5-2016

Assessing the Economic and Flow Regime Outcomes of Alternative Hydropower Operations on the Connecticut River's Mainstem

Luke Detwiler

Assessing the Economic and Flow Regime Outcomes of Alternative Hydropower Operations on the Connecticut River's Mainstem

A Project Presented

by

Luke W. Detwiler

Master of Science in Civil Engineering

Department of Civil and Environmental Engineering
University of Massachusetts
Amherst, MA 01003

May 2016

Assessing the Economic and Flow Regime Outcomes of Alternative Hydropower Operations on the Connecticut River's Mainstem

A Masters Project Presented

by

Luke Detwiler

Approved as to style and content by:

Richard N. Palmer, Chairperson

Brett Towler, Member

Sanjay Arwade
Civil and Environmental Engineering Department

Table of Contents

Table of Figures

Table of Tables

Assessing the Economic and Flow Regime Outcomes of Alternative Hydropower Operations on the Connecticut River's Mainstem

To be submitted to the Journal of Water Resources Management and Planning

1 Abstract

Hydropower provides a source of reliable and inexpensive energy, producing approximately 20% of the global energy supply, though it comes at a cost to riverine ecosystems. To maximize revenues, major hydropower facilities store and release water with respect to short-term changes in energy price, causing significant sub-daily flow regime alterations that impact downstream ecological communities. In the United States, the Federal Energy Regulatory Commission (FERC) is responsible for hydropower regulation and this is administered, in part, during periodic relicensing of existing facilities. The process of relicensing provides the opportunity to evaluate the goals and concerns of interested parties and evaluate potential operational changes in licensure which may support these goals, often including constraints aimed at supporting ecological improvements.

This paper explores potential changes in reservoir operating rules for a series of five peaking hydropower facilities on the Connecticut River undergoing FERC relicensing that should complete in 2019. This paper evaluates the trade-offs between two primary goals: maximizing revenues from hydroelectric power generation and returning the river to a more natural flow regime. These trade-offs are assessed using the Connecticut River Hydropower Operations Program (CHOP), a linear programming (LP) optimization model applied at an hourly time-step to capture the sub-daily effects to the flow regime. The model objective function is formulated to maximize hydropower revenues with respect to historical regional energy price data and is

demonstrated to accurately mimic hydropeaking operating conditions and match historical power generating rates.

A case study compares modeled hydropower operating conditions between current hydropeaking operations and a strict run-of-river condition, where dam inflows must be directly released as outflows at all times. Analysis suggests that the run-of-river condition would result in a total economic loss of 7-9% of average annual revenues at the four mainstem facilities and as much as 17% at the larger, pumped-storage facility. However, an exploration of operating revenue losses at the pumped-storage facility suggests that there is potential for reoperations within the run-of-river operating condition to substantially reduce these losses. The run-of-river operation is demonstrated to improve the Connecticut River's flow regime on the sub-daily time scale, with significant reductions in rates of change in flows to levels that approach those observed at a nearby unaltered location. The modeled improvements to the flow regime demonstrate the merit of this run-of-river condition as a potential reoperation for the hydropower system.

2 Introduction

Hydropower currently provides approximately 20% of the world's energy supply and is noted for being inexpensive, reliable, and having a low CO_2 footprint (Sommers 2004). However, the negative impacts of hydropower on natural ecosystems have been noted for decades and concern for the preservation of riverine ecosystem services has subjected the hydropower industry to increased environmental regulation (Jager and Bevelhimer 2007; Pearsall et al. 2005; Richter and Thomas 2007). The impacts of dams and their operations have significant consequences for natural riverine ecologies, creating the need to seek management solutions that support both ecological and power generating goals (Arthington et al. 2006; Petts 2009; Poff and Zimmerman 2010).

Hydropower, together with municipal water supply, irrigation, flood control, navigation, and recreation represent the primary human uses of major river systems. In addition, river systems provide a variety of environmental services that are essential to the health of river ecology. Features of a river's flow regime affect hydrological and geomorphological processes which provide stability and diversity of habitat necessary for the persistence of aquatic and riparian communities (Naiman et al. 2002). In this way, riverine ecosystems can be seen as legitimate water users with needs that often compete with those of human water uses, including hydropower. Hydropower is produced at 13% of the 7,664 major dams in the United States (Error! Not a valid bookmark self-reference.**)**, demonstrating that there is a significant concentration of hydropower in New England, where hydropower represents nearly 60% of the region's renewable energy source.

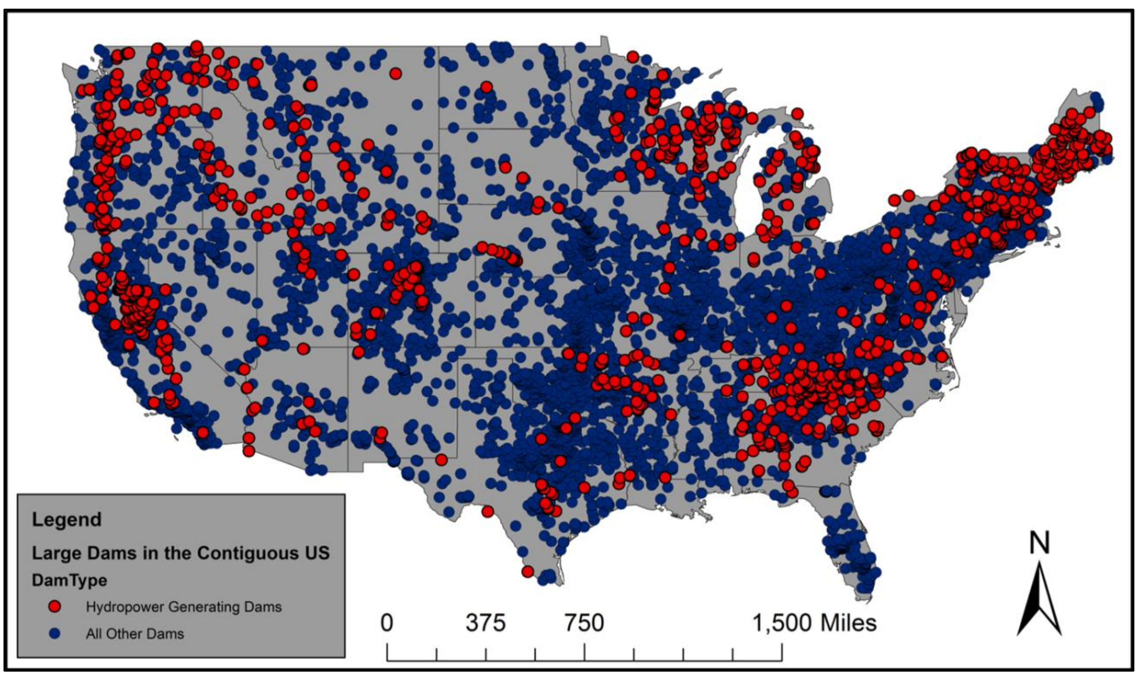


Figure 1 – Hydropower production is present at 13% of the major dams from the National Inventory of Dams (NID) dataset. Here, major dams are defined as those with greater than 5,000 acre-foot of reservoir storage or 50 feet of head.

Hydropower in the United States is regulated by the Federal Energy Regulatory Commission (FERC). Hydropower facilities must obtain operating licenses from FERC, which typically have a 30-50 year operational period. FERC offers an Integrated Licensing Process (ILP) that allows interested parties to request the investigation and mitigation of specific environmental concerns before licenses are granted (Viers 2011). Currently, the FERC is responsible for more than 1,000 active hydropower licenses, 303 of which expire between 2015 and 2025.

The Connecticut River has five sequential hydropower projects that are currently in a joint FERC relicensing process, scheduled to conclude in 2019. This joint relicensing procedure presents a unique opportunity to consider potential hydropower reoperations to minimize the negative effects on riverine ecology while maintaining many of the hydropower benefits. Using an established optimization-based reservoir operations modeling tool, this research evaluates potential hydropower system reoperations that will improve ecological health in the context of returning the river to a less altered flow regime.

3 Background

Researchers have created a substantial body of literature that addresses how to best quantify the ecological impacts of human water use changes on the natural flow regime and determine the management strategies necessary to support the natural needs of a river system (Petts 2007; Poff et al. 2010; Richter et al. 2003). Numerous researchers suggest that river ecosystems are healthiest in their most natural state, with natural flow serving as a master variable in the ecological equation (Naiman et al. 2002; Poff et al. 1997). Under this framework, understanding a river’s natural flow regime and attempting to return an altered flow regime to this state serves as a means to specifically address potential for ecological reparations.

A river's flow regime may be categorized by five characteristics: magnitude, frequency, duration, timing, and rate of change in flows. While the features of a river's natural flow regime are site specific, ecosystem functions may include the mobilization of nutrient rich sediments during high flow events and seasonally timed flow magnitudes which serve as environmental cues in the life cycles of various species. Flow regime alterations from human water uses generally degrade the river's ability to provide these ecosystem functions (Postel and Carpenter 1997).

To describe the degree of flow regime alteration, river scientists quantify the differences between a river's natural state in comparison to its current state (Petts 2007). Richter (1996), together with other researchers at The Nature Conservancy (TNC) developed and implemented 32 flow metrics (termed the Indicators of Hydrologic Alteration (IHA)) to create a framework to quantify the degree of river alteration in terms of the five major flow regime characteristics. These metrics are applied across varied time scales to calculate the difference between altered and pre-altered periods of record to identify the specific nature of a river's hydrologic alteration.

The IHA framework contains metrics that are correlated, suggesting that a subset of representative metrics may be more appropriate (Gao et al. 2009; Yang et al. 2008). Still, authors of the IHA submit that the complete suite of metrics should be considered to preserve the quality of information on the alterations to a river system. Regardless of these debates, there is an important need to quantify specific hydrologic alterations in order to inform management strategies.

Hydropower dam operations impose distinctive alterations to a river's natural flow regime. They often cause unnaturally large sub-daily variations in flow rates in response to quick, demand-driven changes in energy pricing (Cushman 1985). Further, these variations can have antecedent effects on water quality and temperature both in-reservoir and downstream (Caissie 2006). Hydropeaking may also lead to the unnatural loss of water in the hyporheic zone during low flow months (Yellen and Boutt 2015).

The rapid change in flows from a hydropower facility may be overlooked if viewed from a daily, rather than hourly, perspective. For instance, analysis of daily mean flows may reveal systematically lower weekend flows attributed to lower energy demand, but they may seriously underestimate peak flow magnitudes and can ignore characteristic sub-daily variations. Given that the IHA and other longstanding metrics were designed for the analysis of daily flow data, new indices have been developed to assess sub-daily fluctuations in flow. These indices generally compare the rate of change in flow at the finer 15-minute, or hourly time scale to the total flow during the period of a day, allowing for a relative assessment of the sub-daily alteration between different flow regimes.

Zimmerman et al. (2010) utilized four sub-daily flow metrics to demonstrate the range of alterations observed at many gage sites along the Connecticut River. Analysis of these data demonstrated that river reaches downstream of peaking hydropower facilities exhibit a noticeably higher degree of sub-daily alteration than reaches subjected to run-of-river operations or those that remain unregulated. Similar applications in both the United States and Europe have demonstrated the value of quantifying alterations from hydropower operations on a sub-daily time scale (Bevelhimer et al. 2015; Carolli et al. 2015).

While flow alteration caused by a hydropeaking flow regime may be quantified, understanding ecological responses to these alterations poses a greater challenge. It is expected that alterations on the sub-daily time scale may be of significant consequence to riverine ecosystems because they induce conditions to which a wide range of species lack evolutionary adaptations (Cushman 1985). Case studies indicate that regulated sub-daily flow fluctuations may impact migration, feeding ability, and spawning success of various fish (Barwick 1985; Carmichael et al. 1998; Grabowski and Isely 2007). These are only a few general examples, and site-specific flow-ecology relationships should be established to provide ecological value to flow management decision-making. Though adverse effects may be well understood in a theoretical sense, the development of explicit flow-ecology relationships directly relates reservoir operations to adverse ecological responses, making them valuable river management decision-making tools (Bevelhimer et al. 2015).

3.1 Managing Altered Streams for Ecological Improvement

The need to manage the ecological health of river resources downstream of dams (including hydropower) had originally been met with minimum release requirements (Petts 2009). This approach has been criticized as a vestige of allocation protection in western water law, incapable of representing the suite of environmental goals that contribute to river health (Stalnaker 1990). Further, the author suggests a need for a more robust approach to environmental considerations, in which scientists determine specific flow-ecology relationships to inform case-specific environmental flow rules.

While ecological research is formulating a more complex consideration of specific flow regimes, much of the environmental flow requirements in practice remain in the form of minimum flow magnitudes (Arthington et al. 2006). There are numerous challenges in transforming a simple minimum flow rule to a more prescriptive set of operational rules, including the fact that more complex rules may be more operationally constraining for hydropower operators.

3.2 Developing a Comprehensive Assessment Framework

Poff et al. (2010) suggests a synthesis of previously existing hydrologic and ecological classification techniques to address more appropriate regulation of flow regimes (noted as the Ecological Limits to Hydrologic Alteration (ELOHA)). Poff suggests that scientists and river managers co-develop a hydrologic basis for river classification, define the river's level of alteration, and develop flow-ecology linkages that can inform environmental flow standards. These environmental flow standards are applied along with flow-ecology monitoring to provide a metric for the quality of restoration and to inform future changes in flow standards.

Whether ELOHA or another approach is applied, a comprehensive and iterative assessment of impacts to flow regime and ecology serves as an "ideal approach" to guide ecological studies performed for hydropower projects undergoing the FERC's ILP. To be successful, these processes should occur in an environment where the complex needs of all major stakeholders are addressed, such that effective management strategies can be achieved. Various research explores approaches for developing alternative flow management strategies and explicitly demonstrates or cites the value that computer modeling contributes to these pursuits (Carolli et al. 2015; Homa et al. 2005; Naiman et al. 2002; Petts 2009; Richter and Thomas 2007; Sale et al. 1982; Steinschneider et al. 2014).

3.3 Exploring Reoperations

To effectively develop operational guidelines, computer models offer the opportunity to explore a wide range of alternatives and compare their ability to achieve specified objectives. A case study of management on the Roanoke River demonstrates the effectiveness of such an approach, showing that hydropower operators and ecological entities like TNC can co-produce shared goals and create a solution that supports multiple needs (Pearsall et al. 2005). In this example, models are used in the decision-making framework, allowing exploration of current and alternative hydropower system operations.

In the context of water resources management, both simulation and optimization modeling tools are common means of establishing an understanding of baseline operations and comparing these to alternate scenarios. Optimization has a history of extensive application to evaluate operations for reservoir systems (Labadie 2004; Vogel et al. 2007). Optimization provides a distinct advantage by providing an efficient means to evaluate solutions from which one may be selected to best achieve an operational objective or combination of multiple objectives (Steinschneider et al. 2014). Since hydropower releases are often influenced by changing electricity demands and pricing, optimization provides an opportunity to explicitly model this behavior (Barros et al. 2003).

3.4 Connection to Project

In this research, an alternatives assessment tool was created to assess the impacts from hydropower operations on the mainstem of the Connecticut River. The engine of this tool is a linear program (LP) optimization model, denoted as the Connecticut River Hydropower Operations Program (CHOP). Since the Connecticut River's flow regime has been identified to be significantly altered on the sub-daily time scale (Zimmerman et al. 2010), CHOP is formulated to operate at an hourly time-step. Flow and historical energy pricing data are provided in hourly increments to allow for the consideration of the impacts to the flow regime caused by sub-daily hydropeaking. Efforts were made to effectively mimic actual operations to the extent possible including both hydropeaking behavior historical rates of power generation. A 'Baseline' version of the model was then compared to an alternative operating scenario in which mainstem reservoirs were operated under a modeled 'Run-of-River' condition. The two modeled outcomes are compared in terms of estimated economic output and effects to flow regime on the sub-daily time scale.

4 Study Area and Model

4.1 Connecticut River & FERC Study Area

The Connecticut River basin is New England's largest river system, with 38 major rivers contributing a total of 11,985 square miles of drainage to the 410 river mile mainstem. Its headwaters begin in Canada, draining through New Hampshire, a small portion of Maine, Vermont, Massachusetts, and Connecticut, before ultimately discharging into the Long Island Sound. With over 2,700 dams, the Connecticut River Basin has a history of flow regime alteration dating back to logging during early settlement and later hydropower development during New England's industrial revolution (Clay and Nedeau 2006). After more than two centuries of development, the river network now provides its residents with water supply, flood control, recreation, and hydropower, resulting in flow alteration across various geographic and temporal scales.

Having recognized the strong ecological impact of these flow alterations, TNC sponsored research at the University of Massachusetts Amherst to develop and implement studies and models to assess the potential for ecologically beneficial reoperations at the basin's largest dams. Previously, this work focused on modeling the basin's 54 largest dams at a daily time-step and demonstrated the potential for reoperations at the 14 United States Army Corps of Engineers flood control facilities (Steinschneider et al. 2014). For this thesis, the optimization modeling approach was re-scaled to an hourly time-step for five mainstem hydropower facilities. CHOP includes the subsystem of the Connecticut River reservoir network currently undergoing FERC's joint relicensing procedure to evaluate alternative operations to the current hydropeaking system.

Figure 2 shows the physical system including the five hydropower facilities, upstream hydropower facilities, and a USGS gage used to capture operations from hydropeaking at these upstream facilities.

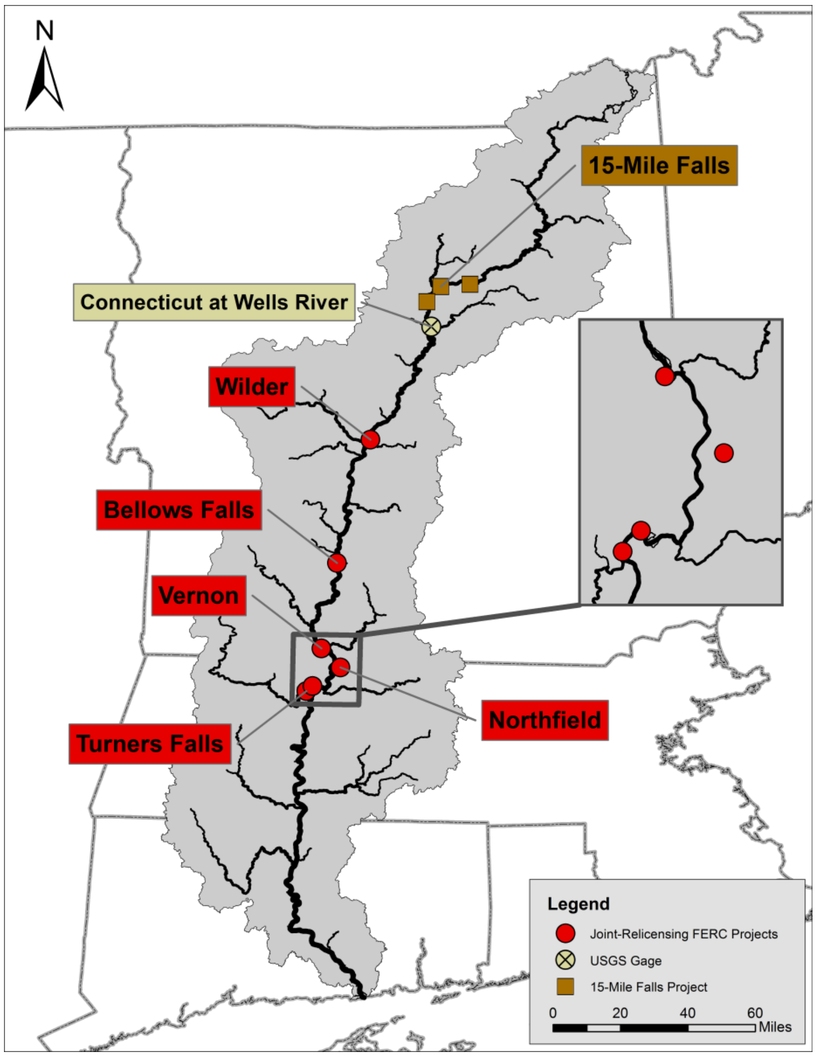


Figure 2 - Study Area for the Connecticut River hydropower facilities undergoing a joint FERC ILP. The inset map provides detail on the location of the off-stream Northfield pumped-storage facilities well as the two power houses at the Turners Falls project.

4.2 Hydropower System Description

The five hydropower facilities under study are operated by two companies which have engaged in a joint ILP in which the five physically independent facilities are considered under the same relicensing process. Table 1 provides information for each of the 5 hydropower facilities, demonstrating their most significant hydrologic characteristics and power capacity. The turbine capacities of all five facilities are sized above the average inflows to allow for maximum power production within a normal range of flows. An estimated refill time is calculated through the relation of average inflow and reservoir storage capacity. The comparatively small capacity of storage relative to mainstem flows suggests that these facilities generally do not alter the mainstem flow regime when considered on time scales greater than a day. While these facilities have low system storage, they are capable of storing sufficient water to perform hydropeaking operations which cause substantial sub-daily flow alterations.

Table 1 – Dam characteristics for the studied Connecticut River hydropower dams.

Facility	Facility type	Ownership	Turbine capacity (cfs)	Average inflow (cfs)	Useable storage capacity (acre-foot)	Estimated average time of refill (hr)	Power capacity (MW)
Wilder	Peaking	TransCanada	12,700	6,400	13,350	25	35.6
Bellows Falls	Peaking	TransCanada	11,010	10,500	7,480	9	48.5
Vernon	Peaking	TransCanada	17,010	12,200	18,300	18	32.4
Northfield	Pumped Storage	FirstLight	20,000	N/A	12,318	10	1,119.2
Turners Falls	Peaking	FirstLight	16,000	13,900	16,050	14	67.7

Wilder, Bellows Falls, and Vernon hydropower dams are operated as peaking facilities by TransCanada Hydro NorthEast Inc. Northfield and Turners Falls hydropower dams are operated by FirstLight, an Engie company (previously GDF Suez). All five facilities expect re-licensure by April of 2019 as a result of filing for a 1 year extension of the original 2018 deadline, though in March of 2016, both companies announced their intention to sell operating rights to the aforementioned facilities (FERC 2015).

Unlike the mainstem facilities, Northfield is a large pumped-storage facility situated off-stream on Northfield Mountain, approximately 820 feet above the local elevation of the mainstem of the Connecticut River (Figure 2). Turners Falls reservoir extends north from its dam and terminates at the outlet of Vernon Dam. The impoundment serves as the lower reservoir for Northfield's pumped-storage operations, with Northfield's intake located directly west of the pumped-storage facility's mapped location. Where others only have one, the Turners Falls facility has two powerhouses; the upstream Station No. 1 and downstream Cabot Station, with the power capacities of 5.7 MW and 62 MW, respectively.

Hydropeaking operations at these small-storage projects are similar across the mainstem facilities. Historical flows observed downstream of Wilder Dam are representative of hydropeaking operations for the system, reflecting hydropeaking responses to typical, daily energy demands for the region (Figure 3). Hydropower operators match releases to generate power during peak morning and evening demand since the New England energy market compensates for power production at a rate proportional to real time energy demands. Because the power generating market also responds to seasonal changes in energy demands and hydropower operators are constrained by the volume of water available to facilities, this hydropeaking structure does not always occur, though this hydrograph represents the mainstem's flow regime in its typical, altered state.

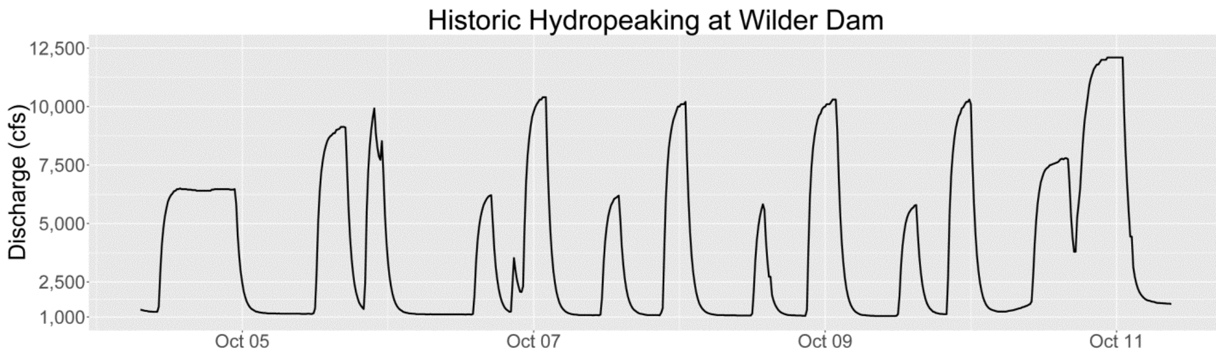


Figure 3 – Hydrograph (USGS #01144500) for October of 2015, demonstrating typical hydropeaking operations at Wilder Dam.

4.3 Hydropower Model

The CHOP model formulation replicates current operations through an explicit mathematical representation of the real-world operating objective to maximize profit. Simply stated, the LP's objective function seeks to maximize the system's total hydropower revenues:

$$Max: \sum_{d=1}^{D} \sum_{h=1}^{H} R_{d,h} \times C_d \times E_h$$

subject to the linear constraints

$$Ax \leq b$$

where:

$R_{d,h}$= the turbine release for dam d at hour h,

C_d= the linear conversion between turbine release and power generation for dam d, and

E_h= the market energy price at hour h, for which the product forms an estimated hydropower revenue for dam d at hour h.

Constraints that limit this objective include: minimum flow rates, turbine capacities, reservoir storage capacities, ramping rates, and mass balance. The model evaluates alternative operations by altering the operating objectives and constraints and comparing output among modeled scenarios.

To achieve the computational efficiency associated with an LP formulation, it was assumed that the heads of these facilities remained relatively constant allowing for a linearization of the relationship between modeled flow rate and power generation. Where hydropower potential is calculated as a product of turbine efficiency, mass flow rate through the turbine, and hydraulic head, this formulation relied on a linear relation between maximum turbine flow and power generating capacity to convert modeled flows into hydroelectric power estimates. This assumption was deemed acceptable following the fact that the possible range of hydraulic head is relatively small (<10%) in comparison to the total operating head for each of these facilities. On the mainstem, the largest range of operating head relative to net head is calculated as 7% at Turners Falls where reservoir elevation may fluctuate as much as 4 feet with respect to its normal operating head of 60 feet. The same calculation for Northfield shows that operating head may vary by 62.5 feet, an 8% range of head with respect to its lowest operating head of 753 feet.

4.3.1 Model Inputs

Model inputs include hydrologic flow data for the basin and historical energy price data for the Western Massachusetts region. The two datasets overlapped for the years 2003 – 2011, providing 9 years of hourly model data. To calculate the hydrologic inputs for the modeled hydropower facilities, contributing flows were selected from a basin-wide dataset of estimated natural daily flows calculated using the Connecticut River UnImpacted Streamflow Estimation (CRUISE) tool developed by the United States Geological Survey (USGS) (Archfield et al. 2013). These flows were disaggregated from the daily time-step to 24 hour increments using a simple smoothing function to prevent discrete changes in flow at the daily scale.

Stakeholders in the modeling process were interested in ensuring that CHOP included considerations of hydropeaking from upstream facilities which contribute to the mainstem flow regime by operating upstream of Wilder. Since these facilities and their licensed operations are outside the scope of the current FERC relicensing process, stakeholders identified the need to consider how these upstream operations might continue to affect the downstream study area during alternative operations of the modeled facilities. As a result, historical hourly flows from the Connecticut River at Wells River USGS gage (01138500) were incorporated into the hourly disaggregated CRUISE dataset, effectively capturing hydropeaking effects from the three upstream facilities collectively termed the 15-Mile Falls project (Figure 2). Because of changes to licensed operations at 15-Mile Falls in 2002, the modeled inflows were limited to the 2003-2011 period where available CRUISE and USGS flow data overlapped and reflected recent 15-Mile Falls operational procedures (FERC 2002). Figure 4 shows a week of sample flows from the combined hydrologic dataset, demonstrating the successful incorporation of historical hydropeaking from 15-Mile Falls.

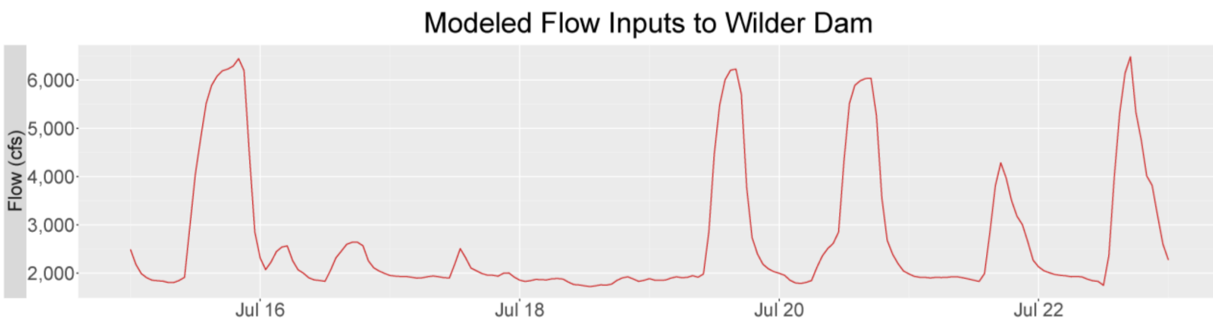


Figure 4 – Sample hydrograph of modeled flow input to Wilder Dam, including historical operations at 15-Mile Falls for a period in July of 2004. The flow dataset includes CRUISE combined with estimated natural flows USGS 01138500 data.

The New England energy market structure operates by providing energy generators and purveyors with demand-driven, hourly energy price signals that establish prices for energy that is bought and sold. Independent System Operator New England (ISO-NE), the region's energy transmission manager, provides these hourly data for the historical years of 2003 to present day. These data were incorporated into the model to serve as the signal which would cause CHOP to perform hydropeaking operations. Figure 5 shows modeled hydropeaking operations for a period of three days, showing that turbine releases match the driving energy price signal for optimal revenue generation from turbine releases.

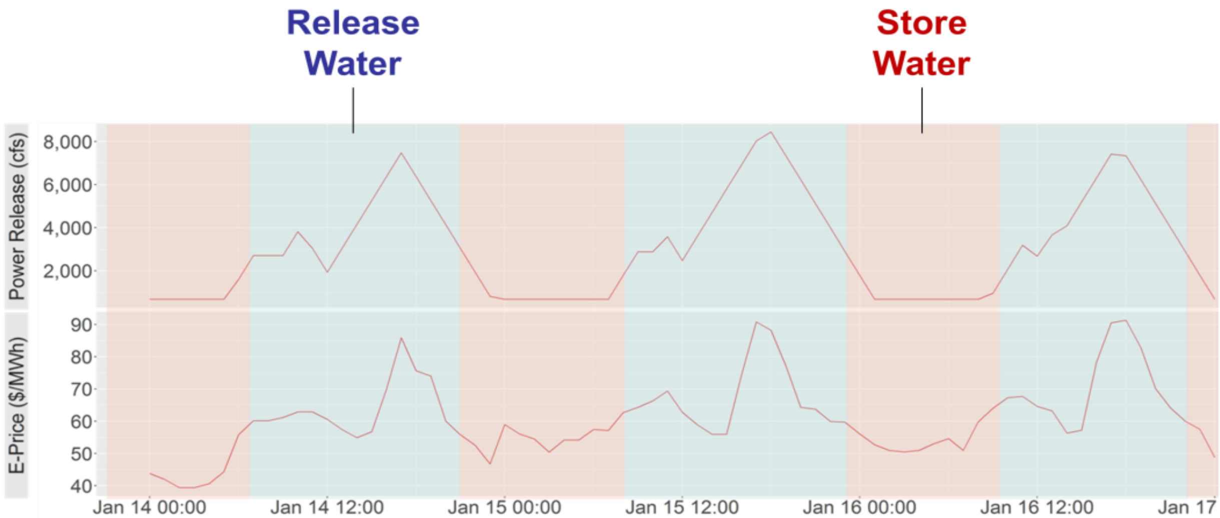


Figure 5 - Sample hydropower optimization showing modeled turbine releases at Wilder Dam, timed with ISO-NE's historical energy price signal for January of 2005.

4.3.2 Calibration

To calibrate the model, historical reported power generation data were compared to modeled hydroelectric generation. Monthly power generation data were provided as part of the filing process for relicensing for a seven year period of 2003 to 2009. Figure 6 demonstrates that for the 7 years of available historical data, the baseline model accurately estimates average annual power generation to within 10% of the historically reported values across all reported facilities.

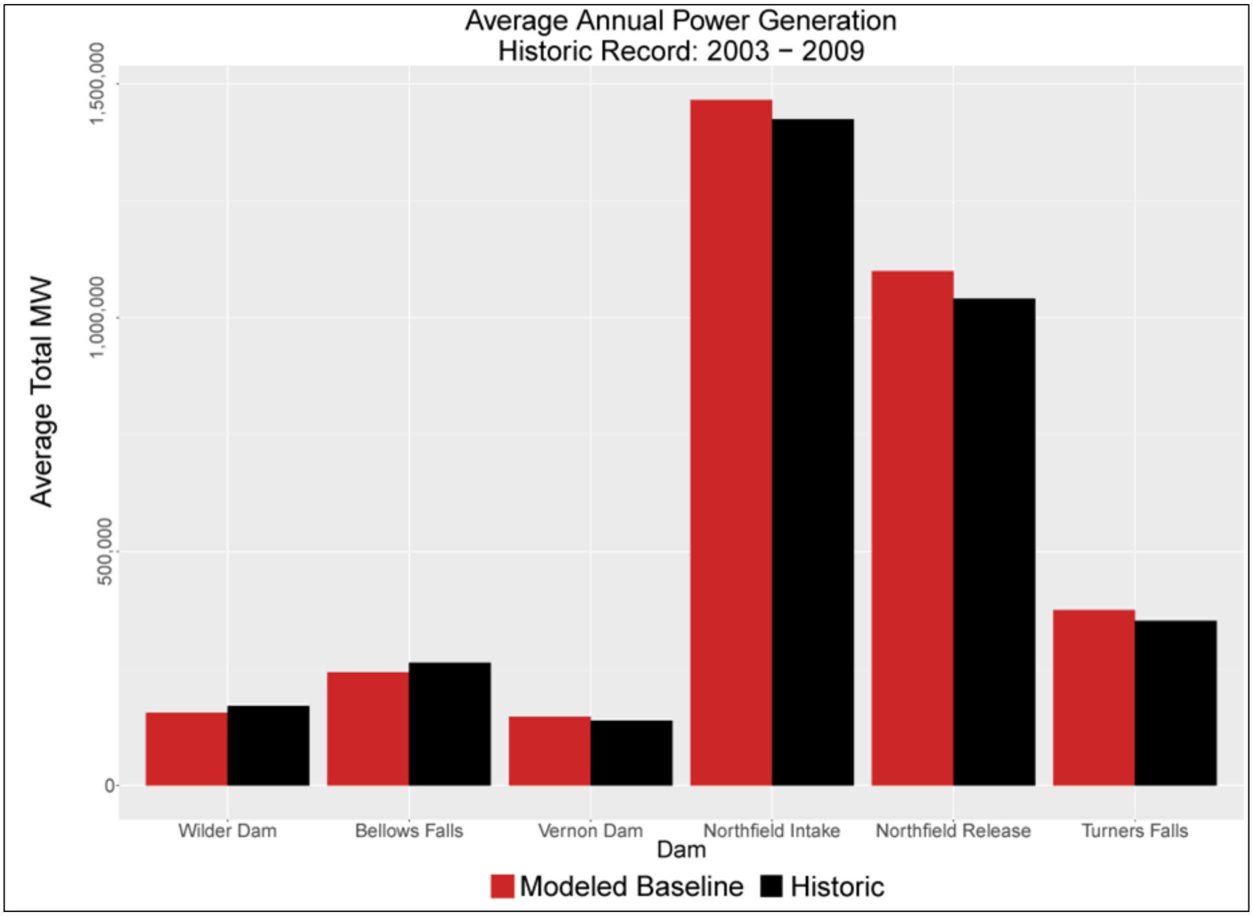


Figure 6 - Modeled average annual hydropower generation for the 2003-2009 period for which model data and historical power generation data overlapped.

5 Case study: Evaluating the Impacts of a Run-of-River Operating procedure

5.1 Run-of-River Condition

Ecologically interested parties like TNC are actively pursuing means within the FERC relicensing process to benefit the riverine ecosystems on the Connecticut River. Much of this work focuses on identifying potential improvements to the flow regime by considering alternative hydropower operations procedures. One consideration is an instantaneous run-of-river flow requirement, where hydropower operators must ensure that operated releases equal inflows at all times. This operational regime is of interest because it has the potential to mitigate alterations to the sub-daily flow regime caused by hydropeaking while still allowing operators to generate hydroelectric power.

Jager and Bevelhimer (2007) describe 38 hydropower facilities in the U.S. where this operational change has been successfully implemented. While there are site-specific reasons for the adoption of these reoperations, they generally seek to improve the ecological services provided by the rivers, including those to populations of migrating fish and other aquatic biota. Jager et al. suggest an estimated 3% loss of hydroelectric power generation across these facilities, though this work neglects to consider how operational revenues have been affected. This is likely due to the challenge of comparing these multiple hydropower facilities across their varied operational conditions and energy markets, though a consideration of economic impact is a major component of evaluating reoperations.

To assess the potential flow regime benefits and economic impacts of a run of river operating condition, these operating rules were formulated and modeled (Run-of-River) in comparison to modeled real world operations (Baseline) for the five Connecticut River hydropower facilities.

Figure 7 illustrates the functional differences between the two scenarios. The Baseline model is formulated as the current physical system during real-world operations, allowing for hydropeaking at all five facilities. The Run-of-River model forces inflows at mainstem facilities to be equal to outflows during all time-steps, while allowing Northfield to perform normal hydropeaking operations by drawing water from its lower Turners Falls reservoir. The Run-of-River condition is achieved by constraints that require inflows to be equal to outflows at all mainstem facilities during all time-steps.

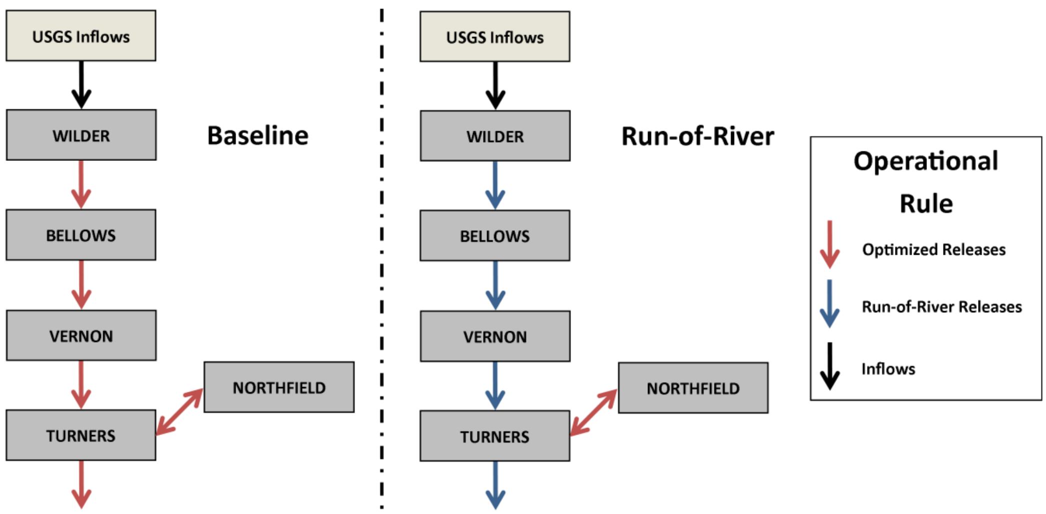


Figure 7 - Hydropower optimization schematic for modeled Baseline and Run-of-River scenarios.

Since the three consecutive peaking facilities known as 15-Mile Falls are operated upstream of this reservoir system (Figure 4), the Run-of-River condition only prevents local hydropeaking operations, though peaks from upstream operations are attenuated by contributing inflows.

5.2 Flow Regime Impacts

Even with continued impacts from upstream hydropower operations at 15-Mile Falls, the Run-of-River scenario was expected to locally improve the lower mainstem's sub-daily flow regime in terms of flow magnitude, timing, and rates of change. A sample hydrograph is presented, demonstrating the difference in flow regime between the Baseline and Run-of-River scenarios (Figure 8). For the Baseline scenario, modeled dam releases exhibit local hydropeaking behavior, while inflows are instantaneously released during the Run-of-River scenario. The peaks observed in the Run-of-River hydrograph are from operations at the upstream 15-Mile Falls facilities, demonstrating that the lower mainstem would remain impacted by hydropeaking, albeit at attenuated magnitudes.

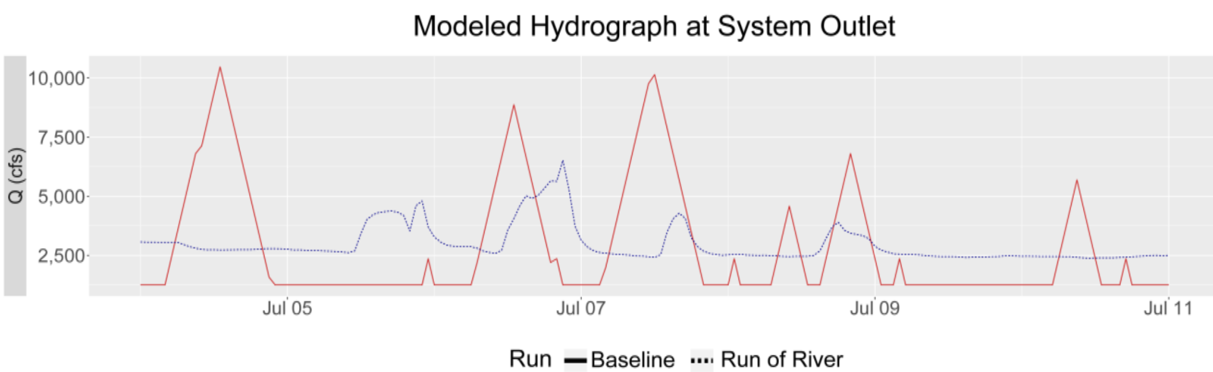


Figure 8 - Sample modeled hydrograph demonstrating a difference in flow regime between Baseline and Run-of-River downstream of Turners Falls Dam.

Various flow statistics were calculated to explicitly quantify the change to the sub-daily flow regime. Despite the distinct difference in operations between the two scenarios (Figure 8**)**, there are negligible differences in average daily flow rates between the two model runs (Figure 9**)**. This demonstrates that the hydropower system's small storage capacity is insufficient to retain large quantities of water at periods greater than the daily time scale. The inability to discern between a hydropeaking operating regime and a run-of-river operating regime at the daily time scale further shows the importance of quantifying hydropeaking impacts at the sub-daily time scale.

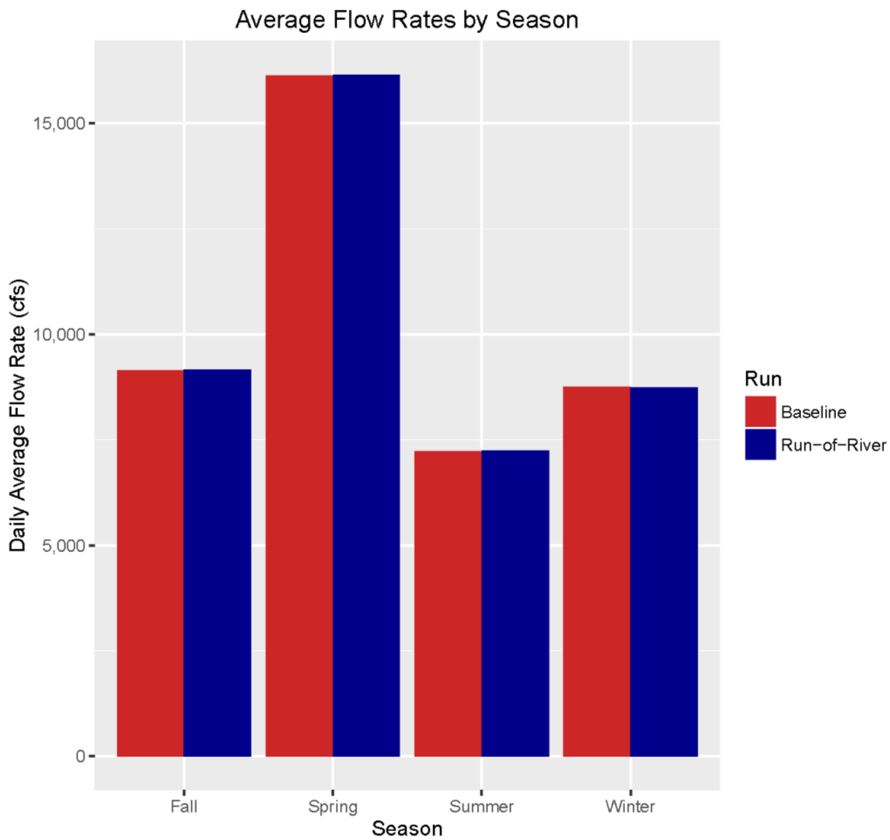


Figure 9 - Comparison between Baseline and Run-of-River modeled average flow rates by season.

Average daily peak flow rates for the Baseline run are substantially higher than Run-of-River, demonstrating an improvement to the magnitude component of the river's flow regime (Figure 10**)**. In conjunction with the previous finding that the same daily volume of water is routed through the hydropower system (Figure 9**)**, this finding demonstrates an improvement to the timing of the sub-daily flow regime and further implies a reduced rate of change in flows.

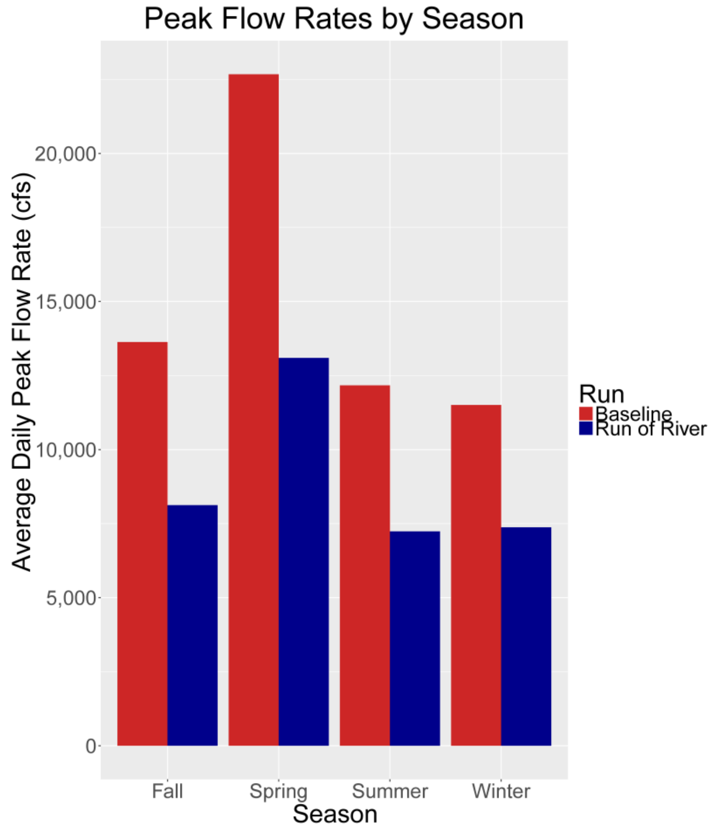


Figure 10 - Comparison between Baseline and Run-of-River modeled average daily peak flow rates by season.

Sub-daily flow metrics known as 'flashiness' metrics quantify the rate of change in flows at the sub-daily time scale. In general, these flashiness metrics provide daily indices of the rate-of-change of flow by calculating the total sub-daily change in flow rate, divided by the total flow for a given day (Zimmerman et al. 2010). For the purposes of this study, the Richards-Baker Flashiness Index (RBF) was chosen because of its intuitive formulation, expressed simply as:

$$RBF = \frac{\sum_{t=1}^{N} 0.5(|Q_{t+1} - Q_t| + |Q_t - Q_{t-1}|)}{\sum_{t=1}^{N} Q_t}$$

where Q_t= flow rate at sub-daily time-step t. Figure 11 shows results from applying RBF to modeled output, with calculated values for an unregulated gage serving as a reference to natural rates of change in flows. The reduced average magnitude and range of RBF between the two scenarios indicate that a Run-of-River condition could cause a substantial reduction in the unnatural sub-daily rate of change in flows caused by hydropeaking. Comparison between the modeled Run-of-River condition and historical USGS flows for the unregulated Whiter River tributary to the Connecticut River suggest that this reoperation could assist in returning the sub-daily rates of change in flow on the lower mainstem to pre-altered levels.

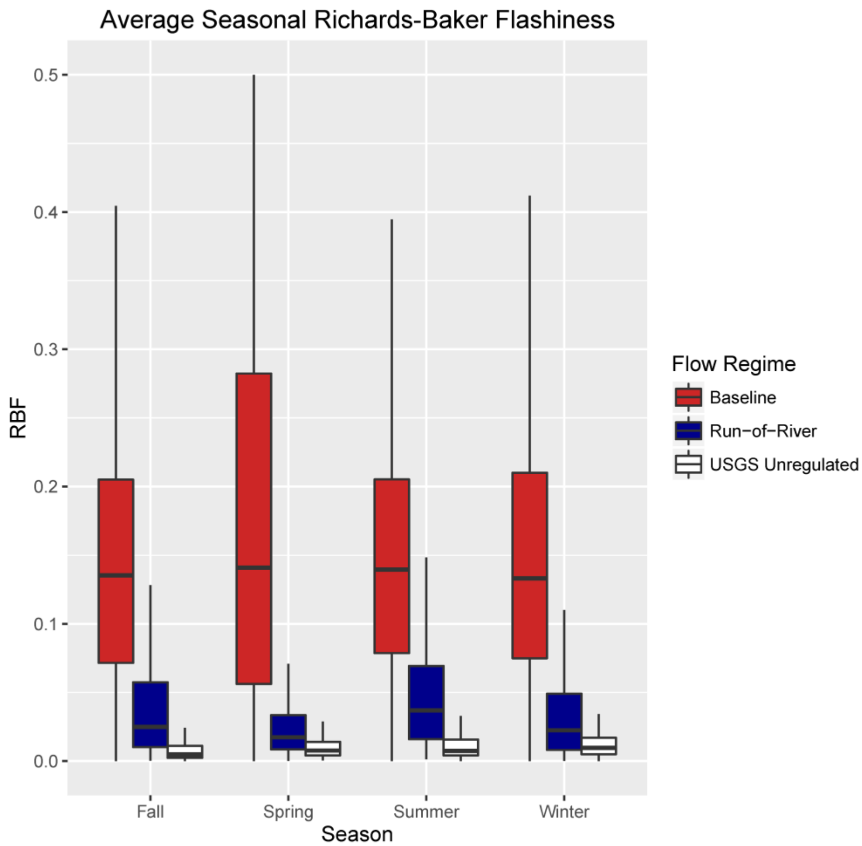


Figure 11 - Comparison between Baseline and Run-of-River modeled RBF by season with historical White River data as reference for natural.

5.3 Economic Impacts of Run-of-River Reoperations

The Run-of-River condition improves the flow regime by significantly reducing the impact of local hydropeaking at an expected loss to hydropower operating goals. Modeled hourly power generation and subsequent revenues were compared between the Baseline and Run-of-River scenarios to quantify these losses across the five hydropower facilities. Figure 12 shows the relative difference in average annual power generation (a) and revenue (b) between the two scenarios.

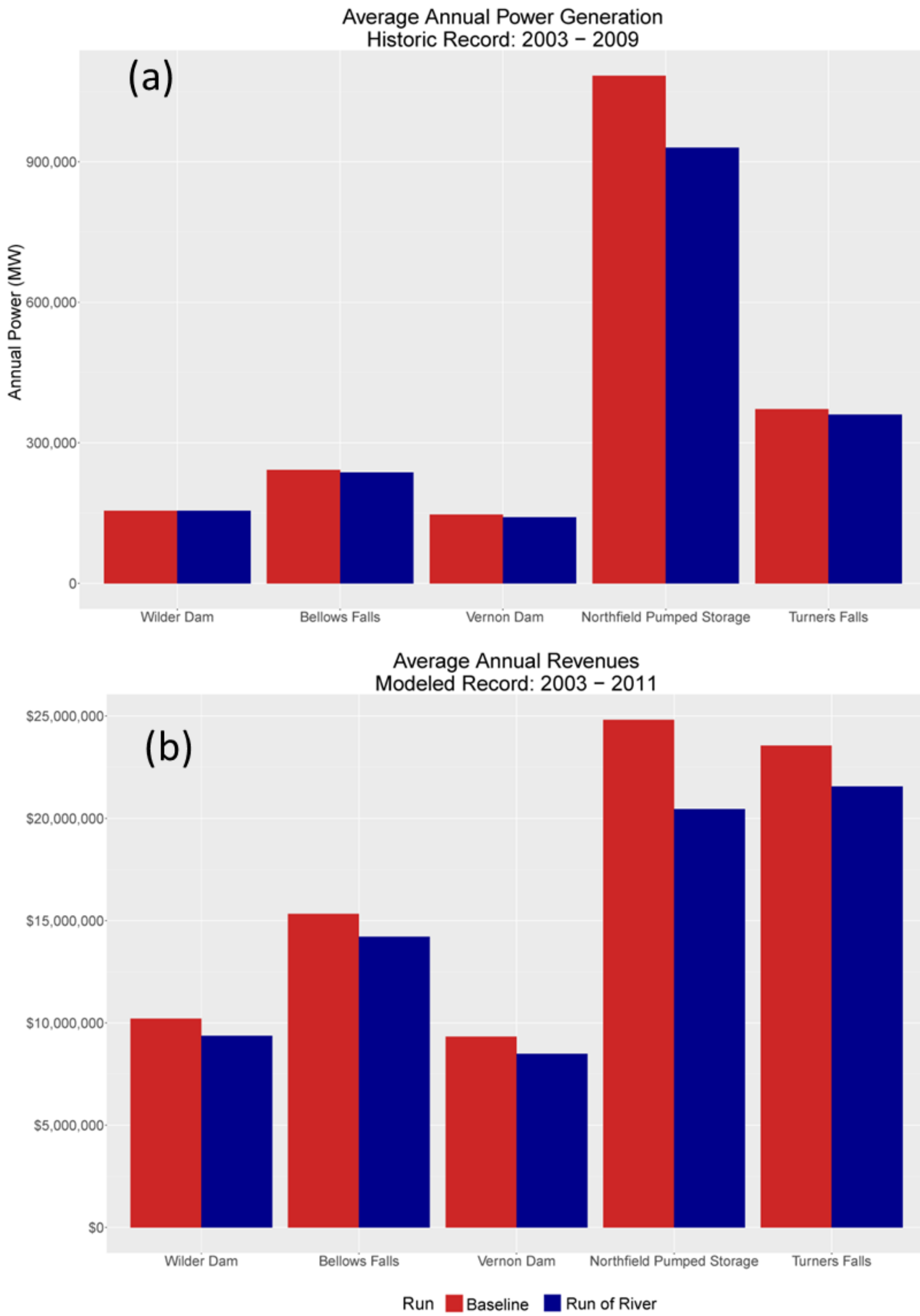


Figure 12 - Modeled average annual hydropower revenues for the 2003-2011 period for which input energy price data and flow data overlapped.

A comparison of power generation shows negligible change for the mainstem facilities, since the same volume of water passes through the turbines at large enough time scales (**Figure 3**). However, the Northfield pumped-storage facility does experience a loss in power generation due to a limited supply of water under the Run-of-River condition. Northfield can only draw stored water from the Turners Falls reservoir where the Baseline condition provides both stored water and inflows from Vernon Dam.

A comparison of average annual revenues demonstrates economic losses to the system caused by the Run of River scenario. For mainstem facilities, modeled revenue losses are within the range of 7-9%, while Northfield experiences a 17% loss in annual revenues. These revenues can be attributed to limits on available water to Northfield caused by the Run-of-River condition.

Northfield pumped-storage operates with the Turners Falls reservoir as its lower source. During normal operations, Northfield may rely on both the storage capacity of Turners Falls and upstream inflows to provide ample supply for its 12,318 acre-foot reservoir. However, the Run-of-River condition forces the upstream inflows to be routed directly through Turners Falls, leaving only the reservoir capacity for supply to Northfield. The Turners Falls reservoir is licensed for a 9 foot fluctuation though the reservoir rarely fluctuates more than 4 feet and is modeled as such to correspond to real world operations Figure 13. With the lower reservoir limited to a smaller storage capacity than the upper reservoir, the Run-of-River condition effectively limits Northfield’s net storage capacity, thus limiting its power generating capacity.

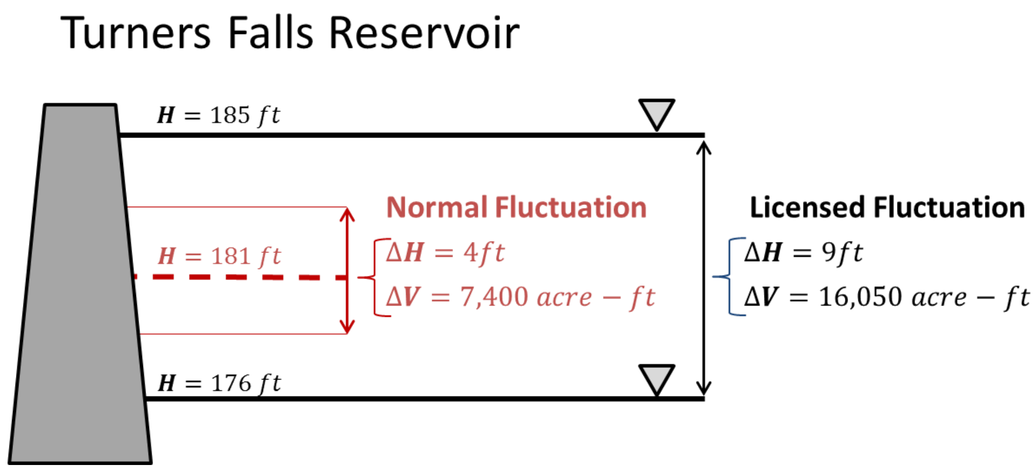


Figure 13 - Schematic of allowed vs. licensed reservoir fluctuation at Turners Falls. Elevations are reported with respect to mean sea level.

5.3.1 Assessing Potential for Improved Hydropower Performance under the Run of River Condition

With Northfield Pumped Storage providing a large capacity for the generation of reliable, on-peak energy to the New England power distribution system, the modeled Run-of-River loss to hydroelectric power and revenue generation demands further investigation. Two scenarios were considered in which the operating conditions at Turners Falls were altered from Run-of-River such that operations at Northfield might be improved.

5.3.1.1 Varying Reservoir Fluctuation at Turners Falls

To understand the effect that the Turners Falls reservoir fluctuation has on Northfield operations, the Run of River model was run for a range of allowed fluctuations. Figure 14 shows modeled Run-of-River scenarios with a varied range of allowed fluctuation for the Turners Falls reservoir, demonstrating the range of possible outcomes from below the normally operated 4 foot and licensed 9 foot fluctuation.

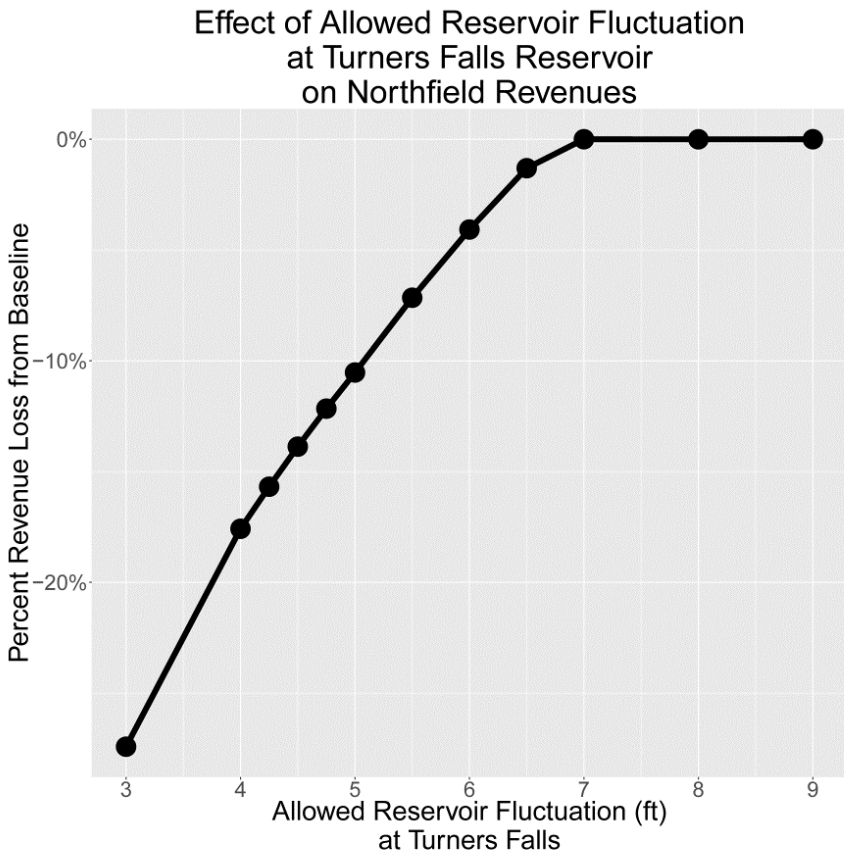


Figure 14 - Modeled Run-of-River scenario results for the exploration of the relationship between allowed Turners Falls reservoir fluctuation and Northfield revenues.

As expected, Northfield revenues increase with respect to the range of allowed reservoir fluctuation. Analysis suggests that an allowed 7 foot reservoir fluctuation at Turners Falls would permit Northfield to operate at its full power and revenue generating potential. Further, the consideration of a 3 foot fluctuation suggests that any additional limitation on reservoir fluctuations would result in increased reductions to the operating potential of Northfield Reservoir.

Note that the considered range of reservoir fluctuations were modeled under a Run-of-River condition and would therefore have no effect on the mainstem's flow regime. Instead, impacts would be local to the reservoir at Turners Falls and increased fluctuations might have negative consequences for the inhabitants on this stretch of the river. To protect these inhabitants, limiting the Turners Falls fluctuation to no more than the current 4 foot fluctuation may be in the best interest of the local ecology. A Run-of-River condition that allows larger reservoir fluctuations at Turners Falls could minimize negative impacts to hydropower operators and the New England energy market while still improving the sub-daily flow regime on the Connecticut River's mainstem. If operators were to consider a Run-of-River condition, the outlined economic relationship may support some compromise between the currently licensed 9 foot fluctuation and the targeted 4 foot fluctuation.

5.3.1.2 Allowing Inflow Storage at Turners Falls

As an alternative to increasing the allowed reservoir fluctuations at Turners Falls, an alteration to the modeled Run of River condition was considered for Turners Falls. Where the original Run of River condition forces all inflows to be discharged through Turners Falls, a percentage of upstream inflows is allowed to be stored at the Turners Falls dam during this scenario, effectively increasing the available water for Northfield operations. Figure 15 shows the modeled results from varying the amount of allowed inflow storage at Turners Falls. Figure 15 A shows the relationship between the amount of allowed inflow storage at each time step and average annual revenue losses at Northfield in comparison to revenues from the Baseline model run. At 15% allowed inflow storage, revenue loss is shown to be below 5% of Baseline, down from 17% under the original Run of River condition. Figure 15 B demonstrates the impact that this change in operations could have on downstream rates of change in flows. Under the same 15% allowed inflow storage condition, the average downstream flashiness is shown to be less than 20% of the Baseline scenario. This alternative demonstrates a marked improvement in flow regime and, though it is lesser than that observed during the original Run-of-River condition, it demonstrates potential for reoperations which continue to improve the river's flow regime while working to minimize losses to hydropower operators.

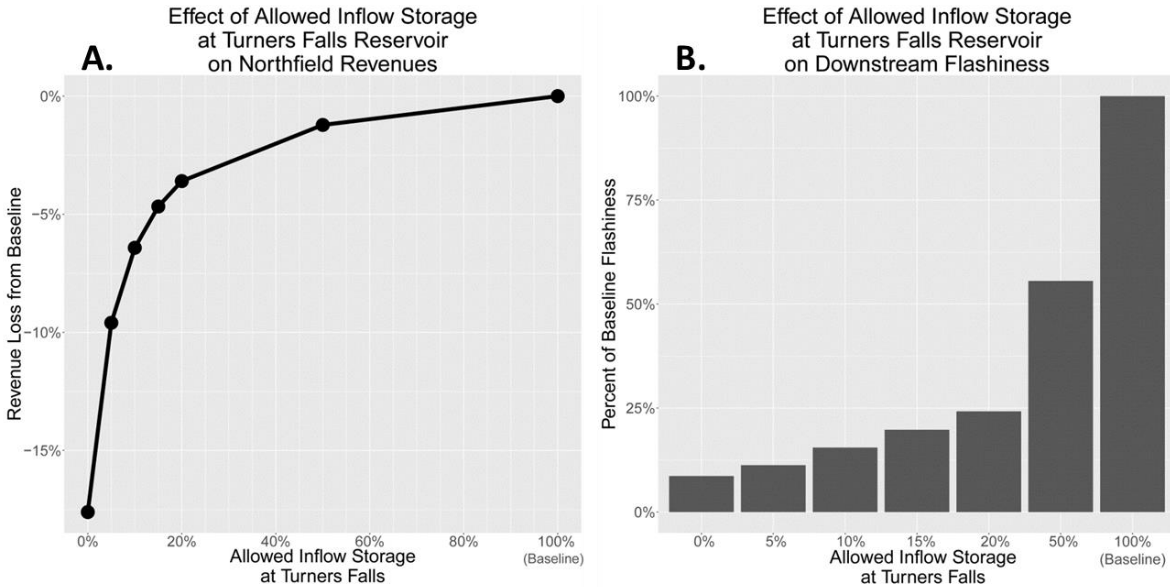


Figure 15 - Modeled results for a Run-of-River condition which is modified to allow storage operations at Turners Falls, where some fraction of inflows at each time step may be stored. Results demonstrate the relationship between the percent allowed inflow storage from 0% (Run-of-River) to 100% (Baseline) and revenue losses at Northfield (A) as well as downstream impacts to rates of changes in flows (B).

6 Discussion and Conclusions

This research demonstrates the successful implementation of CHOP, a reservoir operations model which serves as an alternatives assessment tool used to evaluate the potential flow regime and economic impacts to hydropower reoperations on the Connecticut River's mainstem. It is important to note the limitations of the CHOP formulation to inform the quality of modeled output as decision support data. The model contains the assumption of a linear relationship between modeled turbine releases and hydroelectric power generation. This assumption provides a significant computational advantage over nonlinear alternatives and appears reasonable given the small range of head fluctuations at these facilities.

Further, the model contains the assumption of constant efficiency across a range of head and flows. It is known that power production efficiency is affected by the specific physical characteristics of independently operating turbines. To maintain a LP formulation, the model considers the bulk generating capacity at each hydropower facility and while this approach neglects specific turbine efficiencies, it allows for an effective, systems-scale consideration of hydropower operations.

Finally, the model is only capable of calculating the revenues generated by producing and selling power in regional energy markets. It is known that these hydropower facilities also engage in other energy markets, like the forward capacity market, where operators are paid to guarantee their facility's power generating capacity three years in advance. The capability to understand the impacts that system reoperations may have on the ability of these facilities to compete and generate revenue in these forward markets is beyond the scope of this model.

Despite these limitations, CHOP provides a framework to provide meaningful relative comparisons between various hydropower operational schemes in the absence of better information. The ability to consider relative trade-offs in both economic output and flow regime, makes the model a useful tool in an arena where these considerations represent some of the major, and potentially conflicting, goals of operators and other stakeholders.

In this case study, CHOP demonstrates an instantaneous run-of-river scenario for mainstem hydropower facilities as a reoperation which indicates substantial improvements to the flow regime on the Connecticut River's mainstem at a cost to hydropower operating goals. This improvement comes at a loss to hydropower operating objectives because it redistributes hydropower releases over the course of the day, leading to the loss of optimal revenue generation attained through hydropeaking. For mainstem facilities, these modeled economic losses are within the range of 7-9% of average annual revenues, while Northfield is modeled to experience losses of 17%. Though, further modeling suggests that there is potential for improved operational performance at Northfield under scenarios which continue to improve the mainstem flow regime.

Modeled results indicate that the application of a strict run-of-river condition applied to mainstem peaking facilities could improve the flow regime by reducing unnatural sub-daily impacts to the magnitude, timing, and rates of change in flows on the mainstem. Ecologically interested parties have the expectation that riverine ecologies will experience substantial ecological benefits from a more natural flow regime. While this expectation has a strong theoretical basis, it lacks the same tangibility afforded by the comparison of economic outcomes. While the development of case-specific flow-ecology relationships is indeed a challenging task, these or other means to provide linkages between modeled flow regime improvements and positive species responses to these improvements could help to bolster the value of the modeled run-of-river scenario and other alternative operations.

Future work will involve the application of CHOP to various other alternative hydropower operations scenarios which may demonstrate other means of improving the ecological viability of the Connecticut River's flow regime and attempt to incorporate useful findings from ecological studies performed as part of the FERC relicensing process. Future modeling efforts will also focus on improving the resolution of the modeled reservoir system such that the two power stations at the Turners Falls facility and other unique components might be discretely modeled in hopes of assessing more localized impacts of hydropower operation.

References

Archfield, S. A., Steeves, P. A., Guthrie, J. D., Ries III, K. G. (2013). "Towards a Publicly Available, Map-Based Regional Software Tool to Estimate Unregulated Daily Streamflow at Ungauged Rivers." *Geoscientific Model Development*, 6(1), 101-115.

Arthington, A. H., Bunn, S. E., Poff, N. L., Naiman, R. J. (2006). "The Challenge of Providing Environmental Flow Rules to Sustain River Ecosystems." *Ecol. Appl.,* 16(4), 1311-1318.

Barros, M., Tsai, F., Yang, S., Lopes, J., Yeh, W. (2003). "Optimization of Large-Scale Hydropower System Operations." *J. Water Resour. Plann. Manage.,* 129(3), 178-188.

Barwick, D. (1985). "Food and Feeding of Fish in Hartwell Reservoir Tailwater, Georgia-South Carolina." *Proc. Annu. Conf. SEAFWA,* 39, 185-193.

Bevelhimer, M. S., McManamay, R. A., O'Connor, B. (2015). "Characterizing Sub-Daily Flow Regimes: Implications of Hydrologic Resolution on Ecohydrology Studies." *River Research and Applications*, 31(7), 867-879.

Caissie, D. (2006). "The Thermal Regime of Rivers: A Review." *Freshwat. Biol.,* 51(8), 1389-1406.

Carmichael, J. T., Haeseker, S. L., Hightower, J. E. (1998). "Spawning Migration of Telemetered Striped Bass in the Roanoke River, North Carolina." *Trans. Am. Fish. Soc.,* 127(2), 286-297.

Carolli, M., Vanzo, D., Siviglia, A., Zolezzi, G., Bruno, M. C., Alfredsen, K. (2015). "A Simple Procedure for the Assessment of Hydropeaking Flow Alterations Applied to several European Streams." *Aquat. Sci.,* 77(4), 639-653.

Clay, C., and Nedeau, E. (2006). "The Connecticut River Watershed: Conserving the Heart of New England." *The Trust for Public Land*, .

Cushman, R. M. (1985). "Review of Ecological Effects of Rapidly Varying Flows Downstream from Hydroelectric Facilities." *N. Am. J. Fish. Manage.*, 5(3), 330-339.

FERC. (2015). "Order Amending Licenses; TransCanada; Project Nos.1855-048, 1892-028, 1904-076." *152 Ferc ¶ 62,048*, .

FERC. (2002). "ORDER ISSUING NEW LICENSE (MAJOR PROJECT); USGen New England, Inc.; Project no. 2077-016." *99 Ferc ¶ 62, 025*, .

Gao, Y., Vogel, R. M., Kroll, C. N., Poff, N. L., Olden, J. D. (2009). "Development of Representative Indicators of Hydrologic Alteration." *Journal of Hydrology*, 374(1–2), 136-147.

Grabowski, T. B., and Isely, J. J. (2007). "Effects of Flow Fluctuations on the Spawning Habitat of a Riverine Fish." *Southeastern Naturalist*, 6(3), 471-478.

Homa, E., Vogel, R., Smith, M., Apse, C., Huber-Lee, A., Sieber, J. (2005). "An optimization approach for balancing human and ecological flow needs." *Proc., Proceedings of the EWRI 2005 World Water and Environmental Resources Congress*, .

Jager, H. I., and Bevelhimer, M. S. (2007). "How Run-of-River Operation Affects Hydropower Generation and Value." *Environ. Manage.*, 40(6), 1004-1015.

Labadie, J. (2004). "Optimal Operation of Multireservoir Systems: State-of-the-Art Review." *J. Water Resour. Plann. Manage.*, 130(2), 93-111.

LINDO Systems, I. (2010). *LINGO 14.0 User's Guide, Chicago,* LINDO Systems, Inc., 1415 North Dayton Street; Chicago, IL 60642.

Naiman, R., Bunn, S., Nilsson, C., Petts, G., Pinay, G., Thompson, L. (2002). "Legitimizing Fluvial Ecosystems as Users of Water: An Overview." *Environ. Manage.,* 30(4), 455-467.

Pearsall, S. H., McCrodden, B. J., Townsend, P. A. (2005). "Adaptive Management of Flows in the Lower Roanoke River, North Carolina, USA." *Environ. Manage.,* 35(4), 353-367.

Petts, G. E. (2009). *Instream Flow Science for Sustainable River Management1,* .

Petts, G. E. (2007). *Hydroecology: The Scientific Basis for Water Resources Management and River Regulation,* John Wiley and Sons: Hoboken, NJ, .

Poff, N. L., Richter, B. D., Arthington, A. H., Bunn, S. E., Naiman, R. J., Kendy, E., Acreman, M., APSE, C., Bledsoe, B. P., Freeman, M. C., Henriksen, J., Jacobson, R. B., Kennen, J. G., Merritt, D. M., O'Keefe, J. H., Olden, J. D., Rogers, K., Tharme, R. E., Warner, A. (2010). "The Ecological Limits of Hydrologic Alteration (ELOHA): A New Framework for Developing Regional Environmental Flow Standards." *Freshwat. Biol.,* 55(1), 147-170.

Poff, N. L., and Zimmerman, J. K. H. (2010). "Ecological Responses to Altered Flow Regimes: A Literature Review to Inform the Science and Management of Environmental Flows." *Freshwat. Biol.,* 55(1), 194-205.

Poff, N. L., Allan, J. D., Bain, M. B., Karr, J. R., Prestegaard, K. L., Richter, B. D., Sparks, R. E., Stromberg, J. C. (1997). "The Natural Flow Regime." *Bioscience,* 47(11), pp. 769-784.

Postel, S., and Carpenter, S. (1997). "Freshwater Ecosystem Services." *Nature's Services: Societal Dependence on Natural Ecosystems.* Island Press, Washington, D.C., 195-214.

Richter, B. D., and Thomas, G. A. (2007). "Restoring Environmental Flows by Modifying Dam Operations." *Ecology and Society,* 12(1), 12.

Richter, B. D., Mathews, R., Harrison, D. L., Wigington, R. (2003). "Ecologically Sustainable Water Management: Managing River Flows for Ecological Integrity." *Ecol. Appl.,* 13(1), 206-224.

Richter, B. D., Baumgartner, J. V., Powell, J., Braun, D. P. (1996). "A Method for Assessing Hydrologic Alteration within Ecosystems; Un Métro Para Evaluar Alteraciones Hidrológicas Dentro De Ecosistemas." *Conserv. Biol.,* 10(4), 1163-1174.

Sale, M. J., Brill, E. D., Herricks, E. E. (1982). "An Approach to Optimizing Reservoir Operation for Downstream Aquatic Resources." *Water Resour. Res.,* 18(4), 705-712.

Sommers, G. L. (2004). "Hydropower Resources." *Encyclopedia of Energy,* Elsevier, New York, 325-332.

Stalnaker, C. (1990). "Minimum Flow is a Myth." *Bain MB,* 90(5), 31-33.

Steinschneider, S., Bernstein, A., Palmer, R., Polebitski, A. (2014). "Reservoir Management Optimization for Basin-Wide Ecological Restoration in the Connecticut River." *J. Water Resour. Plann. Manage.,* 140(9), 04014023.

Viers, J. H. (2011). "Hydropower Relicensing and Climate Change1." *JAWRA Journal of the American Water Resources Association*, 47(4), 655-661.

Vogel, R. M., Sieber, J., Archfield, S. A., Smith, M. P., Apse, C. D., Huber-Lee, A. (2007). "Relations among Storage, Yield, and Instream Flow." *Water Resour. Res.*, 43(5), n/a-n/a.

Yang, Y. E., Cai, X., Herricks, E. E. (2008). "Identification of Hydrologic Indicators Related to Fish Diversity and Abundance: A Data Mining Approach for Fish Community Analysis." *Water Resour. Res.*, 44(4), n/a-n/a.

Yellen, B., and Boutt, D. F. (2015). "Hydropeaking Induces Losses from a River Reach: Observations at Multiple Spatial Scales." *Hydrol. Process.*, 29(15), 3261-3275.

Zimmerman, J. K. H., Letcher, B. H., Nislow, K. H., Lutz, K. A., Magilligan, F. J. (2010). "Determining the Effects of Dams on Subdaily Variation in River Flows at a Whole-Basin Scale." *River Research and Applications*, 26(10), 1246-1260.

Appendix A: CHOP model formulation & parameterization

The Connecticut River Hydropower Operations Program (CHOP) is formulated in the proprietary LINGO™ optimization software environment. LINGO™ provides a modeling environment where optimization problems are intuitively formulated using the software's set-based modeling language and solved using the software's suite of linear, binary, and nonlinear optimization algorithms (LINDO Systems 2010). The CHOP model uses the simplex-based solver to solve the linear program (LP) hydropower optimization formulation and takes advantage of LINGO's™ interactive data management capabilities to import modeled input data from a Visual Basic for Applications (VBA) enabled Microsoft Excel workbook. The following sections explain the CHOP modeling environment, the components of the LP formulation, the scripts used to model the Baseline and Run-of-River scenarios, and important model parameters.

A.1 General model structure

The major components of the CHOP modeling environment include model inputs, modeling procedure, and post-processing. Figure 16 shows the general structure of the CHOP modeling framework, including flow and energy price as inputs to the coupled Excel- LINGO™ model and post processing in the open-source R coding language. Model inputs are housed within the large, 150 megabyte spreadsheet which contains hourly flow and energy price data as well as documented physical and operating parameters

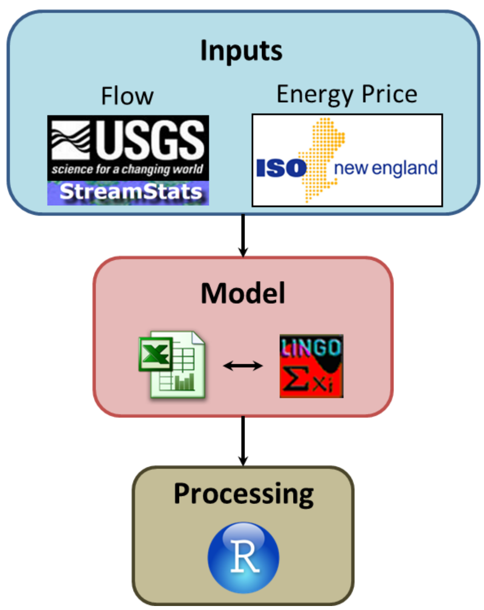


Figure 16 - Schematic of the generalized CHOP workflow

used to constrain the hydropower optimization objective. Using a VBA script, these data are passed to the LINGO™ model, and hydropower optimization is executed at yearly increments.

Modeled output is aggregated in simple text files for post-processing in the R coding environment where necessary data adjustments can be made before performing model analyses.

A.2 LP formulation

The following section defines the unique components of the linear program formulation for CHOP including the objective function formulation and operational constraints used to limit hydropower operations to real-world operations in the order presented in the LINGO™ script defined in the next section.

A.2.1 Objective function

Simply stated, the hydropower optimization objective is formulated to maximize revenue from hydropower dams as described in the main document. For each year of hydropower optimization, the objective function maximizes the aggregate revenues of the modeled five dams at the hourly time-step. Within the objective function, weights are associated with each of the hydropower facilities such that the relative importance of these facilities can be operated correctly. For instance, releases from Vernon Dam supply water to Northfield and since Northfield may generate three times the revenue of Vernon, the optimization may unintelligently choose operations which maximize Northfield revenues at a detriment to Vernon's. In order to ensure normal operations, the objective weight for Vernon is scaled to be three times as large as Northfield, encouraging the model to model intuitive hydropower operations.

While only the hydropower objective was used in this study, the model is easily formulated for a multi-objective approach which allows for the consideration of explicit ecological objectives. A version of this model already exists, though this ecological objective was not of interest to ecological stakeholders in its current form. The opportunity to reformulate and use this multi-objective approach to explicitly consider trade-offs between ecological and hydropower objectives is a basis for future work.

A.2.2 Model constraints

To ensure that CHOPS accurately mimics operations on the current hydropower system, various physical and operational constraints are applied to the model to define the basic functional components of hydropower facilities and their operation.

A.2.2.1 Continuity

A mass balance is applied at each modeled reservoir to ensure continuity of flows and water storage along the mainstem. The mass balance constraint simply states that the storage of any given reservoir is the summation of its storage at the previous time-step and its inflows and releases at the current time-step. To ensure continuity of reservoir storage across modeled years, the initial and final storages are constrained to the same value for each year.

A.2.2.2 Physical and operating constraints

Each facility is constrained to its physical limitations including useable reservoir storage, maximum turbine flow rate, and maximum power generating capacity. Operating constraints are applied in the form of licensed minimum flows and hydropower release ramping rates. The ramping rates are applied to ensure realistic hydropower generation at levels matching closely to historically reported power generation.

A.3 Baseline LINGO script

The following section shows the LINGO™ script code for the objective and constraint formulation of the Baseline model, designed to mimic real-world hydropower operations for the FERC relicensing system. Both the programming language and the variable nomenclature follow an intuitive scheme which is supported by commented explanations. Variables names follow the general format: TYPE_LOCATION_VARIABLE where the TYPE is most generally RES for reservoir, the LOCATION is some character set such as WILD for Wilder Dam, and VARIABLE may be PR for power release or ST_MAX for storage maximum.

```
!---Objective Function---;

MIN =
!Maximize Income from Hydropower Projects;
-RES_WILD_P_WT * @SUM(hour(I): RES_WILD_INC(I)) - !Wilder Total Income;
RES_BFAL_P_WT * @SUM(hour(I): RES_BFAL_INC(I)) - !Bellows Falls Total Income;
RES_VERN_P_WT * @SUM(hour(I): RES_VERN_INC(I)) - !Vernon Total Income;
RES_NORT_P_WT * @SUM(hour(I): RES_NORT_INC(I)) - !Northfield Total Income;
RES_TURN_P_WT * @SUM(hour(I): RES_TURN_INC(I)) + !Turners Falls Total Income;
!Minimize Pumping Cost @ Northfield;
RES_NORT_INTAKE_WT * @SUM(hour(I): RES_NORT_INTAKE_COST(I)) + !Northfield Intake Cost;
;
!-----------------------;

!---Model Constraints---;

!Reservoir Mass Balance;
! (Reservoir Storage = Previous Storage + Side Inflows + Upstream Releases - Reservoir
Releases;
@FOR (hour(I) | I #GE# 2:
RES_WILD_ST(I) = RES_WILD_ST(I-1) + FLOW_WILD_SIDE(I) - RES_WILD_R(I);
RES_BFAL_ST(I) = RES_BFAL_ST(I-1) + RES_WILD_R(I) + FLOW_BFAL_SIDE(I) - RES_BFAL_R(I);
RES_VERN_ST(I) = RES_VERN_ST(I-1) + RES_BFAL_R(I) + FLOW_VERN_SIDE(I) - RES_VERN_R(I);
RES_NORT_ST(I) = RES_NORT_ST(I-1) + RES_NORT_INTAKE(I) - RES_NORT_R(I);
RES_TURN_ST(I) = RES_TURN_ST(I-1) + RES_VERN_R(I) + FLOW_TURN_SIDE(I) - RES_TURN_R(I)
- RES_NORT_INTAKE(I) + RES_NORT_R(I);
);

!Constrain Initial and Final Storages;
! (ensure consistency across each modeled year);
@FOR (hour(I) | I #EQ# 1:
RES_WILD_ST(I) = RES_WILD_ST_MAX;  !13350 acre-ft;
RES_BFAL_ST(I) = RES_BFAL_ST_MAX;  !7476 acre-ft;
RES_VERN_ST(I) = RES_VERN_ST_MAX;  !18300 acre-ft;
RES_NORT_ST(I) = RES_NORT_ST_MAX;  !12318 acre_ft;
RES_TURN_ST(I) = RES_TURN_ST_MAX;  !21500 acre-ft;
);

@FOR (hour(I) | I #EQ# 8760:
RES_WILD_ST(I) = RES_WILD_ST_MAX;  !13350 acre-ft;
RES_BFAL_ST(I) = RES_BFAL_ST_MAX;  !7476 acre-ft;
RES_VERN_ST(I) = RES_VERN_ST_MAX;  !18300 acre-ft;
RES_NORT_ST(I) = RES_NORT_ST_MAX;  !12318 acre_ft;
RES_TURN_ST(I) = RES_TURN_ST_MAX;  !21500 acre-ft;
);

!Storage Operating Range;
! (define useable storage capacity);
@FOR (hour(I) | I #GE# 1:
RES_WILD_ST(I) < RES_WILD_ST_MAX;  !13350 acre-ft;
RES_BFAL_ST(I) < RES_BFAL_ST_MAX;  !7476 acre-ft;
RES_VERN_ST(I) < RES_VERN_ST_MAX;  !18300 acre-ft;
RES_NORT_ST(I) < RES_NORT_ST_MAX;  !12318 acre_ft;
RES_TURN_ST(I) < RES_TURN_ST_MAX;  !21500 acre-ft;
);
```

```
!Minimum Flows;
! (ensure licensed minimum flow conditions are always met);
@FOR (hour(I) | I #GE# 1:
RES_WILD_R(I) > RES_WILD_R_MIN;
RES_BFAL_R(I) > RES_BFAL_R_MIN;
RES_VERN_R(I) > RES_VERN_R_MIN;
RES_TURN_R(I) > RES_TURN_R_MIN;
);

!Releases;
! (Release term R includes SPILL + PR (Power Release). This ensures R >= PR);
! (SPILL is not an explicitly defined term, but implied through this relationship such
that when R > PR, SPILL = R-PR);
@FOR (hour(I) | I #GE# 1:
RES_WILD_R(I) >= RES_WILD_PR(I);
RES_BFAL_R(I) >= RES_BFAL_PR(I);
RES_VERN_R(I) >= RES_VERN_PR(I);
RES_NORT_R(I) = RES_NORT_PR(I);
RES_TURN_R(I) >= RES_TURN_PR(I);
);

!Constrain flow through turbines;
@FOR (hour(I) | I #GE# 1:
RES_WILD_PR(I) < RES_WILD_PR_MAX; !10,500 cfs maximum turbine capacity;
RES_BFAL_PR(I) < RES_BFAL_PR_MAX; !10,700 cfs maximum turbine capacity;
RES_VERN_PR(I) < RES_VERN_PR_MAX; !15,000 cfs maximum turbine capacity;
RES_NORT_PR(I) < RES_NORT_PR_MAX; !3,800 (x4) cfs turbine capacity;
RES_TURN_PR(I) < RES_TURN_PR_MAX; !16,000 cfs is design flow of the canal;
);

!Release Ramping - limit ramp rates for realistic hydropeaking power release;
! (With ramp rates unconstrained, power releases would exhibit blocky (On/Off) release
behavior);
! (Unique ramping rates were chosen for each facility to calibrate average annual
power production to historical rates);
@FOR (hour(I) | I #GE# 2:
! Ramping up constraint;
[RES_WILD_PR_UP] RES_WILD_PR(I) - RES_WILD_PR(I-1) < RES_WILD_RAMP_UP;
[RES_BFAL_PR_UP] RES_BFAL_PR(I) - RES_BFAL_PR(I-1) < RES_BFAL_RAMP_UP;
[RES_VERN_PR_UP] RES_VERN_PR(I) - RES_VERN_PR(I-1) < RES_VERN_RAMP_UP;

[RES_NORT_PR_UP] RES_NORT_PR(I) - RES_NORT_PR(I-1) < RES_NORT_RAMP_UP;
[RES_NORT_IN_UP] RES_NORT_INTAKE(I) - RES_NORT_INTAKE(I-1) < RES_NORT_RAMP_UP;

[RES_TURN_PR_UP] RES_TURN_PR(I) - RES_TURN_PR(I-1) < RES_TURN_RAMP_UP;

! Ramping down constraint;
[RES_WILD_PR_DN] RES_WILD_PR(I-1) - RES_WILD_PR(I) < RES_WILD_RAMP_DOWN;
[RES_BFAL_PR_DN] RES_BFAL_PR(I-1) - RES_BFAL_PR(I) < RES_BFAL_RAMP_DOWN;
[RES_VERN_PR_DN] RES_VERN_PR(I-1) - RES_VERN_PR(I) < RES_VERN_RAMP_DOWN;

[RES_NORT_PR_DN] RES_NORT_PR(I-1) - RES_NORT_PR(I) < RES_NORT_RAMP_DOWN;
[RES_NORT_IN_DN] RES_NORT_INTAKE(I-1) - RES_NORT_INTAKE(I) < RES_NORT_RAMP_DOWN;

[RES_TURN_PR_DN] RES_TURN_PR(I-1) - RES_TURN_PR(I) < RES_TURN_RAMP_DOWN;
);

!Constrain power generated;
! (Define maximum power capacity of each facility);
@FOR (hour(I) | I #GE# 1:
RES_WILD_P(I) < RES_WILD_P_MAX;
RES_BFAL_P(I) < RES_BFAL_P_MAX;
RES_VERN_P(I) < RES_VERN_P_MAX;
```

```
RES_NORT_P(I) < RES_NORT_P_MAX;
RES_TURN_P(I) < RES_TURN_P_MAX;
);

!Calculate the power production;
@FOR (hour(I)| I #GE# 1:
! CONV term = PR_MAX/(P_MAX * efficiency);
RES_WILD_P(I) = RES_WILD_PR(I)/RES_WILD_P_CONV;  !334 cfs per MW produced;
RES_BFAL_P(I) = RES_BFAL_PR(I)/RES_BFAL_P_CONV;  !349 cfs per MW produced;
RES_VERN_P(I) = RES_VERN_PR(I)/RES_VERN_P_CONV;  !644 cfs per MW produced;
RES_NORT_P(I) = RES_NORT_PR(I)/RES_NORT_P_CONV;  !23  cfs per MW produced;
RES_TURN_P(I) = RES_TURN_PR(I)/RES_TURN_P_CONV;  !295 cfs per MW produced;
);

!Reservoir Income;
! (Revenue calculated from product of estimated power and historical energy price);
@FOR (hour(I) | I #GE# 1:
RES_WILD_INC(I) = RES_WILD_P(I) * ENERGY_PRICE(I);
RES_BFAL_INC(I) = RES_BFAL_P(I) * ENERGY_PRICE(I);
RES_VERN_INC(I) = RES_VERN_P(I) * ENERGY_PRICE(I);
RES_NORT_INC(I) = RES_NORT_P(I) * ENERGY_PRICE(I);
RES_TURN_INC(I) = RES_TURN_P(I) * ENERGY_PRICE(I);
);

!Northfield Power Intake;
! (Modeling Northfield's pumped storage operations requires an INTAKE term to define
flow rates, power, & costs associated pumping water up to the facility);
@FOR (hour(I)| I #GE# 1:
! Define limits for INTAKE flow term between 0 and MAX (15,000 cfs);
@BND(0,RES_NORT_INTAKE(I), RES_NORT_INTAKE_MAX);
! Define INTAKE_P power generation term;
! (the power conversion ratio (cfs/MW) for pumping water is ~4/3 the ratio used for
power generated using release);
! (pg. 99/537 of the Firstlight FERC Pre-Application document defines this
relationship (17.9 cfs/13.6 cfs ~ 4/3));
RES_NORT_INTAKE_P(I) = (RES_NORT_INTAKE(I)/RES_NORT_P_CONV)*4/3;
!Conversion from power generation to power cost;
RES_NORT_INTAKE_COST(I) = RES_NORT_INTAKE_P(I)*ENERGY_PRICE(I););
!-----------------------;
```

A.4 Run-of-River LINGO script

The following section shows the changes in the LINGO™ script from the Baseline model to the Run-of-River system. The objective formulation remains the same as in the Baseline scenario, though mainstem facility operations are constrained such hydropower releases may not be optimized at these locations. Constraints which were removed from the Baseline run are shown in ~~strikethrough~~ and added constraints are shown in normal text below.

```
!Release Ramping - limit ramp rates for realistic hydropeaking power release;
! (With ramp rates unconstrained, power releases would exhibit blocky (On/Off) release
behavior);
! (Unique ramping rates were chosen for each facility to calibrate average annual
power production to historical rates);
@FOR (hour(I) | I #GE# 2:
! Ramping up constraint;
[RES_WILD_PR_UP] RES_WILD_PR(I) - RES_WILD_PR(I-1) < RES_WILD_RAMP_UP;
[RES_BFAL_PR_UP] RES_BFAL_PR(I) - RES_BFAL_PR(I-1) < RES_BFAL_RAMP_UP;
[RES_VERN_PR_UP] RES_VERN_PR(I) - RES_VERN_PR(I-1) < RES_VERN_RAMP_UP;

[RES_NORT_PR_UP] RES_NORT_PR(I) - RES_NORT_PR(I-1) < RES_NORT_RAMP_UP;
[RES_NORT_IN_UP] RES_NORT_INTAKE(I) - RES_NORT_INTAKE(I-1) < RES_NORT_RAMP_UP;

[RES_TURN_PR_UP] RES_TURN_PR(I) - RES_TURN_PR(I-1) < RES_TURN_RAMP_UP;

! Ramping down constraint;
[RES_WILD_PR_DN] RES_WILD_PR(I-1) - RES_WILD_PR(I) < RES_WILD_RAMP_DOWN;
[RES_BFAL_PR_DN] RES_BFAL_PR(I-1) - RES_BFAL_PR(I) < RES_BFAL_RAMP_DOWN;
[RES_VERN_PR_DN] RES_VERN_PR(I-1) - RES_VERN_PR(I) < RES_VERN_RAMP_DOWN;

[RES_NORT_PR_DN] RES_NORT_PR(I-1) - RES_NORT_PR(I) < RES_NORT_RAMP_DOWN;
[RES_NORT_IN_DN] RES_NORT_INTAKE(I-1) - RES_NORT_INTAKE(I) < RES_NORT_RAMP_DOWN;

[RES_TURN_PR_DN] RES_TURN_PR(I-1) - RES_TURN_PR(I) < RES_TURN_RAMP_DOWN;
);

!Run of river condition (releases = inflows);
@FOR (hour(I) | I #GE# 2:
RES_WILD_R(I) = FLOW_WILD_SIDE(I);
RES_BFAL_R(I) = RES_WILD_R(I) + FLOW_BFAL_SIDE(I);
RES_VERN_R(I) = RES_BFAL_R(I) + FLOW_VERN_SIDE(I);
RES_TURN_R(I) = RES_VERN_R(I) + FLOW_TURN_SIDE(I);
);
```

A.5 Model parameterization

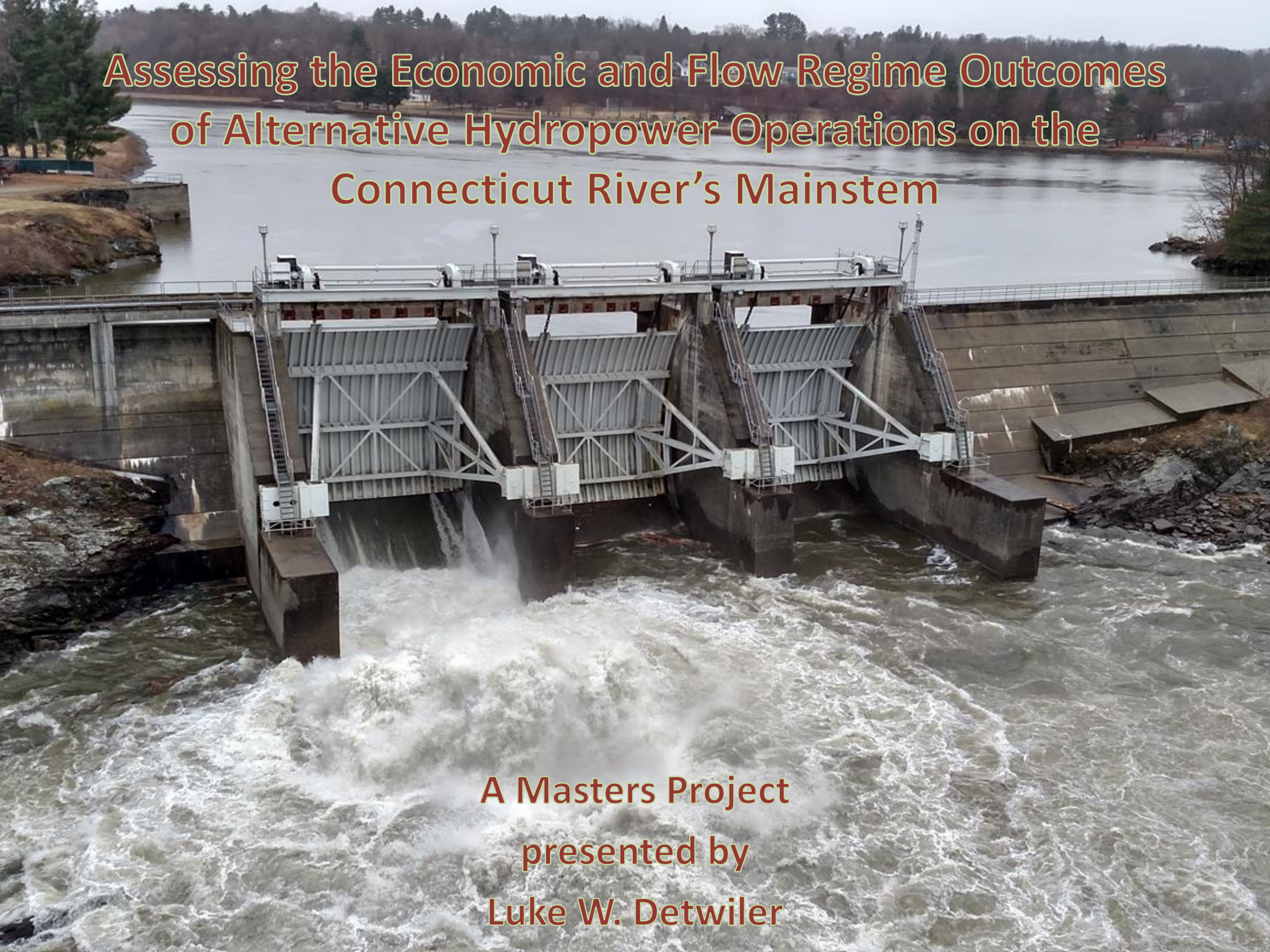
The following section shows the values of the various modeled parameters used in the above reservoir modeling formulations. The values are derived from documentation on each reservoir found in FERC pre application documents.

Reservoir Data

Minimum Release		
RES_WILD_R_MIN	675	*cfs*
RES_BFAL_R_MIN	1,083	*cfs*
RES_VERN_R_MIN	1,250	*cfs*
RES_NORT_R_MIN	N/A	*cfs*
RES_TURN_R_MIN	1,250	*cfs*
Maximum Turbine Release		
RES_WILD_PR_MAX	10,700	*cfs*
RES_BFAL_PR_MAX	11,400	*cfs*
RES_VERN_PR_MAX	17,100	*cfs*
RES_NORT_PR_MAX	20,000	*cfs*
RES_TURN_PR_MAX	16,000	*cfs*
Maximum Pumping Rate		
RES_NORT_INTAKE_MAX	15,200	*cfs*
Ramping		
RES_WILD_RAMP_UP	1,111	*cfs*
RES_WILD_RAMP_DOWN	1,111	*cfs*
RES_BFAL_RAMP_UP	1,111	*cfs*
RES_BFAL_RAMP_DOWN	1,111	*cfs*
RES_VERN_RAMP_UP	1,111	*cfs*
RES_VERN_RAMP_DOWN	1,111	*cfs*
RES_NORT_RAMP_UP	1,800	*cfs*
RES_NORT_RAMP_DOWN	1,800	*cfs*
RES_TURN_RAMP_UP	1,111	*cfs*
RES_TURN_RAMP_DOWN	1,111	*cfs*
Max Operating Storage		
RES_WILD_ST_MAX	13,350	*acre-ft*
RES_BFAL_ST_MAX	7,476	*acre-ft*
RES_VERN_ST_MAX	18,300	*acre-ft*
RES_NORT_ST_MAX	12,318	*acre-ft*
RES_TURN_ST_MAX	7,400	*acre-ft*

Power Data

Maximum Power Generation		
RES_WILD_P_MAX	35.6	*MW*
RES_BFAL_P_MAX	48.6	*MW*
RES_VERN_P_MAX	32.4	*MW*
RES_NORT_P_MAX	1119	*MW*
RES_TURN_P_MAX	67.7	*MW*
General Turbine Efficiency		
RES_WILD_EFF	0.9	*ratio*
RES_BFAL_EFF	0.8	*ratio*
RES_VERN_EFF	0.82	*ratio*
RES_NORT_EFF	0.88	*ratio*
RES_TURN_EFF	0.9	*ratio*
cfh per MW (=Max Turbine Release/(Max MW x Efficiency))		
RES_WILD_P_CONV	334	*cfs/MW*
RES_BFAL_P_CONV	293	*cfs/MW*
RES_VERN_P_CONV	644	*cfs/MW*
RES_NORT_P_CONV	20	*cfs/MW*
RES_TURN_P_CONV	263	*cfs/MW*



Assessing the Economic and Flow Regime Outcomes of Alternative Hydropower Operations on the Connecticut River's Mainstem

A Masters Project

presented by

Luke W. Detwiler

Overview

1. Project
2. Background
3. Study Area & Model
4. Findings
5. Conclusions & Future Work

Connecticut River Project

TNC Goals:

- Provide conservation services to benefit the Connecticut River basin's ecosystem

Project Goals:

- Identify alternative dam operations which may improve flow regime

UMass Task:

- Develop models and assessment tools to assist in this process

The Nature Conservancy

UNIVERSITY OF MASSACHUSETTS AMHERST 1863

UMASS AMHERST

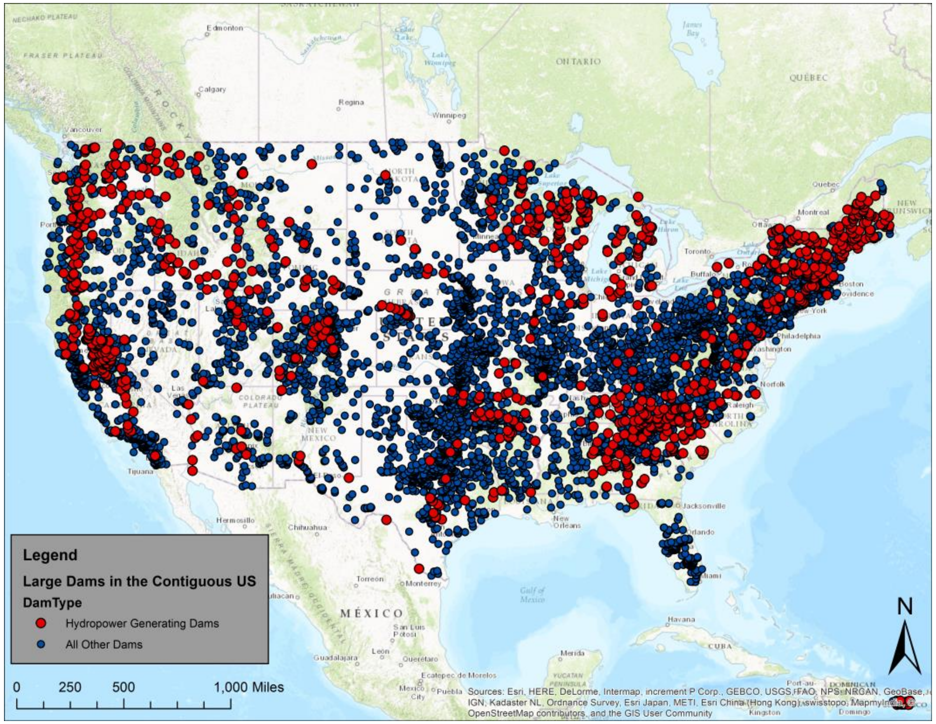
Importance of Hydropower

Ecological

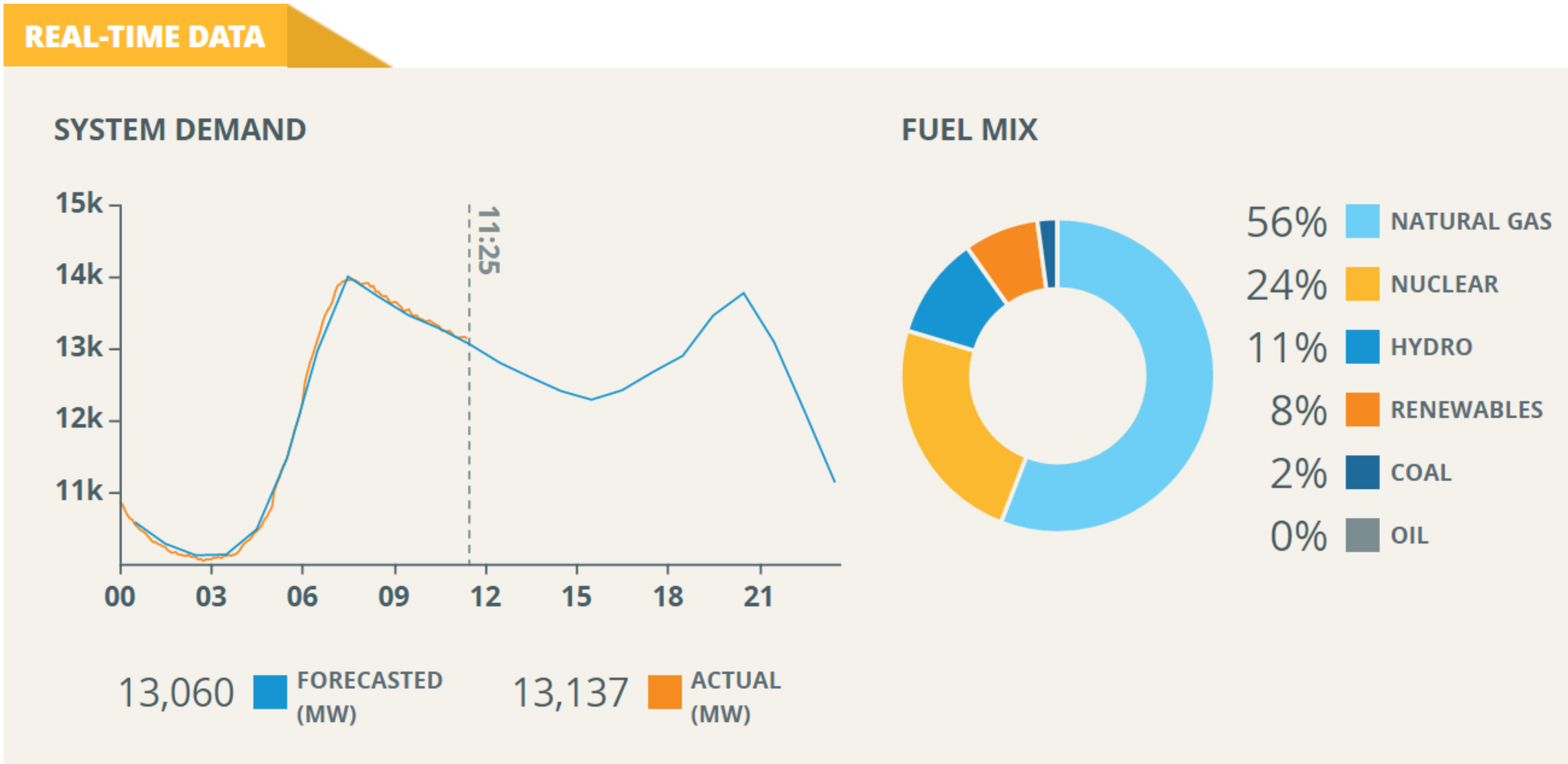
- Sub-daily alterations to flow regime
- Negative ecological responses

Economic

- Energy Supply
  - 20% globally
  - 7% in United States
  - 8% in New England



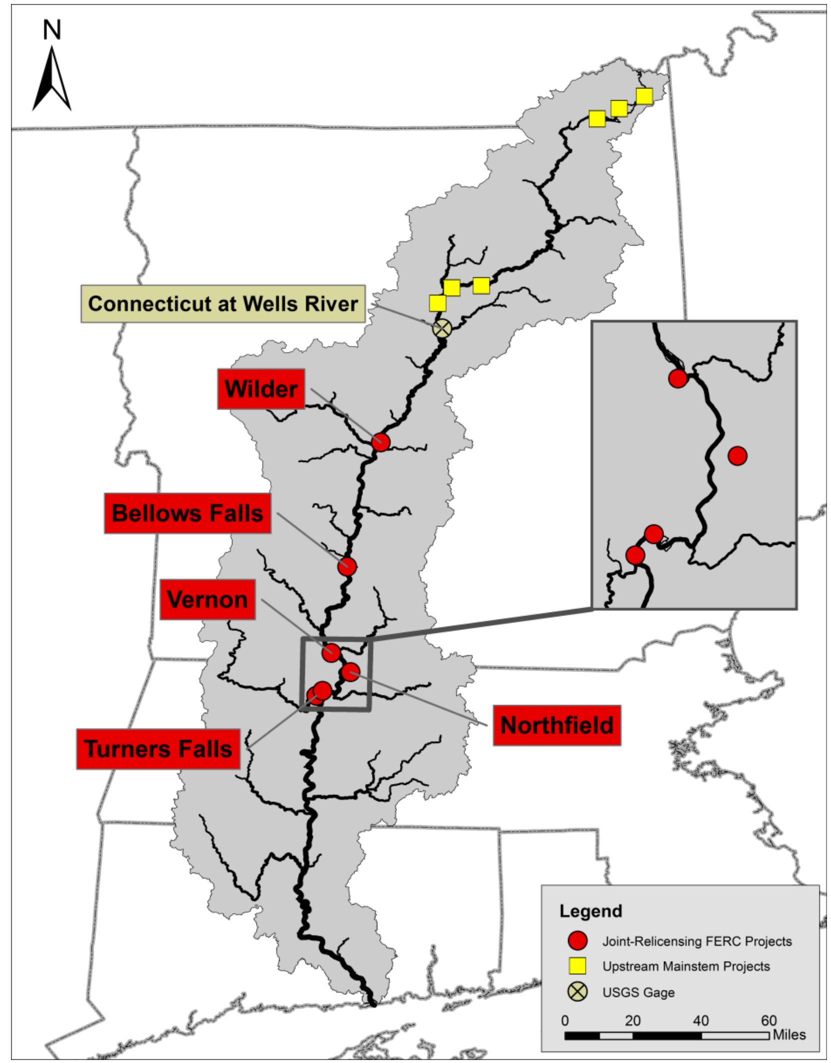
Energy in New England – Today



Our Study Area

Connecticut River

- 5 hydropower facilities
  - 4 Peaking
  - 1 Pumped Storage
- Relicensing for 2019
  - 30-50 years of licensure
- Changes in ownership
  - Current owners selling



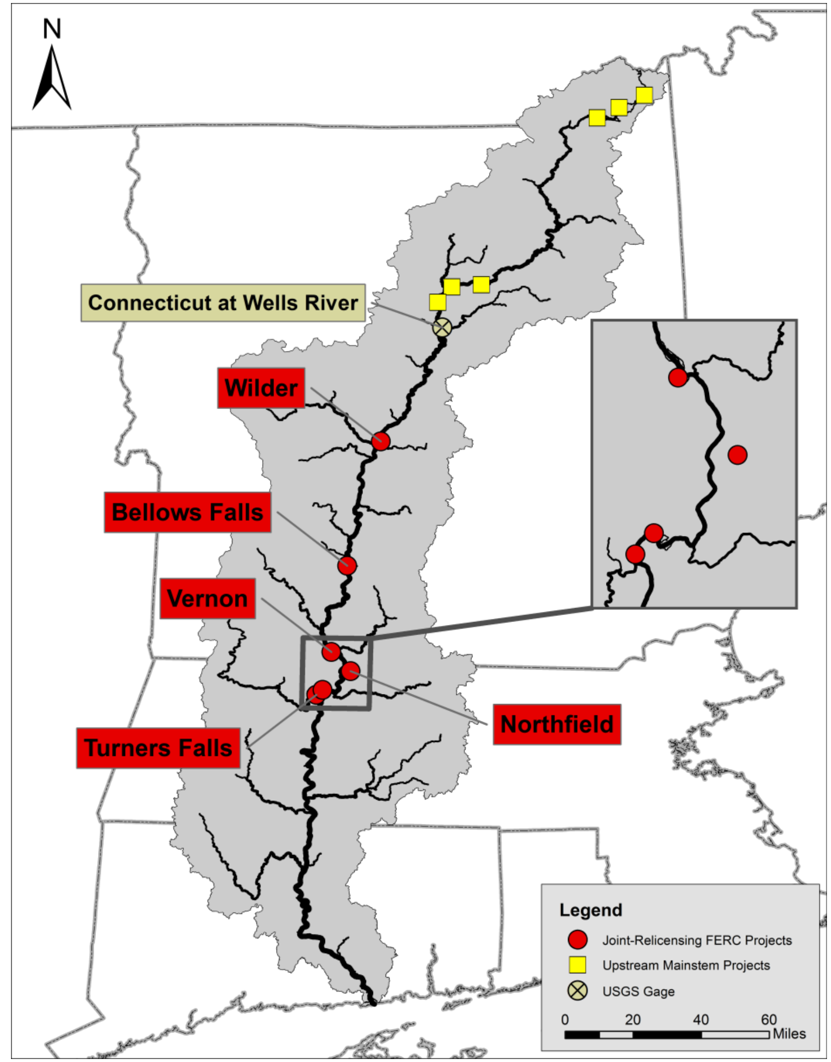
Dam Characteristics

Facility	Type	Avg. Annual Inflow (cfs)	Hydro Capacity (cfs)	Power Capacity (MW)
Wilder	Peaking	6,400	12,700	35.6
Bellows Falls	Peaking	10,500	11,010	48.5
Vernon	Peaking	12,200	17,010	32.4
Northfield Pumped Storage	**Pumped Storage**	**N/A**	**20,000**	**1,119.2**
Turners Falls	Peaking	13,930	16,000	67.7

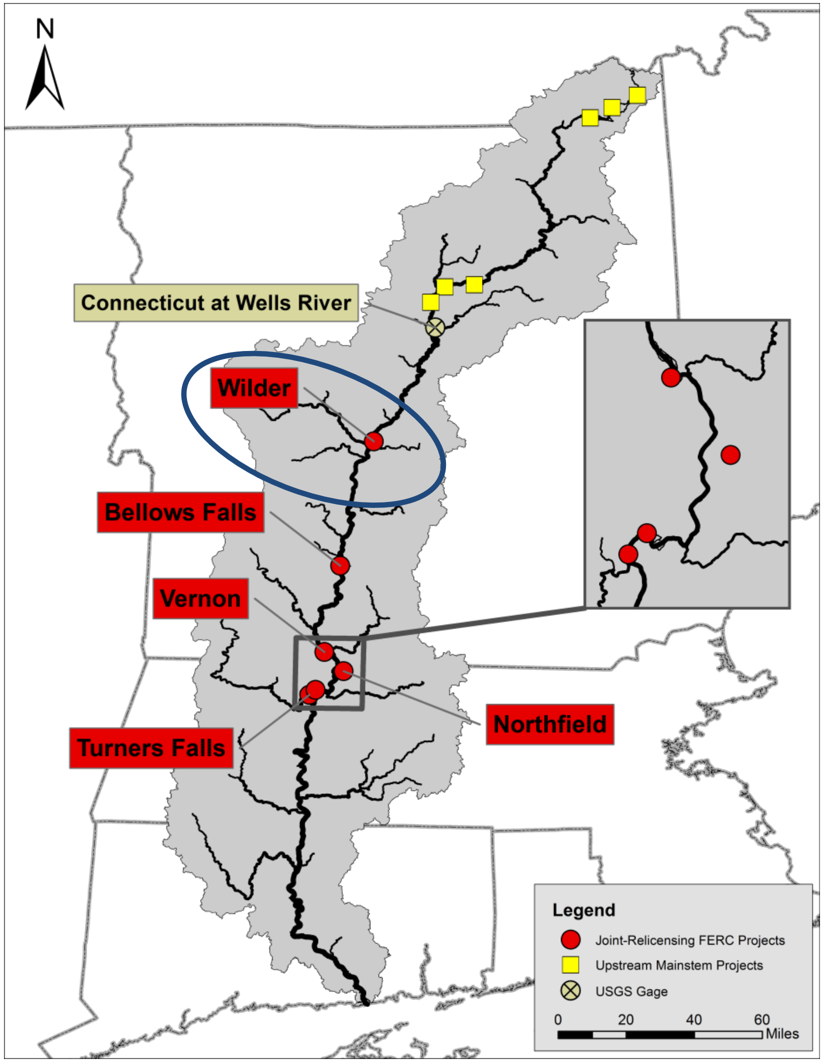
Total Power Capacity: 1,303 MW

Today's Peak Demand: 14,000 MW

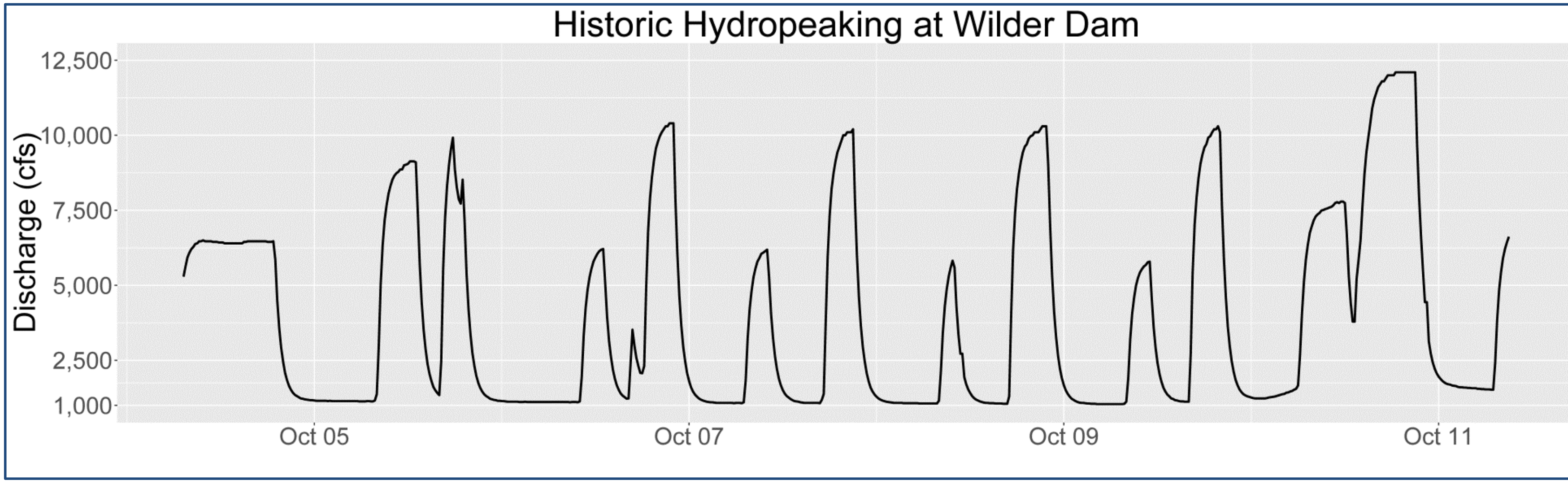
Capacity is ~9% of today's demand



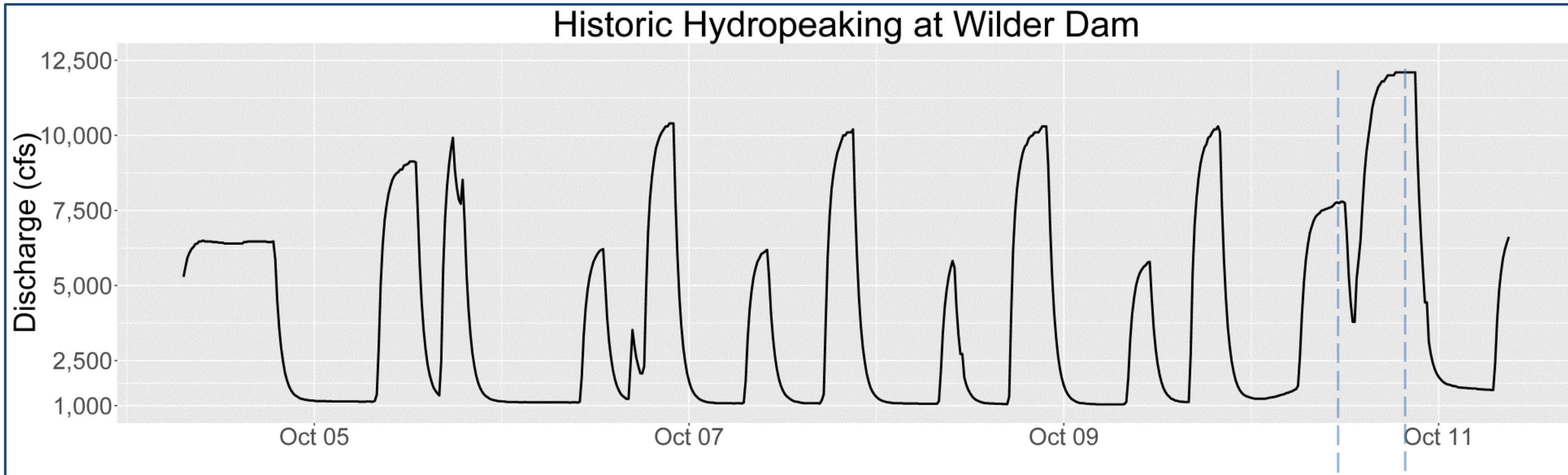
Hydropeaking Flow Alterations

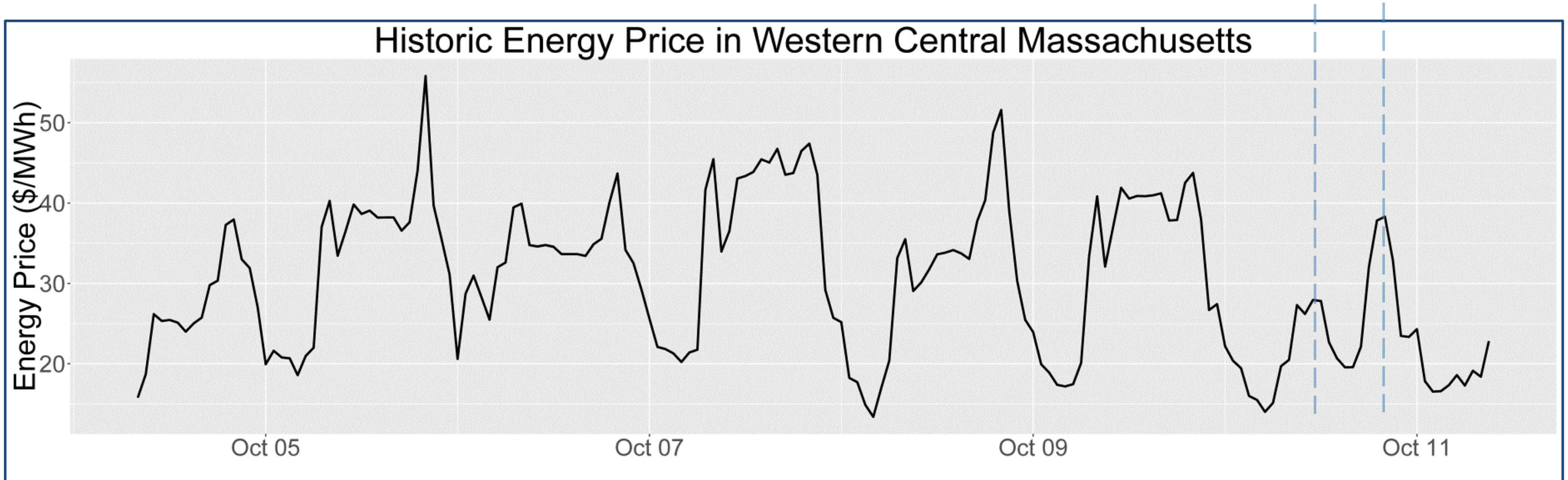


Hydropeaking Flow Alterations

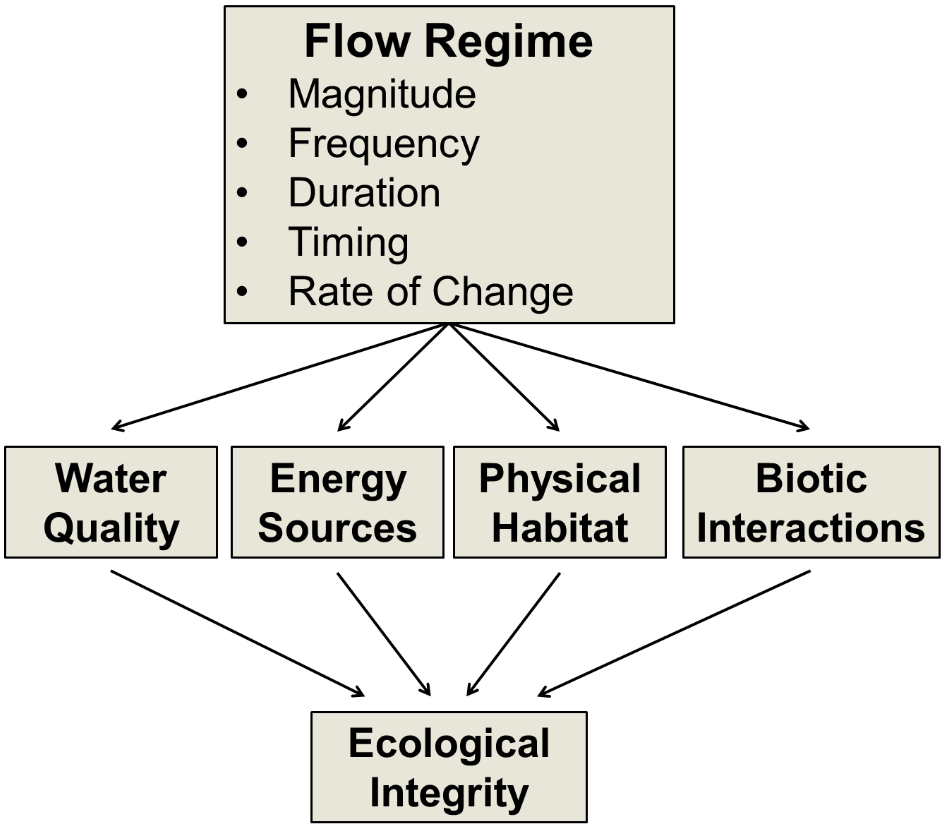


Hydropeaking Flow Alterations





Environmental Implications



Hydropeaking introduces unnatural:

- Peak magnitudes
- Rates-of-change
- Frequency, duration, & timing

Environmental Implications

Potential Impacts:

- Loss of critical growth periods
  - Loss of uninterrupted low flows
    - Juvenile fish
- Loss of habitat suitability
  - Water level fluctuations
    - Mussels, Insects, Fish
- Survival stresses
  - Rapid flow changes
  - Water quality

Our Question

What alternative operations could mitigate these sub-daily flow alterations?

(to provide a more ecologically healthy flow regime)

Modeling Hydropower Operations

Hydropower operations model:

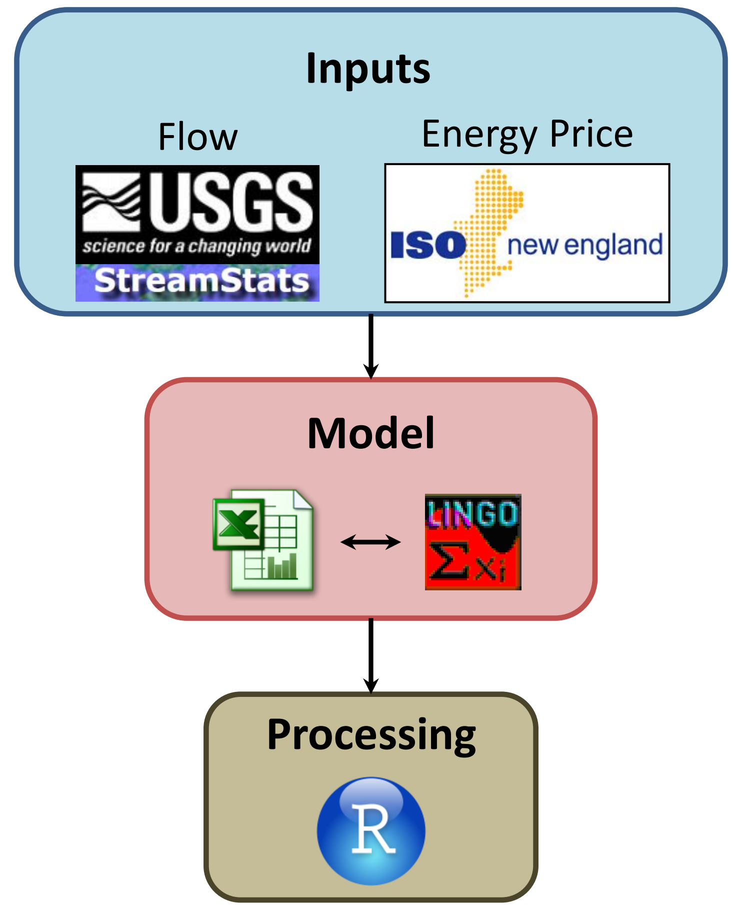
- Optimization (LP)
- Hourly time step

Objective:

Maximize: $\$_{\text{Hydropower}}$

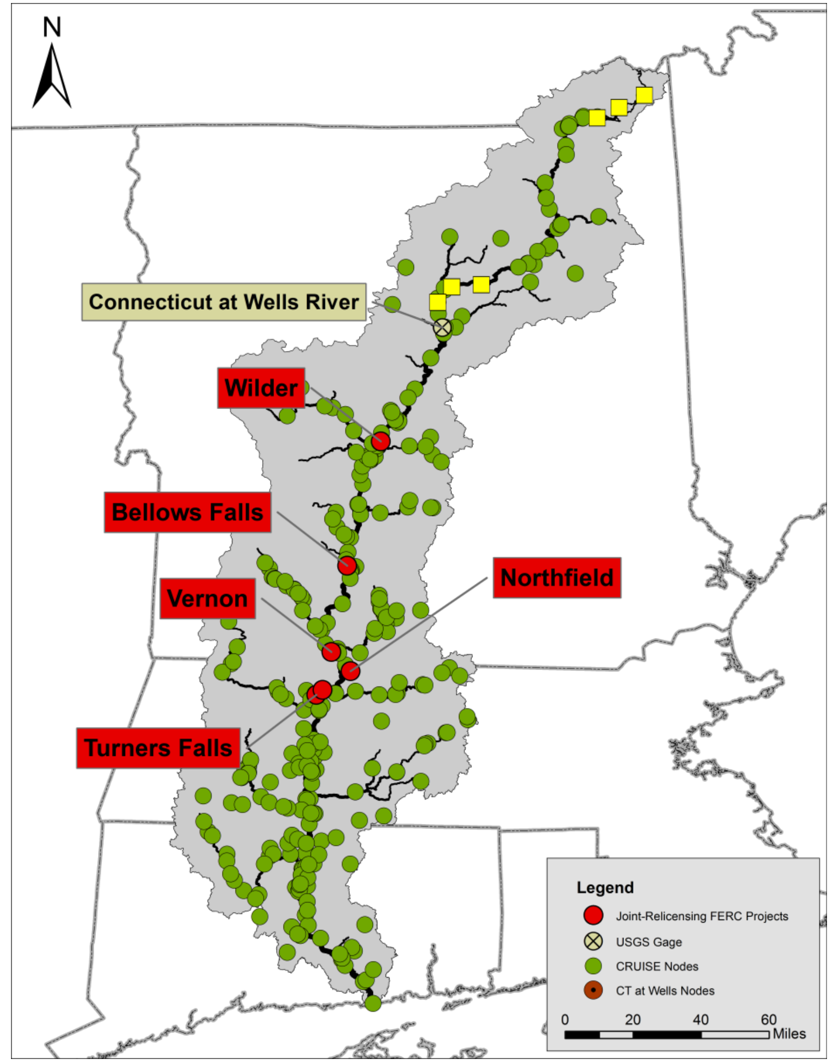
Simplifying Assumption:

$$Power = C \times Q$$



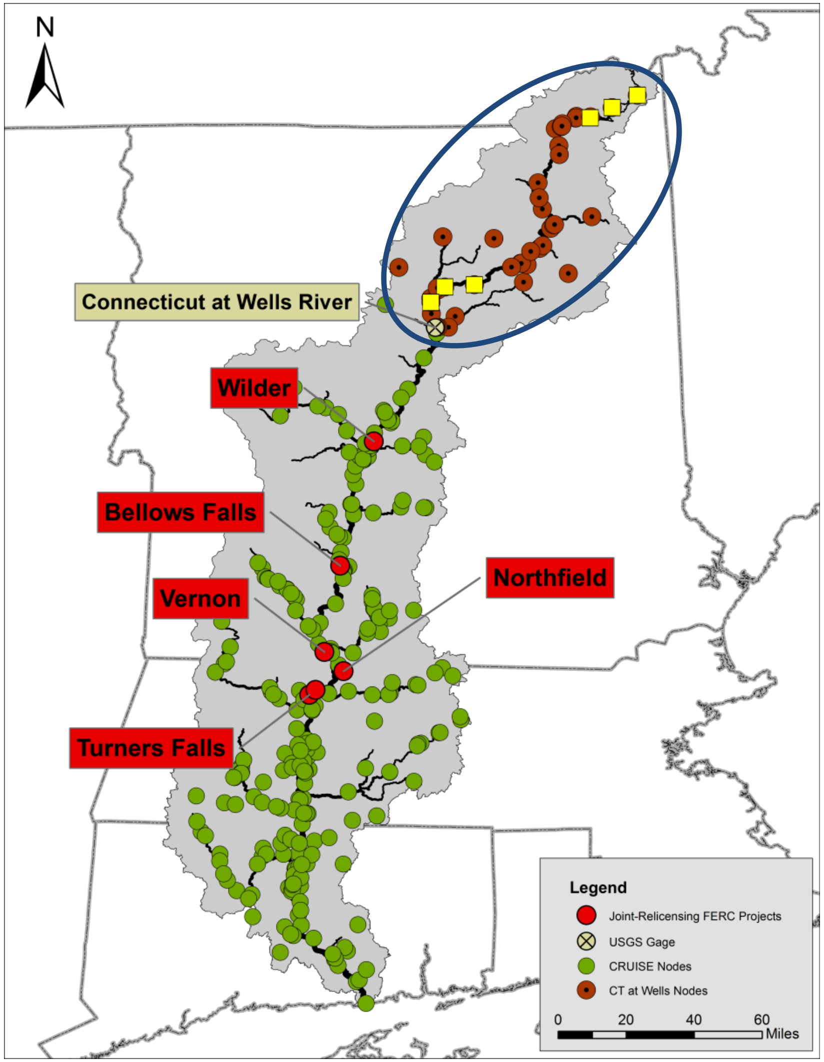
Flow Dataset

- Basin-wide unimpaired flow dataset (1961 – 2011)
  - Unimpaired flows calculated using USGS Streamstats tool
    - Connecticut River Unimpacted Streamflow Estimation (CRUISE)
  - Daily flow estimates disaggregated & smoothed to hourly time step



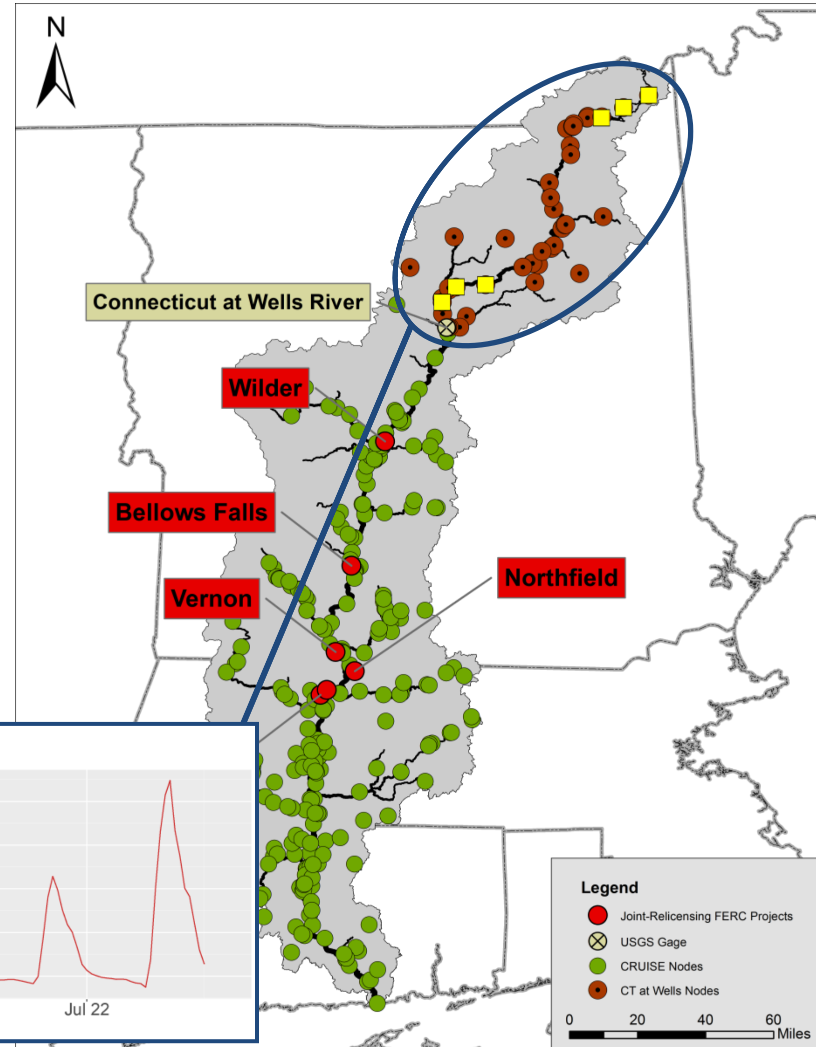
Flow Dataset

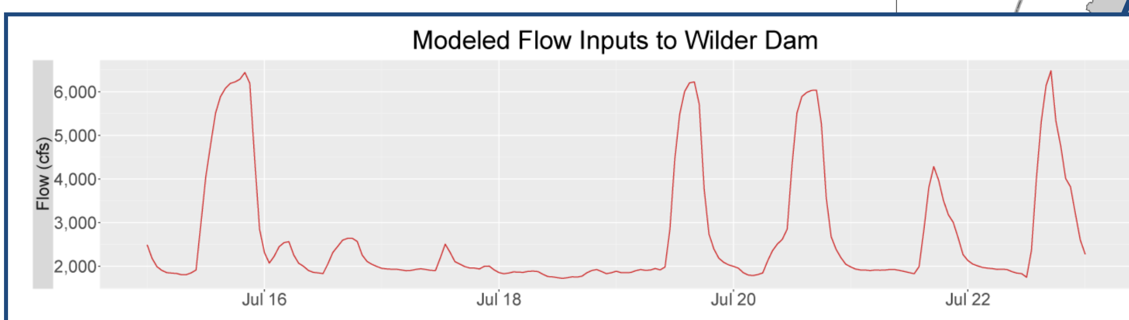
- Upstream hydropower operations
  - 15 Miles Falls projects
    - Operations relicensed in 2002
  - Historic operations captured by USGS #01138500
    - Combined with CRUISE



Flow Dataset

- Upstream hydropower operations
  - 15 Miles Falls projects
    - Operations relicensed in 2002
  - Historic operations captured by USGS #01138500
    - Combined with CRUISE





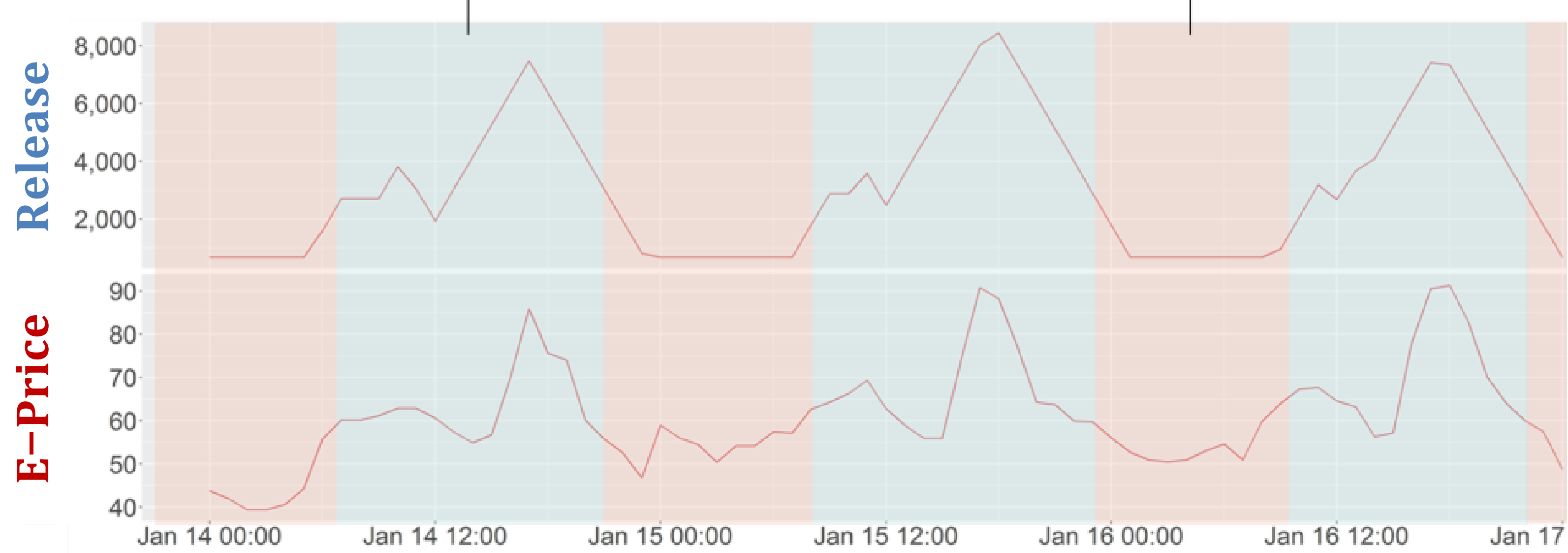
Modeling Approach

- Maximize Hydropower Revenue:

$$\sum_t \left[\boldsymbol{Release}_t \left[\frac{ft^3}{s}\right] \times \boldsymbol{Power\ Conversion} \left[\frac{MWh}{\frac{ft^3}{s}}\right] \times \boldsymbol{E{-}Price}_t \left[\frac{\$}{MWh}\right] \right]$$

Release Water

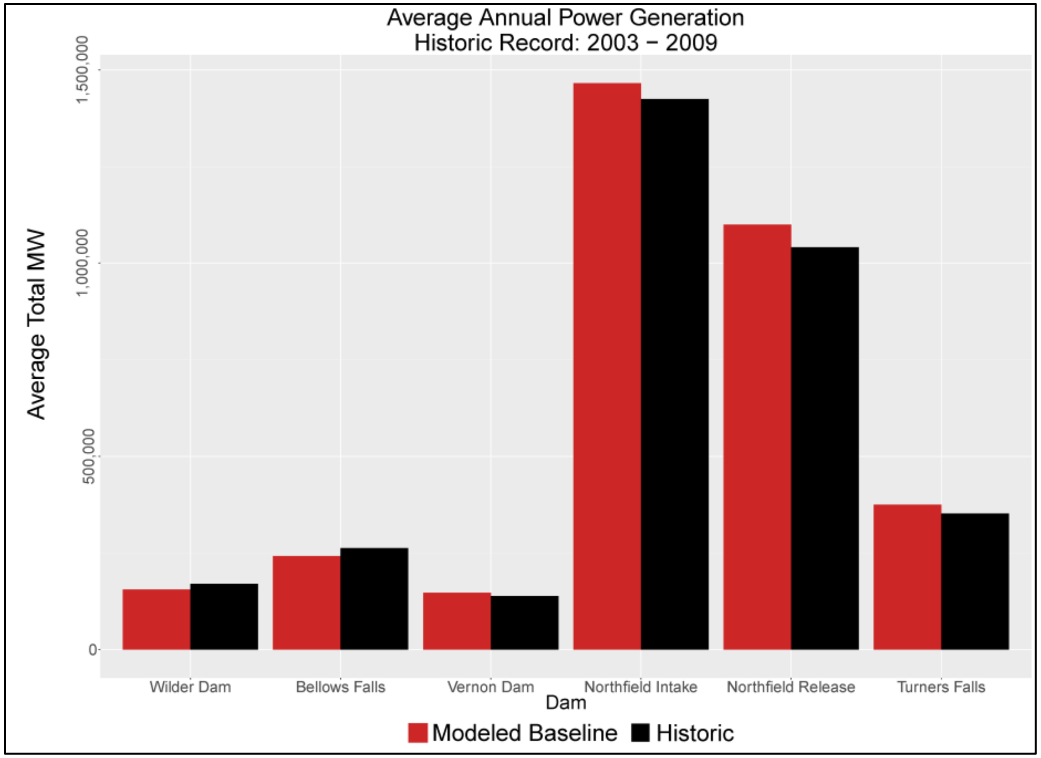
Store Water



Model Constraints & Calibration

Model constrained by:

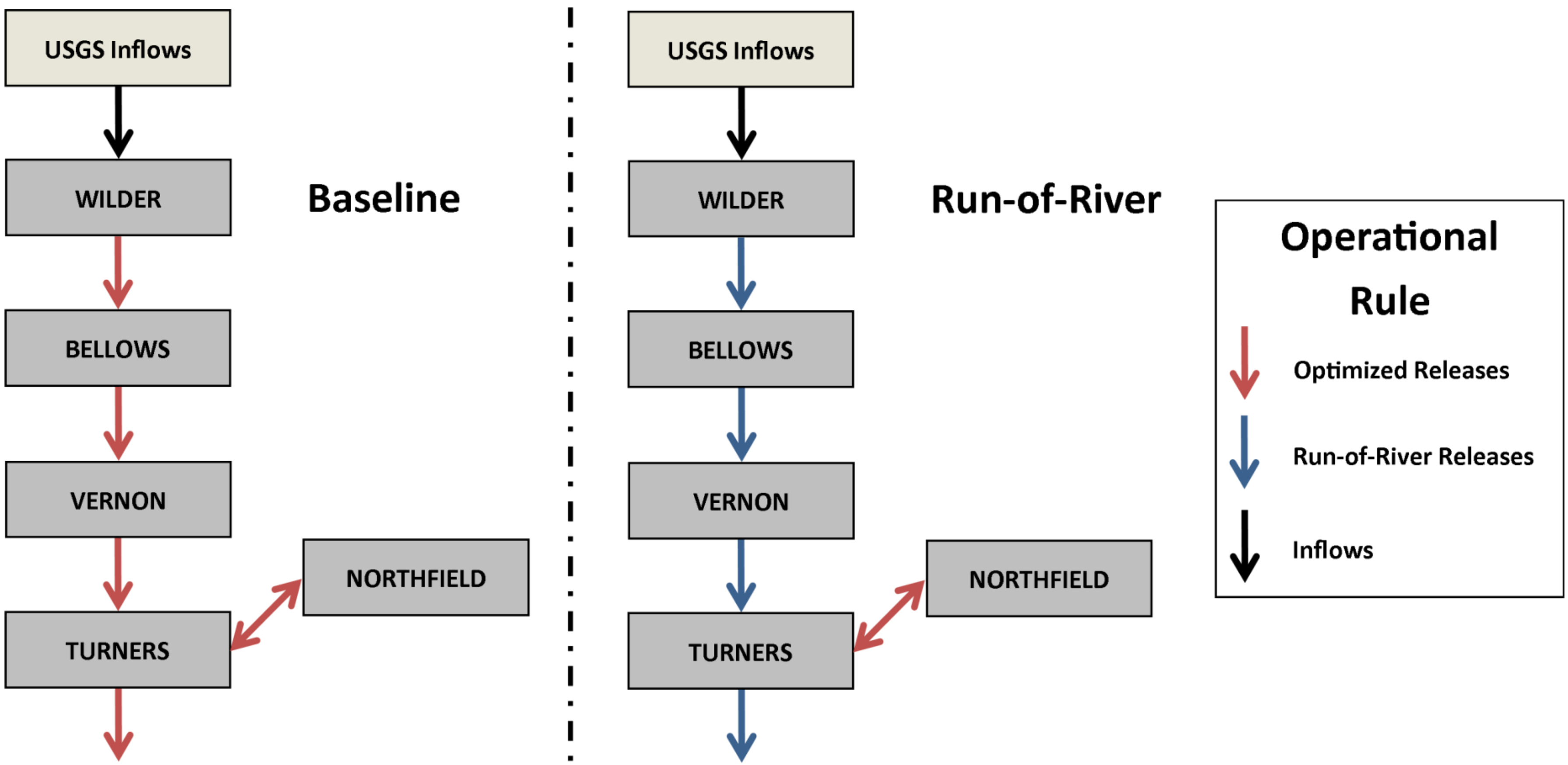
- Known physical & operational constraints
  - Storage, Power, Flow Capacities
  - Minimum Flows
  - Ramping Rates



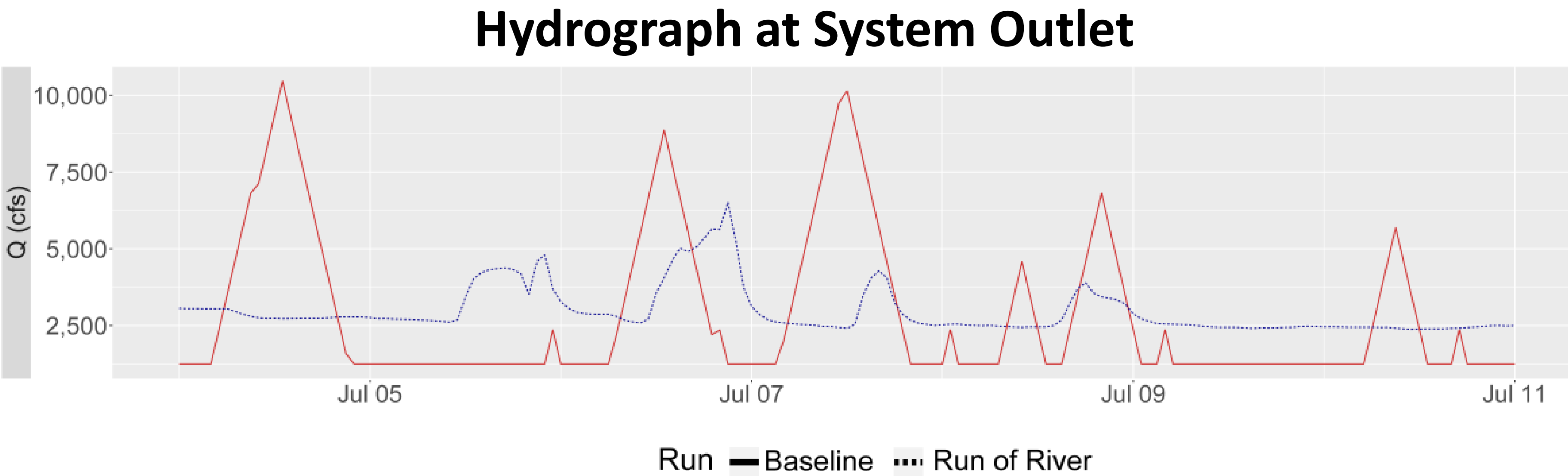
Calibrated to:

- Historical power generation
  - Within 10% of historical averages

Alternative Operations



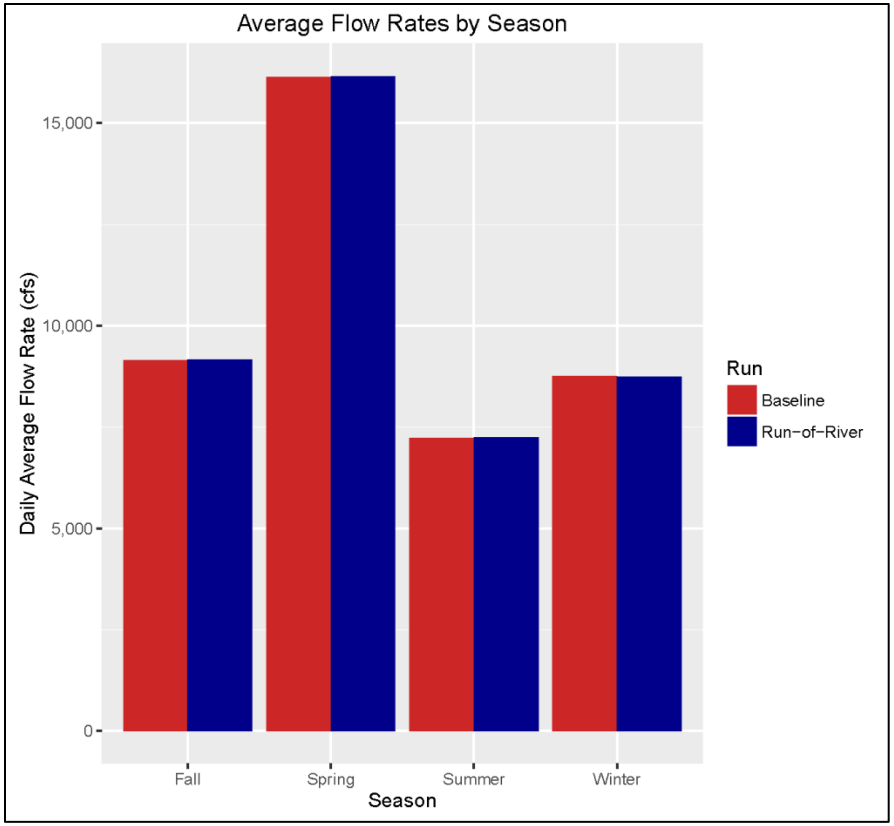
Alternative Operations



Improvement to Flow Regime

Daily flow:

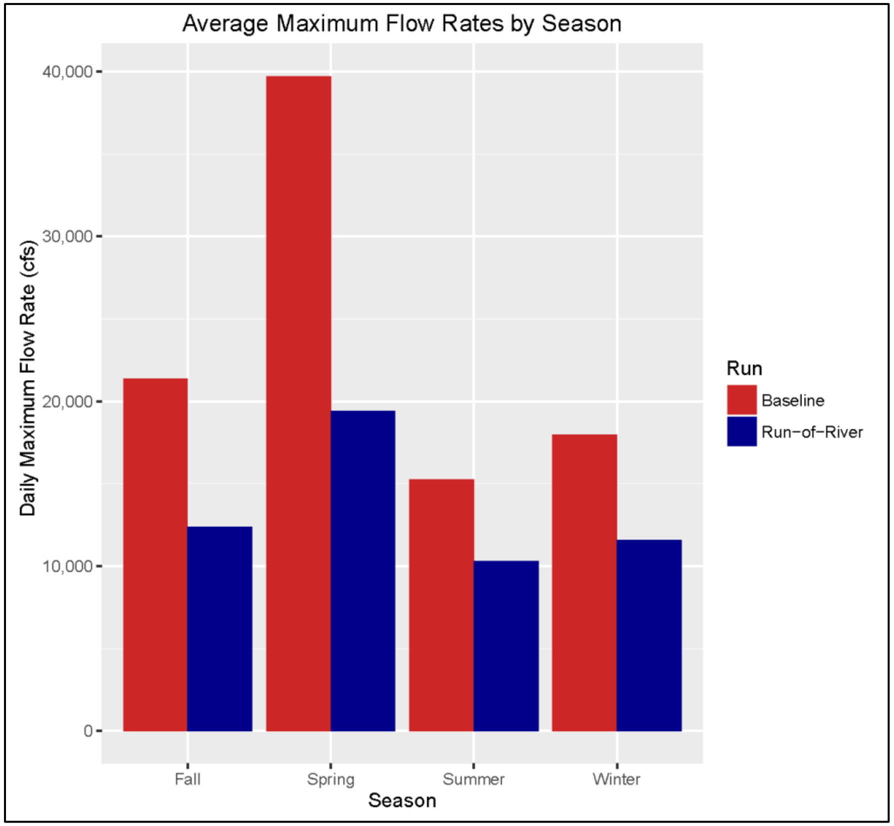
- Average daily flow rate



Improvement to Flow Regime

Magnitude:

- Daily Peak Flows



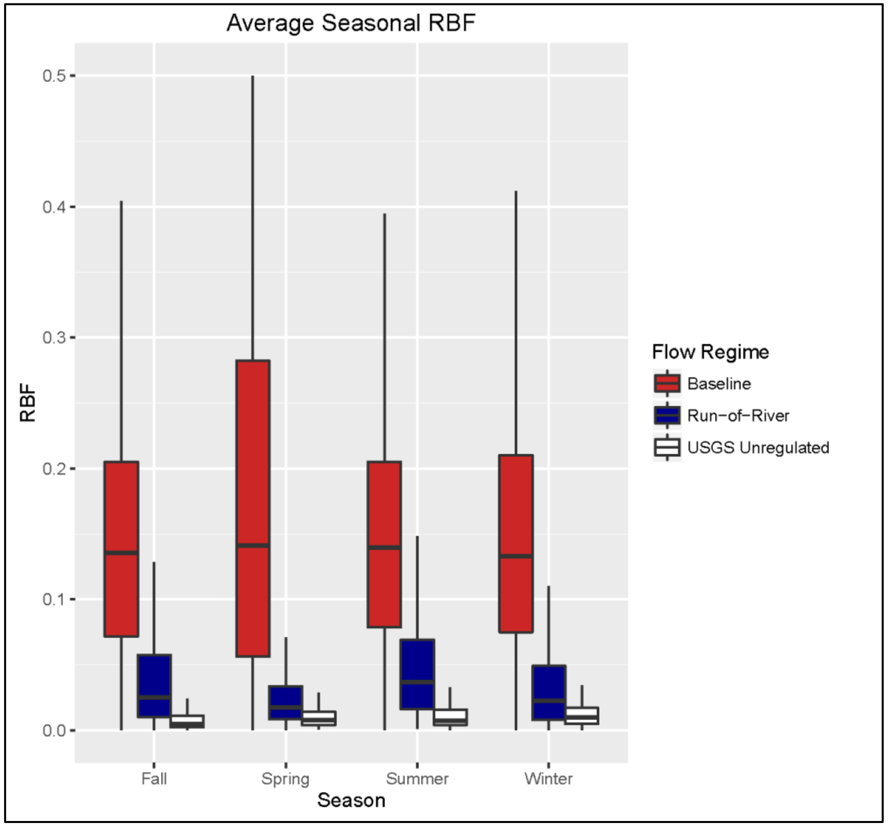
Improvement to Flow Regime

Rate of Change:

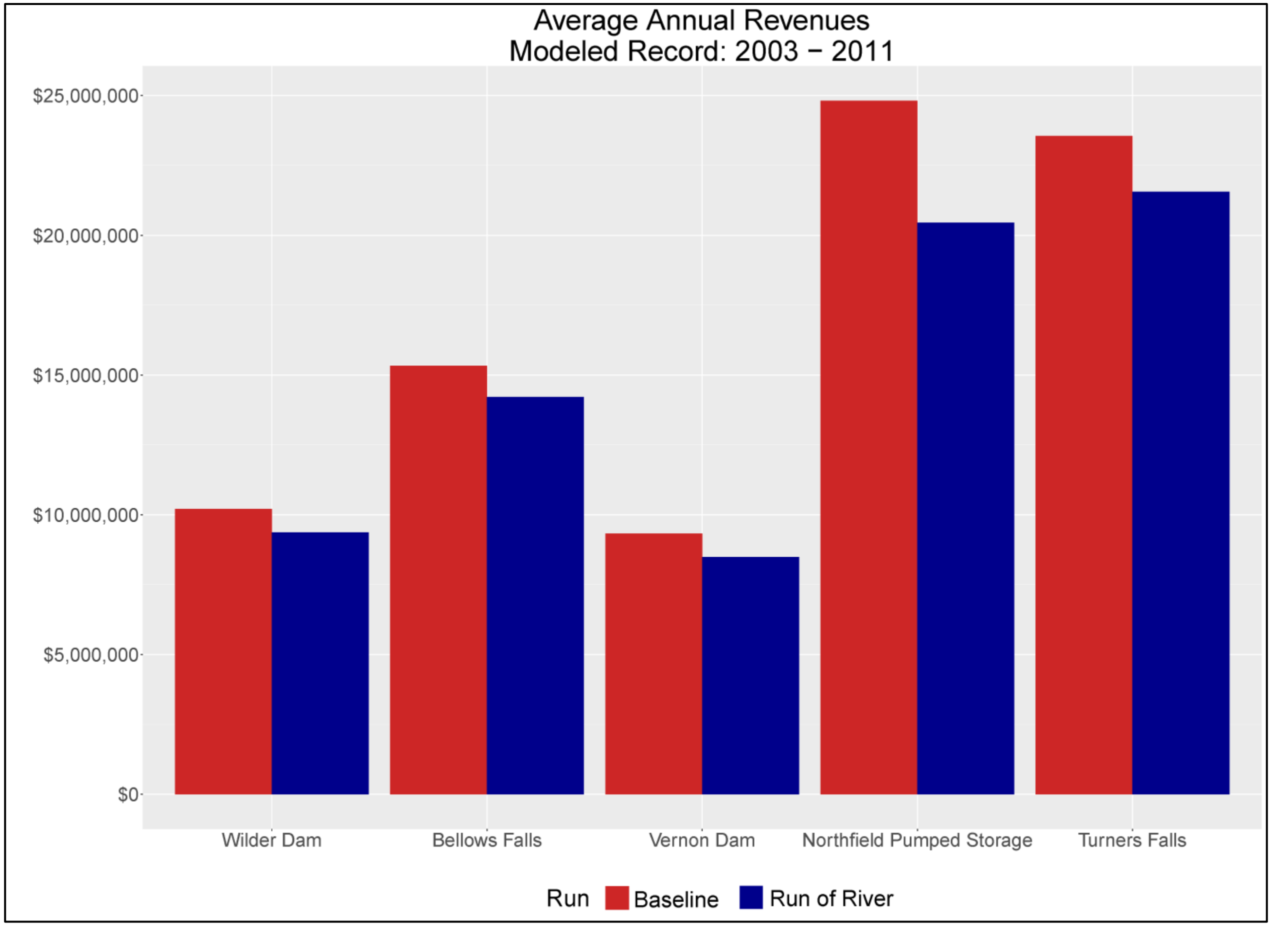
$$\frac{Amount\ of\ change\ in\ a\ day's\ flow}{Total\ flow}$$

- Richards-Baker Flashiness

$$RBF = \frac{\sum_{h=1}^{24} 0.5(|Q_{h+1} - Q_h| + |Q_h - Q_{h-1}|)}{\sum_{h=1}^{24} Q_h}$$



Effect on Revenue



Outcome:

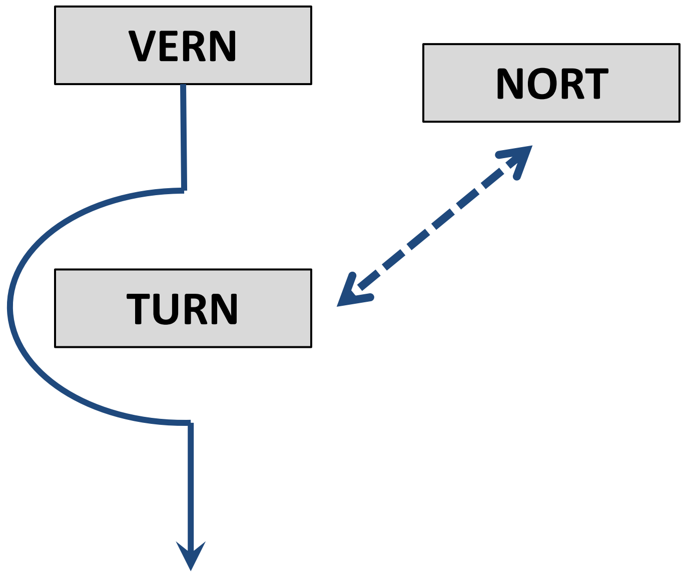
7-10 % loss for mainstem peaking facilities

17% loss for Northfield Pumped Storage

Exploring Improvements to Northfield Operations

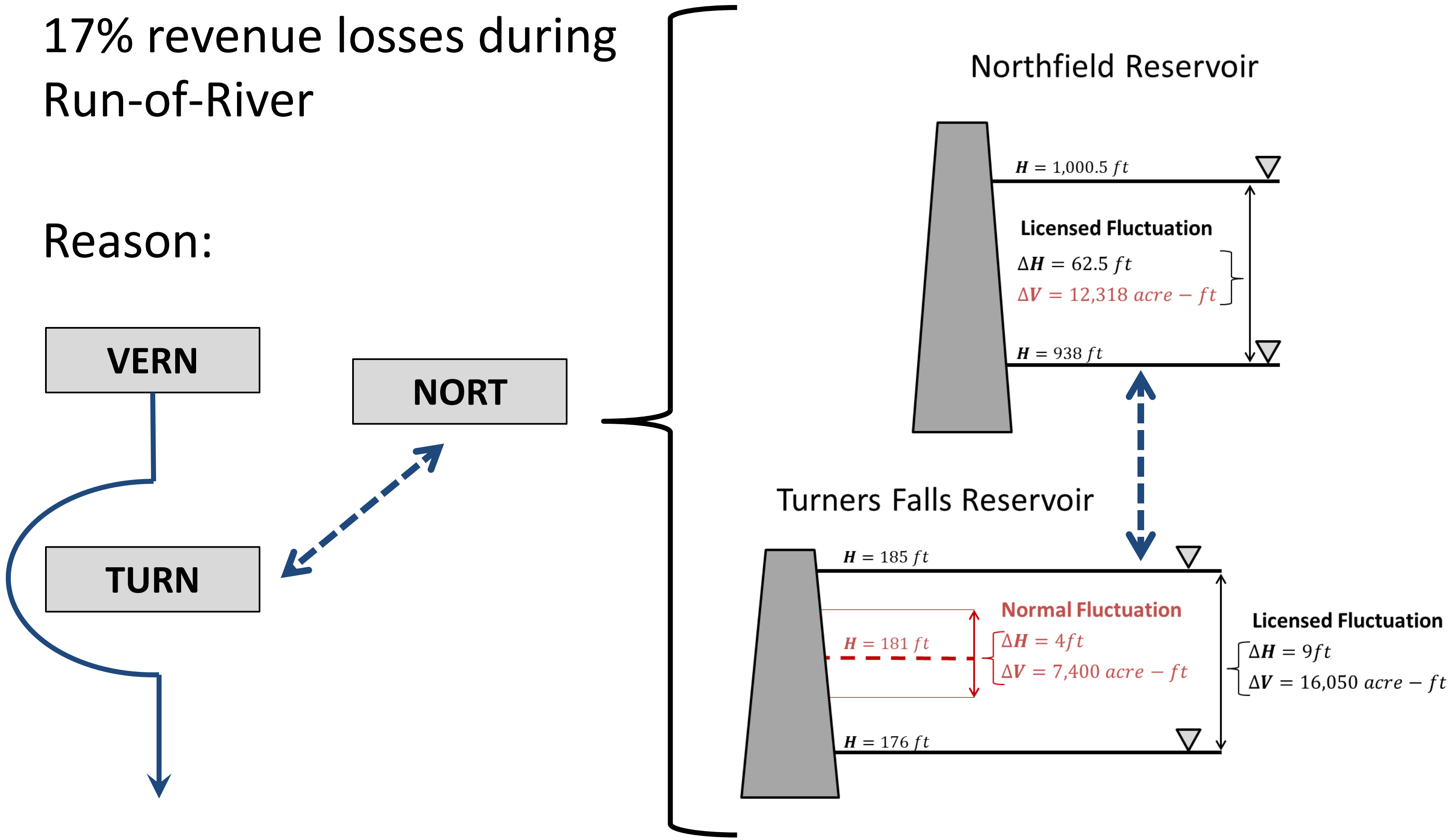
- 17% revenue losses during Run-of-River

- Reason:



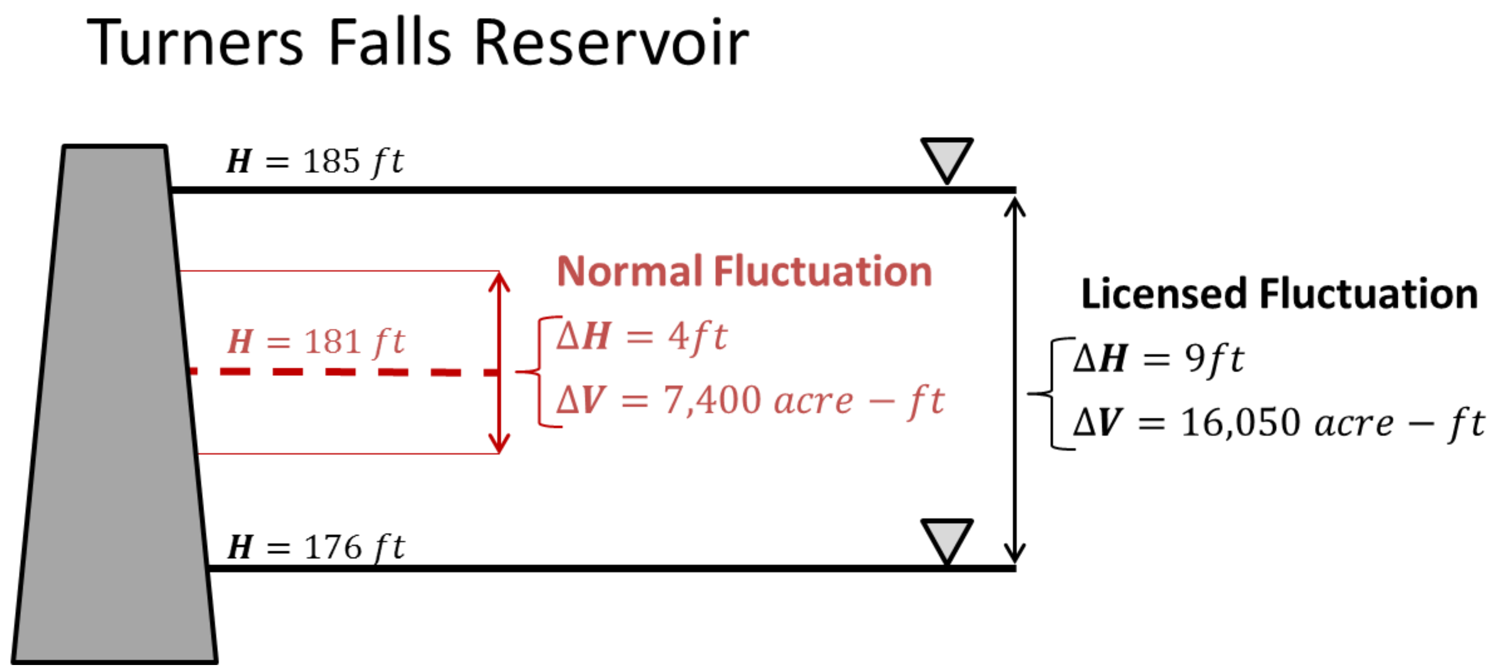
Exploring Improvements to Northfield Operations

- 17% revenue losses during Run-of-River
- Reason:



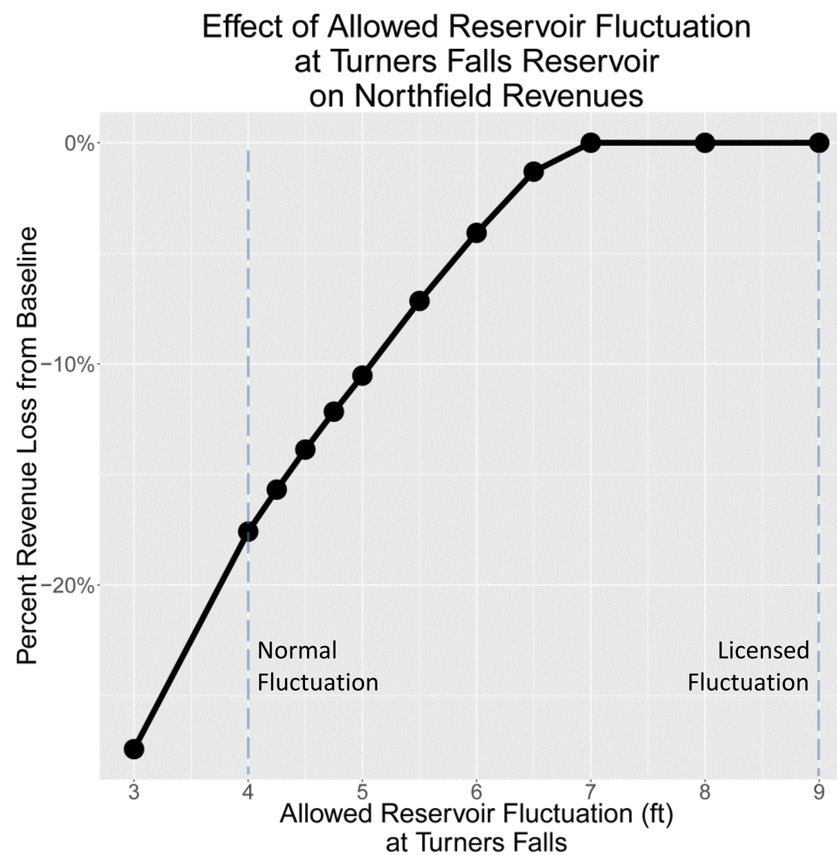
Exploring Improvements to Northfield Operations

(1) Increased Turners Reservoir Fluctuation



Exploring Improvements to Northfield Operations

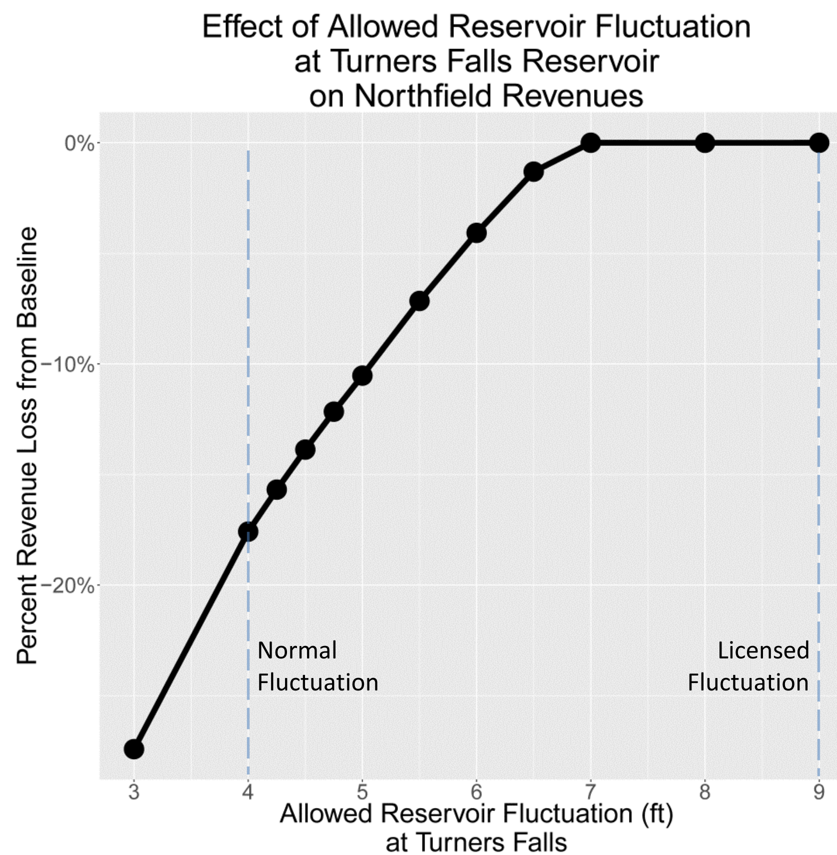
(1) Increased Turners Reservoir Fluctuation



Exploring Improvements to Northfield Operations

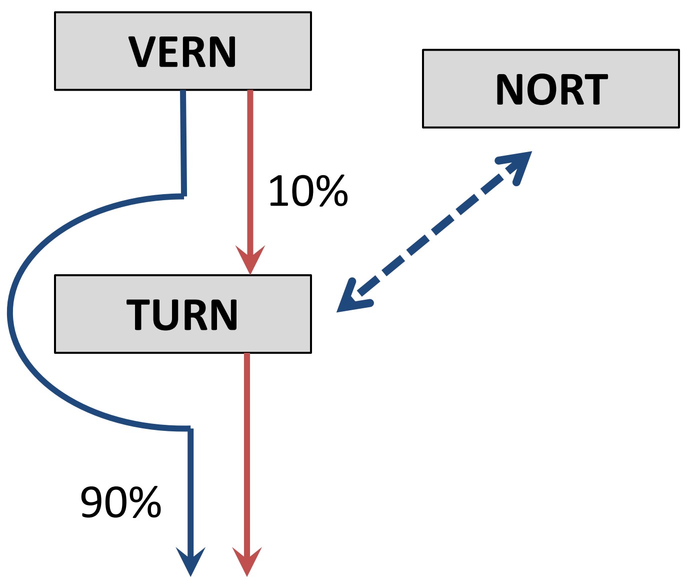
(1) Increased Turners Reservoir Fluctuation

- Improves Northfield operations
- ≤ 4 ft reservoir fluctuation
  - Ecological stakeholder goal



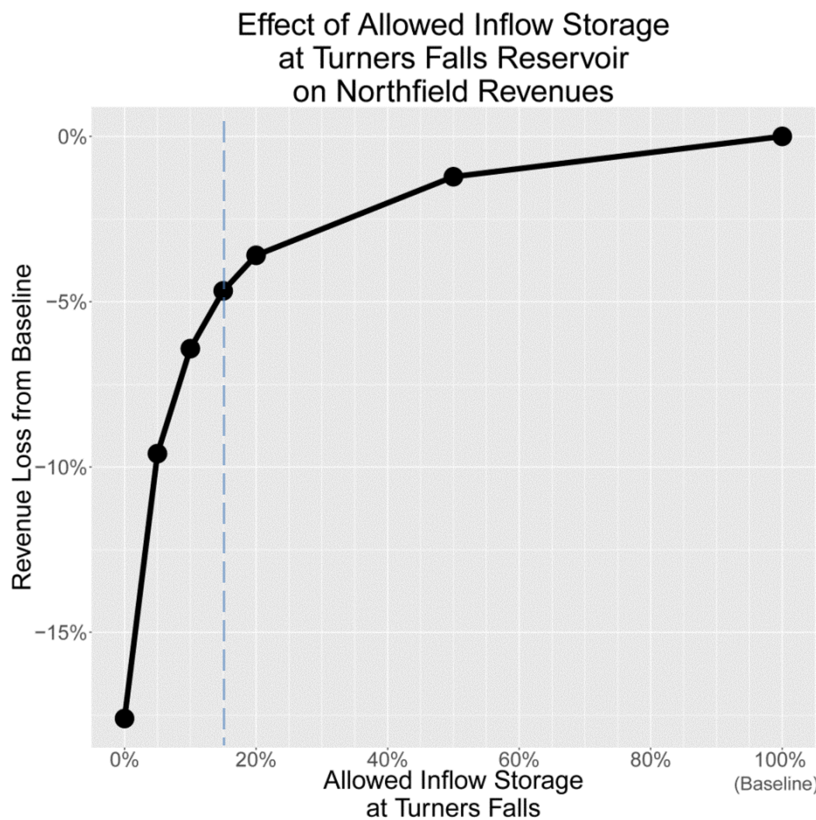
Exploring Improvements to Northfield Operations

(2) Allow Inflow Storage at Turners Falls



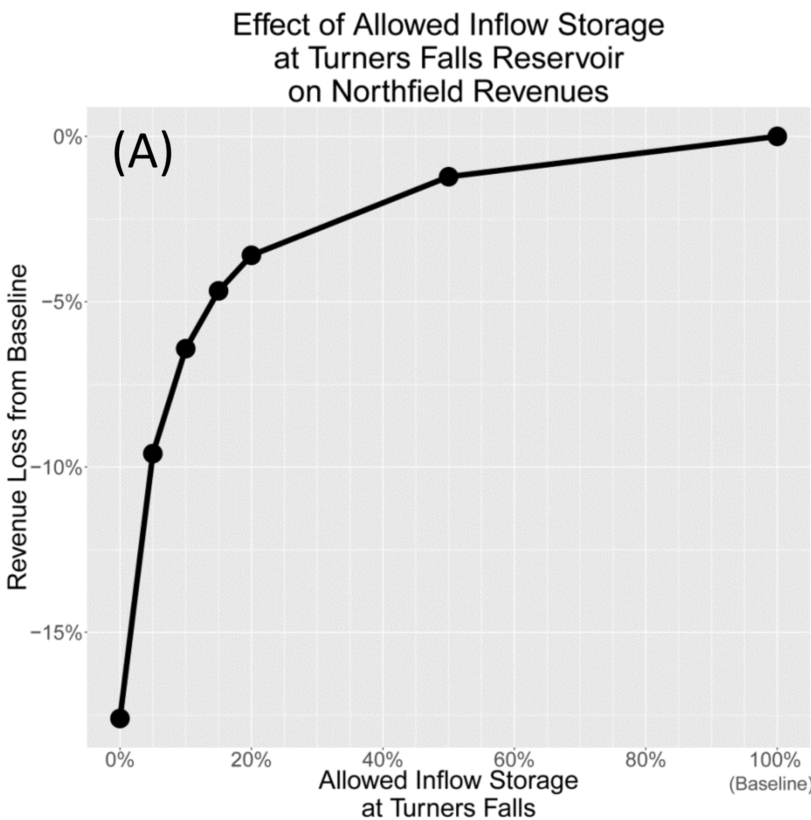
Exploring Improvements to Northfield Operations

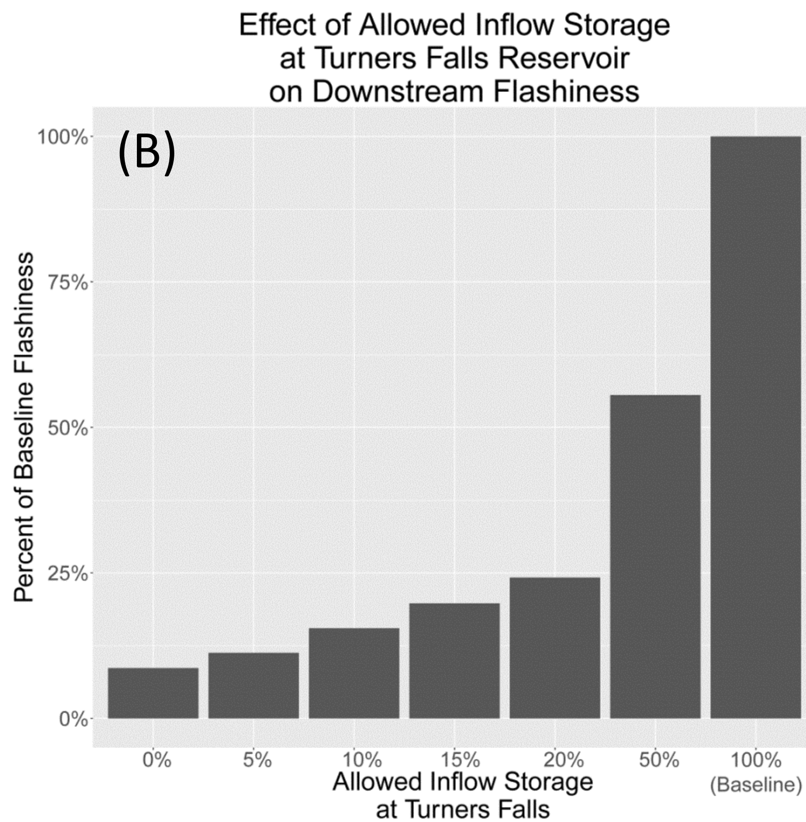
(2) Allow Inflow Storage at Turners Falls



Exploring Improvements to Northfield Operations

(2) Allow Inflow Storage at Turners Falls



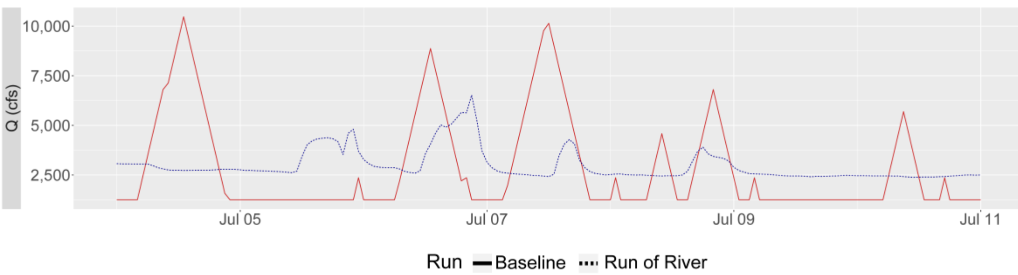


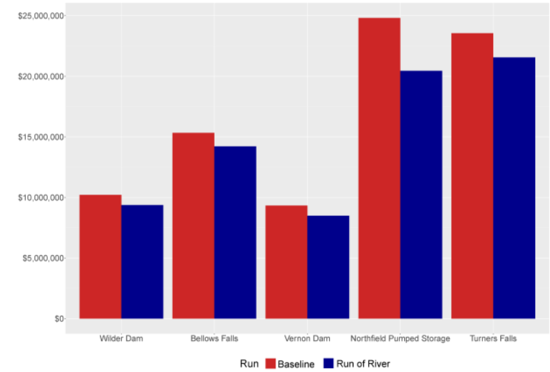
Conclusions

- Model effectively mimics real world hydropower operations
  - Provides
    - Estimate of power generation & revenue
    - Means of assessing various implications of alternate flow regimes:

Conclusions

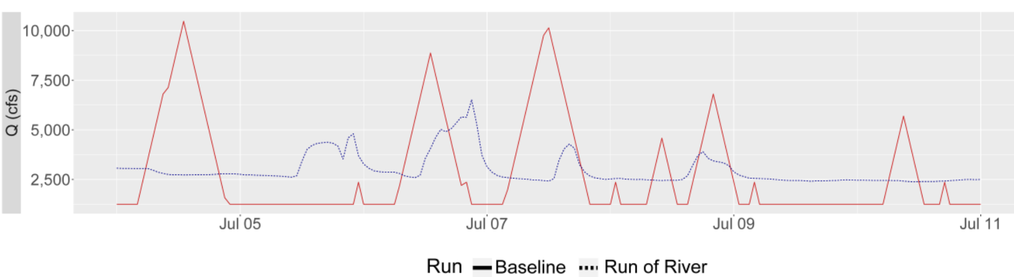
- Model effectively mimics real world hydropower operations
  - Provides
    - Estimate of power generation & revenue
    - Means of assessing various implications of alternate flow regimes:

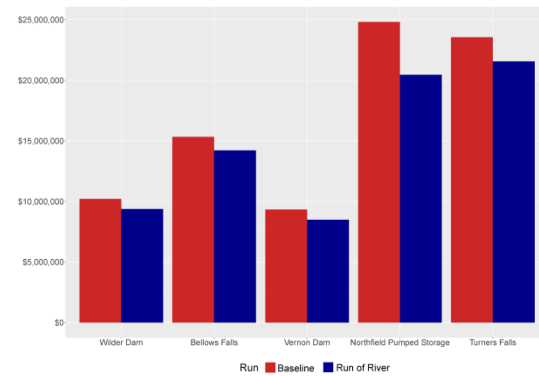




Conclusions

- Model effectively mimics real world hydropower operations
  - Provides
    - Estimate of power generation & revenue
    - Means of assessing various implications of alternate flow regimes:





- Modeling suggests a run-of-river reoperation would:
  - Reduce unnatural sub-daily flow alteration
  - Reduce hydropower generation revenue
    - Losses at Northfield could be mitigated through alternative operations

Future Work

- Identify specific flow ecology relationships to demonstrate value of reoperations
  - Demonstrate economic value of ecological reparations
- Identify other changes which may improve flow regime
  - Other reopoerations
  - Improve model resolution
  - Consider supplemental tools
    - Simulation

Acknowledgements

UMass Amherst:

- Dr. Richard Palmer *- Advisor*
- Sohely Borjian *- Modeling Support*
- Dr. Brett Towler *- Committee Member*

The Nature Conservancy:

- Kim Lutz *- Program Director*
- Katie Kennedy *- Applied River Scientist*

Data & Support:

USGS science for a changing world

ISO new england

Funding: The Nature Conservancy