Designing Hydropower Flows to Balance Energy and Environmental Needs

December 2022

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Designing Hydropower Flows to Balance Energy and Environmental Needs

HydroWIRES Topic A Final Project Report

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HydroWIRES

In April 2019, the Water Power Technologies Office launched the HydroWIRES Initiative to understand, enable, and improve hydropower and pumped storage hydropower (PSH) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electricity system. The unique characteristics of hydropower, including PSH, make it well-suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electricity system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. While increasing deployment of variable renewables such as wind and solar have enabled low-cost clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power-generation sources. Realizing this potential requires innovation in several areas, such as understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and tradeoffs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five laboratories—Argonne National Laboratory, Idaho National Laboratory, National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at https://energy.gov/hydrowires.

Executive Summary

As the future grid will rely on hydropower to provide both flexibility and robust environmental protections, the analyses and tools described in this report are centered on making mechanistic linkages between energy and the environment in hydropower systems. This understanding of energy–environment linkages can provide the foundational understanding needed to quantitatively assess the tradeoffs between increased generation flexibility that hydropower will be expected to provide and the environmental impacts of this flexibility. This report seeks to present an objective foundation for building future science and tools that can be used by a broad spectrum of the hydropower community that is involved in licensing or environmental regulatory proceedings tasked with balancing energy and environmental objectives through flow management.

- Creating environmental and operational flows that meet environmental and economic objectives is possible and actionable. The case studies conducted in this report provide examples of energy and environmental outcome co-assessment to identify energy-environment win-wins including increased generation revenue and increased fish growth, increased generation revenue and increased fish survival, and increased generation revenue and increased sediment transport.

- Ecological outcomes, particularly those aimed at protecting fishery resources, are far and away the most common target of flow requirements across all regions and are likely indicative of the importance of this resource to hydropower stakeholders. These flows are rarely co-optimized for energy objectives and provide additional opportunities to improve the environment and revenue.

- Automatic generator control can enable hydropower facilities to limit their impacts from hydropeaking by precisely controlling peaking operations to times with the highest price signals. Many older and smaller facilities do not have this capability, although optimization algorithms may still improve both environmental and revenue objectives.

- Tools are needed that would allow users to conduct energy–environment co-optimizations and design flows that maximize energy and environmental objectives.

- Using forecast-informed reservoir operations can allow for better management, potentially reducing the negative impacts of hydropower operations. Using this information to reduce uncertainty in planning means more environmental flows that can meet the requirements put in place by hydropower regulatory processes.

Attribution of Work

Oak Ridge National Laboratory (ORNL) created the instream flow dataset (Cameron, Pracheil) and the flow to environment linkages (Pracheil, Moody, Hansen, Jager), conducted ecological modeling in the Yadkin-Pee Dee case study (Jager), led writing on introduction and conclusion chapter, edited final report, and provided overall project coordination (Pracheil).

National Renewable Energy Laboratory (NREL) conducted production cost modeling of U.S. power grid to provide price information for Yadkin-Pee Dee and Glen Canyon case studies (De Silva, Jorgenson), provide inputs for flow to power linkages, and contributed to report writing (De Silva).

RTI supported creation of the flow to environment linkages (Carney, Perrot), conducted CHEOPS and DDP modeling in the Yadkin-Pee Dee case study (Quebbeman, Watson), led modeling coordination between RTI, NREL, and ORNL for the case study (Carney), and provided associated writing and review for related chapters of the report.

Argonne National Laboratory conducted the Glen Canyon Dam demonstration case study (Veselka, Ploussard), contributed to the writing of this document, and created methodologies that explore and discover solutions that simultaneously improve hydropower economic value and multiple environmental objects. Also created the Win-Win Exploration Modeling Toolset and compared toolset results for the Base Case to results produced by an established model that has been used for Glen Canyon operations, planning, and studies for decades.

Acronyms and Abbreviations

AF	acre foot
ANL	Argonne National Laboratory
AST	Alternative Screen Tool
BAU	business-as-usual
DA	day-ahead
DDP	Dual-Dynamic Programming
CAISO	California Independent System Operator
CHEOPS	Computer Hydro Electric Operations and Planning Software
CRSP	Colorado River Storage Project
ECRE	Eagle Creek Renewables
EI	Eastern Interconnection
EIS	Environmental Impact Statement
EMMO	Energy Marketing and Management Office
FERC	Federal Energy Regulatory Commission
FSP	fuel security plan
GCD	Glen Canyon Dam
GHG	greenhouse gas
HBC	humpback chub
IFIM	Instream Flow Incremental Methodology
IPP	independent power producer
IRP	integrated resource plan
LMP	locational marginal price
LTEMP	Long-Term Experimental Management Plan
MAF	million-acre-feet
MIP	mixed integer programming
NREL	National Renewable Energy Laboratory
PCM	production cost model
RM	river miles
ROD	Record of Decision
RT	real-time
SERC	Southeastern Electric Reliability Council
SOS	special ordered set
TAF	thousand-acre foot
UCRB	Upper Colorado River Basin
USACE	U.S. Army Corps of Engineers
USGS	U.S. Geological Survey

WAPA	Western Area Power Administration
WI	Western Interconnection
YOY	young of year

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1.0 Introduction

Average atmospheric temperatures are projected to increase by 2-6°C over the next 30- to 50-year Federal Energy Regulatory Commission (FERC) license term for hydropower projects issued licenses this year (U.S. Federal Government, 2021). Among the challenges of natural resource management in a rapidly changing climate is creating environmental measures in FERC hydropower licenses that can support the needs of the grid and environment today and into the future. Growing penetration of variable renewable energy sources such as solar and wind can facilitate decarbonization of the power sector but require support from flexible generation sources that can quickly ramp up and down production levels and generate additional energy when the sun is not shining or the wind is calm. Hydropower resources are well-suited to provide this flexibility, but the environmental consequences of increased hydropeaking operations can include stranding fish, inundating nests of terrestrial animals living near the water, eroding shorelines, or creating hazardous boating conditions.

Upcoming expirations for a large portion of the FERC-licensed hydropower fleet present an opportunity to design hydropower flows that enable wins for energy and the environment given current and projected future conditions (Figure 1). The relicensing process requires iterative negotiations between applicants and a diverse body of stakeholders that help determine project environmental impacts and mitigations that will be included in the FERC license (Levine et al. 2021). Flow requirements—a specification or restriction on the amount or rate at which water is released—are designed to offset flow alterations and support or improve environmental outcomes like fish spawning and recreational boating among the most frequently included environmental mitigations included (Pracheil and Singh 2021).

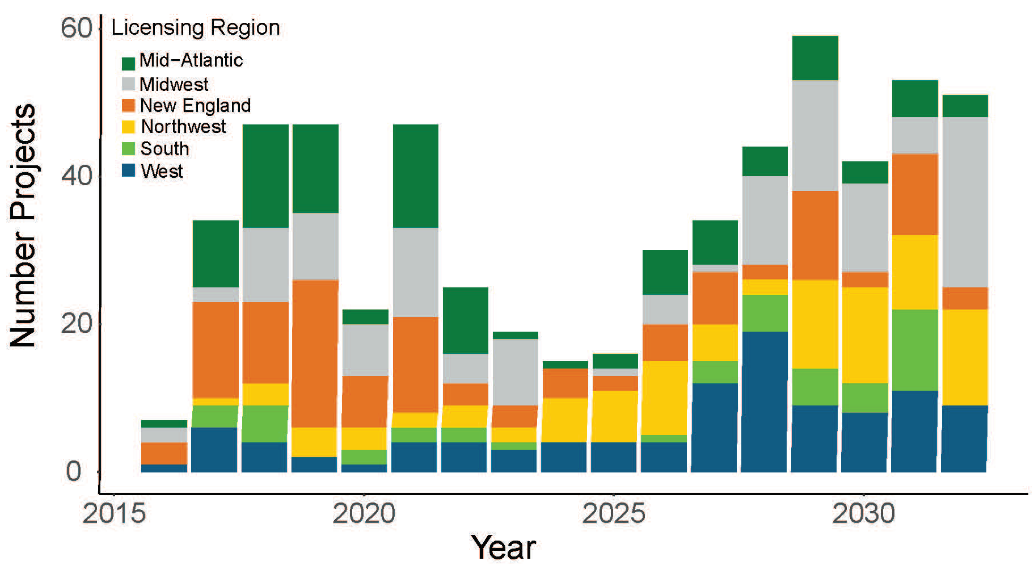


Figure 1. Expected Hydropower Relicense Notice of Intent (NOI) Filings Through 2032 by FERC region.

A review of 435 FERC licenses issued between 1997 and 2013 found that 1,424 mitigations of the 5,000 included in the review (28%) had some type of flow requirement (Schramm et al. 2016). This study reported that of the 1,424 flow requirements, 460 specified a minimum flow requirement and 22 specified ramp rate restrictions. Because flow requirements regulate the amount of water released from a hydropower facility, all have some interaction with operational flexibility. However, it is unclear whether or when bounds on flow releases are meaningful for grid reliability and resilience under current conditions, let alone the 30- to 50-year time horizon of the license.

1.1 Flow Requirements

While our understanding of interactions between flow requirements and the ability of a hydropower facility to provide functions and services to the grid is limited, we can make some initial predictions. For example, one prediction is that not all flow requirements have the same effect on hydropower functions or services. Table 1 details the function and services, their definitions, temporal scale, and the effects of different types of flow requirements on these functions and services. Green boxes indicate that a flow requirement is mildly limiting to that function or service, gold boxes indicate that a flow requirement is moderately limiting, and red boxes indicate that a flow requirement is significantly limiting. Prescribed flows, that is flow requirements that specify a constant flow rate or a very narrow band of allowable flow rates, have effectively no flexibility and are the most limiting to hydropower functions and ancillary services. On the other hand, we predict that flow requirements that allow for a wide range of operations between the minimum and maximum flow rate, and do not limit the speed at which generation can be ramped up or down, have the most flexibility.

Table 1. Hydropower Function and Services

		Effect of Flow Requirement			
Functions and Services	Temporal Scale	Min	Max	Prescribed	Ramp
Load-following or energy-balancing units	Hourly plan with 5-10 min resolution				
Reactive supply and voltage control	Continuous with response in seconds				
Frequency regulation*	Every few minutes, minute-to-minute resolution				
Spinning operating reserve	Begin within 10 seconds, full power within 10 minutes				
Non-spinning operating reserves	Respond within 10 minutes				
Replacement reserves	Respond within 60 minutes, run up to 2 hours				
System black start	As required				
Firm capacity	As required				

*Assumes min and max flows must be always met, not ≥ average hourly time scale.

To support the role of hydropower in the evolving grid and changing climate, there needs to be a greater quantitative understanding of how or whether environmental flow requirements impact flexibility and how energy–environment win-wins may be realized. Typically, published studies that co-optimize flows for energy and environmental goals use energy generation as an optimization endpoint rather than services like flexibility (e.g., Ziv et al. 2012; Jager et al. 2015; Winemiller et al. 2016; Flecker et al. 2022). There is thus a need for new science to create new connections between energy and the environment that will allow these tradeoffs to be assessed.

1.2 Roadmap for the Report

As the future grid will rely on hydropower to provide both flexibility and robust environmental protections, the analyses and tools described in this report are centered on making mechanistic linkages between energy and the environment in hydropower systems. This understanding of energy–environment linkages can provide the foundational understanding needed to quantitatively assess the tradeoffs between the increased generation flexibility that hydropower will be expected to provide and the environmental impacts of this flexibility. This report seeks to provide an objective foundation for building future science and tools that can be used by a broad spectrum of hydropower stakeholders involved in licensing or regulatory proceedings that are tasked with balancing energy and environmental objectives through flow management.

The remainder of this report details the components for creating a more mechanistic understanding of energy and environmental outcomes in hydropower systems that can yield meaningful quantitative tradeoff assessments. Section 2 characterizes environmental flow requirements from FERC hydropower licenses to help provide context for the environmental outcomes and how they are mitigated through flow requirements. Section 3 describes linkages between energy and environmental outcomes through the flow decisions and details from tools developed in this project. Tools discussed in this section include the Energy-Environment Linkage Map and the companion Model and Tool Database for detailing, quantitatively, these linkages. Section 4 uses a set of three case studies to explore strategies and tools for assessing energy–environment tradeoffs with the added goal of seeking out scenarios that lead to positive outcomes for both energy and the environment. Finally, Section 5 provides a summary of project findings and future focus areas for research and collaboration.

2.0 Characterization of Environmental Flow Requirements

Understanding tradeoffs between energy and the environment first requires a greater understanding of the complexity and nuance of environmental flow requirements. Currently, there is not a broad understanding of what types of flow requirements are in effect across the United States and whether there are regional patterns or what those patterns might be. Seasonal and hourly differences in energy demand mean that flow requirements vary not only by the type of requirement (e.g., minimum flow, ramp rate restriction), but also by any temporal (e.g., day of the week, hour of the day, month of the year) specifications of the requirement.

Currently, environmental flow requirements have not been named as a critically limiting source of operational flexibility within the hydropower fleet (although this may be true at some individual plants), but the degree to which the requirements may or may not constrain the ability of hydropower to support a transition to more renewable energy in the future power system is unclear. Moreover, climate change creates additional uncertainty and risk, potentially affecting power system reliability through water stress and extreme temperatures and weather. Gaining an understanding of the extent to which hydropower functions and services interact with flow requirements requires information about the type and distribution of requirements across the United States.

In this chapter, we describe and summarize environmental flow requirements from 50 FERC-licensed hydropower projects and discuss implications of instream flow requirements to hydropower operational flexibility, functions, and services. Detailed methods for this chapter are provided in Appendix A.

2.1 Methods

Information was recorded from 50 hydropower projects with FERC licenses issued from 2013 to 2019. Each flow was then characterized by augmentation type, which was the reason provided for the requirement (i.e., fish, general, recreation, industrial), flow requirement type (i.e., minimum flow, prescribed flow, and ramp rate restriction) and hours of the day, days of week, and months of the year that a requirement was in effect.

While this chapter focuses on flow requirements from FERC hydropower licenses, it is important to note that federal hydropower is also subject to satisfying environmental operational requirements. Federal projects were not included because a centralized repository of federal hydropower documents, similar to the FERC eLibrary, does not exist for federal hydropower.

2.2 Summary of Environmental Flow Requirements

The 50 licenses surveyed for this study included 98 individual hydropower facilities (see Figure 2). These facilities were not evenly distributed among regions, although licenses surveyed were randomly selected. Of the 50 licenses surveyed, eight were from the Northwest, nine from the Midwest, eight from the Mid-Atlantic, eight from New England, ten from the South, and seven from the West.

These FERC licenses had 1,461 individual instream flow requirements among the 50 projects. Flow requirements were not evenly distributed (see Figure 3), for example the Upper American River project in California (FERC Docket number P-2101) contained 715 individual flow requirements, which was nearly half the requirements reported in this study and the most of any project. Only one other project, the Chili Bar project in California (FERC Docket number P-2155) with 119 requirements, had more than 100 flow requirements. No projects had zero flow requirements, although six projects—one project in every region except for the Midwest—had only one requirement. An additional 24 projects had ten or fewer flow requirements: five of eight projects in the Mid-Atlantic, all nine projects in the Midwest, six of eight projects in New England, six of eight projects in the Northwest, five of ten projects in the South, and four of eight projects in the West.

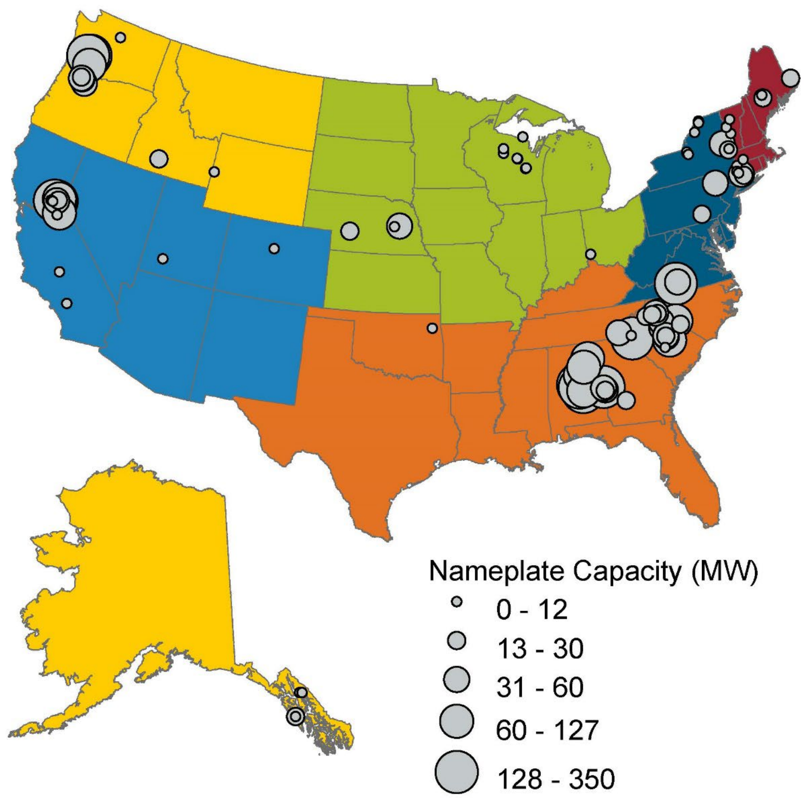


Figure 2. Locations and Nameplate Capacity Classification of Hydropower Facilities Surveyed

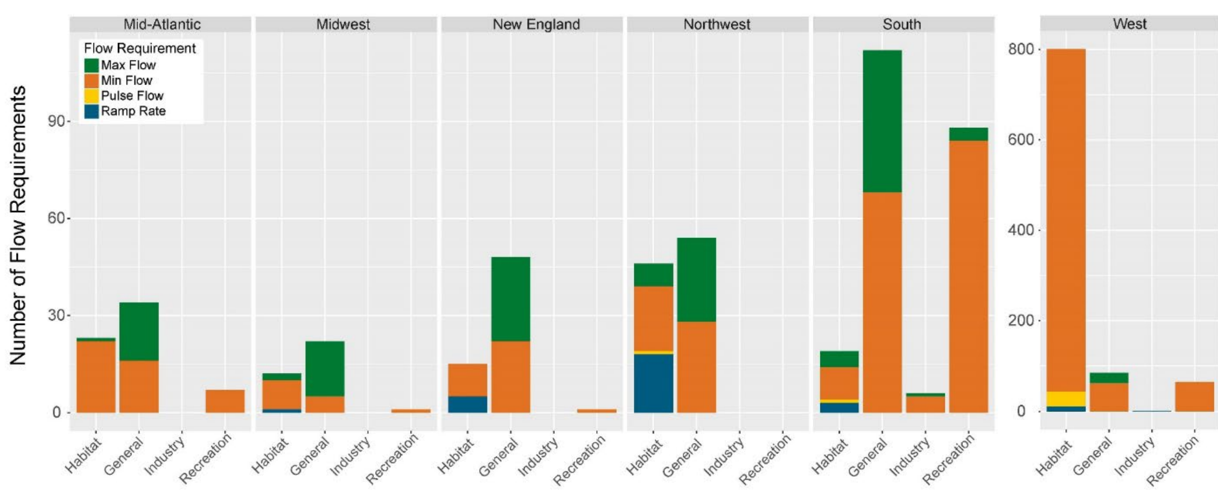


Figure 3. Total Number of Flow Requirements by Requirement Type and Augmentation Type

2.2.1 Augmentation Type

For most projects, requirements categorized as general flow were the most common augmentation type, although there are some instances of fisheries/habitat flow requirements dominating at a project. Two of eight projects in the Mid-Atlantic, one of nine projects in the Midwest, one of eight projects in New England, four of eight projects in the Northwest, and two of seven projects in the West had more fisheries/habitat flow requirements than general flow requirements. Figure 4 shows the average number of flow requirements per project by augmentation category and FERC licensing region. Bars represent standard error. Note that in Panel A, the West region has a different y-axis. In the West, the fisheries/habitat dominate the flow requirements—the Upper American River project where 684 of the 715 requirements were for fisheries/habitat—while recreation/boating appear to be less common. But if the Upper American River project is excluded, recreation/boating flow requirements were issued at two of seven projects and comprised 44 of 237 (19%) of the flow requirements.

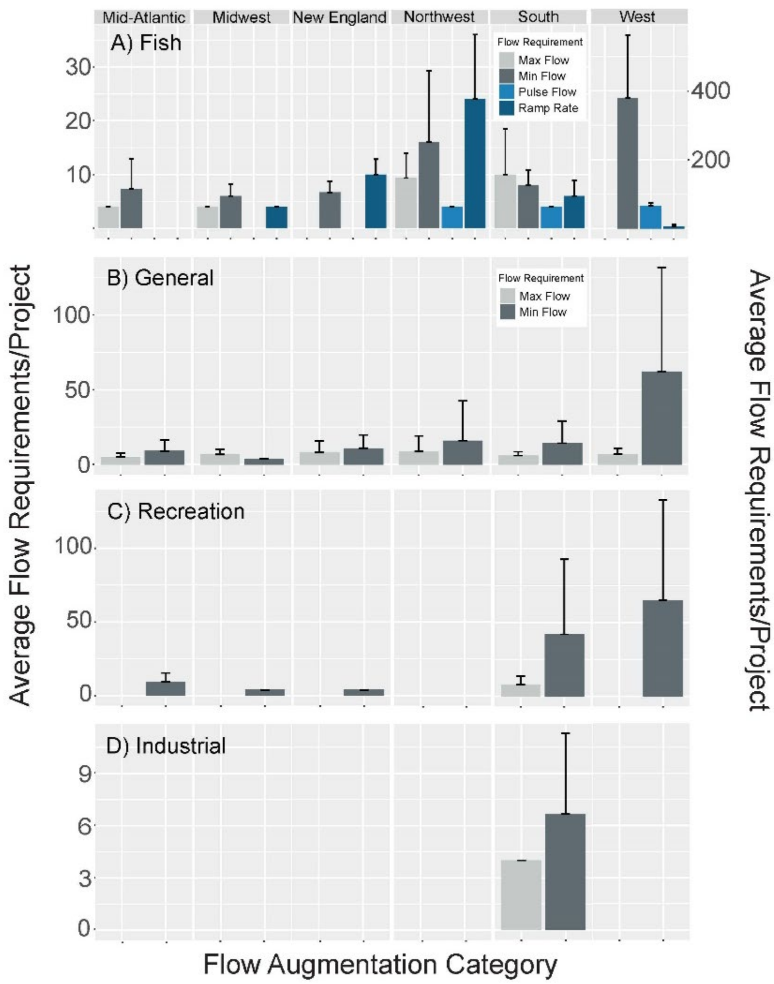


Figure 4. Average Number of Flow Requirements per Project by Augmentation Category

General flow requirements were the most common augmentation type in all licensing regions except for the West. The recreation/boating augmentation type was uncommon in all regions except for the South where it consisted of 88 of 225 (39%) flow requirements, but it also comprised 65 of 952 (7%) requirements in the West. Flow requirements for recreation/boating were the dominant augmentation type for three of 50 projects including one project in the Mid-Atlantic (Wallenpaupack Project FERC Docket P-487), and two projects in the South (Coosa River Project P-2146 and Nantahala Project P-2692).

2.2.2 Flow Type

Overall, minimum flow requirements were the most common (68%) followed by prescribed flows (23%), maximum flows (6%), and ramp rate restrictions (4%) as shown in Figure 5. The most common augmentation type differed by flow type with maximum flow requirements and ramp rate restrictions being most associated with general requirements, minimum flow requirements most associated with fisheries/habitat, and prescribed flows being most associated with recreation/boating. Prescribed flows were commonly issued in the Mid-Atlantic and South regions and were most associated with fishery/habitat in the Mid-Atlantic and recreation/boating in the South. Prescribed flows were issued relatively less commonly in the West and were exclusively issued for recreation/boating. Ramp rate restrictions were most issued in the Northwest, typically associated with the general augmentation type. Ramp rate restrictions were relatively uncommon in other regions.

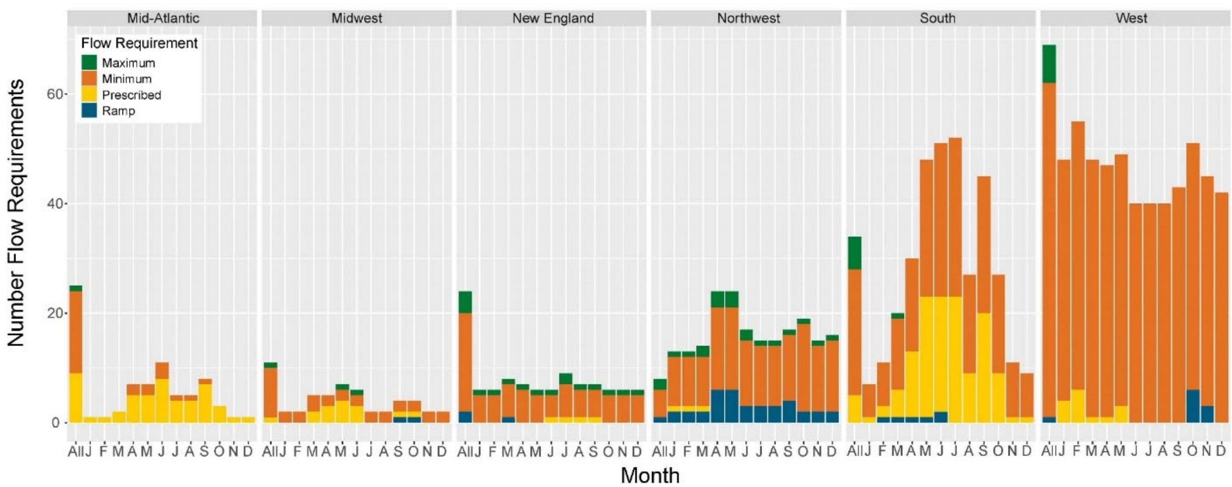
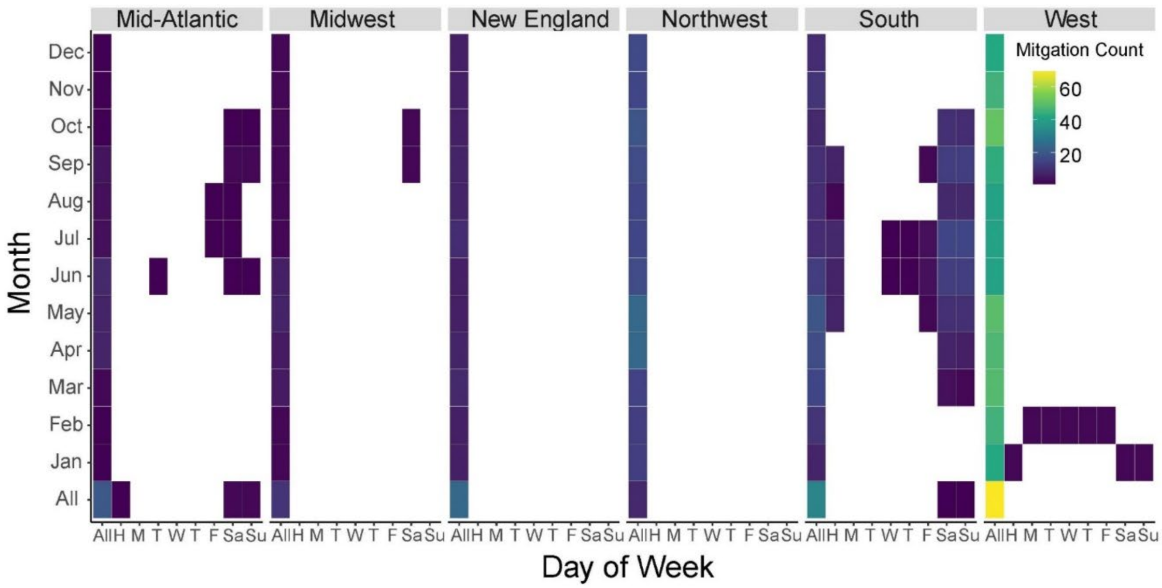


Figure 5. Total Number of Flow Requirements by Type, Month, and FERC Licensing Region

2.2.3 Timing of Flow Requirements

Flow requirements often had specified time periods in which they were active, including requirements applying to specific months, days, and hours of the day. Across regions, 12% of flow requirements were in place throughout the year. Most flow requirements were applied during all days of the week (84%) at all times of day (85%).

The months in which flow requirements applied differed by region and flow type (Figure 6). May was the most common month for flow requirements to be active, with 10% of 1,461 flow requirements active, followed by June, September, April. and July, each with 9% of 1,461 flow requirements active. In the West, the number of minimum flow requirements were greatest in the winter and spring months of January through May but were reduced in the summer months of July through August. Although prescribed flows were not common in the West, when they were issued, they were also issued in the January through May timeframe. In contrast, both minimum and prescribed flow requirements in the South were most common in the spring/summer months of May through September. When prescribed flows occurred, they were commonly associated with U.S. holidays, particularly those that bookend summer—Memorial Day in May and Labor Day in September—and Independence Day in July.



Abbreviations are for days of the week starting with M = Monday.
Other abbreviations are All = in effect all days of the week and H= holidays.

Figure 6. Heatmap of Total Flow Requirements in Each Region by Month and Day of Week in Effect

Across regions, 84% of flow requirements were active all days of the week. Flow requirements that specified days of the week most frequently listed Saturday and Sunday. Of the 15% of flow requirements that specify hours of the day they apply, 89% of are active from 10:00 to 15:00 with 98% active from 12:00 to 15:00 (Figure 7).

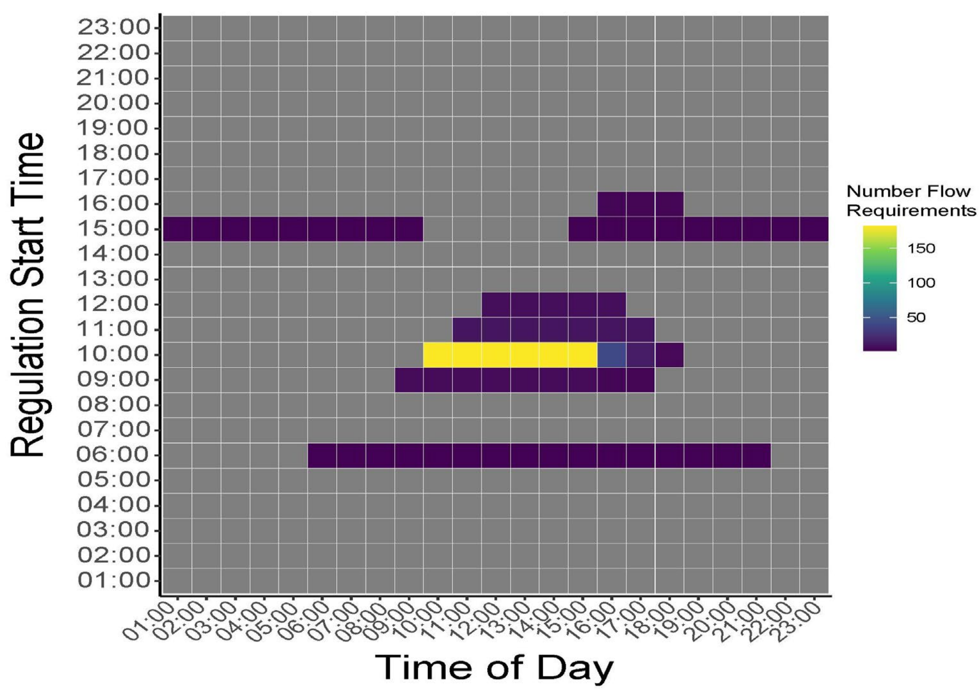


Figure 7. Heatmap of Total Flow Requirements in each Region by Time of Day Regulation Starts and Time of Day

2.3 Discussion

Minimum flow requirements are an important tool in the resource management toolbox for ensuring aquatic biota have suitable habitat in riverine ecosystems with altered flow regimes. These flows, which are the most ordered type of environmental flow license requirement, are likely to have relatively minimal effects on short-term operational flexibility because they do not limit ramp rates or maximum flows, both of which are important for maintaining many hydropower functions and services. However, longer term operational flexibility may be impacted due to reservoir water availability, which may become even more important in a changing climate where temperature and precipitation patterns change.

Prescribed flows are not commonly found across all regions and are a flexible type of flow requirement because they specify flow that removes the ability of a facility to ramp up or down in response to generation needs. In the South, for instance, prescribed flows are the most common requirement type. These flows occur during summer months, often during the hottest times of the day, when electricity consumption is high and flexibility and ancillary services may be most valuable. However, because prescribed flows in this region are typically in effect during weekends or holidays when electricity demand is lower compared to weekdays, the need for flexibility may not be as high. In the Southeast Independent System Operator, there is no ancillary services market so licensees and applicants may not be incentivized to maintain a higher level of flexibility and may be more willing to negotiate prescribed flows with other stakeholders than licensees/applicants in other regions.

Understanding where and how hydropower flexibility and instream flow requirements interact may help create a framework for negotiating instream requirements and creating energy–environment win-wins in comprehensive settlement agreements and/or basin-wide licensing approaches that are gaining interest in some parts of the country (Curtis and Buchanan 2019). This may enable greater value propositions for both energy and environmental stakeholders where less impactful types of instream requirements (i.e., minimum flows) at some facilities may be traded off for more restrictive requirements (e.g., ramp rate restrictions) at others.

Differences in stakeholder priorities are evident in instream flow requirements. In much of the United States, requirements support habitat for fish and other aquatic biota (probably including some that are classified as general for an unspecified reason in the Protection, Mitigation, and Enhancement section of the license order that was surveyed for this project), although recreation/boating is a very important source of instream flow requirements in some regions.

Conducting this initial assessment requires an understanding of many factors, including the type of flow requirements a facility has, time of year the requirements occur, time of day augmentations occur, generation capacity of the hydropower facility, and more. We expect minimum flows—the most common flow requirement listed among projects surveyed in this study— have relatively low impact on short-term operational flexibility, but it is important to note that our analysis is not commenting on the impact of flow requirements on the economics of hydropower generation or other industries that may rely on the water provisioning, aesthetic, recreational, etc. ecosystem services provided by a hydropower system.

2.4 Conclusions

Protecting fish and other aquatic life, recreation, and other authorizations of rivers and reservoirs in an uncertain future may require new and innovative water management strategies. For example, environmental flow requirements are often set using Instream Flow Incremental Methodology (IFIM) studies that help determine how much habitat is available at different flow releases. While IFIM methods will likely still be important for setting flow requirements into the future, there may be increasingly complex tradeoffs to be assessed in addition to the authorizations of rivers and reservoirs mentioned above. These tradeoffs may include grid reliability, water supply, water temperature, greenhouse gas emissions, etc.

Recent assessments looking to reduce the impacts of hydropower to natural resources via multi-objective optimization typically focus the energy side of the optimization on actual or potential megawatts generated or generation revenue (Winemiller et al. 2016; Flecker et al. 2022). However, hydropower is likely to take on a different role in the grid of the future, where its ancillary services will be valuable to the power system through contributions to grid reliability, such as black-start capability and real-time inertia rather than baseload generation. As such, multi-objective optimization in these future scenarios should also, or perhaps instead, be using one or more measures of ancillary services in their optimizations.

3.0 Assessments of Environment–Energy Flexibility Tradeoffs

Understanding the tradeoffs between energy flexibility and environmental impacts is critical to assessing sustainability of an energy system, but assessing these tradeoffs requires 1) an inventory of what power system and environmental outcomes are possible and 2) a mechanistic understanding of the factors affecting these outcomes. In a hydropower system, for instance, making energy–environment tradeoffs require some understanding of factors such as energy markets, hydrologic cycles, aquatic biodiversity, recreation, stakeholder priorities, and regulatory requirements. The complexity of factors involved in determining sustainability of a hydropower project can be seen in recognized hydropower sustainability protocols such the International Hydropower Association Sustainability Protocol that evaluates 24 criteria representing environmental, social, technical, and economic/financial perspectives (IHA 2020). While these criteria provide a framework of sustainable hydropower components, assessing tradeoffs still requires understanding the mechanisms of how outcomes arise that employ a diversity of technical lexicons and expertise that may lead to communication challenges with stakeholders from different professional backgrounds.

This chapter presents the conceptual links between power system and environmental outcomes for hydropower that are illustrated in a set of interactive maps. These maps are linked to a database of quantitative methods and tools for linking power system and environmental outcomes based on hydropower flow decisions that may be useful for identifying energy–water–environment tradeoffs and communicating these tradeoffs to diverse groups of stakeholders.

3.1 Methods

To create this webtool, hierarchical taxonomies of power system and environmental outcomes that can be related to flow were created based on input from project team domain experts. The links between flow and the highest levels of environmental and power system outcome taxonomy served as the building blocks for the executive summary map (https://hydrosource.ornl.gov/dataset/hydrowires-linkage-maps). Links between flow and specific power system and environmental outcomes are illustrated on submaps (Appendix B). These links were also determined by domain experts on the project team and a literature review examining the relationships between environmental and ecological outcomes with hydropower and flow, and hydropower production and flow. Taxonomy for environmental maps was based on Parish et al. (2019) and Aldrovandi et al. (2021). We also added an "Other" category that encompassed human health, agriculture, and water supply topics that were not covered in Parish et al. (2019) or Aldrovandi et al. (2021).

This literature search was also used to create a database of models and tools that can make quantitative links between flow and power system outcomes and flow and environmental outcomes to help stakeholders in hydropower regulatory proceedings communicate across disciplines. This database is not intended to be fully comprehensive, but rather allow the user to assess possibilities and potential solution pathways for their objective by answering five primary questions: (1) what is the outcome/metric of interest to be measured; (2) what type of modeling approaches are available for each discipline/outcome; (3) what input variables are needed; (4) how were the models validated; and (5) how can the models be applied and integrated across disciplines/outcomes? Further, this database lists the advantages and limitations of the models and tools and identifies challenges and opportunities for future research and development that aim to assess the energy–water–environment nexus.

3.2 Results

Due to the cross-disciplinary nature of the tool we have developed, there may be many linkages that will be unfamiliar to the average user. In this section, we focus on describing the intricacies of the linkages in the hydropower energy–environment system so that an aquatic scientist, for instance, may still be able to understand linkages in the power system part of the diagram.

3.2.1 Map Orientation and User Guidance

The Executive Summary Map serves as the starting point for exploring links between hydropower system performance outcomes and environmental outcomes (Figure 8). The map serves as the guiding reference for navigation to discipline specific submaps and outcomes. The central topic on this map is flow from hydropower system, which is connected to hydropower operations through flow through turbines and non-turbine flows, and to environmental outcomes through reservoir elevation and flow downstream of the hydropower system. To the left of these central topics, hydro-mechanical operations are linked through hydro-electrical operations to hydropower performance outcomes (reliability, resilience, revenue, emissions). On the right, environmental outcomes are grouped together by their physical location: upstream outcomes (upstream geomorphology, upstream recreation, upstream habitat, upstream biota and biodiversity, upstream water quality and greenhouse gas, outcomes relevant to both upstream/downstream or dam interface (navigation, dam safety and maintenance, human health, water supply, flood control, fish passage), and downstream outcomes (downstream geomorphology, downstream recreation, downstream habitat, downstream biota and biodiversity, downstream water quality greenhouse gas).

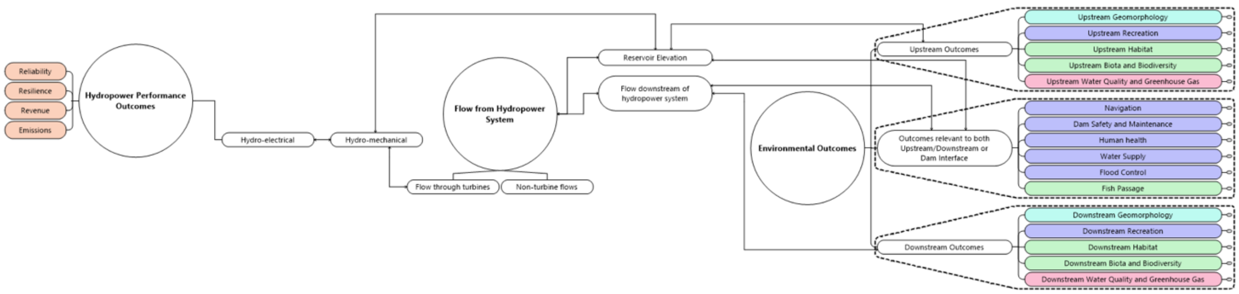


Figure 8. Executive Summary Map

Some topics in the maps are related through parent-child relationships which can be opened or collapsed (number within bubble denotes children within parent category) as shown in the Figure 9. In some cases, boundaries (dashed lines) are used to group the parent topic with all its child topics to visually delineate the respective relational grouping.

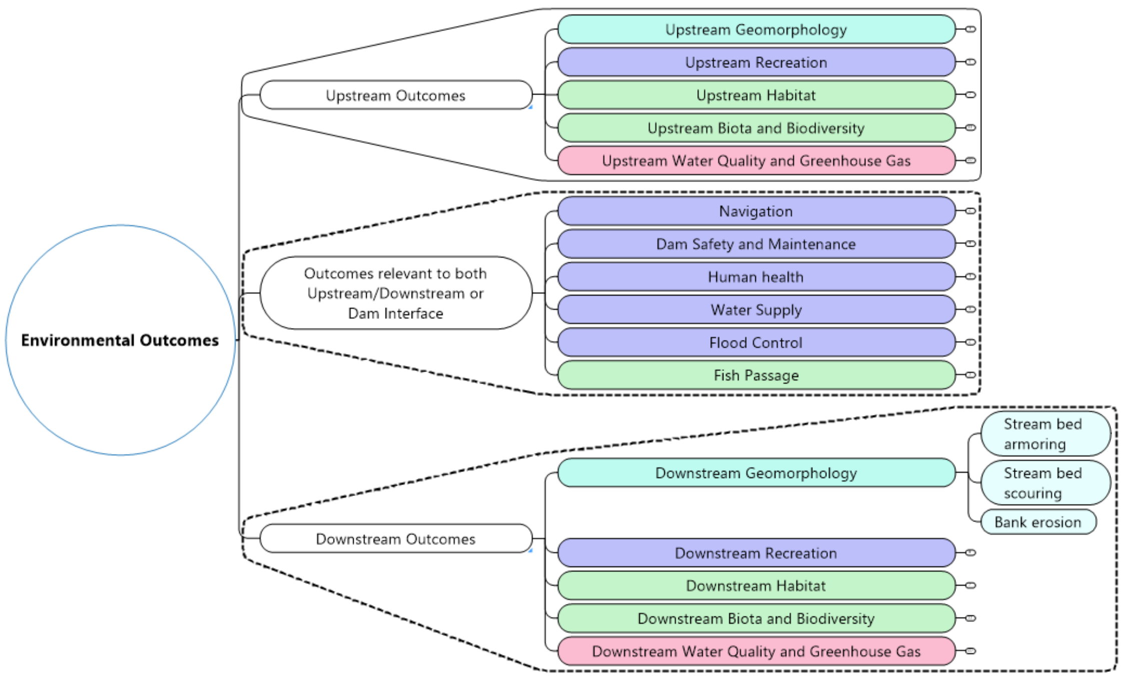


Figure 9. Parent-Child Relationships and Boundaries Showing Groupings of Similar Child Nodes

Figure 9 shows collapsed nodes for all categories of environmental outcomes, except for the Downstream Geomorphology category, which is shown expanded to reveal the child nodes (specific outcomes). Select nodes are linked to a submap with greater detail, describing specific elements and processes. Some topics have notes on the map (Figure 10) giving more detail about the corresponding topic, the processes that connects one element to another, and relevant references.

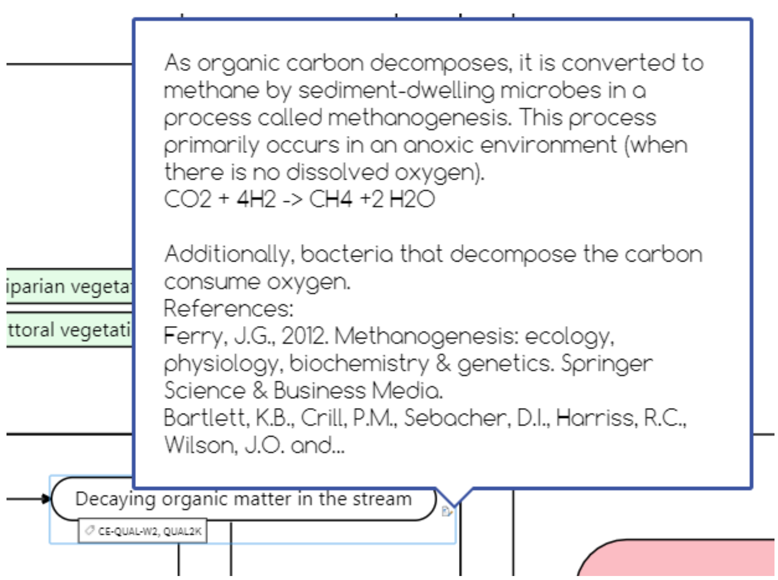


Figure 10. Example of Notes Describing a Specific Node and its Relationships to Other Nodes

Many topics include tags as shown in Figure 11. These tags suggest some of the most common models and modeling software used in academic literature and industry to model the corresponding topic. The tags on the map are not intended to be comprehensive or include every model/modeling software available but are a guide for users for model availability and applicability. Descriptions of the included models and tools, data inputs necessary, strengths and weaknesses, and further details about the characteristics of the models/tools are provided in our accompanying modeling inventory database (Appendix C).

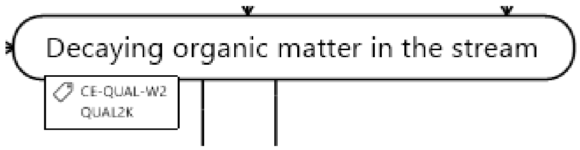


Figure 11. Tags Indicating Common Models that Include Representation of this Node

Relationships between topics are denoted with connecting lines. A solid line with no arrow between topics indicates that the two nodes inform each other (i.e., the relationship is bidirectional). A solid line with single-sided arrow indicates that the node on the point end of the relationship informs the node on the end with the arrowhead (i.e., the relationship is unidirectional). A colored solid line was generally applied to declutter the map and make relationships easier to follow. The color is based on the topic of origin and/or the boundary around a parent topic. Detailed descriptions of map components and mechanisms can be found in Appendix D.

3.2.2 Model and Tool Database

We compiled an inventory of common models and modeling software/tools that are relevant to specific hydropower or environmental outcomes. The model/tools inventory is designed to function as a single table within a relational database (Appendix C), as illustrated in Figure 12.

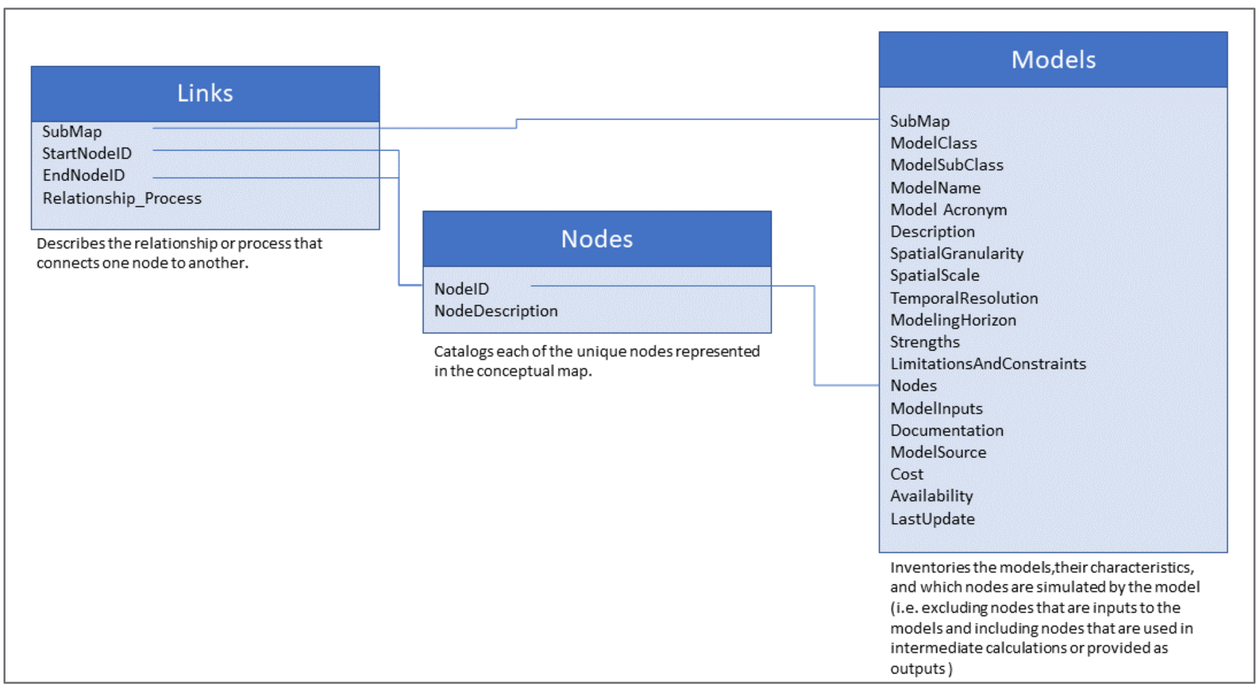


Figure 12. Simplified Entity-Relationship Diagram

The table contains the following information for individual models or modeling software: spatial and temporal scales and resolutions, a brief assessment of known modeling limitations, references, and availability/accessibility information. Structure of the database is important for enforcing relationships between the model inventory and other database tabs that contain the elements and links relating elements in hydropower and environmental systems. This strategy for detailing models and their connections to these elements enables the evaluation of gaps in modeling capabilities. For instance, dynamic queries can be used to discover which models have been documented for an individual element or multiple elements related to hydropower or environmental outcomes. Alternatively, queries can be used to subset those elements that are not yet represented in any documented model.

The model/tools inventory database complements the visual representation of the connections between hydropower, social, environmental, ecological systems, and outcomes in the linkage maps. For example, in Figure 13 processes are mapped to show the complex relationships that exist within these systems. The model or software listed in the inventory table has been included in this map as tags, indicating which models are applicable to a particular element, referred to as a node. Users can then search for a particular model of interest in the database (e.g., RiverWare, HEC-ResSim) to further assess its utility for their specific needs. Additionally, users can choose to visualize only particular models of interest and at what nodes or topics they occur across linkage maps by using the “tag” filter to select a model. In some cases, nodes (white) or processes (gray) may have one or more relevant models identified in the inventory (e.g., flow downstream of hydropower system), while others do not yet have any models (e.g., embankment erosion). Those without models represent gaps in the current inventory.

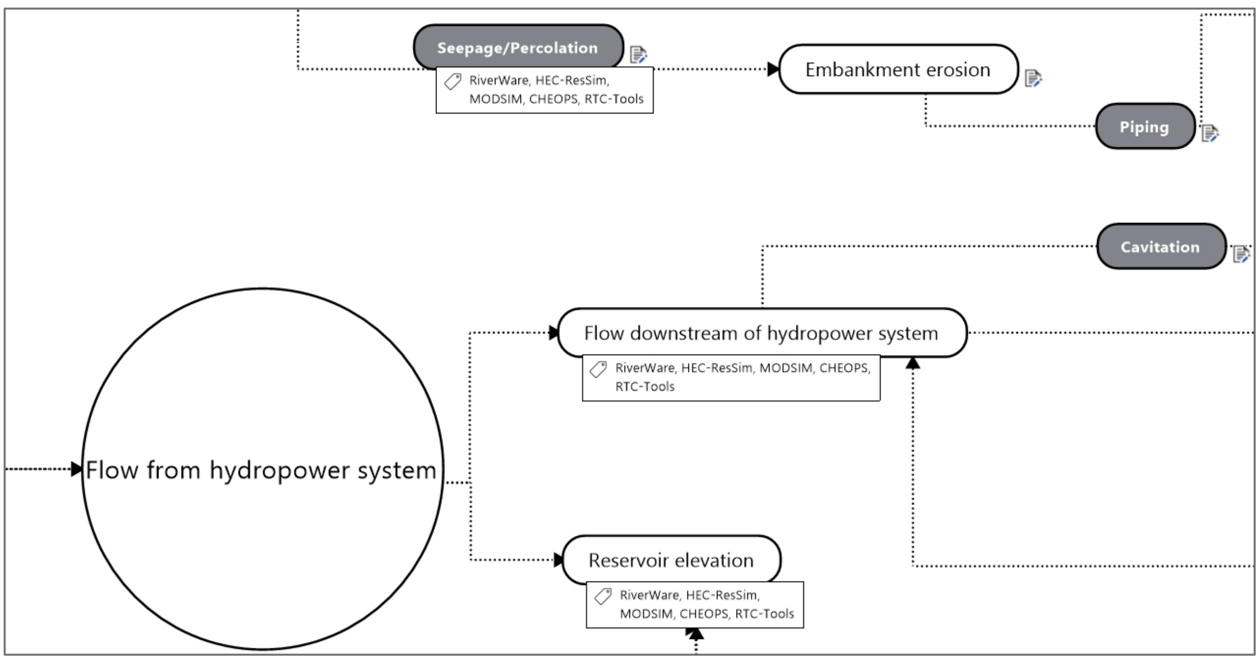


Figure 13. Excerpt of Linkage Map Showing Nodes Tagged with Relevant Models

3.3 Discussion

Environmental flow requirements of hydropower facilities, including providing flow hospitable for aquatic biota and habitats, human health, recreation, water supply, flood control, and more, can limit the ability of a hydropower facility to respond to needs of the grid. Conversely, extreme fluctuations in flow rate can dramatically affect the environment and biota in hydropower-impacted systems. Understanding and quantifying the opportunities for co-optimization of power production and environmental protection are necessary as future power production will rely more heavily on hydropower.

The linkage map framework presented here provides a qualitative and quantitative holistic perspective across the hydropower energy–water–environment nexus. While various frameworks, models, and tools have previously been developed to either optimize hydropower power production or understand the impacts of flow on environmental outcomes, our framework provides a unique and integrative path for understanding the relationships across the full spectrum. Specifically, our power–flow–environment linkage framework provides a greater understanding of how flexibility in environmental requirements can be leveraged to create positive outcomes for both the power system and the environment.

This framework provides a roadmap to understanding where these opportunities of co-optimization may arise. By using the framework, goal-oriented or hypothesis-driven inquiries can be examined through the lens of flow to investigate the impacts of hydropower. Not only can users examine these impacts within a discipline/area (e.g., fish passage) users can also determine how, when, where, and why integration across disciplines (e.g., fish passage – dam infrastructure – flood control flow – power production) can elevate our knowledge on the impacts of hydropower and arrive at win-win solutions that can be designed and implemented.

The linkage map framework is further supported with models and tools that can be used to understand the effects of flow and can potentially be used for integrative modeling approaches. For example, existing ecological models provide a basis to assess the impacts of hydrological regimes and water quality on the habitat suitability of fish, macroinvertebrates, and algae caused by the installation and operation of hydropower dams (e.g., PHABSIM, IFIM, SWAT). Despite their wide use, many of these models do not incorporate abiotic and biotic interactions, organismal processes (e.g., metabolism, population growth rate, genetic variation), or the limiting outcomes these factors can have on flow requirements and power production. However, through our linkage framework, users can readily identify models that are integrated together, and with advances in computational methodologies, this can result in increased parameter space being explored and higher-level questions being answered.

3.4 Conclusions

While our model and tool database cover all the aspects of our framework (power system–flow–environment), we did not develop this database with the intention of it being fully comprehensive or exclusive. Rather our database provides the launching point for users to discover the modeling and software tools available and their respective usages, strengths, and limitations. Further, many ecological, genetic, functional morphology, and fitness models are use-specific and written in Python, MATLAB, or R. Their functionality and replicability are beyond the scope of this paper, but it should be noted that such development is commonplace. Additionally, statistical models (e.g., regression, Bayesian, network) are implemented across multiple platforms and packages, and therefore their applicability is dependent on user questions and goals.

While we aimed to capture the interconnectedness within our linkage maps with arrows, links, models, and notes, we recognize there may be interactions we did not uncover in our literature search and could be iterated into the framework. We also acknowledge that, even though our linkage framework provides a roadmap for identifying energy–environment co-optimization opportunities, it may not be applicable to all situations. Not every hydropower project will be able or need to conduct studies that integrate across disciplines and scales. However, in these situations the framework could still provide valuable insight into the parameters of the intended objectives.

Understanding the opportunities for win-win outcomes between hydropower benefits and the environment will be critical for sustainable energy development and production. Arriving at sustainable solutions in hydropower will help illustrate power–flow–environment linkages that will be important in understanding outcomes under future climate scenarios. For example, research in the Mekong basin using future climate scenarios predict an increased streamflow and that hydropower–environmental tradeoffs will be amplified by streamflow variability. Further, maintaining current levels of environmental regulations in the future could result in a hydropower deficit in the Mekong basin for which thermal power would need to compensate, resulting in generating additional greenhouse gas emissions (Zhong et al., 2021). These results reveal the potential challenges facing hydropower and environmental sustainability in the future and emphasize the importance of developing adaptive mitigation techniques under climate change. Our framework would enable such studies to be conducted by understanding where climate change models could be incorporated.

Providing stakeholders and policy makers with transparent, rigorous, and thorough evaluations of energy–flow–environment co-optimization strategies will aid in future regulatory decision-making processes. The relative importance and applicability of each portion of the linkage map will vary from project to project, but the overall schematic and holistic viewpoint will aid in providing robust estimates of tradeoffs and further the decision-making procedures by providing hydropower regulatory participants a communication tool for illustrating energy–water–environment connections to participants with other expertise or priorities.

4.0 Case Studies in Energy–Environment Tradeoffs

As discussed throughout this report, a future electric grid that leans on hydropower to provide ancillary services will still be held to environmental protection standards that are critical to healthy ecosystems but may limit hydropower flexibility. Tools and analyses that can help find energy–environment win-wins will ensure that hydropower producers can satisfy environmental, grid, and economic needs. In this chapter, we present three case studies demonstrating approaches and tools that can support these needs. These case studies demonstrate energy–environment win-wins that 1) maximize generation revenue from previously designed environmental flow requirements, 2) rapidly evaluate operating criteria for energy–environment win-wins, and 3) create reservoir operational policies that maximize fish survival and generation revenue.

Table 2. Summary Information for Case Studies

Study	Objective	Flow	Environmental Endpoint	Power System Endpoint
Economic Valuation Tool (INL)	Maximize generation revenue from previously designed environmental flow requirements		No explicit environmental endpoint, but provides valuation for flow requirements	Generation revenue
Yadkin-Pee Dee Case Study (ORNL, NREL, PNNL, RTI)	Create reservoir operational policies that maximize fish survival and generation revenue	CHEOPS reservoir operations model	Survival of egg, larva, and age-0 juvenile smallmouth bass	Generation revenue, generation (MW)
Glen Canyon Dam (ANL)	Rapidly creates and evaluates a large operating criteria landscape in search of energy-environment win-win solutions		Fish growth rate, sediment transport	Annual economic value of hydropower energy production

In all case studies, we will present brief methods used in the demonstrations, and highlights of how the case studies demonstrated energy–environment win-wins. Detailed methods and results can be found in Appendix E.

4.1 Maximizing Generation Revenue

Environmental flow releases can be designed for a variety of purposes, although requirements designed to improve outcomes for fish are the most common followed by flow requirements designed for recreation. Flow requirement targets, in part, dictate what the terms need to be and whether the requirement needs to be always met (continuous) or for an average over a certain time period (instantaneous). For example, minimum flow requirements designed to prevent dewatering of endangered salmon redds or mussel beds will likely need to be always met, whereas the intended outcomes of requirements designed for whitewater boating or aesthetics may be satisfied by flows averaged over a certain time period. It is in this latter case where there is some flexibility in the requirement, such that both the letter and the spirit of the requirement can be met (i.e., flows that support safe whitewater boating) even when allocating flows to maximize revenue.

This case study evaluates generation revenue using a two-stage optimization model that incorporates observed and forecasted hydrologic information, plant release capabilities, and uses hourly day-ahead (DA) and real-time (RT) electricity market prices to minimize the difference between prices to maximize revenue. This demonstration does not explicitly evaluate environmental outcomes. Instead, it represents a situation where environmental outcomes would have been assessed a priori by participants in a hydropower regulatory proceeding and generation revenue is maximized within those rules.

4.1.1 Brief Methods

To enable revenue-optimized environmental flows, a prototype algorithm was created that allocates hydropower generation using DA pricing signals and RT market prices within the bounds of environmental flow requirements to maximize revenue from electricity market participation (Figure 14). In this demonstration, the tool is implemented for a hypothetical hydropower plant using flow (both overserved and forecast) and California Independent System Operator (CAISO) locational marginal price (LMP) data corresponding to Trinity River above Coffee Creek near Trinity Center, California. This location was selected because 1) availability of observed and forecast flow data, 2) linkages between the power system and environment in this area are of interest, and 3) this location does not require proprietary information from an existing power plant. A set of synthetic data was then prepared to conduct the demonstration based on hypothetical environmental flow and storage requirements for the observed range from flow data. The tool enables more accurate valuation of a single-reservoir system and can compare multiple scenarios defined by a conceptually intuitive set of inputs to assess outcomes across scenarios.

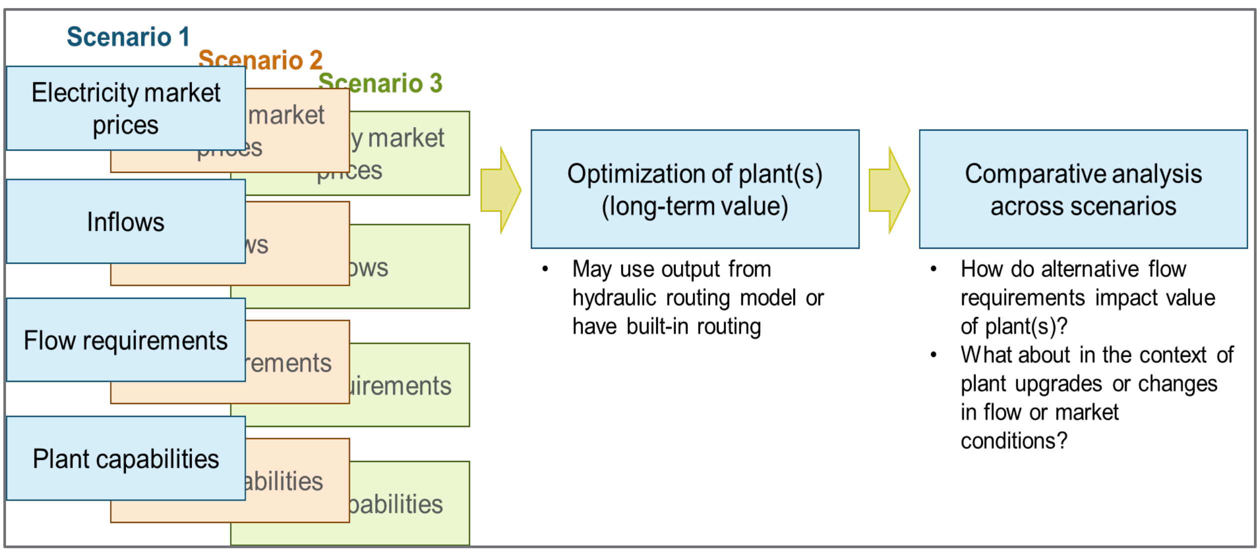


Figure 14. Hydropower Flexibility-Valuation Tool

We then used the tool to describe monthly and hourly generation revenue from flow patterns designed to represent the following representative scenarios: (a) run-of-river and peaking modes of operation; (b) plant capabilities (e.g., reservoir size of generation capacity); and (c) including inflow forecasting in generation planning or not. The tool's optimization model was designed to consider a single reservoir and corresponding power plant. It captures basic characteristics of each, such as reservoir storage, hydropower plant limitations, and operational considerations such as flow requirements. In this single-reservoir system, the tool is designed to evaluate multiple scenarios encapsulating differences in electricity market prices, water inflows, flow requirements, and plant capabilities using a two-stage optimization method. Figure 15 shows how the model feeds inputs through subroutines. In the first stage, the decision to participate in the DA market is optimized based on a forecasted flow. In the second stage, the decision about RT market participation is optimized based on forecast error and observed flow. Inputs to the tool can include hourly forecasted flow, hourly observed flow, and hourly DA and RT electricity prices. Other input data include power efficiency and power-generation rule, ramping rate, flow restriction based on type of year, and maximum hourly change in water spilling. Elevation head can usually be approximated to be fixed.

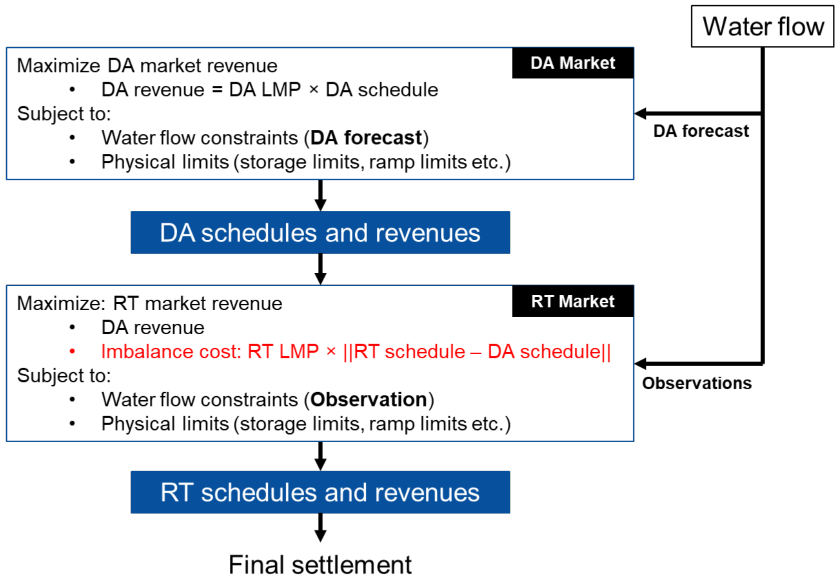


Figure 15. Process Flow of the Two-Stage Revenue Optimization Model

This model is designed to reflect competitive electricity markets with a two-settlement system that consists of a DA forward market and a RT spot market. This model implements a two-stage optimization method to provide accurate assessment of revenue difference caused by environmental-related flow related constraints (Figure 15). The environmental flow constraints are included in both stages of optimization. The DA energy market lets market participants commit to buy or sell wholesale electricity one day before the operating day to help avoid price volatility. The RT energy market lets participants buy and sell wholesale electricity during the operating day. For example, in CAISO the DA market closes at 10 a.m. one day prior to RT, and the imbalance caused by uncertainties are corrected in the RT market. The clearing price in the DA market occurs once per day, whereas the clearing price in the RT market occurs every five minutes. For our tool, the market clearing price is defined as the price where the demand for electricity by consumers is equal to the electricity that can be generated at that price; it is the price where supply and demand are equal. Market operators collect bids from market participants and clear the markets using unit-commitment and economic-dispatch models, which give the locational marginal prices (LMPs) for energy at each node. The revenue of a hydropower plant comes from selling energy to the electricity market, which includes forward transactions in the DA market and delivery of electricity in the RT market.

In this two-stage revenue optimization method, the decision to participate in the DA market is optimized based on a forecasted flow (Figure 15). The objective function in the first stage (DA market) aims to maximize the total generation of all hydropower plants during the planning horizon considering environmental flow and physical limit constraints (e.g., storage limits, ramp limits). In the second stage, the decision about RT market participation is optimized based on forecast error and observed flow. The objective function aims to minimize imbalanced energy costs caused by deviation of actual generation while maximizing the revenue for monthly operations on an hourly timestep. The plant operator determines the optimal schedules by maximizing total revenue based on hourly water inflow. Because of forecasting errors of water flow, the DA schedules usually differ from the RT schedules, which are settled by imbalanced costs based on RT prices.

Environmental flow can be applied in the model to allow comparison of multiple potential flow or operational regimes. Examples of the types of flows that can be simulated include minimum instream, ramping rate limits, hydropower output limits, and storage constraints. The regulatory requirements on stream releases can be defined as reservoir operating ranges and targets, as well as license and contract requirements under different water availability conditions (e.g., wet, normal, dry). These include minimum instream flow requirements, water rights, and reservoir-release capacities. A reservoir's hourly water-balance constraints determine flow release based on minimum and maximum water-storage requirement by hour. Ramping rate limits are determined by maximum hourly flow variations.

Scenarios implemented in the tool are defined by several factors, including (1) operational mode (e.g., environmental flow considerations), (2) hydropower plant configuration (e.g., reservoir and powerhouse), and (3) hydrology and market (e.g., inflow forecasting, inflow observations, and electricity price signals). Three examples are provided to demonstrate functionality within each of these categories, with only a small set of varied parameters to demonstrate the effect of those parameters. In real applications (e.g., as part of FERC proceedings), scenarios may be constructed and compared that utilize functionality across the categories.

The example demonstrating operational mode considerations looks at the effect of varying operational regimes on revenue. The three scenarios represent the span of flexibility a hydropower plant may have, from no flow constraints to natural variability, with a scenario in between of flow constraints representing a realistic set of requirements (Table 3).

Table 3. Operational Mode Example

Scenario name	No flow constraints	Flow constraints	Natural variability
Power plant capacity	120 (MW)	120 MW	120 MW
Minimum storage requirement	673 (acre-feet)	673 acre-feet	None
Maximum storage requirement	1140 (acre-feet)	1140 acre-feet	None
Maximum hourly up-ramping and down-ramping rates	None	±10% of hourly reservoir water release	None
Maximum water spill rate fluctuation	None	±100% of hourly water spillage	None
Forecasting method	Upstream HydroForecast*	Upstream HydroForecast	Upstream HydroForecast

*Palmer 2021

The example demonstrating the effect of hydropower plant configuration focuses on reservoir storage limits. The three cases considered are no storage, baseline storage, and increased storage (Table 4). In this example, only minimum and maximum storage are varied among scenarios and there are no changes in ramping rates or spill rate variability among scenarios. Input data utilized economic impact of reservoir/storage size and constraints. The base storage scenario has five days of storage, no storage has daily inflow and outflow being approximately equal, and increased storage has 10 days of storage.

Table 4. Hydropower Plant Configuration Example

Scenario name	No storage	Baseline storage	Increased storage
Power plant capacity	120 MW	120 MW	120 MW
Minimum storage requirement	None	673 acre-feet	673 acre-feet
Maximum storage requirement	None	1140 acre-feet	2280 acre-feet

Scenario name	No storage	Baseline storage	Increased storage
Maximum hourly up-ramping and down-ramping rates	±10% of hourly reservoir water release	±10% of hourly reservoir water release	±10% of hourly reservoir water release
Maximum water spill rate fluctuation	±100% of hourly water spillage	±100% of hourly water spillage	±100% of hourly water spillage
Forecasting method	Upstream HydroForecast	Upstream HydroForecast	Upstream HydroForecast

The example demonstrating functionality related to hydrology and market focuses on forecast product used for making DA market commitments. The inputs for this example are the same as the baseline storage case (as shown in Table 4), with the following forecast scenarios

- Perfect foresight that assumes the power plant operator has perfect foresight into the future and the forecasts used in the DA market equal exactly the observations in the RT market.

- Persistence forecast uses recently observed flow values as an estimate of future flows. The persistence forecast used in this scenario was created by averaging all instantaneous U.S. Geological Survey gage (11523200 Trinity River above Coffee Creek near Trinity Center, California) observations of streamflow taken within the 24 hours proceeding the forecast issue time. That average value is applied as the forecast value for all steps in the issued forecast.

- HydroForecast (median) uses long short-term memory networks to generate long-term (i.e., up to 10 days ahead) to short-term (hour-ahead) probabilistic water-flow forecasts in the form of percentiles.

The prediction model used in this research has three main input sources:

1. Weather forecasts (from the National Oceanic and Atmospheric Administration's Global Forecast System model and the European Centre for Medium-Range Weather Forecasts)

2. Near-real-time observations of the land surface such as snow cover, vegetation growth, and day and night land surface temperature (primarily derived from satellites operated by the National Aeronautics and Space Administration)

3. In situ streamflow observations from the U.S. Geological Survey.

These inputs are observed at up to an hourly frequency and aggregated over the entire drainage basin. At each timestep (in our case each hour or day), the long short-term memory takes in new inputs, updates a set of internal states it maintains that represent the hydrologic conditions of the basin, and then outputs a prediction for the current timestep. The model is designed to output the full probabilistic range of values for each model timestep, which can be useful to users in managing risk and using this information in downstream models. This scenario takes the DA median HydroForecast value as the input to the DA scheduling model.

4.1.2 Results and Discussion

The algorithm demonstrated here can be used to find flow requirement patterns that yield an energy–environment win-win for long-term planning such as what might be useful in a FERC license proceeding for communicating value propositions. However, this tool can also be useful for short-term planning by providing a method for helping producers conserve water for release on a future day (by incorporating the DA price signals) with the need for generation revenue based on RT market prices.

Of the scenarios we present in this case study, the one that examines differences between modes of operation is perhaps the most useful to understanding generation revenue outcomes associated with run-of-river (as an example of an environmentally driven flow pattern) and peaking (as an example of a profit-driven flow pattern). Interestingly, although the "no flow constraints" scenario provides higher revenue in each month, the differences are relatively modest in most months (Figure 16). For example, differences in revenue between the no flow constraints scenario (i.e., maximum revenue) and the natural variability scenario (i.e., maximum environmental benefit) is 19% across all months, but only vary 5% in April when revenue is highest for the year due to abundant water. However, revenue differences between the no flow constraints and natural variability scenarios are quite sizable in August through December ranging from 30.7%- 59.3%, although revenue generated during those months is much lower than in the spring.

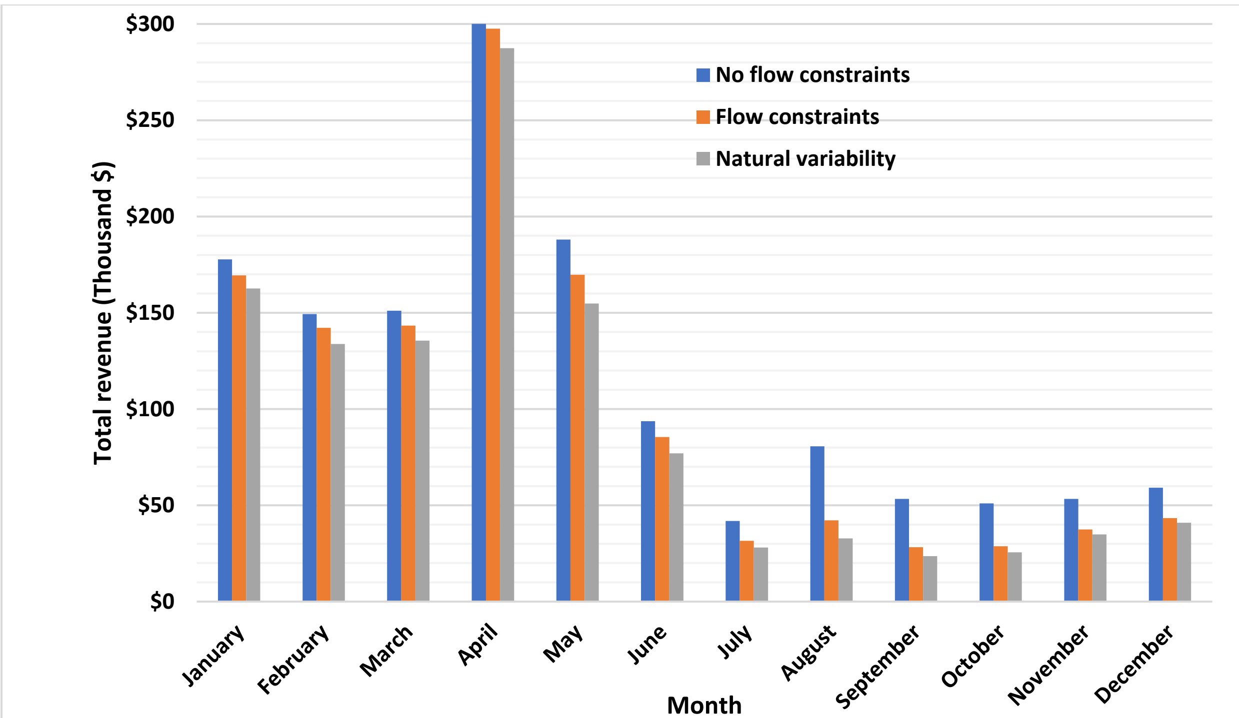


Figure 16. Generation Revenue for Three Flow Constraint Scenarios

On a sub-daily time scale, differences in operations between the three cases vary in a manner consistent with expectations: the no flow constraints scenario varies the most in response to price fluctuations over the course of the day and natural variability is relatively invariant in response to RT market prices because the flow pattern is generated by water availability and is slow to change over the course of the day (Figure 17).

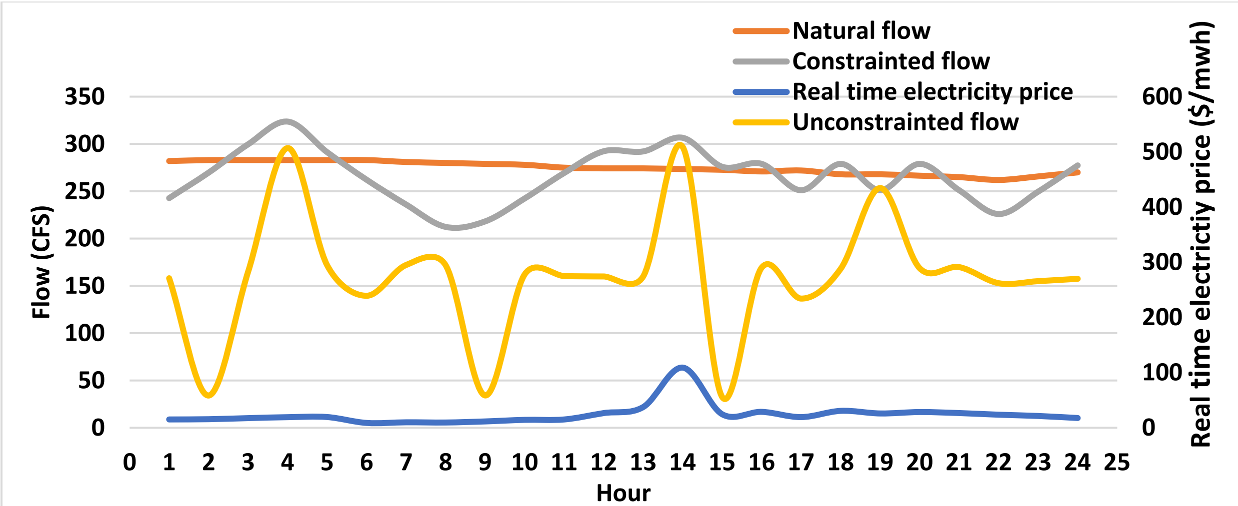


Figure 17. Hourly Water Flow and RT Electricity Price for Three Flow Constraint Scenarios for May 15

Of the scenarios we present in this case study, the one that examines differences between modes of operation is perhaps the most useful to understanding generation revenue outcomes associated with run-of-river (as an example of an environmentally driven flow pattern) and peaking (as an example of a profit-driven flow pattern). Interestingly, although the no flow constraints scenario provides higher revenue in each month, the differences are relatively modest in most months (Figure 18). For example, differences in revenue between the no flow constraints scenario (i.e., maximum revenue) and the natural variability scenario (i.e., maximum environmental benefit) is 19% across all months, but only vary 5% in April when revenue is highest for the year due to abundant water. However, revenue differences between the no flow constraints and natural variability scenarios are quite sizable in August through December ranging from 30.7–59.3%, although revenue generated during those months is much lower than in the spring.

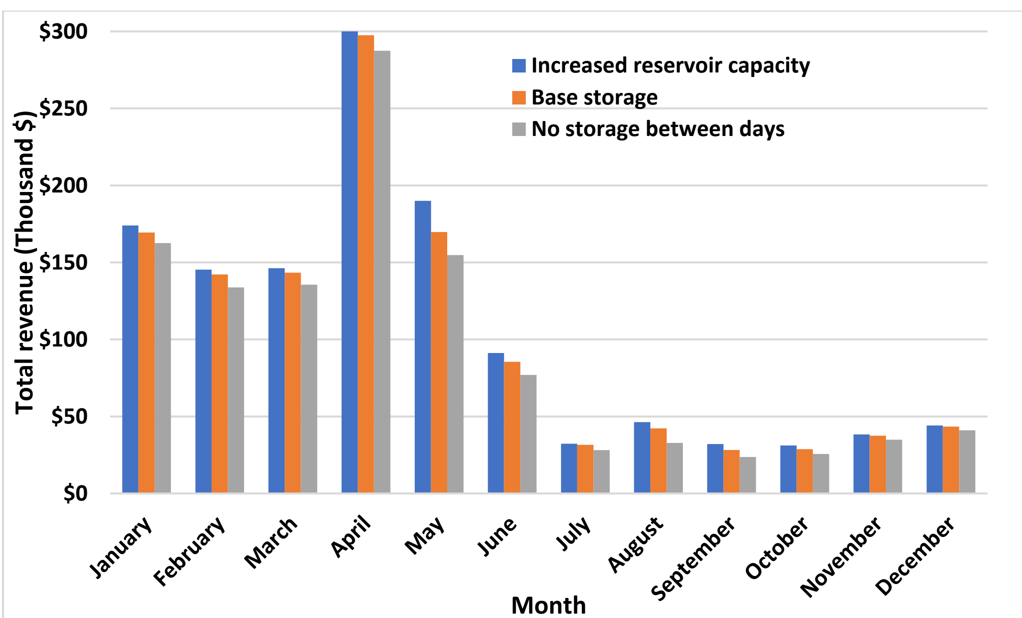


Figure 18. Economic Impact of Storage Scenarios

In general, reservoirs with longer storage times have more severe environmental impacts than reservoirs with low or no residence times, although reservoirs with higher storage have greater flexibility for meeting competing water demands at times of year when water is scarce. Like the findings for the no flow constraints versus natural flow scenarios, this scenario examining the revenue impacts on reservoir storage times also shows little difference in revenue between the higher impact/higher revenue and lower impact/lower revenue reservoir operations. Differences between reservoir operating policies resulted in an average of 6.73% difference in annual revenue with larger differences in May and lower differences in December.

This demonstration of the tool serves to highlight its functionality for assessing different scenarios and tradeoffs. When paired with additional analysis, this may enable identifying generation operations that improve environmental performance without reducing revenue, or at least enable informed discussions around the tradeoffs being evaluated. However, timing of generation is becoming more important for determining the value of generation, storing water today for potential future use can create tension between environmental and revenue objectives, which require their own flow patterns, and the power system requirements for electricity, which are encapsulated in LMPs. Identifying win-win outcomes in this context requires being able to discuss the value of flexibility across stakeholder groups. The intent of the hydropower flexibility valuation tool is to aid in these discussions by providing a straightforward framework that represents how power markets function and dispatch decisions are made and enables building scenarios that are relevant to different stakeholders.

This flexibility valuation tool is highly adaptable across power system and environmental contexts because the information required to set up simulations are relatively straightforward to assemble (flow, price signals, plant capabilities, and flow requirements). Yet, identification of specific win-win scenarios will depend on more information than just what is contained in this tool. It will require understanding how flow regime impacts aquatic species well-being, which is not part of this tool. Therefore, future work will need to link models and tools that relate environmental outcomes with flow to this flexibility valuation tool. These environmental-to-flow relational models are likely to be more regionally specific given that aquatic species and environmental biomes vary significantly between river systems. The role of this flexibility valuation tool is to be an integrator between these regionally specific environmental considerations and the power systems that a given hydropower plant is connected to.

This prototype tool works to assess economic value for flows in individual hydropower facilities in the CAISO market, but additional work is needed to make this tool more generally applicable to hydropower facilities across a broad geographic region. Future research priorities with this tool include creating functionality for implementation in different types of electricity markets (e.g., vertically integrated and competitive) and for different contract types (e.g., main stem, bypass reach, cascade of facilities).

4.2 Rapidly Evaluate Operating Criteria for Win-Wins

For this case study, we explore potential win-win strategies via a set of tools that quantify both environmental metrics downstream of the Glen Canyon Dam (GCD) on the Colorado River, including those in Grand Canyon National Park, and an economic metric for the Western Interconnection (WI) power grid. This case study finds energy–environment win-wins by searching for reservoir and hydropower operations that benefit environment outcomes through evaluation of both fish growth and sediment transport, and by estimating energy outcomes through evaluation of generation revenue. This case study is not intended to produce a final answer to or resolve the GCD operational, water, and/or environmental issues that have been studied by a multitude of researchers, analysts, and modelers for decades. Rather it creates an expansive landscape of plausible operating criteria that is far beyond other studies, and then identifies, in general terms, operating criteria specifications that could provide better solutions than current operating practices.

Past GCD studies have explored alternative operating criteria, but the number of criteria evaluated were limited by computational and labor resources. Many alternative operating criteria beyond those previously evaluated may yield better energy and environmental outcomes. To search for these criteria, Argonne National Laboratory (ANL) created a novel toolset that rapidly generates many thousands of operating criteria and evaluates energy and environment outcomes for each one. Rapid assessments allow for an exploration and evaluation of a vastly larger space than in the past. The toolset constructed and demonstrated in this study leverages existing models and builds new components in a novel framework. This new toolset and processes complement existing methods and models. It does not compete with or replace existing tools.

The GCD demonstration illustrates the types of insights that users can gain from analyzing toolset results. These insights can help decision makers select/formulate improved operating criteria through human-machine interactions. This means that model-derived insights can be used by modelers to finetune successive model runs to improve upon either (1) existing operating criteria or (2) previously discovered win-win solutions.

4.2.1 Brief Methods

The GCD located near Page, Arizona, is a key feature of the Colorado River Storage Project and is approximately 15 river miles (RM) above Lees Ferry (Figure 19). This marks the beginning of 277 miles of Colorado River that flows through the Grand Canyon and then on to Lake Mead, which is formed by Hoover Dam. The 710-foot-high GCD structure forms Lake Powell, which stores 24 million-acre-feet (MAF) of water. This corresponds to several years of water resources for GCD hydropower energy production and more storage capacity than all other Colorado River Storage Project resources combined. In addition to its water-storage value, the power plant at GCD has a total nameplate generating capacity of 1,320 MW, accounting for about 75% of energy and storage resources for the Colorado River Storage Project.

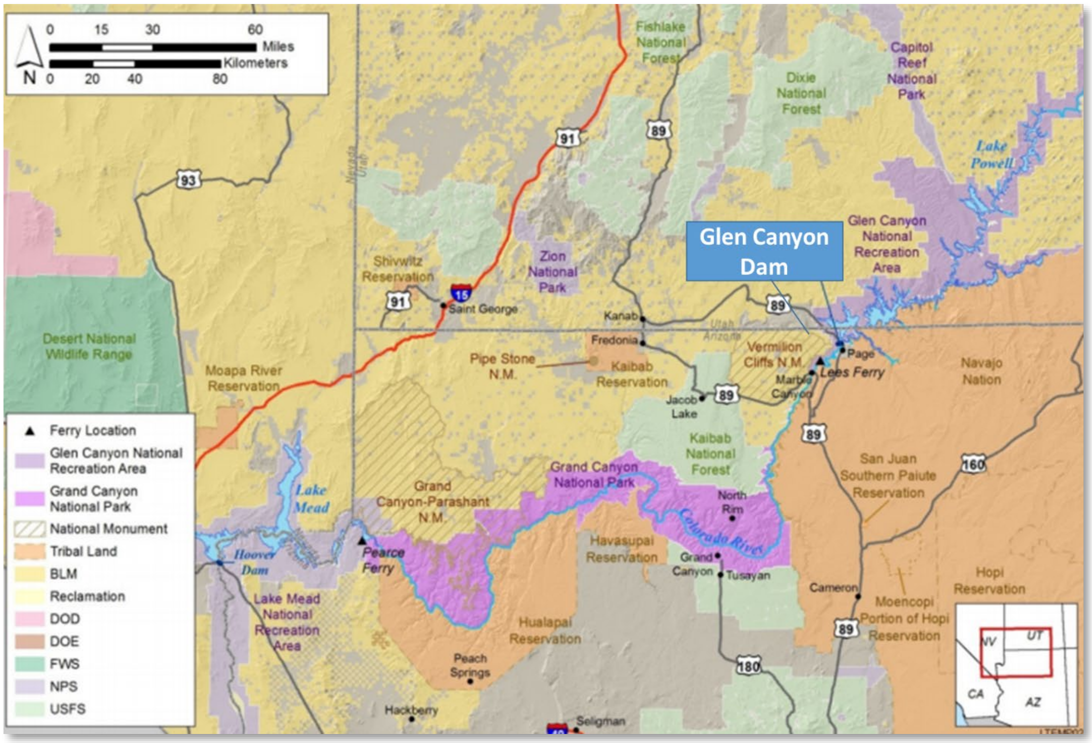


Figure 19. Map of GCD, Lake Powell, and the Colorado River Below the Dam

We selected 2028 as our study year to incorporate into the analysis the impacts of the evolving WI on hydropower operations. Within its geographical footprint, the WI is projected to increase wind and solar power production, retire several coal-fired power plants, and increase its reliance on highly efficient and flexible natural-gas-fired technologies. In total, these measures are expected to substantially reduce greenhouse gas emissions from the power sector, change the behavior of utilities that purchase GCD energy and capacity resources, and modify the utilization of the GCD hydropower resource. These changes are represented in the modeling process via evolving grid LMPs that are in part used to drive use of limited water resources for hydropower production. The toolset is designed for any price pattern such as historical or projected LMPs generated by either sophisticated models or other routines.

For the demo, we assumed a typical annual water release volume from GCD of 8.231 MAF. This typical volume may change (possibly decrease) in the future due to evolving hydrological conditions and increased water withdrawals from the Upper Colorado River Basin (UCRB). Although we assumed an annual water release volume of 8.231 MAF, the Win-Win Toolset is designed to model a large range of feasible annual water releases from Lake Powell. The modeling frameworks used by the toolset consists of three major parts. The first creates numerous (e.g., hundreds of thousands) of hourly water release patterns during a day and then, for each daily pattern, estimates associated economic and environmental implications using new algorithms and existing models from previous studies of the GCD and UCRB system. The second focuses on the monthly and daily allocation of GCD water release volumes and searches for win-win operations. The third creates two-dimensional Pareto frontiers that show tradeoffs between two objectives.

For this demo, criteria specified under the 2016 Long-Term Experimental Management Plan (LTEMP) Environmental Impact Statement (EIS) Record of Decision (ROD) are used for the business-as-usual (BAU) case and serve as the benchmark criteria from which other operating criteria are compared (see Table 5). For the win-win model demo, the BAU benchmark case assumes a typical GCD annual release of 8.231 MAF. In actual operations, the annual water target mainly depends on elevation in Lake Powell, temporal inflows, and water delivery obligations. Monthly water releases, however, sometimes deviate from the plan to support a LTEMP experiment. For example, more water is shifted into a month when a high-flow experiment is conducted and, to comply with the annual release targets, less water is released during one or more non-high-flow experiment months.

Table 5. Operating Constraints Under the 2016 ROD (applied October 2017 through the present)

Operational Constraints	2016 ROD Flows (From October 2017)
Minimum release (cfs)	8,000 from 7:00 a.m.–7:00 p.m. 5,000 at night
Maximum release (cfs)	25,000
Daily fluctuations (cfs/24 hr)	depending on monthly release volume
Ramp rate (cfs/hr)	4,000 up and 2,500 down

Daily fluctuation (change) equal to ten times the monthly volume (in TAF) in June–August, and nine times the monthly volume (in TAF) in other months; daily range not to exceed 8,000 cfs.

The maximum release rate is limited to 25,000 cfs under the 2016 ROD operating criteria. Maximum flow rate exceptions are allowed to avoid spills and/or conduct flood releases during high runoff periods. Under these very wet hydrological conditions, when the average monthly release rate is greater than 25,000 cfs, water must be released at a constant rate during the entire month.

Nonbinding agreements restrict Western Area Power Administration daily water release volumes during each month of the year. These guidelines are referred to as intra-monthly daily restrictions and do not change during the year; that is, daily release volume restrictions remain the same regardless of the month. These guidelines include:

- Weekday volumes are approximately the same each weekday throughout the month
- Saturday, Sunday, and holiday daily release volumes are ≥ 85% of the weekday average
- Saturday, Sunday, and holiday daily release volumes are capped at the weekday average.

For this case study, metrics used to identify operating criteria that result in environmental and hydropower economic win-win solutions for the year 2028 relative to levels computed under the 2016 ROD criteria include the following:

- Economic Energy Value: Historically, the majority of the GCD hydropower plant economic value is from its energy production. For this study, the projected economic value of GCD for the year 2028 is calculated by summing, over all hours of the year, GCD hourly energy production multiplied by the corresponding hourly LMP. Large annual water releases that drive its turbines, coupled with its high output capacity, enable the power plant to generate relatively large amounts of energy at times of the day when it has the highest value (i.e., LMPs). Although we only use one economic metric in this case study, other operational value streams such as ancillary services and capacity metrics can be accommodated by the toolset.
- Humpback Chub (HBC): The HBC is an endangered native fish of the Colorado River that evolved around 3-5 million years ago.[2] For this analysis, we use an existing HBC bioenergetics model that incorporates water temperature and flow to estimate growth at two key habitats in Grand Canyon National Park: 61 RM and 225 RM downstream of GCD. In general, slower river flow rates result in

[2] https://www.coloradoriverrecovery.org/general-information/the-fish/humpback-chub.html

warmer water temperatures at these two sites and promote faster growth rates, especially during warm/hot summer months.

- Sediment Transport**:** Sediment controls the physical habitat of riverine ecosystems downstream of GCD. It is deposited or eroded from the various environments in the Colorado River, and sediment suspended in water determines water clarity. Changes in the amount and areal distribution of different sediment types cause changes in river channel form and habitat. For this case study, we estimate metric tons of sediment transport in the Lower Colorado River. It is primarily a function of water flow with sediment transport that increases with faster water flows.

The win-win tool methodology used in this case study employs a comparative approach. Essentially, metric values computed for the BAU operating criteria serve as a benchmark against which other operational regimes are evaluated. A comparative analysis approach such as this one has been used to measure changes in environmental and economic outcomes associated with alternative hydropower resource operating criteria in the UCRB for more than three decades.

4.2.2 Results and Discussion

Albeit at a much lower level of granularity and detail than some previous studies on the GCD system, the methodology discussed in this report explores many thousands of different water release patterns in search of win-win operating criteria—a scale that was previously not possible to be evaluated due to computational and human resource limitations. This ability to rapidly generate hundreds or thousands of potential operating criteria and quantitatively evaluate potential environmental and economic outcomes of those criteria has the potential to enable operational solutions that improve both environmental and economic outcomes.

Over the past 30 years, numerous financial and economic analyses have been conducted on various GCD operating criteria, experimental water releases, and the marketing of GCD hydropower plant resources. This includes LTEMP EIS studies that analyzed only six primary alternative operating criteria along with non-action operating criteria. None of the alternatives resulted in a win-win solution and, if implemented, only one was expected to provide small hydropower benefits (e.g., lower future energy scenario customer rates by about 0.27 percent).

A key feature of the new toolset methodology that distinguishes it from those used for past GCD studies is that it examines a very large number of alternative operating criteria over a broad range of feasible options in combination with monthly, daily, and hourly water release profiles in the search for win-win solutions. Because we examine a very large landscape/operational space, metrics for this vignette demonstration are, by necessity, measured with less accuracy as compared to very detailed modeling performed in support of previous analyses. Therefore, once potential win-win dam operations are identified, expanded and more detailed analysis should be conducted to determine the validity of the model's solutions. After we gain insights into the general types of operations that lead to win-win results, further adjustments to the criteria can be made to address other considerations outside of the modeling process that are difficult to measure but still important.

The Win-Win Toolset was used to search for solutions that simultaneously increase GCD hydropower economics and HBC growth at both 61 and 225 RM. Over 81,000 random runs were performed with an annual GCD release of 8.231 MAF. All complied with 2016 ROD hourly minimum and maximum water release rate limits and both hourly up- and down-ramp rate restrictions. The daily change limit also remained in place and did not deviate from the monthly levels used in the BAU case. These runs, however, differed from the BAU case as follows:

1. Monthly water release volumes (i.e., intra-annual criteria) were allowed to deviate from the BAU case

2. Relative daily release volumes deviated from those used it the BAU case, but remained within the nonbinding limits that restrict Saturday and Sunday release volumes to be at least 85 percent of the average weekday release

3. Selection of the “best” hourly release patterns to use for each day type is based on a multiple objective that includes both GCD energy production economics and HBC growth rates at RM 225.

Results for 81,000 model runs are shown in Figure 20 as a scatter plot of annual GCD economic value and corresponding HBC growth at RM 225. Each result is relative to the BAU scenario. Note that win-win solutions for power economics and HBC growth at RM 225 also resulted in faster growth at RM 61 (light blue points in the upper-right quadrant). There are, however, also operations that increase HBC growth at RM 226 but not at RM 61.

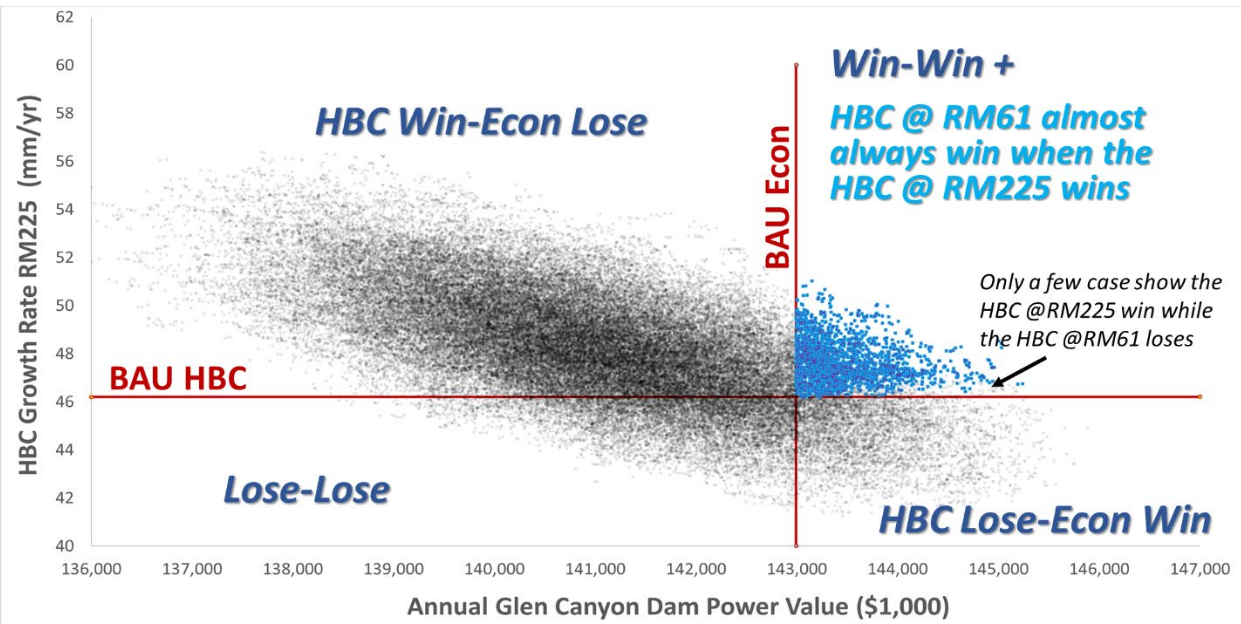


Figure 20. Win-Win Toolset Annual Results Highlighting Random Draws that Simultaneously Improve GCD Power Economics and HBC Growth at Both RM 61 and RM 225

One tool in the Win-Win Toolset creates Pareto frontier of tradeoffs between two metrics. Figure 21 shows monthly release volume patterns for three of these points: (1) max HBC growth at RM 225; (2) win-win outcomes for HBC growth and energy generation value; and (3) max energy generation value. Relative to the BAU case (blue bars), HBC growth is the greatest (top panel) when water releases are high during the winter and early spring months when HBC growth is zero or very low. To balance these higher winter release volumes, water release volumes are lower during other times of the year when warmer low-flow water encourages HBC growth; especially during the summer months and early autumn (e.g., September).

The opposite flow volume pattern occurs when maximizing the value of GCD hydropower energy production (lower panel). To maximize power value, water releases during the summer months and September are higher than the BAU case. Water is essentially reallocated from all other months of the year to support high generation levels when market prices are the most expensive.

Monthly water releases for the win-win case shown in Figure 21 is on Pareto frontier point approximately in the middle of the curve segment that spans win-win solutions. It is a compromise between the two extremes. Relative to the BAU case, more water is released during December and January to take advantage of higher prices during the peak winter load months. These high winter flows have no impact on HBC growth because they do not grow during this those two months.

Monthly release is also relatively high during June and July. These releases also support high economic value because prices are high during these two summer months. These higher flows dampen HBC growth relative to the BAU case. However, lower monthly release during the other times of the year, especially August and September, more than compensate for HBC slower growth during the June and July. More detailed information about the Win-Win Toolset and results for searches with expanded operating criteria landscapes (e.g., alternative intraday limitations such as ramping), under both higher and lower annual water releases, are provided in Appendix F.

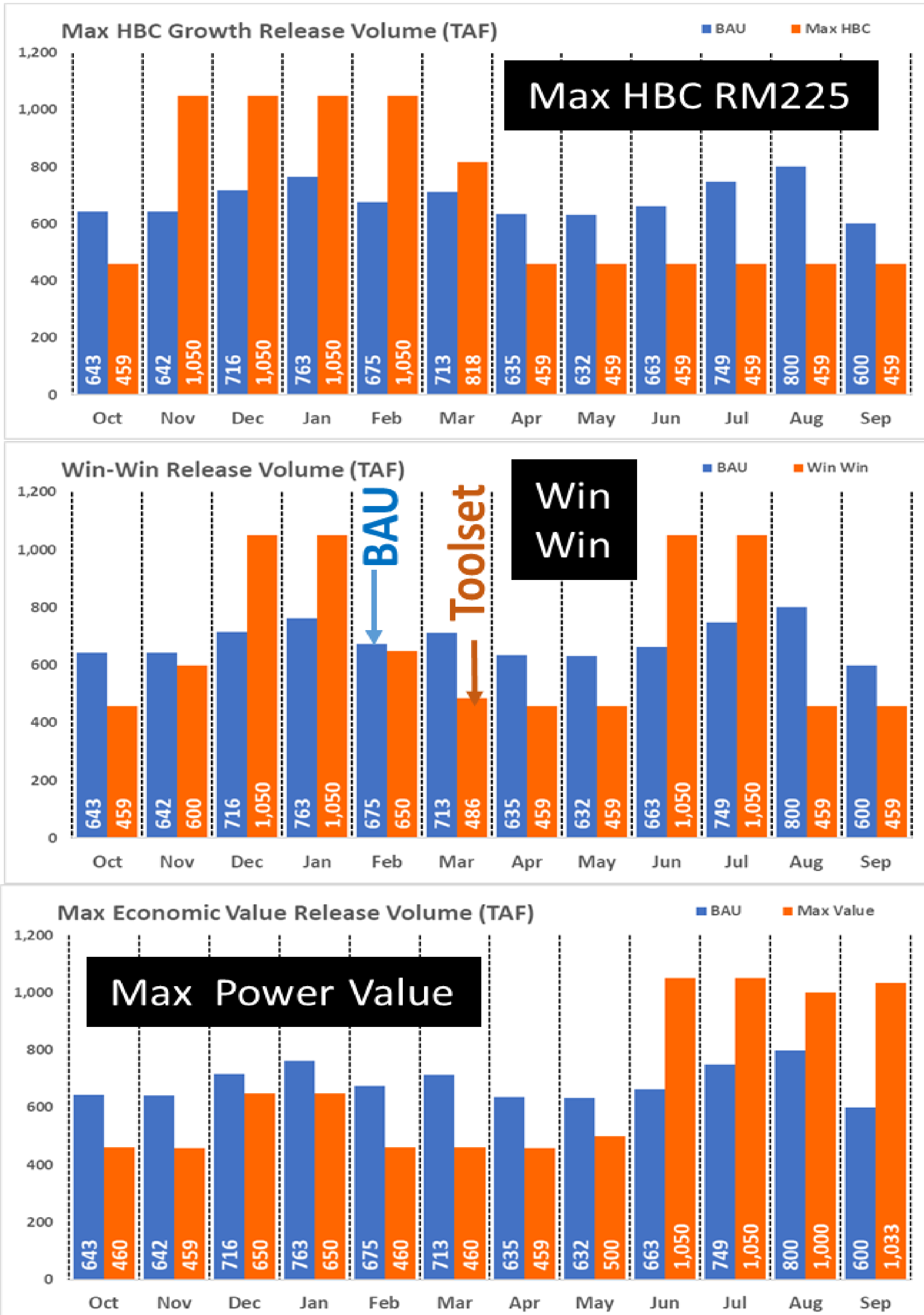


Figure 21. Monthly Release Volumes on the Pareto Frontier of Annual HBC Growth and GCD Hydropower Energy Value

While the model and resource issues explored in this case study are applicable to the GCD system, the general framework of the tools were designed to be generally extensible to hydropower sites across the United States, including sites that must comply with FERC hydropower regulatory criteria. For example, we envision future versions of these tools to evaluate growth of other fish species or potentially evaluate outcomes of resource or water quality issues aside from sediment transport.

The Win-Win Toolset is in the prototype phase of development and the application for the GCD demo site should be viewed as a proof-of-concept application. Future improvements to the toolset could potentially include:

- Developing a smarter win-win search algorithm
- Expanding drives that shape hourly release patterns, including use of multiple weighted drivers
- Expanding the capabilities of the Pareto frontier algorithm to solve for day type release volumes and simultaneously create frontiers for three or more metrics
- Structuring the toolset computer code to solve problems at various levels of granularity and, for many individual processes, run faster and in parallel.

4.3 Policies for Maximizing Fish Survival and Generation Revenue

This case study aimed to demonstrate another way of evaluating energy and environment outcomes to find opportunities that benefit hydropower production and the environment. In this demonstration, we created a set of reservoir policy and fish models based on publicly available information for six dams in the Yadkin-Pee Dee River basin. Specifically, this demonstration focused on understanding the importance of sub-daily, and even sub-hourly, operational flexibility in a hydropower system and the true environmental (fish survival) and hydropower (revenue) tradeoffs. This demonstration provides an example of information that can give improved data to decision makers involved in assessing appropriate operations within defined policies.

4.3.1 Brief Methods

This case study was conducted on the six facilities located in the Yadkin-Pee Dee River Basin in North Carolina and South Carolina (Eastern Interconnection). Reservoir development in the basin includes (from headwaters to mouth) one nonpower facility owned by the U.S. Army Corps of Engineers (USACE), four hydropower facilities owned by Eagle Creek Renewable Energy (ECRE), and two hydropower facilities owned by Duke Energy (Table 6 and Figure 22). This basin typifies many common and challenging aspects of river basin water management such as multiple licensees; diverse landscapes ranging from mountain headwaters to coastal plains; varying natural resource issues such as water supply, fish passage, recreational boating, water quality, and differing balancing authorities; generation capabilities; and generation schedule planning between the two hydropower owners.

Table 6. Summary of Yadkin-Pee Dee Hydropower Projects

Owner	Project Characteristics	Environmental Characteristics	Power System Characteristics
ECRE	Four facilities (215 MW): • High Rock (225,500 ac-ft; 40.2 MW) • Tuckertown (41,000 ac-ft; 38 MW) • Narrows (137,000 ac-ft; 110.4 MW)	• Dissolved oxygen • Species of concern – Freshwater mussels – Upland wildflowers – Bald eagle	• Participates in wholesale energy market • Automated generation control

	• Falls (2,300 ac-ft; 31.1 MW)	• Recreation – Canoe and kayak – Fishing	• Receive inflow from nonpowered USACE dam
Duke Energy	Two facilities (108.6 MW) • Tillery (132,600 ac-ft; 84 MW) • Blewett Falls (27,500 ac-ft; 24.6 MW)	• Dissolved oxygen • Fish passage – American eel – American shad – Atlantic sturgeon – Shortnose sturgeon • Recreation – Canoe and kayak – Fishing	• Vertically integrated utility • No automated generation control • Receive inflow from ECRE facilities so heavily influenced by ECRE decisions

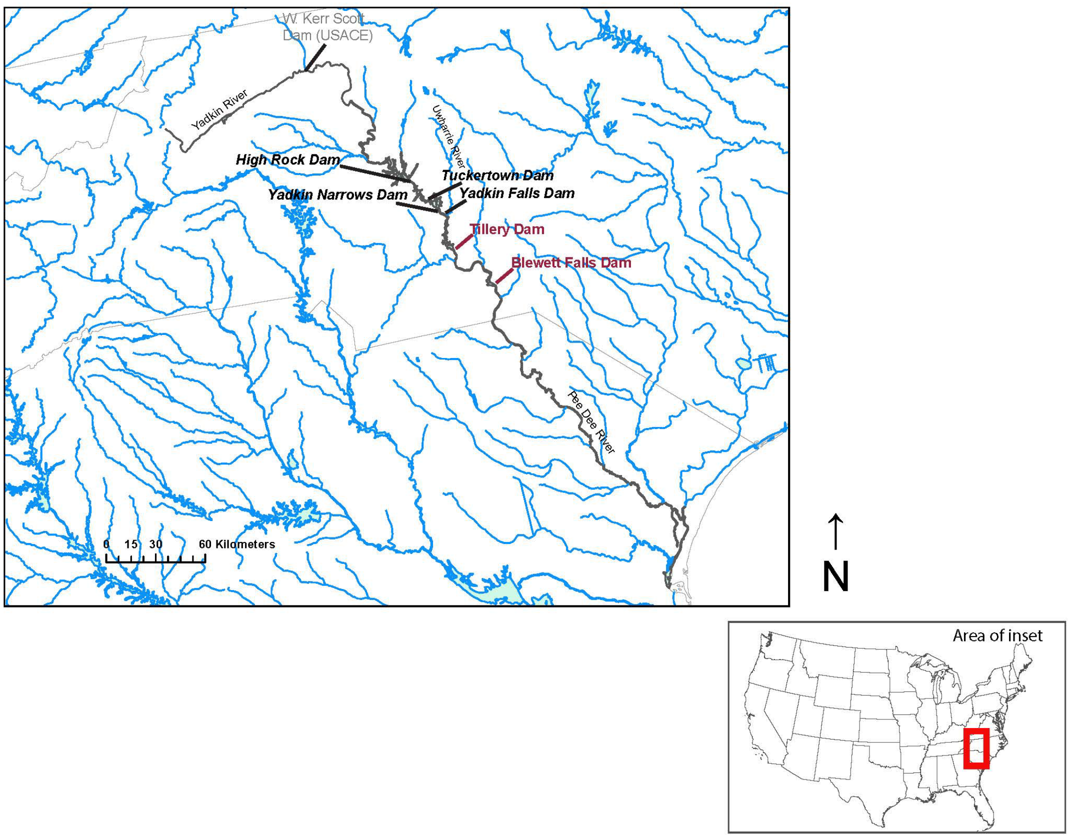


Figure 22. Map of Yadkin-Pee Dee Basin's Dams Including Those Owned by USACE (gray—no hydropower), ECRE (black), and Duke Energy (red)

To evaluate energy-environment tradeoffs and gain a better understanding of the links between power, flow, and the environment in this system, a general framework connecting power generation, flow, and environmental outcomes was developed using 1) a long-term simulation using reservoir policy model and 2) a detailed reservoir, grid, and ecological modeling and evaluation that allows impacts to be assessed at sub-daily time scales. As shown in Figure 23, our framework uses four sets of models/software including Computer Hydro Electric Operations and Planning Software (CHEOPS) for long-range reservoir policy, PLEXOS for energy market simulation, Dual-Dynamic Programming (DDP) for optimization of sub-daily flow distribution, and QUANTUS for simulating linkages between flow and first-year smallmouth bass survival as mediated by flow-influenced temperature and prey availability. These independent models are integrated in a sequential fashion, passing the outputs from one model to the next in the framework. More detail on individual model descriptions and sequencing can be found in Appendix G.

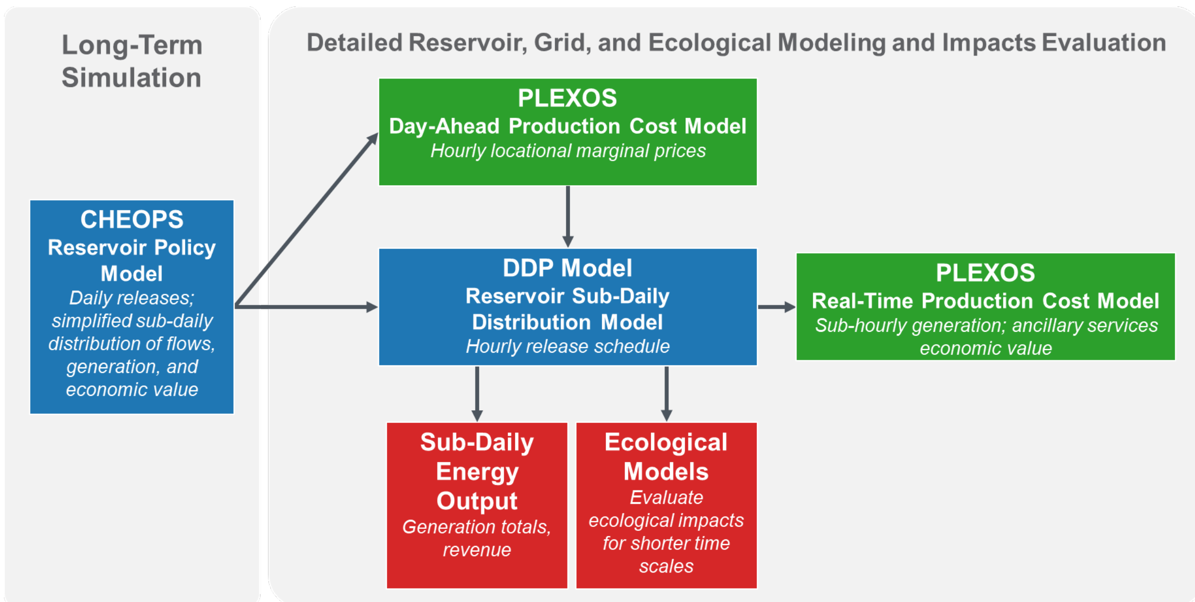


Figure 23. Yadkin-Pee Dee Coordinated Modeling Framework; QUANTUS Model Step Represented by "Ecological Models" Box

The coordinated modeling framework was used to explore operational flexibility for a combination of base cases and alternative reservoir policy scenarios as listed in Table 7. The base case load scenarios simulate three different generation load shapes that reflect current and increasing future renewable penetration. These scenarios are then coupled with alternative operating policy scenarios to investigate the impacts of alternative ramping policies. A production cost model (PCM) conducted using PLEXOS showed finer transmission details of the Southeast Regional Council to get the LMP specifics to the case study power plants. These scenarios are then coupled with alternative operating policy scenarios to investigate the impacts of alternative ramping policies. The hydropower generation for alternative ramping policies were modeled in PCM to understand potential revenue from finer time resolution for providing grid flexibility.

Table 7. Base Case Load Scenario and Alternative Operating Policy Scenarios with Ramp Rate Restrictions

Scenario Name	Base Case Load Scenario	Alternative Operating Policy Scenario
2024 Load-Base Ops	Base 2024 (Current generation)	Base case with current ramping restrictions (300 AF/hr)
2024 Load-Base Ops with Env Policy		Base case with nighttime environmental ramping restrictions (day: 300 AF/hr; night: 25 AF/hr)
2036 Load-Base Ops	Base 2036 (Assumed moderate increase in renewable penetration)	Base case with current ramping restrictions (300 AF/hr)
2036 Load-Unrestricted Ramping Ops		Unrestricted outflow ramping at all times (day: 900 AF/hr; night: 200 AF/hr)

Scenario Name	Base Case Load Scenario	Alternative Operating Policy Scenario
2036 Load-Restricted Ramping Ops		Highly restricted outflow ramping at all times (day: 15 AF/hr; night: 10 AF/hr)
2036 Load-Base Ops with Env Policy		Base case with nighttime environmental restrictions (day: 300 AF/hr; night: 25 AF/hr)
2036 Load-Unrestricted Ramping Ops with Env Policy		Unrestricted outflow ramping during daytime (day: 900 AF/hr; night: 25 AF/hr)
2050 Load-Base Ops	Base 2050 (Assumed high increase in renewable penetration with 2036 output power production)	Base Case with current ramping restrictions (300 AF/hr)
2050 Load-Base Ops with Env Policy		Base case with nighttime environmental restrictions (day: 300 AF/hr; night: 25 AF/hr)

This approach focuses on sub-daily variation to assess the potential benefits of allowing greater intraday (and intra-hour) flexibility. Conventional FERC-type policy evaluations often use assumed or simplified representations of grid needs at the sub-daily operational level and focus on long-term policy impacts. Impact evaluations of generation projections or grid needs are often considered independently from policy evaluations. While appropriate for long-term simulations to understand the impact of different operating policies across the range of natural variability, this often does not consider the need to provide flexibility on shorter time scales in the current or future system beyond basic consideration of ramp rate limitations with little detailed ecological modeling. By modeling the energy and ecological systems at a detailed level, we expect that greater insights can be gleaned regarding impacts of constraints on revenue streams and the energy and ecological systems to help identify new opportunities for win-win reservoir policies.

For this study, three scenarios comparing flexible and nonflexible generation, with and without environmental flow requirements (no nighttime ramping), were examined representing the current renewable energy mix (year 2024), an intermediate level of renewable energy mix (year 2036), and a high degree of renewables penetration (year 2050; Figure 24) for a representative wet year (using 2013 hydrologic data) and dry year (using 2012 hydrologic data). Figure 25 panels a and c show total daily generation by facility and panels b and d show total power generation by month and facility.

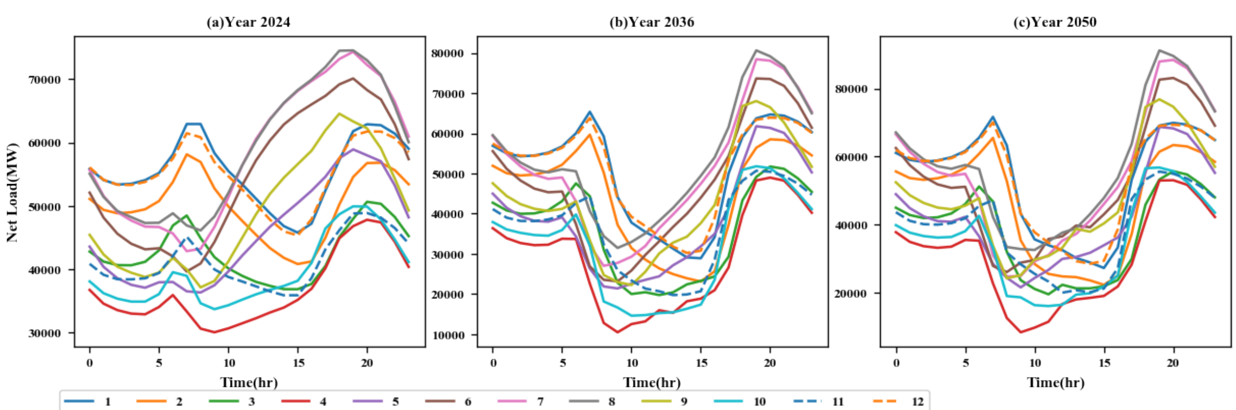


Figure 24. Average Monthly Load Shapes for (a) Year 2024, (b) Year 2036, and (c) Year 2050

These years were chosen to better understand how power system (generation and revenue) and environmental outcomes (young largemouth bass survival) will respond to environmental regulations that limit hydropower operational flexibility. Detailed hourly modeling was conducted for year 2036 to better understand how generation revenue and young largemouth bass survival would respond to flexible generation designed to follow LMPs both with and without nighttime flow restrictions.

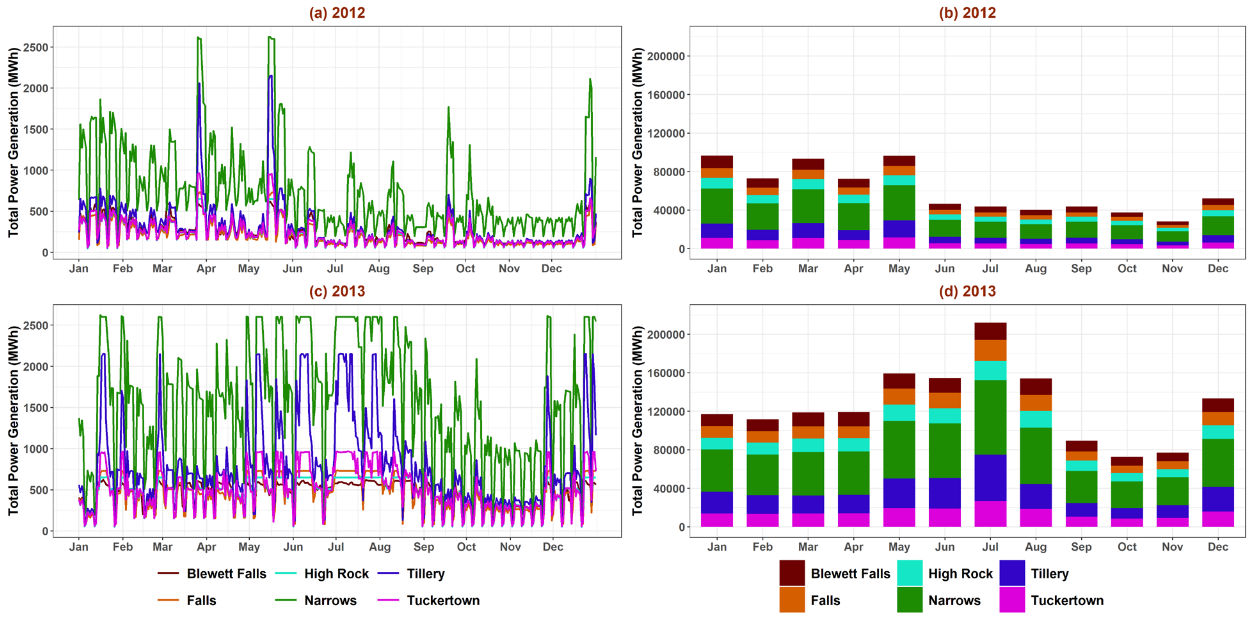


Figure 25. Yadkin-Pee Dee Hydropower Generation for a Dry Year (2012) and a Wet Year (2013)

4.3.2 Results and Discussion

This case study demonstrated that across the scenarios explored here, both energy and environmental objectives can be met while generating higher revenue compared to the CHEOPS model. In this case, restricting nighttime flow fluctuations allows for higher young largemouth bass survival in the 2024 scenario (Figure 26). This scenario allows for flexible generation during the day, following LMPs, while restricting this type of operation overnight when flexibility is less crucial for grid stability and less lucrative. This was apparent during the 2024 high-flow scenario where young largemouth bass had significantly higher survival with nighttime environmental flow restrictions, although nighttime restrictions also consistently showed higher (but not significantly higher) survival across early life history stages. While modeling additional environmental outcomes and scenarios was beyond the scope of this study, other energy–environment win-wins likely could have been identified.

In this case study, we were able to discern similar trends in impacts from reservoir operating policy across the three LMP datasets representing current and future grid needs. Ultimately, we showed that imposing the nighttime environmental policy using the optimization approach provided adequate flexibility in reservoir operations to respond more effectively to grid needs while maintaining desirable flows for fish species. This finding was true across the 2024, 2036, and 2050 scenarios. While we recognize that the benefits for fish species were small, we also realize that further iterations between policy changes and evaluation would allow us to refine the policy in such a way that we would expect greater benefits. There is opportunity to develop scenarios representative of other systemwide uncertainties, such as climate change scenarios, apply this framework, and identify policies that show improvement or desirable results across multiple plausible scenarios rather than develop policies that are tailored to specific representations of uncertainty.

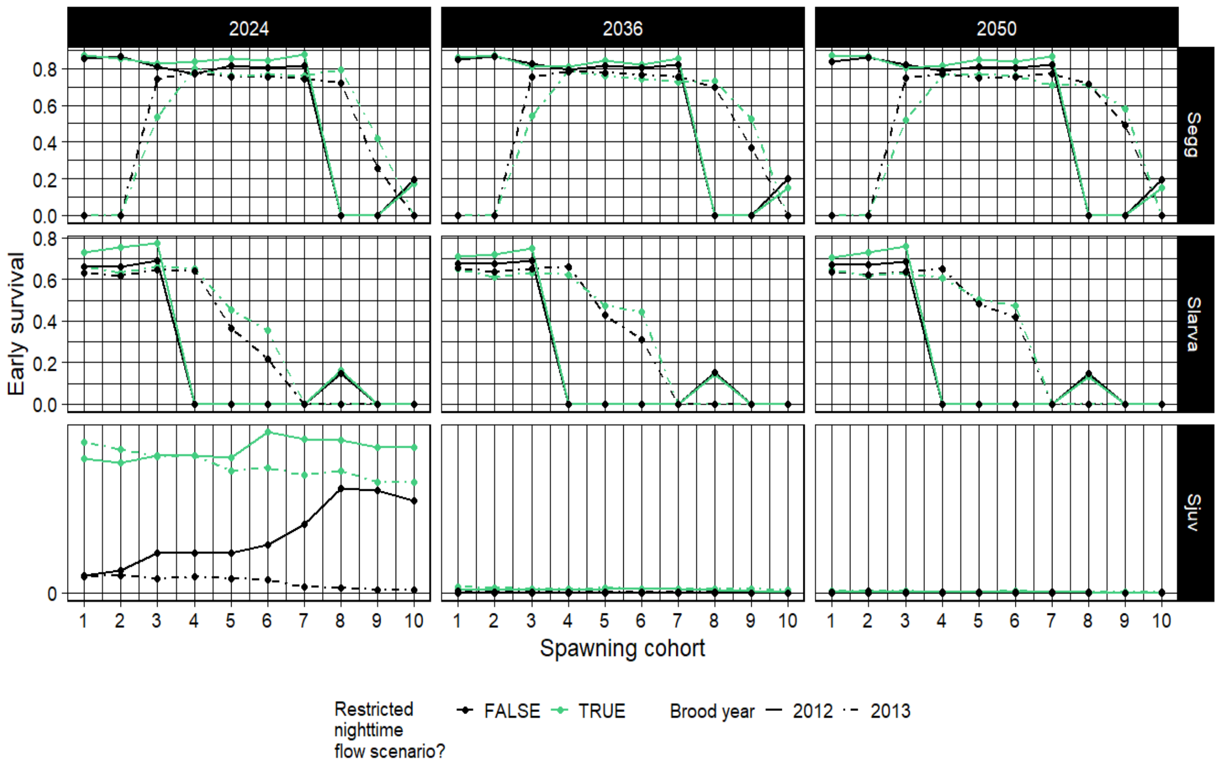


Figure 26. Early Life History Survival Under Nighttime Flow Ramping

High flow was identified as the most dramatic source of decreased survival for largemouth bass across their early life history, although cold shock also caused decreased survival for eggs and larvae. Figure 27 shows survival due to six causes under different operational scenarios for each of three early life stages. Lines connect median values averaged across spawning cohorts for each cause. Individual points represent different brood years. Abbreviations are Env = nighttime ramping restriction, NoEnv = no nighttime ramping restriction, EnvAHigh = unrestricted daytime ramping with nighttime ramping restriction, NoEnvAHigh = unrestricted daytime ramping with no nighttime ramping restriction, and NoEnvALow = load-restricted ramping. These sources of decreased survival may differ between species, life stages, locations, or times of year fish are spawning. However, partitioning environmental impacts in this finer scale may provide additional opportunities for energy–environment win-wins.

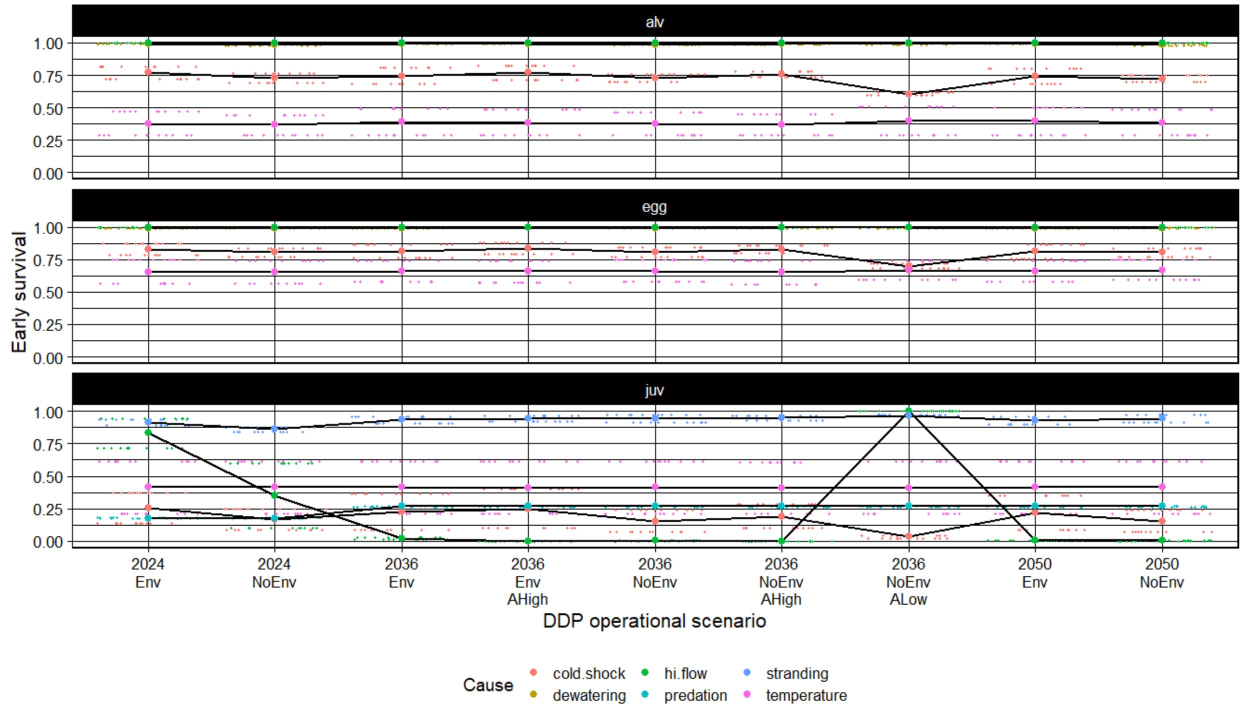


Figure 27. Survival Under Different Operational Scenarios

Differences in generation between the CHEOPS and DDP models within year types (i.e., wet year, dry year) had only modest differences, but differences in revenue between the models were large (Figure 28). All scenarios were held to the same approved hourly generation budgets, yet we were still able to identify operations yielding higher revenue by using the DDP optimization model that would help to target generation during times with high LMPs. By operating the reservoirs in a more coordinated fashion, the optimization helped to gain generation flexibility and benefit to the system within defined constraints. This has implications for other systems that may currently be operated in a simplified manner but could benefit from more sophisticated operational decision-making to satisfy both grid and environmental needs.

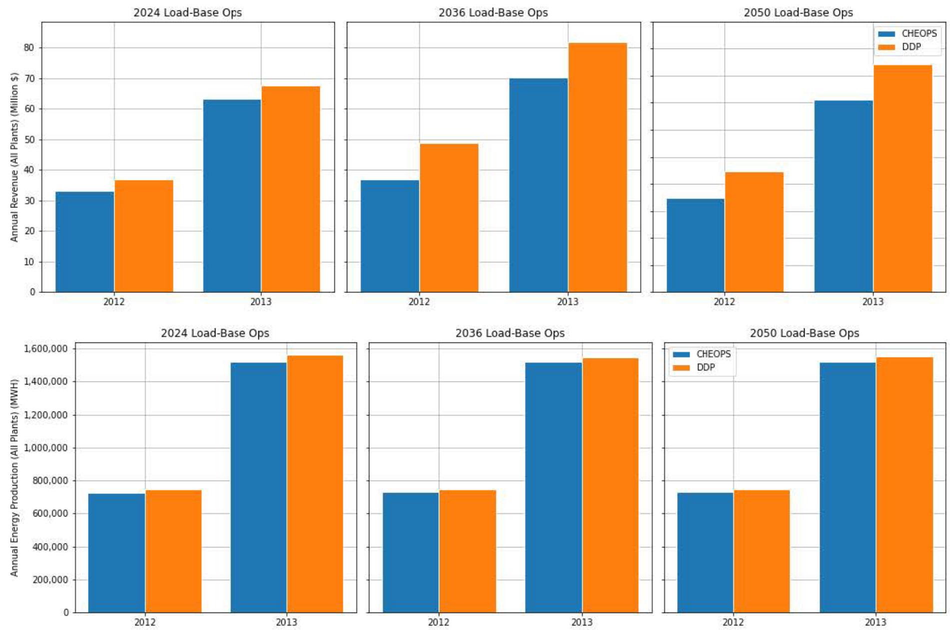


Figure 28. Annual Revenue (top) and Energy Production (bottom) for Base Case Load Scenarios Using CHEOPS (blue) and DDP (orange) Models

The DDP model also made it possible to find energy–environment win-wins within wet and dry year simulations of load scenarios for year 2036. In this future renewable energy penetration projection, unrestricted daytime ramping with no nighttime ramping had the third highest revenue of the six scenarios for the wet and dry year simulations, although there was, again, limited differences among scenarios in generation (Figure 29). In fact, the base ops with no nighttime ramping policy—still an environmental benefit— also had higher generation revenue than the CHEOPS base operations and restricted ramping operation for both wet and dry year simulations.

In FERC licensing efforts, rule-based simulation models (like CHEOPS) are often used to represent operating policy and evaluate how reservoir systems operate across many years. These models can make broad assumptions regarding power generation and the needs of the grid that may obscure finer-scale environmental impacts. Although appropriate for understanding the total generation for a system, the simplifying assumptions can limit understanding how the needs for hydropower generation shift over time and may obscure finer-scale environmental impacts and changes over time. For instance, with greater renewables penetration, we anticipate that the value of hydropower will shift from solely being of interest for providing direct generation to its ability to provide supporting services through flexibility. Likewise, the simplification of rule-based simulations can also limit discovery of win-win or win-no loss outcomes and evaluation of tradeoffs. For example, by being able to restrict peaking to daytime hours when LMPs are highest, the DDP model was able to find a solution that both benefited young largemouth bass survival and increased revenue compared to the rule-based model.

Interestingly, we found LMP datasets that span from the present day into the future with different assumptions regarding degrees of renewable buildout to be useful even without executing site-specific PCM modeling. While we recognize the limitations of using LMPs to inform the complete value that hydropower currently provides or will be asked to provide in the future, even generalized LMP datasets can be used in a manner like that employed for this case study to assess how the value of generation could change in the future for an individual facility.

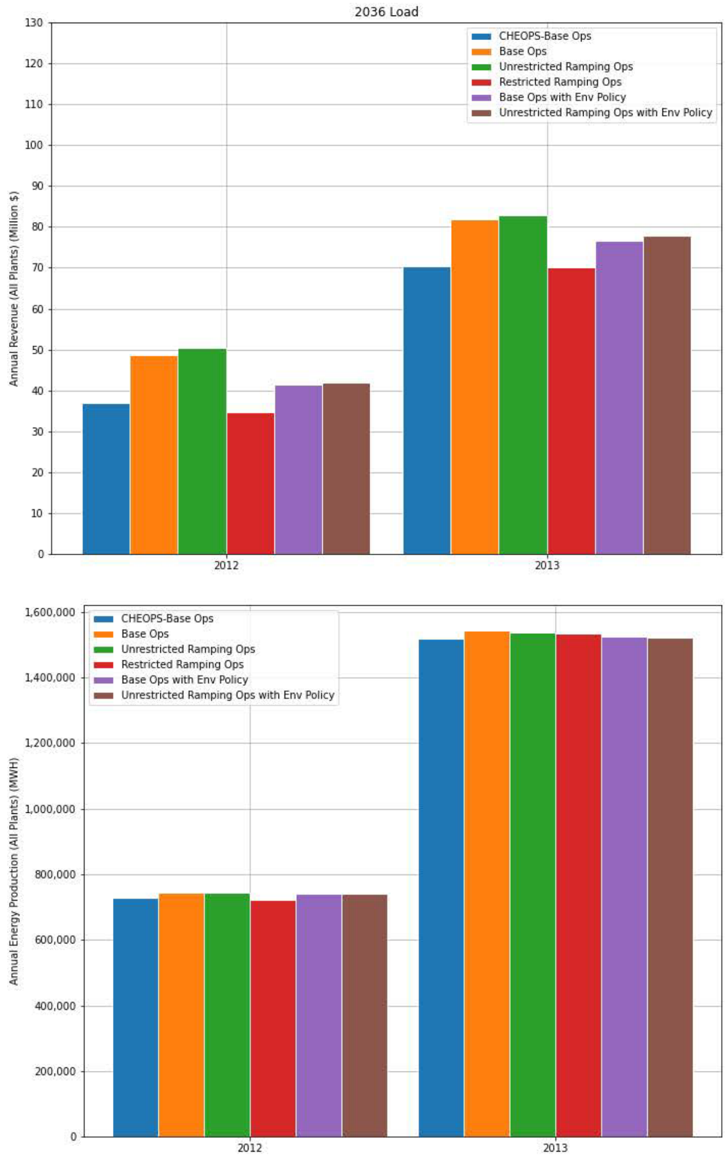


Figure 29. Annual Revenue (top) and Generation (bottom) for 2036 load Alternative Operating Policies Scenarios

The ability of hydro plants to quickly respond to market prices (LMPs) increases potential higher revenue than operating for fixed capacity levels. Shorter time resolution PCM indicates shorter term price variation, which can be realized as energy or ancillary service prices RT power market. These sub-hourly operation changes, which are not constrained by ecological requirements, can be enabled from investing for technical capabilities (e.g., auto governor control) to maximizes the hydropower revenue. While reduced time-lags between generation responses to price signals may increase revenue in a way that is agnostic to environmental impacts, little is known about the ecological impacts of short-term flow fluctuations and should be a high-priority subject of additional research.

5.0 Conclusions

As greater penetration of intermittent renewable generation sources in the grid occurs, the role of hydropower will become more important to providing grid reliability as a key source of ancillary services. However, the flexibility of hydropower that makes it so potentially useful for the future grid also can result in environmental impacts that are unacceptable to many stakeholders and regulatory process participants. And while there are burgeoning strategies for mitigating some of these impacts, such as using batteries coupled with hydropower to provide some flexibility rather than relying entirely on ramping the hydropower plant up and down, those solutions are not yet mature and will still require energy–environment tradeoff assessments in both the interim and long term. Providing frameworks and tools for making these tradeoff assessments is especially crucial to preparing for a future with a high penetration of intermittent renewables because flow requirements which, by definition, limit operational flexibility, are the most common instrument for protecting and improving environmental outcomes.

While the products of this initial energy flexibility–environmental tradeoff project do not provide a direct and generalizable solution to making energy–environment tradeoffs, when taken together they illustrate a diversity of approaches, scales, and pieces of frameworks for finding energy–environment win-wins and making tradeoff assessments.

- The instream flow dataset we created from 50 randomly selected FERC licenses provides insight into the types of flow requirements that may need to be evaluated with tools or frameworks created and investigated by this or future projects. We found that ecological outcomes, particularly those aimed at protecting fishery resources, are by far the most common target of flow requirements across all regions. The importance of protecting fishery resources through flow requirements indicates that valuation tools must be able to simultaneously value both ecological/biological and energy outcomes.

- The first step in assessing energy–environment tradeoffs for hydropower is gaining a mechanistic understanding of how energy and environmental outcomes are influenced by flow. The linkage diagram we created provides some of those pathways, in addition to a model and tool database that can help quantify and place value on these outcomes.

- Both the Yadkin-Pee Dee and GCD case study demonstrations provide examples of simultaneous assessment of energy and environmental outcomes of flows and generate both environmental (fish survival— Yadkin-Pee Dee; fish growth and sediment transport—GCD) and energy (revenue) outcomes. The Economic Valuation Tool case study demonstration provides a method of economically valuing a suite of flows with the assumption that the flow being valued was designed to meet a specific environmental need. Combining approaches used across these case studies may allow for a comprehensive framework for valuing energy–environment tradeoffs in hydropower regulatory proceedings.

This project has identified several important research gaps and challenges that must be addressed in addition to creating pathways for evaluating energy–environment outcomes.

- Coupling batteries with hydropower systems has been suggested as a mitigation for negative environmental effects of hydropeaking. Continuing assessments may be warranted as battery technologies advance. Tools that can provide this tradeoff assessment would be useful.

- Simultaneous valuation of economic and ecologic/environmental in a way that is geographically generalizable presents a challenge for creating tools with broad applicability. Software tools created to assess energy-environment tradeoffs must overcome the challenge of containing flow, economic, and ecologic input options that can account for the site-specific needs of each hydropower plant while still being general enough to provide insight to most hydropower facilities.

- Truly valuing flexibility has special challenges that must involve assessing ancillary services and effects of repeated and chronic flow fluctuations on fish and other aquatic biota. Coupling this assessment with other energy–environment tradeoff assessments is critical for fully understanding how economic and environmental outcomes are influenced by hydropower.

- Decisions on hydropower flow requirements are made on a facility-by-facility basis. Since other flow requirements and their energy impacts are not considered on a larger scale, it is possible there could be a cumulative impact on flexibility at many facilities that could impact reliability and manifest at the grid scale. However, this may not be the case, but there is currently no understanding how or if the flexibility impacts of flow requirements on one facility scale to the grid scale. Current proposed solutions to decreasing FERC licensing timelines involve conducting basin-scale licensing assessments; similar solutions to improving grid reliability by considering grid-scale needs in licensing assessments may be useful.

- Using forecast-informed reservoir operations can allow for better operations, potentially reducing some of the negative impacts of hydropower operations. Using this information to reduce uncertainty in operations planning allows for more environmental flows that can meet the requirements put in place by hydropower regulatory processes.

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Appendix A – Detailed Methods and Results for Chapter 2: Characterization of Environmental Flow Requirements from FERC Hydropower Licenses and Their Implications for Flexible Hydropower Operation

Approximately 55% of nonfederally owned hydropower facilities in the United States are required to obtain a license from FERC (Uria-Martinez 2017). The hydropower licensing process is stakeholder-driven and brings together a diverse body of stakeholders from natural resource, recreational, and industry interests as well as regulators from municipal, state, federal, and tribal jurisdictions. In this process, stakeholders are involved in determining the environmental impacts of the project and how or if to study and/or mitigate them. Topics addressed during negotiations include biota and biodiversity, water quality, geomorphology, connectivity, water quantity, landscape and landcover, recreation, cultural, historic, and aesthetic resources depending on stakeholder priorities and regulatory requirements (Parish et al. 2019; Pracheil et al. 2019; Aldrovandi et al. 2021).

Table 1. Instream Flow Requirement Information from Protection, Mitigation, and Enhancement Sections of 50 FERC License Orders

Term	Description
Facility Type	Location at facility where instream flow requirement applies. Options are bypass reach, canal, fish passage, project works (e.g., penstock, power tunnel), sluiceway, project/facility.
Flow requirement dates	Days of the year flow requirement must be met.
Flow requirement days	Days of week flow requirement must be met.
Restriction Start	Time of day flow requirement begins
Restriction End	Time of day flow requirement ends
Drought Level	Type of water year for which a flow requirement is designed. Options are wet, dry, and normal year. In cases where the flow requirement was not designed for a water year type, this field is blank.
Augmentation type	Type of environmental outcome flow requirement is designed to improve. Options are fishery/habitat, recreational/boating, industrial, or general.
Flow type	Type of flow requirement. Options are minimum flow, maximum flow, prescribed flow (a specified flow or flow range that project must maintain), or ramp rate restriction.
Augmented flow rate	Actual flow requirement in cfs where possible, although some are qualitative descriptors.

Appendix B – Flow–Energy Outcomes, Flow–Environmental Outcomes Linkage Maps Described in Chapter 3: Enabling Assessments of Environment–Energy Flexibility Tradeoffs in Hydropower by Linking Power System and Environmental Outcomes Through Flow Releases

Appendix C – Flow–Energy Outcomes, Flow–Environmental Outcomes Linkage Maps Supporting Model and Tool Database Described in Chapter 3: Enabling Assessments of Environment–Energy Flexibility Tradeoffs in Hydropower by Linking Power System and Environmental Outcomes Through Flow Releases

(link to Excel file)

Appendix D – Detailed Descriptions of Linkage Map Components for Maps Described in Chapter 3: Enabling Assessments of Environment–Energy Flexibility Tradeoffs in Hydropower by Linking Power System and Environmental Outcomes Through Flow Releases

D.1 Power System Submaps

D.1.1 Hydromechanical Processes

Hydromechanical processes within the context of hydropower can be divided into two main sub-areas. These are, as shown in the hydromechanical submap of the Linkage maps, a) dam characteristics and b) turbine/generator. As also shown in the submap, hydromechanical characteristics are influenced by the flow regime of the body of water that is being used to generate electricity (i.e., flow through turbines). Each of the sub-areas directly related to hydromechanical characteristics of hydropower are discussed in detail in the subsequent subsections.

The flow downstream of hydropower system in the Linkage maps is the total water flow going downstream of the dam through the hydropower turbines and does not include nonturbine flows.

D.1.1.1 Dam

Hydromechanical energy conversion processes at hydropower facilities depend on characteristics of the dam impoundment and reservoir. Characteristics in our diagram included “impoundment height,” “penstock length,” “spillway design,” and “valve opening/closing speed.” These characteristics work together to influence flow regimes through the turbine machinery at hydropower facilities. Specifically, the impoundment height and penstock characteristics of a facility directly affect key hydropower parameters, such as “net head” and “channel velocity,” which in turn influence how much power can be generated by the power plant.

The intimate connections between physical attributes of the dam and power-generation output also influence hydropower operational metrics and parameters. Net head and channel velocities both work as indirect inputs to calculating parameters represented in our diagram, such as “head-dependent water-to-power ratio,” “reservoir volume limits,” and “time-dependent reservoir volume.” In turn, the dam itself, through time-dependent reservoir volume, is connected to “output capacity,” which represents the power output of the generating units at the hydropower facility. In much the same way, channel velocity directly influences output efficiency of the generating unit and, through a phenomenon known as water hammer, affects the generating unit's setpoint, pumped storage, or generation decisions and generator availability.

D.1.1.2 Turbine/Generator(s)

Hydro turbines convert the energy of rushing water into mechanical energy to drive a generator. These turbines rotate or spin as a response to water being passed through their blades. The generator then converts the mechanical energy into electrical energy. In hydroelectric facilities, this combination is called a generating unit (Donev et al. 2020, Renewables First, Energypedia, OpenLearn, Sorensystems).

Two main technical characteristics that parameterize hydroelectric generators/turbines are their efficiency (%) and capacity (MW). The three mechanical components that synthesize the overall efficiency of a hydro facility are the pump efficiency, turbine efficiency, and generator efficiency. In general, hydroelectric facilities are one of the most efficient means of producing electric energy. Conversion efficiencies can be as high as 95% for large installations and between 80–85% for smaller plants with output power less than 5 MW. In pumped storage hydropower facilities, the term round-trip efficiency is usually employed to measure the energy lost by converting electricity to gravitational potential energy and then converting it back into electricity. Typical round-trip efficiencies of pumped storage vary between 70–80%.

Like efficiency, the overall plant's capacity (MW) is also synthesized by the three capacities of the individual components (pump, turbine, generator). Capacity is the maximum level of electric power (electricity) that a power plant can supply at a specific point in time under certain conditions. Large hydropower plants can reach capacities that exceed 6,000 MW. In pumped storage, capacity is subject to charge rate limits related to the pump's technical characteristics. Ramp rate limits, which indicate the rate at which a hydropower facility can increase or decrease its generation output, could also constrain the capacity of pumped storage and conventional hydropower facilities, especially in cases where the ramp rate requirement is higher than the rate limits.

D.1.2 Hydroelectrical Processes and Pumped Storage

Hydroelectrical processes mainly consist of power generation and pumped storage. As shown in the hydroelectrical processes submap of the linkage maps, these can be broken into three main sub-processes: a) power system analysis; b) market operation analysis; and c) long-term energy system analysis. Each of these are discussed in detail in the following subsections.

D.1.2.1 Power System Analysis

There are two main aspects of power system analysis.

1) Steady-state power-flow or load-flow analysis is the study of a power system's capability to have balance, which is to have adequate supply to feed the system load. Using alternating current power-flow analysis, the values of voltage magnitude (V), phase angle (δ), real power (P), and reactive power (Q) are calculated at each bus of the power system model, along with the total system losses and individual line losses. There are multiple methods for conducting the power-flow analysis: the Newton-Raphson Method; Gauss-Seidel Method; Fast-Decoupled-Load-Flow Method; and Holomorphic Embedding Load Flow Method. There are multiple modeling tools that have the capability to conduct a steady-state load-flow analysis. In addition to the power-flow analysis, some of these tools also have the ability to calculate unit-commitment (using automatic generation control) and economic dispatch, also known as the optimal power-flow analysis. The optimal power-flow analysis provides the conditions for least cost per Kilowatt hour delivered. Some modeling tools that have the capability to conduct steady-state power flow along with optimal power-flow analysis are shown as tags attached with the analysis topic in the hydroelectrical characteristics submap of the linkage maps, including PowerWorld, PSS/E, PSLF, Matpower, and Pypower.
2) Transient stability analysis is the study of the system's temporal behavior and health, which measures the system stability following a disturbance/contingency over a very short period of time (approximately 0–60 secs). This is done using dynamic models of system assets including all types of generators (such as natural gas, hydro, and wind) and loads. The response of all system assets to a disturbance is measured using system frequency as a metric. The responses provided by all generators to any contingency (time t = 0 secs) are characterized as: a) inertial response (between t = 0–10 secs); b) primary frequency/governor response (between t = 5–60 secs); c) secondary

frequency response (between t = 60–300 secs); and d) tertiary frequency response (for t > 300 secs). There are many different modeling tools that have the capability of carrying out dynamic stability analysis. All of these tools only evaluate the transient stability over the first 60 secs maximum and thus only capture the inertial response and primary frequency response provided by generators. Some of these tools are PowerWorld, PSS/E, PSLF, and Dynamic Contingency Analysis Tool.

The results of power system analysis contribute directly to system reliability and the extent is measured using standard reliability metrics such as the loss of load expectation, system average interruption duration index, system average interruption frequency index, customer average interruption duration index, etc. Power system analysis contributes to other aspects of reliability such as system stability and N-k security as shown in the hydroelectrical characteristics submap of the linkage maps. Using power system analysis tools and methods, we can directly draw a link between hydropower generation and its contribution to power system reliability and all its different aspects.

D.1.2.2 Market Operation Analysis

Market operation analysis refers to the methods used by electricity market participants (e.g., power producers) and relevant decision agents (e.g., independent power system operators) to answer a range of operational questions, including how economically a power system operates and the financial value (i.e., profits) of generation resources that participate in electricity markets. In general, there are two dominant market operation methods that are represented by different modeling frameworks presented below.

1) *Least production cost models*

   Least production cost operational models (also referred to as PCMs or unit-commitment models) belong to a family of mathematical optimization problems that minimize power systems operating costs subject to a range of plant-specific constraints, system-level constraints, and environmental constraints (e.g., water availability). Power systems' operating costs are variable (typically accruing proportionally with demand); they largely consist of fuel costs and startup/down costs of the generating units. Constraints on individual generating units include the minimum and maximum generation capacity limits, minimum up and down times (time required for a unit to be turned on or off), and hour-to-hour ramping limits. System-level constraints include power balance (supply = demand) and constraints on the provision of ancillary services, as well as the maximum and minimum power-flow capacity limits of the transmission lines.

   In PCMs, hydropower facilities are subject to hydraulic constraints. Because of the link to water systems, we observe diversity in hydraulic representations that we categorize into exogeneous and endogenous. In the exogenous representation, a river-routing reservoir operations model optimizes individual power plant operations according to water management objectives and in response to projected electricity prices, or dynamic prices in the case of co-optimization models. The hourly generation at individual hydropower plants is then input to the power system operational model and is considered as "must-take" by the unit-commitment process at each timestep. The river-routing reservoir operations model and power system operational model can be run in sequence with a prescribed frequency (hourly or daily) to update information (price and generation) over the operating horizon and not overly constrain the power system model dispatch.

   In this representation, hydropower potential is endogenously scheduled by PCMs in one of two ways that we refer to as modes of operations according to the hydroelectrical characteristics submap of the linkage maps:

   a) Proportional load following: A portion of the hydropower generation available is assigned to follow the system's load shape within provided minimum and maximum generation capacity and energy limits. A proportionality constant (usually referred to as K value) is calibrated at each plant, reflecting the plant's ability to adjust to load variations.

b) Hydrothermal coordination: A portion of a hydropower plant's available generation is dispatched in accordance with the overall model's cost minimization objective (meaning hydropower is scheduled during the highest marginal cost hours). The hydrothermal coordination representation relies upon the proportional load following generation schedule, which is further modified by a proportionality constant (usually called the p factor). This factor represents the fraction (between 0 and 1) of a plant's capacity that can adjust its output based on market price.

2) *Profit maximization models*

a) Profit maximization models seek to maximize profits of independent power producers (IPPs) from participating in electricity markets (i.e., capacity, energy, ancillary services) with their generation resources. In these models, IPPs optimally self-schedule the timing and level of power production from their entire fleet of generators in response to a time series of energy and ancillary service prices (i.e., electricity price forecast, both DA and RT). The underly assumption of these models is that IPPs own a relatively small share of the total generation capacity in the market and do not have control over the market prices. Given some information about hourly prices, IPPs bid into the energy and ancillary service markets subject to the generating unit technical constraints, system-level constraints, and emission constraints. IPPs often employ advanced short-term, mid-term, and long-term forecasting techniques (i.e., neural networks) to better align their offers with the periods of highest prices.

b) Profit maximization models can provide a range of power grid services including energy, capacity, and ancillary services. Ancillary services are further categorized into black start, frequency regulation, and spinning and nonspinning reserves, and are directly related to ensuring the reliability and resilience of the power grid via resisting power outages (N-k security), increasing power grid adaptivity during resilience events and having the capability to recover faster.

D.1.2.3 Long-term Power System Analysis

Planning in the electric power sector is a strong example of the multiple criteria decision-making process. Not only does the power sector have a diverse set of stakeholders, all with unique and sometimes competing goals, but operation of the power system is also influenced by decisions made over timeframes spanning from microseconds to decades.

Within the hydroelectric generation and pumped storage hydro map, long-term planning has a submap of its own with child nodes that are heavily interdependent. For planning decisions made over the annual or decade timeframe, energy system stakeholders have three fundamental categories of analysis motivations: electricity security risk; energy policy; and economic (or least-cost) planning. Long-term power system analyses based on electricity security risk have gained momentum in the last few decades with the increase in computing power and the ability to model complex systems. An example of risk-based planning is the study of climate change on the behavior of the power system. Energy policy-motivated planning analysis for the power system is usually by state or federal technology or emissions mandates. One example of such a standard is the renewable portfolio standard mechanism in the United States. Economic, or least-cost, planning analysis evaluates how the power system could be expanded, contracted, or reconfigured and how those actions could satisfy the goal of serving the required power demands of customers at the least cost. Economic analyses are usually conducted by regional transmission organizations, independent system operators, balancing authorities, and utilities. Economic long-term analysis forms the foundation for electricity rate case filings.

All three motivation categories of long-term planning for power systems lead to three major categories of quantitative analyses—resilience forecasting, electricity demand forecasting, and climate and natural disaster forecasting—all within the context of the electric power system. Resilience forecasting in the context of long-term power system analysis is focused on adequately meeting electricity demand needs using grid-connected capacity resources. This facet of long-term planning is not only concerned with generator capacity, but also transmission and distribution electrical infrastructure. Reliability and resilience forecasting is a process linked with valuable guidance documents such as integrated resource plans (IRPs), fuel security plans, transmission expansion plans and renewable integration plans. The recommendations generated during the reliability and resilience forecasting process drive investments for capacity resources on the power grid. When capacity resources are constructed, retired, or reconfigured to support long-term grid reliability and resilience, power system outcomes including grid reliability (e.g., metrics, stability/inertia, and N-k security), capacity and ancillary service revenues, and power system recovery time are influenced. Hydropower contributes directly to power system outcomes linked to reliability and resilience forecasting by providing power system operators with a dispatchable power-generation capacity resource. Hydropower units can ramp up and down relatively quickly, contributing directly to power system stability, ancillary services (and revenues), and power system recovery times.

Electricity demand forecasting, sometimes called load forecasting, is conducted by system planners to inform decisions related to power system adequacy based on customer needs. Here the focus is on electricity end-use rather than grid operator-controlled assets. Demand forecasting is a foundation-level process for the development of IRPs, fuel security plans, transmission expansion plans, and renewable integration plans. The set of plans that are linked with electricity demand forecasting lead grid operators to invest in assets that ensure the ability to always match electricity supply with demand. Investment decisions by grid operators and IPPs based on demand forecasting affect all the power system outcomes characterizing the power grid's reliability and resilience. Hydropower plays an indirect role in electricity demand forecasting through the connection between load forecasting and reliability and resilience planning. Hydropower's quick ramping ability is an attribute that allows hydropower generating units to closely follow load levels.

Although power system planners have long considered climate, weather, and natural events in their planning processes, recent advances in the understanding of climate science and climate change on regional, national, and global scales have caused more integration of climate and natural event forecasting in long-term power system planning. All three major segments of the power system—generation, transmission, and distribution—could be threatened by increasing frequency of extreme temperature events, rising sea levels, hurricanes, tornadoes, earthquakes, and many more natural or climate phenomena.

Climate and natural event forecasting is now linked with and an important part of IRPs, fuel security plans, transmission expansion plans, and renewable integration plans. The extent to which this area of planning is considered is organization specific; however, even if not explicitly stated in planning documents, power system planners consider the effects of climate and natural events on the long-term adequacy of the power system. During operation of the power system, hydropower resources offer a reduced emissions impact over other dispatchable technologies burning fossil fuels. Climate and natural event forecasting’s contribution to power system planning documents often leads to investments that reduce the overall power grid's carbon footprint. Hydropower assets can help achieve lower emissions. Investments in hydropower motivated by climate forecasting can also contribute to climate adaptation efforts through power system reliability and resilience outcomes. Here, based on context driven by environmental factors, the flexibility of hydropower units either boosts the grid's adaptability to changing weather and natural phenomena, or is constrained by the hydrological effects of climate change.

D.1.3 Hydropower Performance Outcomes

The three main processes at play within the electric power infrastructure system—power flow, market operation, and long-term planning—are all driven by improving a set of electric power system performance outcomes. At the highest level, the main performance outcomes fall within the categories of reliability, resilience, revenue, and emissions. The first two outcome categories are inherent, physical system outcomes related to how the system is operated and managed, and the second two outcomes are based on other systems that are directly influenced by the operation of the power grid, in this case financial and earth systems.

D.1.3.1 Reliability

We define the term reliability as the ability of an alternative electricity source to consistently meet electricity demands without disruptions in energy supply. Hydropower is one of the most reliable and inexpensive sources of electricity because it efficiently and consistently converts water's kinetic energy into electricity. Hydropower can generate a baseload supply of electricity and can adjust output to meet electricity demand. As long as flowing water is available, hydropower plants of any size can reliably generate electricity.

Unlikely solar and wind, hydropower can serve as both a baseload and peak power source. A baseload source is an energy source that can meet the minimum level of energy demand for a given area. Baseload power sources are able to supply the electric grid with an almost constant flow of energy that can meet electricity demand throughout the day. Hydropower can consistently meet demand because hydroelectric plants are always operational, except when maintenance must be performed. Peak power plants augment baseload power sources when electrical demand reaches its peak levels during the day. Although hydropower is often used as a baseload power source, it can also function as a peak power source. Most hydropower plants can increase the level of water flow their turbines receive, thus augmenting power output to meet peak demand.

D.1.3.2 Resilience

Closely related to reliability, resilience of the electric power grid is also an important performance outcome that stakeholders in the energy industry consider. In our formulation, we define resilience as the power system's ability to resist, adapt to, and recover from outages (Cicilio et al., 2021). As a flexible, dispatchable generation asset on the system, hydropower contributes to resilience directly through the way the systems can respond to power-flow analysis signals and market/price cues with relatively short lead times (on the order of minutes) (Phillips et al., 2020). System planners often integrate this flexibility into their planning studies of various timeframes. Because of these two facts, all three of the main processes in the power system directly influence resilience in one way or another.

Resistance of power outages is created through hydropower through long-term planning documents that guide investments in units and their operation modes assumed in longer planning horizons. IRPs at the utility level and fuel security plans (FSPs) at the utility, regional transmission organization/independent system operator, or regional level are the most directly applicable long-term planning documents that influence resistance to outages. These planning documents often consider seasonal and annual hydropower output using various methods to capture constraints on generators' flexibilities.

The power grid's ability to adapt to power outages is not only influenced by IRPs, FSPs and even long-term renewable energy integration plans in the same way resistance is, but also adaptation is affected by market mechanisms that have evolved as the power system has expanded across the world. Power markets in some regions have begun valuing and paying for services provided by electric power generators such as black start. According to Knight (2001), black start can be defined as "the process of restoring an electric power station or part of an electric grid to operation without relying on the external electric power transmission network to recover from a total or partial shutdown." This process could be achieved by hydropower generators by opening penstocks and running water through units when the grid is out to re-energize the local transmission system, assuming that water levels are sufficient to achieve this.

Black start ability of hydropower systems also contributes to the power grid's recovery time from outage events. Long-term system planners take this into account in their IRPs and FSPs as well as a common practice. In this way, both market operations and planning processes are influenced by hydropower's presence on the electricity grid.

D.1.3.3 Revenue

Hydro resources can provide a large array of revenue sources. Revenues can be classified in three main categories:

1) Arbitrage: This involves purchasing inexpensive electric energy to pump water uphill and then storing it to produce and sell electricity when the price is high. High volatility between on-peak/off-peak electricity prices drives energy arbitrage opportunities. As price gaps are volatile, arbitrage is often combined with other services, which brings additional revenues.
2) Capacity: This involves the ability to put quantities of energy on the grid. This service is essential since, at any given time, the quantity of energy produced must be equal to the quantity consumed. It implies that utilities have reserves into which they can tap quickly, thereby increasing the operator's revenue. Capacity is usually priced higher, which makes it financially attractive. Depending on location, capacity can be priced per hour, and with flexible hydro storage can be available for a specified period. Direct agreements between grid operators and plant owners can define the price. With this arrangement, grid stability is safeguarded, while plant operators are ensured a fixed income for the investment.
3) Ancillary services: FERC defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." These operations, which go beyond generation and transmission, help maintain grid stability and security while supporting the continuous flow of electricity so that supply will continually meet demand. They include frequency control, voltage control, and black starts. Hydro resources are suitable candidates to provide ancillary services as they can quickly ramp up and down to meet requirements.

D.1.3.4 Emissions

The emissions profile of the electric power industry has been a popular area of study in recent decades. Motivated by recent advances in earth and climate sciences research that points toward evidence of global climate change, power system stakeholders have begun planning for a changing planet. The main way electric power system stakeholders have been integrating an approach to addressing climate change is by advancing efforts to reduce the overall emissions of electric power generators. For decades, the grid has been dominated by hydrocarbon-burning, centralized power generating stations with uncertain climate impacts. As research uncovered that hydrocarbon climate impacts have been mostly negative, research efforts have been established to determine just how much low-carbon electricity could be generated for the power grid and what upgrades would be needed to achieve a zero (or near-zero) carbon electric power sector. Hydropower generators occupy a unique position to contribute to the emissions outcome of power systems as a zero-carbon resource once established, although the lifecycle carbon emissions of hydropower plants remain an area of open debate.

Power system stakeholders have turned to long-term planning efforts and established some limited market interventions to motivate power-generation companies to think about the long-term implications of their technology choices. In market operations, because of the flexibility and fast ramp times of hydropower units, operators have been increasingly dispatching hydro units in coordination with other unit types to help establish power-generation profiles that match shifting demands throughout the day and even over seasons. This process, called hydrothermal coordination, has a direct impact on the emissions profile of the power sector depending on how many hydro units are generating in relation to how many carbon-burning units are generating at any given time. Consideration is often given to these generation dispatch profiles, at least on a seasonal basis, in planning documents such as IRPs and renewable energy integration plans.

D.2 Environmental Submaps

Flow from the hydropower system can affect the environment through two primary means represented by "reservoir elevation" and "flow downstream of the hydropower system," and whether that flow is modulated through the turbines or not. Reservoir elevation (height of the water level) represented in the linkage map varies due to inflows, losses, and releases for various purposes. This regulation of water contained in the reservoir has consequences for both the upstream environment and processes that affect the upstream/downstream environmental outcomes and dam interface environmental outcomes. The flow produced downstream of the dam, regardless if it is being moved through the turbines for power production or through nonturbine routes, impacts the downstream environment as well as the upstream/downstream and dam interface outcomes. Because these environmental impacts of hydropower flow conditions differ across the landscape, we delineated the outcomes into three primary categories based on spatial positioning relative to the dam: 1) upstream outcomes; 2) outcomes relevant to upstream/downstream or dam interface; and 3) downstream. Although we categorized and structured the environmental impacts of hydropower in a hierarchical way, it is important to remember that many of these factors interact with one another and can function as feedback loops, which we aimed to illustrate through our linkage maps.

D.2.1 Reservoir Systems

Before discussing specific environmental outcomes, the environmental outcome maps all have a set of common nodes related to water balance for the reservoir and reservoir operating policy. The water-balance-related nodes include flow into the reservoir, consisting of total reservoir inflow and direct precipitation on the reservoir surface, reservoir evaporation losses, and diversions (note seepage losses are considered within the "dam safety and maintenance" nodes). Most of these are driven by natural variability in weather and climatic conditions, but are also influenced by external factors such as water demands or interactions with other reservoirs in a system of reservoirs. Flow into the river downstream of dams is also influenced primarily by natural flows, but also point discharges into the river.

The amount of water released from hydropower reservoirs is influenced by the aggregated combination of water uses, including needs for dam safety and flood management, recreation, agriculture, water supply, environmental flow requirements, and energy production needs. The combination of these factors is often referred to as the reservoir operating policy, consisting of the combination of policies governing when releases need to be made given various factors, such as the time of year, current pool elevation, inflows, downstream demands, energy needs, and operating objectives. The reservoir operating policy may also include consideration of inflow forecasts, where operations may be modified to release in a manner that more effectively uses the available water in a reservoir to meet needs given projections of future inflows.

The reservoir operating policy may involve clearly defined, closely regulated rules with little flexibility, or may be less rigorously defined and provide greater flexibility to operators to modify releases for particular flow ranges or pool-level operating ranges.

The degree of sophistication associated with decision making surrounding reservoir operations within an existing reservoir operating policy varies substantially between locations. Furthermore, a wide variety of tools are available to support real-time decision making, as well as tools to replicate decision making in a simulation environment (e.g., to support defining and evaluating operating policy alternatives during the FERC relicensing process). Application of the aggregate reservoir operating policy interacts heavily with both environmental outcomes and the energy generation needs for different locations.

D.2.2 Upstream Outcomes

Environmental impacts that are upstream of a dam are directly linked to reservoir elevation. As the reservoir water level increases or decreases, these fluctuations can affect geomorphology, habitat, biota and biodiversity, water quality and greenhouse gas (GHG) emissions, and recreational usage of the tributaries, streams, and rivers that feed into the reservoir, as well as the reservoir itself.

D.2.2.1 Upstream Geomorphology

Upstream geomorphology refers to the substrate structure and shape in the reservoir and in the tributaries, streams, and rivers above a hydropower dam. Flows through nonturbine pathways (e.g., gated/ungated spillways, sluice gates, bypass gates) can be modulated for purposes such as downstream temperature and/or dissolved oxygen (DO) regulation, minimum flows, or sediment flushing. The variation in nonturbine flow rates can contribute to variation in the efflux of sediments out of the reservoir and the rate of sedimentation in the reservoir. Concurrently, the influx of sediment from upstream to the reservoir and the rate of sedimentation in the reservoir are affected by flow rates both into and out of the reservoir (i.e., suspended sediments settle out of the water column to the bottom of the reservoir as the flow velocity decreases). As the reservoirs fill with sediment, the upstream geomorphology changes with formation of deltas (Stand & Pemberton 1928; Subcommittee on Sedimentation 2017).

D.2.2.2 Upstream Recreation

Dam operators work with local communities to design and develop recreational access and usage. Boating, swimming, fishing, camping, housing, and cultural site preservation are just some of the examples of recreational activities that can take place within hydropower water systems. Recreational activities above hydropower facilities can be impacted by flow variation because of the consequences on reservoir sedimentation rates and build up, reservoir elevation, flood control parameters, and accessibility. For example, increases in reservoir sedimentation can result in water depth that is too low for marina operations, and boat ramps can eventually become buried (Subcommittee on Sedimentation 2017). Reservoir elevation, which can be manipulated for downstream processes and energy needs, can result in too little water in the reservoir to sustain recreational activities. As elevation is reduced, access to the reservoir pool is decreased (i.e.,shoreline access is affected by the magnitudes of mud flats). If the reservoir levels are too low, boat ramps and docks can be rendered unusable, available reservoir area for boating and fish is decreased, and visitors to cultural sites or nature watching may decline due to less than desirable aesthetics (Platt 2000; Miranda & Meals, 2013). Further, if the rate of change of the reservoir elevation is too fast, boats may unexpectedly be stranded on dry ground. Lastly, downstream flood management constraints often limit downstream releases during large events, causing reservoir inundation of upstream recreational areas (e.g., swimming beaches, picnic areas, campsites) and cultural sites (Platt 2000). Reservoir flooding can also decrease the number of fishable areas in the reservoir and reduced catch probabilities as the fish populations are spread over larger areas (Miranda & Meals, 2013). The common metrics to quantify upstream recreation are the number of visitors, days of sufficient reservoir elevation, and frequency of inundation (flooding) across recreational activities (e.g., lake houses/docks, nature watching, cultural fishery, cultural site preservation, boating, and camping).

D.2.2.3 Upstream Habitat

Hydropower facilities can drastically alter both the aquatic and terrestrial landscapes by altering abiotic conditions and biotic composition. Dam construction and operation can result in the loss, fragmentation, and degradation of habitats that are essential for species survival. Dams can also limit access to important habitats for spawning and foraging and can impede migratory species from completing their lifecycle due to reduced or absent passages through a hydropower facility. Regulation of flow rates and variability can have consequences on upstream habitats by altering upstream geomorphology, water quality, biota and biodiversity, decomposition rates, and recreational activities.

Changes in upstream geomorphology, which can vary due to flow conditions, can result in changes to the physical structure of the aquatic habitat and the composition of substrate material. Sediment transport and rate of deposition can contribute to mass transport of pollutants and organic material, which can have broad sweeping effects on water quality and nutrient composition. These changes in abiotic parameters can affect the composition of habitat, amount of available habitat, suitability of habitat for organisms to inhabit them, and productivity/metabolic processes of habitat.

Hydrodynamic processes (i.e., reservoir stratification/vertical mixing, current velocity, shear stress on reservoir sediment, and discharge/flow rate and variability) can affect the rate at which organic material is decomposed. Changes in decomposition rates can shift the composition of organic compounds and available nutrients in the aquatic environment, impacting the productivity/metabolic processes of the habitat, as well habitat suitability and availability.

Recreational access and activities can also change the structure of and impact habitat availability and suitability. Moreover, recreational activities can contribute to fragmentation of habitats or even destructions of vulnerable, sensitive, or critical habitat types.

Upstream habitat can be quantified with metrics that determine habitat suitability, availability, productivity/metabolism, substrate, and fragmentation. Habitat suitability includes diversity (i.e., estimates of heterogeneity) and quality, which can be assessed at the individual (i.e., selection gradient) or population level through population growth factors. Parameters of population growth for species of interest (e.g., threatened and endangered, culturally important, fisheries, sport/recreational species, native, nonnative/invasive species) to be estimated are:

- Carrying capacity: Maximum population size of a species that can be sustained in a specific environment given the resources

- Rate: Number of births versus deaths, number of induvial at time 0 (N_0, where time depends on study objective), and number of individuals at time t (N_t, where time depends on study objective).

Habitat availability depends on the physical habitat but also the biotic community composition and species' abundances. Quantification of habitat availability includes habitat type area, resource abundance (i.e., count, mass) and organismal capacity to use resources available, which is not easily measured because it is relative to an organism's point of view. Therefore, measuring habitat availability is species and system dependent. The productivity and metabolic process of the habitat can be measured with chlorophyll concentrations, stable isotope analysis (e.g., carbon and nitrogen concentrations), and dissolved oxygen levels (i.e., concentration and concentration per unit time). Substrate is measured as substrate type classification (e.g., pebble, gravel, sand, silt, rock) and percent coverage. Habitat fragmentation occurs across three dimensions and can be quantified for each as longitudinal connectivity from headwaters to the sea, vertical connectivity from the river toward the hyporheic interstitial and groundwater, and lateral connectivity from the main channel to the floodplains.

D.2.2.4 Upstream Biota and Biodiversity

Environmental impacts of hydropower facilities can have varying effects across species, life stages, and individuals. Most model approaches base their biodiversity assessments in hydropower systems on water quality and habitat, primarily fish species focused. However, biota and biodiversity depend on both the upstream habitat and the biota and biodiversity downstream, as well as the capabilities of organisms to utilize fish passageways. Hydropower can also affect terrestrial biodiversity as the landscape is modified for generating facilities and land use practices can change in surrounding communities (e.g., forestry practices, rural to urban gradients). The impacts of hydropower on biota and biodiversity can range from the molecular and cellular scale up to ecosystem functioning.

The composition of whole communities (the type and amount of species present) can change due to alterations in flow regimes. For example, low-flow rates can result in increased water temperature and pollutant concentrations beyond the critical physiological limits for organismal survival or reproduction, which can cause extirpation of local populations. Standard metrics for community composition are alpha and beta diversity and estimates of community similarity/dissimilarity, which can all be modeled in the vegan R package (Oksanen et al. 2013).

Flow regimes can have sweeping impacts on specific species or taxonomic groups of species categorized here as fishes, crustaceans, mollusks, aquatic insects, vegetation, amphibians, reptiles, birds, and mammals. Within each taxonomic group the effects of flow can be quantified according to the impacts on organismal health, bioenergetics, population growth, and diversity.

D.2.2.5 Organismal Health

Organismal health encompasses the factors that can affect the ability to grow, reproduce, adapt, perform, and maintain homeostasis, categorized here as: parasites, disease, bioaccumulation and biomagnification, toxicity, performance (e.g., swimming), and fitness (fecundity and survival). Alterations to flow regimes can affect the way in which parasites, diseases, and contaminants are distributed and dispersed though the water column, availability and abundance of intermediate hosts, host species densities, and frequency and probability of transmission rates or exposure.

The effects of parasites on an individual can depend on whether they are ectoparasites or endoparasites and can vary in their host-parasite relationships/outcomes from beneficial to commensal to detrimental. To understand the effects of parasites on the host, as well as the eco/evolutionary dynamics of the parasite themselves and the consequences of flow, a number of metrics can and should be quantified. The first step is to know which species are present to understand the pathology of the parasite and its potential impacts on the host, as well as to understand parasite community diversity measured as alpha and beta. Second, quantifying prevalence (fraction of parasite-infected host individuals) and intensity (mean number of a parasite species per infected host) is needed to understand the costs of parasites on the host and the fitness of the parasite.

These three metrics—diversity, prevalence, and intensity—are most often measured alone and rarely simultaneous. However, newer model development demonstrates the importance of measuring all three parasite-host components to understand the cost of parasitism (Shaw et al., 2018). Further, studies on parasite-host eco/evolutionary dynamics demonstrate the need to understand the interaction between parasite-host genetic diversity and differentiation. Genetic diversity can be measured as allelic diversity (the average number of alleles per locus in a population) to estimate levels of heterozygosity, homozygosity, the number of alleles, and allelic richness. Single nucleotide polymorphisms can estimate levels of heterozygosity, homozygosity, haplotype diversity, and nucleotide diversity, and effective population size (N_e). Genetic differentiation can be measured as F_{ST} (fixation index or proportion of the total genetic variance contained in the subpopulation (S) relative to the total genetic variance (T)), F_{IS} (inbreeding coefficient or proportion of variance in the subpopulation contained in an individual), G_{ST} (average amount of genetic differentiation observed over multiple loci), and D (comparison of the average number of pairwise differences with the number of segregating sites, Tajima's D or Jost D). There are several software packages for estimating these metrics; however, we chose to highlight the package adegent (Jombart, 2008) in R because it is robust, widely used, and open-source. The software MLNe and SNeP are common programs for estimating effective population size (Wang & Whitlock, 2003; Barbato et al., 2015), as well as the NB package in R (Hui, 2014).

The consequences of diseases on macro-organismal fitness and survival depends on the type of disease-causing organism (viral, bacterial, or fungal), the pathogen community, and the characteristics of the pathogen. Similar to parasite infections, pathogenic infections are quantified according to species diversity, prevalence, load (synonymous with parasite intensity), and genetic diversity and differentiation. Other important metrics of consideration for pathogenic diseases are doubling time for viral and bacterial infections, carrying capacity, and growth rate, which all can be model with the tool Growthcurver (Sprouffske & Wagner, 2016). Pathogenic and epidemiological characteristics and metrics can be quantified and model with other tools such as Epi, epitools, DSAIDE, and EpiModel (Aragon et al., 2017; Handel, 2017; Jenness et al., 2018; Carstensen et al. 2021).

Flow mediation and variability can impact the dispersal and accumulation of contaminants and toxins in the environment and result in bioaccumulation, biomagnification, and toxicity in aquatic organisms. Tools such as FIAM, BLM, ICRP, and IEUBK can be used to quantify and model the impacts of contaminants and toxins through the environment and into organismal tissues (Burton, 1984; Campbell, 1994; Leggett, 1994; Pounds & Leggett, 1998; White et al., 1998; Paquin et al., 2002). The ways in which organismal bioaccumulation, biomagnification, and toxicity levels are measured include histopathology, isotope analysis, growth rates, dietary assimilation efficiency, uptake rate, ingestion rate, and efflux rate.

Swimming performance in aquatic organisms is directly related to flow, both the rate of flow and the variation in the flow profile. Further, changes in flow hydrodynamics can occur rapidly in hydropower systems (e.g., with hydropeaking) causing acute and rapid stress on organismal swimming behavior and abilities (MK Taylor et al., 2014; Boavida et al., 2017). Swimming performance is measured through studies on swimming speed, locomotion, kinematics, and muscle fibers (typing and use) and can be quantified with user-designed and individual-based biomechanical models developed by the user in Matlab, R, or Python.

Bioenergetics, the study of transformation of energy through living organisms, can be affected by changes in flow and is a widely used approach in fisheries management research. For example, decreased flow can result in higher temperatures, changes in food distribution and availability, and affect density-dependent growth rates (Myrvold & Kennedy, 2018; Gibeau & Palen, 2020). To quantify bioenergetics, length and weight, growth rate, oxygen consumption, acceleration, stable isotopes, and temperature should be measured. Fish Bioenergetics 4.0 is an R interface tool that houses over 80 bioenergetic models for fish and aquatic invertebrates and allows for modification of species and habitat-dependent variables and processes (Deslauriers et al., 2017).

Population growth is measured as rate, carrying capacity, population size at time zero, respective to study design, and population size at time t, respective to study design. Changes in flow parameters can affect population growth through many processes, including but not exclusive to changing habitat availability, food resources, water quality, and intra- and interspecific interactions. Population growth is commonly used in fisheries science as a metric for management decisions with regard to specific categories of species (i.e., threatened and endangered, culturally important, fisheries, sport/recreational, native, and nonnative/invasive). Several tools exist for modeling population growth and the factors affecting it, including demogR, FSA, simecol, and fishdynr (Jones, 2007; Petzoldt & Rinke, 2007; Taylor & Mildenberger, 2015; Ogle & Ogle, 2017).

Lastly, diversity, from genetic to species, can be affected by changes in flow. Environmental factors that are directly impacted by flow regimes, like habitat and water quality, as well as biotic factors, intra- and interspecific variability, and interactions, can have consequences on and change the underlying organismal genetic variation. These changes can result in reduced fitness, inbreeding, and mortality. Understanding the linkages between flow and genetic variation is critical for improving flow requirement decision making and management actions. Standard population genetics parameters need to be estimated, which include effective population size (Ne), genetic (allelic diversity and single nucleotide polymorphisms), and genetic differentiation.

As our genetic toolset has increased with advancing technologies, the information we can garner from the gene has advanced. Studies that look at adaptive variation and differential gene expression can further our understanding of environmental change on genetic and phenotypic variation. Phenotypic variation (i.e., demography, morphology, life history, behavioral, and phenology) is not only linked to genetic variation but is also a result of environmental plasticity (phenotypes can arise due to environmental cues without any underlying genetic basis). Changes in fish morphology from flow, due to either genetic architecture and/or plasticity, have been widely documented and can have serious consequences on organismal fitness, reproduction, foraging, and competition (Franssen et al., 2013; Benejam et al., 2016; Fenkes et al., 2016). Both changes in genetic and phenotypic variation can lead to changes in species diversity in the community due to immigration/emigration and colonization/extinction dynamics, which can in turn affect genetic and phenotypic variation.

Changes in environmental conditions due to changes in flow can have sweeping effects on aquatic biota, from microorganisms to vegetation to macrofauna. Understanding the impacts of flow dynamics on aquatic biota and biodiversity begin with quantify the metrics necessary to address the user's question. Once those variables are measured, then statistical and simulation modeling, such as regression analyses, Bayesian approximations, network analysis, individual-based models, are needed to quantify the relationships between flow and biotic biodiversity outcomes. No singular model, tool, or software will be adequate to address all of these topics, and many have been developed already. The R environment is a prime source for packages that can be used to tailor questions about flow and biotic and biodiversity impacts. Some of the packages are highlighted in the model/tool database, which is not all inclusive.

D.2.2.6 Upstream Water Quality and Greenhouse Gas

River impoundment and the subsequent increase in water elevation and reduction in flow, as water is stored for hydropower generation, results in major changes to water quality and biogeochemical processes that produce GHGs, including methane, carbon dioxide, nitrous oxide, and ammonia. Many of these parameters are monitored or measured to meet the National Pollution Discharge Elimination System permit or water quality certification requirements (such as Clean Water Act Section 401 permits or licenses). GHG emissions are not currently included in these types of permits; however, they are important environmental outcomes that are essential to understanding the carbon footprint of hydropower and are considered when conducting facility assessments under the National Environmental Policy Act.

Some of the most foundational water quality characteristics are dissolved oxygen and water temperature, which are closely tied to the biota and biodiversity. As flow through the system decreases and reservoir elevation and inundated areas increase, the types of vegetation and biota that are supported may be affected, which affects oxygen availability. Oxygen and temperature are closely related, and as reservoir elevation changes, this can impact the stratification or development of zones with distinct oxygen and temperature conditions. As light penetration decreases (due to increased depth and/or reduction in water clarity), water cools and is more dense than warmer water. The denser, cooler water remains at the bottom of the reservoir where there are greater rates of oxygen depletion (lower photosynthesis and greater decomposition activity). Especially in temperate climates and deeper reservoirs where the lower zone warms during the summer, there is often a fall turnover event where substantial mixing of temperature and oxygen occurs. Changes to the stratification patterns (depth at which stratification occurs, timing of turnover, etc.) can have ripple effects on many biogeochemical processes in the reservoir. For example, rates of methanogenesis, which converts decaying biomass into gaseous methane that travels through the water column and is released to the atmosphere in a process known as ebullition, increase with greater temperatures and readily occurs in oxygen-poor conditions. Release rates for nitrous oxide and ammonia diffusion into the atmosphere can also be driven by the cascading impacts of oxygen and temperature on sediment-bound compounds and denitrification rates.

Other water quality characteristics are more related to upstream geomorphology and external watershed processes. For example, the combination of reservoir geometry and landcover/mass transport or runoff processes in the watershed largely determine the types of sediment (and whether they contain nutrients, pollutants such as lubricants or solvents, and/or metals) and the depositional patterns of sediments within the reservoir. Deposition has direct impacts on hotspots of GHG emissions; there are common longitudinal trends where higher ebullition rates occur over the deltas of sediments that build up near the mouth of the reservoir, and emissions in deeper portions where sediment is not as readily deposited and is dominated by diffusion of carbon dioxide.

Water quality and GHG emissions in the reservoir are also influenced at different scales by reservoir operations or the fluctuation/alteration of flows through a reservoir. The fluctuation in reservoir elevation (on a daily to seasonal scale) as water is released for energy generation leads to repeated exposure and inundation of sediments and vegetation that may influence composition and the availability of gas, nutrients, metals, and mercury. Withdrawal of water (through turbines or nonturbine flows) can create movement that affects bottom sediments, water-column mixing, and transport of sediment and other materials (e.g., nutrients, algae) downstream. These outflow and removal processes are highly dependent on the intake depth of the outlet works of the reservoir.

D.2.3 Downstream Outcomes

D.2.3.1 Downstream Geomorphology

Downstream geomorphology is impacted by both upstream and downstream processes. Similar to upstream, downstream geomorphology can be affected by reservoir sedimentation. Reservoir sedimentation impacts downstream sediment transport because, as reservoirs fill with sediment, the sediment transports in the reservoir outflow is greatly reduced, although some reservoirs are equipped to pass sediment through its infrastructure (Kondolf, 1997). Unlike upstream, downstream geomorphology is impacted by both the flow through turbines and nonturbine pathways, which affects the flow rate downstream of the hydropower system. The rate of downstream sediment transport increases as a function of downstream flow, which can occur at sub-daily time scales (e.g., during hydropeaking) or when the energy demand is high. Stream bed armoring (measured by median grain size at the surface and subsurface) and stream bed scouring can both occur. Additionally, high river stages can result in water encroaching on erodible areas (e.g., banks, floodplains) leading to greater sediment inputs (Richards, 1928) and can change bank geometry.

D.2.3.2 Downstream Recreation

Downstream recreation activities can include boating, fishing, camping, picnicking, and similar activities. The popularity of downstream recreation can result in operating policy specifically aimed at supporting these activities. For instance, reservoir owners upstream of major rafting and kayaking reaches may introduce operational constraints that limit the rate of change in outflow during particular times of day and days of the week to maintain safe conditions for activities on the river, which influences the ability to satisfy other operating objectives such as hydropower peaking.

Conversely, the accessibility, safety, and quality of recreational activities downstream of dam facilities are influenced by reservoir operations for other objectives. If a dam is operated to support energy generation and introduces substantial variability in release rates to satisfy varying generation needs, the rapid shifts in flows and resulting changes in water surface elevation in the downstream reach may make fishing or boating activities untenable for a certain distance below the reservoir. During high-flow periods, recreation activities may not be possible; flood management activities targeting reducing the flashiness of river responses can increase the amount of time that recreation activities are possible in the downstream reaches. Furthermore, these changes in flow regime may favor specific sporting species introduced below dams for fishing, yet may also be detrimental to native species. Low-flow rates can also impact recreational activities and increase the probability of boating accidents (e.g., previously submerged terrain becomes operational obstacles). Additionally, sufficient flows are needed for fishing to ensure that activities do not increase stress and pressure on fish populations.

D.2.3.3 Downstream Habitat

Parallel to the effects of dam facilities on upstream habitat, downstream habitats can become lost, fragmented, or degraded, limiting access to important habitat for species survival and impeding fish passage. Regulation of flow rates and variability can have consequences on downstream habitats by altering geomorphology, water quality, biota and biodiversity, decomposition rates, recreational activities, and upstream habitat.

As previously discussed, sedimentation alters geomorphology and water quality. Because dams act as physical barriers to movement of particulate matter from above to below dam habitats, the water released below the dam is devoid of sediment (up to 99% removed), expect when sediment flushing protocols are enacted (Grimshaw & Lewin, 1980; Williams & Wolman, 1984). The resulting water is sediment starved and has excess kinetic energy that is transferred to the stream bed, channels, and embankments, and can cause stream bed scouring, erosion, and armoring (Kondolf, 1997). This causes drastic alterations to the types and structure of downstream aquatic habitats. Additionally, the reduction of sediments compared to natural flowing systems alters the patterns of channels, deltas, and beach formation, and has resulted in the loss of deltas and wetland habitats (Nyman et al., 1990; McCully, 1996; English et al., 1997). Hydropeaking can amplify these impacts and make them much less predictable as flow vortices and intensities rapidly change. Reduced flow and sedimentation also increase water temperature, reduce dissolved oxygen levels, and reshape nutrient flow and food web structures (Ibàñez et al., 1996; Fantin-Cruz et al., 2016; Kennedy et al., 2016; Simonović et al., 2021).

These changes in downstream substrate and habitat directly impact the aquatic biota and biodiversity. Substrate diversity is a critical component of habitat, as organisms seek refugia to avoid predation, for reproduction (e.g., egg nest protection), and for protection during flooding events. Because of the reduction of substrate and habitat diversity downstream of dams, organisms will abandon suboptimal habitats in search for better resources; however, may not be able to find a better habitat in the altered riverscape (Saltveit et al., 2001; Harby et al., 2020). The expended drain on energy can result in reduced foraging, mating and reproduction, and fitness, and can eventually result in local extirpation or extinction. Further, the presence and aquatic diversity affect the habitat resulting in a feedback loop. Quantification of the effects of flow on downstream habitats involves measuring the same parameters as upstream, including habitat availability, suitability, productivity/metabolism, substrate, and fragmentation.

D.2.3.4 Downstream Biota and Biodiversity

The organisms that inhabit downstream are determined by a combination of the organisms' lifecycle, habitat requirements, interaction with other species, and abiotic conditions (e.g., water temperature and quality). As discussed previously, changes to flow affect geomorphology, habitat, water quality, fish passage, flood control, and recreation, which in turn have consequences on downstream biota and biodiversity. Additionally, changes in flow can have direct consequences on the organism itself, including but not limited to organismal behavior, performance, physiology, morphology, and genetic variation, which can be quantified using the same metrics, models, and tools as upstream biota and biodiversity.

Downstream organisms are also susceptible to the effects of hydropeaking, which include the rapid increase in flow and turbidity, quick down-ramping, and high variability in flow rates and vortices. These changes in flow can reduce food supply due to algal scouring and reduction in algal production; trapping or stranding organisms; reduction in hatching, recruitment, and migration; physiological and behavioral stresses; and reduced growth, injury, and interrupted or terminated spawning (Schmutz et al., 2015). Understanding the biotic consequences of hydropeaking will become even more important as the need for on-demand power production increases.

D.2.3.5 Downstream Water Quality and GHGs

Downstream water quality conditions affected by flows through a hydropower system can be described under three general categories: changes in stream stage/velocity; changes in water quality constituents due to mass transport processes; and physical inputs or processes at the point of discharge and generation.

Flow rates can impact the downstream elevation or stage; however, this impacts oxygen and temperature differently in shallower, lotic systems than deeper reservoirs upstream (where stratification can develop). It is important to note that oxygen and temperature stratification can be particularly relevant in cascading systems (where one reservoir flows into another). Stream stage is generally inversely related to temperature, but the downstream temperature is also heavily influenced by the temperature of other inflows besides those coming from the hydropower system (surface and groundwater). The rate of flow also directly influences the velocities downstream of a hydropower system, which can shape channel geometry, resulting in feedbacks on downstream geomorphology and riparian/benthic vegetation through erosion/transport of sediment from the stream bed and banks.

Many downstream water quality parameters are affected by the amount and location of releases; there is a direct connection between what is trapped or passed through the hydropower system and what continues to be instream or transported further downstream. Reservoirs and dams often enable sediment deposition and trapping, which can create sediment-starved water downstream, which then has a greater capacity to erode and carry sediment from the stream bed and banks. Conversely, reservoirs often require regular maintenance or flushing of sediments that can result in temporary, episodic flushing of high sediment-laden water, often containing sediment-bound nutrients or metals that are then carried downstream. Location of the intakes and releases can play a major role in determining levels of depth-dependent water quality constituents including oxygen, temperature, algae, and sediment that are passed downstream. For example, releases through deep submerged intakes are more likely to pass cooler, oxygen-poor water downstream compared to spills, bypasses, or shallow intakes from near the surface.

Finally, the physical operation of dam and hydropower infrastructure can be a source of pollutants, though this is typically only in the event of a leak or failure (i.e., leaks of lubricants used in the operation of generation equipment or gates). Additionally, the striking of water against turbine blades when it is used for generation results in a rapid change in pressure that forces methane and carbon dioxide gases to be released in a process known as degassing. This is distinct from the diffusion that occurs naturally at the air/water interface, as the gases may have remained dissolved and transported and diffused further downstream if it were not for interaction with generating units.

D.2.4 Dam Outcomes Relevant to Both Upstream and Downstream

D.2.4.1 Navigation

Navigation, the movement of boats up and down a river and reservoir, is dependent the dam infrastructure (turbines, spillways, locks, etc.) as well as several factors that are directly related to flow: downstream flow, reservoir elevation, reservoir sedimentation, reservoir storage capacity, upstream geomorphology, reservoir operating policy, and interaction with other operating objectives. Dam infrastructure acts as both barrier and aid to river navigation of shipping/cargo and recreational vessels. The dam itself is an instream barrier to travel but lock systems can aid in the passage of vessels around the dam. Flow downstream of the hydropower system (stage, discharge, variability) is directly related to the outflow from the reservoir (discharge, variability). If the river stage is not high enough, navigation of shipping/cargo and recreational vessels is impeded.

River velocity and discharge are also critical factors in determining navigability and affect lock operations. Further, if flow is highly variable, it can lead to dangerous conditions for passages. Reservoir elevation depends on the inflow and outflow rates to and from the reservoir. If the reservoir levels become too low, navigation within the reservoir and upstream can be impeded. Flow rate within the reservoir is also affected by sedimentation. As inflow decreases, sediment transported by rivers, streams, and tributaries settle out of the water column to the bottom of the reservoir, which can directly impact navigation but also affects reservoir storage capacity. More sedimentation results in less storage capacity in the reservoir. Adequate storage capacity is necessary to guarantee safe passage and navigation of shipping/cargo and recreational vessels through the reservoir (Lane, 1953). Reservoir sedimentation also impacts upstream geomorphology. As reservoirs fill with sediment, upstream deltas and sand bars can form that adversely affect navigation and due to shallower waters (Strand & Pemberton, 1982; Subcommittee on Sedimentation, 2017).

D.2.4.2 Dam Safety and Maintenance

Dam safety and maintenance concerns often include the potential for overtopping, seepage, generating unit/turbine maintenance, other outlet work maintenance, and sediment flushing. The natural variability of inflows and potential for extreme events that could overwhelm and overtop a dam result in operating restrictions that limit the maximum elevation of a reservoir. The risks associated with overtopping are directly related to physical infrastructure (e.g., spillway capacity). Understanding the probability of overtopping often influences specific operating restrictions for a dam. The operating pool is often lowered during high-flow seasons, both to provide flood management capacity and for dam safety purposes, affecting a variety of other environmental and energy outcomes during this time.

Water-storage results in pressurized water against the upstream side of dams, which in turn can cause seepage through the dam. If seepage is sufficiently high, it can cause internal erosion that could compromise the safety of the dam (Dorji & Ghomashchi, 2014). If seepage concerns are significant, major operating restrictions may be enforced to mitigate the risk or lower the pool during rehabilitation activities.

The frequency of changes in releases through turbines affects wear and tear on the turbines, particularly for locations with more significant “rough zones” (discharge ranges that cause greater degrees of turbine vibration during operation). The frequency and magnitude of release fluctuation to meet energy needs thus can affect the required frequency of maintenance activities. Furthermore, the degree of fluctuation in pool elevation and rate of change are often limited by potential upstream bank erosion.

Increases in flow volume and velocity through outlet works can cause cavitation to occur, the formation of small vapor bubbles (cavities) in the water. When these cavities collapse, they create miniature shock waves. When surface irregularities exist in the dam infrastructure, cavitation can cause damage and erosion, which in turn can lead to further weakness, damage, and erosion in the surface of spillways or other outlet structures (Falvey, 1990; Trojanowski, 2008). Similar to the impacts on upstream geomorphology, as flow rates through a reservoir decrease, sedimentation rates increase in the reservoir. This increase in sedimentation can result in increased need for sediment flushing, both in volume and frequency.

D.2.4.3 Human Health

Modifications to flow regimes can have consequences on human health by increasing exposure and probability of contact with harmful contaminants in the reservoir and rivers. Contaminants can leach or be directly released from contaminated waters and soils into rivers that are hydrologically connected to the reservoir. Hydrologic connectivity increases as the reservoir and/or floodplain inundation area increases. Sediment transport and retention in the reservoir reduces storage capacity, increasing the frequency of higher pool elevations, and result in greater reservoir inundation.

D.2.4.4 Water Supply

Agriculture, municipal, and industrial functioning depend on reliable supplies of water. Many reservoirs include water supply provision as one operating objective. The concepts of water ownership and priority of use differs across the country (e.g., the difference between prior appropriation in the west and riparian appropriation in the east), which in turn affects how water is allocated and used. The relative priority of providing water supply and for operating objectives varies between locations. For reservoirs with significant water supply objectives, the capture of runoff during high-flow periods and release of water during low-flow periods to meet downstream demands is often the driving factor affecting releases and pool elevation of a reservoir, and thus strongly interacts with other environmental and energy outcomes.

In locations with significant sediment load/reservoir sedimentation, water supply capacity can be reduced over long timeframes as sediment builds up in the reservoir. In these locations, proper sediment flushing is not only imperative for ensuring that withdrawal structures and hydropower infrastructure are not damaged and are capable of operating to their designed function, but to ensure the maintenance of full reservoir capacity for water supply (Dorji & Ghomashchi, 2014; Schellenberg et al., 2017).

D.2.4.5 Flood Control

Dams, including hydropower producing facilities, are an important player in flood mitigation for many parts of the United States and the world. Dams and associated reservoirs can manage and reduce flood risks by retiming upstream flows, thereby reducing downstream flooding impacts. Reservoir operating policies often dictate release limits to minimize downstream flooding in population centers or agricultural areas. These release limits interact with other operating objectives (desired releases for hydropower generation, water supply storage, or dam safety concerns). Similar to water supply, reservoir sedimentation can affect the storage capacity available for flood management activities. Finally, flood management operations can substantially alter the flow regime for the downstream river by flattening peak flows. This can have detrimental impacts on biota dependent on natural flood events that occur under the natural flow regime of a river system.

D.2.4.6 Fish Passage

Many aquatic species have a migratory phase during their lifecycle. The maintenance of migratory pathways, and hence population connectivity, is critical to their survival. Hydropower facilities have integrated passageway structures (e.g., ladders, lifts, spillways) into the facility design that allow for movement of organisms from downstream to upstream habitats. However, the ability of species to use passageways depends on both the architecture and design of the structure, as well as the water flow through the system. Downstream passage is also impeded by dam structures and can be detrimental to fish populations, as fish can be entrained in outlet structures, turbines, and trash racks (without fish screens), and washed over spillways. Outcomes of fish passage can be estimated with conventional fisheries assessments (e.g., species presence/absence, abundance, demography, and survival), as well as species diversity and swimming performance to help understand the physical effects (e.g., shear stress, entrainment).

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Appendix E – Detailed Methods and Results for Chapter 4.1: Maximizing Generation Revenue from Previously Designed Environmental Flow Requirements

E.1 Tool Demonstration Overview

The tool has been designed to simulate real-world conditions, both plant operations and environmental flow considerations, in a manner consistent with how operators think about their plants while also being straightforward enough that it is accessible and usable by a relatively wider array of stakeholders. The tool is designed to reflect bidding strategies and market participation approaches that reflect real-world plant dispatch decisions. For example, it considers both DA and RT markets and inflow forecasts. It enables participants to optimize operations across multiple days (e.g., if a reservoir has multiday storage) or to simply optimize sub-daily operations. Sub-daily operation functionality is of benefit either if (a) the plant is limited to sub-daily storage (i.e., inflows must equal outflows on a 24-hour basis) or if multiday optimization is performed exogenously by a water management group (e.g., if these decisions are based on factors such as water supply and flood control or the plant is part of an extensive hydropower system).

The tool demonstration is designed to highlight functionality for assessing impact of modes of operation (e.g., mimicking natural variability versus peaking), plant capabilities (e.g., reservoir size of generation capacity), and inflow forecasting. In the demonstration, the tool is implemented for a hypothetical hydropower plant using flow (both overserved and forecast) and CAISO LMP data corresponding to Trinity River above Coffee Creek near Trinity Center, California (Table E-1).This location was selected because of availability of observed and forecast flow data, linkages between the power system and environment in this area are of interest, and this location does not require proprietary information from an existing power plant. A set of synthetic data were then prepared to conduct the demonstration based on hypothetical environmental flow and storage requirements for the observed range from flow data.

Table E-1. Data Sources Used in the Hydropower Flexibility Valuation Tool Demonstration

Variable	Dataset Description	Dataset Citation
Power efficiency	HydroGenerate Model	Mitra et al. 2021
Observed flow	Year: 2020	Upstream Tech (2021)
Forecasted flow	Year: 2020	Upstream Tech (2021)
Electricity price	Year: 2020, Node CAISO ANTLER_6_N001	CAISO (2021)

The hydropower plant is defined as having a capacity of 120 MW and multiple environmental flow scenarios are defined to be illustrative of potential tradeoffs. The efficiency of converting water to power at the powerhouse is calculated via INL HydroGenerate Model (Mitra et al. 2021). Using the head and stream flow time series as input, this module estimates the potential hydropower that could be produced if a turbine of the types considered in the tool were to be installed. Observed and forecasted flow at the gage was provided by Upstream Tech (Upstream Tech 2021), a subsidiary of Natel Energy. DA and RT electricity prices are taken from the Antler CAISO node, which is the closest node to the Trinity River above Coffee Creek.

E.2 Tool Optimization Model Structure

The tool's optimization model is currently designed to consider a single reservoir and corresponding power plant. It captures basic characteristics of each, such as reservoir storage, plant limitations, and operational considerations such as flow requirements. In this single-reservoir system, the tool is designed to evaluate multiple scenarios encapsulating differences in electricity market prices, water inflows, flow requirements, and plant capabilities using a two-stage optimization method (Figure E-1). Inputs to the tool can include hourly forecasted flow, hourly observed flow, and hourly DA and RT electricity prices. Other input data include power efficiency and power-generation rules, ramping rates, flow restrictions based on type of year, and maximum hourly changes in water spilling. Elevation head can usually be approximated to be fixed.

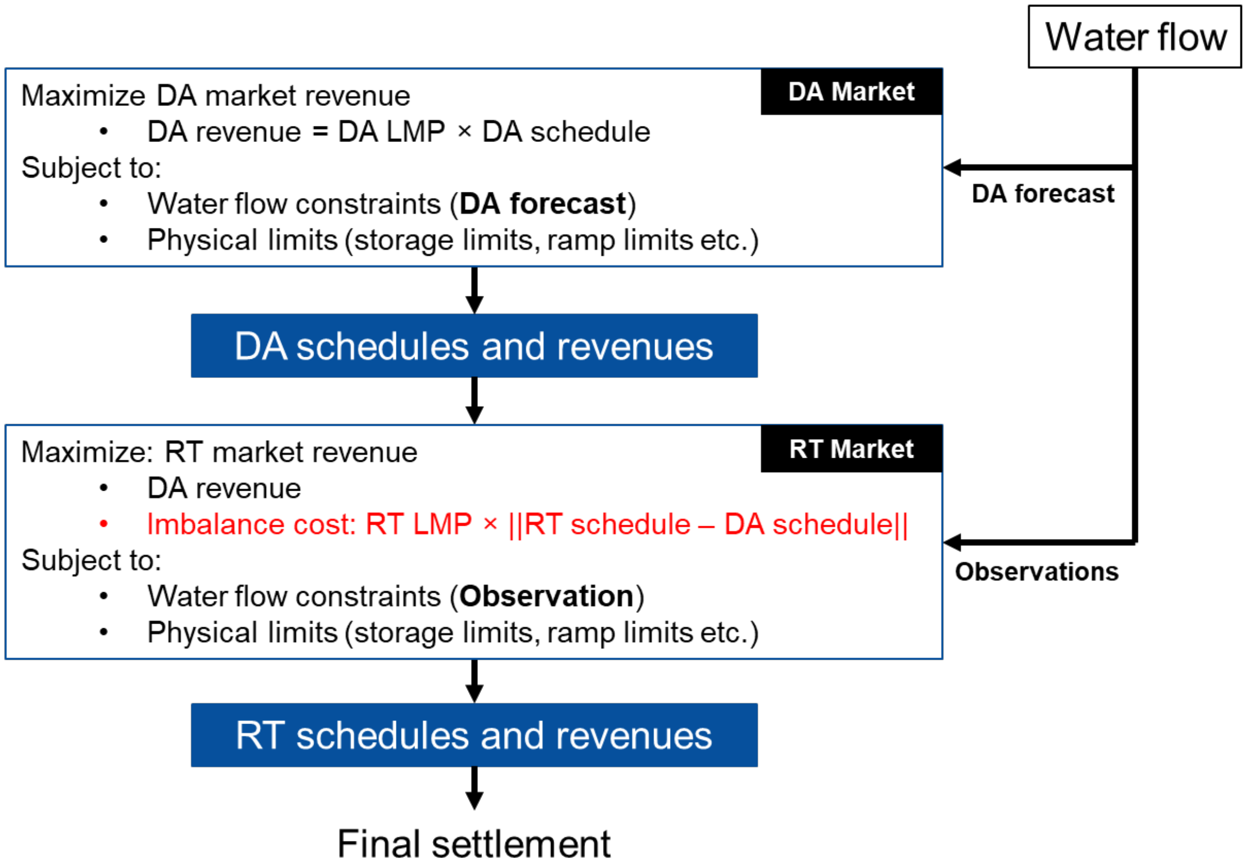

Figure E-1. Process flow of the two-stage revenue optimization model showing how the model feeds inputs through subroutines. In the first stage, the decision to participate in the DA market is optimized based on a forecasted flow. In the second stage, the decision about RT market participation is optimized based on forecast error and observed flow.

The tool is designed to evaluate and compare multiple scenarios. For each scenario, the tool maximizes the plant revenue by optimizing electricity generation within a set of boundary conditions that include factors such as water inflow, reservoir storage, plant capabilities, and environmental flow requirements or operational regimes. The tool can be used to optimize sub-daily decisions based on input from an external operations or hydraulic routing model, or multiday operations can be simulated within the tool. The model considers two dispatch horizons corresponding to DA and RT market bidding. Different price and water profiles can also be used to compare across water year type or expectations about future electricity market conditions. Based on implementing multiple scenarios, the tool enables users to compare revenue estimates across multiple scenarios, assessing how changes in boundary conditions (e.g., environmental flow requirements, plant upgrades) impact potential revenue.

This model is designed to reflect competitive electricity markets with a two-settlement system that consists of a DA forward market and a RT spot market. This model implements a two-stage optimization method to provide accurate assessment of revenue difference caused by environmental flow-related constraints. The environmental flow constraints are included in both stages of optimization. The DA energy market lets participants commit to buy or sell wholesale electricity one day before the operating day to help avoid price volatility. The RT energy market lets participants buy and sell wholesale electricity during the course of the operating day. For example, in the CAISO, the DA market closes at 10 a.m. one day prior to RT, and the imbalance caused by uncertainties are corrected in the RT market. The clearing price in the DA market occurs once per day, whereas the clearing price in the RT market occurs every 5 minutes. For our tool, the market clearing price is defined as the price where the demand for electricity by consumers is equal to the electricity that can be generated at that price; it is the price where supply and demand are equal. Market operators collect bids from participants and clear the markets using unit-commitment and economic-dispatch models, which give the LMPs for energy at each node. The revenue of a hydropower plant comes from selling energy to the electricity market, which includes forward transactions in the DA market and delivery of electricity in the RT market.

In this two-stage revenue optimization method (Figure E-1), the decision to participate in the DA market is optimized based on a forecasted flow. The objective function in the first stage (DA market) aims to maximize of the total generation of all hydropower plants during the planning horizon considering environmental flow and physical limit constraints (e.g., storage limits, ramp limits). In the second stage, the decision about RT market participation is optimized based on forecast error and observed flow. The second stage objective function aims to minimize imbalanced energy costs caused by deviation of actual generation from RT schedule while maximizing the revenue for monthly operations on an hourly timestep. The plant operator determines the optimal operating schedules by maximizing total revenue based on hourly water inflow. Because of forecasting errors of water flow, the DA schedules usually differ from the RT schedules, which are settled by imbalance costs based on RT prices.

Water flow is translated into generation by approximating the hydropower conversion efficiency relationship using piecewise linear curve fitting (Figure E-2). The optimization model has three types of linear variables: hourly reservoir water release, hourly reservoir water storage, and hourly water spillage. A binary variable is used to capture the relationship between hourly power output of a hydropower plant and its hourly water release.

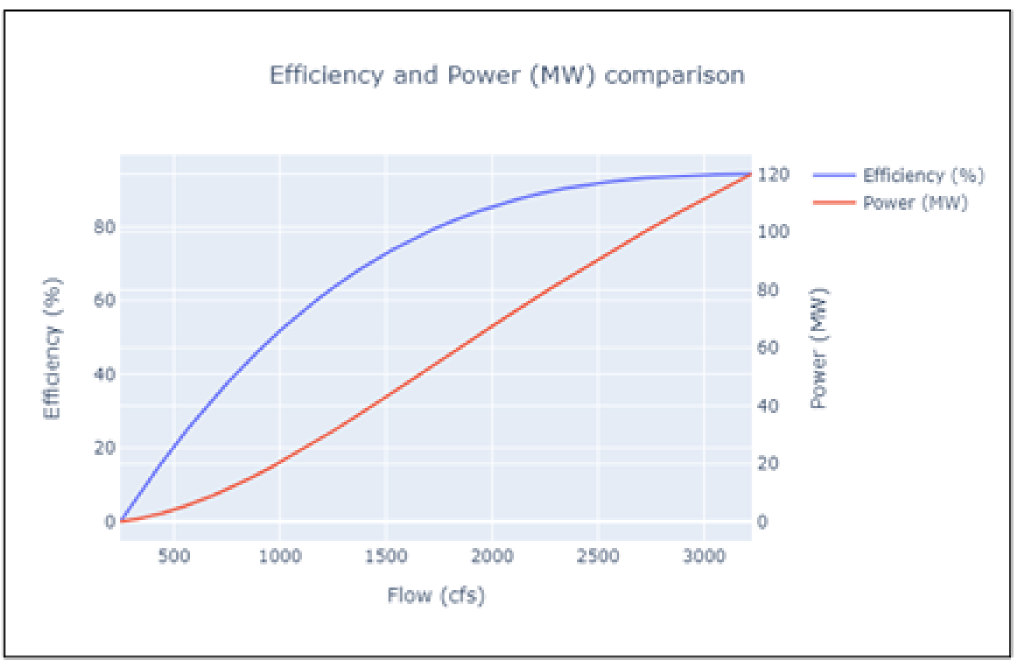

Figure E-2. The nonlinear relationship between water discharge and power generated used.

Environmental flow can be applied in the model to allow comparison of multiple potential environmental flow or operational regimes. Examples types of environmental flows that can be simulated include minimum instream flows, ramping rate limits, hydropower output limits, and storage constraints. The regulatory requirements on stream releases can be defined as reservoir operating ranges and targets, as well as license and contract requirements under different water availability conditions (e.g., wet, normal, dry). These include minimum instream flow requirements, water rights, and reservoir-release capacities. A reservoir's hourly water-balance constraints determine flow release based on minimum and maximum water-storage requirement by hour. Ramping rate limits are determined by maximum hourly flow variations. The resulting optimization model is a mixed integer linear program and is solved via the IBM Cplex commercial solver (via Python API). For computational efficiency, optimization is approximated via linear programming model by assuming linear relationship between water discharge and power generated.

E.3 Scenario Building Functionality in the Tool

Scenarios implemented in the tool are defined by several factors, including (1) operational mode (including environmental flow considerations), (2) hydropower plant configuration (including reservoir and powerhouse), and (3) hydrology and market (including inflow forecasting, inflow observations, and electricity price signals). Examples are provided to demonstrate functionality within each of the three categories. In these examples, only a small set of parameters are varied to demonstrate the effect of those parameters. In real applications (e.g., as part of FERC proceedings), scenarios may be constructed and compared to use functionality across each of these categories.

The example demonstrating operational mode considerations in building a scenario examines the effect of varying operational regimes on revenue. The three scenarios represent the span of flexibility a hydropower plant may have, from "no flow constraints" to "natural variability," with a scenario in between called "constrained flow" representing a realistic set of flow requirements (Table E-2).

Table E-2. Operational mode example comparing three scenarios.

Scenario Name	No Flow Constraints	Flow Constraints	Natural Variability
Power plant capacity	120 (MW)	120 MW	120 MW
Minimum storage requirement	673 (acre-feet)	673 acre-feet	None
Maximum storage requirement	1140 (acre-feet)	1140 acre-feet	None
Maximum hourly up-ramping and down-ramping rates	None	±10% of hourly reservoir water release	None
Maximum water spill rate fluctuation	None	±100% of hourly water spillage	None
Forecasting method	Upstream HydroForecast [4]	Upstream HydroForecast [4]	Upstream HydroForecast [4]

The example demonstrating the effect of plant configuration focuses on reservoir storage limits. The three cases considered are: "no interday storage," "baseline storage," and "increased storage" (Table E-3). In the reservoir storage examples, only minimum and maximum storage are varied among scenarios and there are no changes in ramping rates or spill rate variability among scenarios.

Table E-3. Input data utilized economic impact of reservoir/storage size and constraints. The base storage scenario has 5 days of storage, no storage has daily inflow and outflow being approximately equal, and increased storage has 10 days of storage.

Scenario name	No storage	Baseline storage	Increased storage
Power plant capacity	120 MW	120 MW	120 MW
Minimum storage requirement	None	673 acre-feet	673 acre-feet
Maximum storage requirement	None	1140 acre-feet	2280 acre-feet
Maximum hourly up-ramping and down-ramping rates	±10% of hourly reservoir water release	±10% of hourly reservoir water release	±10% of hourly reservoir water release
Maximum water spill rate fluctuation	±100% of hourly water spillage	±100% of hourly water spillage	±100% of hourly water spillage
Forecasting method	Upstream HydroForecast*	Upstream HydroForecast	Upstream HydroForecast

*Palmer 2021

The example demonstrating functionality related to hydrology and market focuses on forecasts for making DA market commitments. The inputs are the same as the baseline storage case, with the following three forecast scenarios. "Perfect foresight" assumes the plant operator has perfect foresight into the future and the forecasts used in the DA market equal exactly the observations in the RT market. "Persistence forecast" uses recently observed flow values as an estimate of future flows and was created by averaging all instantaneous U.S. Geological Survey (USGS) gage (11523200 Trinity River above Coffee Creek near Trinity Center, California) observations of streamflow taken within the 24 hours proceeding the forecast issue time. That average value is applied as the forecast value for all steps in the issued forecast. "HydroForecast" (median) uses long short-term memory networks to generate long-term (i.e., up to 10 days ahead) to short-term (hour-ahead) probabilistic water-flow forecasts in the form of percentiles. The prediction model used in this research has three main input sources:

1. Weather forecasts (from the National Oceanic and Atmospheric Administration's Global Forecast System model and the European Centre for Medium-Range Weather Forecasts)
2. Near-real-time observations of the land surface such as snow cover, vegetation growth, and day and night land surface temperature (primarily derived from satellites operated by the National Aeronautics and Space Administration)
3. In situ streamflow observations from the USGS.

These inputs are observed at up to an hourly frequency and aggregated over the entire drainage basin. At each timestep (in our case each hour or day), the long short-term memory takes in new inputs, updates a set of internal states it maintains that represent the hydrologic conditions of the basin, and then outputs a prediction for the current timestep. The model is designed to output the full probabilistic range of values for each model timestep, which can be useful in managing risk and in downstream models. This scenario takes the DA median HydroForecast value as the input to the DA scheduling model.

E.4 Scenario-Builder Example Results and Interpretation

E.4.1 Operational Mode

Differences in revenue between cases in the operational mode example vary by month and show that while the "no flow constraints" scenario provides higher revenue, the differences are relatively small in each month (Figure E-3). The impact of flow constraints on revenue varies by constraint and by month.

For example, January through April, which have high flows, also have the smallest differences in revenue; conversely, August through October, which are relatively low-flow months, have the largest differences in revenue. Sub-daily differences in operations vary in a manner consistent with expectations: “no flow constraints” varies the most in response to price fluctuations, “flow constraints” varies some but not as much, and “natural variability” is not responsive to prices (Figure E-4).

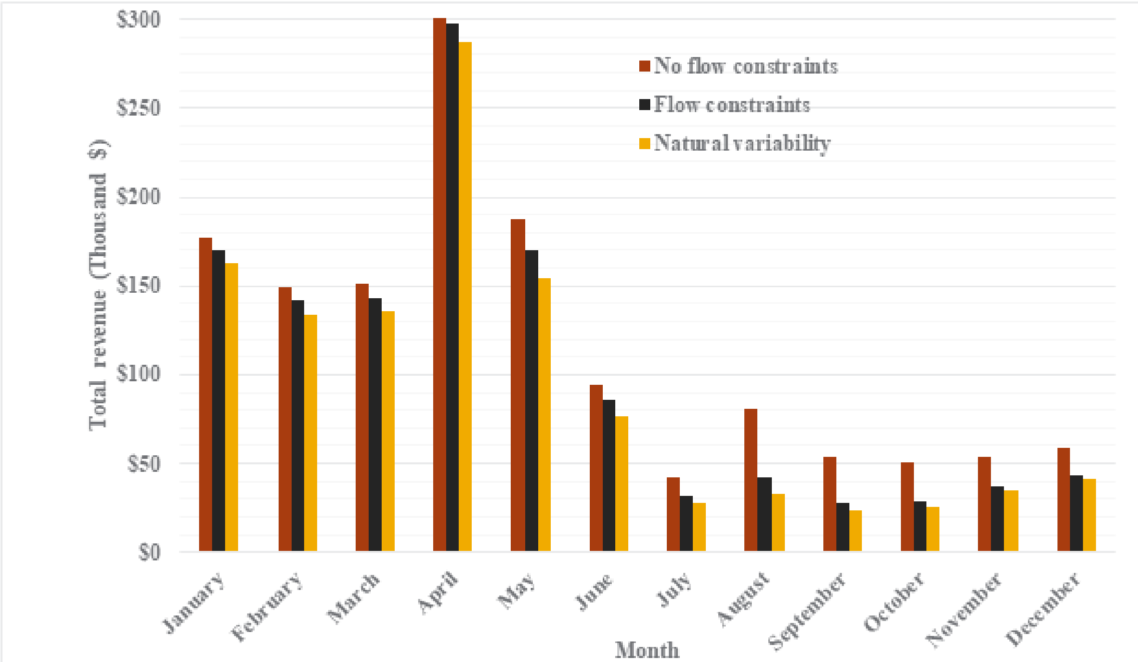

Figure E-3. Generation revenue for scenarios no flow constraints, flow constraints, and natural variability.

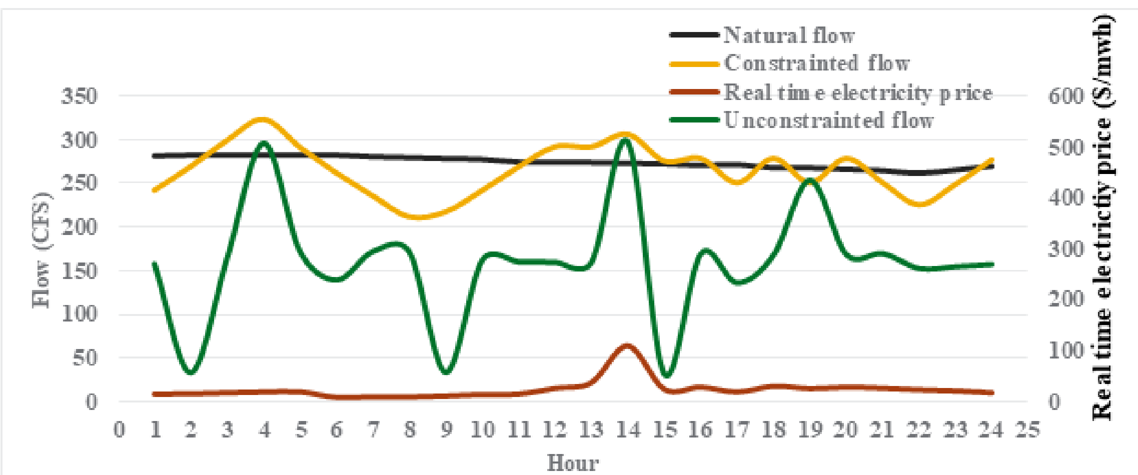

Figure E-4. Daily hourly water flow and RT electricity price for scenarios no flow constraints, flow constraints, and natural variability for May 15th.

E.4.2 Hydropower Plant Configuration

Reservoir storage capacity can enable hydropower plants to have flexibility that improves both market participation and ability to meet environmental flow objectives. This analysis isolates only the reservoir capacity, holding environmental flows constant. Given this setup, it is expected and observed that increasing reservoir storage increases revenue (Figure E-5). Value of the reservoir storage is greatest in the spring runoff months of May and June, which is when the CAISO electricity market has abundant cheap hydropower.

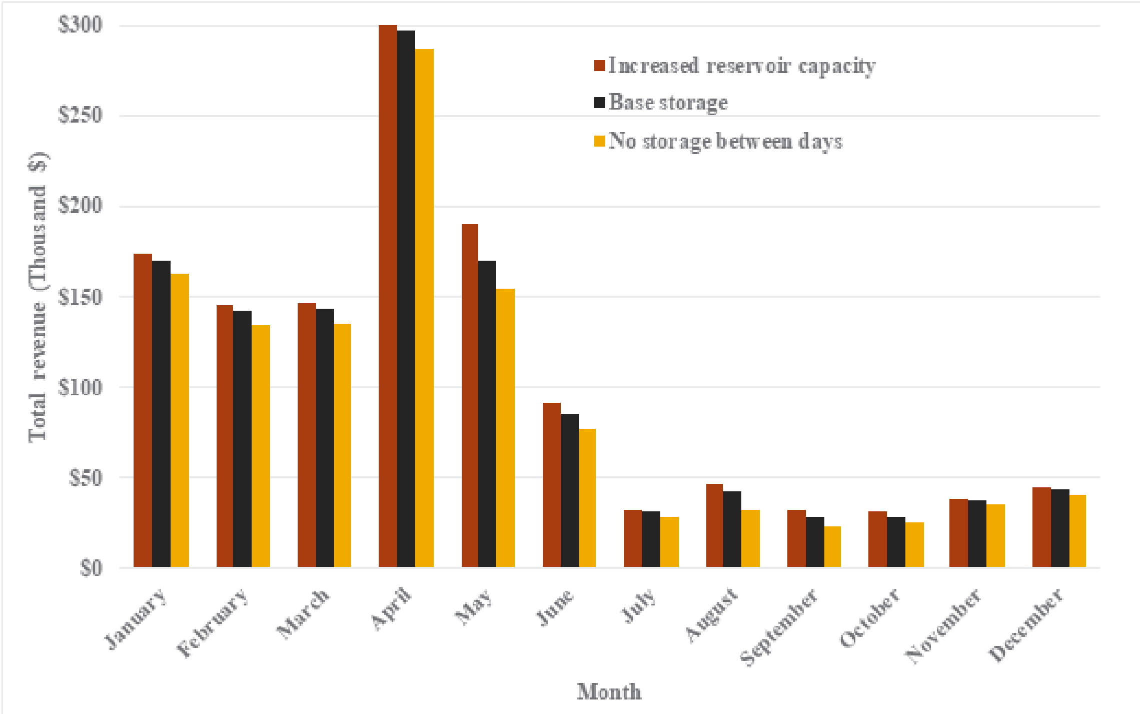

Figure E-5. Economic impact of different storage requirements.

E.4.3 Hydrology and Market

Inflow forecasts are necessary for hydropower operators and water managers to make dispatch decisions that account for future conditions. Therefore, by having improved forecasts, it is possible the decision makers can better satisfy both power market and environmental objectives. Consistent with this expectation, in the hydrology and market example, it is seen that the highest revenue case is that which uses "perfect foresight" (Figure E-6). Perfect foresight, however, is not possible in the real world. Of the two potential forecasts tried, "HydroForecast" and "persistence forecast," HydroForecast results in higher revenue by 0.3–7.4% depending on month. This is expected because HydroForecast is a more sophisticated forecast model than persistence. There is not a clear pattern to the months in which HydroForecast produces the most additional value. In part, it depends on the forecast accuracy across different water conditions and events.

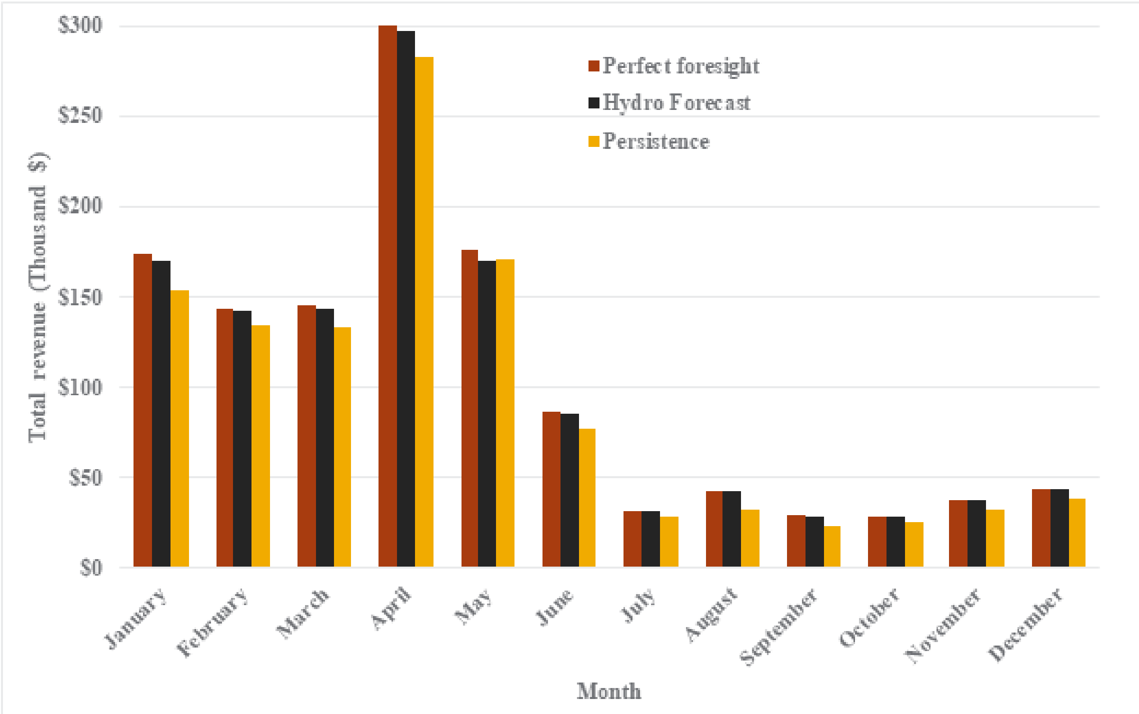

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Figure E-6. Monthly revenues for each forecast scenario.

E.5 References

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Appendix F – Detailed Methods and Results for Chapter 4.2: Rapidly Evaluate Operating Criteria for Energy-Environment Win-Win Study Site Description

F.1 Study Site

GCD and the power plant located in the UCRB (Figure F1) was selected as the first demonstration site for the application of the Win-Win Toolset.

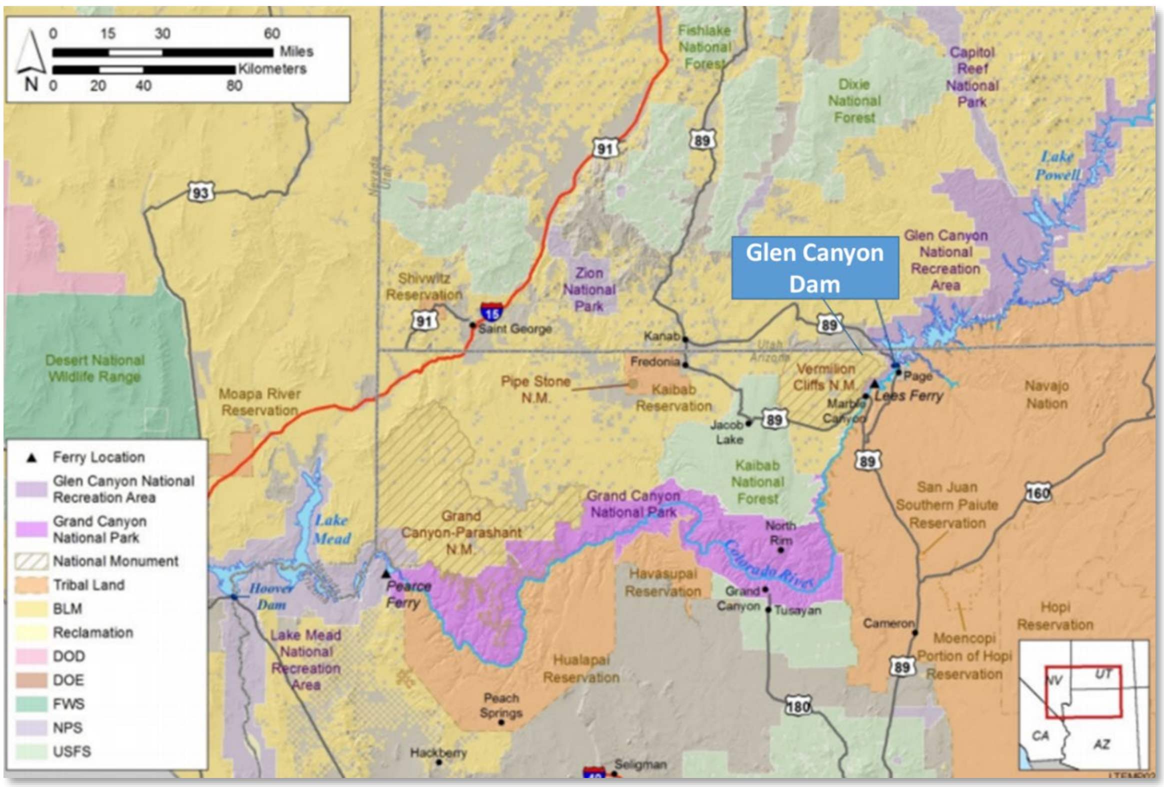

Figure F-1. Map of GCD, Lake Powell, and the Colorado River below the dam.

It was selected for the following reasons:

1. The GCD reservoir, Lake Powell, is the second largest in the United States[1]
2. The GCD power plant is relatively large with an installed nameplate of 1,320 MW[2] that produces an average of about 5 billion kwh each year[3]
3. It is located upstream of a diverse and ecologically important riverine environment[4]
4. Key organizations and stakeholders involved with GCD power and UCRB water resources, including the Bureau of Reclamation (Reclamation), Grand Canyon Monitoring and Research Center, and the

[1] https://www.usbr.gov/uc/water/crsp/cs/gcd.html
[2] https://www.usbr.gov/projects/index.php?id=522
[3] https://eros.usgs.gov/image-gallery/earthshot/glen-canyon-dam
[4] https://ltempeis.anl.gov/documents/final-eis/

Western Area Power Administration (WAPA), are interested in improving GCD operations for multiple purposes

5. Extensive power and environmental analyses on GCD operations are available that can be leveraged.

The GCD located near Page, Arizona, is a key feature of the Colorado River Storage Project (CRSP). As shown in Figure F-1, the GCD is approximately 15 RM above Lees Ferry. This marks the beginning of 277 miles of Colorado River that flows through the Grand Canyon and then on to Lake Mead, the reservoir for Hoover Dam.

The 710-foot-high GCD structure forms Lake Powell behind it. When full, the lake stores 24 MAF of water. This corresponds to several years of water resources for GCD hydropower plant energy production and more storage capacity than all other CRSP resources combined. In addition to its water-storage value, the power plant at GCD is a valuable component of the WI power grid.

The power plant at the toe of the dam is the largest hydroelectric facility in the CRSP system. It consists of eight 165 MW generators, each of which is driven by a Francis turbine, for a total nameplate generating capacity of 1,320 MW. The GCD hydropower plant accounts for about 75% of CRSP capacity and energy resources. It also supplies the grid with spinning reserve and both regulation-up and regulation-down services.

CRSP, and therefore the GCD hydropower plant, is integrated with the operation of other federal hydropower resources that are marketed by WAPA. These resources include hydropower plants in the Seedskadee, Dolores, Collbran, and Rio Grande projects. Hydropower generation schedules from all of these projects are managed by the WAPA Energy Marketing and Management Office (EMMO). Located in Montrose, Colorado, EMMO schedules federal hydropower resources to serve electricity demand for 5.8 million consumers in 10 western states in the WI power grid. Plant-level production is scheduled by EMMO on a DA, hour-ahead, and RT basis. Energy short and long positions are balanced by EMMO via bilateral market transactions that span various lengths of time, typically ranging from seasonal to RT.

Reclamation is responsible for managing water resources in the entire Colorado River Basin via scheduling of monthly and/or daily reservoir-specific water release volumes in the CRSP system. This includes not only the UCRB but also the lower basin. It also operates, maintains, and upgrades CRSP dams and hydropower resources.

F.1.1 Natural Resource Issues

Controlled water releases from Lake Powell via dam penstocks/outlets for energy production and nonpower routes (bypass tubes and spillways) have resulted in an altered aquatic and terrestrial ecosystem compared to the one that existed before the dam was built. Cold, clear water flows support a rainbow trout fishery in the river reach near the dam, while native fishes, including the two species of endangered fish, HBC *Gila cypha* and razorback sucker *Xyrauchen texanus*, live further downstream where water temperatures are warmer. Vegetation is established closer to the river's edge than in the past due to the elimination of annual flood scouring and has increasingly become dominated by nonnative plant species.

Lake Powell, Lake Mead, and the Colorado River connecting these two reservoirs, support important recreational resources. This recreation and the hydropower produced by GCD have important effects on the local and regional economy. All of these resources are of vital importance to the social and economic wellbeing of Tribes with ancestral ties to Glen and Grand Canyons. Most cultural resources are located at higher elevations away from the area affected by dam operations but, at some locations, operations may affect the availability of windblown sand that helps replenish eroded sites.

F.1.2 Operating Criteria

Before 1990, GCD had few operating restrictions. Apart from a minimum water release requirement, its daily and hourly operations were constrained only by the physical limitations of the dam structure, the power plant, and the amount of water stored in and released from Lake Powell. Market price signals and temporal load profiles from CRSP firm electric service customers were the principal scheduling/dispatch drivers, often resulting in large hourly and daily fluctuations of the plant's power output and associated water releases.

Concerns about the impact on downstream ecosystems and endangered species, including those in Grand Canyon National Park, prompted Reclamation to conduct a series of experimental releases from June 1990 to July 1991 as part of an environmental studies program. Based on an analysis of these releases, Reclamation imposed operational flow constraints on August 1, 1991. These constraints were in effect until February 1997, when new operational rules and management goals specified in the 1997 GCD ROD were adopted.

Rules and management goals were changed once more as a result of findings from GCD LTEMP EIS studies that were conducted a few years ago. Analyses identified environmental and economic issues and consequences associated with taking no action as well as a reasonable range of alternatives to no action. The alternatives addressed in the LTEMP EIS included several operation and experimental actions that together provided an evaluation of possible impacts from a range of criteria/actions including the one that was selected under the 2016 ROD.

The 2016 ROD specifies GCD operating rules, nonflow actions, and appropriate experimental and management actions that comply with the Grand Canyon Protection Act of 1992 requirements to minimize impacts on resources within the area impacted by dam operations. The water-operating criteria is specified by the 2016 ROD for two time horizons; namely monthly release volume targets and restrictions that limit hourly operations within a day. These intraday criteria limit hourly releases, changes in releases between two consecutive hours, and the range of hourly flows that occur during 24-hour rolling periods. Although not specifically mandated by the 2016 ROD, WAPA and other interested parties have a nonbinding agreement that restricts daily water release volumes. These restrictions are referred to in this document as intramonthly daily restrictions.

The 2016 ROD requires that Reclamation and WAPA periodically conduct various GC experiments. These include the aforementioned high-flow experiments and other types of experiments such as trout management flows and "bug" flows. Exceptions to intraday operating criteria are also made to accommodate experimental releases. These experiments are neither simulated nor analyzed for this vignette demo.

F.2 Win-Win Toolset Algorithms and Methods

We selected 2028 as our study year to incorporate into the analysis the impacts of the evolving WI on hydropower operations. Within its geographical footprint, the WI is projected to increase wind and solar power production, retire several coal-fired power plants, and increase its reliance on highly efficient and flexible natural-gas-fired technologies. In total, these measures are expected to substantially reduce GHG emissions from the power sector, change the behavior of utilities that purchase GCD energy and capacity resources, and modify use of the GCD hydropower resource. These changes are represented in the modeling process via evolving grid LMPs that drive the utilization of limited water resources for hydropower production. The toolset is designed to use any price pattern such as historical or projected LMPs generated by sophisticated models or by other routines.

For the demonstration, we assumed a "typical" annual water release volume from GCD of 8.231 MAF. This typical release volume may change (possibly decrease) in the future due to potentially evolving hydrological conditions and increased water withdrawals from the UCRB. Although we assumed an annual volume of 8.231 MAF, the Win-Win Toolset is designed to model a large range of feasible annual water releases from Lake Powell.

For the GCD demo, we explore potential win-win strategies via a set of tools that quantify both environmental metrics in the Colorado River downstream of the dam, including those in Grand Canyon National Park, and an economic metric for the WI power grid. It is **not** intended to produce a final answer to or resolve GCD operational, water, and/or environmental issues that have been studied by a multitude of top researchers, analysts, and modelers for decades. Instead, the intent of this project is to complement and augment past and current models and fill a significant modeling gap that exists today. That is, past GCD studies have explored a wide range of alternative operating criteria at GCD, but these were few (typically less than 10) and far between. However, there are multitudes of other alternatives between those few options and beyond that may potentially yield better results.

Many analysts recognize that studying more alternatives would provide useful information in the decision-making process, but historically GCD alternatives were very expensive and time consuming to formulate and conduct. The challenge is to develop a process that automatically constructs alternative sets of operating criteria and inexpensively computes relative impacts for various metrics of interest rapidly. In addition, the toolset must address these impacts simultaneously with a level of fidelity that produces reasonably accurate results. To accomplish this, the toolset constructed and demonstrated in this study leverages existing models but applies the models in a novel framework. That is, the new toolset and processes complements existing methods and models. It does not compete with or replace existing tools.

The GCD demonstration illustrates the types of insights that users can gain from analyzing the toolset results. These insights can help decision makers select and formulate improved operating criteria through human-machine interactions. That is, model-derived insights can be used by modelers to fine-tune successive model runs to improve upon either existing operating criteria or previously discovered win-win solutions.

F.2.1 Water Release Criteria

For this demonstration, criteria specified under the 2016 ROD are used for the BAU case and serve as the benchmark from which other operating criteria are compared. Table F-1 contains information from the 2016 LTEMP EIS final report. It provides an example of monthly release volume targets as a function of total annual water release. In general, Reclamation currently uses the values in this table to guide monthly release decisions. For the win-win model demo, the BAU benchmark case assumes a typical GCD annual release of 8.231 MAF. Note that the monthly release targets associated with this annual release level are shown in bold text.

In actual operations, the annual water target dictated by Reclamation mainly depends on the amount of water that is stored in Lake Powell, temporal inflows, and water delivery obligations. Monthly water releases, however, sometimes deviate from the plan in order to support a LTEMP experiment. For example, more water is shifted into a month when a high-flow experiment is conducted. To comply with the annual release level, less water is released during one of more non-high-flow experiment months. In addition, water releases sometime deviate from the levels shown in Table F-1 because of inflow forecast errors. Biannual and monthly water release volumes are planned by Reclamation prior to the beginning of each water year based on a forecast of future events. Actual events sometime deviate from these expectations and plans for the next 24 months are revised each month as time unfolds because of differences between actual events and previous projections.

Table F-1. Sample target monthly release volumes for the 2016 ROD operating criteria as shown in final GCD LTEMP EIS report.

Annual	**7,000**	**7,480**	**8,231**	**9,000**	**9,501**	**10,501**	**11,001**	**11,999**	**13,001**	**14,001**
October	480	480	**643**	643	643	643	643	643	643	643
November	500	500	**642**	642	642	642	642	642	642	642
December	600	600	**716**	716	716	716	716	716	716	716
January	664	723	**763**	857	919	1,041	1,102	1,225	1,347	1,470
February	587	639	**675**	758	813	921	975	1,083	1,192	1,300
March	620	675	**713**	801	858	973	1,030	1,144	1,259	1,373
April	552	601	**635**	713	764	866	917	1,019	1,121	1,223
May	550	599	**632**	710	761	862	913	1,014	1,116	1,217
June	577	628	**663**	745	798	905	958	1,064	1,171	1,277
July	652	709	**749**	842	902	1,022	1,082	1,202	1,322	1,443
August	696	758	**800**	899	963	1,091	1,156	1,284	1,413	1,537
September	522	568	**600**	674	722	819	867	963	1,059	1,160

Some of the alternative operating criteria that were examined in support of LTEMP EIS studies had monthly water release targets that differed from those shown above. Some were less conducive for power economics relative to the 2016 ROD, while others yield higher economic values.

The 2016 ROD hourly restrictions are shown in Table F-2. It requires water release rates to be 8,000 cfs or greater between the hours of 7:00 a.m. and 7:00 p.m., and at least 5,000 cfs during the night. The criteria also limit how quickly the release rate can increase and decrease between consecutive hours. The maximum hourly increase (up-ramp rate) is 4,000 cfs/hr, and the maximum hourly decrease (down-ramp rate) is 2,500 cfs/hr. The 2016 ROD operating criteria also restrict how much the releases can fluctuate during rolling 24-hour periods. This daily change (fluctuation) constraint varies monthly depending on the monthly volume of water release. Capped at 8,000 cfs, the daily fluctuation is equal to ten times the monthly volume in thousand acre-foot (TAF) from June to August and nine times the monthly volume in TAF during other months of the year.

Table F-2. Operating constraints under the 2016 ROD (applied October 2017 through the present).

Operational Constraint	2016 ROD Flows (From October 2017)
Minimum release (cfs)	8,000 from 7:00 a.m.–7:00 p.m. 5,000 at night
Maximum release(cfs)	25,000
Daily fluctuations (cfs/24 hr)	Depending on monthly release volume
Ramp rate (cfs/hr)	4,000 up 2,500 down

Daily range not to exceed 8,000 cfs.

The maximum release rate is limited to 25,000 cfs under the 2016 ROD operating criteria. Maximum flow rate exceptions are allowed to avoid spills and/or conduct flood releases during high runoff periods. Under these very wet hydrological conditions, when the average monthly release rate is greater than 25,000 cfs, water must be released at a constant rate during the entire month.

Nonbinding agreements restrict WAPA daily water release volumes during each month of the year. These restrictions are referred to as intramonthly daily restrictions and do not change during the course of the year (i.e., restrictions remain the same regardless of the month of the year). The guidelines that WAPA has agreed to are as follows:

- Volumes are approximately the same each weekday throughout the month

- Saturday, Sunday, and holiday release volumes are no less than 85% of the weekday average
- Saturday, Sunday, and holiday release volumes are capped at the weekday average.

F.2.2 Environmental, Energy, and Revenue Outcome Metrics

In support of the GCD LTEMP EIS, the following resources were studied and analyzed under each alternative: (1) archaeological and cultural; (2) natural processes; (3) HBC; (4) hydropower and energy; (5) other native fish; (6) recreational experience; (7) sediment; (8) tribal; (9) rainbow trout fishery; (10) nonnative invasive species; and (11) riparian vegetation. Because of time and budget limitations, this vignette demonstration measured impacts of alternative operations for a subset of these considerations. Also as stated above, the purpose was to demonstrate a complementary modeling methodology and toolset. Therefore, results from the GCD demonstration should be interpreted through that lens with the realization that we only address a few impacts. It is not intended to provide definitive solutions to any real-world GCD problems.

For GCD demonstration purposes only, metrics used to identify operating criteria that result in environmental and hydropower economic win-win solutions for the year 2028 relative to levels computed under the 2016 ROD criteria include:

Economic energy value: Historically, the majority of the GCD hydropower plant economic value is from its energy production. For this study, the projected economic value of GCD for the year 2028 is calculated by summing, over all hours of the year, GCD hourly energy production times hourly LMP. Large annual water releases that drive its turbines coupled with its high output capacity enable the power plant to generate relatively large amounts of energy at times of the day when they have the highest value (i.e., LMPs). Although we only use one economic metric for GCD for this vignette demo, other operational value streams such as ancillary services and capacity metrics can be accommodated by the toolset.

HBC: The HBC is an endangered native fish of the Colorado River that evolved around 3-5 million years ago.[5] For this analysis, we measure the impacts of GCD water release patterns on the HBC using fish growth-rate metrics at two key HBC habitats. These are located 61 and 225 RM downstream of GCD. Both locations are within the Grand Canyon National Park. In general, slower river flow rates result in warmer water temperatures at these two sites and promote faster HBC growth rates especially during warm/hot summer months.

Sediment transport: Sediment controls the physical habitat of riverine ecosystems downstream of GCD. It is deposited or eroded from the various environments in the Colorado River, and sediment suspended in water determines water clarity. Changes in the amount and areal distribution of different sediment types cause changes in river channel form and river habitat. For this vignette demo, we estimate metric tons of sediment transport in the Lower Colorado River. It is primarily a function of water flow with sediment transport that increases with faster water flows.

As discussed previously, this proof-of-concept vignette demo considers only three of the 11 LTEMP study topics; namely, HBC, hydropower/energy, and sediment. The framework and methods developed for this analysis could, however, be expanded to include all of the above resources.

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5 https://www.coloradoriverrecovery.org/general-information/the-fish/humpback-chub.html

F.2.3 Modeling Framework, Methods, Tools, and Supporting Data

Over the past 30 years, numerous financial and economic analyses have been conducted on various GC operating criteria, experimental water releases, and the marketing of GCD hydropower plant resources. This includes LTEMP EIS studies that analyzed only six primary alternative operating criteria along with the nonaction operating criteria. None of the alternatives resulted in a win-win solution and, if implemented, only one was expected to provide small hydropower benefits (e.g., lower firm electric service customer rates by about 0.27 percent).

A key feature of the new toolset methodology that distinguishes it from those used for past studies is that it examines a very large number of alternative operating criteria over a broad range of feasible options in combination with monthly, daily, and hourly water release profiles in the search for win-win solutions. Because we examine a very large landscape/operational space, metrics for this vignette demo are, by necessity, measured with less accuracy as compared to very detailed modeling performed in support of previous analyses. Therefore, once potential win-win dam operations are identified, more detailed analyzes should be conducted to determine the validity of the model's solutions. After we gain insights into the general types of operations that lead to win-win results, further adjustments to the criteria can be made to address other considerations outside of the modeling process that are difficult to measure but still important.

The win-win methodology uses a comparative approach. Essentially, metric values computed for the BAU operating criteria serve as a benchmark from which other operational regimes are measured. A comparative analysis approach like this has been used to measure changes in environmental and economic outcomes associated with alternative hydropower resource operating criteria in the UCRB for more than three decades. This includes high visibility studies that support EISs.

F.2.4 Win-Win Toolset Components

The Win-Win Toolset uses existing models/routines and new ones to fill in modeling gaps. Existing models that are used in the toolset include a PCM, a detailed hydropower centric model, and the LTEMP EIS screening tool. For the GCD demo, the lab team used PLEXOS for WI production cost modeling and the GTMax model to conduct detailed simulations of Lake Powell water releases (both power and nonpower) and associated hydropower energy production. Although these models were used, the win-win framework can accommodate other PCMs and hydropower models which produce key results that are used by other toolset components.

New routines were built and used specifically for this project to address modeling gaps. In combination, these routines perform the following functions:

1. Automatically construct alternative operating criteria/rules
2. Allocate a limited daily water release volume to hours of the day and compute hourly metric values
3. Construct functions that estimate the impact of daily water release volumes to various metrics (e.g., power economic, HBC growth, and sediment transport)
4. Select the best hourly water release pattern from the given set constructed by function 3
5. Compute monthly and annual metric values for both user-defined and randomly constructed sets of operating criteria, daily release volumes, and monthly water release volumes
6. Calculate pareto frontier (tradeoff) curves
7. Uniquely display model results in both two- and three-dimensional spaces.

F.2.5 Toolset Modeling Processes

The toolset methodology uses several modeling processes/functions that conceptually are performed in sequence. These processes are grouped into sets that produce the following final products:

Process Set 1: Daily metric computation as a function of water release volume. Thousands of polynomial functions that relate daily water release volumes to various metrics. Functions are derived for all combinations of (a) intraday alternative operating criteria, (b) three different day types, (c) monthly water release distributions, (d) base hourly shaped water release patterns, and (e) morphed hourly shapes.

Process Set 2: Evaluating metrics intraday and intramonthly. Operating criteria with tens of thousands or more sets of metric values for toolset constructed sets of intraday alternative operating criteria and intra-annual criteria (monthly/daily water release volume) combinations.

Process Set 3: Creating Pareto Frontiers. Two-dimensional pareto frontiers (tradeoff curves for metric pairs) for each alternative intraday operating criteria.

Details about each of these process sets are provided below.

F.2.5.1 Process Set 1

The first set of processes performed by the Win-Win Toolset creates thousands of polynomial functions that describe the impact of daily water releases on various metrics. As shown in Figure F-2 below, the first set of model processes begins with PLEXOS, a detailed PCM. For this study, it projected 2028 WI grid operations over the entire WI. It also simulates both DA slow-start and hour-ahead fast-start unit commitments, schedules resource actions, and estimates time series of hourly LMPs throughout the WI, including those at the GCD hydropower plant. As a modeling simplification, it was assumed that RT operations do not deviate from hour-ahead schedules. Because RT is computationally very expensive, it was decided that, for the purpose of this proof-of-concept demo, the finer RT 5-minute temporal granularity was not warranted. The PLEXOS model run was performed by NREL staff and LMP results associated with the GCD were then input into the first modeling process shown below. ANL developed the process and applied the PLEXOS LMPs to the demo case.

A parallel process creates unique intraday alternative operating criteria. Each set of operating criteria is comprised of various components. For this demonstration, six types of criteria components were used based on constraints specified in the 2016 ROD. Illustrated in the upper-right corner of Figure F-3, these intraday criteria components consist of: (1) daytime minimum release rate; (2) nighttime minimum release rate; (3) hourly up-ramp limit; (4) hourly down-ramp limit; (5) a daily change/range limit; and (6) a flow rate ceiling. When the daily water volume can only be realized if the ceiling is exceeded, then water releases during the entire day are at a constant rate (flat flow).

For each of these six components, the model user specifies one or more limits. For example, three daily change limits of 400, 800, and 1,200 acre foot per hour (AF/hr), are entered in the table on the right side of Figure F-3. These limits constrain the range of GCD daily operations (i.e., max minus min release rate during each 24-hour period). After information is entered into the table for all six types, the algorithm generates a list of all possible combinations of these components and eliminates those that are either redundant and/or contradictory. Each of these unique combinations (one from each category) constitutes an alternative operating criterion set. In addition, the user can specify additional operating criteria sets manually, such as those shown in first three rows of the larger table shown in the left-hand side of Figure F-3. Note that the user-input form shown below also contains key model parameters such the definition of daytime and nighttime hours and the assumed pool elevation of Lake Powell.

Figure F-2. Overview of Process Set 1, which constructs multiple daily release patterns and computes estimates of both power and environmental metrics.

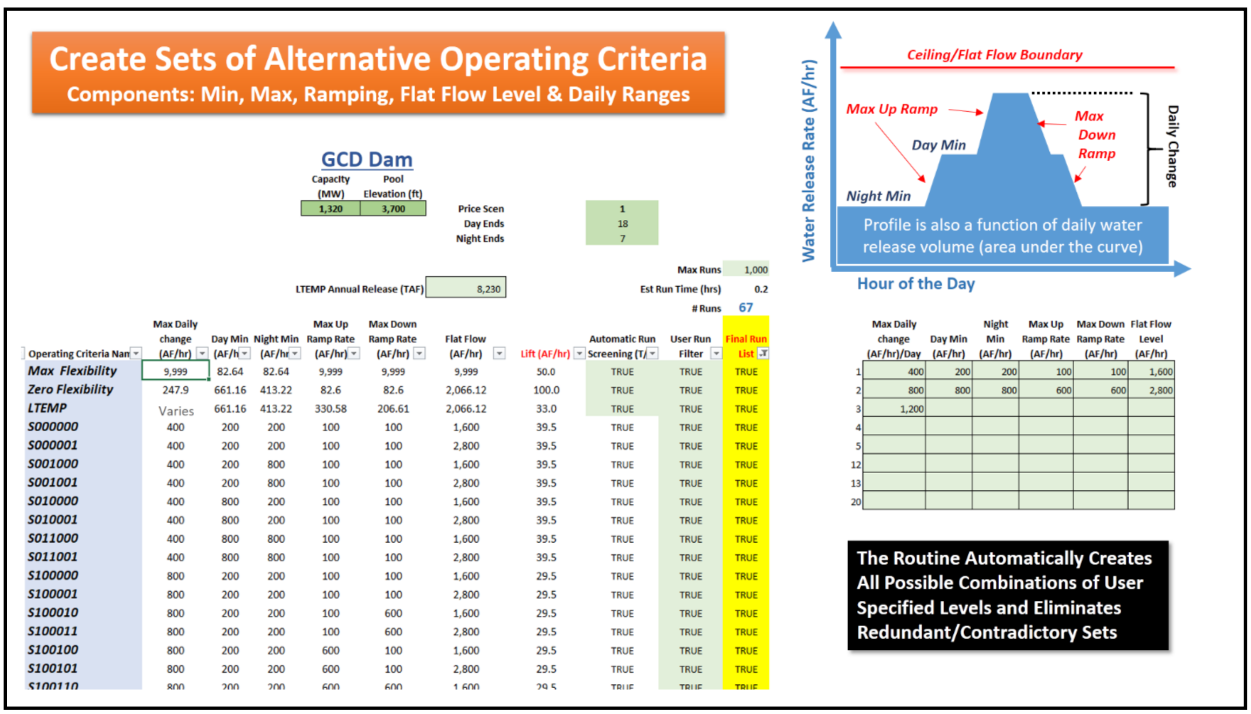

Figure F-3. User-input form and sample sets of computer-generated combinations of daily operating criteria.

The next step in the modeling process uses the GCD LMPs projected by PLEXOS to shape numerous hourly water release patterns under specific operating criteria for typical day types for each month of the year. Day types consist of three categories: (1) Sundays/holidays; (2) weekdays; and (3) Saturdays.

Figure F-4 shows sample daily water release patterns created by the win-win model for the GCD 2016 ROD operating criteria (benchmark case) for various levels of daily water release volume during a typical Sunday in January 2028. The figure also shows an hourly price profile that drives water release patterns. It is the average hourly PLEXOS LMP profile of all Sundays/holidays during January 2028. These average (typical) prices are represented by the green dashed line in the graph (i.e., market price shown on the secondary axis).

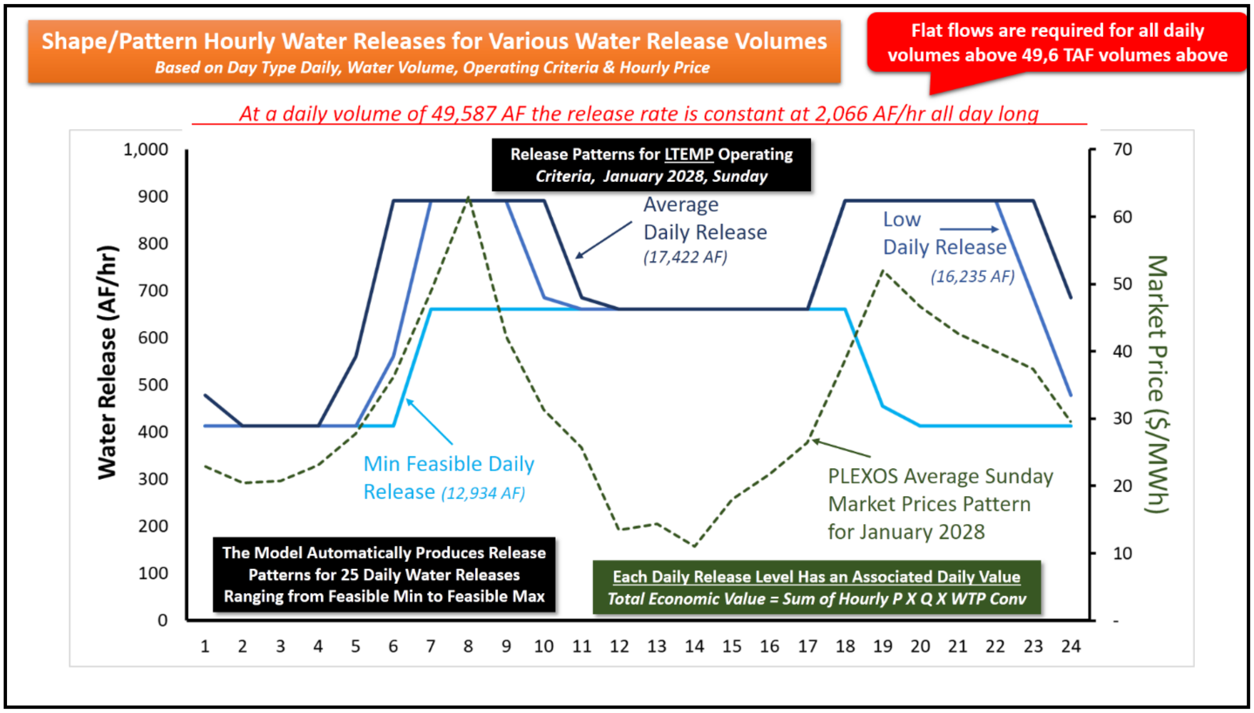

Figure F-4. Sample daily water release patterns under the LTEMP operating criteria (benchmark case) for various levels of daily water volumes during a typical Sunday in January 2028.

The hourly water release pattern under the 2016 ROD operating criteria associated with the smallest compliant daily release volume (12,934 AF) is shown as the light-blue line in the figure. This pattern conforms to 2016 ROD minimum daytime and nighttime flow rate requirements. Also, the ramping that occurs during transition hours between the day and night periods are compliant with 2016 ROD maximum up and down ramp-rate limits. At this low daily water volume, operators have very little to no discretion on the daily water release pattern. In this document, the daily water release volume above the minimum level is refer to “discretionary water” because operators can pattern its hourly release in a flexible manner as long as it does not violate operating criteria.

The dark blue line illustrates how the model patterns a daily water release volume of 17,422 AF. This pattern releases the largest possible amount of discretionary water allowed by the 2016 ROD during hours of the day that have the highest prices. In this case, the fastest allowable release rate is constrained by the daily change limit of about 477 AF/hr per 24-hour period plus the nighttime minimum release of 413 AF/hr (i.e., a total of 890 AF/hr). There are 35 daily release patterns with an hourly temporal granularity constructed for each month, day type, and daily water release combination. Each one has a different volume with a pattern that, within 2016 ROD operating criteria, is primarily driven by market prices and capped by a maximum flow rate of 980 AF/hr.

The form shown in Figure F-3 includes a user lift input for each set of operating criteria. A lift parameter value is either entered directly by the user for each alternative or determined by an equation that is formulated by the user. The model uses the lift parameter to morph a basic release pattern into other patterns that are also compliant with the intraday operating criteria. It does this by increasing the daily min and max release level. Figure F-4 is based on a lift level of 0.0 AF/hr, the results of which are night release rates that are at the minimum allowable level and, because the daily change constraint is binding, the daytime flow rate (approximately 890 AF/hr) that is substantially less than the allowed maximum of 2,066 AF/hr. This result may be economically suboptimal. By increasing the lowest flow rate during the night, more water would be released during the highest priced hours, while at the same time complying with the daily change constraint. When the lift level increases to a sufficiently high level, however, the daily change constraints are no longer binding. Instead, the maximum allowable flow rate restricts the highest daily flow rate. For example in Figure F-4, if the minimum release was lifted more than 1,176 AF/hour, the daily change constraint would not be binding; that is, a 890 AF/hr release (max flow using a 0.0 AF/hr lift) plus a lift of 1,176 AF/hr equals 2,066 AF/hr; that is, the max hourly flow rate limit. This implementation of the lift factor to create many different release patterns is computationally very efficient.

As mentioned earlier, water release patterns are constructed for each day type. Day type release patterns are typically not the same because the average daily price patterns that are used to shape water releases often differ in terms of the timing of price peaks and valleys. Absolute price level is also dissimilar; for example, Sunday prices tend to be lower than weekday prices.

For each month, 2,625 water release patterns for the 2016 ROD operating criteria are automatically created by the toolset (i.e., 25 daily water release volumes × 35 lift levels × 3 day types). For a year, this amounts to 31,500 patterns (12 months × 2,625 patterns/month). Identical numbers of water release patterns are constructed for each set of intraday operating criteria examined by the win-win model. All of the release patterns discussed above were used for the GCD demo. The win-win modeling framework, however, enables the tool to create either more or less patterns.

For this demonstration, LMPs are used as the primary driver to shape hourly releases during a day; however, other divers or combinations of drives could be used to shape hourly flow patterns. For example, if higher flows are preferred for river rafting and people raft during specific daytime hours, then a vector of indexes that represents the preference for higher water flows during specific hours could be input into the model. Application of this rafting index would result in a pattern that benefits rafting. Likewise, a weighted multi-objective index could theoretically be used as a driver.

For each daily water release pattern, values for power economic and environmental metrics are computed, the results of which are then used to create various curves that are expressed as fourth-order polynomial equations. To illustrate this process, the method used to construct a GCD hydropower economic value equation is discussed in detail below.

Constructing Hydropower Value Equations

The win-win modeling process automatically constructs hydropower value equations as functions of daily water release volume. The first step in the modeling process computes the total daily value of energy production associated with each of the release patterns discussed in the previous section. Daily values are computed by first multiplying an hour water release rate by both a water-to-power conversion factor[6] and an hourly price. If an hourly release rate exceeds the physical maximum turbine flow, the flow rate used by the calculation is capped at this maximum energy production level. Next, these hourly values are added together over all hours of the day to compute the daily total.

After values are computed for each daily water release pattern, curves and equations are constructed that relate daily water release volumes to daily GCD economic value for each combination of intraday operating criteria, month, day type, and lift level. For example, for the GCD demo, 900 curves are produced for the BAU case (12 months × 3 day types × 35 lift levels). One such curve for a typical Sunday in January 2028 is shown in Figure F-4. Note that the curve is based on 25 pairs of water release volumes and associated economic values. In this example, these points correspond to the same 25 daily release volumes discussed above for the zero-lift level. A fourth-order polynomial equation based on a least-square fit of the value/volume points is then constructed. The result is a mathematical description of the relationship between daily economic hydropower value and daily water release volume. As shown in the figure, the curve fit has a high R2 value (over 0.999) with a small error value.7 For the GCD application, polynomial curve errors are usually less than 0.5%.

Figure F-5 also shows an incremental value of water curve (i.e., green dotted line). This line describes the additional value of GCD energy production if one additional AF of water is released from the reservoir. When the water release volume is low, an additional AF of water yields a relatively high economic value because this water can be used to produce power during the time of the day when the price is at its peak. Note in Figure F-4 that if the daily water release volume increased from 12,934 AF (i.e., no discretionary water) to 12,935 AF, the additional AF of water is discretionary and would be used by the model to produce power at 8 AM when the market price of energy is about $65/MWh. However, as more water is released, the incremental value of water decreases because release levels during high price hours are reaching the maximum allowable. The incremental AF of water is therefore released during an hour that has a lower price. At the high end of the curve, the incremental value of water is determined by the hour with the lowest price because all other hours during the day have water releases at the maximum allowable level. When the plant is operating at all hours of the day at the maximum power, the economic value of releasing more water is at best zero.[8]

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[6] Water-to-power conversion factors used in this study are based on an analysis of many years of historical monthly turbine-water release volumes, associated monthly generation levels, and Lake Powell forebay elevations (as recorded in form PO&M-59). The analysis reveals a strong correlation between the GCD water-to-power conversion factor and forebay elevation such that the power-conversion factor increases linearly as a function of higher reservoir elevation. This relationship between elevation and power conversion increased over time as turbine rewinds and upgrades were made to the power plant. Because GCD is a high-head dam, this approach provides for a fairly accurate estimate of water-to-power conversion efficiency. Alternative approaches may need to be developed, especially at low-head power plants.

[7] Errors refer to the difference between the value calculated by the least-square fit equation and individual water volume and economic value points.

[8] In most situations, additional releases above the maximum turbine flow rate decrease power production and therefore the value of hydropower because the additional water increases tailwater elevation below the dam and thereby reduces both the hydraulic head and turbine water-to-power conversion efficiency.

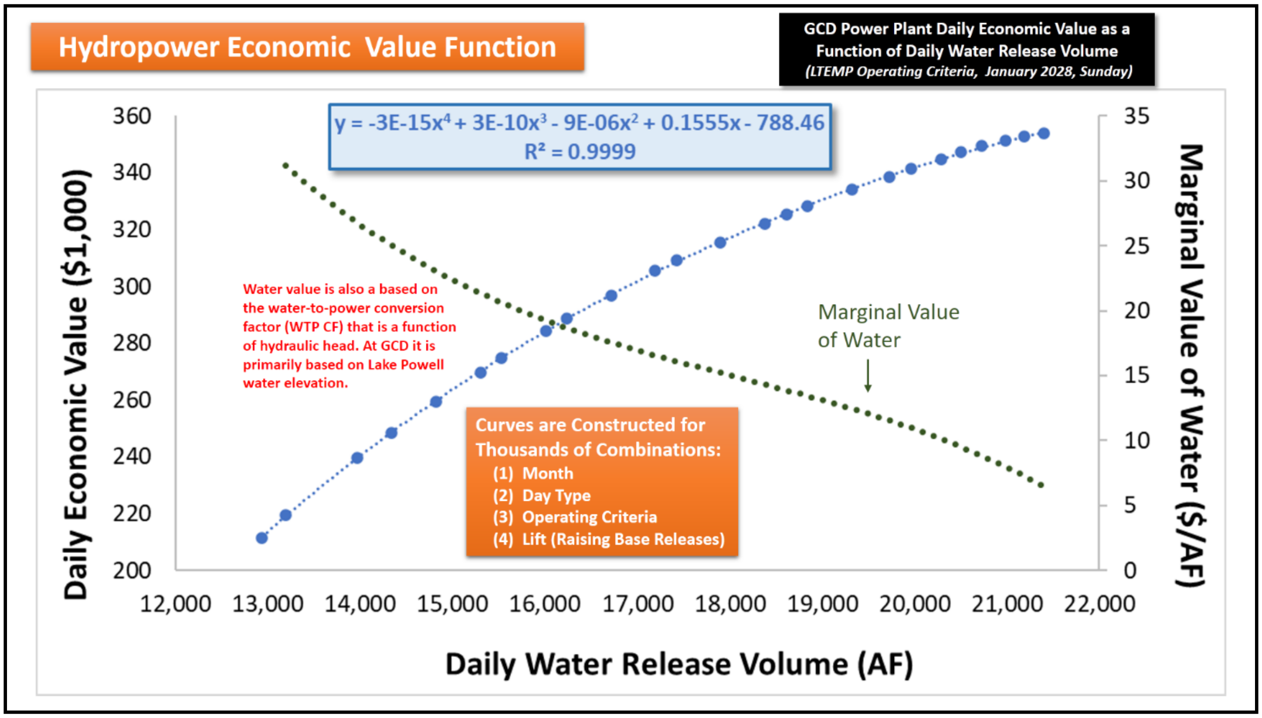


Figure F-5. GCD daily total and marginal economic value as a function of daily water release volume.

<u>Characteristics of Environmental Metrics and Daily Environmental Impact Curves</u>

To measure environmental outcomes associated with water release patterns and daily volumes, ANL is leveraging models and tools that have been developed to support LTEMP EIS analyses. This includes the GCD LTEMP EIS Alternative Screen Tool (AST) that models linkages among Colorado River average flow rates below GCD to HBC health indicators and sediment transport. AST is based on years of very detailed studies, research, and science. Although AST does not yield exact quantifications of environmental metrics, it quickly produces reasonable results that, for comparative analyses, are used to compute the relative magnitude of environmental benefits associated to different flow patterns.[9]

Figure F-6 shows relationships, in the form of fourth-order polynomial equations, between HBC growth rates and GCD water-flow rates for four months of the year at RM 61 and RM 225. These were developed for this study using AST.[10] Similar fourth-order polynomial equations were constructed for other months of the year. Note that during warm months, such a July and September, the HBC growth rate is high relative to the rate during cooler months (e.g., November). In addition, the growth rates during these warm months are more sensitive to changes in water-flow rates, especially at low levels. Based on AST, some winter months have zero growth at both downstream locations over the entire flow rate spectrum.

9 AST also performs power economic calculations, but these were not used because the approach described in the report and utilized by the win-win tool produced results that are significantly more accurate and considers a much larger array of different release patterns.

10 The AST model computes HBC growth rates and sediment transport on a monthly time step. However, the win-win tool methodology requires an hourly granularity. Therefore, the AST results were scaled from monthly values to hourly. Because of time and budget constraints, the accuracy of scaling has not been evaluated in detail. It was, however judged sufficient for this vignette demonstration of the win-win tool because the focus is on the methodology, not model results. In addition, HBC results using the scaled growth rates produced ballpark results that for comparative purposes were similar to using a monthly time step.

The seasonal characters of HBC growth rates point to some potential win-win solutions between hydropower economics and fish growth rates. For example, if less water (1,000 AF) was released during April, a month that typically has relatively low energy prices, and more water (also 1,000 AF) was released during January when wintertime prices peak, then power economics would improve. The monthly reallocation of water release volumes would also benefit the HBC. Note that HBC growth rates would be higher during April due to slower flows and therefore warmer water temperate. The HBC during January would largely be unaffected; that is, growth rates would continue to be zero. These win-win improvements occur even though the annual water release volume is identical under both cases.

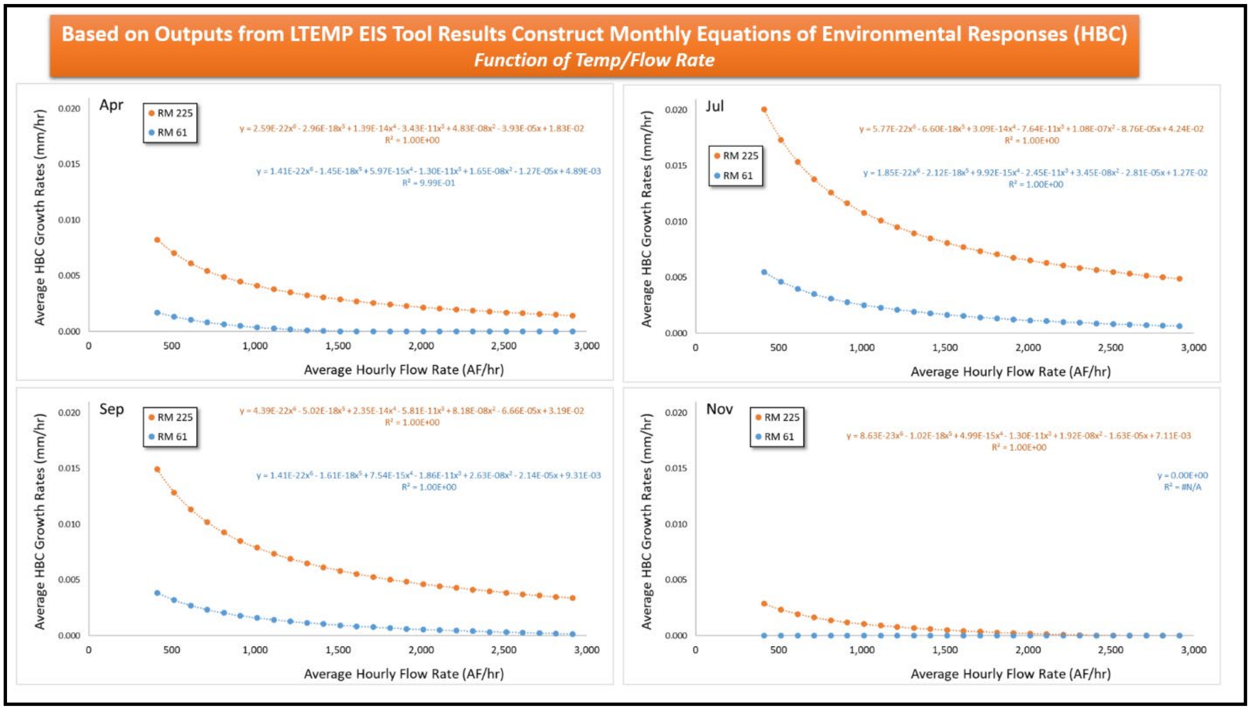


Figure F-6. Illustrative HBC growth rates as a function of water releases from GCD.

Using the same 13,500 daily release patterns[11] that were used for power economics, HBC daily growth rate was estimated by applying the hourly HBC polynomial equations described above to the water release patterns. A similar process that uses an hourly sediment transport equation based on AST was used to compute daily sediment transports levels. The final products of these processes are economic value, HBC growth at RM 61 and RM 225, and sediment transport amounts that correspond to each daily water release pattern and are consistent among all metrics.

Similar to power economics, curves and equations were constructed for daily HBC growth rate at both locations and sediment transport as a function of GCD daily water release volume. Examples of these curves are shown in Figures F-7 and F-8 for HBC growth rates and sediment transport, respectively. It should be noted that all daily metric curves created for the GCD demo site are influenced by the hourly water release pattern. However, both daily hydropower value and HBC growth rates are also a function of the month of the year.

11 These flow patterns include various unique combinations of monthly water volume, day type, and lift levels for each month of the year.

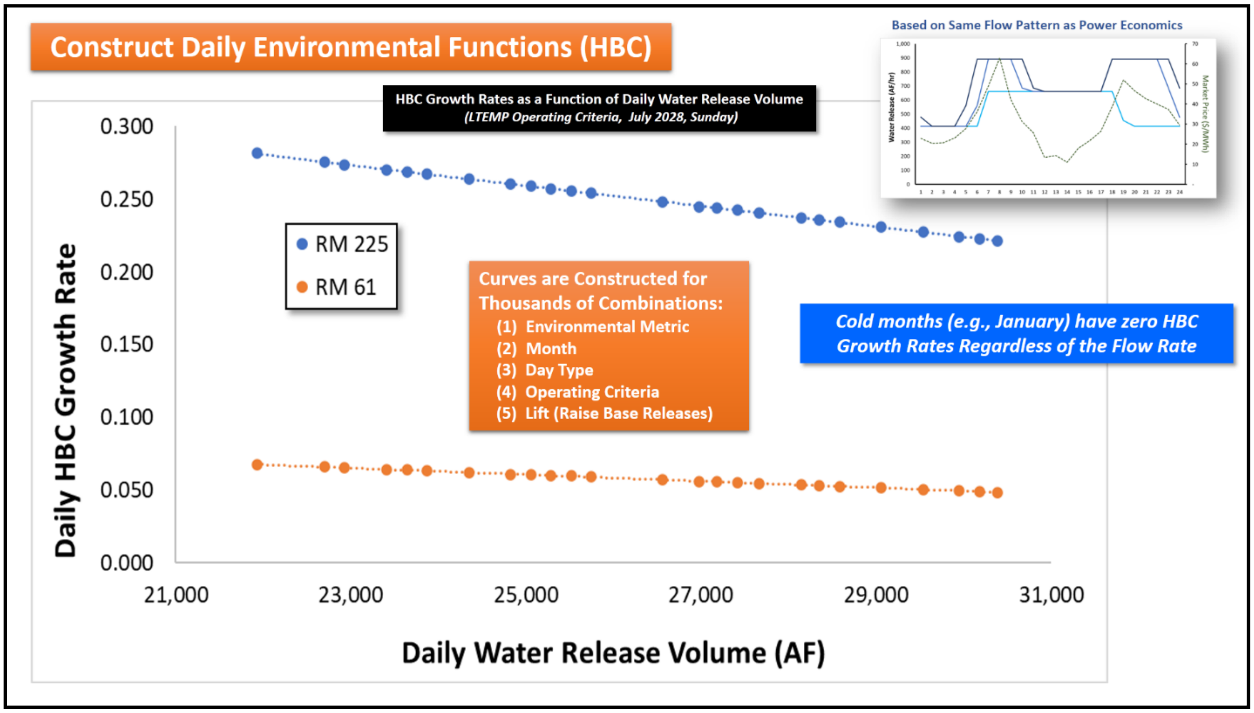


Figure F-7. Illustrative daily HBC growth as a function of GCD daily water release volume.

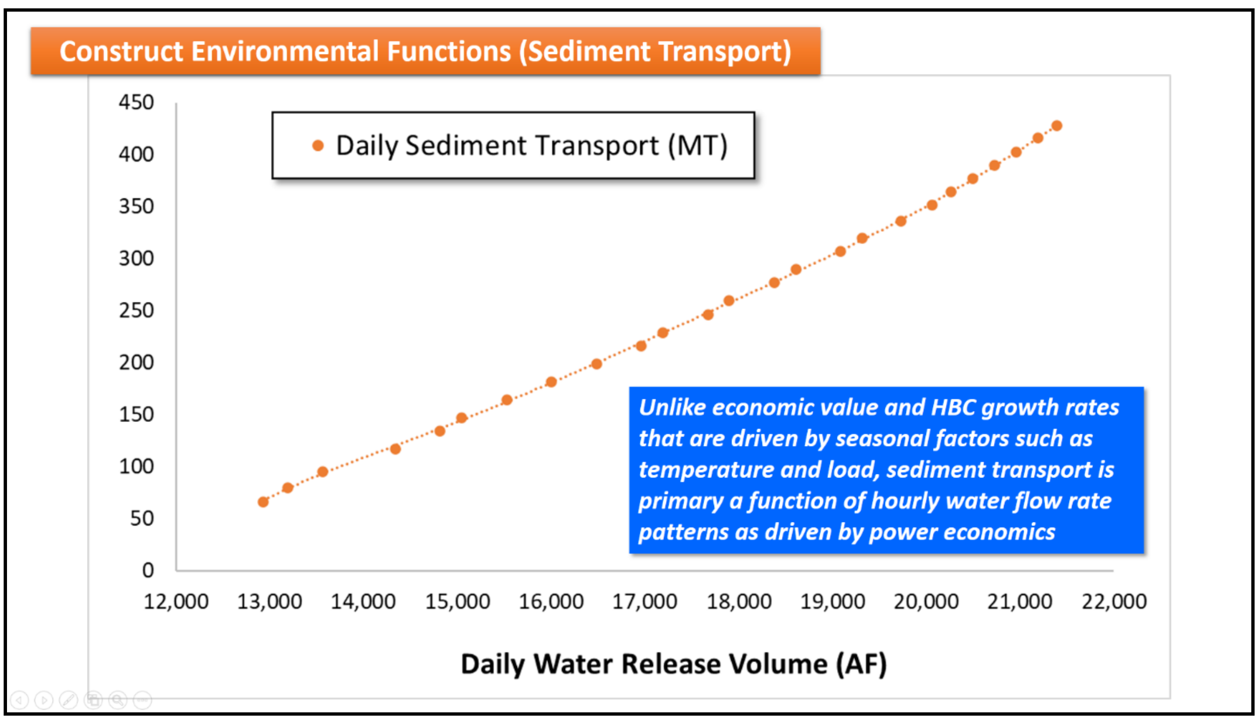


Figure F-8. Illustrative daily sediment transport as a function of GCD daily water release volume.

F.2.5.2 Process Set 2

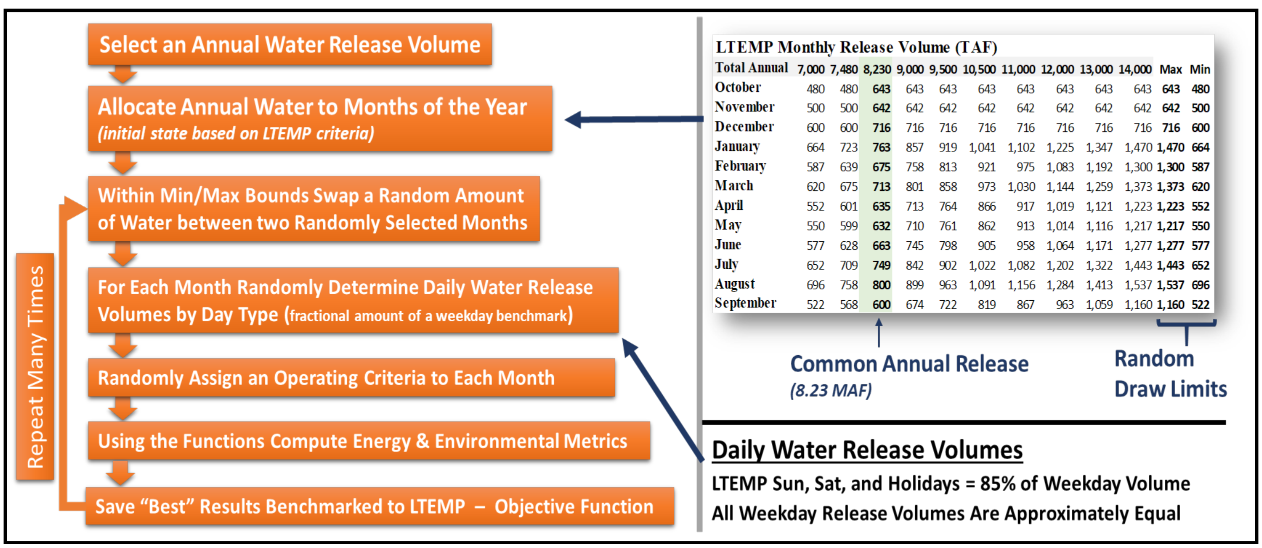
The first set of win-win modeling processes create daily water release patterns governed by various operating criteria components and construct equations that describe release pattern economic and environmental implications. The second set of processes used these equations to compute annual metric values for up to 1 million predefined and/or user-constructed sets of intraday and intra-annual (monthly or daily water release volume) alternative operating criteria combinations.

The purpose of this second set of processes was to find operating criteria with specific intraday and intra-annual limits that simultaneously increase power value and improve downstream riverine environments. As shown in Figure F-8, the first step in the search process randomly creates time series of monthly and daily GCD water release volumes that deviate from the benchmark 2016 ROD targets shown in the right-hand side of the figure.

<u>Criteria Creation and Evaluation</u>

For this case, the model searched for win-win operations under the assumption that 8,230 TAF of water would be released from Lake Powell in 2028. This annual water release volume is typical for GCD. The model initially uses the monthly water release volumes highlighted in green in the table and swaps a random volume of water between two randomly selected months. The volume of water that is reallocated from one month to another must not cause either of the months to fall outside the user-specified allowable range of monthly release volumes.

Under current operating practices, the volume of water released every weekday during a month is nearly the same; however, less water is released on Saturdays, Sundays, and holidays. Typically, these lower volumes are about 85% of the weekday water release volumes. The win-win search methodology simulates release volumes for the three day types that deviate from current practices. Deviation levels are based on random draws that, in relative terms, are within user-defined limits. Although this process results in a time series of monthly and daily water release volumes that differ from current 2016 ROD levels, the total annual amount released always equals 8.23 MAF.



Total Annual	7,000	7,480	8,230	9,000	9,500	10,500	11,000	12,000	13,000	14,000	Max	Min
October	480	480	**643**	643	643	643	643	643	643	643	**643**	**480**
November	500	500	**642**	642	642	642	642	642	642	642	**642**	**500**
December	600	600	**716**	716	716	716	716	716	716	716	**716**	**600**
January	664	723	**763**	857	919	1,041	1,102	1,225	1,347	1,470	**1,470**	**664**
February	587	639	**675**	758	813	921	975	1,083	1,192	1,300	**1,300**	**587**
March	620	675	**713**	801	858	973	1,030	1,144	1,259	1,373	**1,373**	**620**
April	552	601	**635**	713	764	866	917	1,019	1,121	1,223	**1,223**	**552**
May	550	599	**632**	710	761	862	913	1,014	1,116	1,217	**1,217**	**550**
June	577	628	**663**	745	798	905	958	1,064	1,171	1,277	**1,277**	**577**
July	652	709	**749**	842	902	1,022	1,082	1,202	1,322	1,443	**1,443**	**652**
August	696	758	**800**	899	963	1,091	1,156	1,284	1,413	1,537	**1,537**	**696**
September	522	568	**600**	674	722	819	867	963	1,059	1,160	**1,160**	**522**

Figure F-8. Overview of the process used for the second win-win modeling component that assembles time series of randomly selected monthly and daily water release volumes constrained by randomly selected monthly operating criteria.

The last set of random draws determines the operating criteria that will be used to limit daily water release patterns. The pool of criteria from which random draws are made were created using the process discussed previously. See Figure F-3 to view the user-input form and sample computer-generated sets of criteria. The user has the option to apply the same operating criteria to all months of the year or for the model to randomly select criteria sets for each month.

The toolset allows the users to define the types of criteria that are evaluated. This includes upper and lower limits of both monthly and daily water releases and the set of intraday operating criteria from which to make random draws. By examining toolset results and patterns of solutions, the user gains a better appreciation for the types of overall criteria (combinations of intraday components and monthly/daily release) that lead to various metric outcomes.

Best Hourly Release Criteria

As previously described, there are many 2016 ROD compliant flow patterns that follow prices; some yield a higher power economic value for the same daily water volume as others. In addition, each compliant hourly release pattern yields a different value for all other metrics. This section describes the process that is used to identify the best flow pattern to use for each month and day type.

The toolset uses the lift process to create these different compliant patterns. Each one results in a unique hourly release pattern with associated daily power economic (econ) and environmental (HBC RM61, HBC225, and SedTransp) outcomes. Outcomes for various release volumes are then used to create metric curves/equations for each lift level. Curves with lower lift levels describe daily release volumes that are relatively small, while larger lift levels describe daily water releases that are larger (Figure F-9). Most of the individual functions typically have portions of the curve it describes overlap with two or more of the other lift curves. For example, Figure F-10 shows 11 lift curves overlap at a daily release volume of 21,315 AF during a typical Sunday in January. Depending on the lift level equation that is used, the daily economic value ranges between $352,100 and $365,900. In this example, the economic value is maximized when release rates during the daytime and nighttime are at least 300 AF/hr higher than the minimum requirement. By shifting/lifting the base curve upward relative to pattern, more water, and therefore generation, is produced during peak price hours. On the other hand, lifting the entire curve also results in higher limited water resource releases during off-peak periods.

When analysis solely focuses on maximizing the hydropower economic metric (i.e., no weight given to HCB and sediment transport), then the hourly water release pattern associated with the 300 AF lift level is used. When other metrics, such as HBC growth rates and sediment are considered, the 300 AF/hr lift level may be suboptimal (from a modeling perspective). Therefore, when multiple objectives are considered, the best lift curve and release point selected by the toolset (e.g., 21,315 AF using the 300 AF/hr lift) are not based on a specific metric (e.g., economic value curves). Instead, the curve/point selection process is based on lift curves that are constructed from the weighted importance given to each metric. The user inputs monthly weights for each metric (e.g., economics, HBC growth) into the toolset. For each month, the sum of these weights equals 1.0.

The Win-Win Toolset then uses these weights and individual metric curves to create a composite score for each lift level for a given daily water release volume. Model computed scores for each metric are benchmarked relative to the 2016 ROD outcome. For example, a score of 1.1 for the economic metric for a specified daily release volume during a Sunday in January means that the alternative operating criteria results in a value that is 10 percent higher than the economics of the BAU case. The lift level that yields the highest total monthly score (i.e., sum of metric score × the user-specified monthly weight) is selected as the best release pattern associated with an alternative operating criteria. A total weighted score higher than 1.0 indicates that one or more of the metrics does better than the BAU case for that month and day type.

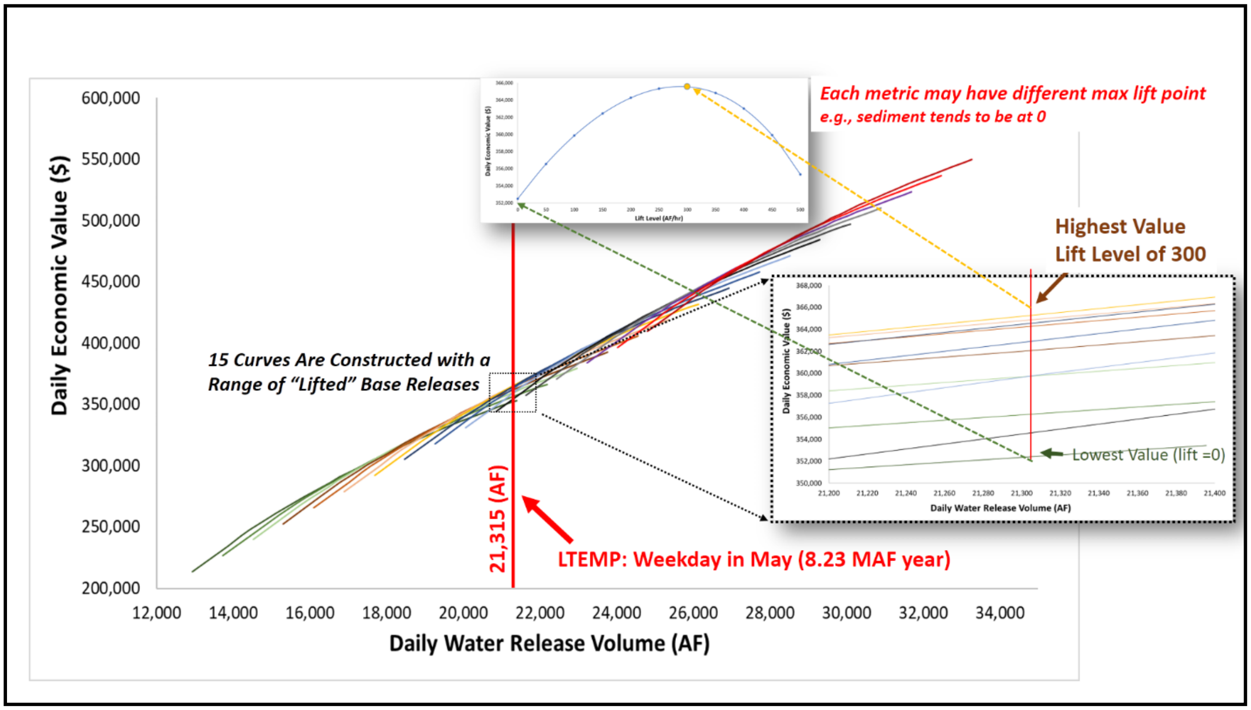


Figure F-9. Economic value of GCD energy production as a function of lift level for a daily water release volume of 21,315 AF.

The annual score is the average of the 12 monthly scores in the year. Note that model win-win solutions have objectives that may look at times conflicting. Typically:

a) Win-win solutions may not have the best annual score (highest possible value) for individual metrics, but these individual scores are better than scores from the BAU case

b) For some months of the year, the score of one metric may be less than the one from the BAU, but the annual average of this metric is still higher for the win-win solution.

For example, the win-win solution may yield an economic value that is $50,000 less than the 2016 ROD benchmark in April, but is $75,000 higher in January, due to a reallocation of monthly water release volumes. The $75,000 increased economic value during January, however, may not be the highest possible level.

Selected toolset results are saved for every alternative operating criteria examined and a post-process is used to display these results along with pareto frontiers (tradeoff curves). Results can also be filtered by the user to help identifying common characteristics of criteria that fall into various categories (e.g., win-win, lose-lose).

F.2.5.3 Process Set 3

Search results produced by Process Set 2 may find win-win solutions, but regardless of the number of random and user define operating criteria that were examined, they do not guarantee the search will find the global optimum for either single or multiple objectives. Therefore, another modeling capability was added to the Win-Win Toolset to approximate two-dimensional Pareto frontiers; that is, tradeoffs curves between two given metrics (e.g., hydropower value and HBC growth at RM 225).

The method that constructs these curves uses mixed integer programming (MIP), which guarantees that mathematically the Pareto frontier is precisely at the maximum level over all points of the curve. By necessity, however, the mathematical formulation that is put into the Pareto frontiers model for this application is imprecise (a simplification of the problem/reality) and only considers some aspects of the problem. Therefore, it is possible that the random modeling approach could produce some results that may be slightly outside (better than) the Pareto frontier. A detailed explanation of why this may occur is provide later in the section.

The toolset leverages Process Set 2 capabilities that for each month is used to approximate metric values at various user-defined water releases ranging from the lowest possible monthly release volume to the highest. The results from this first step of Process Set 3 are used to assemble monthly piecewise linear functions. These functions (one per month for each metric) are represented in the MIP construct using special ordered sets of type 2 (SOS2) formulation. This method correctly evaluates functions that have any shape.[12] Depending on the structure and size of the formulation, however, MIP models that use the SOS2 technique may take a very long time to solve.

Figure F-10 shows monthly curves for monthly HBC growth at RM 225 as a function of water release volume that are produced via the Process Set 2. It was constructed for a very fine level of granularity (i.e., small water volume intervals) giving the stepwise curve a smooth appearance. Note that for the same monthly water release volume, warm months of the year have much faster growth rates than cooler months. In addition, for any given month HBC growth decreases as the release volume increases. Growth rates for December and January are always zero, even at the lowest monthly release volume. Piecewise linear curves such as these are constructed for all metrics, but the current Pareto frontiers model only uses two of them at a time. It is possible to expand the capabilities of the model to solve frontiers with three or more dimensions; that is, simultaneously analyze tradeoffs among more than two metrics.

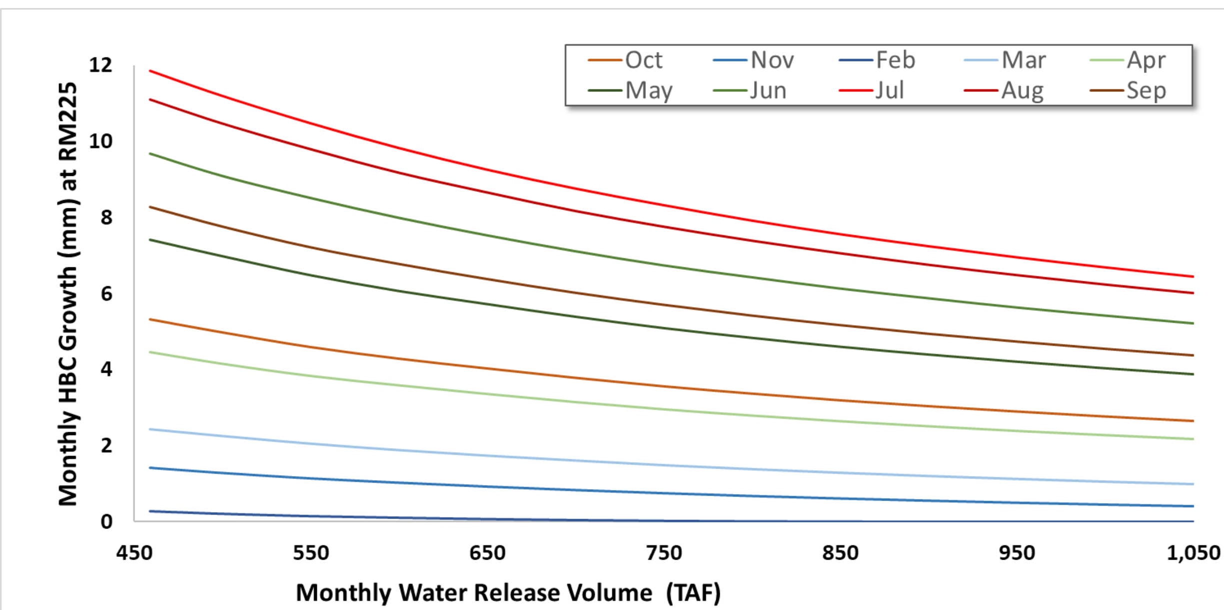


Figure F-10. Monthly HBC growth rate at RM 225 as a function of monthly water release volume.

12 MIP formulation uses integers to ensure the various segments of the piecewise linear curves are used in the correct order, regardless of the shape of the curve it represents. In contrast, linear programming requires that piecewise linear curves are convex; that is, a shape with a specific characteristic that increases upward.

These curves are based on a user-specified set of relative daily release parameter values. These inputs vary by month and day type, but not monthly release volumes. Although, accommodated by the model structure, these inputs could also be adjusted for each monthly water release volume simulated by Process Set 2. They would, however, be very labor intensive; therefore for this study, modelers only used a static set of monthly day type input values that in general produced good results over all daily water release volumes. Alternatively, the model could potentially be reformulated such that it also solved for daily release volumes; however, this would substantially expand the size of MIP problems and it may take the MIP/SOS2 model a very long time (hour/days) to find the optimal solution.

The next Pareto frontiers modeling step is to run the MIP/SOS2 formulation such that it maximizes the sum of annual values for two metrics, whereby each metric is assigned a weight. Weight pairs (one per metric) must sum to 1.0. The model performs metric value calculations for several different pairs of weights (preferences) ranging from [1.0, 0.0] (metric 1 and metric 2, respectively) to [0.0, 1.0]. A weight pair of [0.5, 0.5] equally balances outcomes for both metrics. The result of the MIP model for a run with a given weight pair are monthly water releases and metric values. These [x, y] value pair solutions form a piecewise linear Pareto frontier. The higher the number of unique weight pair points evaluated, the more precise (e.g., smooth) the curve. Results of the Pareto frontier model for an annual water release volume of 8.231 MAF is shown in Figure F-11.

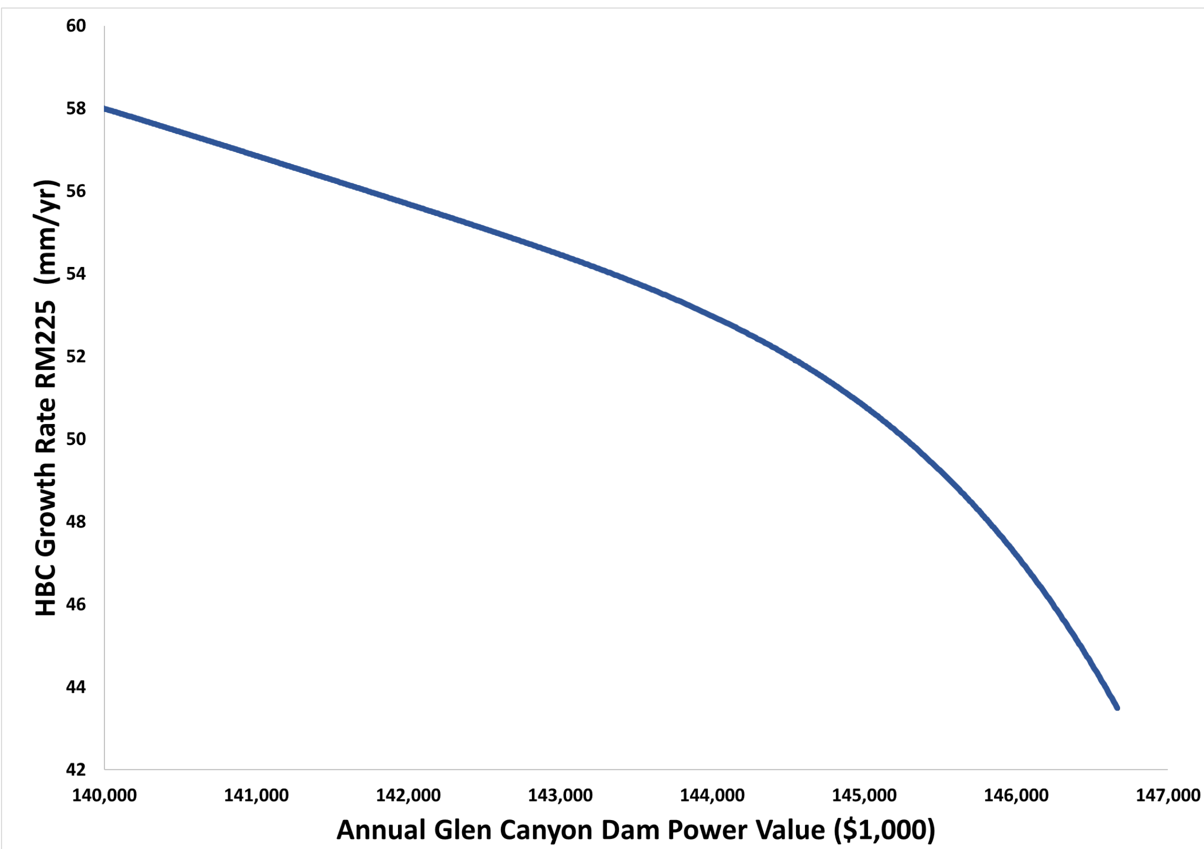


Figure F-11. Pareto frontier showing tradeoff between annual HBC growth at RM 22 and GCD hydropower energy value.

F.3 Study Results

F.3.1 BAU Benchmark Result

In order to identify hydropower economic and environmental win-win operating rules relative to the BAU case, we evaluated thousands of alternative operating criteria. Each one is a unique combination of daily and monthly water release patterns that are consistent with the BAU annual water release volume. In this section, we first describe results for the BAU case and then use this as a benchmark from which to compare results from alternative operating criteria.

The final LTEMP EIS report shows sample monthly water release volumes for the preferred alternative that meet various annual release targets (see Table F-1). The preferred alternative was selected by the 2016 ROD and, therefore, is used to represent the BAU case in this study. Although not specifically required by the EIS, in practice, Reclamation has been using these sample volumes for the past few years in its decision-making processes.

Recall that the first set of toolset processes construct thousands of hourly water release patterns as driven by energy market price profiles and intraday operating criteria. The second set of toolset processes determine which ones are best to use for specific daily water release volumes by day type and month. For the demo case, the GCD annual water release is 8.231 MAF.[13] Using the monthly water release volume in Table F-1, relative daily water release volumes by day types are applied to these monthly volumes to compute daily amounts. Relative day-type parameter values are either determined by the model via many random draws or input by the user.

Figure F-13 shows a comparison of water release patterns between two model results; that is, the Win-Win Toolset results and patterns projected by the GTMax model. The GTMax model was selected for this comparison because it has been successfully used for many years by both WAPA and ANL for numerous financial and economic analyses including LTEMP EIS studies. It is also currently used by WAPA EMMO staff for estimating:

1) Available hydropower for potential short-term firm sales of excess CRSP monthly/seasonal capacity and energy
2) CRSP power purchase requirements to serve WAPA hourly firm electric service load obligations under long-term firm contracts
3) Patterning of CRSP reservoir water releases and power plant generation including resources at Lake Powell/GCD.

The figure shows that toolset results are very similar to GTMax patterns for both the average of all January weekdays and a typical Tuesday in January 2028. Both are restricted by BAU operating criteria and are driven by the same PLEXOS price profile. Note that the win-win pattern is similar to GTMax, but it is slightly higher. This is, in part, because toolset Process Set 1 produces price patterns at discrete lift levels, of which only one is selected by Process Set 2; that is, there is no interpolation between lift levels, and therefore smaller intervals increase Win-Win Toolset accuracy.

13 The 1922 Colorado River Compact requires that the UCRB deliver 8.23 million acre-feet (MAF) of Colorado River water to the lower basin and Mexico every year https://www.glencanyon.org/lake-powell-reservoir-a-failed-solution/.

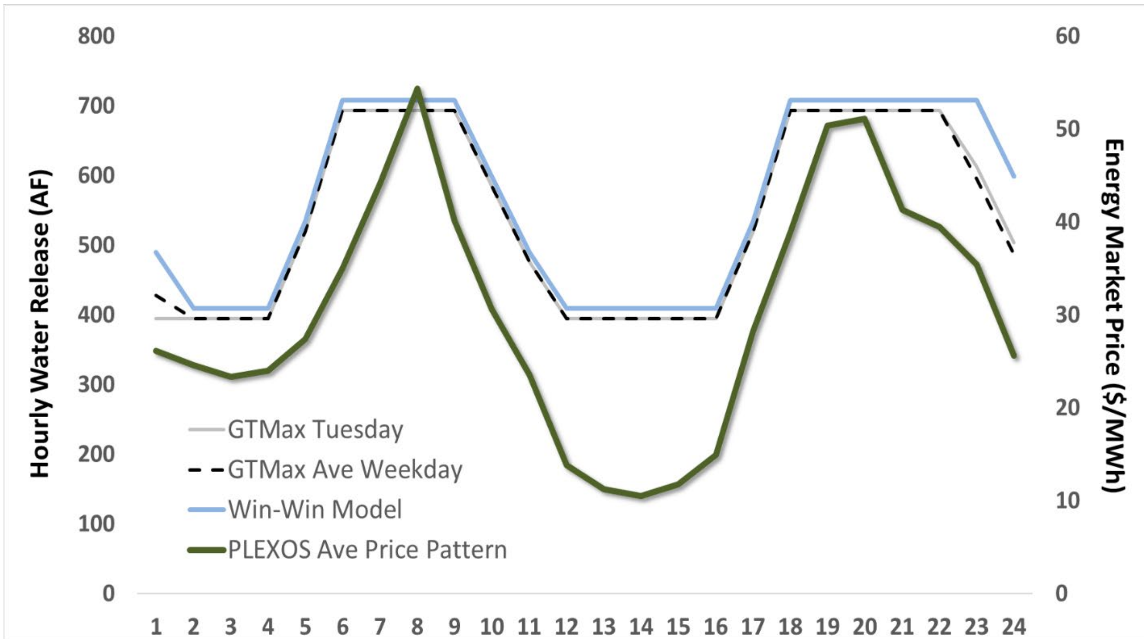


Figure F-13. Comparison of hourly water release patterns produced by the Win-Win Toolset and the GTMax Model.

The higher toolset release pattern for January weekdays is reflected in the relative daily water release volumes. Figure F-14 compares model/toolset these values by day type and month. Note that for January relative parameter values for the two models are identical (i.e., 1.0) for both weekdays and Sundays. The toolset, however, has a slightly lower relative water release parameter value for Saturdays. Because both models release the same water volume during January, the Win-Win Toolset has a lower release volume on Saturdays.

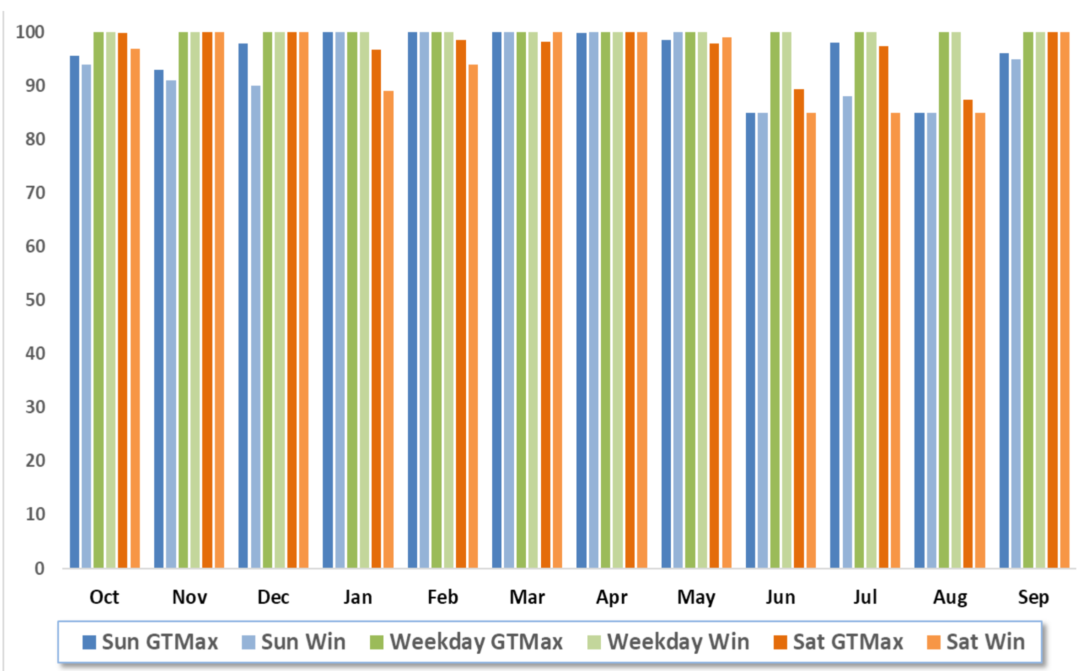


Figure F-14. Comparison of relative daily water release volumes by day type produced by the Win-Win Toolset and the GTMax Model.

GTMax daily water release volumes are an output of the model that primarily solves the problem using a linear programming formulation. In contrast, the Win-Win Toolset selects the best set of randomly drawn relative release parameter values for each day type while holding both monthly water volumes and intraday operating criteria fixed. Alternatively, the user can enter relative daily release parameter values using expert judgment and/or testing various combinations using trial-and-error techniques.

Because both daily water release volumes and hourly release are similar, GTMax and the Win-Win Toolset also produce similar estimates of GCD power economics. As shown in Table F-3, GCD annual economics estimated by the two models are within 0.17%. The largest difference between the two is 1.22% in August. Unlike other months of the year, this one had several hours with steep drops in prices resulting in relatively large negative LMPs. Because of this price profile, the quadratic equations that describe daily economic value as a function release volume are less precise. This gap in estimated economics could potentially be reduced by creating and applying polynomial equations at a higher order. For this vignette, application fourth-order polynomial equations were used.

Table F-3. Comparison of GTMax model and Win-Win Toolset results for the monthly value of GCD energy production.

	Monthly Economic Value ($1000)												
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Annual**
GTMax	10,097	9,683	12,410	13,384	10,976	10,152	9,318	10,940	14,273	15,759	15,125	11,126	**143,242**
Win-Win	10,081	9,676	12,398	13,356	10,958	10,127	9,308	10,931	14,327	15,767	14,941	11,125	**142,993**
% difference	**0.15**	**0.08**	**0.09**	**0.21**	**0.17**	**0.25**	**0.10**	**0.08**	**-0.38**	**-0.05**	**1.22**	**0.02**	**0.17**

F.3.2 Win-Win Toolset Results

After benchmark power economics were estimated, the Win-Win Toolset was used to randomly search for solutions that simultaneously increase GCD hydropower economics and HBC growth at RM 225. Over 81,000 random runs were performed with an annual GCD release of 8.231 AF. All complied with 2016 ROD hourly minimum and maximum water release rate limits and both hourly up- and down-ramp rate restrictions. The daily change limit also remained in place and did not deviate from the monthly levels used in the BAU case. These runs, however, differed from the BAU case as follows:

1) Monthly release volumes (i.e., intra-annual) were allowed to deviate from those shown in Table F-1

2) Relative daily release volumes deviated but within the nonbinding limits that restrict Saturday and Sunday release volumes to be at least 85% of the average weekday release

3) Selection of the best hourly release patterns to use (see Figure F-14) for each day type is based on a multiple objective that includes both GCD energy production economics and HBC growth rates at RM 225.

Results for random draws are shown in Figure F-15 as a scatter plot of annual GCD value and corresponding HBC growth at RM 225. Each random draw result is compared to the BAU case and classified as:

1) Win-win (upper-right quadrant): Both power economics and HBC growth are greater than the BAU case

2) Lose-lose (lower-left quadrant): Both power economics and HBC growth are less than the BAU case

3) HBC win-Econ lose (upper-left quadrant): HBC growth at RM 225 is greater than the BAU case, but power economics is lower

4) HBC lose-Econ win (lower-right quadrant): Power economics is greater than the BAU case, but HBC at RM 225 is lower.

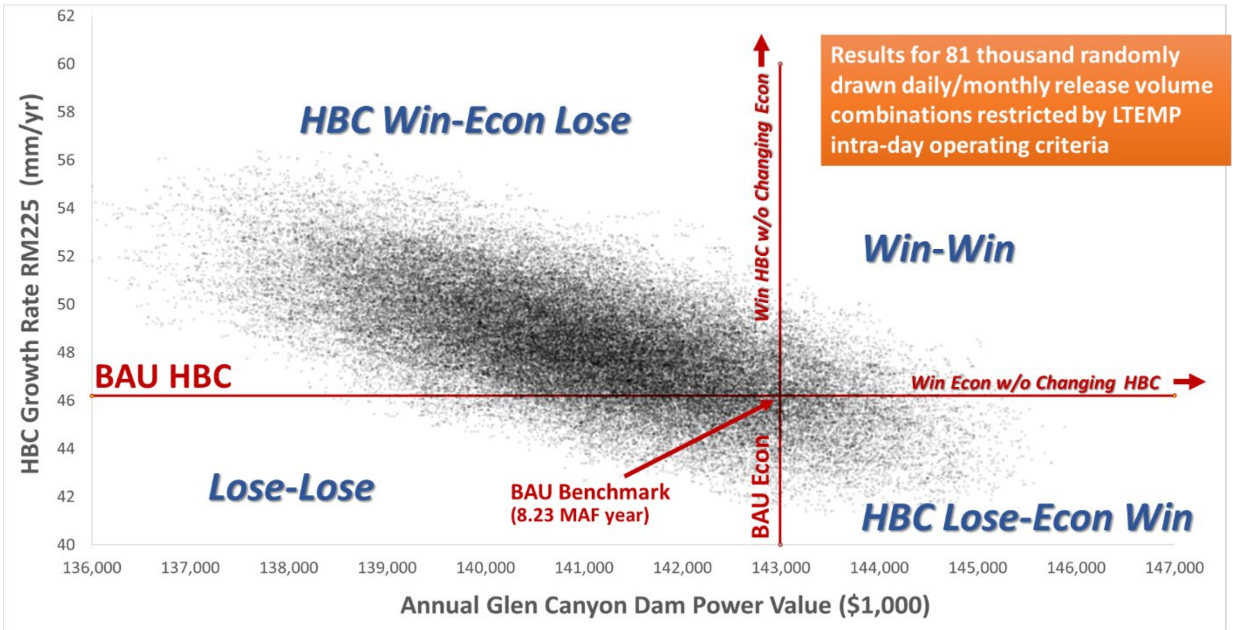


Figure F-15. Win-Win Toolset annual results for HBC growth at RM 225 and GCD hydropower plant economics from thousands of random draw model runs.

Note that many win-win solutions were discovered despite the very simplistic search method. However, most of the random draws produced results that were less than the BAU case for economics or HBC growth. Some were inferior to the BAU case for both metrics.

For the same set of random draws, many that were win-win for power economics and HBC growth at RM 225 also resulted in faster HBC growth at RM 61. Draws that improved all three metrics simultaneously are shown in Figure F-16 as light-blue dots in the upper-right quadrant. Note that in most cases when the HBC did better at RM 225, the HBC also does better at RM 61. There are only a few random draws in the win-win quadrant that did not increase HBC growth at RM 61. These are shown in Figure F-15 as gray dots in the upper-right quadrant that are slightly above the red BAU HBC line.

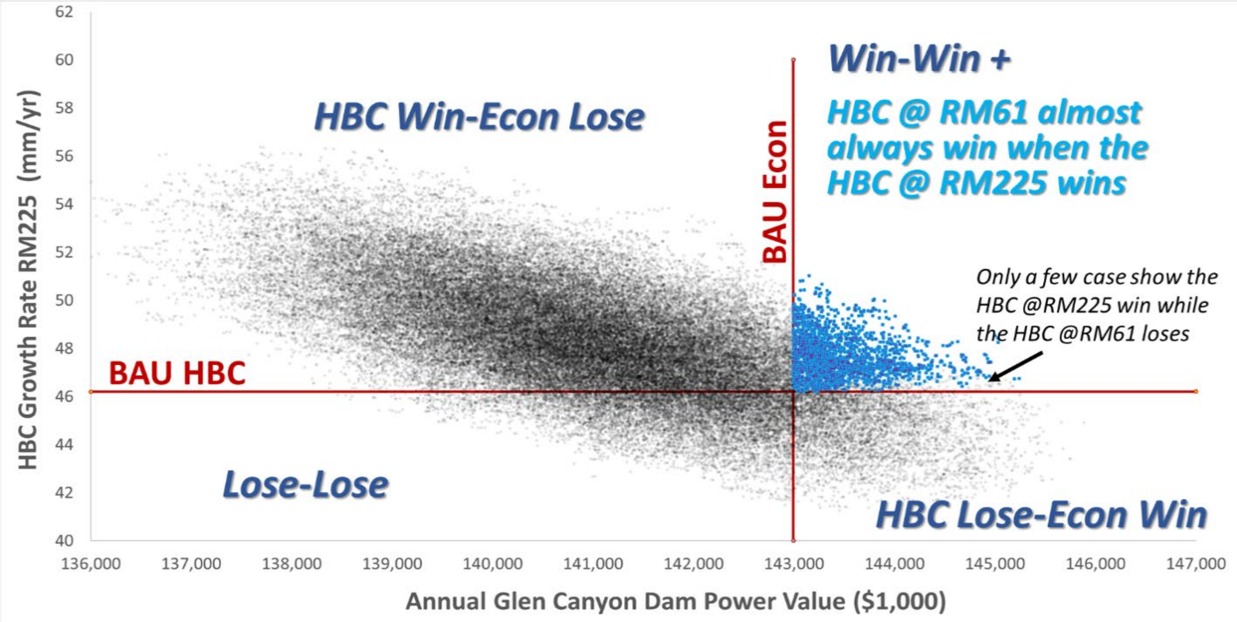


Figure F-16. Win-Win Toolset annual results highlighting random draws that simultaneously improve GCD power economics and HBC growth at both RM 61 and RM 225.

This result occurs because, as shown on Figure F-17, there is a strong correlation between annual HBC growth at the two downstream locations. It therefore follows that a set of conditions beneficial to the growth of HBC at RM 61 is also beneficial to HBC growth at RM 225.

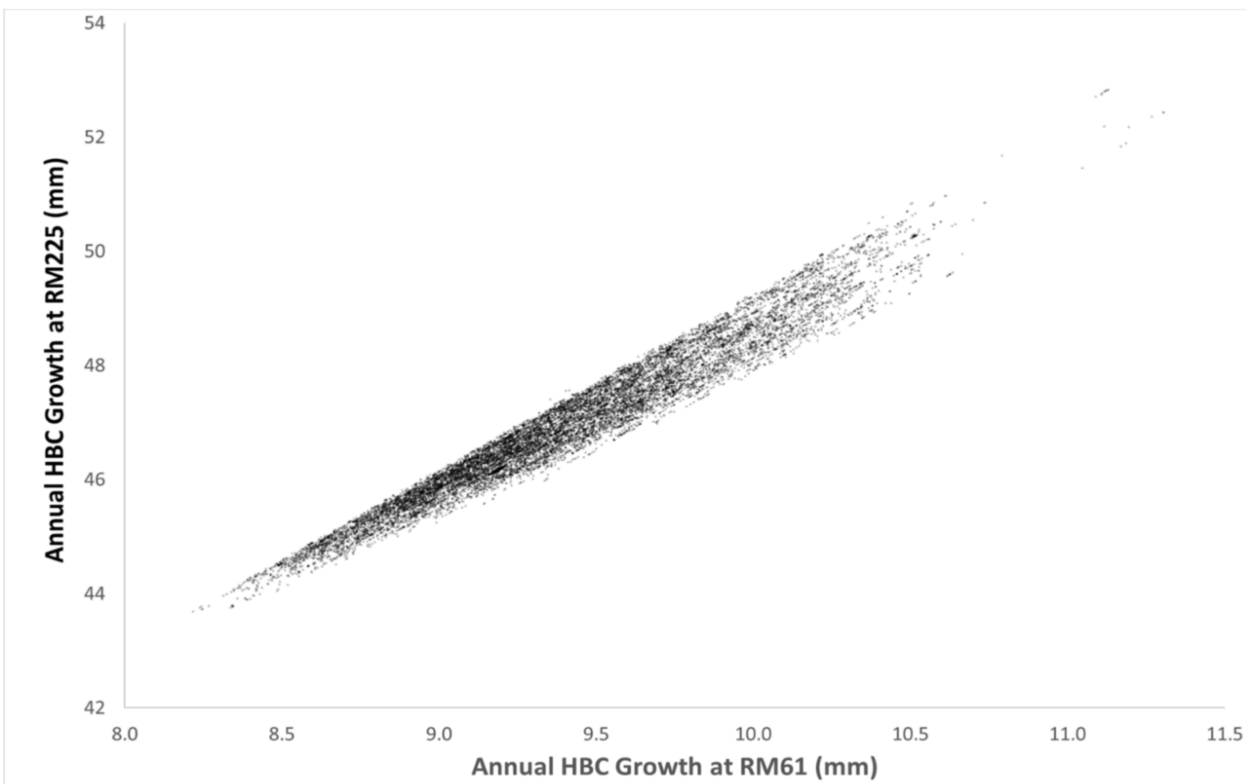


Figure F-17. Correlation between annual HBC growth at RM 61 and RM 225.

Figure F-18 layers the fourth study metric, sediment transport, onto the graphic display. Only those random draws that have lower annual sediment transport (better) than the BAU case are displayed on the scatter plot (small yellow circles). Note there no sediment cases that do better than the BAU case in the win-win quadrant. Most are in the HBC win-Econ lose quadrant. This occurs because sediment transport increases exponentially as a function of water-flow rate (i.e., the curve is a convex upward shape); therefore, sediment transport for a given volume of water release is minimized (best) when flows are flat. This is directly opposite to hydropower value that is typically maximized when releases fluctuate rapidly in response to volatile energy market prices.

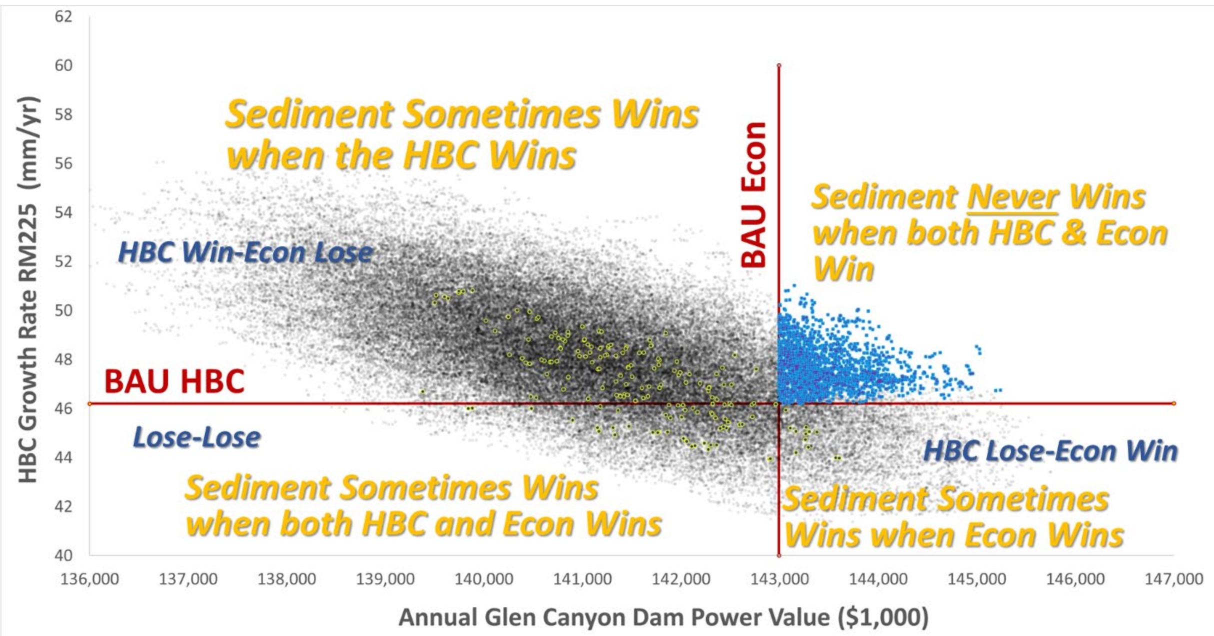


Figure F-18. Win-Win Toolset annual results highlighting random draws that reduce (improve) sediment transport relative to the BAU case.

This is evident in Figure F-19 that shows both sediment transport and economic value increase as more water is released during July; that is, as annual hydropower economic values improve, sediment transport becomes exponentially worse. On the other hand, conditions that improve HBC growth also result in lower sediment transport. For example, during summer months, low-flow rates lead to warmer water temperatures that are conducive to faster HBC growth. These same low flows transport less sediment than faster flow rates.

As the sediment transport metrics are currently defined, very few cases have a sediment transport win and at the same time increase the economic value of hydropower. In these cases, the economic improvement is relatively small. If the sediment transport is either more or less environmentally important during specific times of the year, there could potentially be some operating criteria sets that increase all four metrics simultaneously. For example, if minimizing sediment transport in the months leading up to a high-flow experiment is more desirable than sediment transport after a high-flow experiment, then reallocating monthly water release volumes could potentially improve the sediment metrics and simultaneously increase hydropower value.

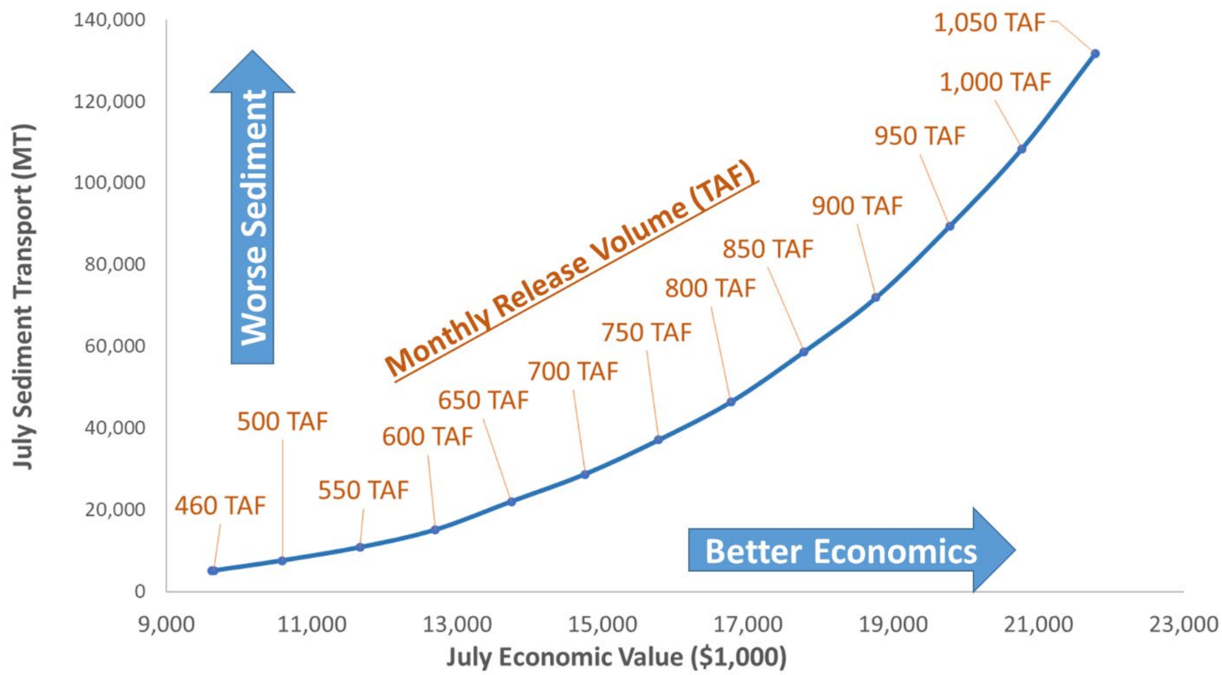


Figure F-19. Relationship between July sediment transport and GCD economic value for various monthly water release volumes.

To illustrate the types of analyses that can be performed with random draw results, Figures F-20 and F-21 show Win-Win Toolset annual results that highlight random draws in the win-win quadrant that have sediment transport amounts that hypothetically (for illustration only) may be tolerated. Figure F-20 shows random draws with sediment transport level that range from 0–+15% of the annual BAU sediment level.

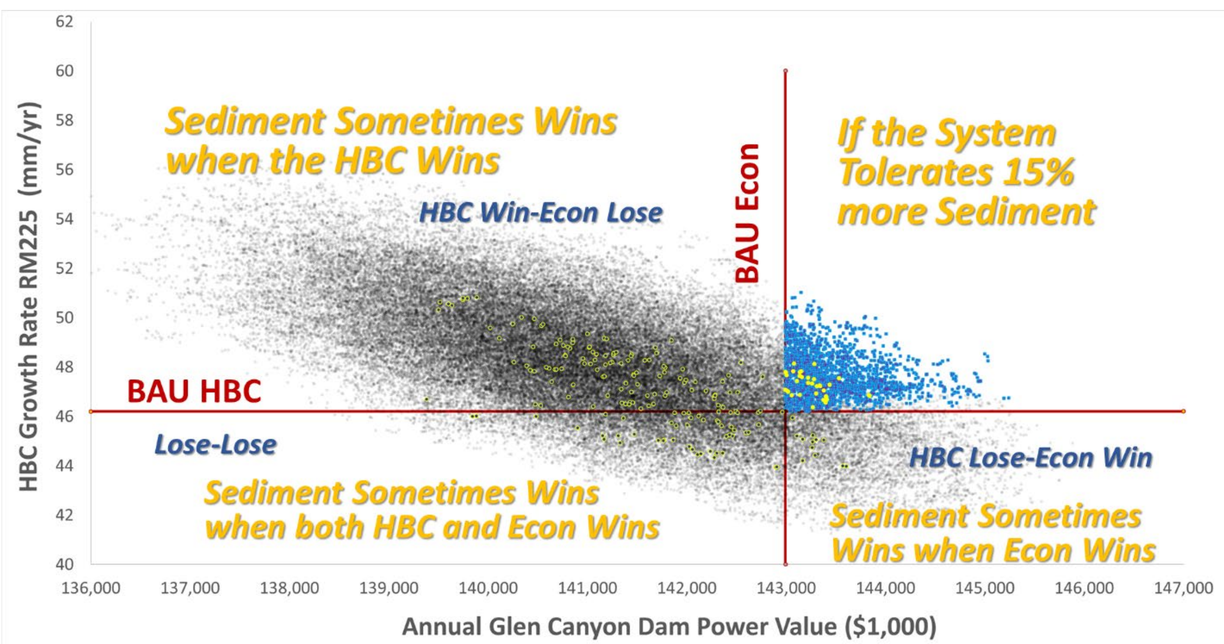


Figure F-20. Win-Win Toolset Annual Results Highlighting Random Draws in the Win-win quadrant that have sediment transport amounts that are between zero and plus 15 percent of the BAU case sediment transport level.

If the hypothetical sediment tolerance level is increased to 25% higher than the BAU level, the number of random draws that meet that threshold increases substantially as shown in Figure F-21.

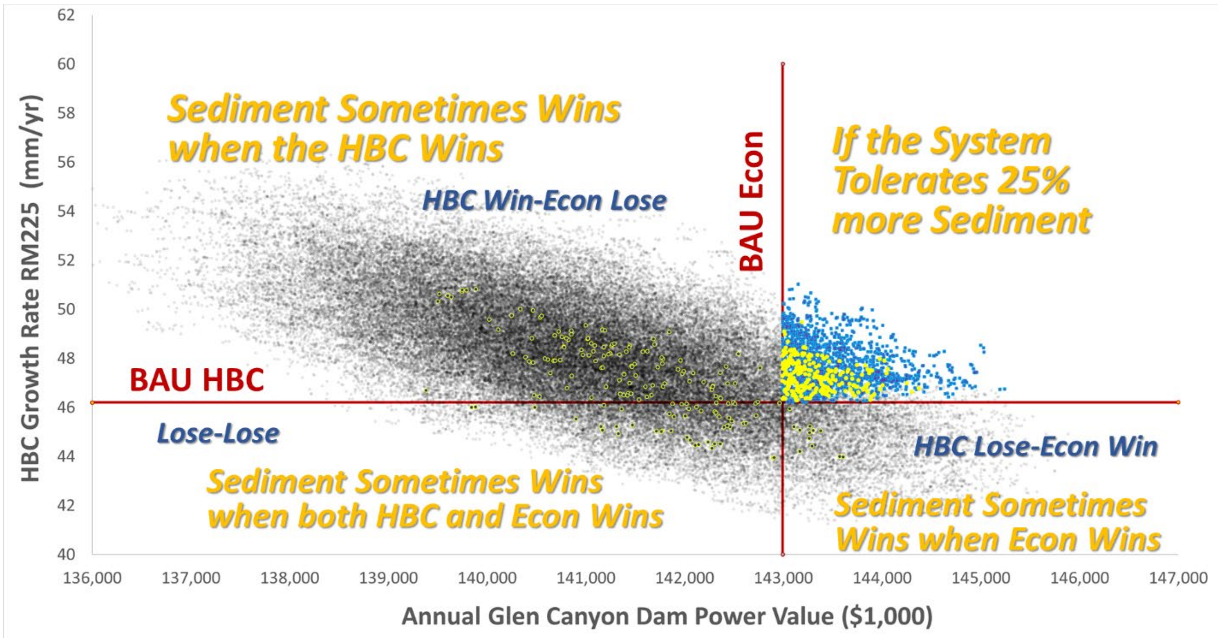


Figure F-21. Win-Win Toolset annual results highlighting random draws in the win-win quadrant that have sediment transport amounts between 0–+25% of the BAU case sediment transport level.

The same information that is displayed on Figure F-21 can also be viewed in a three-dimensional scatter plot such as the one in Figure F-22. The tool that ANL uses to create the plots allows the user to interactively rotate the graph on the x, y, and z axis in order to study model results from different vantage points. One such view is shown on Figure F-23 that relates annual HBC growth at RM 225 to sediment transport.

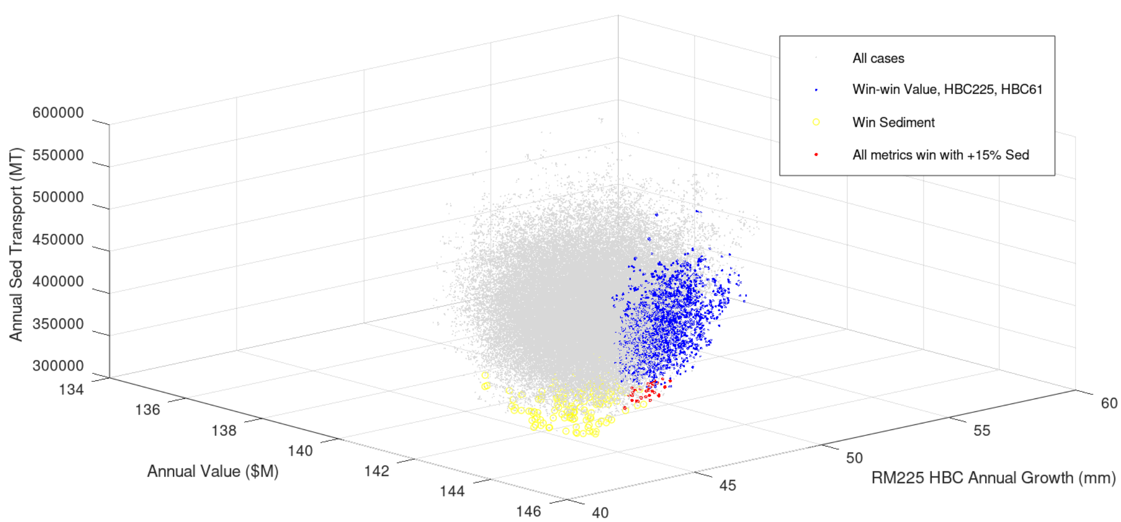


Figure F-22. Three-dimensional display of Win-Win Toolset annual results for economic value, sediment transport, and HBC growth at RM 225.

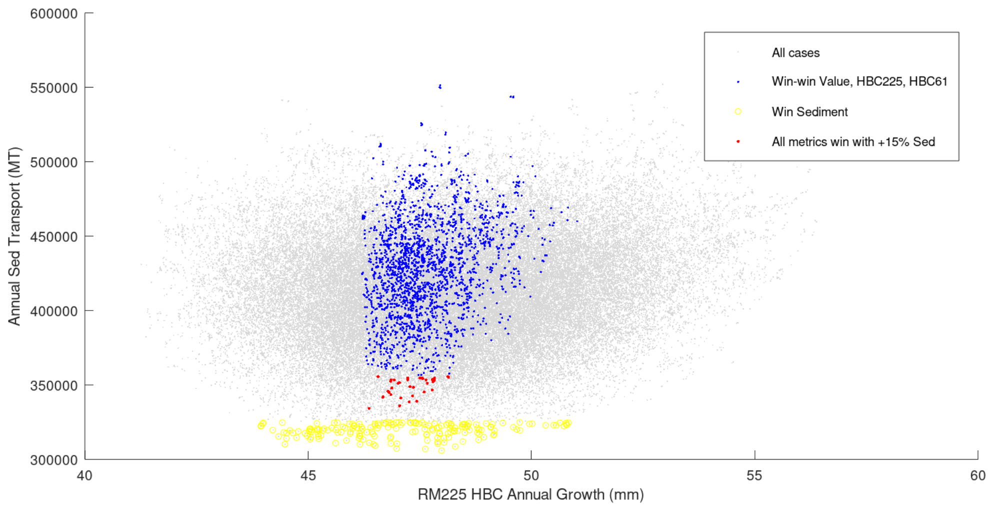


Figure F-23. Rotated three-dimensional display of Win-Win Toolset annual results for economic value, sediment transport, and HBC growth at RM 225 versus annual sediment transport.

F.3.3 Pareto Frontier Results

The Pareto frontier of tradeoffs between GCD economic value and HBC growth at RM 225 along with random draw results are shown in Figure F-24. This frontier assumes that 2016 LTEMP intraday operating criteria apply as described in the previous section. The figure also displays BAU benchmark results. Note that none of the random draw results lies on or above the frontier. Therefore, many other monthly, daily, and hourly win-win release patterns may potentially exist, but have not been found via the random draw process. One method of finding these is to simply perform and evaluate additional random draws. Another potential solution is to improve on the current random draw process by having the code more "intelligently" perform next draws by "learning" from previous ones.

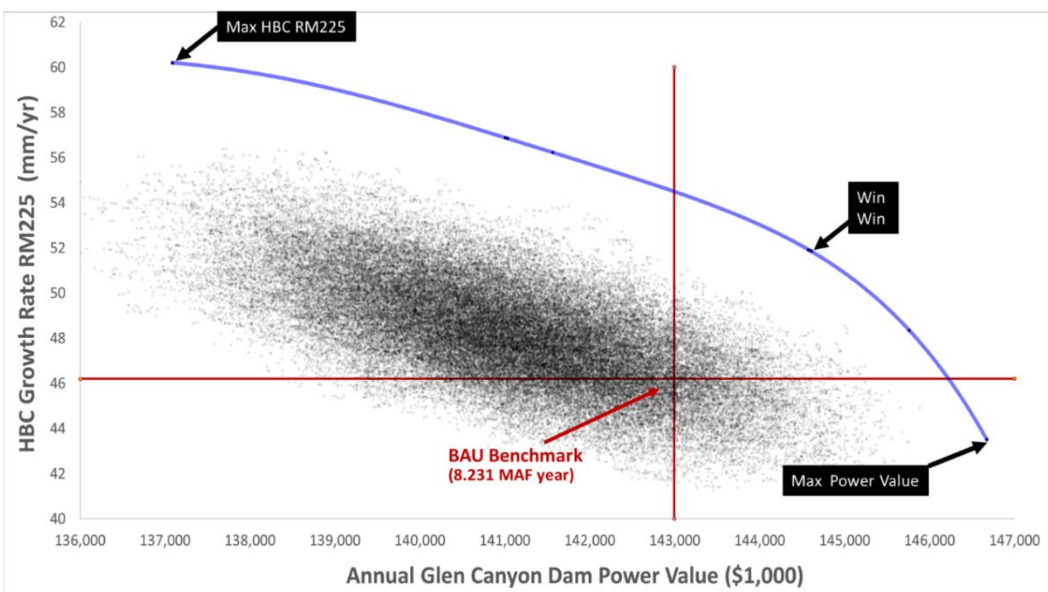


Figure F-24. Pareto frontier of annual HBC growth at RM22 and GCD hydropower energy value and results from random draws.

Each of the points on the frontier is associated with a unique pattern of monthly release volumes. Patterns for three of these points—max HBC at RM,225, win-win, and max power value—is shown on the bar-chart in Figure F-25. Relative to the BAU case (blue bars), HBC growth is the greatest (top panel) when water releases are high during the winter and early spring months when HBC growth is either zero or very low. To support these higher release volumes, water release volumes are lower during other times of the year when warmer low-flow water encourages HBC growth; especially during the summer months and early autumn (e.g., September).

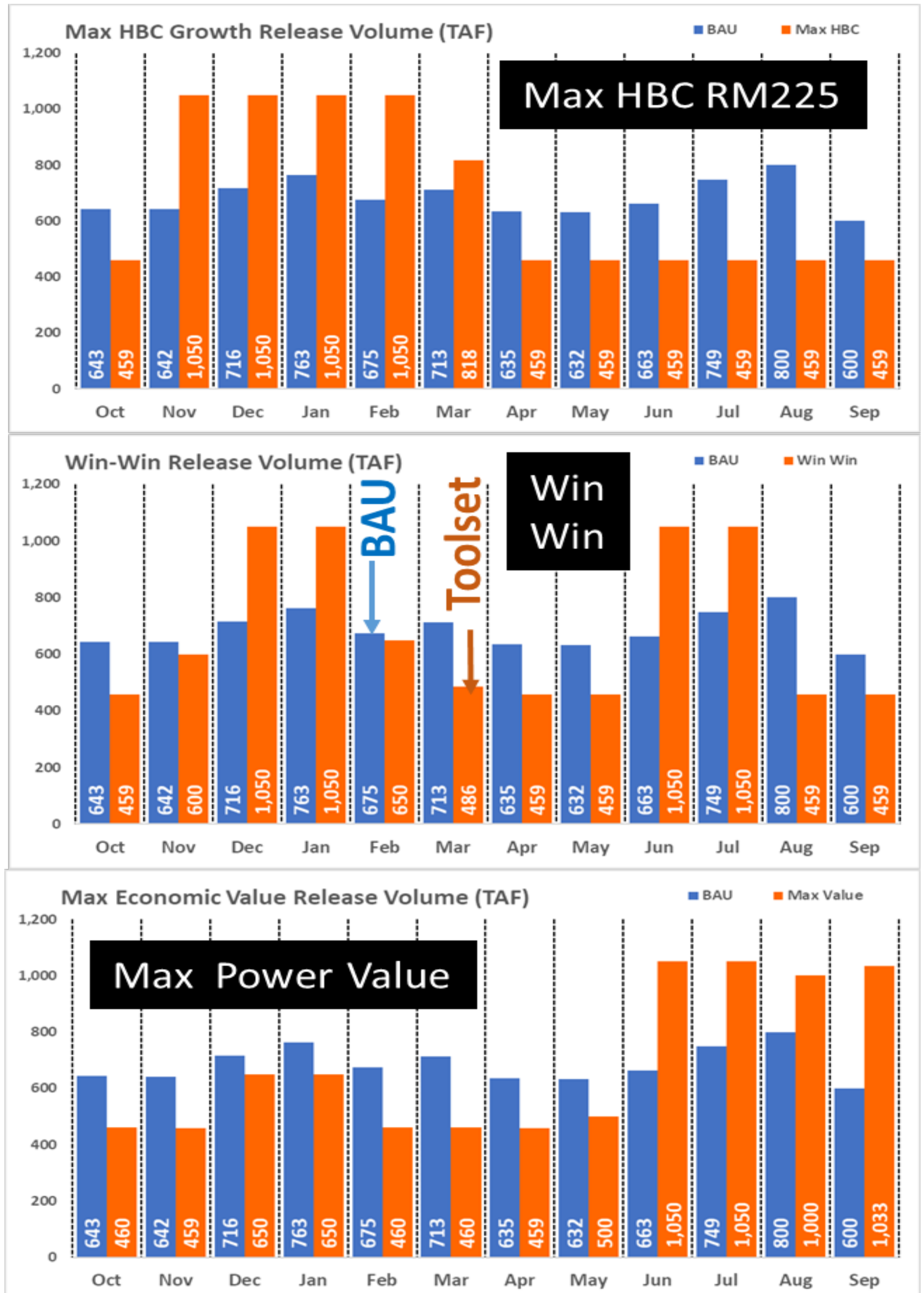


Figure F-25. Monthly release volumes on the Pareto frontier of annual HBC growth at RM 22 and GCD hydropower energy value.

The opposite flow volume pattern occurs when maximizing the value of GCD hydropower energy production (lower panel). To maximize power value, water releases during the summer months and September are higher than the BAU case. Water is essentially reallocated from all other months of the year to support high-generation levels when LMP is the most expensive.

The win-win Pareto frontier point that is approximately in the middle of the curve segment that spans the win-win quadrant is illustrated in the center panel of Figure F-25. It is a compromise between the two aforementioned extremes. Relative to the BAU case, more water is released during December and January to take advantage of higher prices during the peak winter loads months. These high winter flows have no impact on HBC growth because it never grows during this those two months. Monthly releases are also relatively high during June and July. These higher flows, however, dampen HBC growth relative to the BAU case, but lower monthly release during the other times of the year, especially August and September, more than compensate for HBC slower growth during June and July. Both cumulative HBC growth and hydropower economics during 2028 are shown for all four cases in Figure F-26.

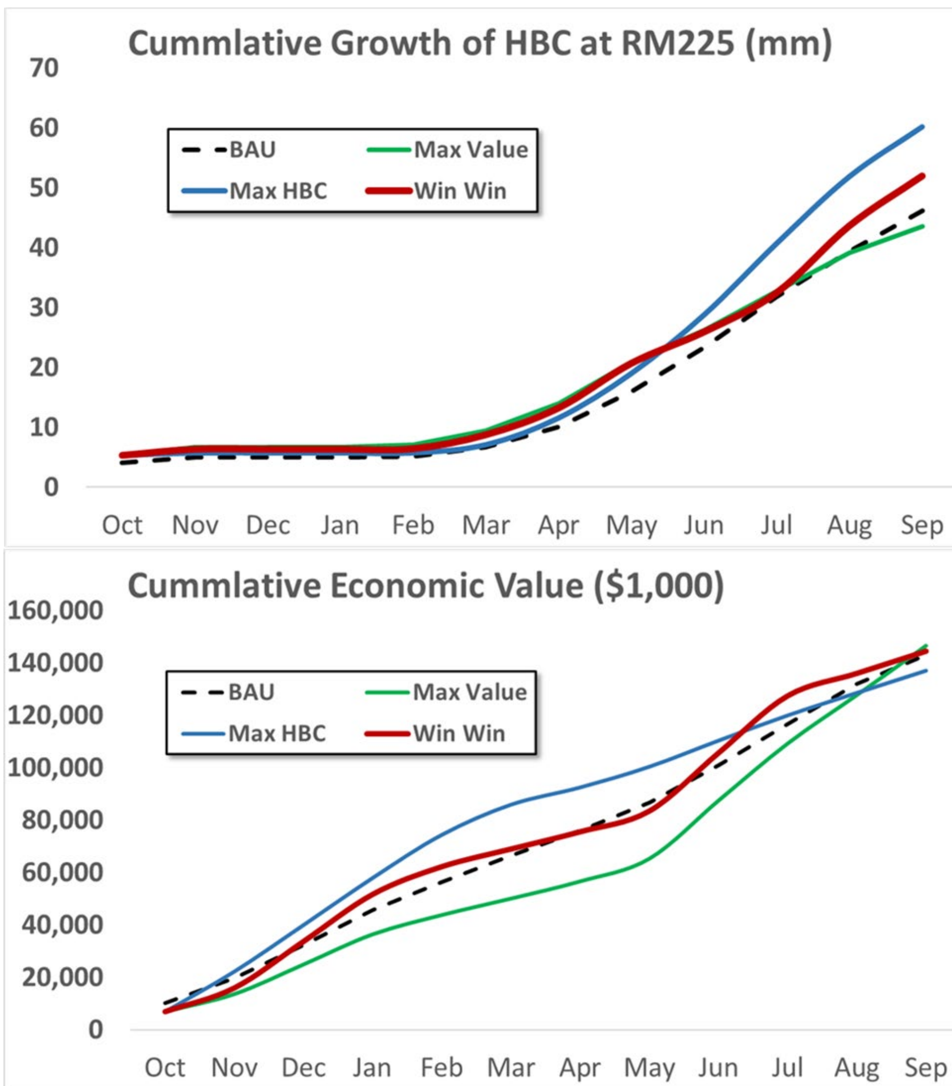


Figure F-26. Cumulative HBC growth at RM 225 (top panel) and economic value (lower panel) over time on the Pareto frontier of annual HBC growth at RM 22 and GCD hydropower energy value.

The Win-Win Toolset methodology can be used to not only examine the results of random draws from a single intraday set of operating criteria, it can also examine possible win-win solutions from one or more alternative intraday criteria. Figure F-27 shows Pareto frontier results for intraday operating criteria with a range of flexibility. The lowest frontier (green tradeoff curve) has criteria with a higher hourly minimum release, a lower maximum release, slower allowable up and down ramp rates, and a smaller daily change (hourly release range). Relative to the LTEMP criteria (blue tradeoff curve), it has a much smaller win-win potential. On the other hand, when intraday operating criteria are relaxed (yellow tradeoff curve), potential win-win solutions significantly expand.

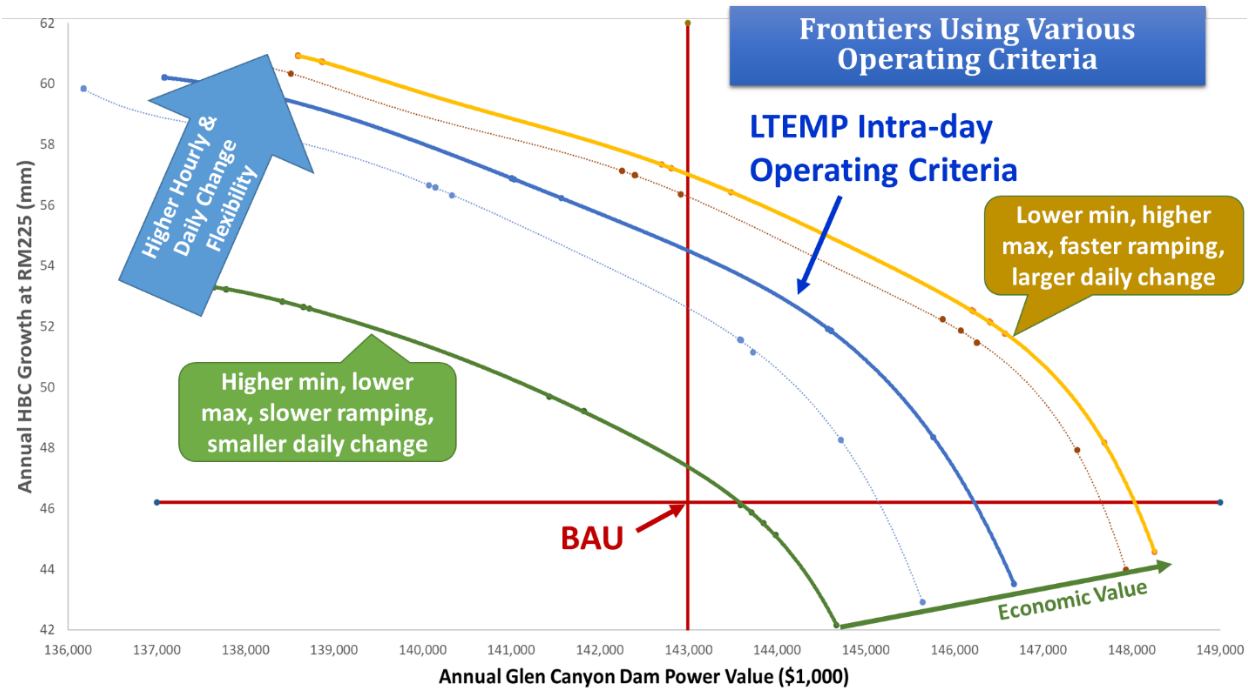


Figure F-27. Pareto Frontiers for intraday operating criteria with various degrees of flexibility.

The author again emphasized that this illustration of relaxed intraday operations may have many negative impacts that are not measured in this proof-of-concept vignette. The intent of the graph is to demonstrate toolset capabilities and the display of toolset results.

The methodology can also make random draws from more than one set of intraday operating criteria. As specified by user inputs, a randomly selected intraday operation is applied to all months of the year, or a different random draw is made monthly. By allowing the criteria to vary monthly, the potential for additional win-win solutions grows. For example, the HBC may be able to tolerate higher hourly water fluctuations during some seasons/months, while at other times of the year it may be very sensitive to flow rate changes. By allowing the toolset to randomly selecting operating criteria in addition to monthly and daily water release volumes, the solution landscape dramatically increases. Therefore, the number of random draws that are needed to explore this landscape adequately are much larger and the need for a smarter random draw and machine learning algorithm becomes increasing important as the problem size grows (Figure F-28).

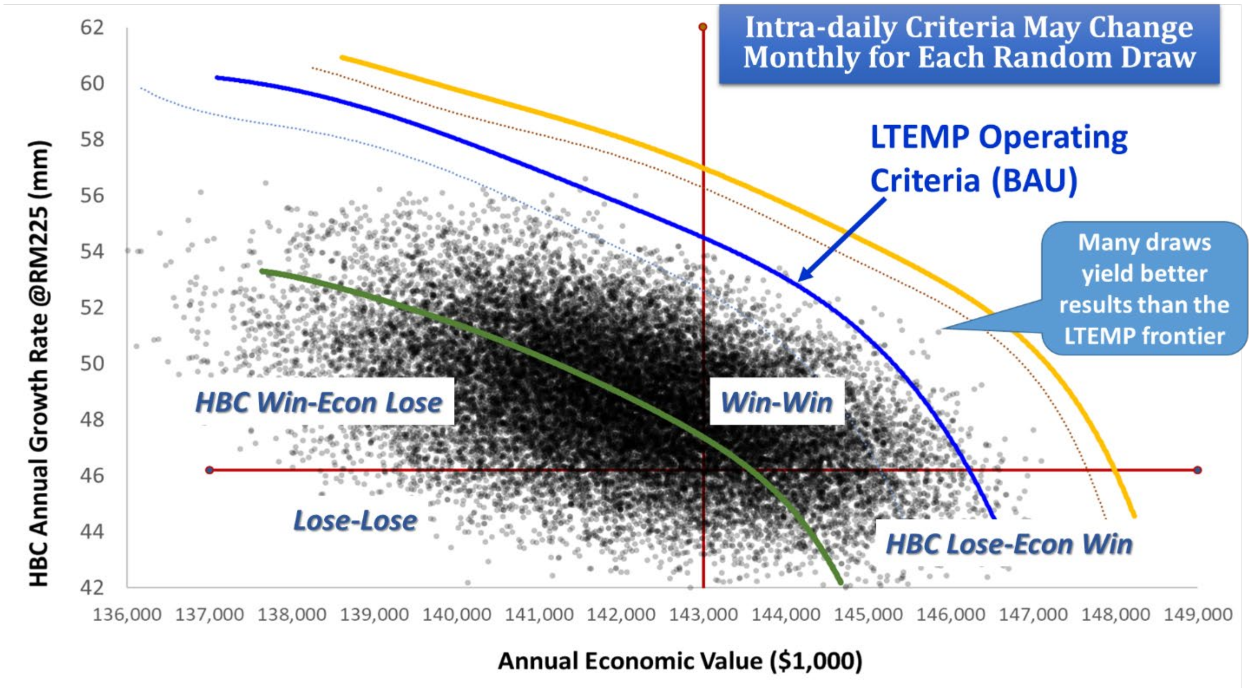


Figure F-28. Pareto Frontiers for various intraday operating criteria and results from random draws, and monthly and daily release volumes that may change each month.

Appendix G – Detailed Methods and Results for Chapter 4.3: Operational Policies for Maximizing Fish Survival and Generation Revenue

G.1 Study Site

This case study was conducted using the six hydropower facilities in the Yadkin-Pee Dee River Basin in North Carolina and South Carolina (Eastern Interconnection or EI) as hypothetical examples for finding energy-environment win-wins. Reservoir development in the basin includes (from headwaters to mouth) one nonpower facility owned by the USACE, four hydropower facilities owned by ECRE, and two hydropower facilities owned by Duke Energy (Table G-1, Figure G-1). This basin typifies many common and challenging aspects of river basin water management such as multiple licensees, diverse landscapes (mountain headwaters to coastal plains), natural resource issues (e.g., water supply, fish passage, recreational boating, water quality), and differences in operational strategies (e.g., balancing authorities, generation capabilities, generation scheduling planning) between the two hydropower owners.

Table G-1. Summary of Yadkin-Pee Dee hydropower projects.

Owner	Project Characteristics	Environmental Characteristics	Power System Characteristics
ECRE	Four facilities (215 MW): • High Rock (225,500 ac-ft; 40.2 MW) • Tuckertown (41,000 ac-ft; 38 MW) • Narrows (137,000 ac-ft; 110.4 MW) • Falls (2,300 ac-ft; 31.1 MW)	• Dissolved oxygen • Species of concern ▪ Freshwater mussels ▪ Upland wildflowers ▪ Bald eagle • Recreation ▪ Canoe and kayak ▪ Fishing	• Participates in wholesale energy market • Automated generation control • Receive inflow from nonpowered USACE dam
Duke Energy	Two facilities (108.6 MW) • Tillery (132,600 ac-ft; 84 MW) • Blewett Falls (27,500 ac-ft; 24.6 MW)	• Dissolved oxygen • Fish passage ▪ American eel ▪ American shad ▪ Atlantic sturgeon ▪ Shortnose sturgeon • Recreation ▪ Canoe and kayak ▪ Fishing	• Vertically integrated utility • No automated generation control • Receive inflow from ECRE facilities so heavily influenced by ECRE decisions

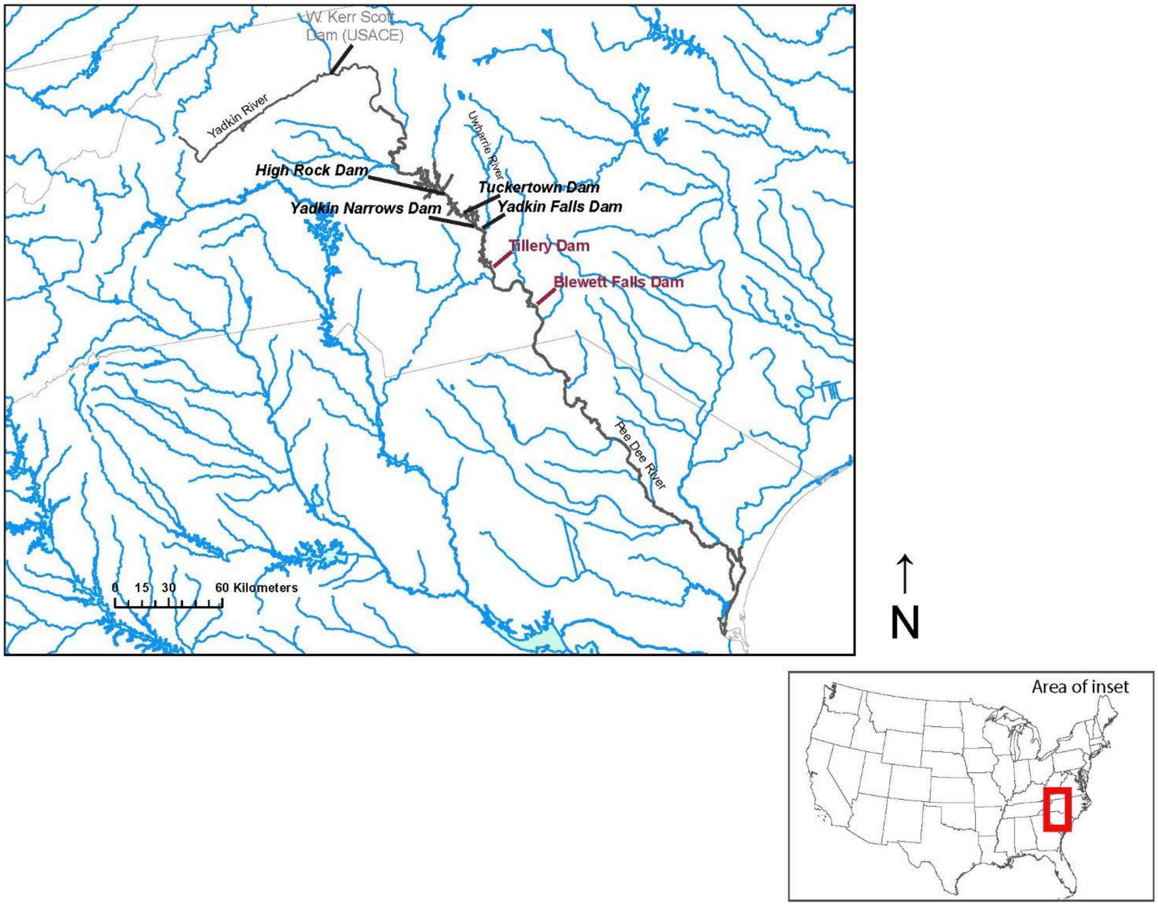


Figure G-1. Map of Yadkin-Pee Dee River basin showing seven mainstem dams owned by USACE (gray), ECRE (black), and Duke Energy (maroon). The upstream USACE facility (W. Kerr Scott) is operated primarily to provide flood control and water supply benefits and has no hydropower.

G.2 Description of Modeling Components

To evaluate energy-environment tradeoffs and gain a better understanding of the links between power, flow, and the environment in this system, we first had to develop a general framework connecting power generation, flow, and environmental outcomes using 1) a long-term simulation created with a reservoir policy model and 2) detailed reservoir, grid, and ecological modeling and evaluation that allows impacts to be assessed at sub-daily time scales.

As shown in G-2, our framework uses four different sets of models/software including CHEOPS for long-range reservoir policy, PLEXOS for energy market simulation, DDP for optimization of sub-daily flow distribution, and QUANTUS-SD for simulating linkages between flow and freshwater survival, mediated by temperature and prey availability for smallmouth bass. These independent models are integrated in a sequential fashion, passing the outputs from one model to the next in the framework.

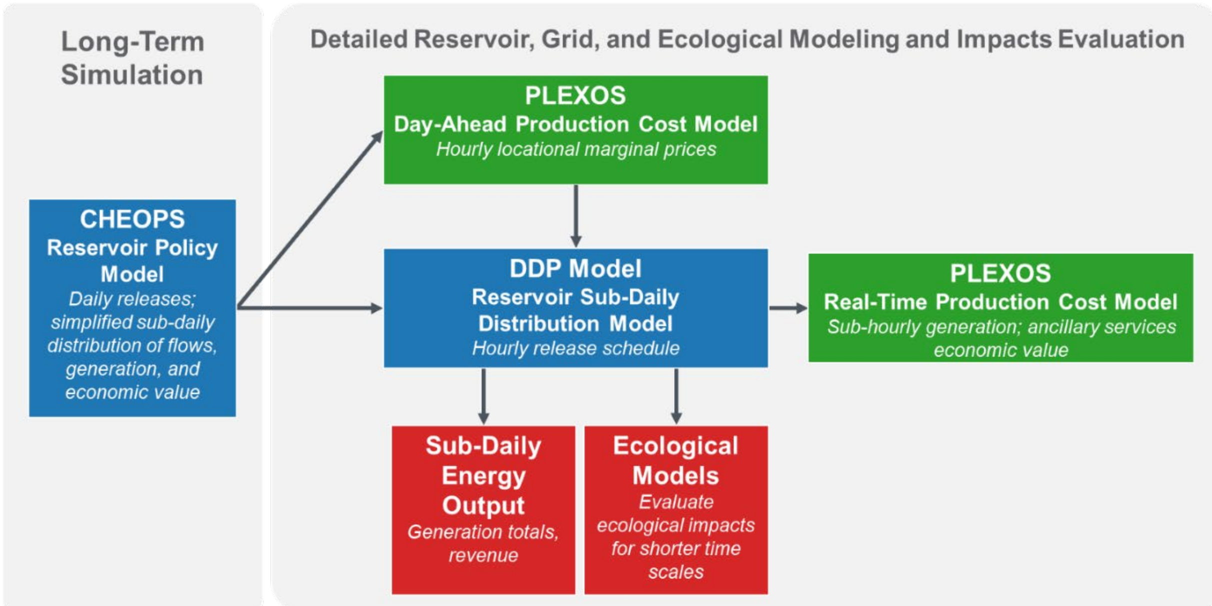


Figure G-2. Yadkin-Pee Dee coordinated modeling framework.

CHEOPS simulated both long-range reservoir policy and day-to-day plant operations based on user-defined hourly power price categories (i.e., peak, secondary peak, off-peak). This model was developed by HDR Engineering, Inc. to support relicensing of the Duke Energy Yadkin-Pee Dee Hydro Project (P-2206) and is still used by Duke Energy as their reservoir operations model. This model simulates diversion demands, reservoir and turbine characteristics, and operating policy for each of the reservoirs. CHEOPS provides a GUI for defining policy scenarios and evaluating the resulting impacts on meeting water supply targets, minimum flow requirements, and generation totals. It is designed to simulate a 60-year period of record at 15-minute time steps.

PLEXOS is a PCM used to help understand large-scale grid generation requirements and impacts of different generation mixes (e.g., the impact of increased wind and solar) on the electricity system. In this case study, PLEXOS co-optimized energy and reserve products to find the least-cost generation mix at all times across the North American EI domain. The plant-level operational capabilities for all generators, including hydro, are constrained by several factors, including maximum and minimum generation capacity, ramp rate, and energy limits. PLEXOS used the energy system projections to estimate LMPs, that is the value of generating at a location at given point in time. The LMP at a given location represents the marginal cost of providing generation to the system at that location in the grid, recognizing differences in generation costs per facility, transmission costs, and other factors. When LMPs are high, generation from low-cost sources is more valuable (e.g., from hydropower) than at other times. Our case study used PLEXOS models of the North American EI that assumed hydropower was either a resource that could provide only energy or provide both energy and operating reserves (Bloom et al. 2016; Brinkman et al. 2021; Novacheck and Schwarz 2021).

The DDP model uses daily water allocations created by the CHEOPS long-range reservoir policy model and LMPs created by the PLEXOS model to retime hourly releases to maximize revenues based on the LMP inputs while ensuring that the accepted long-range reservoir policy and sub-daily constraints are maintained. We developed the DDP model to allocate sub-daily flows because, while CHEOPS offers a representation of policy in the Yadkin-Pee Dee Basin that is accepted by cooperating entities and FERC for licensing purposes, CHEOPS model assumptions limit our ability to understand differences in the value of hydropower now and under future renewable buildout scenarios. Specifically, in contrast to the

DDP model, CHEOPS cannot respond to variability in LMPs. Instead, CHEOPS designates hydropower releases with distinct generation periods for every day of the month based on aggregated generation economic value (peak, secondary peak, and off-peak), but does not account for day-to-day differences in grid needs (and the subsequent LMPs) that may indicate the necessity (and benefit) of altering the response of the reservoir system, both under current and future grid buildout scenarios.

QUANTUS is an ecological model originally developed for optimizing the timing of seasonal pulse flows for fall Chinook salmon (*Oncorhynchus tshawytscha*) (Jager 2014). In our case study, QUANTUS was adapted for smallmouth bass (*Micropterus dolomieu*) to simulate effects of flow- and thermal-peaking linked effects on early life history survival at a 15-minute scale. This implemented a generic recruitment model for species in the Pee Dee River and estimates survival of smallmouth bass through three stages: 1) egg incubation; 2) larval development; and 3) juvenile development as described in (Jager 2014). We included fish growth in the model using a Von Bertalanffy relationship to evaluate environmental outcomes for sub-daily fluctuations in flow and temperature.

G.2.1 Model Sequencing

In our framework (Figure G-2), we first execute the CHEOPS model for a given operating policy. This results in outputs of hourly generation (passed to the PLEXOS DA model) and daily total flows (passed to the DDP model).

The PLEXOS model simulates the forecasted DA electricity system at an hourly time resolution. This simulation uses the hourly generation from CHEOPS at each Yadkin-Pee Dee plant as an input (i.e., these generation totals are not changed in the PLEXOS solution) and solves to determine the commitment (i.e., on/off status) of large, slow-starting generators, ultimately resulting in an output of LMPs at each node in the model, including the various Yadkin-Pee Dee reservoirs. Because these reservoirs comprise only a minor piece of the total generation mix in the EI, the LMPs provide a good approximation of the value of generating on a given timestep, regardless of what the actual Yadkin-Pee Dee generation was, and can be used as inputs to DDP to optimize sub-daily operations.

The DDP optimization model uses the LMPs produced by the PLEXOS DA model to retime the daily CHEOPS flows to provide generation at the most valuable times to the grid, maintaining the daily flows produced by CHEOPS as well as sub-daily operating constraints for the system.

Finally, because we were interested in understanding the potential benefits that sub-hourly flexibility from the reservoirs could provide to the energy system, we identified key periods within each year and executed the PLEXOS 5-minute RT model for different periods using operating policies with differing sub-hourly generation restrictions. The RT model simulates the system at a 5-minute resolution and includes 5-minute realized generation profiles for solar and wind. Therefore, the model can be used to better understand the impacts of short-interval fluctuations in renewables generation relative to the DA forecasted generation, and the impacts on sub-hourly ramping requirements and real-time LMP fluctuations.

To fully understand both hydropower and sub-daily environmental tradeoffs of release decisions, we performed ecological modeling to evaluate the impacts to the environment given the release decision changes from CHEOPS to DDP. The ecological modeling is unique in that it focuses on sub-daily impacts of flow. We then compared revenue, grid, and environmental metrics between scenarios to better understand where potential win-wins could be identified.

G.2.2 Modeling Scenarios

For this study, we selected three scenarios for analysis using this existing model, representing approximately the current state of the system (year 2024), an intermediate level of change (year 2036), and a high degree of renewables penetration (year 2050). We chose these years to better understand how the need for flexible generation will shift as the grid changes over time. The coordinated modeling framework was used to explore operational flexibility for a combination of base cases and alternative reservoir policy scenarios as listed in Table G-2. The base case load scenarios simulate three different generation load shapes that reflect current and increasing future renewable penetration. These scenarios are then coupled with alternative operating policy scenarios to investigate the impacts of alternative ramping policies.

This approach focuses on sub-daily variation to assess the potential benefits of allowing greater intraday (and intrahour) flexibility. Conventional FERC-type policy evaluations often use assumed or simplified representations of grid needs at the sub-daily operational level and focus on long-term policy impacts. Evaluations of impacts of generation projections or grid needs are often considered independently from policy evaluation. While appropriate for long-term simulations to understand the impact of different operating policies across the range of natural variability, these evaluations often do not consider the need to provide flexibility on shorter time scales in the current or future system beyond basic consideration of ramp rate limitations with little detailed ecological modeling. By modeling the energy and ecological systems at a detailed level, we expect that greater insights can be gleaned regarding impacts of constraints on revenue streams and the energy and ecological systems to help identify new opportunities for win-win reservoir policies.

Table G-2. Base case load scenario and alternative operating policy scenarios.

Scenario Name	Base Case Load Scenario	Alternative Operating Policy Scenario
2024 Load-Base Ops	**Base 2024** (Current generation)	**Base Case** (Current ramping restrictions)
2024 Load-Base Ops with Env Policy		Base Case with Nighttime Environmental Restrictions
2036 Load-Base Ops	**Base 2036** (Assumed moderate increase in renewable penetration)	**Base Case** (Current ramping restrictions)
2036 Load-Unrestricted Ramping Ops		Unrestricted Outflow Ramping at All Times (day and night)
2036 Load-Restricted Ramping Ops		Highly Restricted Outflow Ramping at All Times (day and night)
2036 Load-Base Ops with Env Policy		Base Case with Nighttime Environmental Restrictions
2036 Load-Unrestricted Ramping Ops with Env Policy		Unrestricted Outflow Ramping During Daytime (nighttime environmental restrictions still apply)
2050 Load-Base Ops	**Base 2050** (Assumed high increase in renewable penetration with 2036 output power production)	**Base Case** (Current ramping restrictions)
2050 Load-Base Ops with Env Policy		Base Case with Nighttime Environmental Restrictions

First, we executed PLEXOS for three renewables generation cases (2024, 2036, and 2050) to develop LMP traces for each of the three base case scenarios. These LMPs provided the price signal input for the base case analysis and the alternative operating policy scenarios associated with each base case. Note that these scenarios rely on current assumptions for lake evaporation and water supply demands; the potential impacts of changing climate and demand conditions are not reflected in this analysis. We recognize that these factors are very important, yet they typically have a greater impact on long-range operating policy considerations handled by standard simulation modeling. In future applications of this framework, it may be beneficial to include additional uncertainties outside of changing energy demand, such as climate change impacts on hydrology, changing municipal, industrial, and agricultural demands, and changing landscapes.

The alternative operating policy scenarios are implemented in DDP and explore impacts of various ramping rate constraints. The scenarios test the impacts of constraints imposed at every time step of a simulation as well as a more restrictive ramping rate applied at nighttime only, where nighttime is determined based on sunrise and sunset times for the Yadkin-Pee Dee basin area. Outflow ramping rates for all modeled reservoirs are tabulated in Table G-3. The current ramping rate restriction was determined based on median outflow rate changes in historical data. For the unrestricted ramping rate case, it was necessary to tune the rates to allow extreme flexibility without creating modeling instabilities. Similarly, the highly restricted ramping rates were calibrated to be low enough to simulate desired limited ramping while still allowing the full volume of outflow to be released over a given day.

Table G-3. Alternative operating scenario ramping rates.

Scenario	All Day Ramping Rate (AF/hr)	Nighttime Ramping Rate (AF/hr)
Highly Restricted	15	10
Base Case (current rate)	300	25
Unrestricted	900	200

For the long-term simulation, CHEOPS was run for the 60-year period from January 1955 through December 2013. For the detailed simulation modeling and evaluation, the team selected two years (2012 for a low-flow condition and 2013 for a high-flow condition) to understand how hydropower flexibility is impacted by flow conditions while ensuring that model run time was within reason for PLEXOS, which is computationally expensive. The monthly Yadkin-Pee Dee basin inflows for these years are shown in Figure G-3.

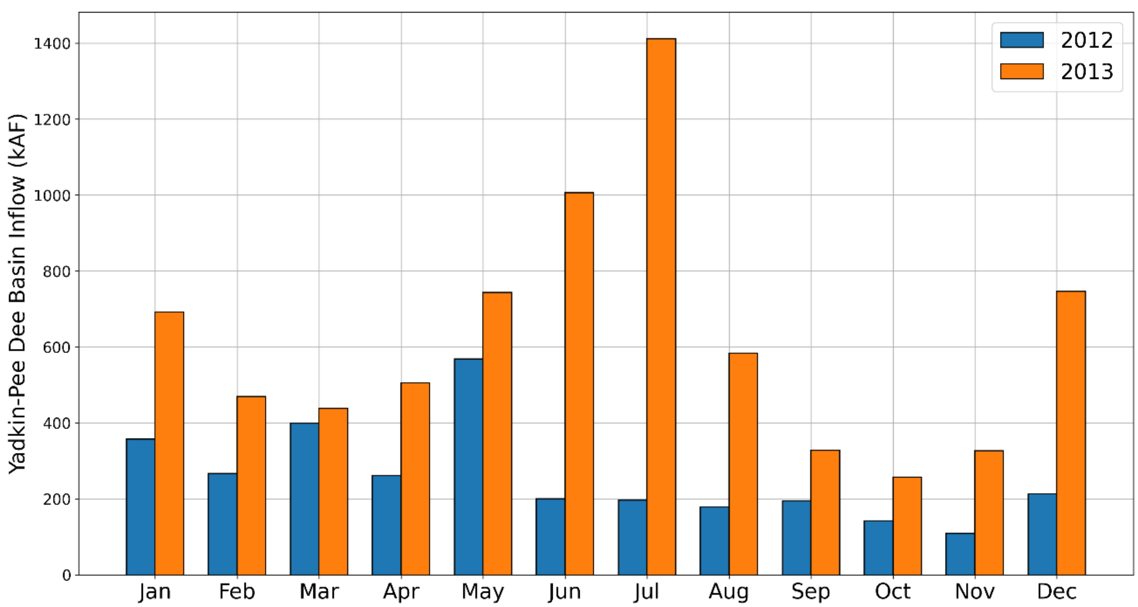


Figure G-3. Yadkin-Pee Dee Basin inflow covering the two evaluation years.

As discussed above, in addition to evaluating the impacts and benefits of different ramping rates at a sub-daily scale, we were interested in the impacts of ramping restrictions on the sub-hourly scale as well. To limit computational burden, we selected multiple periods within the 2-year analysis period to help highlight the differences. The periods were selected to cover combinations when hydropower flexibility is expected to provide greater value to the grid—periods with spikes in LMPs (when the electricity generation system struggles to provide the required energy), periods with normal-range LMPs (more typical conditions), periods with high and low solar, wind generation, and fluctuations (ramping mile), periods with high and low net load and fluctuations (ramping mile), and periods with high and low flows (when the hydropower system would have more or less flexibility in how generation occurs). Table G-5 summarizes the some of the detailed periods analyzed using the real-time PLEXOS modeling.

Table G-5. Key evaluation events for the detailed power systems modeling.

Event	Date Range	Justification
1	01-04-2036 – 01-08-2036	Winter week that includes lowest 10% solar generation events, highest 10% wind ramping event, and price spikes due to grid stresses
2	07-23-2036 – 07-31-2036	Summer representative week that includes high solar generation and low wind generation
…	11-29-2036 – 12-07-2036	Winter week that includes lowest 10% solar, highest 10% Southeastern Electric Reliability Council (SERC) hydro generation, highest 10% wind generation

G.2.3 Model Development and Implementation

The proposed framework and approach in this case study explores how detailed modeling (sub-daily modeling of reservoir operations, hourly and sub-hourly energy market grid modeling, and hourly ecological impacts analysis) provides insights that are otherwise unrecognized in longer range modeling and planning typically performed for FERC-like studies. The ultimate goal is to develop a framework that allows simulation and analysis of alternative operating plans to deeply understand the corresponding effects on reservoirs, the grid, and the environment at a detailed level. This detailed approach involving computationally expensive modeling requires foresight and planning in identifying specific alternative operating policy scenarios and periods of interest to simulate. While the policy space and hydrological conditions are more limited, purposeful selection of these simulation conditions can help identify win-win opportunities that would not be seen at a daily or weekly modeling level and can provide complementary information to that obtained from typical longer range modeling efforts. This approach requires development of detailed models for the region of interest as well as understanding how the reservoir, grid, and environmental models should be connected to gain a full understanding of the integrated water-environment system.

G.2.4 Reservoir Modeling

As discussed previously, the reservoir modeling aspect of this project involves two types of models: a conventional simulation model (CHEOPS) and an optimization model (DDP). Coupled simulation-optimization approaches are widely applied throughout the water resources field because detailed operations or physical processes can be captured effectively using simulation models. This allows for rule-based (step functions, decision trees, etc.) operations and nonlinear physical processes to be captured traditionally with meaningful parameters. Detailed simulation models can be wrapped or connected to more generalized optimization algorithms for a variety of reasons, such as automatically calibrating model parameters to historical conditions or identifying Pareto-optimal decisions or policy triggers under a range of uncertain parameters.

This coupled modeling approach allowed for the CHEOPS model with accepted policy to dictate long-range operational decisions and targets while allowing a generalized optimization algorithm connection to refine intraday outflow decisions given constraints informed by CHEOPS policy and LMPs informed by PLEXOS, which cannot be readily used as-is in CHEOPS. This provides us with a means of evaluating the needs for flexibility under future generation buildout scenarios (as represented by LMPs for future scenarios).

G.2.4.1 CHEOPS

The CHEOPS model was specifically designed and developed for the most recent FERC relicensings of the two Yadkin-Pee Dee basin hydropower projects and includes fully parameterized physical characteristics, such as reservoir elevation-volume-surface area relationships, evaporation coefficients, tailwater and spillway rating curves, and turbine and generator efficiencies and capacities. The model also includes policy based on time of year and day in the form of guide curves, reservoir operating fluctuation limits, water supply withdrawals, recreational flows, and desired minimum and maximum pool elevation and outflows. For CHEOPS, we focused on developing load shape input parameters for the base cases, as listed in Table G-6.

Table G-6. Load shapes assigned to base case scenarios.

Base Case Scenario	Load Shape
Base 2024 (Current generation)	Seasonal variations in weekday current conditions Seasonal variations in weekday current conditions
Base 2036 (Assumed moderate increase in renewable penetration)	Seasonal variations in weekday future conditions
Base 2050 (Assumed high increase in renewable penetration)	Seasonal variations in weekend future conditions

While we maintained consistency in other modeling parameters with the work completed for the Yadkin-Pee Dee Hydroelectric Project (P-2206) FERC relicensing process, we took advantage of NREL's expertise and understanding of current and future generation buildout to define load shape patterns as inputs for the preliminary CHEOPS modeling. Although CHEOPS is fairly limited in providing load shape information, we were able to inform these parameters by analyzing net and total load patterns for ECRE and Duke Energy projects and qualitatively adjusting CHEOPS load shapes. The main goal was to properly characterize high-renewables penetration in the future load shape patterns.

For CHEOPS, an hourly pattern of load categories may be provided to represent each month of the year for weekdays and weekends. For weekdays, the categories include primary peak (peak), secondary peak (sec peak), and off-peak periods. For weekends, the categories include primary peak (peak) and off-peak periods. The current conditions load shape includes a late morning peak and evening peak for the spring, fall, and winter seasons. For the summer season, there is a single late evening peak. On weekdays, a secondary peak surrounds most of the peak period. Tables G-7 and G-8 show weekday and weekend load shape parameters for the current base case.

Table G-7. Current base case weekday load shape.

Start Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
1:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
2:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
3:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
4:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
5:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
6:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
7:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
8:00 AM	peak	peak	peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	peak	peak	peak
9:00 AM	peak	peak	peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	peak	peak	peak
10:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
11:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
12:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
1:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
2:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
3:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
4:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
5:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	peak	peak	peak	peak	sec-peak	sec-peak	sec-peak	sec-peak
6:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
7:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
8:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
9:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
10:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	off-peak	off-peak	off-peak	off-peak	sec-peak	sec-peak	sec-peak	sec-peak
11:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak

Table G-8. Current base case weekend load shape.

Start Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
1:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
2:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
3:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
4:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
5:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
6:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
7:00 AM	peak	peak	peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	peak	peak	peak
8:00 AM	peak	peak	peak	peak	off-peak	off-peak	off-peak	off-peak	peak	peak	peak	peak
9:00 AM	peak	peak	peak	peak	off-peak	off-peak	off-peak	off-peak	peak	peak	peak	peak
10:00 AM	peak	peak	peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	peak	peak	peak
11:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
12:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
1:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
2:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
3:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
4:00 PM	off-peak	off-peak	off-peak	off-peak	peak	peak	peak	peak	off-peak	off-peak	off-peak	off-peak
5:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
6:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
7:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
8:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
9:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
10:00 PM	peak	peak	peak	peak	off-peak	off-peak	off-peak	off-peak	peak	peak	peak	peak
11:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak

The future conditions load shape includes two peak periods, with higher generation throughout the morning in all seasons and with off-peak periods around midnight only. Tables G-9 and G-10 show weekday and weekend load shape parameters for this condition.

Table G-9. Future base case weekday load shape.

Start Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
1:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
2:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
3:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
4:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
5:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
6:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
7:00 AM	sec-peak	sec-peak	peak	peak	peak	peak	peak	peak	peak	peak	sec-peak	sec-peak
8:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
9:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
10:00 AM	peak	peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	peak	peak
11:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
12:00 AM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
1:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
2:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
3:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
4:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
5:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
6:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak
7:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
8:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
9:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
10:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
11:00 PM	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak	sec-peak

Table G-10. Future base case weekend load shape.

Start Hr	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
1:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
2:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
3:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
4:00 AM	off-peak	off-peak	peak	peak	peak	peak	peak	peak	peak	peak	off-peak	off-peak
5:00 AM	off-peak	off-peak	peak	peak	peak	peak	peak	peak	peak	peak	off-peak	off-peak
6:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
7:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
8:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
9:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
10:00 AM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
11:00 AM	peak	peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	peak	peak
12:00 AM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
1:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
2:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
3:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
4:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak
5:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
6:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
7:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
8:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
9:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
10:00 PM	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak	peak
11:00 PM	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak	off-peak

G.2.4.2 Reservoir Sub-Daily Distribution Model

DDP is an efficient optimization algorithm for convex, multiperiod, multistate problems, which makes it an ideal candidate algorithm for this case study where we are optimizing operations at six reservoirs over 24-hour periods. The generalized code is built on the open-source Julia package *SDDP* (stochastic dual-dynamic programming). The model is currently set up deterministically, but it is expandable to include stochastic variables or uncertainty in inputs (for example, uncertainty in inflows or LMPs). For this implementation, we are using the DDP algorithm to distribute fixed daily release volumes to hourly intervals given LMP information.

The DDP model includes Muskingum routing for reaches between the six facilities to account for related travel times. This becomes important during sub-daily modeling when it cannot be assumed that releases from an upstream reservoir reach the downstream reservoir within a single modeling timestep. Figure G-4 shows an example day of routed flow between two projects. For the optimization model, we developed linearized power planes for each project to define multidimensional relationships between reservoir storage, inflows, and power production. This approach allows compilation of power constraints given variable unit efficiencies with variable head and flow, which drive the potential power generation. The planes allow linearization and estimation of these nonlinear components within the DDP formulation.

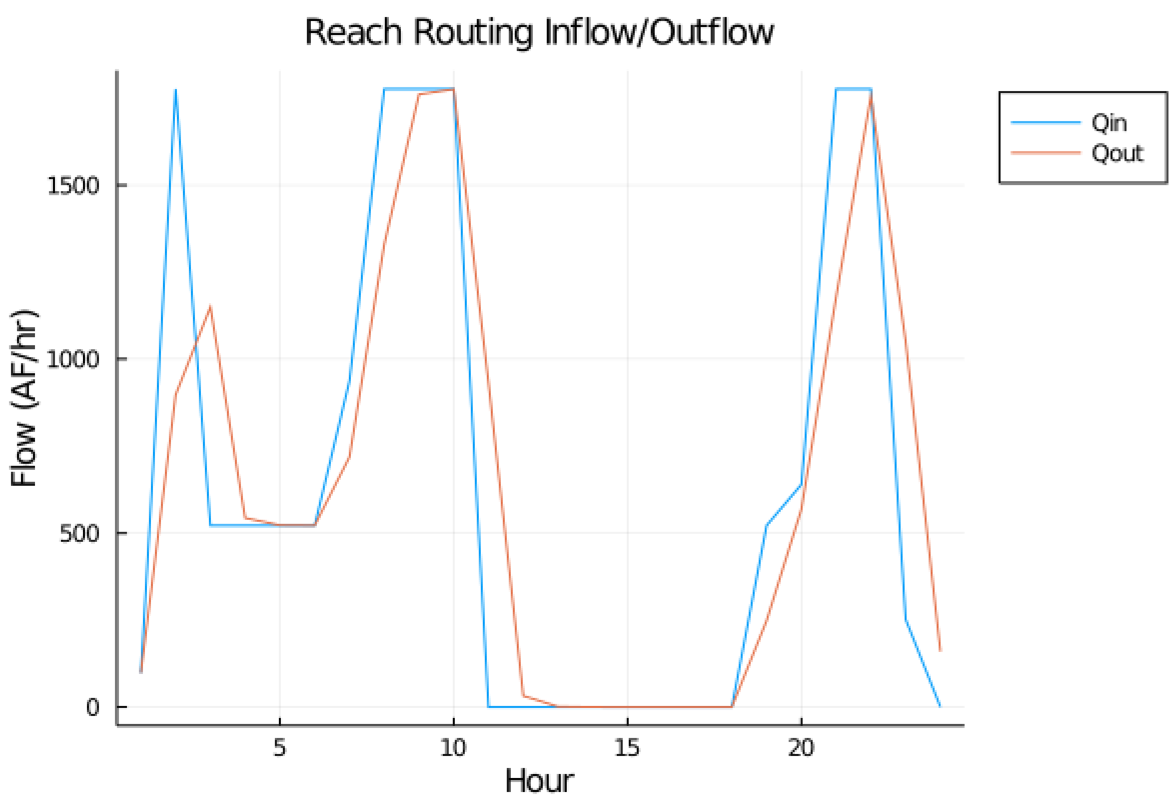


Figure G-4. Example Muskingum routing between projects (Qin: flows at the upstream end of the reach; Qout: flows at the downstream end of the reach).

We recognize that the optimization objective currently coded into the DDP model is based on maximizing the total collective generation revenue for all six facilities, thus optimizing based on coordinated operations between ECRE and Duke, while enforcing release of the daily inflow volumes (provided by CHEOPS) during that same day. Constraints passed from CHEOPS to DDP allow other operational objectives, such as minimum environmental flows, desired recreational releases, and following seasonal guide curve target storage, to be implicitly satisfied while optimizing for collective revenue. While we are not optimizing for these conflicting objectives within DDP, we test the alternative operating policy scenarios as defined in Table G-2 to improve these other objective benefits and assess the tradeoffs between hydropower and the environment.

G.2.4.3 Simulation-Optimization Connections

For the CHEOPS and DDP connection, we process outputs from CHEOPS for each day of the simulation. The daily outputs include starting storage for each project, the daily volume of local inflow (assumed constant throughout the day less water supply diversions and evaporation), and the daily aggregated volume of outflow (which DDP disaggregates throughout the day). The DDP algorithm must fully allocate the exact outflow volume determined by CHEOPS, which ensures that the starting and ending elevations/storages between the two models are consistent every day.

From the CHEOPS model, we also provide processed minimum and maximum pool bounds that follow the accepted seasonal policy. As shown in Table G-11, the target elevation (or guide curve) is constant throughout the year at all modeled reservoirs. For ECRE reservoirs, the operating band narrows between April 15 and May 15 per provisions of the Comprehensive Settlement Agreement. Duke Reservoirs (Tillery and Blewett Falls) operate within seasonal operating bands year-round. When processing these limits from CHEOPS to DDP, we considered the simulated CHEOPS results because, in events of extremely low flows or high flows, the CHEOPS simulated pools would deviate outside of these required pool bands. In those cases, to mitigate mass balance instabilities, we adjusted the allowable pool fluctuation bands to the CHEOPS simulated results. In both CHEOPS and DDP, physical limits of minimum and maximum pool stage constraints supersede these flexible daily bands, ensuring that the reservoirs do not over-release, resulting in negative storage, or exceed top of dam elevations.

Table G-11. Daily pool fluctuation constraints.

Plant	Target Elev (ft)	Date	Weekday			Weekend		
			Max Elev (ft)	Min Elev (ft)	Op Band (ft)	Max Elev (ft)	Min Elev (ft)	Op Band (ft)
High Rock	622.9	1/1	672.90	572.90	100	672.90	572.90	100
		4/15	623.90	621.90	2	623.90	621.90	2
		5/16	672.90	572.90	100	672.90	572.90	100
		12/31	672.90	572.90	100	672.90	572.90	100
Tuckertown	564.2	1/1	614.20	514.20	100	614.20	514.20	100
		4/15	565.20	563.20	2	565.20	563.20	2
		5/16	614.20	514.20	100	614.20	514.20	100
		12/31	614.20	514.20	100	614.20	514.20	100
Narrows	508.8	1/1	558.80	458.80	100	558.80	458.80	100
		4/15	509.80	507.80	2	509.80	507.80	2
		5/16	558.80	458.80	100	558.80	458.80	100
		12/31	558.80	458.80	100	558.80	458.80	100
Falls	332.3	1/1	382.30	282.30	100	337.30	327.30	10
		4/15	333.30	331.30	2	333.30	331.30	2
		5/16	382.30	282.30	100	382.30	282.30	100
		12/31	382.30	282.30	100	382.30	282.30	100
Tillery	278	1/1	278.17	273.17	5	278.17	273.17	5
		3/1	278.09	275.59	2.5	278.05	276.55	1.5
		4/15	278.05	276.55	1.5	278.05	276.55	1.5
		5/16	278.09	275.59	2.5	278.05	276.55	1.5

Plant	Target Elev (ft)	Date	Weekday			Weekend		
			Max Elev (ft)	Min Elev (ft)	Op Band (ft)	Max Elev (ft)	Min Elev (ft)	Op Band (ft)
		12/15	278.17	273.17	5	278.17	273.17	5
		12/31	278.17	273.17	5	278.17	273.17	5
Blewett Falls	177	1/1	178.08	172.08	6	178.08	172.08	6
		4/15	177.36	175.36	2	177.36	175.36	2
		5/16	178.08	172.08	6	178.08	172.08	6
		12/31	178.08	172.08	6	178.08	172.08	6

DDP also includes outflow ramping rate constraints. These constraints are not directly tied to the CHEOPS simulation but were needed to output realistic outflow patterns when retiming CHEOPS outflows. For the base case scenarios, the median hourly change in flow seen in the historically available gaged flows below Tillery Dam provided the outflow ramping constraint in the DDP model. Since the reservoirs are in a cascading system, we determined that a consistent ramping rate across all reservoirs could be employed and yield reasonable results. In the alternative operating policy scenarios, we explore how changes in this outflow ramping rate constraint impact the hydropower flexibility and win-win tradeoffs. For the unrestricted and highly restricted (all day and nighttime only) scenarios described in Table G-2, we manually adjusted outflow constraints until model stability was achieved. These constraints keep the DDP algorithm from over-allocating outflows during certain times of the day. The transfer of data between the two models is shown in Figure G-5.

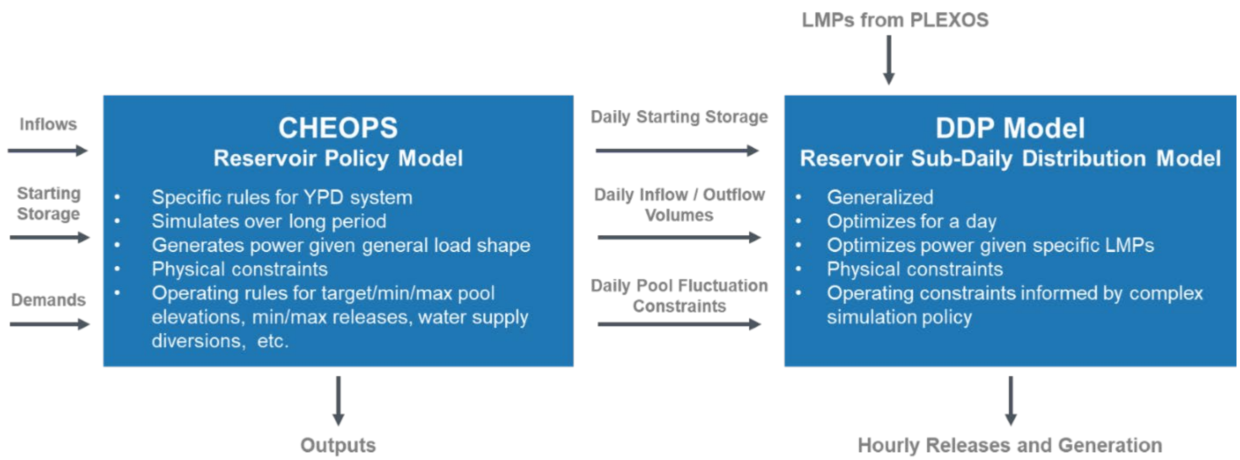


Figure G-5. CHEOPS-DDP framework.

G.2.4.4 Ecological Modeling

We obtained parameters to represent several species that spawn in spring, including nesting and broadcast spawning species. Black bass are a nesting species, and we tested the model for smallmouth bass, *Micropterus dolomieu*, introduced from nearby basins. These are similar to those for native largemouth bass, *Micropterus salmoides*, which are an important native gamefish in reservoirs but also nest in riverine sections. Use of floodplain habitat can be an important influence on juvenile growth for black bass.

QUANTUS-SD, the sub-daily version of the QUANTUS model (Jager 2014), simulates the effects of hydro- and thermo-peaking regimes on the most vulnerable, sessile life stage of fish with different reproductive life histories. We implemented a generic recruitment model for species in the Pee Dee River.

An interactive Rmarkdown version of the model has been published on https://rpubs.com/hjager/803529. The model estimates survival of smallmouth bass through three stages: 1) egg incubation; 2) larval development; and 3) juvenile development as described in (Jager 2014), with some modifications to account for sub-daily fluctuations in flow and temperature. The model is simplified to represent growth using a Von Bertalanffy relationship, although bioenergetics can be included if calibrated parameters are available at the site.

The primary goal of this model is to evaluate changes in reservoir operation under future grid scenarios. Flow and water temperature are two main drivers that we can use to simulate historical conditions or alternative flow release patterns designed to follow demand (load following) from upstream dams. Because shifts in diurnal fluctuations under future scenarios with increased variable renewable penetration is a primary goal, we used 15-minute flow and temperature drivers. In addition to flow and temperature, QUANTUS-SD requires meteorological data, including air temperature and solar radiation. Air temperature, T_{air}, is needed to impute missing water temperatures. Solar radiation is needed to determine whether it is daylight or not because some risks apply only when it is dark (e.g., displacement) or light (visual predators).

Different modes are provided for running the model. First, historical gage measurements can be used. Second, different future flow regimes calculated by CHEOPS in response to inflows and electricity price information can be used. When this is done, water temperatures are estimated from relationships in historical data. Finally, we provide the option of generating sub-daily flow data from historical data based on known block-loading patterns.

For historical conditions, we used inputs for each reach of interest for a representative series of years, here 2010-2019. Because RT data were missing for some periods (mainly winter), we imputed missing 15-minute flow data by using daily minima for off-peak hours and daily maxima for on-peak hours. Where daily data were also missing, we used the rolling seven-day minima and maxima of 15-minute flow centered over the missing time interval for off-peak and peak intervals, respectively. Finally, any intervals still lacking an estimate were assigned the daily average flow. Historical flows are shown in Figure G8-6.

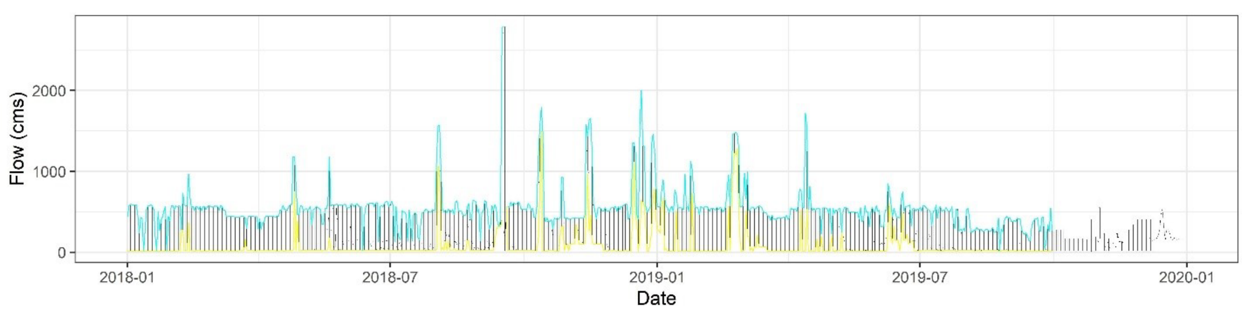


Figure G-6. Historical flows from USGS gage 0212378405 on the Pee Dee River at Hwy 731 below Lake Tillery including imputed winter values. Daily minima are in yellow and maxima are in cyan.

Similar gaps occurred in historical RT water temperature data. To fill 15-minute time periods, t, with gaps, we developed relationships with daily average air temperature, flow (Q_t), and time interval, t (Equation 1, middle, adj $R^2 = 0.87$; $\upsilon = 0.5871$, $\Upsilon = -0.001893$, $\tau = 0.005828$). Daily average water temperature, Tw_d, was added as a predictor when available, and this approach was given priority.

$$\mathrm{Tw}_r = \begin{cases} Tw + \alpha\, Tair_d + \eta\, Tw_d + \gamma\, Q_t + \rho\, t, \text{ t missing } T_w \\ Tw + \nu\, Tair_d + \gamma\, Q_t + \tau\, t, t\ missing\ Tw_d \\ \frac{1}{4\times 24\times 7}\sum_{t-336}^{t+336} Tw_t \text{ , t missing } Q_t \end{cases} \qquad \text{Eq. 1}$$

For intervals not filled by applying these relationships, we used a rolling seven-day average. These relations were successively used, in the order shown, to impute winter temperatures at gages just below Tillery Dam. Results are shown in Figure G-7.

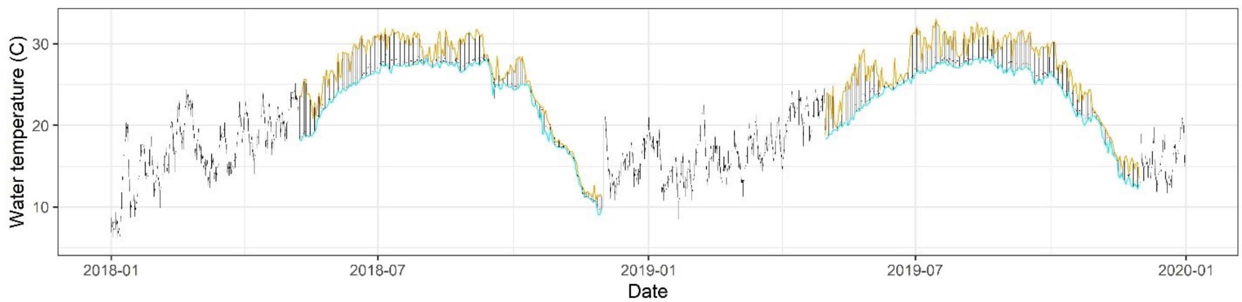


Figure G-7. Historical temperatures from USGS gage 0212378405 on the Pee Dee River at Hwy 731 below Lake Tillery including imputed winter values. Daily minima are in cyan and maxima are in orange.

Superimposing within day block loading on daily flow regimes, we provide the option of simulating block loading with historical daily flows. The efficient hydraulic capacity of downstream Blewett Falls turbines is 203.88 m^3s^{-1}. Typical block-loading patterns fluctuate between six units run at 203.9 m^3s^{-1} and three at 101.9 m^3s^{-1} in summer. We provide the ability to simulate block-loading patterns by superimposing sub-daily fluctuation on daily average flow and temperatures. We impose patterns of sub-daily flow based on parameters that define up to two intervals (hour of the day), a_1 to b_1 and a_2 to b_2, when higher flows are released to generate during peak demand, and Q_{min}, assumed to be the minimum flow released in off-peak hours. The minimum flow can be specified during different seasons. In the Pee Dee River, a higher minimum, $Q_{min.spr}$, is specified in spring (Eq. 2).

$$Q_t = \begin{cases} Q_{max}, hr(t) \in \cup\ (a_1, b_1), (a_2, b_2) \\ Q_{min},\ otherwise \end{cases} \qquad \text{Eq. 2}$$

where:

$$(a_1, b_1) = \text{1st daily period peak demand}, (a_2, b_2) = \text{2nd daily period peak demand}$$

$$Q_{max} \;=\; 4\left[24\, Q_{avg} - (24 - \#peak\ hrs)\, Q_{min}\right],\ peak\ hrs = (b_1 - a_1) + (b_2 - a_2),$$

$$Q_{avg} = \frac{1}{count(t)} \sum_{t=0}^{t\in year} Q_t$$

Simulating with CHEOPS flow data, we obtained CHEOPS flow outputs at 15-minute intervals. We estimated temperatures from relationships with air temperature, T_{air}, flow, Q, and hour of day observed in the historical data, $T_w = \alpha + \beta\, T_{air} + \lambda\, Q + \pi\, hr$ as in Eq. 1.

Physical Habitat

We evaluated habitat below each dam based on flow and temperature. Key features of physical habitat represented in the model are spatial functions of flow. We developed lookup tables relating wetted perimeter and average depth to flow based on transect information from an instream flow study below

Tillery Dam (Figure G-8). Water surface elevation (stage, m) increased linearly with flow (29.672 + 0.00124 flow, $R^2 = 0.985$), whereas wetted perimeter increased linearly from 180 m between flows of zero to 80 m3s, and then reached an asymptote at around 300 m. Average depth reached 2 m for flow ~450 m^3s.

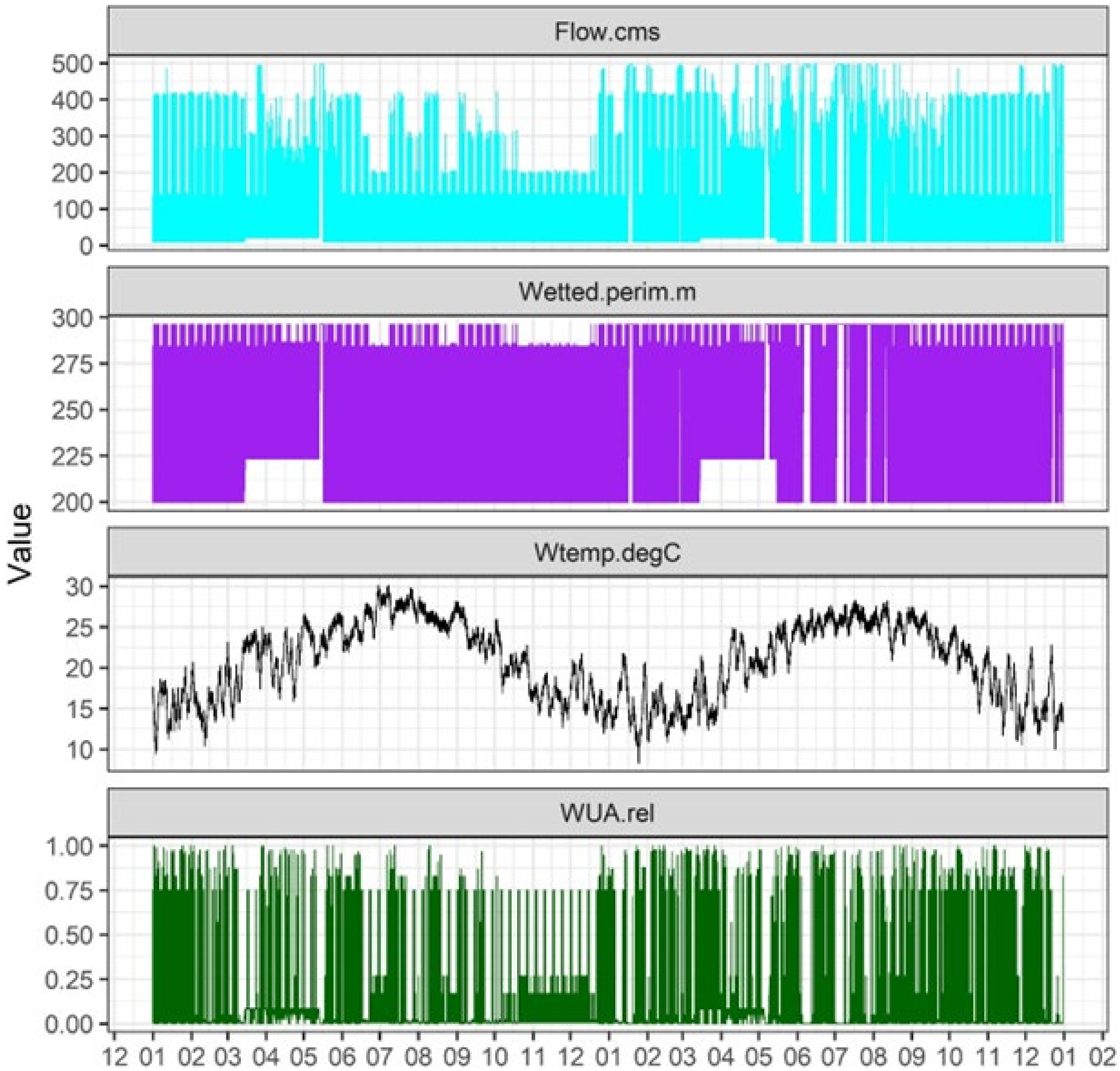


Figure G-8. Time series of flow (m^3s), wetted perimeter (m), water temperature (°C), and relative weighted usable area for two years (2012 and 2013), based on CHEOPS simulated operations for a BAU scenario in 2024.

Spawning and Early Development

We represented species with different early life histories to ensure that the resulting modeling tool would be general. The model begins with reproduction, which occurs in the spring for many species. One can specify the type of cue for spawning activity (temperature, degree days, daylight) and a range of values within which spawning occurs. This range is used to set a distribution of days, and quantiles from this distribution are tracked by the model over a 2-year period, returning an estimated final survival for each quantile. Results for quantiles can be averaged or examined to better understand temporal patterns and the costs/benefits of early versus late spawning.

Black bass build nests and deposit eggs in the spring. Nests are guarded until swim-up fry reach 16 mm (DeAngelis et al. 1993; Ridgway 1988). Egg development is represented as a function of degree-days above T_{base} = 10°C as described in an individual-based model of smallmouth bass in streams (Jager et al. 1993).

Below, we estimate mechanistic sources of survival for incubation of eggs and larvae and for juveniles. Because running the model with daily drivers is allowed, all survival values below are estimated as daily rates and converted to 15-minute survival, $S^{(1/4\times24)}$. Some risks apply only during daylight or nighttime hours, or during certain times of year (Figure G-9).

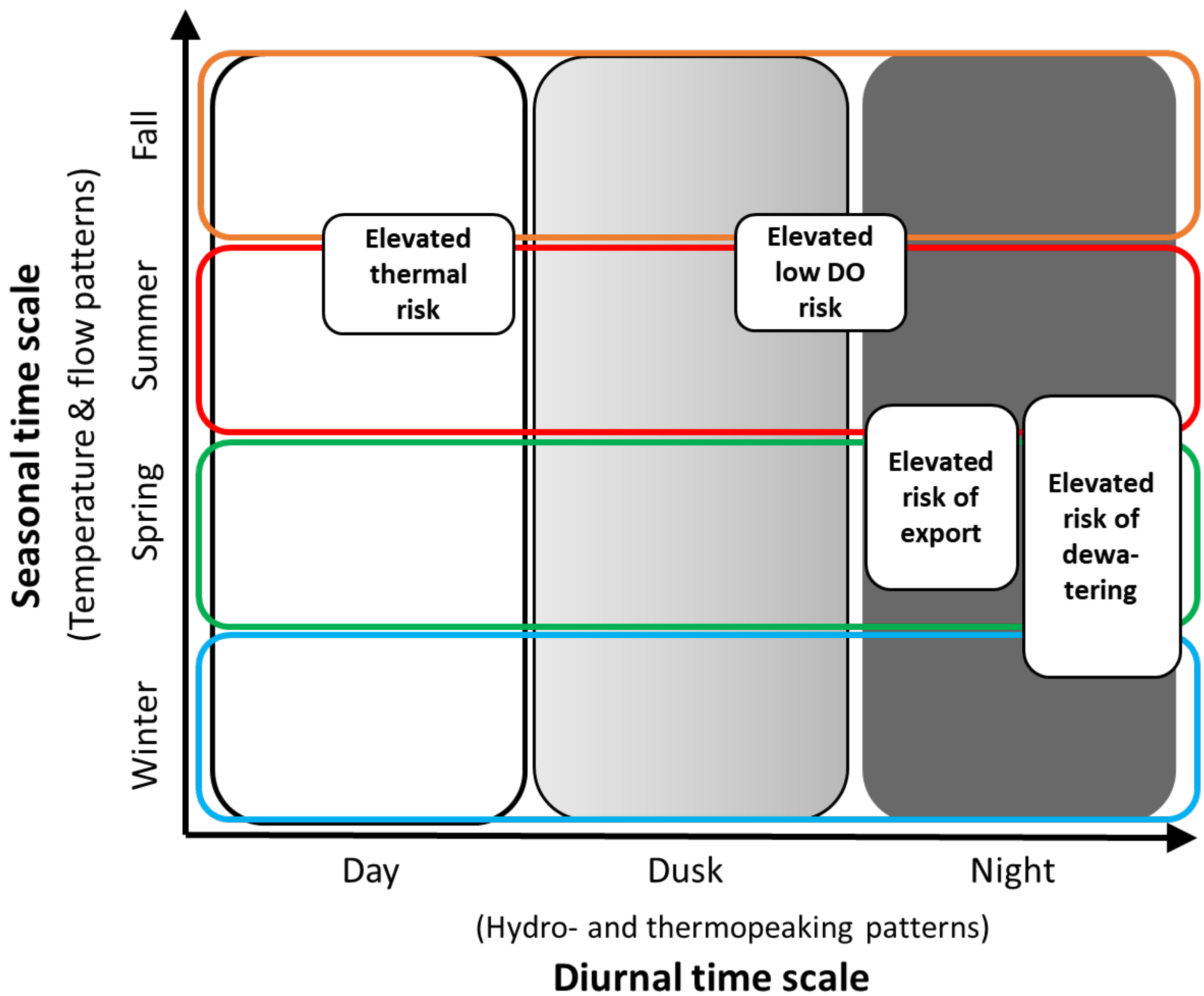


Figure G-9. Risks to individual fish depend on seasonal and diurnal patterns in flow and temperature. These are mediated by life stage (e.g., lower mobility during incubation and rearing) or size and responses to flow are mediated by temperature.

Incubation Survival

Baseline egg and larval survival is assumed to be high, S_{base}, for bass species (Clark et al. 1998). For all species, we assume 100% egg and larval survival within an optimal range of temperatures (*SincToptL* - *SincToptU*) and a linear decrease to ST_{min} as water temperatures approach extreme low*, SincTL*, or high, *SincTU*, values (Table G-12). Additionally, fish eggs are killed at freezing temperatures and when diurnal fluctuations in temperature are significant (Becker and Neitzel 1985).

Table G-12. Regression modeling of QUANTUS-SD showing effects of nighttime flow restriction on survival of eggs, larva, and young-of-year (YOY) juveniles.

	Eggs	Larvae	YOY
(Intercept)	0.61 ***	0.19 ***	0.01 ***
	(0.05)	(0.03)	(0.00)
Future.year2036	-0.01	0.00	-0.01 ***
	(0.05)	(0.03)	(0.00)
Future.year2050	0.00	0.01	-0.01 ***
	(0.06)	(0.03)	(0.00)
Is.envTRUE	0.02	0.02	0.00 ***
	(0.04)	(0.02)	(0.00)
poly(tQile, 2)1	-1.53 ***	-3.53 ***	0.00
	(0.30)	(0.15)	(0.00)
poly(tQile, 2)2	-2.08 ***	1.01 ***	-0.00
	(0.30)	(0.15)	(0.00)
brood.yr2013	-0.17 ***	0.10 ***	-0.00
	(0.04)	(0.02)	(0.00)
N	198	198	198
R2	0.32	0.76	0.62

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$.

Fish species that have different incubation strategies experience shallow depths differently. For nest-guarding bass, shallow water depths lead to reduced survival because of nest abandonment. If the temperature falls below the temperature range suitable for spawning or drops more than 2°C in a short time, the guarding male abandons the nest and results in high predation mortality (Landsman et al. 2011). We assume a 50% risk for each 15-minute event.

We estimate survival as the proportion of current wetted perimeter, WP_t, to the wetted perimeter at the time of spawning, WP_0. In general, eggs are less vulnerable to dewatering than larval stages, especially once larva begin to use their gills (Fisk et al. 2013). However, larvae can potentially avoid dewatering. Here, we treat them as having the same risk (Eq. 3).

$$\mathrm{S}q_{lo} = \mathrm{Sdewat} + (1 - Sdewat)\ \min\left[\frac{min_t(WP_t)}{WP_0},\ 1\right] \qquad \text{Eq. 3}$$

The timing of high flows is important. Prior to nesting, velocities high enough to keep silt-sized material in suspension or resuspend and velocities that remove silt can be beneficial for many fishes and mussels. However, during incubation, extreme high flows add risk by scouring nests or displacing larvae. Spates can displace the guarding male or scour nests. Following Jager et al. (1993), we assumed 50% daily risk of nest scouring for any species with average water-column velocities exceeding, $V_{crit} = 0.2\ \mathrm{m\ s^{-1}}$. This is consistent with estimates of critical shear stress for incipient motion of sand particles (Shvidchenko et al. 2001). We note that the protective effects of cover could be represented in the future.

Survival of Juvenile Fish

Juvenile survival is modeled as a function of length-dependent predation and by functions of flow and temperature extremes and fluctuations. Predation is simulated for juvenile fishes as a decreasing function of size (Perkins and Jager 2011), with parameters *SLmin*, *SL50*, *SL90*. Fish growth, measured by fork length, is simulated using a Von Bertalanffy relationship with three parameters, *VBLinf*, *VBk*, and *VBt0*. The risk to fluctuations in flow and temperature depends on when they occur (Figure G-10) and the swimming ability of the fish. We model responses to temperature changes and extremes as follows. For high temperatures, we used a logistic function with parameters *STLC50* and *STLC90* to describe survival for both species per Jager and Rose (2003). Parameter values are from studies for bass (Smale and Rabeni 1995) (Table G-12).

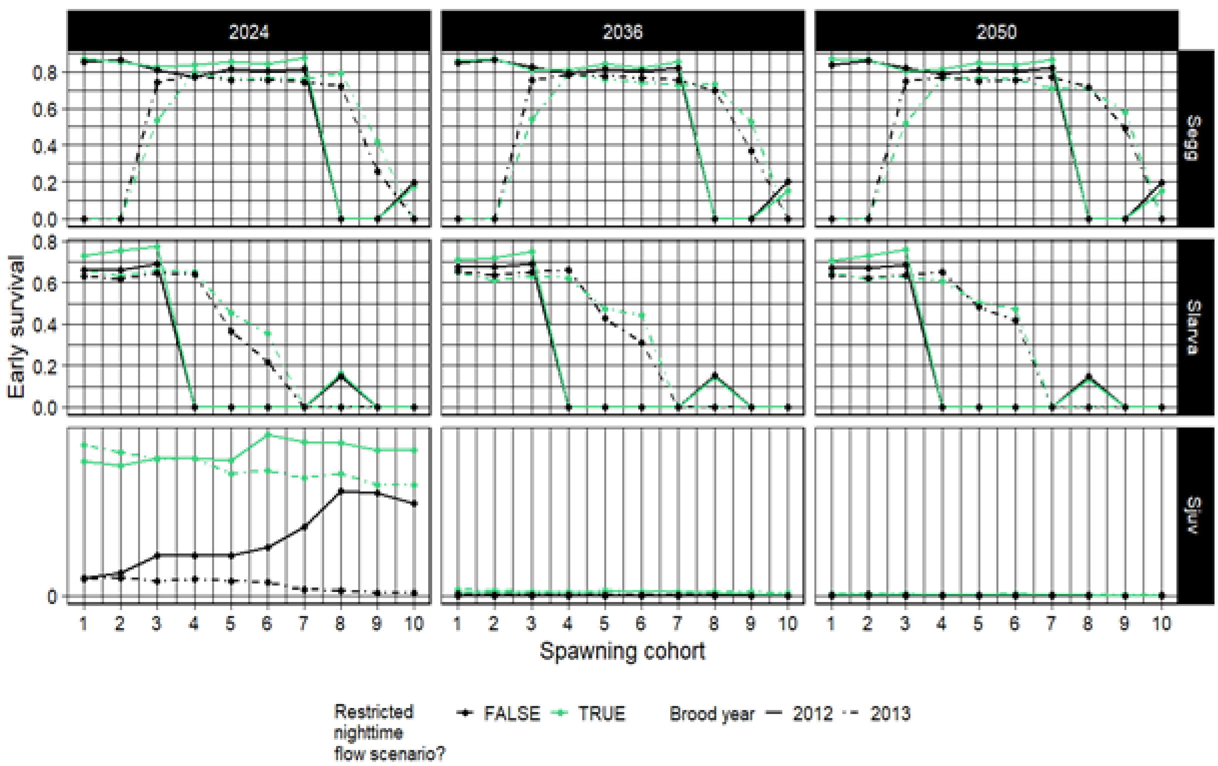


Figure G-10. Survival of eggs (S_{egg}), larva (S_{larva}), and juveniles (S_{juv}) under flows resulting from operational scenarios that do (green line) and do not (black line) include nighttime ramping restrictions for 2024, 2036, and 2050.

Cold shock is a significant risk for fish experiencing rapid reductions in body temperature (Donaldson et al. 2008). Rates of change less than 0.1°C min^{-1} can ensure that deep-body temperature can track ambient temperatures and avoid thermal shock (Ziegeweid et al. 2007). For largemouth bass, significant cortisol responses acclimated from 20°C in response to a 12°C cold shock, but not in response to an 8°C decrease or to temperature increases of comparable magnitudes. Fish may experience 'cold coma' in response to a 10°C drop in temperature from a 20°C acclimation temperature (Clarkson and Childs 2000; Michie et al. 2020). Although the rate of predation decreased in colder water, predation success was doubled when attacking fish experiencing cold hock (Ward and Bonar 2003) and swim speed was reduced by 40% (Ward et al. 2002). We model cold shock as a daily risk of $S_t = 0.5$ for time intervals that experience decreases greater in magnitude than *Cold.shock.juv*.

We assume that mobile life stages of fish (juveniles) can avoid risks associated with changes in flow during daylight hours if temperatures are high enough for juveniles to avoid being swept away (> *SincToptL*). Otherwise, a daily rate of 50% mortality is simulated in response to increases in flow that exceed the maximum prolonged swim speed expressed in body lengths, *Umax.BL*. Such relationships have been developed for species with different body types (Cano-Barbacil et al. 2020). At the other extreme, stranding may occur when flow falls quickly. For time intervals in which wetted perimeter WP_t decreases, survival is represented as it was for eggs and larvae (Eq. 3), except that the risk is estimated based on wetted width in the previous timestep rather than the date of spawning.

G.2 5 Power Systems Modeling

We used PCM to better understand the operations and economics implications of the Yadkin-Pee Dee cascade hydropower plants. We used PLEXOS, a commercially available PCM developed by Energy Exemplar. We carried out three modeling steps in PLEXOS to simulate how a system operator might commit and dispatch the power system according to forecasts of wind, solar, hydro, and electric load (Figure G11).

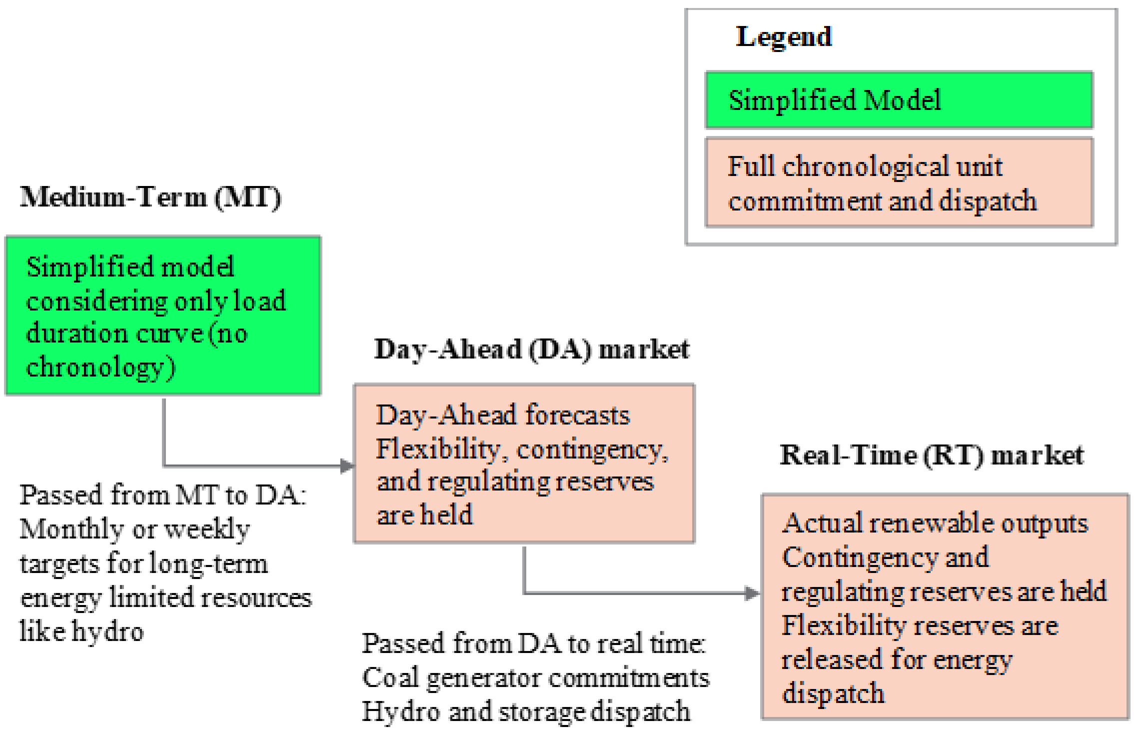


Figure G-11. Simulation steps of the PLEXOS to represent power grid operation.

The Yadkin-Pee Dee hydropower plants are in the SERC region of the U.S. power grid. Hence, this case study uses a representation of the EI at busbar level for transmission. First, Figure G-12 examines the SERC region daily load profiles for three infrastructure years (2024, 2036, and 2050). These infrastructure years assume that 17%, 50%, and 65% of total generation comes from renewable energy resources, respectively, and are modeled as such to understand the energy and reserve product prices for various levels of renewable energy contributions. Average load shapes of year 2024 have a single peak in warmer months and two peaks in colder months. For years 2036 and 2050 load shapes have two peaks in morning and evening. Further, due to high solar penetration, the shape of the "duck curve" with increased slopes in morning and evening hours to form deeper "bellies" can be noticed in years 2036 and 2050 load shapes for all months when compared to the year 2024. Two hydrology years (2012 and 2013) are considered to represent the dry and wet years for the Yadkin-Pee Dee basin and the rest of the power system (Figure G-13). The PCM runs are carried out in two phases to examine the tradeoffs in power and nonpower outcomes for water resources planning.

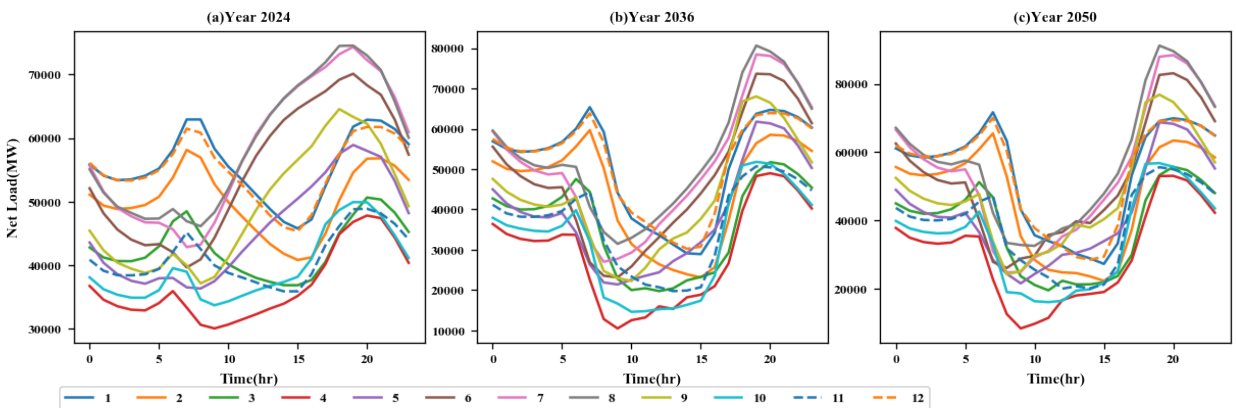


Figure G-12. Average load shapes of January to December (1-12) months of (a) year 2024, (b) year 2036 and (c) year 2050.

Our first PLEXOS model simulates the DA unit-commitment and economic dispatch of the system with hourly resolution, with forecasted profiles for wind and solar. In this step, the Yadkin-Pee Dee hydropower plants are treated as an input dataset using the 15-minute generation output time series from the baseline CHEOPS model. These time series reflect the larger operating policy, but not the detailed sub-daily constraints developed for the Yadkin-Pee Dee due to limitations in CHEOPS. Figure G-13 presents the power-generation output from CHEOPS and used as input to the DA PLEXOS model.

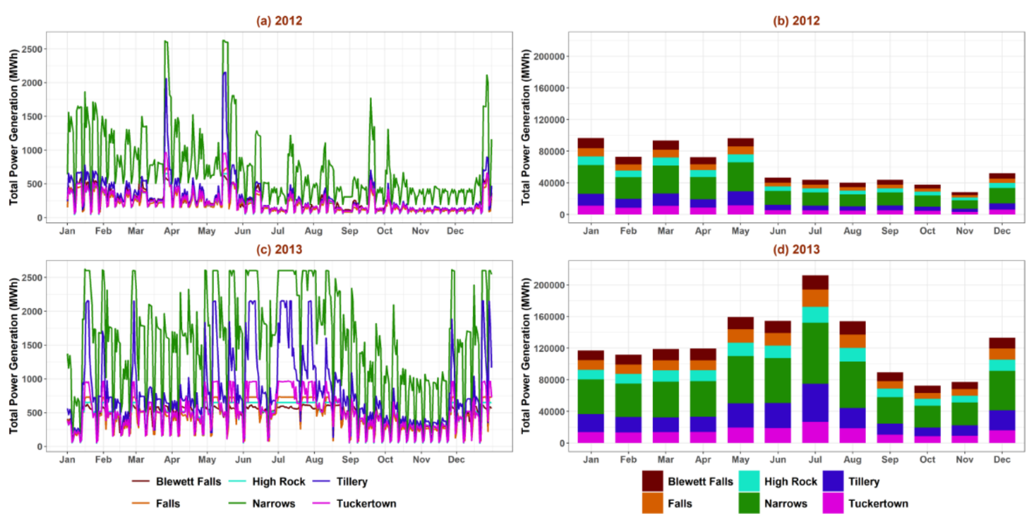


Figure G-13. Yadkin-Pee Dee hydropower generation of six power plants to represent a dry year 2012 and a wet year 2013.

For each of the infrastructure buildout years (2024, 2036, and 2050), LMPs are extracted from the PLEXOS results for each of the Yadkin-Pee Dee hydropower plants for use as inputs to the DDP modeling for all the operating policy scenarios evaluated (i.e., both the baseline and alternative policy scenarios). These formed the primary power system input to the study.

In addition to the PLEXOS DA modeling, we also considered 5-minute RT modeling to evaluate the power system impacts of different operating policies at a sub-hourly timestep for limited periods. In the PLEXOS RT modeling step, the generator commitment status for large or slow-start generators such as coal or gas combined-cycle generators are taken from the DA and are used as inputs to the RT, along with 5-minute realized generation profiles for solar and wind. In this case, we used Yadkin-Pee Dee hourly hydro generation time series output from DDP as fixed inputs, which are based on the LMPs determined by the PLEXOS DA, and other operational constraints at an hourly time scale.

For the RT modeling, two main scenarios were carried out to understand hydropower flexibility to provide grid ancillary services. In the first scenario (flexible generation), hourly generation is modeled with hourly maximum energy limits. RT optimization is carried out for each hour at 5-minute resolution. We assume that ramping rates of the Yadkin-Pee Dee hydro plants do not constrain the 5-minute optimization and flexibility to operate. In the second scenario (fixed generation), Yadkin-Pee Dee power plants hourly generation is modeled as fixed generation, which is interpolated between the consecutive hours during dispatch without any flexibility in RT. We examine the periods of system stress on the grid for greater understanding of required grid services from hydropower and revenue received by hydropower in the three infrastructure scenarios.

G.3 Analysis Process

There are three major computation steps of the framework for performing the analyses of the scenarios listed in Table G-6. These steps are described in the subsequent sections.

G.3.1 Step 1: Generate Base Case LMPs

The following model executions are performed in this step:

1. Use the base case operating policy defined in CHEOPS along with peak, secondary peak, or off-peak load shape information as described in Section G.2.4.2 to generate the CHEOPS outputs (as shown in Figure G-14) for each buildout case.

2. Run PLEXOS DA using the CHEOPS outputs to generate LMPs for direct generation for each of the three buildout cases and the evaluation windows.

Figure G-14 summarizes the data flow between CHEOPS and PLEXOS during the Step 1 executions. The resulting hourly LMP sets constitute the Base Case LMPs that are used to evaluate different operating policy scenarios. The PLEXOS DA model is not executed again after this step in the process.

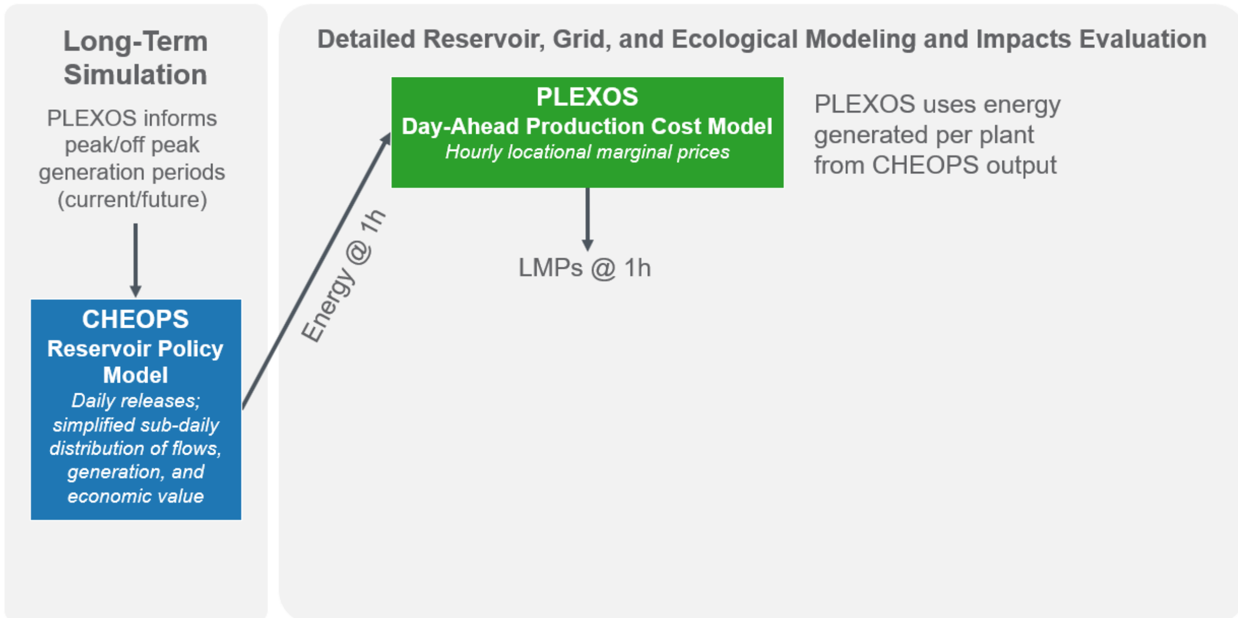


Figure G-14. Step 1 Yadkin-Pee Dee coordinated modeling framework.

G.3.2 Step 2: Reservoir Policy Modeling and Environmental Modeling

CHEOPS, DDP, and the environmental models have short run times that allow exploring a larger suite of scenarios and selecting the most impactful to evaluate in the detailed PLEXOS RT model in Step 3.

Step 2 includes the following executions for each alternative operating policy scenario:

1. Define operating policy in the DDP model (i.e., define ramping rate constraints).
2. Select the appropriate base case CHEOPS outputs as inputs for the operating policy scenario.
3. Run DDP and generate summary outputs.
4. Run environmental models for long-term or short-term periods and generate summary outputs.

In Step 2, evaluation of alternative operating policy scenarios could extend beyond the sub-daily period into longer range impacts on resource concerns such as water supply. For this particular case study, all alternative policies focused on release changes at the sub-daily policy level, where outflow volumes, starting and ending pool elevation/storage, and seasonal operating policy were unchanged from the accepted base case policy. For other studies, it would be important and informative to assess long-range impacts (using traditional simulation models) if new seasonal operational policies are explored.

Figure G-15 summarizes data exchange between the different modeling components.

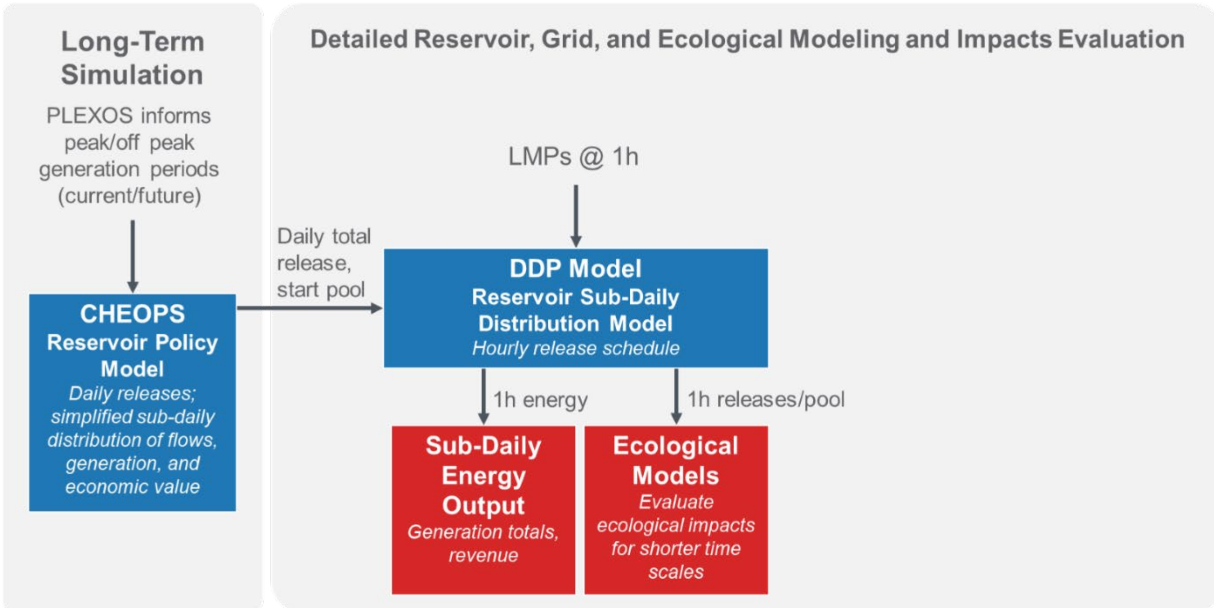


Figure G-15. Step 2 Yadkin-Pee Dee coordinated modeling framework.

G.3.3 Step 3: Detailed Power Systems Modeling

For the detailed power systems modeling we identified several key events for which the PLEXOS RT model was executed to compute more detailed grid-related outputs. Figure G-16 summarizes the related data exchange. As shown, DDP energy outputs inform the PLEXOS RT modeling in Step 3.

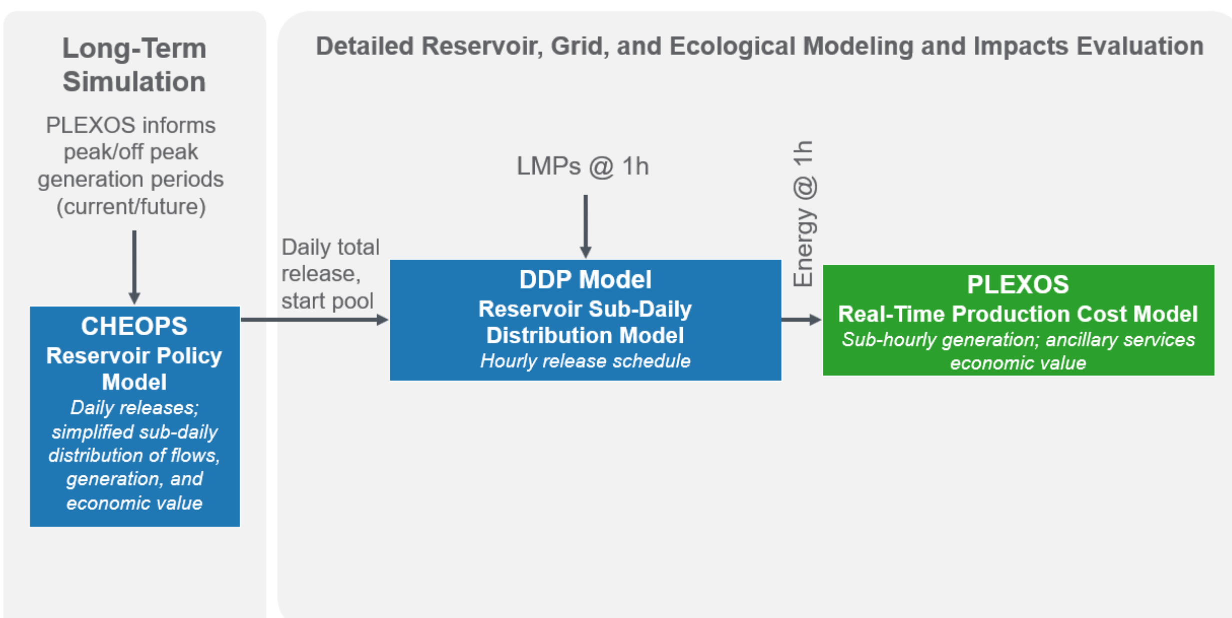


Figure G-16. Step 3 Yadkin-Pee Dee coordinated modeling framework.

G.4 Results

Case study results are discussed for each detailed modeling component in the following sections. Recall that the scenarios of interest include the following:

- 2024 Base Case Load Scenario
  - 2024 Load-Base Ops
  - 2024 Load-Base Ops with Env Policy
- 2036 Base Case Load Scenario
  - 2036 Load-Base Ops
  - 2036 Load-Unrestricted Ramping Ops
  - 2036 Load-Restricted Ramping Ops
  - 2036 Load-Base Ops with Env Policy
  - 2036 Load-Unrestricted Ramping Ops with Env Policy
- 2050 Base Case Load Scenario
  - 2050 Load-Base Ops
  - 2050 Load-Base Ops with Env Policy

G.4.1 Operations Comparisons

For the coupled simulation-optimization reservoir modeling, we focus our analysis on high-level takeaways of the benefits of sub-daily detailed modeling (DDP model), implications of the various load-base case scenarios, and impacts of alternative reservoir operating policies on win-win objectives. To capture the impacts of moving toward more detailed reservoir modeling at an hourly timestep, we compare the simulated revenue, energy, and operations between CHEOPS and DDP. Recall that the base case scenarios do not impose new operational policy outside of allowing DDP to fully utilize the allowable operating pool bands within a given day.

The base case scenarios show how CHEOPS and DDP operate to respond to changes in hydropower load assumptions between years 2024, 2036, and 2050. In Figure G-17, we compare LMP traces from the three base case scenarios for High Rock dam (as an example). These LMPs are representative of grid needs as demand and penetration of renewables are assumed to grow. In 2024, with a larger proportion of conventional energy sources, there are fewer extreme peaks in the LMP dataset relative to 2036 and 2050. Additionally, the 2024 dataset is less variable, with energy values consistently greater than \$0 and less than \$100 most of the time, which indicates that grid demand is currently satisfied with the current available generation sources online. However, as the penetration of renewables grows, the LMPs become more variable, with prices regularly dropping to \$0 in times when available energy exceeds demand, reaching \$100 consistently, and spiking to high prices more often, showing a growing need for flexible energy sources.

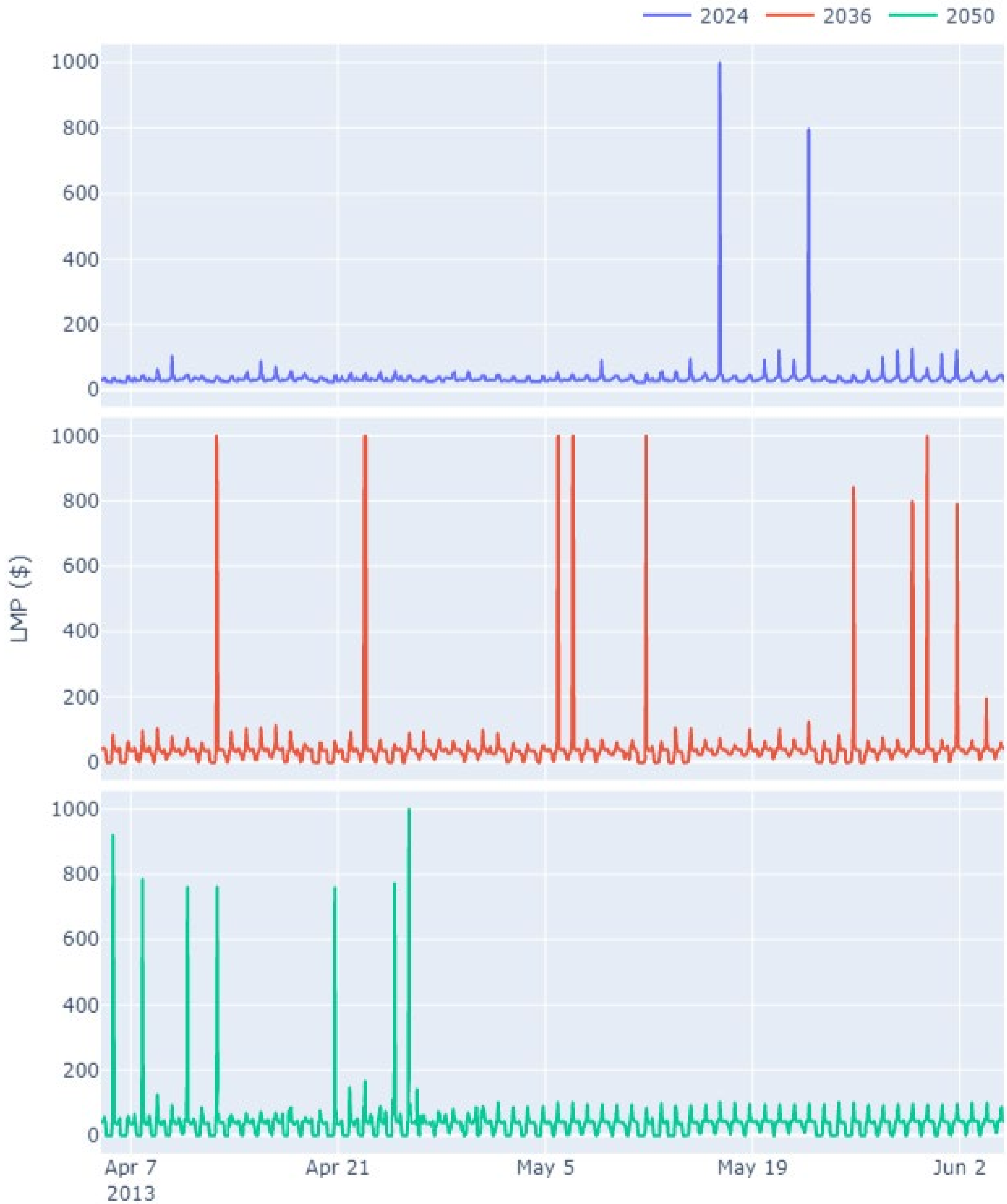


Figure G-17. Locational marginal pricing for High Rock Dam for 2013 from day-ahead PLEXOS modeling.

In Figures G-18 and G-19, we calculated the total annual revenue across both ECRE and Duke reservoirs for the 2012 and 2013 operating years from both the CHEOPS and DDP simulations. While CHEOPS uses coarse information to schedule power releases, we still use the LMPs to post-process the annual revenue accrued by the model. Throughout this analysis, we highlight revenue differences because the

LMPs that served as an input to DDP provide insight to the benefits that the reservoirs and their operations can provide to the grid. While the LMPs allow us to calculate direct revenue to the hydropower producers, they also indicate when flexibility is most valuable and helpful to the grid. If hydropower can meet the most valuable need (i.e., release in response to higher LMP values), then we can assess how flexible hydropower energy can be and whether this flexibility occurs when the grid needs it.

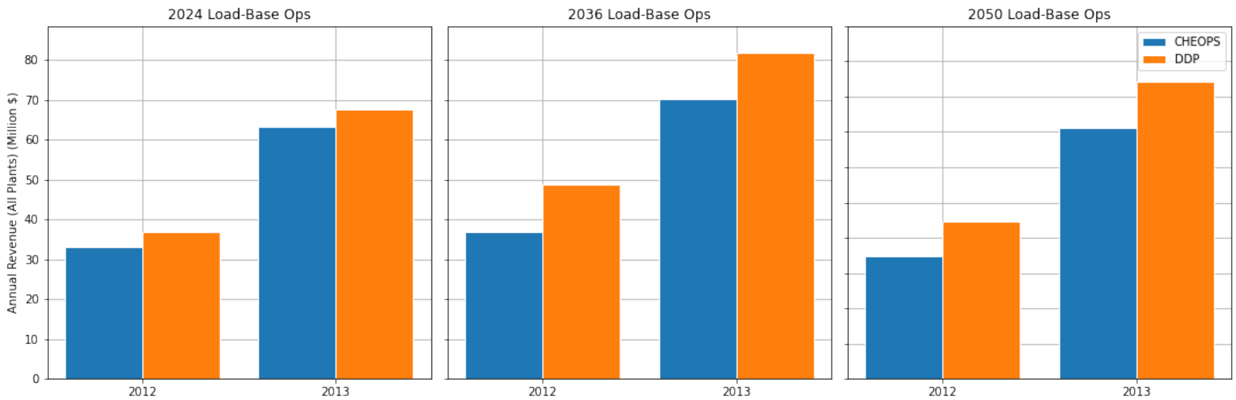


Figure G-18. Annual revenue for base case load scenarios.

Across all three base case scenarios, the DDP optimization approach provides significant improvement in revenue earnings. In the complementary Figure G-19, it is evident that this revenue increase occurs even though the overall hydropower production is generally unchanged. The same volume of water is released between CHEOPS and DDP; however, the changing head throughout a given day may result in a slightly different hydropower production.

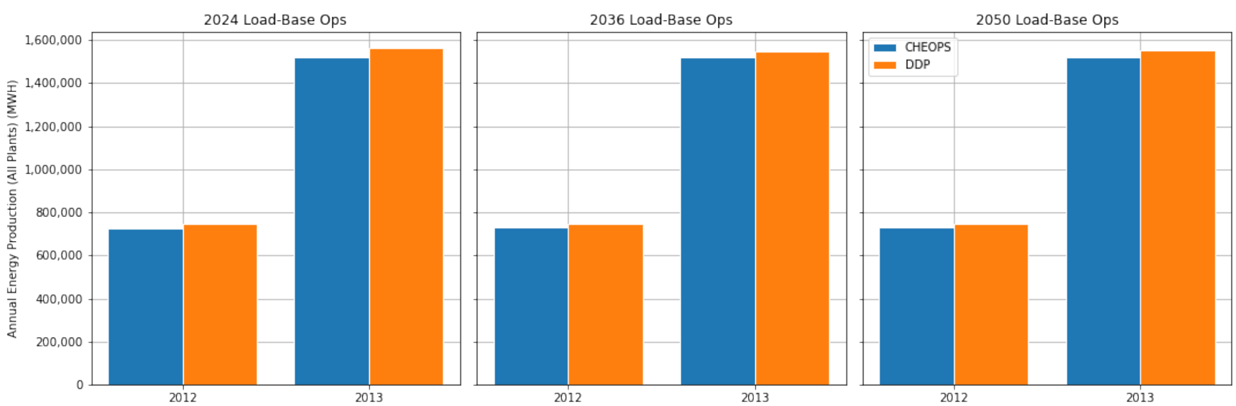


Figure G-19. Annual energy production for base case load scenarios.

CHEOPS provides a reasonable representation of hydropower generation to help understand the impact of different policy changes on total generation and corresponding revenue. However, it does not provide information to help understand how the reservoir system can (or cannot) react to a shift toward more variable grid needs (reflected in the greater variability in LMPs). In contrast, by integrating the use of LMP information (and the associated grid changes represented by the LMP datasets), we can see how effectively the reservoir system can react to periods of high or low demand in support of the system.

By comparing CHEOPS and DDP generation production and corresponding revenues, it is evident that including LMP information (i.e., integrating grid modeling) directly in the power scheduling process using an optimization model (DDP developed for this case study) or within a simulation model allows the reservoirs to take advantage of available flexibility and respond to the grid's anticipated needs more effectively and proactively. The DDP model provides a more realistic understanding of how operations could be executed at an hourly basis without changing long-term operational goals. Just by improving the level of detail of the reservoir model, we improve hydropower operations and more effectively use the flexibility that does exist without any changes to the seasonal operational policy.

The base case load scenarios result in similar trends between CHEOPS and DDP revenue and hydropower production results. As expected, in all three base case conditions, the 2012 low-flow operating year results in less revenue than the 2013 higher flow operating year. However, the improvement in revenue from modeling using simplified hourly reservoir operation assumptions to more detailed modeling (DDP) is higher on a percent basis in the low-flow year, showing that opportunity for hydropower production flexibility exists in both low- and high-flow periods (see Table G-13).

Across the three load scenarios, the timing of when energy is needed throughout the day is changing based on the anticipated energy demand (load) and mix of conventional and renewable energy sources. Since the DDP simulation improves revenue in all three cases, we show that hydropower in the Yadkin-Pee Dee basin is flexible enough to adapt to changing load patterns, even with a fixed daily total generation volume. It is also interesting to note that DDP improves revenue from the CHEOPS model by a greater percent increase in the future scenarios (2036 Load-Base Ops and 2050 Load-Base Ops) than in the current scenario (2024 Load-Base Ops), as shown in Table G-13. This indicates that the Yadkin-Pee Dee hydropower projects actually respond more effectively as the energy market shifts to a higher penetration of renewables.

Table G-13. Annual revenue for base case load scenarios with calculated percent increase.

Scenario	Model	2012	% Inc	2013	% Inc	Total	% Inc
2024 Load-Base Ops	CHEOPS DDP	$32,970,000 $36,800,000	12%	$63,310,000 $67,550,000	7%	$96,280,000 $104,350,000	8%
2036 Load-Base Ops	CHEOPS DDP	$36,940,000 $48,680,000	32%	$70,350,000 $81,940,000	16%	$107,290,000 $130,620,000	22%
2037 Load-Base Ops	CHEOPS DDP	$34,910,000 $44,680,000	28%	$71,040,000 $84,330,000	19%	$105,950,000 $129,010,000	22%

Figure G22 compares the DDP model re-distribution of outflows to the CHEOPS simulated results for an example base case (2024 Load) scenario over a selected period in winter of 2013. The top plot shows total inflows into High Rock (the most upstream reservoir included in the DDP model). Intermediate inflows for each downstream reservoir are not plotted because local incremental inflows are usually small relative to the flows routed through the cascading system; therefore, upstream outflows are representative of downstream inflows for both models. It should be noted that travel times are relatively small between projects, but routing methods are used in both CHEOPS and DDP. The subsequent plots below the inflows show outflows and pool elevations, respectively, from the most upstream reservoir (High Rock) down to the most downstream reservoir (Blewett Falls) included in the case study modeling. In addition to the simulation pool traces, the pool elevation plots include dashed lines that show the allowable operating pool bounds. The pool bands are not shown if they are significantly above or below the simulated pool traces. The bottom plot shows a representative LMP trace. The PLEXOS DA model provides an individual LMP trace for each reservoir; however, all LMP traces follow the same trends and are within the same relative magnitude; therefore, a single representative trace of LMPs for Blewett Falls reservoir is shown in the plot.

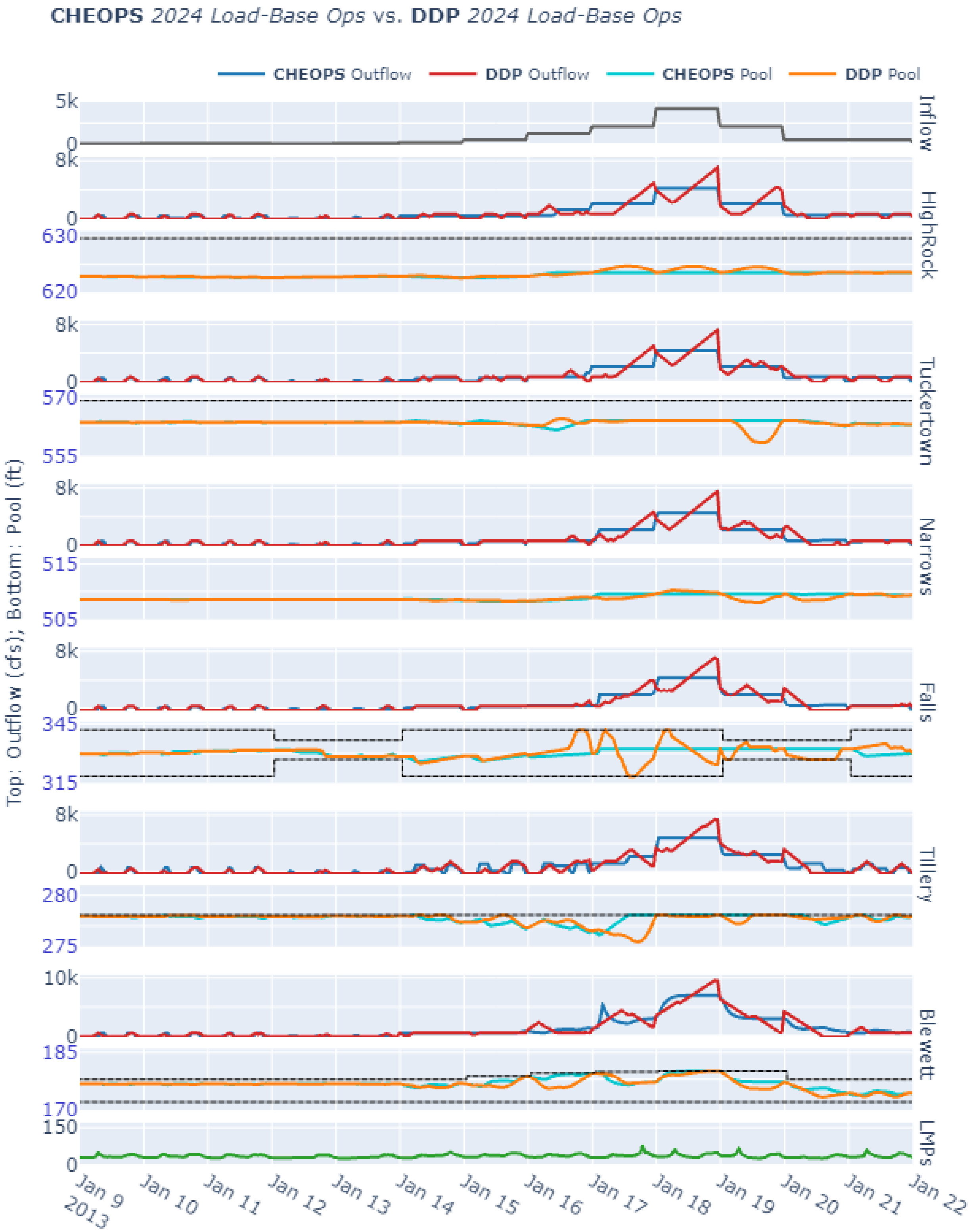


Figure G20. CHEOPS and DDP simulated results for 2024 load-base ops scenario.

This period was selected because it includes both a lower flow condition at the start of the period and a higher flow condition beginning on January 15. At each reservoir, the daily starting and ending pool elevations (midnight) are the same in both models, with the intraday pool elevation deviating between the two simulations due to the difference in outflow timing throughout the day. During the low-flow condition at the beginning of the selected period, both models result in similar outflow patterns. This indicates that we were able to effectively inform the load shape assumptions from the results of the PLEXOS Step 1 DA modeling. Without applying the PLEXOS modeling information to CHEOPS, the default assumed periods of when power is more valuable to the grid would be unrealistic and result in less revenue. Even without implementing a specific optimization technique for a system, detailed power systems modeling offers information that is beneficial in improving hydropower production.

As the inflows increase, it is evident DDP places outflows more precisely to the peaks in the LMP traces, diverging from the block-shaped releases designated by CHEOPS. The slope of the release ramping illustrates that the median ramping constraint included in DDP does constrain releases. Additionally, the ramp-up change in outflows in CHEOPS block-shaped releases occurs more rapidly than the upward ramping in DDP results, confirming that the DDP ramping constraint is within reason and may be more desirable for other beneficiaries of reservoir operations such as downstream recreators. The other constraint of interest is the allowable pool bounds, which are shown as the black dashed lines. These bands were set as defined in CHEOPS without changes. Considering Falls, a relatively small reservoir, as an example, DDP fluctuates the Fall reservoir pool elevation across the full allowable operating range during a higher flow period to increase the generation benefits achieved in the system while still meeting the same end-of-day pool elevation as CHEOPS. We recognize that upon further review, different constraints may be imposed to avoid large fluctuations such as those seen in these operations. However, the results do reveal that a sub-daily optimization model can help identify and use flexibility inherent in a system without violating defined constraints.

Within the framework developed for this case study, we are able to test various operational policies against each other for the base case load scenarios in the reservoir modeling step. Since CHEOPS and DDP have short run times, we tested a larger suite of policies than shown in this final report. It was helpful to simulate alternative policies of interest to the full team, evaluate their effectiveness with respect to reservoir operations, then select interesting policies to move forward to the ecological modeling and PLEXOS RT modeling, which has a significantly longer run time and requires high-performance computing for execution. Ultimately, we concluded that policies imposing different ramping rate restrictions showed tradeoffs that were otherwise unexplored in the modeling.

As mentioned above, we tested several other policies, which attempted to narrow the pool bounds to significantly smaller bands as well as allow unrestricted operating range in both CHEOPS and DDP. Ultimately, we learned that extremes in inflows to the system that drive operational response do not allow pools to stay within the narrow bounds we imposed. Periods of lower inflows forced pools to draw down below the operating band, while periods of higher inflows forced the pools to fill above the operating band due to outflow constraints. Without completely shifting to run-of-river operations, which then eliminate all potential operational flexibility that reservoir storage provides, imposing a narrower band offered no advantage. Conversely, we anticipated that removing all pool boundary constraints, while unrealistic, would result in a much higher return in revenues. The results showed that the extremes in inflows in the hydrological years considered in this case study were not extreme enough to use more of the operating pool than the base case policy; therefore, the operating pool bands both provide desirable operational constraints while offering enough space for flexibility.

The final set of alternative operating policy scenarios were simulated using DDP under all three base case load scenarios. Analogous to the results presented here, similar trends were seen across the three load scenarios, so we have selected the 2036 scenario to explore the impacts of various ramping scenarios. We will compare the alternative ramping scenarios, listed in Table G-14, against CHEOPS and DDP solutions for the 2036 Load-Base Ops scenario. The aim of this comparison is to understand the full range of tradeoffs of maintaining desirable operations for different beneficial uses such as hydropower production and recommended environmental flows for fish species below the dams.

Table G-14. Alternative operating policy scenarios.

Scenario Name	Alternative Operating Policy Scenario
2036 Load-Base Ops	Base Case (Current ramping restrictions)
2036 Load-Unrestricted Ramping Ops	Unrestricted Outflow Ramping at All Times (day and night)
2036 Load-Restricted Ramping Ops	Highly Restricted Outflow Ramping at All Times (day and night)
2036 Load-Base Ops with Env Policy	Base Case with Nighttime Environmental Restrictions. Nighttime environmental restrictions impose a highly restricted outflow ramping rate during the nighttime to create a stable environment for fish species below the dam
2036 Load-Unrestricted Ramping Ops with Env Policy	Unrestricted Outflow Ramping During Daytime (nighttime environmental restrictions still apply)

Annual revenues for each study period year for all alternative operating policy scenarios are shown below. The blue (CHEOPS-Base Ops solution) and orange (DDP-Base Ops solution) bars demonstrate that we can improve hydropower revenue and provide more flexible energy to the grid simply by intentionally using more of the full operational band when possible.

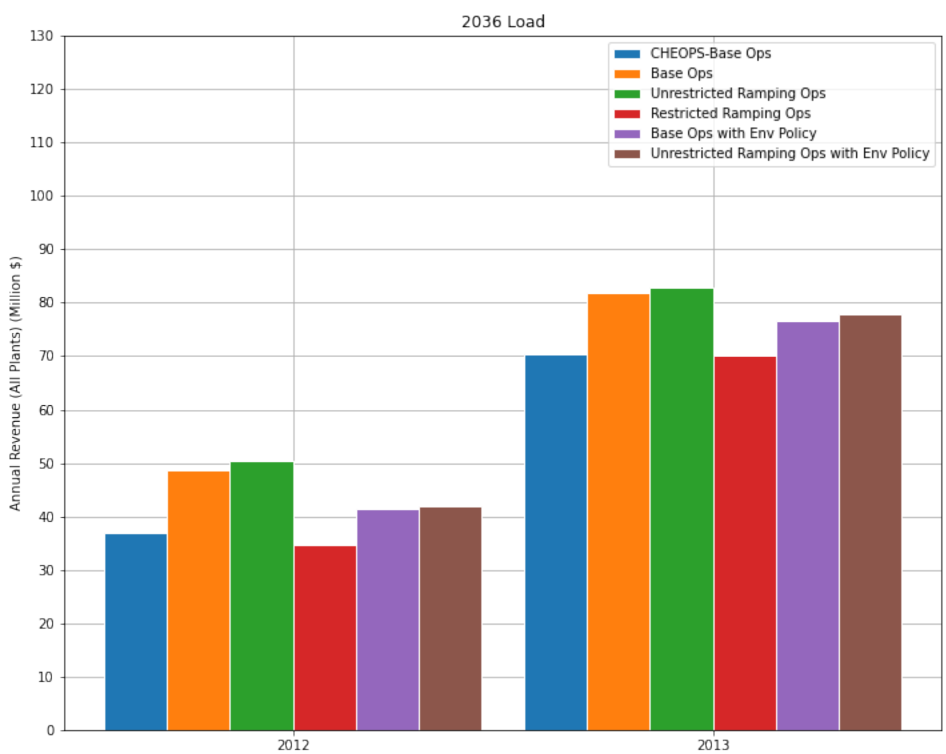


Figure G-21. Annual revenue for 2036 load alternative operating policies scenarios.

Interestingly, the unrestricted ramping ops scenario offers relatively little improvement in hydropower revenue values compared to the DDP-base ops scenario, indicating that we gain the most benefit by using the operating pool band more effectively within the current allowable outflow ramping rate. The lowest performing scenario with respect to revenue is the restricted ramping ops scenario that highly restricts outflow ramping at all times. This restriction effectively forces the DDP solution to distribute outflows more uniformly to allocate the entire required outflow volume throughout the day, and therefore cannot respond as successfully to the hourly changes in LMPs.

The final two scenarios implement the environmental policy, which limits the ramping rate at nighttime. The base ops with env policy scenario only imposes new restrictions at nighttime, whereas the unrestricted ramping ops with env policy loosens the ramping rates during the day and imposes the same nighttime restrictions as base ops with env policy. There is a tradeoff between ensuring a stable environment for fish species during nighttime and hydropower revenue, as shown by the decrease in revenue from the DDP base ops policy to the base ops with env policy. However, the base ops with env policy still outperforms the CHEOPS base ops solution, revealing a win-win opportunity for the Yadkin-Pee Dee system.

If we allow the operational policy during the daytime to use a greater range of the operating pool band, deviating from the CHEOPS representation of reservoir operations, and impose more restrictive nighttime ramping constraints on operations, we improve hydropower revenue while also providing additional benefit to downstream fish species. Echoing the findings found from the unrestricted ramping ops policy, loosening the ramping constraint during the daytime does not offer a significant improvement in revenue, meaning that current ramping rates during the daytime allow enough flexibility for the system. Figure 41 shows the total hydropower production for each year and alternative operating policy. Hydropower production is similar across all scenarios, with small changes due to changes in head throughout the simulation period based on the retiming of outflows.

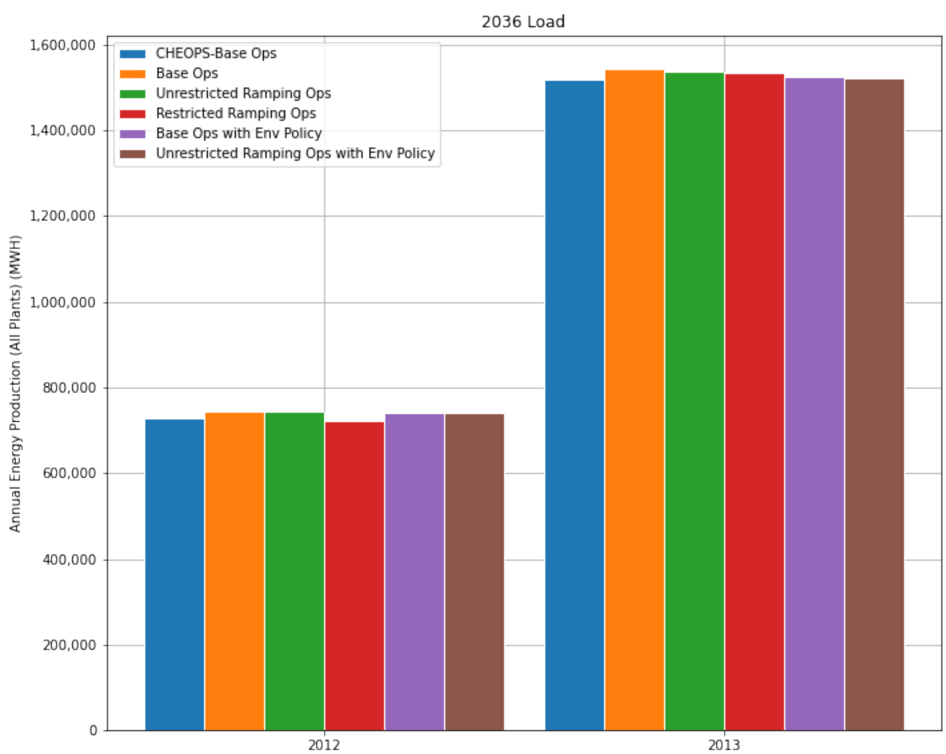


Figure G-22. Annual energy production for base case load scenarios.

To visualize examples of how DDP reallocates releases under the alternative ramping rates, Figure G-23 presents results for the 2036 Load-Restricted Ramping Ops compared to the 2036 Load-Unrestricted Ramping Ops. For all reservoirs, the effect of the ramping rate is very apparent during the higher inflow period on May 15. The Restricted Ramping Ops solution maintains a blockier release with a slight increase throughout the day to capitalize on the spike in LMPs near the end of the day. The restriction in the ramping rates also constrains the pool from using the full range of the allowable pool bands.

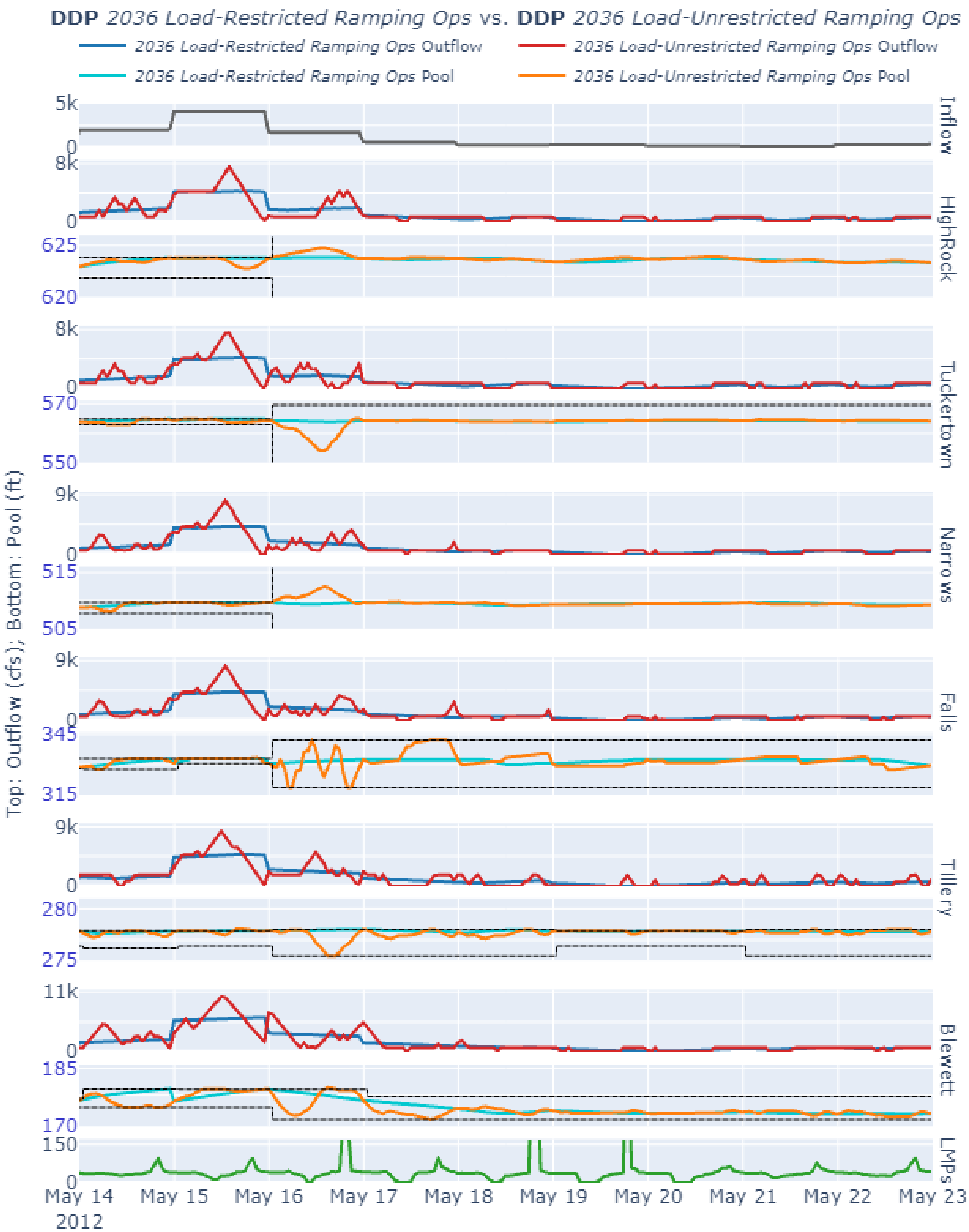


Figure G-23. DDP simulated results for alternative operating plans for the 2036 load scenario (high-flow period).

Even though the impact on reservoir operations is most apparent during high-flow periods, a change in ramping restrictions would also impact low-flow operations (Figure G-24). Although the low flows prevent the pool elevation from fluctuating as significantly, releases turn on and off more frequently (still maintaining minimum flows) to place releases during higher value hours. This has two implications. First, even though the Yadkin-Pee Dee system provides a relatively small amount of energy, the benefits to the grid can be increased by allowing less restrictive ramping. However, because the Yadkin-Pee Dee does not contribute a significant amount of energy to the grid, it may be more appropriate to set the operating policy such that ramping restrictions are tighter during low-flow periods to reduce environmental impacts during more critical low-flow periods. Evaluating the impacts for the grid and for the environment over various flow ranges can allow end users to identify appropriate compromise solutions that sufficiently provide for both needs.

In the high-flow period (shown in Figure G-23), the Unrestricted Ramping Ops solution allows the outflow to ramp up to a much higher peak and then ramp back down within a single day. While this outflow peaking behavior results in higher revenue earnings, it is interesting that the peak does not strictly align with the spike in LMPs during the same day. First, energy production is dependent on both head and turbine release. Second, while this is the unrestricted ramping rate case, the DDP model is still constrained to the mass balance determined by CHEOPS. DDP must end at the same pool elevation and allocate the same total volume of outflow. This can result in an outflow peak occurring earlier in the day than would be anticipated based on the LMP traces.

Ultimately, these policies represent the extremes in operations with respect to the hydropower and environmental tradeoffs we were interested in highlighting in this case study. With highly restricted ramping rates, we limit the flexibility of operations in the reservoir, but provide a very smooth transition of flows to downstream recreators and fish species. However, operations with looser ramping rate constraints allow the flexibility of reservoir storage to respond to energy needs for the grid by responding to increases in LMP traces. Between these two, we can identify a compromise policy that offers benefits to hydropower operators and power grid needs and environmental and recreational users.

In Figure G-25, we present a comparison of two scenario operations that fall between the Restricted Ramping Ops and Unrestricted Ramping Ops alternatives discussed above for 2036. For the 2050 load scenario (Figure G-26), we compare the DDP simulation results for the Base Ops against the Base Ops with Env Policy where nighttime outflow ramping rate restrictions are applied. The yellow and gray backgrounds denote daytime and nighttime, respectively. During the daytime throughout the selected period, both solutions follow similar outflow ramping rates, ramping up in response to the increasing LMPs until the early evening LMP peak. During the nighttime period, the policy with restrictions keeps outflows relatively stable. Note that in several of the midnight transitions there is a sharp change in outflows—this is a modeling artifact caused by DDP solving day by day. We introduced a constraint to maintain the ramping restriction for the midnight transition between days, but this sometimes must be violated to maintain the routing mass balance across days. This could be resolved by splitting the solution of days at another time of day (e.g., early morning), but this change was not made.

With both policies, we show utilization of the allowable pool band that was unseen in the base CHEOPS policy. It is also evident that the policy imposing nighttime restrictions still allows enough flexibility for the reservoirs to release to the daytime LMP peaks, meaning hydropower can provide benefit to the grid when it is most needed since nighttime energy requirements do not have the same peaking behavior. It should also be noted that an advantage of the sub-daily modeling provided by DDP allows for specific nighttime effects to be reflective of the time of year. In the DDP modeling, we use daylight as a function of geographic location to determine when nighttime restrictions are applied, which means that nighttime restrictions occur for a longer duration during winter relative to summer.

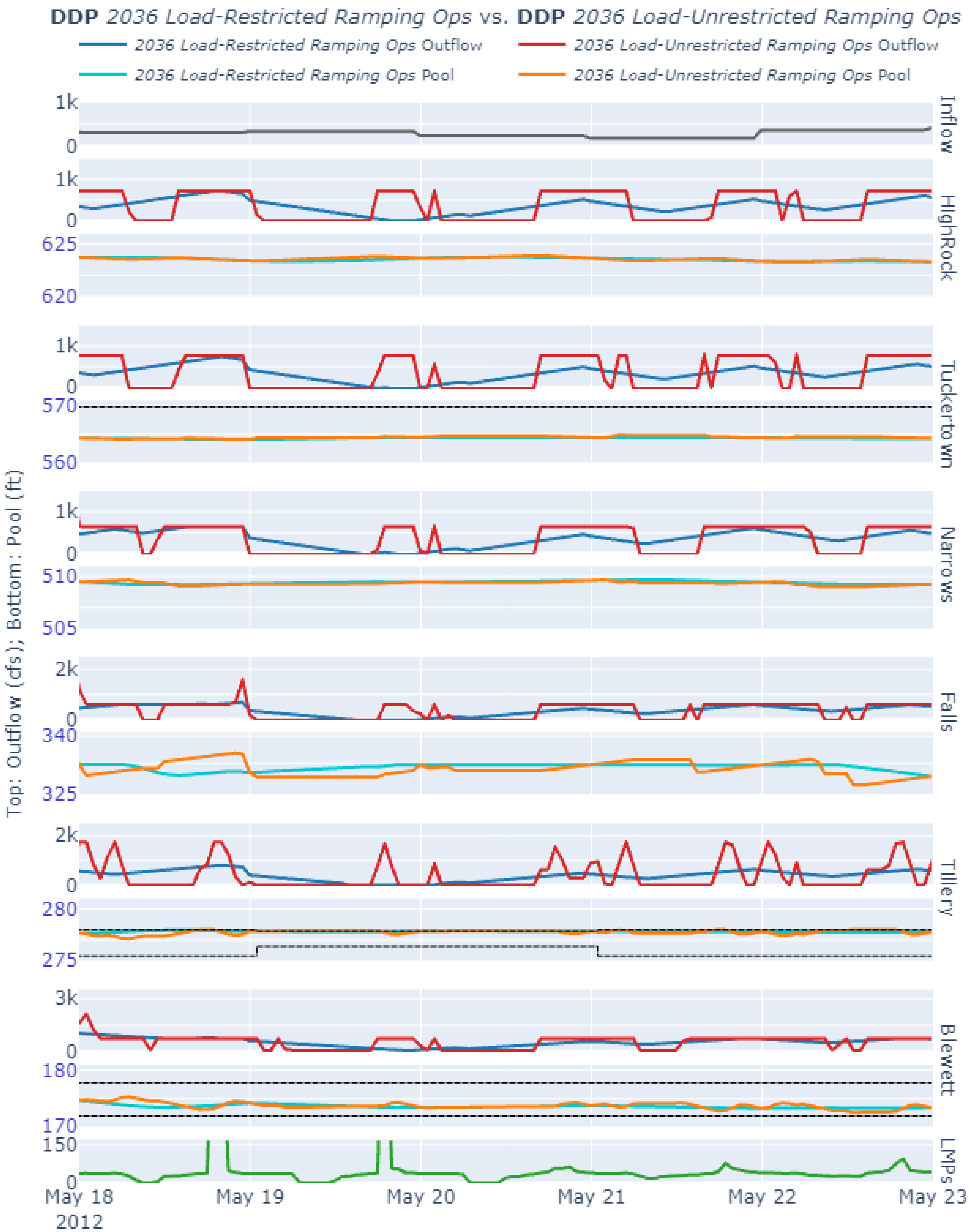


Figure G-24. DDP simulated results for alternative operating plans for the 2036 load scenario (low-flow period).

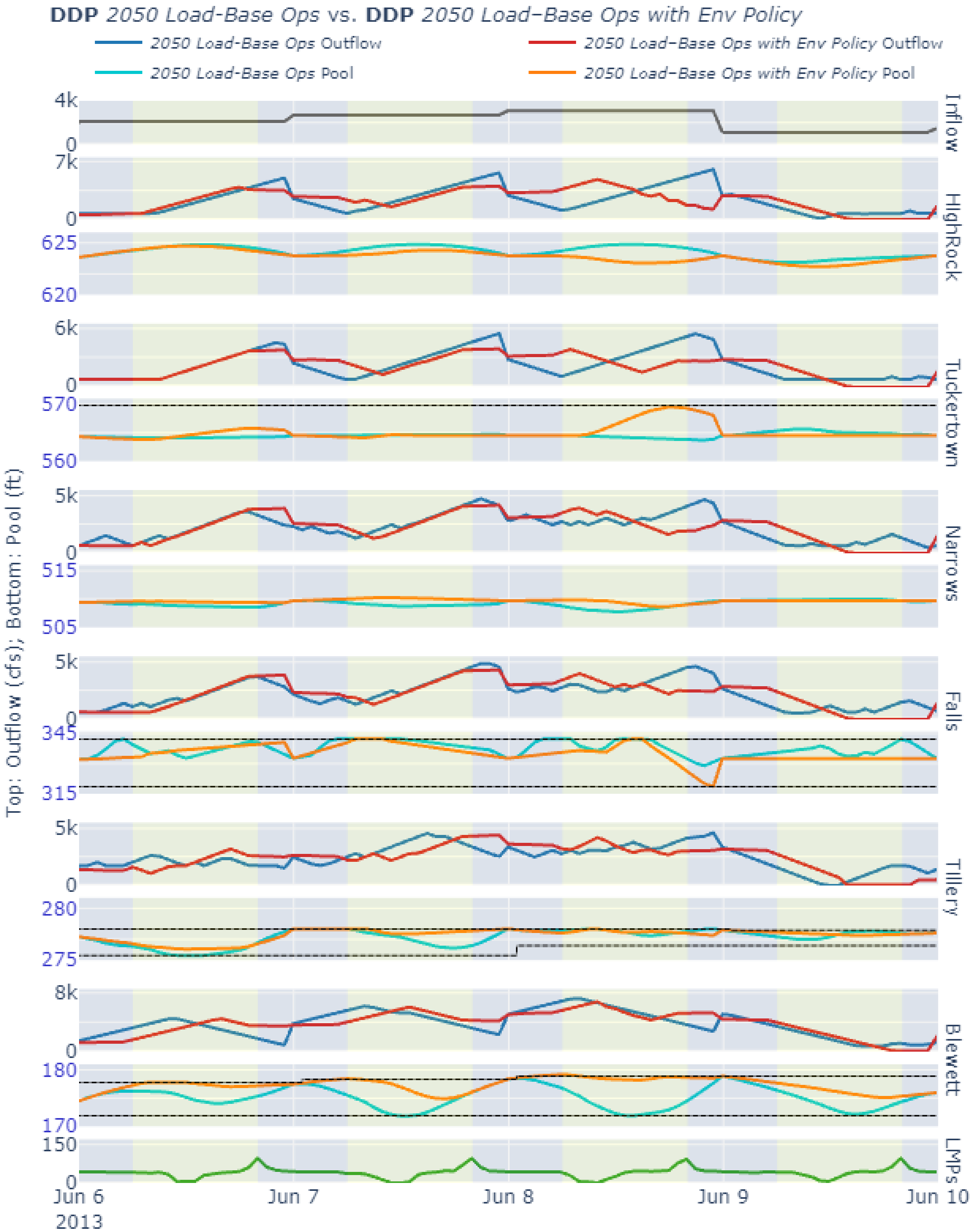


Figure G-25. DDP simulated results for alternative operating plans for the 2050 load scenario.

Figure G-26 directly compares the policy from CHEOPS for the 2036 Load-Base Ops (without environmental restrictions) with the DDP 2036 Load-Base Ops with Env Policy. A period of low steady inflow is the selected period of interest. During this period, it is evident that while DDP does use some additional flexibility, without a higher inflow, there is a limit on the additional benefits that retiming outflows can offer. However, we do show that during the daytime (yellow band), the DDP model is able to push the outflows higher when LMPs indicate value while still ensuring a steady outflow in the nighttime. Ultimately from this comparison, we confirm that even when we impose an environmentally beneficial operational policy, if we can use the LMP information effectively though sub-daily modeling, we can achieve an improvement in both hydropower and environmental objectives. The magnitude of improvement is dependent on the available inflows and storage. Periods of lower inflows, as shown here, reduce operational flexibility overall. Correspondingly, periods of extremely high inflows result in similar lack of flexibility because the reservoirs do not have the flexibility to store extra water in early periods for use later in the day. In those cases, outflows are pushed high across all operational policies (CHEOPS and DDP) to keep the pool elevation as close to the allowable operating bands as possible.

As discussed above, while we do show that imposing the environmental nighttime policy limits the flexibility seen in both the DDP Base Ops and DDP Unrestricted Ramping Ops policies, we still see improvement over the CHEOPS Base Ops policy. In Figure G-27, the annual revenue is compared between the CHEOPS-Base Ops, DDP-Base Ops, and DDP-Base Ops with Env Policy. Even under changing load assumptions, we see the DDP solution with the imposed nighttime restrictions does as well or better than the CHEOPS policy in the revenue objective. By modeling the reservoir operations at a sub-daily level using hydropower information (LMPs) and constructing a policy beneficial to the environment (limited ramping at nighttime), we have identified a win-win policy for the Yadkin-Pee Dee system.

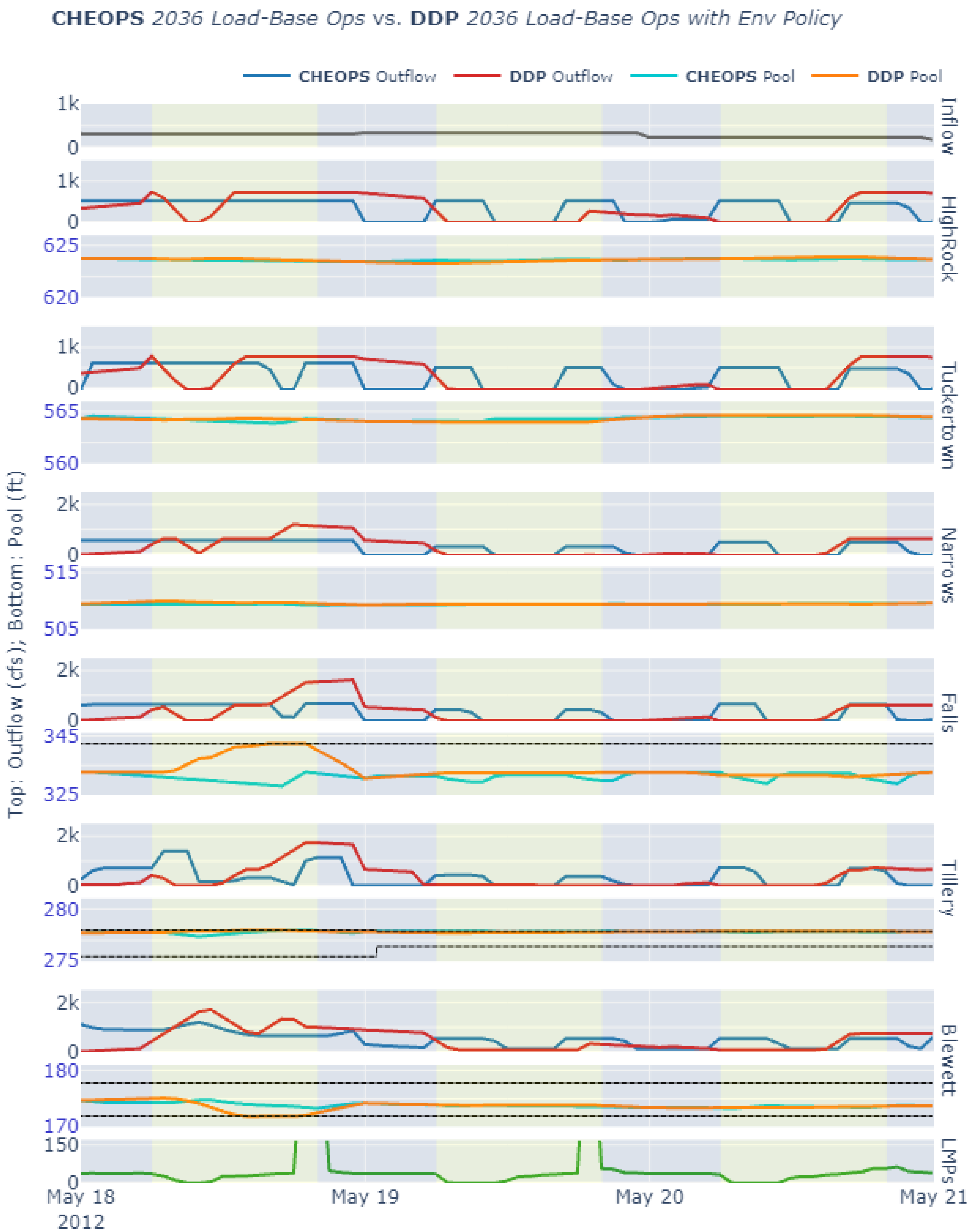


Figure G-26. CHEOPS and DDP simulated results for alternative operating plans for the 2036 load scenario.

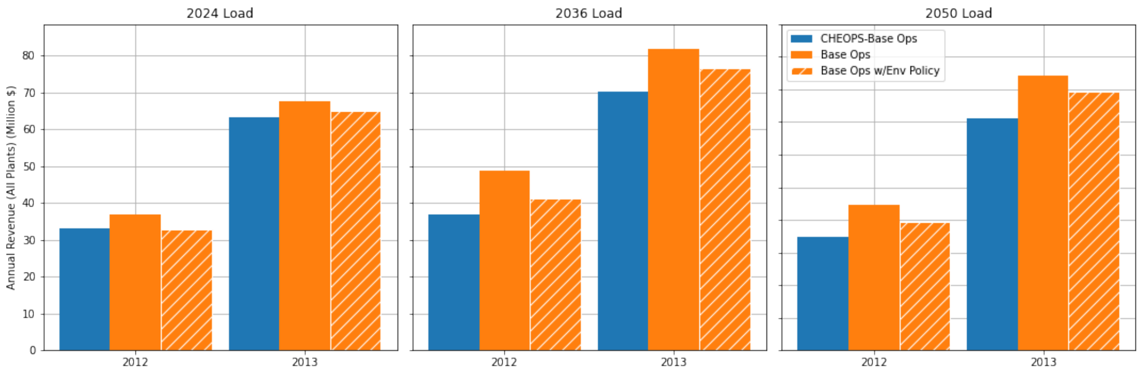


Figure G-27. Comparison of revenue from operations with and without nighttime environmental restrictions to CHEOPS-defined operations.

G.4.2 Comparison of Ecological Impacts

Results of regression models constructed to simulate survival estimates for three future years showed that scenarios restricting nighttime flow were consistently associated with higher survival than scenarios that did not restrict nighttime flow fluctuations (Table G-15). However, this effect was large enough to be significant only for YOY juveniles. Survival of flow regimes with restricted nighttime flows had the greatest survival benefit for YOY bass in the 2024 scenarios (Figure G-28).

Table G-15. Regression modeling of QUANTUS-SD results for a) eggs, b) larvae, and c) YOY juvenile bass: effects of nighttime flow restrictions.

	Eggs	Larvae	YOY
(Intercept)	0.61 *** (0.05)	0.19 *** (0.03)	0.01 *** (0.00)
Future.year2036	-0.01 (0.05)	0.00 (0.03)	-0.01 *** (0.00)
Future.year2050	0.00 (0.06)	0.01 (0.03)	-0.01 *** (0.00)
Is.envTRUE	0.02 (0.04)	0.02 (0.02)	0.00 *** (0.00)
poly(tQile, 2)1	-1.53 *** (0.30)	-3.53 *** (0.15)	0.00 (0.00)
poly(tQile, 2)2	-2.08 *** (0.30)	1.01 *** (0.15)	-0.00 (0.00)
brood.yr2013	-0.17 *** (0.04)	0.10 *** (0.02)	-0.00 (0.00)
N	198	198	198
R2	0.32	0.76	0.62

*** p < 0.001; ** p < 0.01; * p < 0.05.

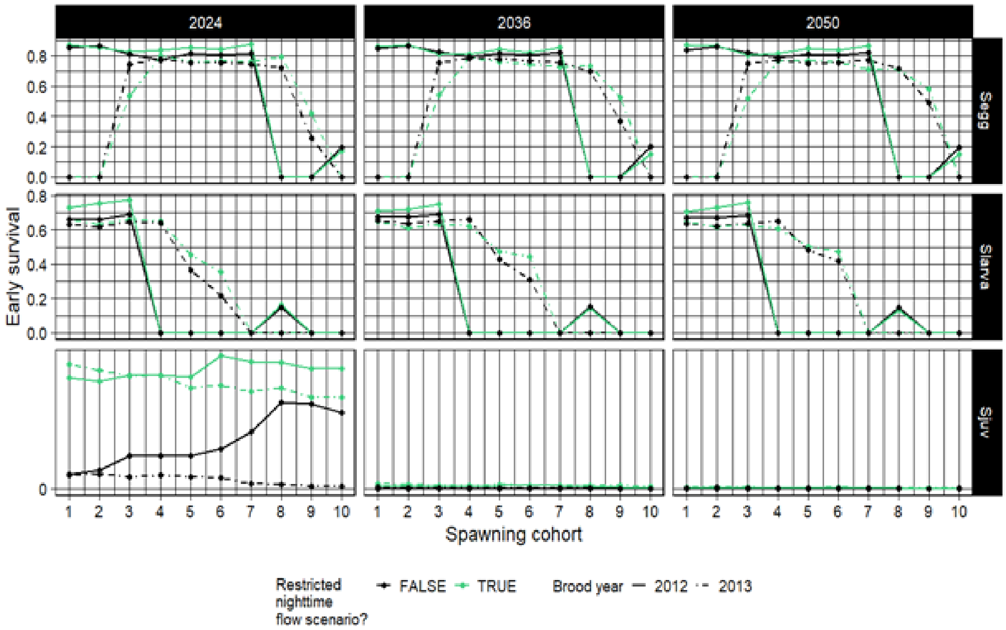


Figure G-28. Early survival under flows resulting from operational scenarios that do and do not include nighttime ramping restrictions.

Results highlight the differences between two years. Flows in 2013 were much lower than those in 2012. However, simulated survival rates were not consistently lower. In addition to nighttime restrictions, there were significant differences in YOY survival for flows shaped to meet demands in future years 2036 and 2050. The most significant influence on egg and larval survival was the spawning cohort (i.e., timing of spawning). Survival was highest for eggs spawned at intermediate dates, whereas survival of larvae was highest for those from the earliest nests. For future year 2036, two additional operation scenarios were compared, one with unrestricted ramping (*Ahigh*) and one with load-restricted ramping (*Alow*). Effects on survival of eggs and larvae were modest and insignificant, but unrestricted ramping had a strong negative effect on YOY bass (Table G-16).

Table G-16. Regression modeling to compare effects of unrestricted ramping (Ahigh) and load-restricted ramping (Allow) on eggs, larvae, and YOY juvenile bass.

	Eggs	Larvae	YOY
(Intercept)	0.54 ***	0.16 ***	0.00 ***
	(0.07)	(0.04)	(0.00)
poly(tQile, 2)1	-1.11 **	-2.61 ***	-0.00 *
	(0.39)	(0.20)	(0.00)
poly(tQile, 2)2	-1.56 ***	0.73 ***	0.00
	(0.39)	(0.20)	(0.00)
brood.yr2013	-0.16 *	0.11 **	0.00 ***
	(0.07)	(0.04)	(0.00)
Is.envTRUE	0.01	0.02	0.00
	(0.09)	(0.05)	(0.00)
Is.highTRUE	0.07	0.04	-0.00 ***
	(0.09)	(0.05)	(0.00)
N	66	66	66
R2	0.33	0.76	0.95

*** $p < 0.001$; ** $p < 0.01$; * $p < 0.05$.

We compared survival due to six simulated causes: cold shock, dewatering, high flow, predation, stranding, and high temperature. Several of these (cold shock, high flow, and high temperature) apply to all life stages, whereas dewatering of nests is the functional equivalent of stranding for juveniles and predation is only simulated for juveniles. For juveniles, which generally had the lowest survival, results show particularly high mortality due to high flows (Figure G-29). In two scenarios, this was not the case, the scenario with nighttime restrictions (Env) for future year 2024 and the scenario with load-restricted ramping for future year 2036.

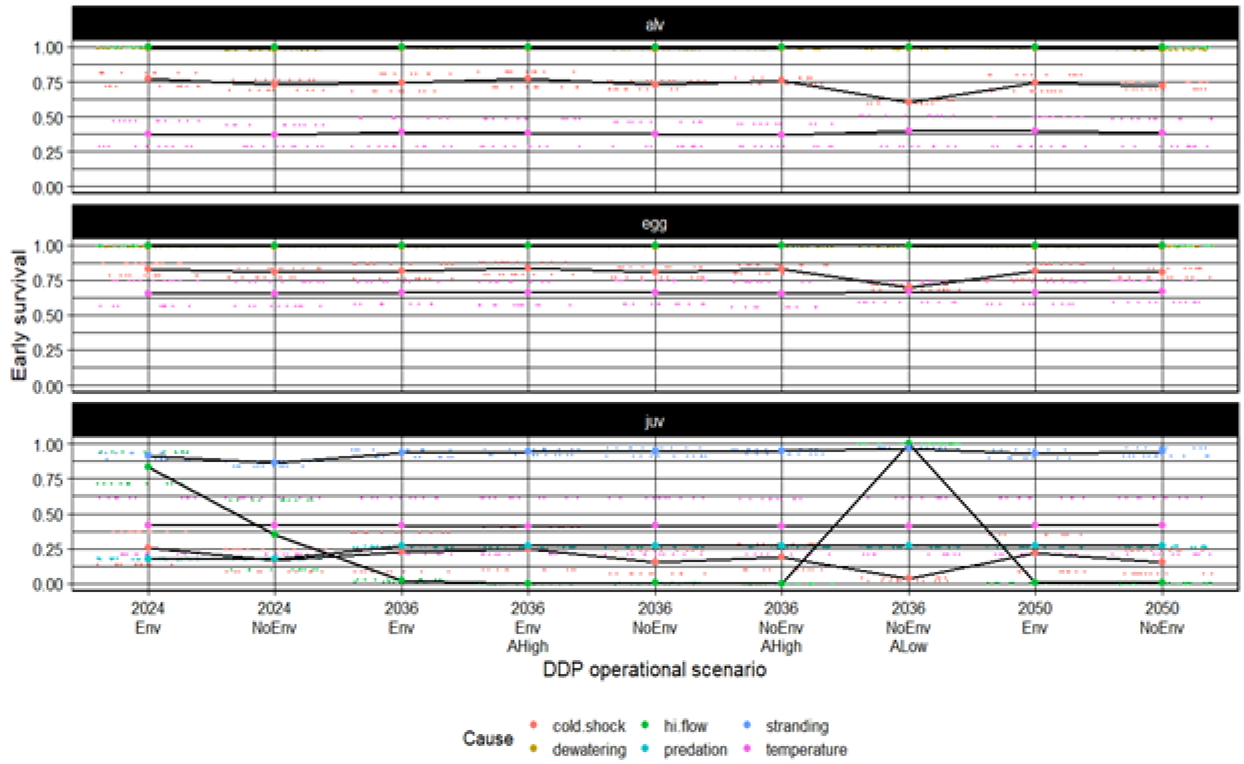


Figure G-29. Survival due to six causes under different operational scenarios for each of three early life stages. Lines connect median values averaged across spawning cohorts for each cause. Individual points represent different brood years.

G.4.3 Hourly and Sub-Hourly Power Impacts

G.4.3.1 DA Hourly Power System Operation

The PLEXOS results for DA simulation provide the hourly energy and ancillary services prices of the power grid. Each of the six Yadkin-Pee Dee hydropower plants get approximately similar hourly busbar-level prices or LMPs, as shown in Figure G30(a) for all hours of the year. Approximately 98% LMPs are less than \$100/MWh. For example, in the 2013 hydrology year and 2036 grid infrastructure year, approximately 150 hourly LMPs are greater than \$100/MWh, and about 30 LMPs greater than \$1,000/MWh. The LMPs from PLEXOS represent the *marginal* or *incremental* cost of electricity at that location, meaning the next MWh of electricity produced. High LMPs result from using the highest marginal cost generators, which are often inefficient and fueled by the most expensive sources of fuel. The highest LMPs (greater than \$1,000/MWh) often indicate that the model is hitting some sort of penalty, whether from violating a monthly energy constraint, dropping reserves, or going over the thermal limits of power lines. Often, the times of highest LMPs correspond to times of system stress, when generation or flexibility is the most required. Figure G30(b) shows the LMPs for the Narrows Dam across all infrastructure and hydrology years. The results indicate that increasing renewable integration (Figure G30(b) the dashed lines indicating 2050 infrastructure year) increases energy prices received by hydropower plants for most of the time.

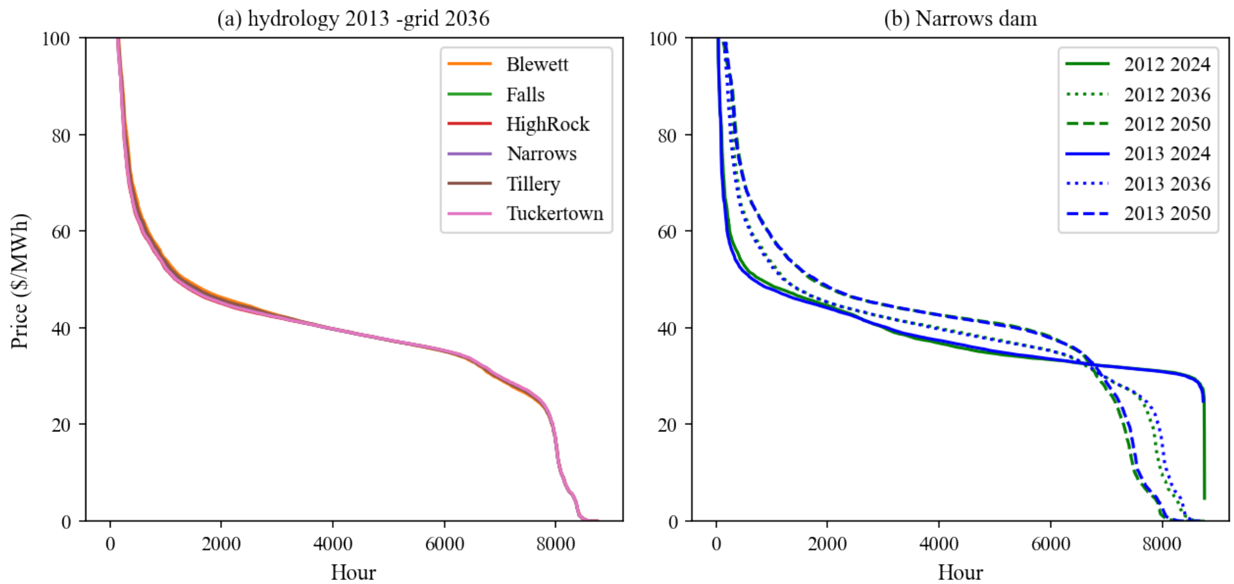


Figure G-30. LMPs for (a) Yadkin-Pee Dee six hydropower plants for hydrology 2013 and grid infrastructure 2036 and (b) LMP comparison across hydrology years 2012 and 2013 for grid years 2024, 2036, and 2050.

Specifically, price spikes such as LMPs greater than $100/MWh occur more frequently in 2050. For example, the Narrows LMPs in 2024 grid year are approximately 40 points greater than $100/MWh and year 2036 and 2050 are approximately 150 points. On the other hand, we see more frequent zero-priced hours during 2050 as an increased fraction of generation comes from zero-marginal priced resources (renewable generation). Overall, for the 2050 infrastructure year, we see more frequent low- *and* high-priced hours, indicating increased volatility.

These high price points and zero prices are spread throughout the year and are related to wind and PV generation. Figure G-31 shows the daily hydropower revenue based on these prices and can show price variation across the year for each of the three infrastructure years for Narrows. High revenue for hydro energy is indicated for high renewable penetration of 2036 and 2050 years. As noticed in the price duration curves, daily revenue variability is higher for 2036 and 2050 years than 2024. During the summer and winter months, the variability of the revenues is the highest. Net load is the highest in the summer, leading to higher price variability. In the winter, net load is somewhat low, which likely leads to more over-generation and more zero-priced hours.

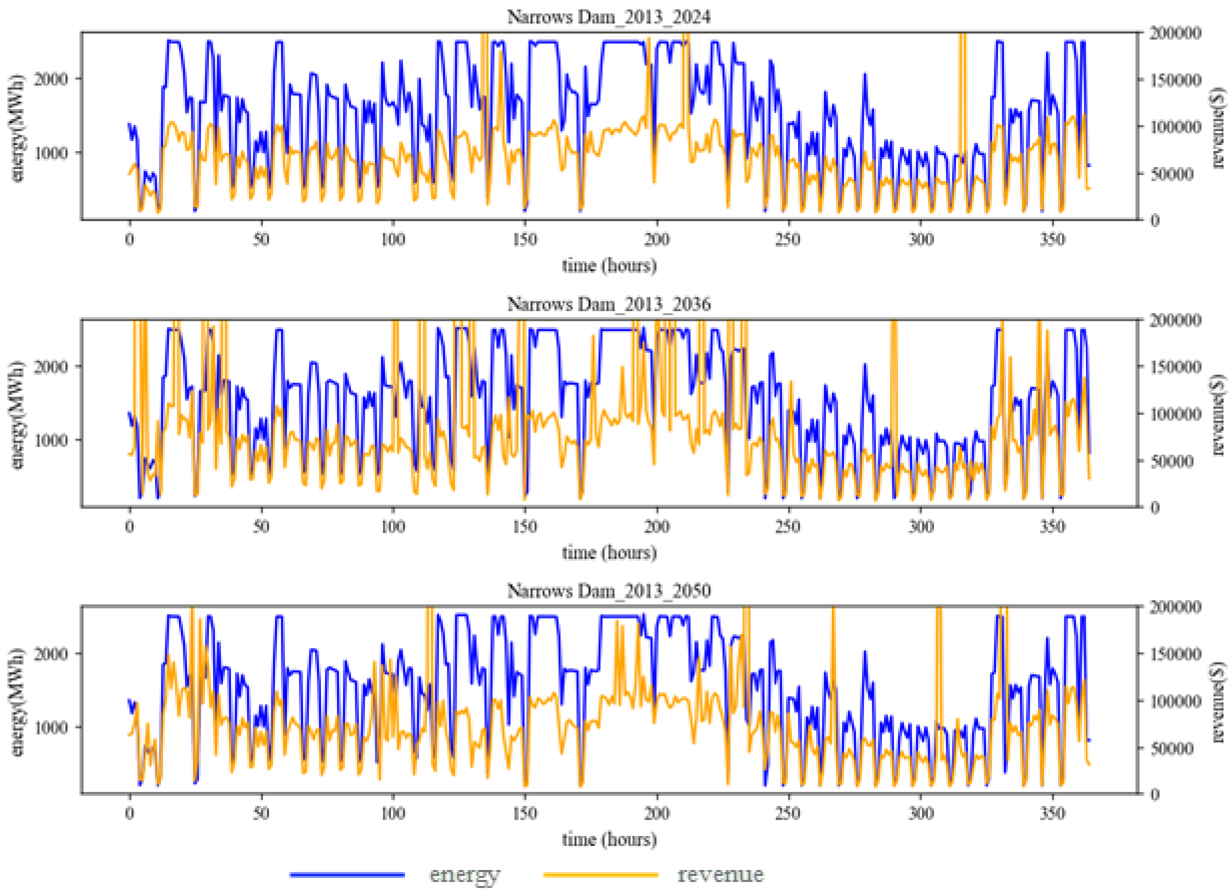


Figure G-31. Narrows dam daily energy and daily revenue received for hydrology 2013 and grid years 2024, 2036, 2050 indicates variability of energy and prices across the years.

We selected periods that combine the SERC region's high and low solar, wind generation, high and low netload fluctuations (netload ramping mile); high and low hydropower generation; and hydropower revenue to understand the details of Yadkin-Pee Dee hydropower dispatch, LMPs, and revenues.

Figures G-32 and G-33 examine daily wind, and solar, and hydro generation as well as SERC's net load to better understand the variability of prices. SERC's wind generation is higher during winter months and lower during summer months. On the other hand, solar generation is higher during summer and lower during winter months. Similar to Narrows dam, SERC total hydro generation is higher during winter months and summer months for 2013 hydrology year (Figure G-33). Hourly variability of net load, which is equal to the load minus wind and solar generation, is calculated as the daily netload ramping mileage. The large number of higher and lower net load ramping points can be noticed during winter and summer months (Figure G-33). This indicates higher variability of net load, wind, and solar generation, which explains the higher variability of LMPs and hydropower revenue values.

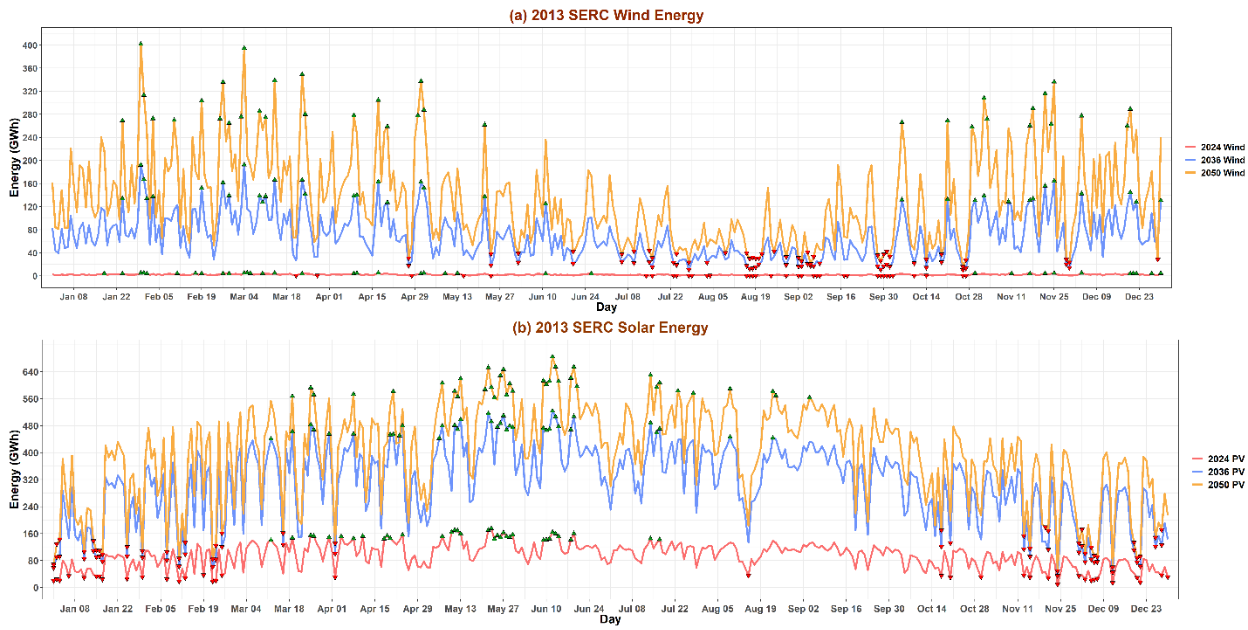


Figure G-32. SERC region wind and solar generation for 2013 meteorology year for grid years 2024, 2036, and 2050. Highest 10% days are shown by green triangles and lowest 10% days are shown red triangles.

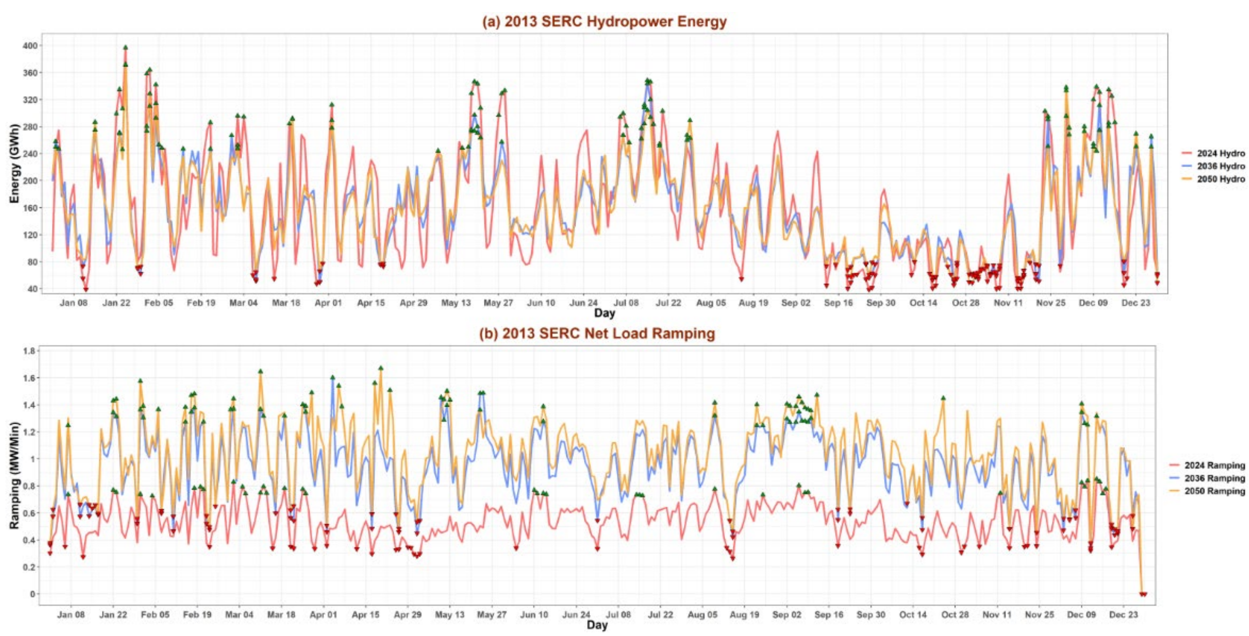


Figure G-33. SERC region daily total hydro generation and daily net load ramping mile for 2013 meteorology year for grid years 2024, 2036, and 2050. Highest 10% days are shown by green triangles and lowest 10% days are shown red triangles.

G.4.3.2 RT Sub-Hourly Power System Operation

Hydropower capability of these grid stress periods as well as normal operation periods are examined in the RT PCM results, which are carried in 5-minute interval. Figures G-34 and G-35 illustrate differences of Yadkin-Pee Dee plants dispatch for fixed generation modeling and flexible generation modeling. Since the hydro dispatch differences do not impact the marginal prices drastically, the LMPs of both scenarios are approximately equal a majority of the time, but occasionally LMPs are deviated with the differences.

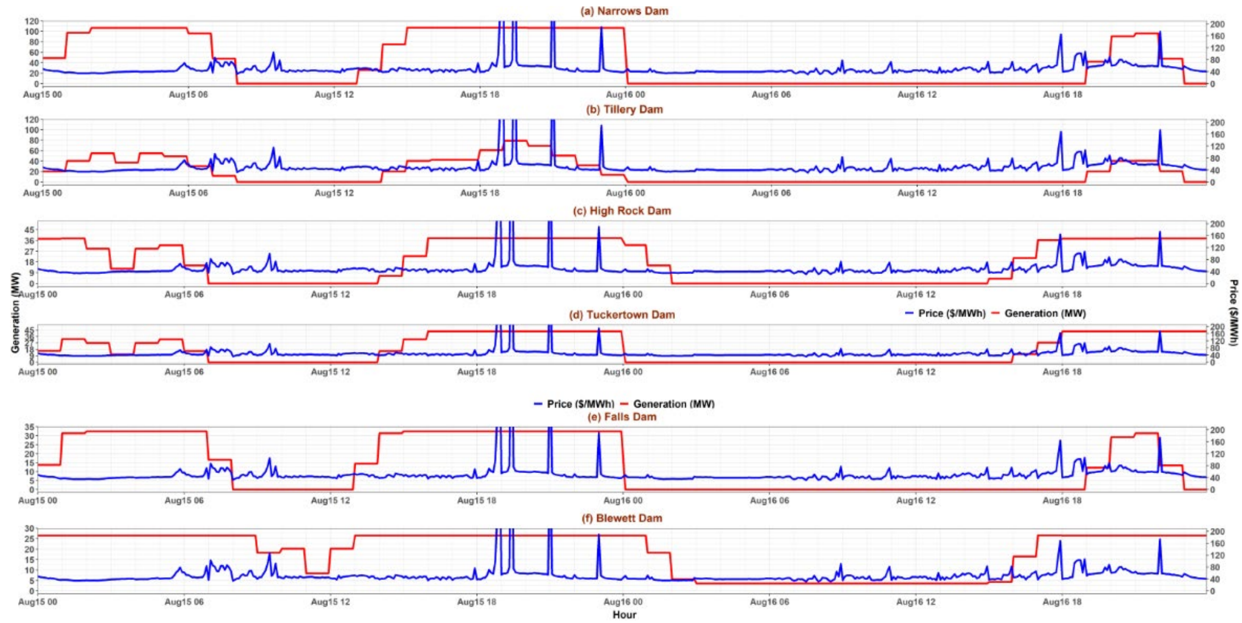


Figure G-34. Dispatch of Yadkin-Pee Dee hydro plants (a) Narrows, (b) Tillery, (c) High Rock, (d) Tuckertown, (e) Falls, and (f) Blewett during July 28–30 for hydrology 2013, grid year 2036 for the fixed generation modeling. (Scale for prices is limited to $200/MWh; however, few price spikes higher than $200/MWh can be noticed.)

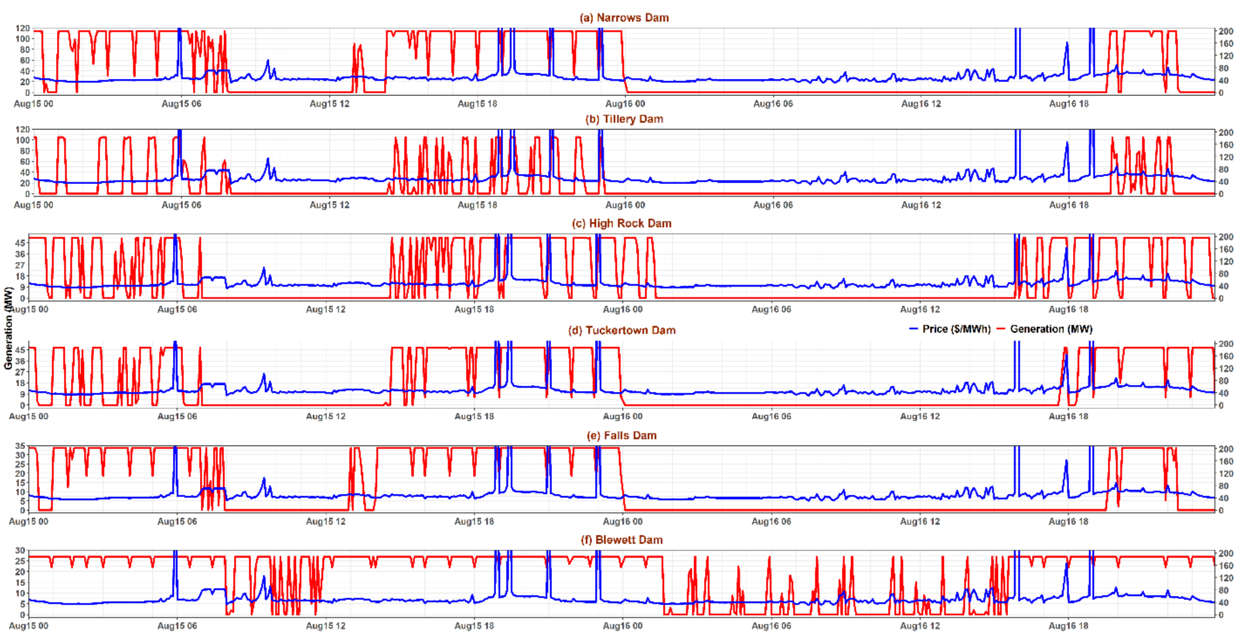


Figure G-35. Dispatch of Yadkin-Pee Dee hydro plants (a) Narrows, (b) Tillery, (s) High Rock, (d) Tuckertown, (e) Falls, and (f) Blewett during July 28–30 for hydrology 2013, grid year 2036 for the flexible generation modeling. (Scale for prices is limited to $200/MWh; however, few price spikes higher than $200/MWh can be noticed).

In fixed generation scenario, power plant operating levels are increased or decreased in one direction within an hour under the plants' ramping rate constraints. In this scenario, flexibility to follow the prices are limited; nevertheless, plants follow the prices under constraints. Flexible plant dispatch indicates that hydro plants are changing the operating capacity between maximum and minimum frequently, if the Yadkin-Pee Dee plants have flexibility to change the operating capacity without ramping constraints (Figure G-35). A majority of the time, plants are dispatched at maximum capacity for shorter time duration of high prices. If the hydro plants have flexibility, plant operating capacity is changing for even smaller price variation for small time duration such as five minutes.

Comparison of Yadkin-Pee Dee dispatch across multiple periods exposes similar operation patterns for flexible 5-minute optimization to respond the short-term prices (Figures G-36, G-37, G-38). During winter periods (four days in January and December considered here) which have morning and evening peaks, price fluctuations are concentrated for the two peaks. Hydro dispatches of both scenarios follow the high prices at two peaks.

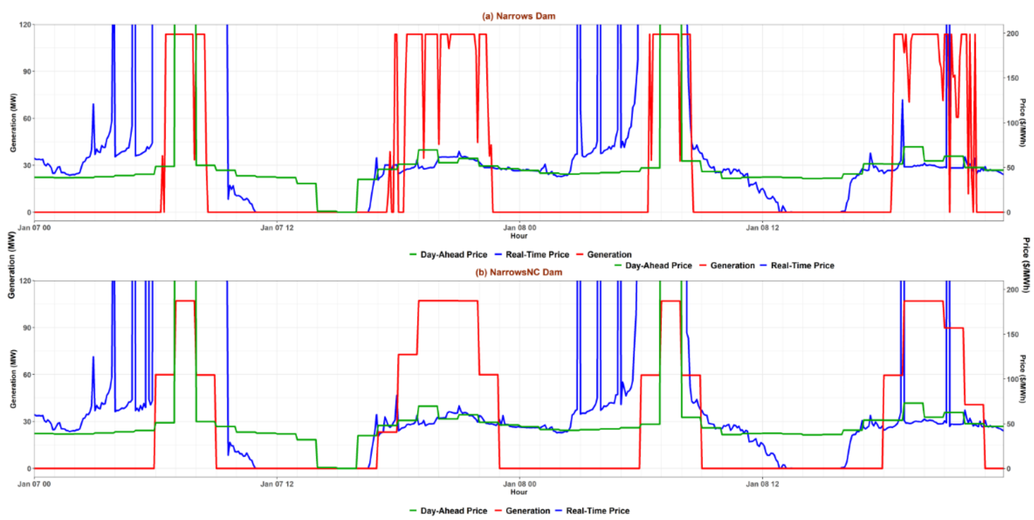


Figure G-36. Narrows dam dispatch during January 7 and 8 for hydrology 2013, grid year 2036, (a) fixed generation under ramping constraints, (b) flexible generation under no ramping constraints.

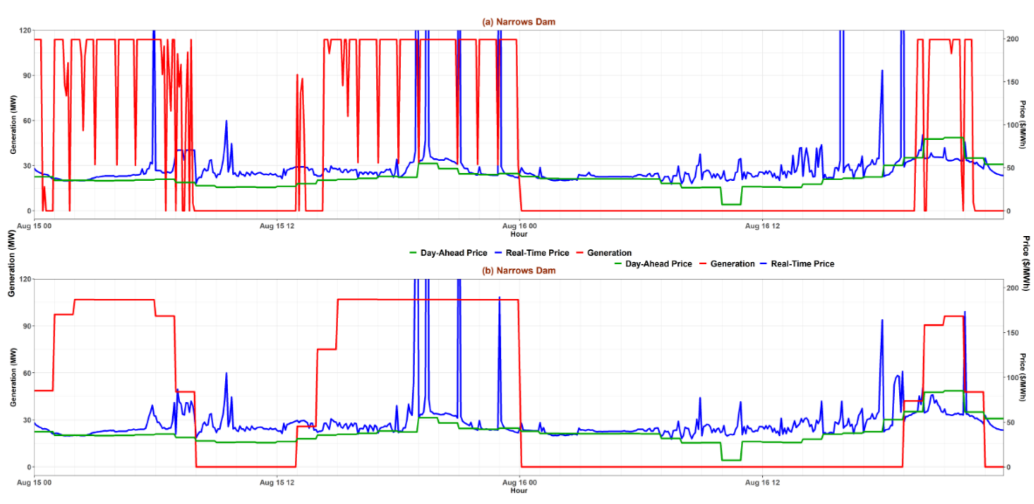


Figure G-37. Narrows dam dispatch during August 15 and 16 for hydrology 2013, grid year 2036, (a) fixed generation under ramping constraints, (b) flexible generation under no ramping constraints.

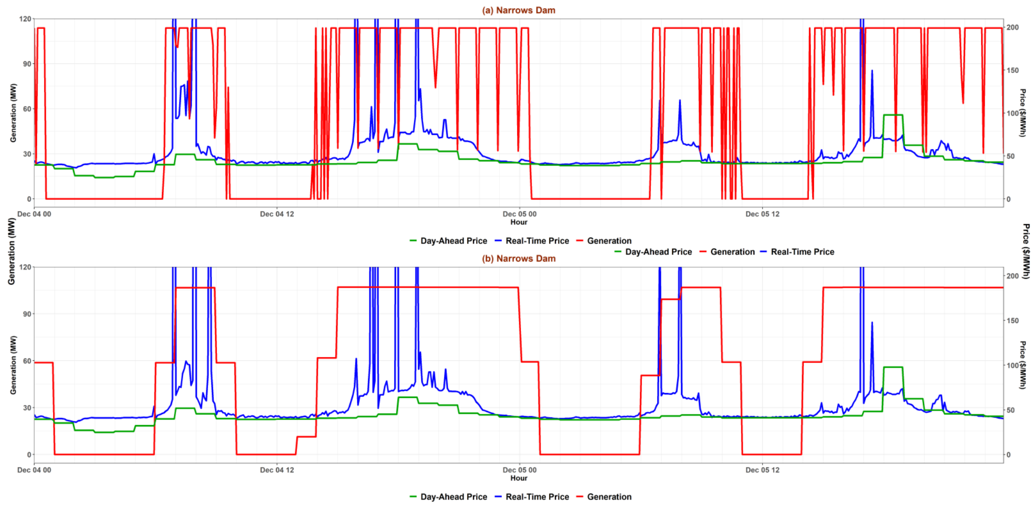


Figure G-38. Narrows dam dispatch during December 4 and 5 for hydrology 2013, grid year 2036, (a) fixed generation under ramping constraints, (b) flexible generation under no ramping constraints.

We compared potential revenue for Narrows dams' hydropower production during power grid operation for six days in January, August, and December to understand the variation for hydropower production in different scenarios and different levels of planning. Results indicate that flexible operation will marginally increase the potential revenue compared to the fixed generation (Figure G-39).

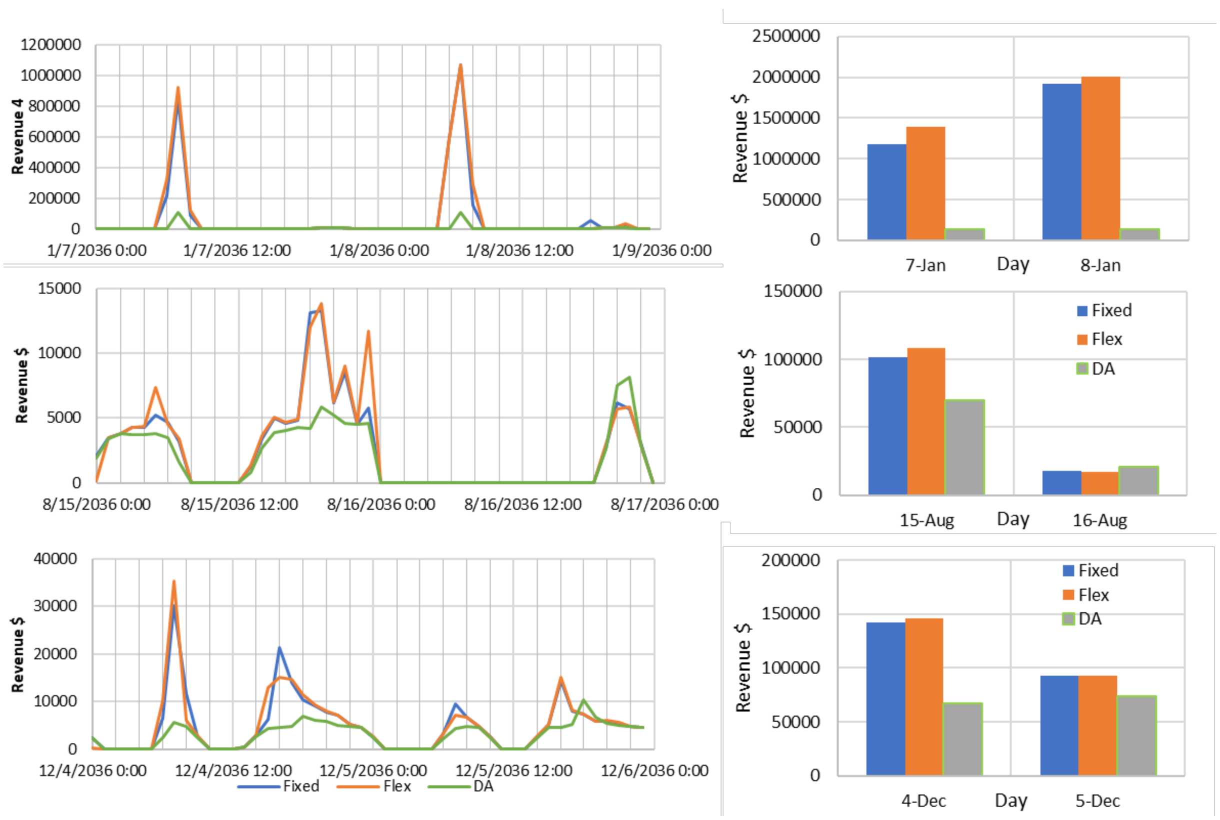


Figure G-39. Hourly and Daily revenue for Narrows dam hydropower production during July 23-31 for hydrology 2013, grid year 2036

Flexible generation has higher opportunity to follow the prices than fixed generation under ramping constraints. Since occurrence of RT price spikes are higher than DA prices, high revenue for the hydropower can be noticed in RT dispatch data. However, these price spikes are not only due to the marginal or incremental cost of electricity at that location. The highest LMPs often indicate that the model is hitting some sort of penalty, whether from violating a monthly energy constraint, dropping reserves, or going over the thermal limits of power lines. Often, the times of highest LMPs correspond to times of system stress when generation or flexibility is the most required.

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