deal with uncertainty in the energy markets.

[2] Ibid.

A careful examination of a few sites representative of the more than one thousand dams in Vermont provided us with real-world examples, concrete economic data and a specific range of costs that Vermont hydropower developers will encounter. These case studies expand on the theoretical frameworks of the literature and help us understand the specific and unique realities of hydropower generation in Vermont. Through consultations with Brian Fitzgerald of the Vermont Agency of Natural Resources and a thorough study of the Vermont Dam Inventory (Vermont Dam Inventory, 2011) we selected five case studies to represent the full breadth of dam upgrade and retrofit projects in the state of Vermont: Gorge 18, Essex 19, Winooski One, Upper Middlebury, and Townshend. These five dams are a representative sample of new and retrofitted hydropower sites with and without stream flow diversion dams in the state. A close study of the costs and benefits associated with each of these five projects helped determine realistic cost and benefit projections for potential future dam upgrades and retrofits. These five sites were selected to represent a diversity of criteria that often alter the cost of dam development in Vermont:

- **Status** - Selecting a range of dams (including some that have completed upgrades or retrofits, some currently undergoing such projects, and some still in the planning stages) was critical to our analysis. The selection of case studies that are currently under construction or in the planning phase presents a more realistic picture of how the process works today, as compared to projects completed in the l980s or 1990s. Examination of these cases aided our understanding of what the road forward will most likely look like.
- **Original Dam Purpose** - Dams that were originally intended to generate electricity will likely have fewer associated construction costs since powerhouses, transmission lines, access roads, and some auxiliary electrical wiring are already in place. On the other

hand, dams that were constructed for other purposes (flood control, recreational use, aesthetics, etc.) will require additional construction costs to install the necessary infrastructure mentioned above.

● **Materials** - Construction and engineering challenges and associated costs differ between earthen dams and concrete dams, both of which are common in Vermont.

● **Upgrade or Retrofit** - Costs and payback time vary immensely when considering whether a project is adding additional generation capacity (an *upgrade*) or whether it is adding electrical generation capacity for the first time (a *retrofit*), simply because there is more existing infrastructure at upgrade sites.

● Owner - Costs and potential benefits are wide ranging depending on whether the owner of the dam is a government entity, a major utility, or an independent power producer. For example, a large utility may be more able to take a large cost risk compared to an individual with less familiarity with the hydropower landscape and less available capital.

● **Regulators** - The duration and complexity of the planning processes for these projects are largely dependent upon the regulating entity. Local, state and federal agencies all require different permits and paperwork, meaning that individual dams may encounter entirely different permitting experiences.

While a range of dams was sought out for each of the above criteria, we also relied on some unifying criteria in the selection of the five case study sites. In order to provide a sample that was representative of existing dams in Vermont while ensuring sufficient data availability, all case studies have the following traits:

● **Greater than 500 kW power potential** - Numerous experts from utilities, private developers, and state regulators suggest that dams with less than 500 kW of power

production will never reach the economies of scale necessary to be considered "cost effective" in Vermont (Castonguay, 2011a; Warshow, 2011b). In addition, we chose dams that are greater than 500 kW because they have the potential to add significantly to Vermont's power supply mix and are the most likely sites to be developed in the near future. We placed no cap on dam size in determining our case studies as there are no dam sites in Vermont so large that their costs and benefits would differ significantly from smaller sites.

- **Available and accessible data** - Case study sites were selected with the understanding that they were sites with cost data available to the public and easy for non-technical audiences to interpret.
- **In Vermont** - While upgrade and retrofit projects in other New England states may be similar to projects in Vermont, selecting case studies from within the Green Mountain State ensures a similar permitting process and all but guarantees that future projects will encounter similar state-based costs.

Considering these criteria, the five case studies we selected fulfilled our goal of examining a range of dams that resemble those that may be upgraded or retrofitted in the future. Our effective population, therefore, is the subset of dams for which enough economic data are available. Hence, our framework is limited in scope, including a general list of costs and benefits that should be considered and how their magnitudes vary.

	Gorge 18	Winooski One	Essex 19	Townshend	Middlebury Upper
Status	In Progress	In Service	In Service	Proposed	Proposed
Town	South Burlington	Winooski	Essex	Townshend	Middlebury
Date of Original Construction	1914	1876	1917	1961	1774
Original Dam Purpose	Hydropower	Mill Dam	Hydropower	Flood Control	Mill Dam
Material	Concrete	Concrete	Concrete	Earth	Concrete
Retrofit or Upgrade?	Upgrade	Retrofit	Upgrade	Retrofit	Retrofit
Owner	Utility (Green Mountain Power)	Private (Winooski One Partnership)	Utility (Green Mountain Power)	Government (Army Corps), Private (Blue Heron Hydro)	Private (Middlebury Electric), Government (Town of Middlebury)
State Regulator	Public Service Board	Public Service Board	Public Service Board	Dept. Environmental Conservation (ANR)	Public Service Board
Federal Regulator	--	FERC	FERC	FERC	FERC
Proposed Changes	Replace Turbine	Install 3 Turbines	Add 5th Turbine	Install 6 Turbines	Install 5th Turbine
Impact of Upgrade/ Retrofit	+ 10,000 MWh/year	+ 30,000 MWh/year	+ 44,500 MWh/year	+ 960 KWh/year	+ 5,800 MWh/year
Total Annual MWh (average post-upgrade)	22,000 MWh/year	30,000 MWh/year	44,500 MWh/year	960 KWh/year	5,800 MWh/year

Source: Vermont Dam Inventory, 2011.

Table 1. Case Study Characteristics. Basic characteristics of the five Vermont case studies examined in this report.

Table 1 shows the diversity of case studies selected to examine the costs and benefits of hydroelectric retrofits and upgrades. There are cases that are currently providing power to the grid ("in service"), some that are undergoing construction ("in progress"), and some that are still on the drawing board and in different stages of the planning process ("proposed"). Two of the projects are upgrades to existing electrical generation infrastructure (Essex 19, Gorge 18), and three are adding—or have added—modern power generation units for the first time (Winooski One, Middlebury Upper, Townshend). There are a variety of owners in our case studies, ensuring

a comprehensive look into how public, private, and utility developers estimate costs and reach out to stakeholders throughout the process. Lastly, some projects are massive undertakings, which add thousands of megawatts of renewable energy to the grid (like the Winooski One project) and others are much smaller and are thus confronted with a different regulatory landscape (like the Townshend project). The five case studies fit the criteria necessary to get a comprehensive view of the hydropower landscape.

It is important to note that there have been other hydropower retrofits and upgrades in Vermont that do not involve dams. Many communities are excited about adding power generation in other sorts of water infrastructure, including natural waterfalls and water supply pipes and conduits. While these are interesting and viable alternatives to dam hydropower, these sites have such different associated cost and benefits that they are unhelpful for our framework. We detail these cases in Appendix A and highlight them as an important topic for further research.

Decision-Making Framework

The following section contains the economic decision-making framework that we designed for upgrading or retrofitting hydroelectricity projects in Vermont. The framework has been formulated to make the entire process of assessing economic viability, from initial back-of-the-envelope revenue calculations to the actual construction of the infrastructure, more accessible. This structure can also serve as a guide to the hurdles that are likely to surface when initiating an upgrade or retrofit project.

Because it has been designed with simplicity in mind, however, our framework has certain limitations. This framework does not contain every single cost that will be incurred in a project. Rather, we have determined the major costs pertaining to a variety of hydropower projects and structured our framework around information gleaned from past projects. As a result, the framework outlines a range of costs based on real projects.

The framework contains two parts, revenues and costs. An estimate of revenue can be determined and projected into the future. That revenue figure should be kept in mind throughout the entire project to determine economic viability at each step of the process. Secondly, one should calculate costs, which we have grouped into easily defined categories so that costs may be compared across different projects. Our framework approaches costs in a chronological order to mimic the order in which costs will arise in a given project. If at any time during the project the expected costs are larger than the desired revenue, or the payback period is too long, the project should be halted immediately.

Finally, this framework cannot account for unexpected delays, such as a lack of cooperation, disagreements, or other considerations amongst the stakeholders. However, the

framework can help developers and owners prepare for the unexpected, and be in a better position to deal with such delays. Furthermore, this framework can point not just to the current economic viability of a project but also to the future viability. For a general discussion of hydropower economics in the literature we examined, see Appendix B.

A. Revenue

When looking to upgrade or retrofit an existing dam, one should first determine the estimated production capacity of a facility as well as the estimated revenue for the life of the dam. This requires a rough estimation of the head and usable flow at the generation site. In many cases, this requires an initial investment for planning and feasibility tests, which can cost upwards of $200,000 as seen in the Gorge 18 project (p. 24).

Using Formula 1 below, one can estimate yearly revenue after the upgrade or retrofit has been completed. Once a realistic estimate of revenue exists, one can make a decision with regards to whether or not to continue with the project.

Formula 1: **AR** = **H** x **UFR** x **G** x **SE** x **ACU** x **R** x **8,766 hours per year***

*8,766 hours per year is used to account for leap years. It represents (365.25 days) x (24hours/day)

where… AR = Annual Revenue ($/year)
H = Head
UFR = Usable Flow Rate
G = Gravity
SE = System Efficiency
ACU = Average Capacity Utilization
R = Marginal Revenue per kWh ($/kWh)

B. Time until Payback

With the high volatility of energy prices, it is difficult to predict future prices, and thus future revenue streams. Hence, similar to Kjaerland (2007), our framework also considers the revenue per kilowatt-hour at which point a project will become viable based on the desired time until payback, as well as the cost to install an additional kilowatt. Thus, the result can be used by anyone, irrespective of his or her expectations regarding future energy prices, to determine the economic viability of current and future projects.

Upon entering into a project, a developer may have a desired time frame for payback in mind as well as an understanding of the rough costs of the project; the desirability of the project, however, depends on the revenue that the developer will receive per kilowatt-hour. Consequently, Formula 2 tells the developer at what revenue per kWh their project will be viable based on specific project characteristics. Depending on revised energy price and developer revenue estimates, a developer may decide if and when the project should go forth.

Formula 2: **R = C** x **P** x **SE** x **ACU** x **8,776**

where… R = Revenue at which point a project becomes viable ($/kWh)
C = Cost to install additional kW ($/kW)
SE = System Efficiency
ACU = Average Capacity Utilization

For cases where the system efficiency or average capacity utilization are unknown, Table 2 represents the marginal revenue at which point such a project would become viable. In Table 2, we have assumed a 50% average facility efficiency (system efficiency multiplied by average capacity utilization), meaning that if a plant has 960 kW of installed capacity, it produces on average 480 kilowatt-hours every hour. A 50% average facility efficiency was chosen as it was in the middle of the ranges seen in our case studies (Table 2).

Revenue per kWh at which project becomes viable ($/kWh)

Desired time until payback (years)

Cost to install additional kilowatt ($/kW)	2	4	6	8	10	12	14	16	18	20
$1,000	$0.11	$0.06	$0.04	$0.03	$0.02	$0.02	$0.02	$0.01	$0.01	$0.01
$1,500	$0.17	$0.09	$0.06	$0.04	$0.03	$0.03	$0.02	$0.02	$0.02	$0.02
$2,000	$0.23	$0.11	$0.08	$0.06	$0.05	$0.04	$0.03	$0.03	$0.03	$0.02
$2,500	$0.29	$0.14	$0.10	$0.07	$0.06	$0.05	$0.04	$0.04	$0.03	$0.03
$3,000	$0.34	$0.17	$0.11	$0.09	$0.07	$0.06	$0.05	$0.04	$0.04	$0.03
$3,500	$0.40	$0.20	$0.13	$0.10	$0.08	$0.07	$0.06	$0.05	$0.04	$0.04
$4,000	$0.46	$0.23	$0.15	$0.11	$0.09	$0.08	$0.07	$0.06	$0.05	$0.05

Table 2. Revenue per kWh at which a project becomes desirable ($/kWh). The table shows what marginal revenue would achieve a desired payback time (columns) at different costs per kW of installed generation capacity (rows). These numbers reflect the assumption of a project with 50% total efficiency.

C. Costs

Once estimated revenue has been defined and determined, one should consider the project costs, both in terms of time and money. Costs representing every phase of the dams' useful lifetime are taken into consideration, such as the design, construction and maintenance of a hydroelectric facility. If at any point costs significantly outweigh the benefits that one hopes to receive (in part represented by the annual revenue streams calculated with Formula 1), it is recommended the project be halted.

This decision-making framework utilizes costs that have been calculated in two ways. First, the estimation of total costs allows the project to be analyzed with regards to a developer's ability to finance such a venture (obtaining loans, investors, etc.). Alternatively, the estimation of the cost of installing an additional kW of capacity enables the developer to compare costs to similar projects of different scales. It also allows the developer to use Formula 2 or Table 2 to calculate when it may be desirable to pursue a project (in terms of when the market offers a certain revenue per kW).

Furthermore, costs can be divided into two main categories: capital costs and expenses. Capital costs include all one-time costs (although payment can be spread out over multiple years) that are required to bring a facility online. Expenses include all recurring costs needed to operate and maintain a facility. Both types of costs can further be broken down into plant costs and regulatory compliance costs. We discuss the costs with regards to when in the retrofitting and upgrading process they are incurred.

Since each example we encountered in the literature review grouped and classified costs differently, we worked to categorize all costs into eleven clearly defined groupings. Through understanding these comprehensive categories, a developer may compare his or her costs to those of the representative case studies. The categories are as follows:

I. Community Outreach Costs (Capital Cost)

Before a project begins, it is crucial to perform extensive community outreach through meetings with local stakeholders and governmental bodies. These meetings can serve to determine a course of action for moving forward. This phase might also include the establishment of project basics such as recognition of who holds relevant water and/or property rights. These initial meetings can also determine whether a hydro project is even feasible in the context of the local political and social climate. While the community outreach costs may be small or appear unimportant at first glance, they are extremely important to the success of a project. By working with relevant stakeholders and reaching compromises in the early stages of the project, a developer may identify and mitigate any roadblocks that could delay the process down the road. This will effectively decrease the likelihood that significant disagreements arise and halt the project later on.

While this process requires an upfront investment, it may ultimately save the project significant amounts of time and money on litigation should a stakeholder object to a project later on.

II. Engineering and Study Costs (Capital, Plant and Regulatory Compliance)

Before the project moves forward, one must perform a comprehensive feasibility study, which involves hiring experienced engineers. These studies address engineering design and assessments of foreseeable engineering challenges.

III. Licensing and Permitting Costs (Capital, Regulatory Compliance)

This segment is composed of all one-time fees necessary to acquire local, state and federal permitting and licenses. These may include, but are not limited to, water quality testing, rare plant studies, and town agreements. These costs will vary greatly from site to site. For example, a FERC license amendment (a time consuming and often expensive process) is not required if the amount of water diverted for hydroelectric generation does not change.

IV. Electrical Costs (Capital, Plant Costs)

Electrical costs include procurement and installation of all the hardware necessary for generation and transmission. For example, the costs of the generator, transformer, substation, and grid interconnection would be included in this section. We recommend seeking the counsel of an engineer familiar with the field for an accurate estimation of the options and costs. It is expected that these costs would be significantly lower in projects

whose aim is to upgrade existing generation infrastructure since it is expected that the electrical infrastructure already exists. For retrofit projects, however, an entirely new electrical unit would be necessary in order to bring the facility online.

V. Mechanical Costs (Capital, Plant Costs)

This section includes the costs for all mechanical infrastructure (i.e. turbine and flashboards). The magnitude of these costs is proportional to the expected change in generation capacity. Once again, if the project is primarily an upgrade of existing infrastructure, costs will generally be lower. Turbines can cost upwards of one million dollars and the costs of different types of turbines vary greatly.

VI. Civil and Structural Costs (Capital, Plant Costs)

This section includes installation and labor costs for all physical infrastructures, which support the mechanical and electrical systems (the dam itself, access roads, powerhouse, etc.) as well as the temporary infrastructure needed during construction (interim dam structures, cranes, tools for demolition, etc.).

VII. Operation and Maintenance Costs (Expenses, Production Plant)

Operation and maintenance costs include yearly salaries for workers that maintain and run the dam. They also include costs required for general facility maintenance and upkeep (cleaning, repairs, testing, etc.). The literature would suggest that, once up and running, hydropower facilities typically have low operation and maintenance costs,

making the generated electricity cost-competitive with fossil fuels on a per kWh basis (Paish, 2002).

VIII. Compliance Costs (Capital & Expenses, Regulatory Compliance)

This section is comprised of all costs required to remain within the regulatory bounds of the licensing agreements for the facility. For example, a town might require one to build and maintain a publicly accessible park near the dam. The construction costs of fishways are another consideration often seen in Vermont and are included in this segment because, although they may be a structural component, their purpose does not affect generation.

IX. Extraneous Costs

Although hydropower projects share many characteristics, some costs are site specific and do not fit into our defined categories. For example, some development projects may experience unanticipated lawsuits about property rights or possible damage to abutting structures. Alternatively, there might be expenses relating to archaeological exploration or the preservation of sites of historical significance.

X. Taxes (Expenses, Production Plant)

Taxes will vary depending on dam location, size, generation capacity and ownership. Since in many instances taxes are proprietary information, it is difficult to compare across different developers' projects.

XI. Contingency Costs

A significant amount of money must be allotted to deal with unforeseen events. These include lawsuits, emergency repairs, as well as the cost of unexpected construction delays. The amount of money that should be set aside should reflect the success of community outreach as well as the complexity of the engineering challenges.

Case Studies

To provide a better understanding of the aforementioned capital costs and expenses, the framework above was applied to five case studies in the state of Vermont: Gorge 18, Winooski One, Essex 19, Townshend, and Middlebury Upper Falls (Figure 2). Each of our case studies was informed by chief stakeholders at the sites such as John Warshow of the Winooski One Partnership, Josh Castonguay at Green Mountain Power, Anders Holm of Middlebury Electric, Inc., and Lori Barg of Blue Heron Hydro, LLC. These stakeholders were and still are heavily involved in the planning and building phases of their respective projects. They were a great asset to our research as they have experienced firsthand the myriad hurdles and complexities involved in such projects. Therefore, these case studies can serve as lessons to potential hydropower developers, providing accounts of tangible, real-world experiences. Costs differ significantly based upon the characteristics pertaining to each retrofit or upgrade. The costs represented in Table 3 are expounded upon to illuminate trends and give potential developers an idea of what to expect when undertaking such a project.

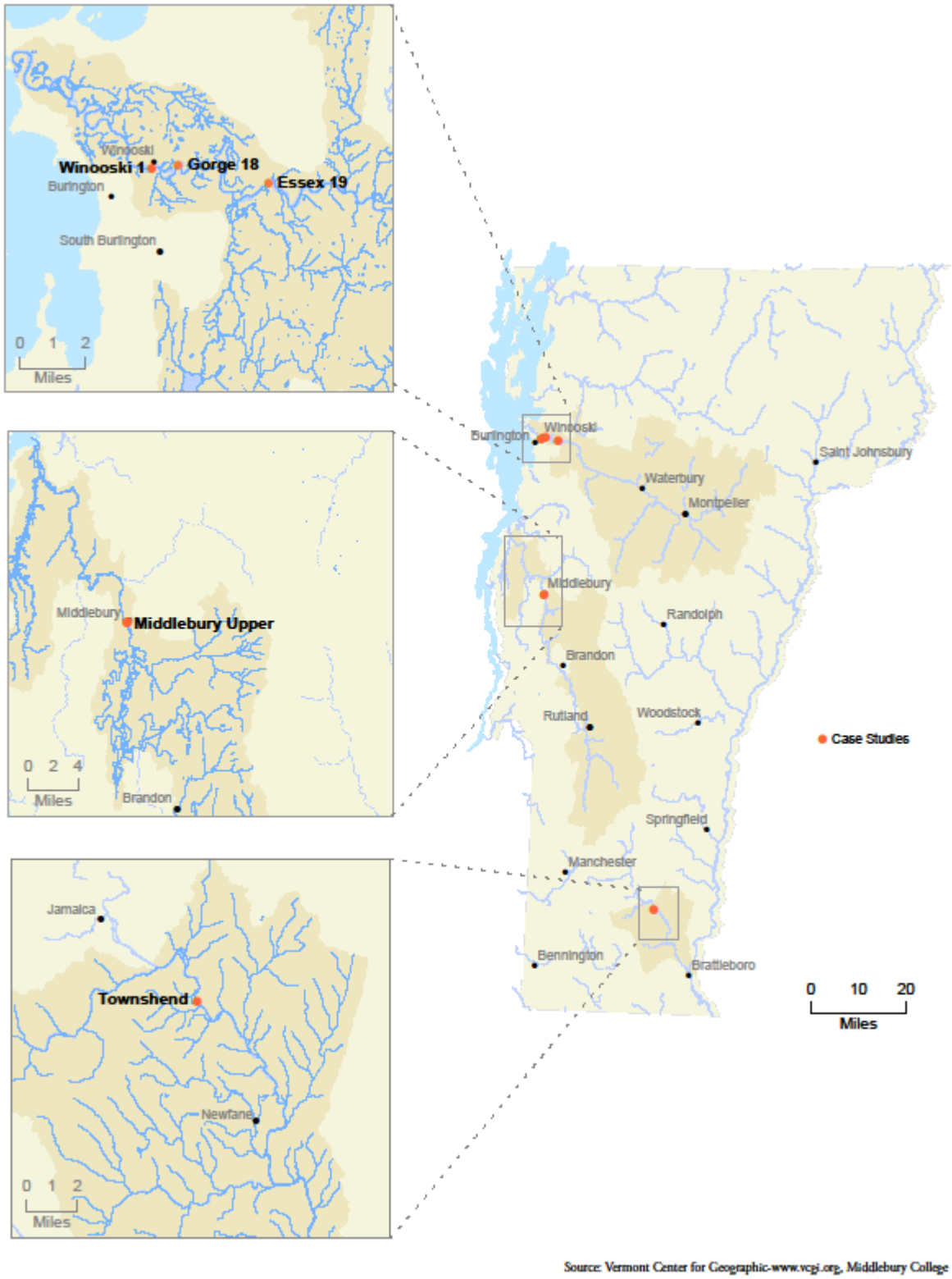

Figure 2. Locations of the five case studies within the context of the state of Vermont and within the context of their respective watersheds.

Cost to Install Additional Kilowatt of Capacity by Case Study

	Gorge 18 *	Winooski One	Essex 19	Townshend	Middlebury Upper
Community Outreach	*Proprietary*	$21	*Proprietary*	*Proprietary*	*$42*
Engineering	$88	$19	$139	$476	$200
Licensing/Permit	$44	$342	*Proprietary*	$182	$375
Electrical	N/A	$178	$56	$208	$600
Mechanical	$789	$493	$1,297	$1,563	$2,291
Civil/Structural	$701	$753	$262	$498	$482
Operating/Maintenance	*Proprietary*	*Proprietary*	$261	$124	$70
Compliance	N/A	$55	*Proprietary*	$391	*Proprietary*
Extraneous	*Proprietary*	$137	*Proprietary*	$119	*Proprietary*
Contingency	*Proprietary*	$205	$216	$275	$492
Taxes	*Proprietary*	*Proprietary*	*Proprietary*	$64	$70
Total	**$2,630**	**$2,204**	**$2,231**	**$3,899**	**$4,622**
Additional kW installed	-	7300	750	960	1000
Additional kWh produced yearly	10000	30000000	4830025	3605000	5800000
Average Facility Efficiency	58%	47%	74%	43%	66%

*Gorge 18 did not install any additional kW capacity, instead they focused specifically on retrofits that improved efficiency by 190%. This correlated to an increase in production similar to what would have been seen as a 2280 kW capacity increase, assuming an average plant efficiency of 50%.

Table 3: Cost to install an additional kilowatt of capacity for each of the five case studies examined in this report.

GORGE 18:

Site History

Gorge 18 is a run-of-river hydroelectric dam owned by Green Mountain Power (GMP). It is located on the Winooski River in South Burlington, Vermont just eleven miles from Lake Champlain. The facility currently produces approximately 11,000 MWh of power annually (Castonguay, 2011c). In the past decade, however, GMP has recognized serious deficiencies within the facility and has thus targeted Gorge 18 as a site for which upgrades could have a significant beneficial impact.

The physical dam structure was completed in 1918 at which point Gorge 18 began hydrogeneration (Kleinschmidt, 2011). Since then, various upgrades have improved upon the initial design (Kleinschmidt, 2011). Even with these sporadic updates, however, Gorge 18 relies on outdated, inefficient technology. In the shortcomings of the existing hydrogeneration machinery, Josh Castonguay, GMP's Leader of Field Operations, sees ample opportunity for improvement and increased power generation (Castonguay, 2011c). Four such ways in which GMP believes it can augment power generation include: replacing the existing runner (the term "turbine" refers to the entire unit, including the propeller, or "runner," as well as the casing and housing); replacing the existing wooden flashboards with automatic pneumatic flashboards; sluicing of trash and ice away from the intake pipe; and stopping, or at least reducing, leakage under the spillway (Kleinschmidt, 2011).

Project Proposal

Gorge 18 currently utilizes a "1955 vintage S. Morgan Smith vertical four-bladed fixed propeller runner" as its primary source of generation (Kleinschmidt, 2011). This machine poses significant limitations on the power generating capacity of the site. The runner is "fixed" in the vertical position meaning that it cannot adapt to varying flow rates. For this reason, the unit is what Josh Castonguay deems "a water hog": it will only come online and begin producing power once flow exceeds approximately 700 cubic feet per second (cfs) (Castonguay, 2011c). When flow is below this level, all water is spilled without generating any power. This represents a substantial loss of energy generation.

Although it results in a significant loss of power generation, this problem is a relatively simple, if not cheap, one to fix. GMP is considering the replacement of the existing turbine with a variable-pitch Kaplan runner. Kaplan turbines are a popular innovation within the hydropower field today because they allow operators to adjust the angle of the blades as well as the angle of the drive shaft in order to capitalize on real-time flows (Castonguay, 2011c). This can be accomplished while the turbine is in motion so no generation is lost. The installation of a Kaplan runner would allow the turbine to begin power production at a flow level around 345 cfs, greatly reducing the generation lost to low-flow conditions. Average predictions suggest that the installation of a Kaplan runner (without the implementation of any further upgrades) will augment facility production by approximately 5,000 MWh annually (Kleinschmidt, 2011). This is almost a 50% increase above current production.

General maintenance that could be conducted during installation of the Kaplan turbine would also have the added effect of reducing leakage under the spillway. A report produced in 1988 by The Johnson Company estimated that the Gorge 18 facility experiences a spillway

leakage of approximately 75 cfs as a result of aging equipment and parts (Kleinschmidt, 2011). This project will eliminate much of the leakage by essentially "plugging up holes" that have accumulated over the years (Fitzgerald, 2011a).

The wooden flashboards represent another antiquated aspect of the Gorge 18 structure. Variable river conditions frequently cause the flashboards to fail completely. When the flashboards are compromised, they fall flat, allowing otherwise-useful water to spill over the dam and also causing the level of the head pond to drop dramatically. This loss of head drastically cuts the efficiency of generation, resulting in lost output and revenue. The failure of these flashboards also poses a significant safety issue to those working to fix them. Crews are frequently sent into the river to manually prop up or fix the failed flashboards, putting themselves at great risk (Kleinschmidt, 2011).

The proposed remedy to this involves the removal of existing flashboards and replacing them with automatic pneumatic flashboards. Such flashboards consist of large rubber tubes filled with air that span the length of the dam. On top of the rubber tubes lies a continuous steel board that is hinged and also covers the length of the dam. When the rubber tubes are deflated, the board lies flat and does not inhibit the flow of water over the dam. Conversely, when the rubber tubes are fully inflated, the board stands vertically, blocking more flow. The amount of air within the tube, and thus the amount of flow blocked by the steel board, can easily be modified to reflect changing river conditions. Regulated remotely, these flashboards would give operators more control over the level of the head pond and give more stability throughout the year. GMP estimates that the installation of these flashboards would contribute five additional feet of head to the facility, bringing the total head to 39 feet (Kleinschmidt, 2011). The same

predictions mentioned above estimate a similar 50% increase on current capacity should GMP choose to replace the flashboards without adopting any further upgrades (Kleinschmidt, 2011).

Trash and ice floating in the river pose another problem to the Gorge 18 facility, often clogging the intake and reducing generation. Temporary outages associated with clogging and generalized failure of flashboards reduce the generation capacity by approximately 5% averaged throughout the year (Kleinschmidt, 2011). This leaves significant room for improvement by directing trash and ice away from the intake. The raised head pond level attributed to automatic pneumatic flashboards would have the additional, indirect effect of raising the trash and ice, which generally float on the upper layer of the water, above the site of the intake (Kleinschmidt, 2011). Such sluicing would greatly reduce the likelihood of clogging and intake interruption.

Current Status

Construction has not begun at Gorge 18 although the design and permitting phases have been completed. If all of these considerations are indeed implemented (as they are scheduled to beginning in December 2011), estimates indicate an increase of 10,000 MWh annually, or a 190% generational increase above current levels. This is a significant improvement, but it does not, however, mean that the process towards implementation is an easy or uncomplicated one.

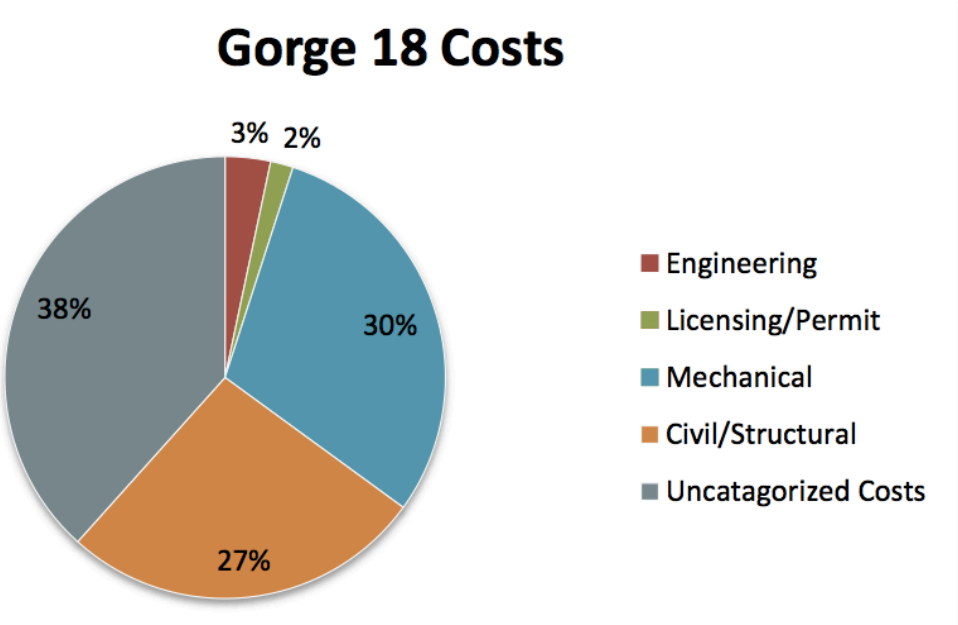

Figure 3. Projected cost breakdown by percentage for the 10,000 MWh upgrade proposed at the Gorge 18 facility. Specific components of these costs are detailed and expanded upon below.

Community Outreach Costs

Gorge 18 required little community outreach in the initial design phases because it is an upgrade that does not alter aesthetic flow rates nor change the general appearance of the dam.

Engineering and Study Costs - $200,000

Kleinschmidt Energy and Water Resource Consultants conducted a feasibility study for the Gorge 18 facility in 2011. They also projected engineering costs at this time. Josh Castonguay estimates that these phases cost GMP approximately $200,000.

Licensing and Permitting Costs - $75,000-$100,000

GMP has been conducting feasibility and site-specific studies since 2005 in order to determine the exact projected costs and benefits associated with this project. One benefit of the planned upgrades is that they will not alter the amount of flow directed for generation purposes.

The station currently utilizes 1,614 cfs (a limit dating to the original inception of the plant in 1918) and will continue to do so into the foreseeable future (Kleinschmidt, 2011). The aforementioned alterations intend to better utilize the water already existing at the site rather than impounding or redirecting any additional resources. As a result, GMP is not required to obtain any updated FERC documentation and can proceed without the burden of this aspect of the permitting process. GMP still needed to acquire permitting for the dam alteration and this cost the company $75,000 to $100,000. Josh Castonguay is quick to note that these costs would have been much higher had GMP needed FERC approval (Castonguay, 2011b).

Electrical Costs

Gorge 18 is already connected to the grid. Thus, electrical costs, other than those involved in the installation phase (detailed below) will be minimal.

Mechanical Costs - $1.8 million

Kleinschmidt estimates that the automatic pneumatic flashboards, four sections in total, will cost approximately $710,000. The variable-pitch Kaplan runner is projected to cost nearly $1.1 million (Kleinschmidt, 2011).

Civil and Structural Costs - $1.6 million

Since the project has yet to break ground, the construction costs presented below are not final. They do, however, represent reasonable estimations of the costs that GMP expects to face beginning with construction in December of 2011. Construction costs outlined by Kleinshmidt in the 2011 feasibility study include:

- Demolition and removal of extant flashboards: $220,000

- Concrete pouring and construction of cofferdams: $288,000
- Modifications to the existing electrical and control systems: $45,000
- Crane rental (one month) and barge rental (four months): $28,000
- Installation of the automatic pneumatic flashboards: $132,000
- Installation of the Kaplan turbine: $700,000
- "Mobilization/demobilization/cleanup": $210,000

Operating and Maintenance Costs

Since the project at Gorge 18 is an upgrade rather than a retrofit, operating and maintenance costs are not expected to rise as a result of the changes. In fact, maintenance costs will be considerably less because the automatic pneumatic flashboards will eliminate the need for frequent repair of the finicky wooden flashboards currently in place. This will cut down costs and also greatly improve the safety of workers.

Compliance Costs

Gorge 18 utilizes a fishway to remain in compliance with their agreement with the Agency of Natural Resources. Under this agreement, at least 40 cfs must pass through the fishway at all times between March 30th and June 13th (Kleinschmidt, 2011). This represents a cost of compliance in that it is lost generating capacity. Actual losses depend upon the flow rate at any given time.

Extraneous Costs

There are no costs that fit into this category for the Gorge 18 project.

Taxes

These data are not available for the Gorge 18 project.

Contingency Costs

The aforementioned costs do not include the cost to actually bring the facility online and make sure that all is running smoothly before calling the project completed. GMP has also figured in a considerable amount of money should unforeseen costs arise in the near future. GMP has allotted approximately $6 million to the Gorge 18 project in order to see it through from beginning to end (Castonguay, 2011b).

WINOOSKI ONE:

Site History

The Winooski One Hydroelectric Project (also known as the Chase Mill Hydroelectric Project and Winooski 1) is located at the lower Winooski Falls on the Winooski River, ten miles upstream of its confluence with Lake Champlain. The falls lie nestled between the city of Winooski, on the north bank, and the city of Burlington, on the south bank. The first dam on the lower Winooski Falls area was constructed by Vermont folk hero Ira Allen in 1786 at the close of the Revolutionary War and was used to power two sawmills on either side of the river (Friends of the Winooski River, 2011). In 1876, that dam gave way to a timber crib dam whose purpose was to power wool mills, a grist mill, and a forge along the Winooski's banks. This dam was actively maintained and used to power the mills that drove Winooski's economy until the 1950s.

Project Proposal

In 1984, the Winooski One Partnership began planning a two-hundred-foot-long, 35-foot-high, poured concrete, run-of-the-river dam that would abut the century-old timber crib structure. In addition to the poured concrete at the existing dam site, a 70-foot-long intake powerhouse, a fishway facility, underground transmission cables, a riverside park, an access road and a 300-foot river diversion were installed in order to bring the hydroelectric station online and begin producing power for the region. Constructed in just fifteen months between 1991 and 1993, the final facility is a 7.3MW power-producing asset for the region. The entire process at Winooski One, including dam planning, permitting, and construction, cost the developers an estimated

$16.6 million. This final cost is within one percent of initial projections. According to John Warshow, a founding partner of the Winooski One Partnership, it is "a testament to good management and…some good skills and some good luck. That was the budget and the way it turned out, we were quite pleased" (Warshow, 2011c). The Winooski One Partnership teamed up with an equity company, GDF Suez Energy, to help finance the project.

It is important to note that, while the presence of the existing timber crib dam qualifies the construction of Winooski One as an upgrade rather than a whole new dam, the Winooski One Partnership estimates that the costs associated with building the poured concrete dam would not differ much from construction of an entirely new dam. Warshow estimates the existence of the timber crib "may have saved $25-50,000…not much in the overall scale of the project." He continues, "We poured new concrete just downstream of it to support the new rubber dam. Because the old dam was on the National Register of Historic Places, it actually cost us about $10-15,000 to do HAER (Historic American Engineering Record) documentation" (Warshow, 2011d).

Current Status

The Winooski One Dam continues producing power today and is an iconic landmark in the City of Winooski. The dam and the Winooski One Partnership are an inspiration for other hydropower projects looking to move forward with retrofits and upgrades in the current energy climate.

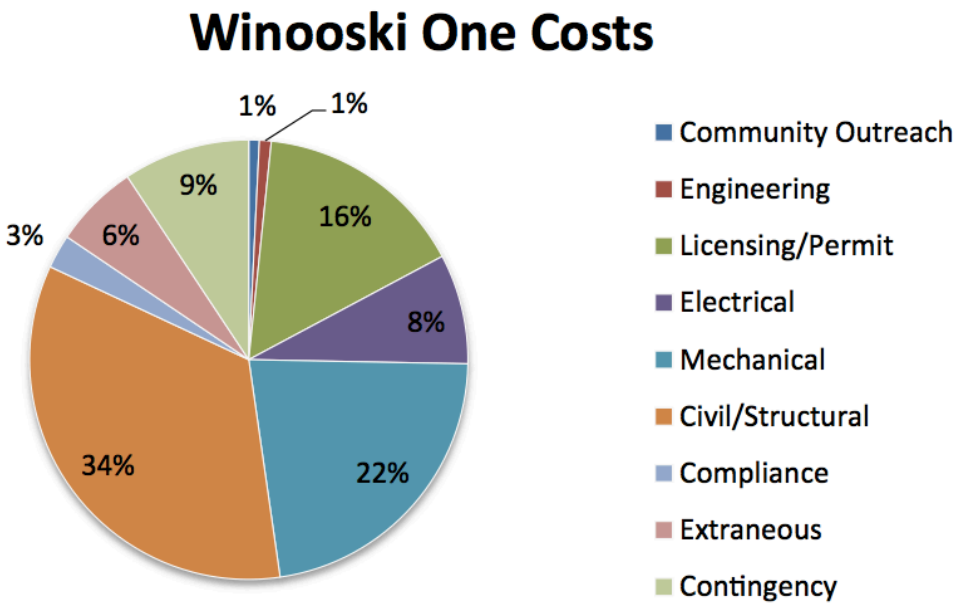

Figure 4. Cost breakdown by percentage for the 7.3 MW retrofit at the Winooski One Dam. Specific components of these costs are detailed and expanded upon below.

Community Outreach Costs - $150,000

One stipulation of the original license agreement mandated that Winooski One develop a recreational park adjacent to the dam. This park provides a place to picnic, play and admire the historic milldam buildings that were once an integral part of power generation at the site. John Warshow notes that this is an additional cost that Winooski One had to contend with and that would not likely be an issue outside of Vermont (Warshow, 2011a).

Engineering and Study Costs - $140,000

Winooski One paid $50,000 to consultants to conduct a rare plant study concerning the *anemone multifida*. This study resulted in an Endangered Species Permit that altered construction plans slightly in order to maintain the preferred habitat of the *anemone multifida*.

Engineering costs, concerning the blasting process and structural engineering challenges in particular, were approximately $90,000. Other engineering costs are included in the EPC (engineering, procurement, construction) contract with Pizzagalli Contractors, detailed below. This number is presented as one lump sum, thus the engineering fees cannot easily be parsed out and will instead be included in the "Civil and Structural Costs" section.

Licensing and Permitting Costs - $2.5 million

In the early 1980s, a group of citizens and hydropower advocates became interested in potentially developing a modern hydroelectric facility at the lower Winooski Falls site. Spearheaded by hydropower advocates John Warshow and Matthew Rubin, this new group of potential developers banded together to form the Winooski One Partnership. This group aimed to gain control of the existing timber crib dam (owned at that point by Green Mountain Power). After months of tenuous negotiations between the Winooski One Partnership, the Burlington Electric Department (BED), and the cities of Winooski and Burlington, GMP sold the land and water rights to the BED, which promptly leased those rights to the Winooski One Partnership. This licensing conversation required some litigation over permitting and water rights, an unexpected cost that did not overwhelmingly alter total projected costs of the project.

After completing the preliminary deal for construction, there were more than a few roadblocks in the completion of the dam itself. Warshow noted that the entire permitting process took almost seven years, and involved 18 permits with nearly 200 conditions from city, state, and federal regulators (Warshow, 2011b). A partial list of permits gives some insight into the amount of work required for construction of any hydroelectric site:

- FERC License (2756-VT), which includes 20-30 sub-permits such as a blasting plan, a construction noise mitigation plan, etc.
- FERC Certification as a Qualifying Facility (Order QF87-345-000, Issued 1987)
- Agreement with the City of Burlington
- Agreement with the City of Winooski
- A three-party agreement with the cities of Burlington, Winooski, and the developers
- VT Agency of Natural Resources 401 Water Quality Certification
- VT Agency of Natural Resources Endangered Species Permit (for the rare plant, *anemone multifida*)
- VT Public Service Board Dam Permit (PSB Docket 5235)
- Clean Water Act Section 404 permit from the U.S. Army Corps of Engineers

While line item budgets are unavailable for all costs associated with the permitting and planning process, John Warshow estimates that the entire permitting process cost the developers about $2.51 million between August 1986 and November 1991 (Warshow, 2011b). A $500,000 agreement with the City of Winooski guaranteeing the right to construct the dam constituted a significant portion of the permitting costs.

Electrical Costs - $1.3 million

While the original timber crib structure did provide power for the region, its electrical system was utterly inadequate in the face of the new Winooski One Dam. As a result, an entirely new electrical system was installed, including underground transmission cables attaching the facility to the grid. Total electrical expenditures needed in order to bring the facility on line exceeded $1.3 million.

Mechanical Costs - $3.6 million

The turbine and generators at the Winooski One facility cost approximately $3.5 million, not including installation. The mechanical parts of the fishway (required by the ANR) cost approximately $60,000, also excluding installation costs.

Civil and Structural Costs - $5.5 million

The Winooski One Partnership signed an $11.5 million EPC (engineering, procurement, construction) contract with Pizzagalli Contractors of South Burlington, VT. Under the terms of this contract, Pizzagalli was responsible for hiring all labor required for construction, purchasing all generators and turbines, performing all necessary rock blasting, and constructing the poured concrete dam, powerhouse, and the rest of the hydroelectric facility. Construction of the dam itself took roughly fifteen months: five months for blasting the Winooski dolomite formation at the site to ready the site for construction, five months of actual construction (pouring concrete, adding structural steel, etc.), and five months of "installing the gadgets": turbines, generators, monitoring systems, and all other auxiliary electrical units. Again, precise itemized budgets are proprietary, but some of the construction costs are as follows:

- Power plant structure (blasting, poured concrete structure): $2.2 million
- Conduit through the dams: $33,000
- Temporary dams and dewatering: $480,000
- Lease fees started under construction: $110,000

Operating and Maintenance Costs

Information regarding operating and maintenance costs is proprietary.

Compliance Costs - $400,000

Winooski One maintains a constant flow of 300 cfs over the spillway during summer months in order to comply with minimum flow requirements geared towards maintaining the aesthetic value. In winter months, this is not an issue due to ice that builds up along the dam and naturally restricts flow over the dam. Similar to the flow diverted through a fishway in the

Gorge 18 case, this required spill results in a reduction in generation (and thus a loss of revenue) during summer months. This lost generation amounts to approximately $100,000 each year. According to John Warshow, this concern for aesthetic aspects creates a cost that is likely unique to Vermont and other environmentally inclined states (Warshow, 2011d).

Winooski One also incurs annual costs associated with the operation and maintenance of the fishway. When fish (primarily salmon and steelhead) enter the fish trap, enticed by high flow levels spilling through the fishway, they are then raised by a hydraulic lift and placed in holding. Since the Gorge 18 Dam is a mere mile upstream from Winooski One, fish are then trucked around and released above Gorge 18. This reduces the likelihood that the fish will circumvent the dam and wind up, once again, below the Winooski One Dam headed upstream (Warshow, 2011d). These costs are relatively constant year to year.

Extraneous Costs - approximately $1 million

One prominent unanticipated wrinkle in the construction of the dam was a lawsuit with a neighboring landowner. The blasting associated with the construction of the dam caused one landowner to sue for cracks and other damages to his property, supposedly caused by the blasting. It is proprietary information what the legal outcome was in this situation, but the associated litigation costs are projected to have run almost $1 million.

As mentioned previously, the original timber crib dam was on the National Register of Historic Structures. For this reason, according to John Warshow, "it actually cost us about $10,000 - $15,000 to do HAER (Historic American Engineering Record) documentation" (Warshow, 2011d).

Taxes

Information regarding annual taxes is proprietary.

Contingency Costs - $1.5 million

Of course, there are myriad other costs associated with the completion of the Winooski One hydroelectric project that do not fall neatly within the aforementioned categories. Some of these costs are listed below:

- Construction interest: $412,000
- Bank commitment fee (paid to ensure adequate liquidity available in the bank to pay for construction, etc.): $76,000
- Contingency fees and debt service reserve: $675,000
- Insurance charges: $40,000
- Financing fees to the bank (Bay Bank of Boston, Massachusetts): $235,000
- Owner's fees (house, office rental, etc.): $75,000

ESSEX 19:

Site History

The Essex 19 facility in Winooski, Vermont is one of many dams contributing to Vermont's illustrious history in hydrogeneration. Located approximately 16 miles from Lake Champlain, the Essex 19 facility has been owned and operated by GMP since 1947 and has contributed significantly to their hydrogeneration portfolio (Essex Community Historical Society). In 1995, a FERC relicensing agreement provided GMP with the opportunity to boost generation while bringing the facility back into compliance. This upgrade continues to augment power generation by 7% annually and utilizes water flow that was once spilled over the dam as waste (Castonguay, 2011c).

The Winooski Valley Power Company built the existing dam structure in order to replace two aging milldams in the same location. Completed in 1917, the Essex 19 facility supplied the majority of Vermont's electric power for a number of years (Essex Community Historical Society). Essex 19 faced a major hurdle in the form of the historic flood of 1927. While many other dam structures were swept away by awesome amounts of water, Essex 19 fared reasonably well. Weathering flow rates exceeding 116,000 cubic feet per second (cfs), Essex 19 emerged with only minimal damage.

In 1928, Essex 19 was deeded to GMP, in whose hands it remains to this day. Until 2006, Essex 19 housed four fixed-blade runner turbines (each with a 2 MW capacity) and generated approximately 46,000 kWh annually (Kleinschmidt, 2001; Castonguay, 2011d).

Project Proposal

Article 402 of the 1995 FERC license imposed a more stringent, "seasonally varying" minimum flow requirement (Kleinschmidt, 2001). This means that, for environmental reasons (in this case regarding the health of local salmon populations), there must be a certain amount of flow emerging from the facility at any given point in time (Table 4). The difference between the station minimum flow and the project minimum flow, a constant 50 cfs, is directed through the fishway at all times.

Period	Project Min. Flow[1] Cfs	Station Min. Flow Cfs
Jan 1 – 31	450	400
Feb 1 – 28	450	400
Mar 1 – 31	450	400
Apr 1 – 30	Run of River	Run of River
May 1 – 15	Run of River	Run of River
May 16 – 31	1000	950
Jun 1 – 15	1000	950
Jun 16 – 30	450	400
Jul 1 – 31	450	400
Aug 1 – 31	450	400
Sep 1 – 30	450	400
Oct 1 – 31	450	400
Nov 1 – 30	450	400
Dec 1 – 31	450	400

Table 4. Minimum flow required through the Essex 19 facility throughout the year Kleinschmidt, 2001). During April and May, the facility operates as run-of-river. This is typically the wettest time of the year, so the affect of low flow on fish populations is not a concern.

According to the Essex 19 Feasibility Study conducted in October of 2001 by Kleinschmidt, "in addition to reducing generation, the minimum flow requirement raises compliance issues because there is no reliable way of complying with the minimum flow requirement during periods of low river flows" (Kleinschmidt, 2001). Before the upgrade, river flows below 275 cfs would render the turbines idle as it was "not practical" to operate the existing turbines at such a low rate of efficiency (Kleinschmidt, 2001). During these times, any

water not diverted through the fishway was simply passed over the dam without generating any power.

Another issue arose from the fact that, during these periods of low flow, the head pond or impounded water was often below the level of the dam. In order to maintain flow levels in these situations, the rubber dam tube must be deflated, thus reducing the height of the dam and allowing water to spill. During this interim period between the turbine shutoff and the refilling of the head pond, no water emerged downstream of the dam. This often left Essex 19 in direct violation of its low flow minimum and thus in violation of its FERC license (Castonguay, 2011c).

Current Status

In order to remedy this problem, GMP proposed the installation of a low flow turbine and implemented these plans in 2006. This fifth runner, with a 750 kW capacity (much smaller than the original four), operates 24 hours a day, providing stability and added generation during periods of low flow (Castonguay, 2011c). This runner takes advantage of any flow below the cut-off point for the four main runners (275 cfs) and above the flow designated for the fishway (50 cfs). The runner was sized to handle any flows in this range. Capturing this previously untapped flow augments the facility's generation by approximately 2,900 MWh annually (Kleinschmidt, 2001).

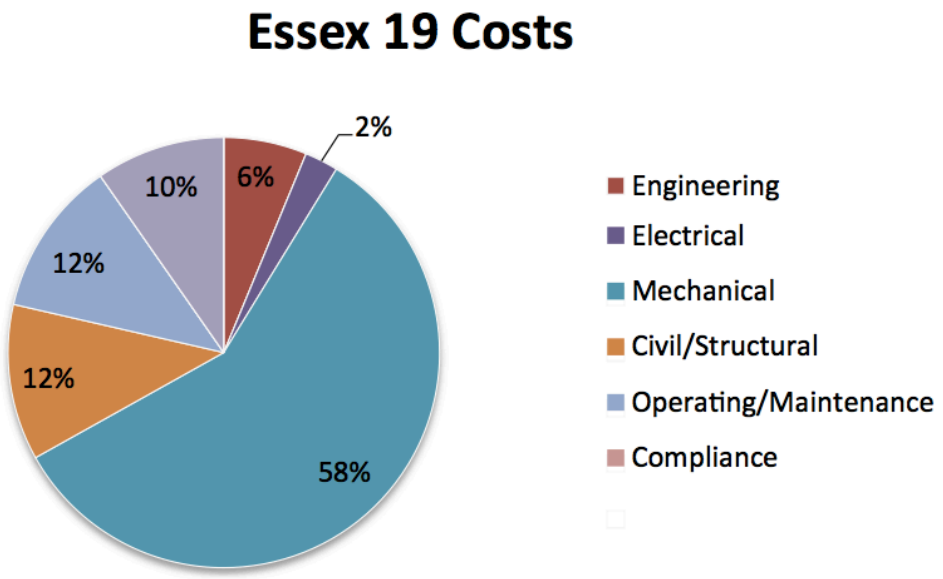

Figure 5. Cost breakdown by percentage for the 750 kW upgrade at the Essex 19 facility. Specific components of these costs are detailed and expanded upon below.

Community Outreach Costs

From the beginning, home- and landowners adjacent to the Essex 19 facility were included in discussions moving forward. There were concerns that alterations made as a result of the project could increase erosion rates and give rise to instability along the banks. For further details of these costs and concerns, please refer to the "Extraneous Costs" section detailed below.

Engineering and Study Costs - $104,300

Kleinschmidt Energy and Water Resource Consultants conducted a feasibility study for the Essex 19 facility in 2001. They also projected engineering costs at this time. The feasibility study estimates that these phases cost GMP approximately $104,300 (Kleinschmidt, 2001).

Licensing and Permitting Costs

This project differs from some of our other case studies in that it was a response to a licensing change. GMP found a way to use the minimum flow requirement to their advantage, but they did not initially designate Essex 19 as a site needing upgrade. Permitting costs were thus relatively low as GMP was working to fulfill a FERC requirement rather than proposing their own new project.

Electrical Costs - $42,000

The minimum flow turbine also necessitated the installation of an entirely new electrical system used solely for its operation. The separate, independently operating electrical system gives GMP the freedom and security to use the minimum flow unit as a temporary backup should the other four turbines get "tripped" by electrical issues (Kleinschmidt, 2001).

Mechanical Costs - $972,500

GMP enlisted the help of Canadian Hydro Components Ltd. during the procurement phase of this project (Kleinschmidt, 2001). The utility spent approximately $972,500 on a "water-to-wire" system that included the following equipment: the 750 kW turbine, the generator, switchgears, protection and controls (Canadian Hydro Components Ltd., 2011). This figure does not include installation fees (see "Electrical Costs" and "Civil and Structural Costs"). The 750 kW, minimum-flow turbine alone cost $550,000 (Castonguay, 2011c).

Civil and Structural Costs - $196,200

Installation of the turbine took advantage of two existing penstocks at the site, each three feet in diameter (Kahl, 2011). The minimum flow unit is most necessary during times of very

low flow. The two penstocks are located at the very bottom of the dam on the upstream side, and both are necessary in order "to get enough water to spin the minimum flow unit." (Castonguay, 2011d) These penstocks once carried water to "excite" turbines with DC energy to bring them online effectively. In 2006, the penstocks were converged into a "y" shape to concentrate the water before it is fed into the new runner.

Specific costs are listed below to give an idea of potential civil and structural costs:

- Restructuring of the existing penstock system: $112,200
- Installation of the 750 kW Kaplan turbine and housing: $70,000
- Excavation: $4,000
- "Mobilization/demobilization/cleanup": $10,000

Operating and Maintenance Costs - $196,000

Kleinschmidt's 2001 feasibility study estimates that annual "carrying" costs to be around $196,000 (Kleinschmidt, 2001). This would include the costs of day-to-day operation and also miscellaneous repairs and general upkeep.

Compliance Costs

As is the case with the Winooski One facility, Essex 19 is constantly held to standards of minimum flow that vary throughout the year (Kleinschmidt, 2001). Essex 19 was able to capitalize on the 1995 change to these minimum flow standards with the retrofit detailed in this case study. However, any reduction of the flow passing through the turbine creates a loss of energy generation and thus a loss of revenue. That being said, the cost of staying in compliance with these requirements is much cheaper than the fines associated with violations.

Extraneous Costs

In 1995, Essex 19 was issued a Cultural Resource Management Plan (CRMP) by the Vermont Division for Historic Preservation. According to the "2010 Annual Cultural Resources Management Plan Report; Essex 19 Hydroelectric Project" published by FERC, "a principal goal of the CRMP, is to manage the [facility] as a unified system by limiting or preventing bank erosion to protect historic properties in conjunction with other resources" (FERC Essex 19, 2010). It also protects archaeologically sensitive land along the banks of the Winooski River near the Essex 19 facility. The CRMP has largely resulted in annual monitoring of these sensitive areas and a raised level of awareness concerning erosion caused by changing head pond levels.

Taxes

Information regarding annual taxes is proprietary.

Contingency Costs - $162,000

Contingency costs for construction were estimated to be 15% of total construction costs or $29,700 (Kleinschmidt, 2001). Contingency costs for equipment were estimated to be 5% of total equipment costs or $51,225 (Kleinschmidt, 2001).

TOWNSHEND:

Site History

The Townshend Dam is located on the West River near Townshend in Windham County, Vermont. It lies approximately 19.5 miles upstream of the confluence of the West River and the Connecticut River. The 1,700-foot-long and 126-foot-high rolled-earth and rock-filled dam controls the flow of water from the West River watershed. The Townshend Dam was initially created as a part of a network of 16 flood control projects on the Connecticut River watershed. This facility was originally constructed by the US Army Corp of Engineers in 1959 and has been operating under their control since 1961. In addition to maintaining its initial purpose of mitigating flood impacts, today the head pond is used as a recreational facility with a beach, boathouse, and numerous picnic tables and grills.

Project Proposal

In early 2009 Blue Heron Hydro, LLC (BHH) submitted a preliminary permit application to FERC proposing to convert the flood control dam to a run-of-river hydrogeneration facility. According to Lori Barg of BHH, the Townshend retrofit aims to reach the gold standard of environmentally and socially responsible renewable energy projects. To achieve this goal, BHH proposes to install twelve small Obermeyer turbine units in the existing intake tower at the dam. These units have an average capacity of 77 kW, with a total combined capacity of 925 kW (Barg, 2009a).

Since this project would represent the first electrical generation at the Townshend site, it will require the construction of new transmission lines to connect it to the grid. The project

proposes to build a new 45-kV transmission line along the existing road. The transmission line will connect the Townshend generation facility to the local electrical distribution network.

Other than the construction of a new transmission line, installation of these turbines will require minimal structural alteration of the Townshend Dam. The retrofit will not diminish or impact the flow of the West River or cause "any other undue negative environmental and socio-economic impacts" (Barg, 2009b). The project also will not affect the recreational pool or the surrounding recreational facilities, and BHH plans to utilize the existing powerhouse structure. The impoundment, embankment and spillway are under the control of the Army Corp of Engineers and will not be addressed in BHH's project. These factors will all help to reduce overall construction costs.

In July 2010, the Vermont ANR issued a 401 Water Quality Certification for the Townshend Dam. This was a huge success as it is the first riverine hydro project to receive water quality certification from the state in 25 years (Keese, 2011). There are two major conditions on which the certification relies. First, the level of the reservoir must be maintained at 21 feet for run-of-river operation; second, BHH must construct a downstream fish passage (Fitzgerald, 2011c).

Current Status

The original goal was to obtain a license for the new project by the end of 2010 or beginning of 2011. Had this proceeded as planned, construction would have begun on October 7th, 2011, the 50th anniversary of the dam. However, the permitting process has been delayed and this projected date passed without any action. On November 1st, 2011, BHH, with the support of Governor Shumlin, petitioned FERC requesting expedited consideration of the

Townshend license application (Shumlin, 2011). License approval is needed before 2012 in order to for the project to qualify for benefits under the American Reinvestment and Recovery Act. Additionally, the project must be operating by the end of 2012 in order to qualify for support from the Vermont Sustainable Priced Energy Development Program (SPEED). Failure to meet either of these deadlines would result in the loss of these state and federal incentives.

The Townshend project is projected to have the total capacity of 960 kW generating, 3,605,000 kWh annually. Considering that the average Vermont household consumes between 6,000 and 8,000 kWh each year, the Townshend facility would generate enough electricity to power 1,300 Vermont households annually (Cone, 2010).

As the project is still in the licensing and permitting phase, the projected costs presented below are not final. These numbers are taken from BHH's cost outline in their July 2010 application to FERC. The total project cost is estimated to be approximately $2.9 million.

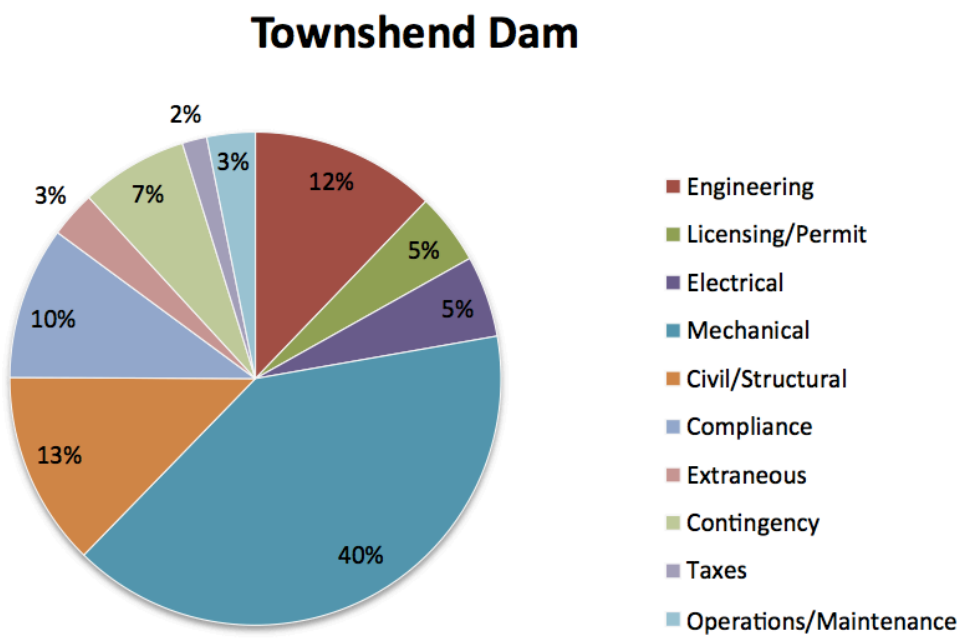

Figure 6. Projected cost breakdown by percentage for the 960 kW retrofit proposed at the Townshend and Ball Mountain Dams. Specific components of these costs are detailed and expanded upon below.

Community Outreach Costs

Townshend would require little community outreach because the upgrade of the dam and introduction of routine operational activities will not produce a significant adverse impact to the historic properties, alter the aesthetic flow, or change the general appearance of the dam.

Engineering and Study Costs - $557,400

BHH conducted a feasibility study early on in the process to assess whether or not the project was, in fact, worth undertaking. This study cost $52,400. Moving forward from this point, the engineering cost to design and implement this study was $100,000.

The total environmental costs for the upgrade are estimated to be $375,000. BHH worked with the Alden Labs to conduct a $30,000 study regarding the impact that the projected facility would have on local fish and ways to mitigate this impact. These studies note the need for a fishway to allow safe passage of a variety of fish species. Of particular concern and interest is the Atlantic salmon. This species, once native to the Connecticut River Basin, disappeared from the region at the beginning of the 19th century. The Connecticut River Basin Atlantic Salmon Restoration Program now aims to restore the Atlantic Salmon through "habitat protection, fisheries management, research, regulation, hatchery production and stocking" (USFWS 2010). As part of the Basin, the Townshend Dam will also play a crucial role in this restoration process, necessitating significant caution and mitigation efforts.

Licensing and Permitting Costs - $175,000

BHH has been considering the Townshend Dam project installation since early 2009. Later that same year, BHH changed the FERC license proposal to include another of their hydroelectric projects, the Ball Mountain Dam. The two dams, located within ten miles of each

other on the West River, are extremely compatible. Since they were both constructed as part of the original flood mitigation network in 1961, they are intended to work in conjunction with one another. The projected future costs listed below will reflect the development of the Townshend Dam and the Ball Mountain Dam as a single, combined project. The assumption is that Townshend will not be pursued on its own, but that both projects will be undertaken when the proper license is received.

If the license application is denied by FERC, BHH will lose approximately $175,000 spent on license activities, including background research, meetings, investigations, and environmental and engineering studies.

Electrical Costs - $200,000

As mentioned previously, a hydrogeneration site at the Townshend Dam will require an entirely new grid connection system. Total electrical costs, including purchase and installation of the transformers and wiring, are estimated to be approximately $200,000.

Mechanical Costs - $1.5 million

The cost of the turbine and generating equipment for the Townshend and Ball Mountain Dam is estimated to be around $1,300,000. The Obermeyer gates and primary pipe conduit are each projected to cost an additional $80,000. The hydraulic equipment will cost another $50,000.

Civil and Structural Costs - $478,000

Realization of this dam upgrade would require significant structural alteration of the dam site and extensive new installations. Some cost estiamtes are outlined below:

- Working Platform: $40,000
- Turbine Hoist Mechanism: $80,000
- Construction Supervision: $50,000
- Labor and Installation: $308,000

Operating and Maintenance Costs - $119,000/year

For the first 20 years of maintenance and operation of the Townshend Dam, the expected annual average cost is $119,000.

Compliance Costs - $375,000

Efforts to mitigate negative impacts on fish will include a screen over the intake and a fish passage. The $5,000 screen, composed of bars spaced at one-inch intervals, is designed to keep fish out of the generation equipment. Along with keeping fish out, the screen will inevitably cause a build up of debris that could clog the intake, reducing usable flow and necessitating regular maintenance. The facility expects to lose $25,000 to $37,000 annually as a result of this 10-15% reduction of flow. Annual operation and maintenance of the fishway system is predicted to be around $20,000. Annual environmental impact assessments will also be necessary to ensure that the Townshend Dam remains in compliance.

The Army Corp of Engineers has been collaborating with the Vermont Agency of Natural Resources to ensure that the proper measures are taken to mitigate the environmental impacts of the flood control dam. The proposed hydroelectric project is determined not create any new negative impacts. Measures taken to mitigate the facility's impact on the basin's environmental resources will be around $375,000.

Extraneous Costs - $114,000

- Construction Loan Fees: $10,000
- Construction Loan Interest: $84,000
- Permanent Loan Financing: $10,000
- Miscellaneous Legal, Accounting, and Professional Expenses: $10,000

Taxes - $61,000

Local, state, and federal taxes are estimated to amount to approximately $61,000 annually.

Contingency Costs - $264,000

It is to be noted that the total project capital cost is dependent on obtaining a FERC license or permit to pursue the hydroelectric generation project. There is a 10% contingency fee and debt service fee on the total initial project cost noting the amount of money that it takes to actually get this project licensed and operating. There is no doubt that there will be some unforeseen costs across the board in licensing and developing the dam.

MIDDLEBURY UPPER FALLS:

Site History

The Otter Creek Falls, a 37-foot waterfall under Battel Bridge in Middlebury, Vermont has a long history of hydropower generation. Beginning in the late-eighteenth century, industrious settlers took advantage of Otter Creek's hydropower potential and "successfully harnessed the river to power lumber mills, grist mills, woolen mills, foundries, and machine shops" (Lake Champlain Basin Program). For many years, Middlebury Upper provided power for the Frog Hollow Mill, a saw and gristmill. In 1890, Middlebury Electric Company installed electrical generating equipment in the mill, later updating the equipment in 1917. Twelve years later, in 1929, Middlebury Electric merged with seven other local electric utilities to become Central Vermont Public Service (CVPS). Under this ownership, the Otter Creek Falls continued to produce hydropower for the Town of Middlebury.

The river produced power continuously from 1774 until 1964, at which point the turbine failed. At the time, the Town decided that it would not be cost-effective to fix the turbine, so hydropower generation halted. The mill was sold to the Town of Middlebury, and then again to a firm called Townscape. Hydro generation fell out of the public eye for a while until CVPS, eager to reinvigorate the project, created a proposal for a hydro system on Middlebury Upper in 1982. Due to aesthetic complaints, insufficient monetary incentives, and proposed redirection of the water flow, the project did not come to fruition.

Project Proposal

Beginning in the late 1980s, Anders Holm, a life-long Middlebury resident and local doctor, took special interest in this site on Otter Creek Falls. He reestablished Middlebury Electric, Inc. and compiled an entirely new proposal for a 1 MW run-of-river hydroelectric project on the Falls (Middlebury Electric, Inc., 2008). Holm's proposal is much improved from the last one, in large part because he suggests a run-of-the-river system that would maintain aesthetics and not alter water flow. "Great pains have been taken to integrate it with existing structures," explained Holm in a 2007 interview (Flowers, 2007). "This plan was designed to be minimally invasive," so the majority of the infrastructure would be placed along the Frog Hollow building and the powerhouse would go under the footbridge that extends over the river. Holm even suggests improving the site for local visitors by cleaning up the riparian area below the falls and marketing it as a park where people could stroll and picnic.

Current Status

The most recent feasibility report states, "Based on a conservative figure of 8 cents per kWh, 5.8 million kWh per year will produce $464,000 in electricity sales," but could even be up to as much as $700,000 (Gomez and Sullivan Engineers, 2006). This project would prevent 25,000 tons of $C0_2$ emissions each year, the annual equivalent of 6,000 tons of coal (Middlebury Electric, Inc., 2008).

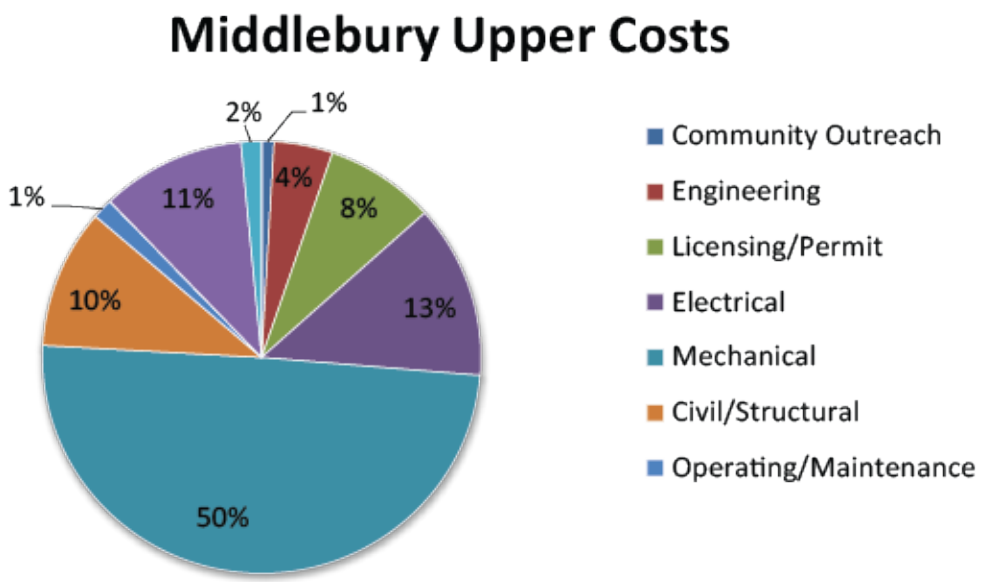

Figure 7. Projected cost breakdown by percentage for the retrofit proposed at the Middlebury Upper Falls site. Specific components of these costs are detailed and expanded upon below.

Community Outreach Costs - $42,000

As of November 2011, the Town of Middlebury had spent $42,000 on legal fees. Middlebury Electric has also spent a comparable amount of money. These fees include the negotiation of water rights, aesthetics and municipal land compensation. After years of stalemate and political hang-ups, the Town is willing to resume work with Holm in the hopes of moving forward with the project (Flowers, 2011). The Town is frustrated by FERC's recent decision to exempt the project from the more extensive Integrated Licensing Process (ILP) and instead evaluate it through the Traditional Licensing Process (TLP). The Town would like to play a greater role in the development of the project to ensure that adequate considerations have been made to provide for the long-term success of the project. All parties are interested in seeing hydropower development move forward at the Falls. Though pleased by the FERC announcement, Holm is frustrated that it came right after the state reached its 50 MW small-scale

renewable quota through its SPEED Program. The program could have saved Holm up to $18 million over the next 20 years, pending project approval. If the next legislative session lifts the quota, Holm will resubmit his proposal to SPEED (Flowers, 2011). In the meantime, Holm has 60 days to respond to FERC and apply for permitting through the TLP.

Engineering and Study Costs - $200,000

Middlebury Electric worked with several groups to perform site studies. Gomez and Sullivan Engineers conducted the pre-feasibility report and Kleinschmidt was responsible for the engineering and design phases of the project.

Licensing and Permitting Costs - $250,000-$500,000

Middlebury Electric has worked to secure licensing and permitting at the local, state and federal levels. Negotiations with the Town of Middlebury are ongoing, as are the discussions with FERC. Construction permitting is estimated to be around $50,000.

Electrical Costs - $600,000

The budget estimates $100,000 of electrical work including procurement and installation of conduits, wiring, lighting, outlets and general station services. Connection to Middlebury's electrical grid would cost an additional $500,000 including wiring and labor.

Mechanical Costs - $2,291,064

Gomez and Sullivan Engineers predict total mechanical costs to be approximately $2.3 million. Some individual costs are detailed below:

- Turbine, generator and control system: $1,070,000
- Transformer and switchgear: $100,000

- Automatic flashboard system: $162,220
- Water control gate: $96,344

Civil and Structural Costs - $482,245

Since the Middlebury Upper site has lain inactive for decades, much work will be needed to bring it back online. Such work will include, but is not limited to, the excavation of debris that has built up above the dam, repair of the flume and penstock—which now sit in disrepair—and construction of an entirely new powerhouse. Other costs are detailed below:

- Installation of the turbine, generator and control system: $150,000
- Installation of the flashboard system: $20,000
- Installation of water control gate: $2,000
- Concrete pouring and the construction of cofferdams: $30,000

Operating and Maintenance Costs - $70,000 annually

The turbine will require minimal maintenance, which will be carried out by CVPS technicians (Middlebury Electric, Inc., 2008). Costs would be low and tasks would be performed by CVPS, with an estimated annual cost of $40,000 per year (Holm, 2011). An additional expense would be $30,000 per year in rent (Holm, 2011).

Compliance Costs

Middlebury Electric hired a Vermont law firm to perform the Certificate of Public Good application process (Middlebury Electric, Inc., 2008).

Extraneous Costs

In order to appeal to the local community, Middlebury Electric plans to build a park by the facility, thereby restoring a section of land that has been greatly damaged by high water flow.

Landworks, a landscape design firm based in Middlebury, generated renderings and three-dimensional simulations of the proposed park renovation.

Taxes - $70,000

Holm predicts taxes will be approximately $70,000 annually (Holm, 2011).

Contingency Costs - $492,000

- Interest: $120,000
- Contingency allowance for the turbine: $344,000
- Contingency allowance for the flashboards: $28,000

Discussion

Vermont's 2011 Comprehensive Energy Plan looks to hydropower as a significant source of its renewable energy portfolio (Vermont Department of Public Service, 2011). The primary source of this untapped opportunity for hydro-generation in Vermont exists in the retrofitting and upgrading of existing small-scale dams. The question then becomes *how* to undertake this development while simultaneously accounting for social, ecological, and economic implications.

In order to do this, we collaborated with a group of five colleagues who were tasked with looking at the ecological implications of retrofitting dams.[3] Through an analysis of the relative environmental benefits of avoided greenhouse gas emissions, this group determined that, in many cases, retrofits intended to add generation capacity to a dam were simply not worth the detrimental ecological impacts to existing ecosystems. In some of these cases, they found dam removal to be the preferred alternative. They propose that Vermont lawmakers and conservation agencies systematically evaluate all 1,100 non-generating dams in the state to determine which ones are candidates for removal and river restoration and which are candidates for hydroelectric retrofit if social or historical factors make the dam impossible to remove.

It is important first to know that a project is acceptable by ecological standards rather than having the development derailed by this fact down the road once other costs have been incurred; therefore, our project picks up where our colleagues left off. After determining the ecological viability of a retrofit or upgrade project, a developer should consider its economic feasibility. The economic considerations of our framework will aid developers in this process.

[3] Ibid.

Our research examines existing cases of hydropower upgrades and retrofits, examples stemming both from our literature review and from first-hand exploration of five case studies in Vermont. We used these five examples to inform our framework, and ultimately to provide a baseline understanding for potential developers as to what they might expect from such a project, and also to help them to assess the viability of their project at an early stage in the process.

The major findings of our work are fourfold. First, we find when assessing economic viability, one should consider cost per kilowatt of generation capacity rather than total project costs. Second, we concluded that in order to account for future energy price uncertainty, a developer should determine when to move forward with a project based on the energy price that will provide the desired payback. Third, we saw that despite initial beliefs, acquisition of upfront capital appears to be the most significant hurdle facing development. Finally, although a project may be deemed economically feasible, it may not succeed because of external factors, not captured in our economic analysis. These findings combined to inform our policy recommendations in order to improve upon the existing process of retrofitting and upgrading dams. A further explanation of these findings can be found below.

A look at cost per additional kilowatt of generational capacity

Many economic studies examine hydropower development on the basis of total project costs. We found this approach to be inadequate because it does not account for the great variation in project scales. That is not to say that total costs are irrelevant, rather that examination of these costs is not sufficient on its own. As mentioned in the cost section of our framework, the estimation of *total* costs allows a developer to gauge his or her ability to finance such a venture and to understand the need for loans or outside investors. These numbers, however, give

the developer little frame of reference with regards to other development projects of different scales.

Alternatively, the estimation of the cost of installing *an additional kW of capacity* enables the developer to compare costs to upgrades and/or retrofits projects of different scales. Furthermore, by comparing generating capacity developers have an indicator of the revenue potential for a given project. This eliminates the need to compare projects of similar scale and site characteristics. In doing so, this approach allows for broader and more comprehensive comparisons and allows developers to learn from myriad examples of hydropower augmentation around the world. In Table 3 we present the range of costs seen in our five case studies; however, in order to define a range of cost per kW that is viable, more information is needed. A thorough examination of more projects would further define the ranges of costs that appear to be economically feasible.

Dealing with price volatility

Our decision-making framework allows a developer with a reasonable prediction of expected revenue per kilowatt-hour to calculate the annual revenue stream of a project. If the developer lacks a reasonable prediction or is looking into future projects at a time when the variability of energy prices is high, the framework indicates at which price per kilowatt-hour it would be viable to develop a project. This decision is made based on the average cost to install each kilowatt and the desired time until payback. If current conditions do not match these criteria, the development plans may be set aside until a reasonable prediction of future energy prices can found.

Barriers to entry: upfront costs

Initial research led us to believe that costs associated with the community outreach, licensing and permitting phases would be the most significant (Fitzgerald, 2011a). As a result, we assumed that these costs would be the most likely to discourage retrofits and upgrades. Close examination of our case studies and associated literature, however, revealed a different trend. Our five case studies suggest that mechanical, civil, structural and engineering costs accounted for the largest portion of total costs.

These findings are consistent with relevant international studies indicating high upfront capital costs are significant deterrents to hydropower development in many regions such as India, Norway and rural western China (Purohit, 2008; Kjaerland, 2007; Byrne et al., 2007). Byrne et al. (2007) found that micro-finance could be a major step forward in making micro-hydro development economically viable by helping developers cope with often-insurmountable upfront costs. We detail our policy recommendations and the ways in which upfront costs are addressed in the current Vermont policy landscape below.

We do not wish to convey the message that community outreach and permitting are unimportant. In accordance with our review of the current literature on this subject, we encourage developers to take these phases into account when determining the quality of a potential hydropower development project (Aggidis et al., 2010; Rojanamon et al., 2009). The regulatory framework in the United States is designed to enforce this multifaceted approach. The process involves extensive fact-finding efforts to identify the most promising sites that minimize the total potential negative impacts on a diverse range of stakeholders while preserving the economic viability of the project. Such stakeholders can include, but are not limited to,

individuals living near the river, recreational or agricultural users of the river and drainage area, consumers of the energy that could be produced, town agencies, and environmental advocates.

This multi-criteria analysis—while an inclusive tactic—comes at a considerable cost to those applying for permits. It is important to note that in the undertaking of a multi-criteria analysis, many studies find small-scale hydropower development to be favorable due to relatively lesser environmental impacts. Regardless of the scale of the development, environmental and social factors greatly impact the design, scale and implementation of a project. This impact can be seen clearly in the Winooski One case study detailed above. The Winooski One Partnership constructed a park in order to appeal to the local community and they operate a fishway throughout the year to remain in compliance with their permitting from the Agency of Natural Resources. Had these issues not been taken into consideration, the project would not have moved beyond the planning phase.

The process of a multi-criteria analysis is also a time-intensive process and delays can stress the budget and lead to a failure to meet deadlines for state and federal incentives. If these phases are not taken seriously—or are not handled early in the process—they can derail a project further down the line once significant costs have already been incurred.

Beyond economic feasibility

We recognize that while our analysis is sound, it does not have the ability to predict with certainty whether a project should move forward or whether it is doomed to fail. Two out of the five cases that we examined have already succeeded (Winooski One and Essex 19), one is in the process of beginning construction (Gorge 18), and two remain in the throes of negotiations and planning (Townshend and Middlebury Upper). Our framework provides a step-by-step process

by which developers can examine costs at any phase of the development and realize the potential for insurmountable costs before they have been spent.

The Middlebury Upper Falls project presents a case in which economic viability does not guarantee that a project will move forward unhampered. Although our framework suggests that Middlebury Upper Falls is economically viable, the reality of the project is much more complicated. Projects and individual costs manifest themselves in many forms and often do not to fall into neatly defined categories. Our framework, however, deals with costs that are visible and, to some extent, predictable giving developers a guide as to what to expect from their projects.

Policy Recommendations

The State of Vermont and the federal government have employed a variety of economic incentives and subsidies to encourage the development of cleaner, domestic energy sources, with mixed success. There are two main policy strategies that can help accomplish this goal.

The first is to offer developers a reward for completing a renewable energy project. This strategy makes it more attractive for developers to look at clean, renewable projects because developers know they will eventually get monetary benefits for producing clean energy. Often these are benefits that will exist in perpetuity rather than one-time, lump sum rewards. In this sort of policy scheme, developers are only rewarded as power is added to the grid, ensuring the government is only paying for projects that have a measurable impact.

The other strategy is to offer developers a pool of risk-free money at the beginning of a project, such as a grant or a loan guarantee. This policy makes it easier for developers to attract complementary investment and removes some of the unknowns in determining the costs and

benefits of the project. Both strategies have benefited hydroelectric developers in Vermont, but our case studies suggest that potential developers are faced with a tough investment climate and would benefit from more emphasis on the latter policy. As developers need upfront capital to help with the sheer magnitude of start-up costs, the timing of government funding becomes equally as important as the dollar amount granted.

John Warshow, a key player in the development of the Winooski One project, writes, "The grants are usually better than the production tax credit. Upfront money is often a problem, it always was for us anyway" (Warshow, 2011e). Lori Barg, an experienced hydropower developer in the state, reports that "many projects, and not just hydro ones" have "fizzled out because they couldn't secure upfront funding" (Barg, 2011a). The framework outlined earlier in this report alludes to one reason why this upfront funding might make more sense to developers: costs associated with upgrades and retrofits tend to be heavily front-loaded. Thus, policies should be designed to increase the amount of funding available for grants, loan guarantees, or other upfront incentives.

One of our proposed policy solutions takes inspiration from a little-known facet of the 2009 American Recovery and Reinvestment Act (ARRA, or the Stimulus Bill). That law temporarily allowed "taxpayers eligible for the renewable electricity production tax credit (PTC) to receive a grant from the U.S. Treasury Department instead of taking the PTC for new installations" (Database of State Incentives for Renewables & Efficiency, 2010). At the conclusion of the 2011 legislative session, the Vermont Legislature (under the urging of the Shumlin Administration) shelved a plan to add a $6.60 annual fee to Vermonters' electricity bills to fund the Clean Energy Development Fund (CEDF) in favor of a similar tax-credit-for-grant swap. As the Vermont Natural Resources Council reports, the 2011 Energy Bill (H. 56) allowed

"businesses offered… a tax credit to take a 50 percent discount on the value of those credits in return for receiving an upfront, one-time grant in lieu of the credit." This approach "will raise between $2.7 million and $3 million of those funds to support other CEDF-approved renewable energy projects — at no additional cost to Vermonters," and focuses state support on upfront money rather than less-needed, down-the-line incentives (Vermont Natural Resources Council, 2011). This policy was viewed as a stopgap measure to temporarily help fund the CEDF while other financing alternatives are studied. In the 2012 Legislative Session, we recommend that the legislature keep this sort of upfront funding in mind as it has been deemed critical to the development of clean energy in the state, and (according to our case studies and preliminary research) is more critical than programs like the Standard Offer or other rate-based incentives.

Government bureaucrats and policymakers have the power and responsibility to provide developers with effective tools to help achieve state energy priorities. In the current policy regime, public funding opportunities do not completely fall in line with the needs of hydropower developers. As upfront costs continue to rise, policies should be designed to help mitigate these barriers to dam construction if the state truly aims to have in-state hydropower generation as a significant portion of its energy portfolio. Switching funding from tax credits to development grants helps to accomplish this goal.

Our research concludes that, while ecologically and economically viable in some cases, dam retrofits and upgrades are not projects that should be undertaken lightly. Any finished product is the result of myriad sub-costs and it is not only the magnitude of these sub-costs that is of particular importance, but also the order in which they appear on a developer's balance sheet. In response to this complexity, we created a framework to better understand the nature of these costs and to help guide developers through the development process.

We have found past cases of retrofits and upgrades to be useful tools for illuminating this complex process. It is not enough, however, to continue on the same trajectory we have been following for decades: examining hydropower development and augmentation on a case-by-case basis and creating a piecemeal "process" as we go. We must build upon past experiences to improve the hydrogeneration scene as *a whole* rather than simply applying our knowledge to individual cases. For instance, an innovation that has the potential to benefit all hydropower retrofits and upgrades could be the implementation of a policy whereby developers can more easily receive upfront capital. We have seen that possession of significant amounts of upfront capital is essential for hydropower projects to move forward. Thus, securing this sort of funding across the board would greatly improve upon the outdated development process in use today.

As energy demand increases and power sources dwindle, expanding the renewable energy portfolio in Vermont is imperative. At this point, upgrading and retrofitting existing dams is the only way to augment hydrogeneration capacity in the State (Fitzgerald, 2011a). It is essential that we undertake this task in a thoughtful, well-informed and thorough manner, examining the social, environmental and economic factors. Only then can we face the future knowing that we have done our best to provide for future generations.

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Glossary

Actual Flow Rate (power generation): Actual flow is determined as the flow that can feasibly and legally be used for generation. State and Federal regulations require that a certain minimum flow be maintained in the riverbed, decreasing the water available to be diverted for generation. In many cases, the minimum flow requirement can severely decrease the profitability of the venture.

Unless it is otherwise determined that spawning/incubation requirements do not exist in the specified basin, the Vermont Agency of Natural Resources adheres to the U.S. Fish and Wildlife threshold. If spawning and incubation requirements are determined to not exist, the ANR requires a year-round release of 0.5 csm (cubic feet per second per square mile). Otherwise, a minimum flow of 1.0 csm or 4.0 csm, for fall or spring incubation and spawning, respectively, is required.

ANR: Agency of Natural Resources

Average Capacity Utilization: A measure of how much capacity is utilized on average throughout the year. For instance, if a facility has 100 kW of installed capacity, but on average only has enough flow to utilize 50 kW of generation, their average capacity utilization would be 50%. Average capacity utilization functions to modify the System Efficiency figure to realistically depict how much of the installed capacity actually ends up as energy on the grid.

Average Facility Efficiency: Average capacity utilization multiplied by system efficiency.

Capital Costs: Includes all one-time costs (although payment can be spread out over multiple years) that are required to bring a facility online.

CEDF: Clean Energy Development Fund

Expenses: Includes all recurring costs needed to operate and maintain a facility.

FERC: Federal Energy Regulatory Commission; responsible for licensing of hydropower generation facilities nationally.

Flashboards: Structures (either wooden boards or, as is the recent technological trend, inflated tubes) that extend the length of the dam to increase or control the height of the dam and thus the head pond.

Generation Capacity: Also known as nominal capacity, this is the maximum generation capacity of a hydropower facility running at full efficiency without any interruption.

GMP: Green Mountain Power; electric utility serving approximately 90,000 Vermonters; owner of the Essex 19 and Gorge 18 facilities.

Head: The height that the water drops as it travels to the generator.

Plant Costs: Costs necessary for successful construction, operation and maintenance of the facility.

Regulatory Compliance Costs: Costs necessary to uphold the conditions of a given licensing agreement.

Run-of-River: A hydrogeneration facility that utilizes the flow of the river as it naturally occurs; such facilities do not use ponding techniques or reservoirs to augment head height and thus generation capacity.

Runner: The propeller of the turbine; the mechanism that actually spins as water is passed through the unit.

System Efficiency (power generation): A measure of how much energy is lost when converting from hydraulic energy to mechanical energy (as given by the turbine efficiency) and when converting from mechanical energy to electrical energy. System efficiencies generally run at around 50-60%.

Turbine: Includes the propeller (see "runner"), casing and housing.

Appendix A

A look at non-traditional hydropower generation

"Where there's a pipe, there's a way"

The scope of our project focused exclusively on existing dam structures in Vermont and the opportunity to upgrade and retrofit these sites. Our research, however, introduced us to possibilities that take advantage of other types of existing infrastructure. This trend takes advantage of what is known as hydrokinetic technology by utilizing water running through existing pipes and other conduits (Kosnik, 2008).

We found this trend in the hydropower scene to be of particular interest since water conduits (including pipes for waste water, storm water and municipal drinking water) are ubiquitous. The potential to use this source of flowing water to turn turbines is not only realistic, it is also feasible on many scales (from large cities to small hamlets) and in many locations. We examined such a proposal to install generation capacity in a pipe conduit in the Town of Barre, Vermont. Below, we have outlined the Barre case study as we did the previous five, and applied the cost framework to better develop our understanding of this emerging trend in hydropower generation.

BARRE:

Project Proposal

In May 2007, the City of Barre partnered with Rentricity, Inc to conduct a feasibility study on the strategic placement of a turbine inside a conduit pipe that runs downhill from the

Dix and Lower Orange Reservoir Dam (both earthen embankment dams near the Town of Barre) as a means of producing electricity (Delcore, 2009). This feasibility study aimed to assess whether or not pursuit of such a small-scale, low-impact hydroelectric system would be a worthwhile investment.

As a firm, Rentricity is interested in low-impact hydroelectric power, and in this study the company focused primarily on the generation potential of an energy system implemented at designated water distribution sites surrounding the City of Barre. In order to better understand the generation potential of the sites, Rentricity collaborated with the engineering company, Kleinschmidt (Schimpff et al., 2007). Kleinschmidt specializes in the mechanical and civil engineering aspects of dams and the associated hydropower. For our purposes, Kleinschmidt will be referred to under the name Rentricity.

This study was divided into two phases. The first phase reviewed a total of nine designated sites around the City of Barre as potential energy generating sources. These sites were analyzed based on the flow rate and the head of the site. Further examination of each site included the estimation of the kW potential and the ease of interconnection with the grid (Spinell, 2011). Based on their assessments, Rentricity determined that the Thurman Dix Reservoir Dam and Lower Orange Reservoir Spillway proved to be the best candidates.

The proposed development at the Dix Reservoir would result in additional flow to the Lower Orange Dam. The developable head estimated for this dam is approximately 30 feet. The Lower Orange Dam would be able to utilize an estimated flow of ten cfs that would contribute to an anticipated generating capacity of 20 kW.

The installation of a siphon style intake over the dam embankment is proposed for the Dix Reservoir site. A conduit would be attached to this intake and connected to a small, pre-

fabricated vault that contains the generating equipment and controls at the bottom of the dam embankment. The powerhouse would be located downstream and would house the turbine and generating equipment. The Lower Orange reservoir intake structure would be built in the spillway sluice channel (Schimpff et al., 2007). Then a conduit would be implemented to direct the flow to the vault. A small transmission line would be constructed to connect the generated power to the treatment facility.

Under the assumption that the Dix and Lower Orange Reservoirs will produce 394,000 kWh and 157,000 kWh and that the estimated price for electricity remains at 0.118/kWh, the payback will be ten years and 16 years respectively. However, the licensing and permitting efforts are not factored into these costs, factors that could increase the estimated payback.

Lori Barg and Nancy Wasserman, both representatives of Vermont Community Hydro, advocated that the small-scale, low-impact hydroelectric project studied would provide a local source of sustainable, renewable power that would be highly beneficial for the City of Barre. A lot of people, state regulators, lawmakers, hydroelectric developers, and utility representatives, have been consulted on the project and agree that the project is technically possible and economically viable. As Wasserman stated; "Everybody agrees this is the next best thing to motherhood and apple pie" (Declore, 2009). However the Barre City Council was originally torn about the small hydroelectric project because of the tight budget and the lack of hard data for projects of this sort nationally.

Securing financial help and funding was one of the biggest obstacles for this project. In the end, a combination of grants from the Vermont Community Development Program, Green Mountain Power, and the Vermont Department of Public Service made it possible to hire Rentricity to conduct the feasibility study.

Since all of the data for this case study are preliminary from the feasibility study, not all of the costs in the different sections are accounted for. The total projected costs are approximately $660,000 (Schimpff et al., 2007).

Community Outreach Costs

No costs are determined for this project as the study is still in the preliminary stage, but it is asserted that the placement of the energy systems will not have an impact on the aesthetics and recreational use of the area.

Engineering and Study Costs

The goal of the feasibility study was to narrow the list of potential sites around the City to the primary sites that would be most appropriate for this type of development. The study then compiled an assessment of the economic, regulatory, and technical aspects of implementing a small-scale, low-impact hydroelectric system at various designated sites around the City (Schimpff et al., 2007). The overall cost of the feasibility study was $40,600.

Rentricity was in charge of the overall project management and the engineering of the hydroelectric systems that would be implemented. Kleinschmidt oversaw the engineering services of the dam. In general 10-20% of the costs were dedicated to the engineering aspect of the development.

Licensing and Permitting Costs

The uncertainty in the permitting process was a major obstacle in this study. In their report, Rentricity recommended that the City of Barre approach the ANR and FERC to clarify the potential environmental issues and safety classifications linked to the proposed sites. The

issues with the permitting process are the same for a hydrokinetic system as they are for retrofitting/upgrading a dam. The timeframe of the permitting process is unpredictable and as a result it is hard to budget such a process. Ideally this hydrokinetic system would have received an exemption from FERC and the traditional regulatory permitting process, but because the proposed pipe was attached to the Lower Orange Dam, FERC considered it as an "extension" of the dam (Spinell, 2011).

Electrical Costs

Rentricity consulted with GMP regarding grid interconnection in Barre. At the Dix Reservoir Dam, the cost of the construction of transmission lines is lessened by the placement of the energy recovery system as close to the spillway as possible and the interconnection to GMP's grid at the nearest electrical distribution point. The proposed plan seeks to avoid the construction of an additional 8,000 feet to connect the generation site to the water treatment facility (Schimpff et al., 2007).

Mechanical Costs

No exact cost has been estimated for the mechanical aspects of this project. The turbines will account for a major portion of these costs, but Rentricity maintains that the selection of the turbine generator and control should occur during the detailed design phase.

Civil and Structural Costs

This proposed energy recovery system is designed not to impose any modifications of existing structures at the designated sites. The only cost will be installation of new mechanical equipment and the construction of the intake structures designed to take in and direct the flow of

water. The materials and the placement of the conduit also contribute to the construction costs, as well as the powerhouse that contains the turbine.

Operation and Maintenance Costs

Operation and maintenance costs are estimated to be approximately $2,500 annually.

Compliance Costs

Not applicable at this site.

Extraneous Costs

Bruce Harvey conducted the archeological assessment of this proposed project at sites below the Thurman Dix Dam and the Lower Orange Dam. Harvey is a cultural resource, archeological and historical expert who works with the State of Vermont to ensure that projects meet the requirements of the state (Schimpff et al., 2007). He concluded that the construction and the placement of the energy systems would not affect surrounding cultural resources.

Taxes

No estimated costs determined.

Contingency Costs

No estimated cost determined.

Appendix B

Basic hydropower economics

The economic viability of a potential hydrogeneration facility is typically estimated by examining the potential revenue of a venture as well as the potential capital costs and expenses. Revenue is directly correlated with the generation potential. Potential generation is estimated using the amount of head (the distance water will fall as a result of the dam), the usable flow (or volume of water flowing through the penstock) along with a value representing the efficiency of the system. Efficiencies vary greatly depending on the type of turbine used, the overall size of the project and flow characteristics of the river. The end result is a predicted number of kilowatt-hours (kWh) the given site should reasonably generate in a year. This energy can be sold over the course of a year to energy consumers on the grid at the prevailing market rate. Generated energy can also be used "behind the meter," meaning that it never enters the grid and is instead used to power the facility itself or another connected enterprise. A predicted rate for future energy prices can be used to compute a discounted benefit stream (Willer, 1981). This stream is discounted because people typically value benefits in the present more than they value projected or potential benefits in the future.

After computing a benefit stream, the next step is the estimation of capital cost data for permitting, design, construction and procurement, and finally annual costs such as operation and maintenance. Costs can vary greatly and depend on site characteristics, existing infrastructure, and technology choices. It is then crucial to compare the estimated benefit stream with the estimated cost stream when deciding whether or not it is economically feasible to undertake a project. If the sum of the annual benefits exceeded the costs within a specific time frame, five

years for example, the project would be deemed economically viable. As noted above, however, economic viability is not the only factor that should be taken into consideration in the decision to development or upgrade a site.

One potential resource that would be valuable to Vermonters is a clear statistical evaluation of the costs associated with existing hydropower facilities. From this information, individuals could develop preliminary cost estimates for further hydropower development in the state. Aggidis et al. (2010) have demonstrated that statistical techniques can accurately predict the engineering and construction costs of hydropower development less than one MW in the UK. Aggidis et al. (2010) analyzed a database containing cost data and site characteristics of 84 hydropower sites. Cost information was also divided based on technology choices such as turbine design. By examining site characteristics such as head height and mean annual flow, the researchers were able correlate the final project costs with site characteristics and provide a preliminary strategy through which project costs can be evaluated. It is important to note, however, that Aggidis et al. (2010) did not include social or environmental costs such as the historical value of the original dam or ecosystem effects due to disrupted flow rates.

Several studies acknowledge that the volatility of energy prices contributes to the uncertainty that potential developers face when considering investments in hydropower projects. A team from Norway used an innovative technique to calculate the price per kWh that would make a hydropower project economically viable (Kjaerland, 2007). By reporting the price per kWh at which a project becomes viable, the economic model insulates itself from the difficult task of predicting future prices. Thus, the result can be used by anyone, irrespective of his or her expectations regarding future energy prices. Furthermore, as official predictions conducted by governmental agencies change over time, the model for whether a hydropower facility is

economically viable remains robust. This finding from our literature review directly informed the recommendations presented in our framework and discussion.

Appendix C

The current policy climate:

Public funding for hydropower development in Vermont

To date, the Vermont Legislature has focused on the payment-over-time strategy to incentivize renewable energy production. One key program that has spurred clean energy development in Vermont is the Vermont Sustainably Priced Energy Enterprise Development (SPEED) Program, which established a slew of clean energy goals for the state when it was created in 2005. A major aspect of the Vermont SPEED program is a policy commonly known as a feed-in tariff, in which the government sets fixed, long-term rates that utilities must pay for a variety of renewable energy sources. This program, known as the Vermont Standard Offer Program was instituted in 2009 and, according to statute, "establishes default prices for the standard offer for different technologies, calculated to allow developers of renewable power purchased through the SPEED program to recover their costs plus a return on their investment" (VermontSPEED, 2011). For example, the SPEED program requires that energy retailers purchase power from hydro plants at a rate of $122.60 per megawatt hour produced (Database of State Incentives for Renewables & Efficiency, 2011). Many hydro developers contacted during our case study research mentioned the SPEED program as a major catalyst for retrofits and upgrades statewide, and a key reason projects were as profitable as they have been (Kahl, 2011; Warshow, 2011e).

One federal incentive that accomplishes similar goals as the Vermont Standard Offer Program is the Renewable Energy Production Tax Credit, or PTC. The PTC, according to the

federal government, is a "per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year" (Database of State Incentives for Renewables & Efficiency, 2010). Under current legislation, the government gives hydropower developers a tax credit of 1.1¢ per kilowatt-hour sold for the first ten years of production (Database of State Incentives for Renewables & Efficiency, 2010). In tandem, this duo of state and federal policies has helped spur interest in hydropower development and would allow upgrades and retrofits to become profitable earlier and more often.

Over the last decade or so, legislators and utilities in Vermont have crafted policies focused on the upfront cost part of the financing equation. The Vermont Clean Energy Development Fund (CEDF) was established by the Legislature in 2005 and is funded annually through the payments from Entergy Nuclear, the owner and operator of Vermont Yankee. Since its creation, the CEDF has made "more than $15 million in direct project grants and related expenditures and…transacted more than $3 million in loans" (Kavet, 2011). Of this funding, almost $500,000 has gone to fund hydropower projects by providing low interest loans, paying for feasibility studies and even paying for the construction and engineering of some projects (Kavet, 2011). A memorandum of understanding between the Department of Public Service and Entergy guarantees funding through the end of 2012, after which (if Vermont Yankee is decommissioned) it is likely the funding for the program will dry up.

A similar funding source is the pool of funds available to Central Vermont Public Service and Green Mountain Power called the Nuclear Electric Insurance, Ltd. (NEIL) fund. In approving the sale of the Vermont Yankee Nuclear Power Corporation by GMP and CVPS to Entergy Nuclear in 2001, the Vermont Public Service Board "determined that a 'significant

portion'" of NEIL credit amounts received "should be used toward the development and use of renewable-energy resources" (Central Vermont Public Service, 2004). While the total value of these funds and a timetable of their distribution aren't public information, Josh Castonguay of Green Mountain Power writes, "We don't know when it could go away. As of now, we will have another disbursement for 2012 and we expect to continue to get them. They have declined slightly over a few years" (Castonguay, 2011e). What is clear, however, is their impact on the utilities' energy development philosophies. Tom Kahl, a Kleinschmidt energy and water consultant who worked with GMP on the Essex 19 project says, "we couldn't have gone forward without the NEIL money" (Kahl, 2011). Both the CEDF and NEIL funds have provided upfront cash for developers starting the process of retrofitting and upgrading hydroelectric dams in Vermont, and both are sources of funding vital to renewable energy production in state, but they have an unclear future.

Vermonters have a variety of incentives at their disposal to help them along, but it is possible that these policies aren't suited to help the majority of developers. While some programs are set up to help with upfront costs and others are designed to incentivize using repeated payouts over time, clean energy developers often need a mix of the two in order to make a project cost effective. While long term programs like the Standard Offer are safe from alteration, other methods such as tax credits, loan guarantees, and renewable energy grants are on shakier political and economic grounds and could be vulnerable to budget cuts in coming years.