THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

What can hydropower deliver in electricity systems?

Operational limits, modeling approaches, and system implications of environmental regulation

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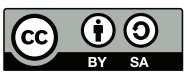

Cover: Painted by Helena Ek Fält. In an age of increasing AI-generated imagery, I asked my mother to paint the cover. I am happy she did.

All photographs are taken by the author at hydropower plants and reservoirs in Sweden and Norway. One photograph has unexpected guests: characters from Dunderklumpen, who pass this exact bridge in the film. Illustrations © Per Åhlin, used with permission.

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ABSTRACT

Hydropower is the largest carbon-neutral electricity source worldwide and a key flexibility resource in electricity systems, capable of adjusting its output across time scales from seconds to years. Yet its operational capabilities are constrained by, among other factors, the physics of how water flows through networks of dams and reservoirs and the technical characteristics of turbines. Moreover, hydropower operations affect river ecosystems, creating a tension between decarbonization and the protection of aquatic biodiversity. Understanding what hydropower can realistically deliver requires both improved modeling and analysis of these limits and their consequences.

This thesis aims to advance both the modeling approaches and substantive understanding of hydropower in electricity systems. To situate this work, the thesis first examines how another flexibility strategy, potential transmission expansion, affects the cost of low-carbon electricity systems. It then turns to hydropower, addressing three research questions: How does hydropower modeling detail affect the realism of modeled operations, and does the choice of representation affect electricity system model results such as costs and electricity prices? How do physical, technical and regulatory constraints affect hydropower's operational capabilities? And what are the electricity system implications of regulatory constraints on hydropower? While the modeling approaches and insights are general, the case study applications focus on Swedish hydropower within the Nordic and Northern European electricity system.

The thesis builds on four appended papers as well as additional analyses. New models are developed that represent individual hydropower plants at high technical detail, both standalone and embedded within an electricity system dispatch model. Using these models, the representation of hydropower in energy system models is scrutinized by comparing formulations ranging from fully aggregated national representations to individual turbines, showing that the choice of modeling approach is consequential for the results obtained. Hydropower's ability to sustain high output during prolonged periods of high demand is quantified under real physical, technical and regulatory constraints. The effects of environmental regulations on Swedish hydropower, including minimum flow requirements and restrictions on rapid flow changes, are assessed both in terms of hydropower operations and electricity system costs. The findings are discussed in light of ongoing regulatory processes for environmental adaptation of hydropower in Sweden.

Keywords: hydropower, electricity systems, modeling, flexibility, environmental regulation, environmental flows, hydropeaking, energy system optimization

APPENDED PUBLICATIONS

This thesis is based upon the following papers:

Paper A H. Ek Fälth, D. Atsmon, L. Reichenberg, and V. Verendel (2021). MENA compared to Europe: The influence of land use, nuclear power, and transmission expansion on renewable electricity system costs. *Energy Strategy Reviews* **33**, p. 100590. DOI: 10.1016/j.esr.2020.100590.

Paper B H. Ek Fälth, N. Mattsson, L. Reichenberg, and F. Hedenus (2023). Trade-offs between aggregated and turbine-level representations of hydropower in optimization models. en. *Renewable and Sustainable Energy Reviews* **183**, p. 113406. DOI: 10.1016/j.rser.2023.113406.

Paper C H. Ek Fälth, F. Hedenus, L. Reichenberg, and N. Mattsson (2025). Through energy droughts: Hydropower's ability to sustain a high output. *Renewable and Sustainable Energy Reviews* **214**, p. 115519. DOI: 10.1016/j.rser.2025.115519.

Paper D H. Ek Fälth, L. Reichenberg, H. Johansson, S. Öberg, and F. Hedenus (2026). "Balancing Rivers and Grids: Electricity System Impacts of Environmental Hydropower Regulation". Manuscript.

Author contributions

Paper A: LR conceived the idea, and HEF, DA, and LR developed it. HEF and DA constructed the models and produced the results with input from LR. VV produced the demand data used in the model. HEF, DA, and LR analyzed the results and wrote the paper.

Paper B: HEF conceived and developed the idea with support from NM, LR, and FH. HEF and NM developed the models and produced the results. HEF, NM, LR, and FH analyzed the results. HEF, NM, and LR wrote the paper with input from FH.

Paper C: HEF conceived and developed the idea with support from FH and LR. HEF constructed the models and produced the results with input from NM. HEF wrote the paper with input from NM, FH, and LR.

Paper D: HEF conceived and developed the idea with support from LR and FH. HEF and HJ developed the models and produced the results with support from SÖ. HEF and SÖ collected the data. HEF and LR analyzed the results. HEF and LR wrote the manuscript with input from FH.

OTHER PUBLICATIONS

Other publications by the author not included in the thesis:

I F. H. Moghimi, H. Ek Fälth, L. Reichenberg, and A. S. Siddiqui (2023). Climate Policy and Strategic Operations in a Hydro-Thermal Power System. EN. *The Energy Journal* **44** (5), pp. 67–94. DOI: 10.5547/01956574.44.4.fmog.

II S. Öberg, L. Göransson, H. Ek Fälth, U. Rahmlow, and F. Johnsson (2024). *Evaluation of Hydropower Equivalents in Energy Systems Modeling.* en. SSRN Scholarly Paper. Rochester, NY. DOI: 10.2139/ssrn.4838295.

"Jag vet precis vart vi är. 130 grader mot nordväst, eller nästan tvärtom."
- En dum en

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I feel like this is the most important part of the whole thesis. Pursuing a PhD is about learning, which I would not have been able to do without all the brilliant and supporting people around me.

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USE OF GENERATIVE AI IN THIS THESIS

Generative AI tools were used during the writing of this thesis. These tools assisted with drafting, restructuring, and editing text based on my instructions, outlines, and source material from the appended papers. All research questions, analyses, results, interpretations, and arguments are my own. I have reviewed and verified all factual claims, references, and technical content. I take full responsibility for everything written in this thesis. The use of generative AI is acknowledged here in the interest of transparency.

When I started my PhD in 2020, generative AI did not yet exist in any practically useful form. By the time I finished this thesis, it had become a natural tool for accelerating writing, coding, and data analysis. As I think many who work with these tools can confirm from their own experience, AI has not made me work less. If anything, I work more, because the faster pace makes it tempting to pursue more ideas. Some parts of my job have become more enjoyable: writing was never what I personally found most rewarding, and having a capable writing assistant has made that part of the work more pleasant and helped me articulate my arguments more clearly. On the other hand, the satisfying puzzle of structuring and problem-solving in code has lost some of its charm now that AI can do much of it for me. I suppose I will have to find that satisfaction playing more board games instead. The introduction of generative AI has far wider implications than what I touch upon here, but that is a discussion for another time.

CONTENTS

CHAPTER 1

Introduction

Low-carbon technologies such as wind and solar power are progressing in terms of cost, performance, and adoption, and the deployment rate is increasing worldwide [1]. Hence, large-scale wind and solar power deployment could constitute a key strategy for reaching a cost-efficient carbon-neutral electricity system. However, the cost of building carbon-neutral electricity systems also depends on a range of other factors, including for instance wind and solar potential, how much land is made available for wind and solar deployment, whether nuclear power is politically available, and the extent to which transmission networks can be expanded. The relative significance of these factors differs between regions. Furthermore, wind and solar power provide variable renewable energy, meaning that they are weather dependent and that the timing of their power output cannot be controlled. Therefore, flexibility measures are essential in electricity systems with a high share of wind and solar, ensuring that the demand can always be met despite variations in the wind and solar power production levels [2–5]. Such flexibility measures include, for instance, transmission expansion, energy storage, demand-side management, and flexible generation technologies such as hydropower [6, 7].

Today, reservoir hydropower is the largest carbon-neutral generation technology worldwide, providing about 16% of the electricity [8]. Due to differences in, e.g., geography, hydropower is more or less prevalent in different regions worldwide. The Nordic countries are an example of a region where hydropower plays an essential role in the electricity system, both as a bulk electricity provider and as an important flexibility measure that facilitates increased shares of wind and solar power. In the Nordic countries, hydropower contributes about 55% of electricity generation [9]. The power output from reservoir hydropower can be controlled on time scales from seconds to years, and can therefore be a crucial flexible resource in carbon-neutral electricity systems by complementing less flexible production.

However, the operation of hydropower has significant impacts on river ecosystems. By controlling the water flow in rivers, hydropower obstructs fish

migration and movements of sediments and nutrients, and disrupts natural flooding patterns [10–13]. Hydropower operations also cause rapid water level fluctuations (hydropeaking) that lead to, e.g., stranding of fish and erosion of riverbanks [14, 15]. This creates a tension between two environmental objectives: decarbonization of the power system, and the restoration and protection of aquatic ecosystems and biodiversity. In the European Union, this tension is reflected in the simultaneous pursuit of carbon-neutral electricity production under the European Green Deal [16] and the restoration towards "good ecological status" for water bodies under the EU Water Framework Directive. In Sweden, all hydropower plants are undergoing a process of obtaining new environmental permits through environmental courts [17], a process that will affect how hydropower may be operated in the future.

Understanding how hydropower can contribute to future carbon-neutral electricity systems, and what the consequences of environmental regulations may be, requires quantitative analysis. Energy system models are commonly used for such purposes, but the flexibility of hydropower is difficult to represent realistically in these models. Due to computational limitations and limited data availability, the representation of hydropower is often highly simplified in energy system models [3, 18–23]. In many models, all hydropower plants in a region are typically aggregated into a single plant with the combined installed capacity and reservoir volume, together with an inflow profile. In reality, however, the network structure of hydropower plants and reservoirs along a river, head-dependent production, and nonlinear turbine efficiency curves constitute additional physical constraints on hydropower production. A model that does not incorporate these constraints overestimates the flexibility of hydropower [24]. Both the International Energy Agency and the National Renewable Energy Laboratory have advocated for improved hydropower representations in energy system models [25, 26]. Capturing a realistic level of flexibility from hydropower is important since the level of flexibility afforded by hydropower affects the need for other flexibility measures in the system. Moreover, environmental regulations pose additional constraints on hydropower operation, further limiting the flexibility that hydropower can realistically provide while protecting aquatic ecosystems. The interplay between technical capabilities, environmental constraints, modeling challenges and electricity system implications of the representation of hydropower flexibility constitutes the core challenge addressed in this thesis.

The research approach, including the types of models used and their scope, is described in Chapter 2. That chapter also discusses the interpretation and limitations of the analyses.

1.1 Aim and research questions

The aim of this thesis is to advance both the modeling approaches and substantive understanding of hydropower in electricity systems. To situate this work, the thesis first examines how resource availability and policy choices can shape the cost of carbon-neutral electricity systems. It then focuses on hydropower, examining how modeling choices affect the realism of modeled hydropower operations, and what this means for electricity system results, such as costs and electricity prices. With improved modeling approaches established, the thesis quantifies what operational flexibility hydropower can realistically provide given physical, technical and regulatory constraints, and assesses the implications of potential environmental regulations on hydropower for the electricity system as a whole. Three overarching research questions guide this work, one methodological question addresses how modeling choices affect results, and two substantive questions address what hydropower can deliver and what the consequences are for the electricity system:

RQ1: How does hydropower modeling detail affect the realism of modeled operations, and does the choice of hydropower representation affect electricity system model results?

RQ2: How do physical, technical and regulatory constraints affect hydropower's operational capabilities?

RQ3: What are the electricity system implications of regulatory constraints on hydropower?

This thesis includes four appended papers and additional analyses. Paper A establishes the broader context by examining how conditions such as land availability, the availability of nuclear power, and transmission expansion affect the cost of low-carbon electricity systems. The three research questions focus on hydropower and are addressed through Papers B, C, and D, along with additional analyses. RQ1 is primarily addressed in Paper B, which compares five hydropower models ranging from highly aggregated to turbine-level detail, and through additional analyses including an electricity system dispatch model comparison that examines whether hydropower modeling detail affects electricity system results such as costs and electricity prices. RQ2 is addressed in Paper C, which quantifies Swedish hydropower's sustained output capability during high-demand periods, and in Paper D, which examines how environmental regulations affect hydropower operations. RQ3 is addressed in Paper D, which quantifies the electricity system cost implications when environmental constraints limit hydropower operations.

1.2 Thesis scope and outline

This thesis focuses on the electricity sector, not the full energy system including heat, transport, and industry. The geographic focus is Swedish hydropower within the broader European electricity system context. Sweden provides a relevant case due to its significant hydropower capacity, amounting to 100% of average demand and 65% of peak demand, producing about 40% of total electricity production, as well as the ongoing process of obtaining new environmental permits for all Swedish hydropower plants. While the analyses are rooted in the Swedish and Nordic context, the methodological insights and general findings are relevant to other regions with significant hydropower resources.

The thesis is structured as follows. Chapter 2 presents the research approach and introduces the optimization models used in this thesis and discusses the aim and interpretation of the analyses. Chapter 3 provides broader context on low-carbon electricity systems, drawing on Paper A to illustrate how conditions such as resource availability and infrastructure affect system costs and to motivate the focus on hydropower. Chapter 4 then focuses on hydropower fundamentals and the constraints affecting its operation, including both technical characteristics and environmental regulations. Chapter 5 addresses how hydropower can be represented in optimization models, comparing different modeling approaches and their trade-offs, drawing on Paper B. Chapter 6 synthesizes findings on what hydropower can realistically deliver when accounting for physical and regulatory constraints, incorporating results from Papers C and D. Finally, Chapter 7 concludes with a synthesis of contributions, discusses policy context and implications and directions for future research.

CHAPTER 2

Research Approach

The questions addressed in this thesis concern the cost and operation of electricity systems under conditions that differ from today's. While some aspects could be studied empirically in regions where similar conditions already exist, many of the questions concern systems or regulations that have not yet been realized, limiting what can be learned from observation alone. Electricity systems also consist of many interacting components, where a change in one part, such as environmental constraints on hydropower, affects the operation and costs of other parts. Models allow controlled comparison where one condition is changed at a time, which is more difficult to achieve through empirical observation. Models that represent the essential components and interactions in a mathematical framework are therefore used in this thesis to systematically explore how different conditions affect system outcomes.

Models are widely used to analyze energy systems, both in academic research and by plant operators and regulators. The modeling approaches used for energy system analysis are commonly categorized by methodology into simulation, optimization, and equilibrium models [27]. Simulation models represent a system through specified equations and decision rules, and the system outcome emerges from those rules. Optimization models find the best combination of decisions, such as which technologies to invest in and how to operate them, according to a specified objective, such as minimizing the total cost of supplying electricity, subject to a set of constraints. Equilibrium models focus on market equilibria where supply and demand balance: general equilibrium models represent the full economy, while partial equilibrium models focus on a single sector such as electricity. A related distinction is between bottom-up and top-down approaches [27, 28]. Bottom-up models represent individual technologies in physical and economic detail, typically using optimization techniques from operations research. Top-down models represent the energy sector as part of the broader economy through aggregate economic relationships.

These categorizations overlap. For instance, a cost-minimizing optimiza-

tion model that includes a supply-demand balance constraint produces market-clearing prices, making such a model structurally similar to a partial equilibrium model. The practical difference lies in scope and detail: optimization models include detailed technology representations and physical constraints but typically treat demand as fixed (price-inelastic), while equilibrium models represent broader economic interactions with price-responsive (elastic) demand but less technological detail. The research questions in this thesis concern what is technically achievable at what cost within the electricity system under different conditions. All analyses are therefore based on bottom-up optimization models for the electricity sector, with detailed technical representation of supply-side technologies.

Optimization provides a consistent reference point for scenario comparison: the cost optimum represents the best achievable outcome given the modeled conditions, and when a condition is changed, the resulting difference represents the minimum unavoidable consequence of that change. Under perfect market assumptions, the cost optimum corresponds to the competitive market equilibrium, providing a theoretical link to market outcomes. The models thus implicitly assume competitive behavior and that all actors are price-takers. The electricity day-ahead market in Northern Europe (Nord Pool), with many producers, a homogeneous product, and transparent pricing, is among the real-world markets that most closely approximate the conditions of perfect competition, making this link practically relevant.

A central part of this thesis work has been the development of optimization models. All models used in the appended papers were developed from scratch, formulated and implemented to address the specific research questions of each paper. Three models were developed: a capacity expansion model for Paper A, the FORSA (Flow Optimization for River Systems Analysis) hydropower scheduling model for Papers B and C, and the RAPID (River And Power System Integrated Dispatch) electricity system dispatch model for Paper D. Developing dedicated models, rather than using existing tools, was motivated partly by the specific research questions and partly by gaps in existing models, particularly for the hydropower scheduling models (Papers B and C) and the dispatch model (Paper D), as discussed in Chapter 5 and Chapter 6. Together, the four papers approach the overarching research questions from different angles and at different scales: Paper A examines the system-wide role of flexibility at the continental scale, Papers B and C investigate what hydropower itself can deliver when represented in detail, and Paper D connects the two perspectives by embedding detailed hydropower in a system-level model to assess the consequences of environmental constraints. This chapter describes the types of optimization models used in this thesis and the approach to using them, while the specific models used in each analysis are described in the appended papers. The chapter first

introduces the general structure of optimization models (Section 2.1), then describes the three model types used across the papers (Section 2.2), and finally discusses the aim of the analyses and how results are interpreted (Section 2.3).

2.1 Optimization models

All models used in this thesis are optimization models: mathematical formulations that find the best solution according to a specified objective, subject to a set of constraints. The building blocks are the *objective function*, which defines what is optimized; the *variables*, which are the endogenous quantities determined by the model (e.g., power generation from each technology at each hour, water releases from reservoirs); the *parameters*, which are exogenous inputs fixed before the optimization (e.g., technology costs, fuel prices, weather data, electricity demand); and the *constraints*, which are equations or inequalities that limit feasible variable values. Constraints can represent physical laws (e.g., production cannot exceed installed capacity), policy or regulatory conditions (e.g., an emissions cap), resource limitations (e.g., available land for wind power), or operational rules (e.g., minimum water flow requirements in a river).

The models are techno-economic, capturing technical and economic aspects of the electricity system. Social and political factors are not modeled explicitly, but some enter the analysis as constraints, e.g., limiting land available for wind power or excluding nuclear power as a politically unavailable technology, as done in Paper A.

2.2 Model types used in this thesis

Three types of optimization models are used across the four appended papers: hydropower scheduling models (Papers B and C), energy system dispatch models (Paper D), and capacity expansion models (Paper A). These model types differ in their objective, scope, in what is endogenous to the optimization, and in the level of detail for individual system components.

2.2.1 Hydropower scheduling models

In hydropower scheduling models, only the hydropower production is optimized, while the surrounding electricity system is represented by exogenous electricity prices. The objective function is to maximize revenue or profit for one or several, often connected by waterways, hydropower plants by timing production to periods of high prices. The exogenous prices can be either

historical or generated by a separate electricity market model. This setup mirrors the situation of a hydropower producer operating in a competitive electricity market: the producer decides when and how much to produce based on market price. By isolating hydropower from the rest of the system, these models allow focused investigation of what hydropower can deliver given its physical characteristics and constraints, with physical detail that can include the cascade network of plants along a river, head-dependent production, nonlinear turbine efficiency curves, and plant-level operational constraints (see Chapter 5). Examples of established hydropower scheduling tools include SHOP [29, 30] for short-term optimization and ProdRisk [31] for medium-to-long-term stochastic scheduling; a broader review is provided in Chapter 5.

The hydropower scheduling models in this thesis are used for exploratory analysis rather than operational production planning. The distinction between these uses, and the implications for how the models are set up, is discussed further in Chapter 5.

2.2.2 Dispatch models

Dispatch models optimize the operation of the full electricity system, determining how all generation technologies, storage, and transmission are used to meet demand at minimum cost. Unlike hydropower scheduling models, electricity prices emerge endogenously from the optimization rather than being specified as input, making dispatch models suitable for analyzing how changes in one part of the system affect costs and operations elsewhere. The installed capacities of all technologies are given as input parameters; no investment decisions are made. The capacity mix can represent either a current or a future system, but is fixed throughout the optimization. This makes dispatch models well suited for questions about how a given system operates under different conditions. Examples of dedicated dispatch models for the Nordic power system include the commercial EMPS [32] and the open-source ODIN [33].

2.2.3 Capacity expansion models

Capacity expansion models, sometimes referred to as investment models, extend the dispatch problem by making investment decisions endogenous: in addition to optimizing system operation, the model determines which technologies to build and how much capacity to install, minimizing total system cost over the modeled period. Many capacity expansion models, such as the well-established PyPSA [34] and TIMES [35], can be run in either dispatch or capacity expansion mode, since the underlying optimization

structure is the same.

These models adopt a long-term perspective, asking what the cost-optimal electricity system would cost and look like under a given set of conditions in a future scenario. They can be applied in a greenfield setting, where the entire system is built from scratch, or a brownfield setting, where existing infrastructure is taken as given and only new investments are optimized. A greenfield approach is most relevant for analyzing systems far enough in the future that most of today's infrastructure has reached the end of its technical lifetime, while a brownfield approach is more appropriate for nearer-term analysis where existing assets still dominate the system. Capacity expansion models can also be formulated with multiple investment stages to model the transition pathway toward a future system [27].

The key advantage over dispatch models is that the system can adapt through investment. For example, if environmental regulations are implemented that reduce hydropower flexibility, this creates investment incentives for other flexible resources, and the resulting investments may partially offset the cost increase, whereas a dispatch model with fixed capacity cannot capture this response. However, making investments endogenous also introduces challenges. If not limited by constraints, large amounts of infrastructure could be built in the model instantaneously, which in reality could take years or decades to construct. Representing realistic constraints on how fast and where capacity can be built requires assumptions that are themselves uncertain. Another difficulty is that technology costs depend on cumulative deployment through learning effects, and representing this endogenously introduces nonlinearities that are computationally challenging [36, 37].

2.2.4 Scope and detail: a trade-off

In practice, greater scope comes at the cost of component detail across three dimensions: the parts of the electricity system covered (from hydropower only to the full system), the geographical extent (from a single river to a continent), and the decisions being optimized (from operational dispatch with fixed capacity to investment optimization). Hydropower scheduling models can represent hydropower in great physical detail because they cover only hydropower at limited geographical extent, while capacity expansion models optimizing investments across the full system are computationally demanding and typically rely on simplified representations. This trade-off motivates one central question of this thesis: what is lost when hydropower is simplified in models with broad scope, and how can more realistic representations be achieved without prohibitive computational cost? This is the subject of Chapter 5.

2.3 Aim of the analyses and interpretation of results

Energy system models can be used for different purposes. Predictive analyses aim to forecast what will happen, for instance future electricity prices or emission trajectories. Prescriptive analyses aim to recommend actions to achieve a specific goal, for instance which investments to make in order to minimize system cost. Exploratory analyses, by contrast, aim to understand system characteristics and trade-offs without claiming to predict or prescribe. The distinction lies not in the model itself, since the same model often can be used for all three purposes, but in what questions are asked and how the results are interpreted [38].

The analyses in this thesis fall mostly in the exploratory category. Specifically, the analyses aim to explore, gain understanding of, and explain electricity system characteristics, for instance how resource availability, technology choices, and environmental regulations affect cost-optimal electricity systems. Some of the analyses address "what if" questions: what happens to system costs and electricity prices if new environmental regulations constrain hydropower operations? How does the cost of achieving a carbon-neutral electricity system change if nuclear power is politically unavailable? Others concern the modeling itself: how does the level of modeling detail affect the resulting hydropower production profile? And others quantify capabilities: what is the maximum sustained output that Swedish hydropower can deliver given its physical constraints?

For the answers to such questions to be informative, the models must represent the relevant aspects of the real system well enough that the direction and relative magnitude of the effects are credible, even if the absolute values are not predictions. The exploratory framing means that the specific numbers (e.g., a cost increase of X%) are not forecasts, but the mechanisms and trade-offs they reveal, such as which type of constraint is most costly and why, are intended to be representative of how the real system behaves. The degree to which the models succeed in this regard depends on the quality of the input data, the level of detail in the representation, and the assumptions made. Validating that a model reproduces known system behavior is an important part of establishing this credibility. These aspects are discussed and reflected on in Section 7.2.

Beyond the assumptions of perfect markets discussed above, all models in this thesis are deterministic and assume perfect foresight: demand, solar and wind generation, and hydropower inflows are known in advance, and operators never make suboptimal decisions due to uncertainty. In reality, many parts of the electricity system are affected by uncertainty, including future fuel prices, equipment failures, weather etc. As one example relevant to this thesis, hydropower operators manage reservoirs several months

ahead based on uncertain inflow and price forecasts. Because future inflows are not perfectly known, operators cannot safely operate reservoirs very close to their upper and lower regulation limits, since unexpectedly high or low inflows could cause the levels to breach these bounds. With perfect foresight, the model exploits the full reservoir range, yielding more flexible and profitable operation than what is achievable in practice. More generally, the deterministic assumption means that the results represent the best achievable outcome given the modeled conditions, not predictions of how the system would actually perform. This is consistent with the exploratory aim: the interest lies in comparing outcomes across scenarios, not in predicting absolute values. Section 7.2 returns to questions about the relationship between model results and reality after the specific models and findings have been presented.

CHAPTER 3

Flexibility in Low-Carbon Electricity Systems

This chapter provides context on why flexibility is a central challenge in the transition to carbon-neutral electricity systems, and how the cost of building such systems depends on regional conditions. Section 3.1 summarizes the flexibility challenge and the main strategies available, drawing on the established literature. Section 3.2 presents Paper A, which investigates how three policy-relevant factors affect system costs differently in two regions with contrasting weather conditions and resource endowments. Section 3.3 connects the findings to the remainder of this thesis, motivating the focus on hydropower.

3.1 The flexibility challenge

In electricity systems with high shares of wind and solar power, the variability and limited controllability of these sources create a need for flexibility, i.e., the ability to adjust generation and demand to maintain the balance between supply and demand at all times [6, 7]. The flexibility challenge increases with the share of variable renewable energy (VRE) in the system, as larger and more frequent mismatches between VRE production and demand must be managed across multiple time scales, from seconds to seasons. Several strategies can provide the required flexibility. Transmission expansion enables the spatial smoothing of VRE variability by connecting regions with different weather patterns, and has been shown to reduce system costs by 10–30% in systems dominated by VRE [19, 20, 39]. Energy storage, including batteries and pumped hydro, can shift energy from periods of surplus to periods of deficit. Demand-side management allows electricity consumers, including industries and households, to adjust their electricity use in response to electricity prices (which reflects system needs). Flexible generation technologies, such as hydropower and gas turbines, can ramp their output up and down to follow the residual demand, i.e., the demand remaining after VRE generation.

Sector coupling, e.g., through power-to-heat or electric vehicles, can provide additional flexibility by linking the electricity sector to other energy sectors [20].

Each of these strategies comes with its own limitations. Transmission expansion faces public opposition, slow permitting processes, and political and institutional barriers when crossing national borders [40, 41]. Battery storage remains costly for large energy volumes and long durations. Hydropower offers unique flexibility through its combination of large-scale storage and rapid ramping, but is geographically limited and comes with environmental impacts, as discussed in subsequent chapters.

Beyond flexibility strategies, the cost of a carbon-neutral electricity system depends on a broad range of other factors. For example, the availability of land for wind and solar deployment may be constrained by competing land uses and public acceptance concerns [42]. Nuclear power, while providing carbon-neutral baseload generation, is contested both in society and in the modeling community, with studies finding widely different cost benefits depending on regional conditions [43–45]. Importantly, how these factors affect system costs varies with regional characteristics such as weather conditions and demand density. This motivates investigations of how different conditions play out across regions, which is the topic of Paper A.

3.2 Paper A: Land use, nuclear power, and transmission expansion

Paper A investigates how three policy-relevant factors affect the cost of carbon-neutral electricity systems: i) the amount of land available for wind and solar power deployment, ii) whether nuclear power is politically available, and iii) whether inter-regional transmission can be expanded. While these factors affect the system in different ways, they share the feature of being politically contested and potentially consequential for system costs. The analysis is conducted for two regions with different weather conditions and resource endowments: Europe and the Middle East and North Africa (MENA). A capacity expansion model (see Section 2.2.3) with hourly resolution is used. The model optimizes the technology mix and operation of a carbon-neutral electricity system to meet electricity demand at every hour at the lowest possible cost. The results provide techno-economic insight into how the three factors affect the cost and composition of a cost-optimal system. The results do not prescribe what to build, since real-world decisions depend on many factors beyond techno-economics (see Section 2.3). The same model and cost assumptions are applied to both regions, so that differences in results can be attributed to differences in weather conditions

and demand rather than to model setup. For each of the three above listed factors, the cost impact is quantified by comparing the system cost of a scenario where the factor is restricted or excluded against a base scenario where it is available. In addition, the sensitivity of all results to uncertain future costs for solar PV and battery storage is tested under three cost regimes (low, mid, high).

3.2.1 Key findings

The system cost for a carbon-neutral electricity system is lower in MENA (42–96 $/MWh) than in Europe (51–102 $/MWh) across all investigated scenarios, reflecting MENA's higher-quality wind and solar resources and lower demand density. The cost ranges reflect variation across the investigated scenarios and the three PV and battery cost regimes.

Each of the three investigated factors can individually increase system costs by up to 20–50%, but their importance varies between the two regions. **Land availability** has a larger cost impact in MENA (up to 47%) than in Europe (up to 25%), since MENA's cost advantage stems from its resource quality, which is eroded when land restrictions force the use of lower-quality sites. **Nuclear power** matters more in Europe (up to 19% cost reduction) where VRE resources are less favorable, while offering little benefit in MENA (up to 4%). The value of **transmission expansion** is more similar in both regions, with cost increases of up to 25% depending on the generation mix; it is most valuable in wind-dominated systems, and least valuable when cheap PV and batteries shift the mix toward solar.

A cross-cutting finding is that the cost impact of each factor depends on the costs of PV and storage. For instance, the impact of restricted land in MENA is largest when PV and batteries are expensive and the system relies more on wind, whose cost is more sensitive to site quality. More broadly, the regional variation in cost impacts implies that conclusions about the importance of specific factors cannot be directly transferred between regions.

3.3 From flexibility to hydropower

Among the three factors examined in Paper A, transmission is the one that provides flexibility, and restricting its expansion increased system costs by up to 25%. This illustrates that the level of available flexibility has significant bearing on system costs. In the Nordic countries, hydropower is an important source of flexibility, yet Paper A, like most energy system studies [3, 18, 20, 21], relies on a simplified representation of hydropower that may overestimate the flexibility it can provide, with potential consequences for cost estimates and other model results. This motivates a closer examination of how hydropower is modeled, what operational limits it faces, and how much flexibility it can realistically provide.

The subsequent chapters examine what hydropower can realistically provide in terms of flexibility, given both its technical characteristics (Chapter 4) and the way it is represented in models (Chapter 5), and assess the system-level implications when constraints limit hydropower operations (Chapter 6).

CHAPTER 4

Hydropower in Context: Technology, Ecology, and Regulation

Globally, hydropower constitutes about 16% of the electricity production [8]. In the Nordic countries, hydropower contributes about 55% of electricity generation [9], making it essential for both bulk electricity supply and system flexibility. Swedish hydropower has an installed capacity of approximately 16 GW across roughly 2,000 plants, generating 60–75 TW h annually depending on hydrological conditions and availability of other production such as wind power. Hydropower represents not only the largest single source of carbon-neutral electricity, but also the primary source of operational flexibility in the Nordic region. As the shares of wind and solar power increase, the flexible operation of hydropower becomes increasingly important for integrating these variable sources into the electricity system [23, 46, 47]. However, the flexibility of hydropower is not unlimited, and the extent to which it can be utilized depends on physical and technical characteristics, environmental constraints, and regulatory frameworks. Understanding these factors is crucial for assessing how hydropower can contribute to a low-carbon electricity system and for representing it accurately in energy system models.

Section 4.1 covers the physical and technical characteristics of reservoir hydropower, including the production function, turbine efficiencies, and cascade effects. Section 4.2 describes the water value concept and its role in reservoir operation and electricity pricing. Section 4.3 reviews the environmental impacts of hydropower operations on river ecosystems. Section 4.4 outlines the policy context, including the EU Water Framework Directive and the Swedish process for revising environmental permits for hydropower plants.

4.1 Physical and technical characteristics

Hydropower is often categorized into reservoir hydropower and run-of-river hydropower. Reservoir hydropower includes plants with large reservoirs that enable flexible operation: water can be stored and released according to electricity demand rather than following natural inflow patterns. Run-of-river hydropower, by contrast, refers to plants with small or no reservoirs, where the production is closely correlated to the natural inflow and therefore less flexible. In reality, there exists a continuum between these two categories. The reservoir size determines over what time scale production can be shifted relative to inflow. A large reservoir relative to the plant's turbine discharge capacity allows the installed turbine power capacity to be used flexibly.

In practice, this flexibility can span timescales from seconds to years: operators can ramp production up or down within minutes while also shifting energy across seasons or even between years, depending on reservoir sizes. This combination of rapid response and long-duration storage is unique among energy technologies. On the long end, reservoirs enable energy to be shifted from high-inflow periods to high-net-demand periods. In the Nordics, this has historically meant shifting water from spring and summer inflows to winter, when demand is highest. Reservoirs can also balance variability across years, conserving water when conditions are favorable and drawing on stored water when they are not. This long-duration arbitrage is something that batteries and other short-duration storage technologies cannot economically provide [46].

To illustrate the magnitude of hydropower's inter-annual storage potential, Figure 4.1 shows the change in aggregate reservoir storage and the annual inflow for Sweden over the period 2015–2024. In some years (2016 and 2021), Swedish hydropower produced over 6 TW h more than the year's inflow could sustain, drawing down reservoirs to cover the difference, while in others (2020 and 2024), over 6 TW h of inflow was retained in the reservoirs for use in subsequent years. These swings correspond to roughly 10% of Sweden's average annual hydropower production. For the Nordics as a whole (Sweden, Norway, Finland), the inter-annual storage ranged from drawing down nearly 30 TW h to saving over 23 TW h across the same period. Figure 4.1 also shows that how much water that is stored or released in a given year is only partially explained by differences in inflow, indicating that electricity price conditions, driven by factors such as wind production, nuclear availability, demand, and conditions in neighboring countries, also influence reservoir strategies.

On shorter timescales, the ability to time production to high-price hours means that flexible hydropower can capture significantly higher revenues per unit of energy than inflexible sources. Hirth [23] shows that 1 MW h of wind energy is worth 18% more in Sweden than in Germany, precisely

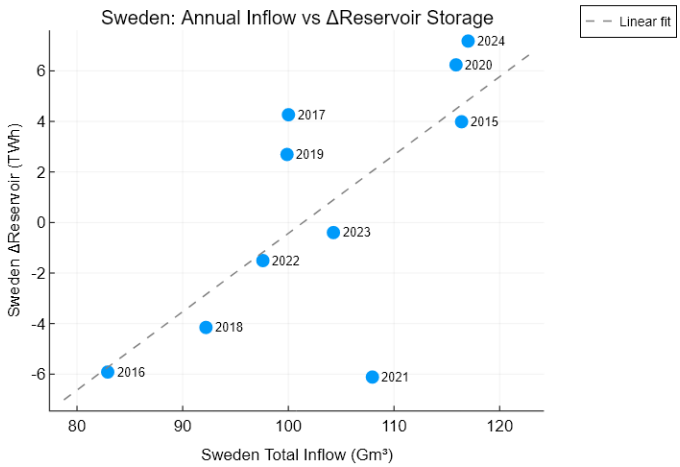

Figure 4.1: Annual inflow versus annual change in reservoir storage for Sweden (SE1–SE3 combined), 2015–2024. Inflow is the total annual volume across nine rivers covering approximately 98% of Swedish hydropower production. The reservoir storage change (ΔReservoir) is the difference in aggregate reservoir content between the last reported week of December in consecutive years, based on ENTSO-E Transparency Platform data. The dashed line shows a linear least-squares fit. The Pearson correlation coefficient is $r = 0.70$ ($n = 10$, $r^2 \approx 0.49$), indicating that inflow accounts for roughly half of the inter-annual variation in net storage change during the observed period.

because the presence of flexible hydropower mitigates the value drop that wind power experiences at high penetration levels. Many turbines can also transition from zero to full output within minutes, enabling load-following and continuous adjustment to system fluctuations. At the fastest timescales, hydropower provides frequency regulation and operating reserves; in the Nordic electricity system, hydropower supplies the majority of frequency containment reserves (FCR) and frequency restoration reserves (FRR).

However, unlike other flexible generation technologies such as gas turbines, where fuel can be procured as needed, hydropower is constrained by the natural inflow of water to the reservoirs. Operators can control *when* water is released, but not *how much* water is available, which gives rise to water values, described in Section 4.2.

Beyond reservoir sizes, the flexibility of hydropower also depends on the network structure of the river system: how reservoirs and plants are located in relation to each other along the river, often referred to as cascading.

4.1.1 Cascaded hydropower plants

Multiple hydropower plants are often located along the same river to utilize as much of the elevation difference (from the high altitude down to the sea) as possible. The cascade of hydropower plants along a river causes an inter-dependency between the plants, since the water discharged from an upstream plant flows downstream and becomes available to downstream reservoirs and plants. The water travels between the plants with a so called delay time, that depends on the distance, flow and river characteristics. Thus, the operation of an upstream plant affects the operation of a downstream plant, and a river system is operated as a coordinated network rather than as a collection of independent units. The distribution of reservoir capacity along the river, combined with the discharge capacities and water travel times between plants, collectively determines how flexibly the cascade can be operated.

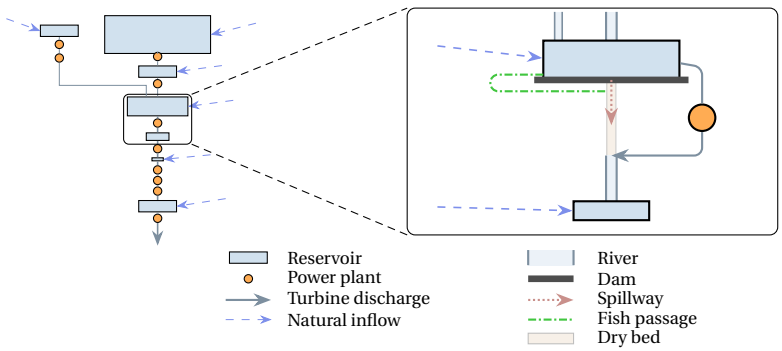

Figure 4.2: Left: schematic of a cascaded hydropower system along a main river and a tributary. Right: detail of a single plant, showing a reservoir, dam, penstock, turbine, and a bypassed river reach (dry bed) between the dam and turbine outlet. The spillway releases water from the dam into the dry bed; the fish passage provides a route for migrating fish around the dam.

4.1.2 The hydropower production function

Hydropower plants convert potential energy to electricity by using an elevation difference in water bodies. The elevation difference induces movement of the water, i.e., the potential energy is converted to kinetic energy, which is converted to electric energy via a turbine connected to a generator, as illustrated in Figure 4.3.

The power produced in a hydropower plant (P, in W) is determined by: the mass flow rate of the water flowing via the penstock through the turbine,

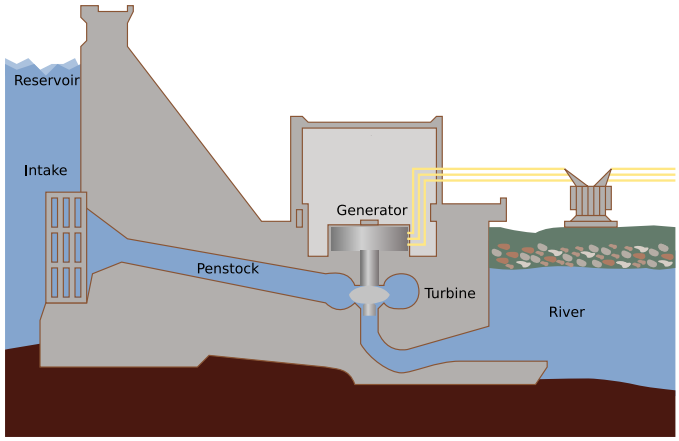

Figure 4.3: Schematic illustration of a reservoir hydropower plant (created by Tomia under the GNU Free Documentation License [48, 49]).

called discharge ($\dot{m}$, in kg/s); the gravitational acceleration constant (g, in m/s^2); the elevation difference, called head (h, in m); and a total conversion efficiency (η). In Figure 4.3, the head, h, is the height difference between the water level in the reservoir and the river by the turbine outlet.

$$P = \dot{m} \cdot g \cdot h \cdot \eta \tag{4.1}$$

The total conversion efficiency η encompasses several components: the turbine efficiency, which depends on both head and discharge; the generator efficiency; head losses due to friction in the penstock; and water leakages.

Two aspects of this production function are important to highlight. First, the head is not constant: it varies with the water level in the reservoir (which changes as water is stored or released) and with the water level downstream of the plant (which may be affected by the discharge itself). As a result, the power output depends on the product of two variables, discharge and head, making the production function nonlinear. Second, the turbine efficiency is itself a nonlinear function of both the discharge and the head. Figure 4.4 shows typical turbine efficiencies as function of the discharge for common turbine types. The efficiency is low at very low discharge levels, rises to a maximum at the turbine's best efficiency point, and decreases again at high discharge levels. Modeling these nonlinear efficiency curves adds computational complexity to optimization models.

The technical characteristics described in this section, i.e., the cascaded network structure, head-dependent production, and nonlinear turbine effi-

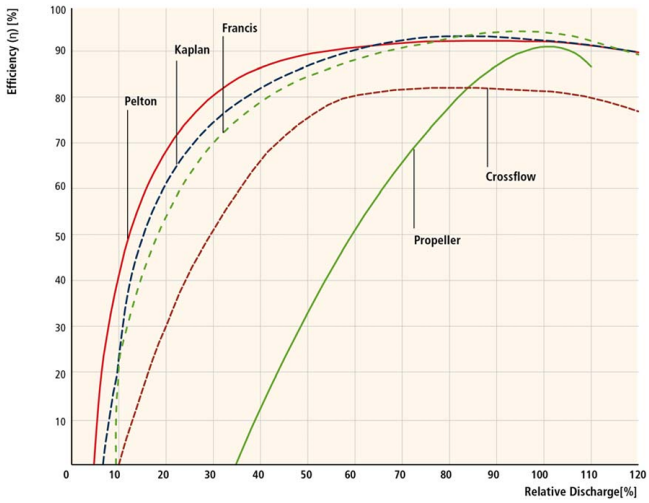

Figure 4.4: Generic discharge-dependent efficiency curves for some common hydropower turbine types. The y-axis shows the conversion efficiency, and the x-axis shows the water discharge relative to the turbine's rated capacity. This figure shows only the discharge dependence; the head dependence makes the turbine efficiency a 3D surface. Figure from Vinogg and Elstad [50].

ciencies, are central to hydropower's behavior but are most often simplified or omitted in energy system models. Representing them faithfully introduces nonlinearities, increases the number of variables, and requires detailed plant-level data that may not be available. How these characteristics can be modeled, and the trade-offs between model accuracy and computational tractability, are the subject of Paper B and Chapter 5.

4.2 Water value and reservoir operation

The economic logic of reservoir hydropower differs fundamentally from that of thermal power plants. A gas or coal plant has a well-defined marginal cost determined primarily by fuel price and efficiency: whenever the electricity price exceeds this marginal cost, it is profitable to produce. Hydropower, by contrast, has near-zero marginal operating costs (no fuel is consumed), yet the water in the reservoir is a scarce resource. Using water to generate electricity now means it is unavailable for production later. The relevant cost of producing one unit of hydropower is therefore not a fuel cost, but an opportunity cost: the value that the same water could generate if saved for a future period with higher prices. This opportunity cost is referred to as the water value. In energy system optimization models, the water value

emerges as the shadow price (dual variable) of the reservoir balance constraint, i.e., the marginal reduction in total system cost from having one additional unit of water available in the reservoir at a given time step. In hydropower scheduling models, which maximize the producer's revenue rather than minimizing system cost, the water value represents the corresponding marginal increase in revenue.

The water value is not a fixed property of a plant. It depends on the current reservoir level, expected future inflow, expected future electricity prices, and the operational constraints of the system described in this chapter. If a reservoir is nearly full and spring inflows are approaching, the water value is low because the risk of spilling water without generating electricity makes immediate production attractive. If a reservoir is drawn down and the outlook is dry, the water value is high because each remaining unit of water may be needed during a future high-price period. Producers rely on hydropower scheduling models, hydrological forecasts and price forecasts to estimate water values under uncertainty [31, 51]. It is the water value that determines when operators choose to store water and when to release it. This is the economic mechanism behind the seasonal and inter-annual reservoir management described in Section 4.1, and also why annual hydropower production does not simply follow annual inflow (Figure 4.1): producers draw down or build up reservoirs across years based on their assessment of water values.

In hydro-dominated electricity markets such as the Nordic system, water value plays a central role in electricity price formation. When hydropower is the marginal source, it is the water value that sets the market price. The market price is then not determined by marginal operational costs, as it would be in a thermal-dominated system, but by hydropower producers' expectations about future inflows and prices. Given this central role of water values in price formation, it is reasonable to expect that how hydropower is represented in energy system models affects the realism of modeled electricity prices, which is examined and discussed in Chapter 5.

Beyond the operational characteristics described so far, there is a further dimension that shapes what hydropower can contribute to the electricity system. The value that hydropower provides as a carbon-neutral and flexible electricity source comes at a cost to the river ecosystems it depends on. Mitigating ecological impacts through environmental regulation constrains how flexibly hydropower can be operated. Understanding these constraints and their consequences is essential, both for informing policy decisions and for realistic representation of hydropower in energy system models.

4.3 Hydropower's impact on river ecosystems

Figure 4.5: The balancing act between hydropower utilization and river ecosystem protection.

While hydropower is valuable for decarbonizing the electricity system, it has significant impacts on river ecosystems. The regulation of water flow in rivers disrupts the natural processes that aquatic and riparian species depend on, creating a tension between two environmental objectives: climate change mitigation through carbon-neutral electricity, and the protection and restoration of aquatic ecosystems and biodiversity. Understanding these ecological impacts is essential for identifying what environmental measures could improve ecological conditions, and for assessing how implementing such measures would constrain hydropower operations and, ultimately, affect the flexibility that hydropower can provide to the electricity system.

The impacts of hydropower on river ecosystems span several categories, each associated with specific ecological stressors and regulatory responses. The remainder of this section describes the main categories of impacts, drawing on the ecological literature on regulated river systems (for comprehensive reviews, see [52, 53]).

Flow regulation and environmental flows

Hydropower dams fundamentally alter the natural flow regime of rivers by storing water in reservoirs and releasing it according to electricity demand rather than ecological needs [10, 13]. In bypassed river reaches (sections between the dam and the tailwater outlet, illustrated in Figure 4.2), water flow may be drastically reduced or eliminated entirely, destroying aquatic habitat. More broadly, altered seasonal flow patterns disrupt ecosystem processes that have evolved in response to natural hydrological variability, such as flood pulse dynamics and the maintenance of physical habitat structure [11]. The ecological consequences of altered flow regimes include changes in aquatic plant and invertebrate community composition, shifts in fish populations from species adapted to fast-flowing water toward generalist species, and reduced riparian vegetation diversity [53]. Environmental flows, defined as the minimum water flow requirements needed to sustain critical ecological functions, are a common regulatory response. Environmental flow

requirements typically mandate a minimum discharge in bypassed reaches or downstream of dams, with the required flow level varying by season and river section [13].

Longitudinal connectivity

Beyond altering the volume and timing of flow, the dam structure itself is also a physical barrier that blocks upstream and downstream migration routes for fish species, disrupts sediment continuity, and alters nutrient transport dynamics [12]. While both issues involve the dam and bypassed reaches, they are ecologically distinct: flow regulation concerns the quantity and timing of water, while longitudinal connectivity concerns passage for organisms and material along the river. Many fish species depend on migration for reproduction (e.g., salmon migrating upstream to spawn) or for completing their life cycles (e.g., eel migrating downstream to the sea). Crucially, releasing minimum flows through a spillway (see Figure 4.2), while effective at eliminating dry bypassed reaches, does not restore longitudinal connectivity: the dam structure itself remains an impassable physical barrier for migrating fish. Restoring connectivity therefore requires dedicated fish passage structures, such as technical fishways or nature-like bypass channels, constructed to allow fish to move around the dam (illustrated in Figure 4.2). Adjusted spill regimes during migration periods and, in some cases, dam removal are additional measures [54]. Blocked migration routes have cascading effects beyond fish populations: freshwater mussels, whose larvae require host fish for upstream dispersal, lose their transport mechanism when fish passage is obstructed [53].

Hydropeaking

Hydropeaking refers to the rapid flow fluctuations that occur *downstream* of hydropower plants in the river channel when generation is ramped up or down in response to electricity demand. These fluctuations can cause drastic water level changes on timescales of hours, leading to stranding of juvenile fish and bottom-dwelling invertebrates, desiccation of egg masses, and disruption of feeding behavior [14, 15]. Riparian vegetation is also affected, since the repeated alternation between wet and dry conditions along river banks alters species composition and can reduce overall vegetation cover [53]. Measures to mitigate hydropeaking include ramping rate limits and restrictions on allowable flow variation, applied to either discharge or water levels, with specific limits depending on river morphology and the ecological sensitivity of the affected reach [54, 55].

Reservoir level fluctuations

While hydropeaking affects the river downstream, the *reservoir itself* is also subject to ecologically damaging water level changes. As water is stored and released over days, weeks, and seasons, reservoir shorelines are alternately flooded and exposed. Frequent drawdowns prevent vegetation from establishing along the shoreline, cause erosion, and reduce biological productivity in the shallow nearshore zone [12]. These impacts reduce the ecological value of reservoir margins, which would otherwise function as transition zones between water and land. Measures to improve these conditions include limits on daily, weekly, or seasonal water level variations, which can stabilize these transition zones and allow vegetation and wetland communities to recover.

Temperature and water quality effects

Hydropower can modify the thermal regime of downstream reaches: water released from deep reservoir intakes tends to be colder than natural summer temperatures and warmer in winter, affecting ice formation, fish behavior, and species composition [53]. Additionally, water passing through turbines or spill gates can become gas-supersaturated, causing fish mortality [52], and reduced discharge in bypassed reaches can lower dissolved oxygen levels [53].

These ecological impacts do not occur in isolation but propagate through the river ecosystem, across the boundary between water and land. Declines in invertebrate populations, for instance, reduce the food base for fish, while changes in aquatic insect emergence affect riverside predators including birds and spiders. Loss of riverside vegetation further compounds these effects by reducing shading, organic matter input, and bank stability [53].

Across all of these impact categories, measures can be tailored with seasonal requirements to protect critical periods in aquatic species' life cycles, such as spawning and migration.

Implementing environmental measures also constrains the operation of hydropower plants. The electricity system consequences depend on which measures are applied, at which plants, and with what stringency: some measures deliver meaningful ecological benefits with limited impact on operational flexibility, while more restrictive combinations approach run-of-river conditions and eliminate most of hydropower's storage value. These trade-offs are explored quantitatively in Paper D and discussed further in Chapter 6. The specific legal environmental permits applied to each plant are determined through regulatory processes, described in the following section.

4.4 European and Swedish policy context

The ecological impacts described in the previous section have led to regulatory frameworks on how hydropower may be operated. This section provides a brief overview of the relevant policy context, focusing on the EU Water Framework Directive and the Swedish process for revising environmental permits.

4.4.1 The EU Water Framework Directive

The EU Water Framework Directive (WFD), adopted in 2000, establishes a framework for the protection and management of water resources across the European Union [56]. A central objective of the WFD is to achieve "good ecological status" (GES) for all surface water bodies and to prevent deterioration in water body status. The WFD is organized around river basin districts and requires member states to classify all water bodies, set environmental quality standards, and develop programs of measures to address pressures on the aquatic environment. Hydropower is identified as one of the main pressures on European river systems [57].

Despite these ambitious targets, the WFD allows for exemptions from full compliance with its environmental objectives [57]. Two exemptions are particularly relevant for hydropower. First, member states may designate a water body as a "heavily modified water body" (HMWB; in Swedish, *kraftigt modifierat vatten*, KMV) if it has undergone substantial physical alterations, such as dam construction, that make achieving GES impossible without significantly affecting the current use. If the societal benefit provided by the modification (e.g., electricity production) cannot be achieved by other means that would be a significantly better environmental option without entailing disproportionate costs, the water body may be classified as HMWB. For an HMWB, the environmental target is lowered from GES to "good ecological potential" (GEP). GEP still requires a functioning aquatic ecosystem, but acknowledges that the physical modification serves an important societal function and thus permits less stringent ecological requirements than GES.

Second, member states may set "less stringent environmental objectives" (*mindre stränga krav*) for water bodies where achieving the applicable target, whether GES for a natural water body or GEP for an HMWB, is impossible or disproportionately costly given the level of human activity affecting the water body. This exemption requires that the socioeconomic needs served by the activity cannot be met through alternative methods that offer significantly better environmental outcomes without disproportionate costs, and that the best possible ecological status is still achieved given the circumstances [57].

Both exemptions thus involve the "disproportionate costs" criterion, but address different questions. The HMWB designation concerns whether the societal benefit of the physical modification can be replaced by less environmentally damaging alternatives without disproportionate costs. The less stringent objectives exemption concerns whether achieving the environmental target itself would be disproportionately costly. Together, they create a hierarchy of environmental ambition: GES as the default, GEP for water bodies designated as HMWB, and objectives below GES or GEP where even these lower targets entail disproportionate costs.

The designation of each water body is therefore consequential: it determines the level of environmental ambition and thereby the stringency of the operational constraints that can be imposed on hydropower in operation permits.

A central challenge is that the WFD provides no detailed guidance on how to evaluate whether costs are disproportionate, which gives national authorities considerable room for interpretation [57]. Cost–benefit analysis (CBA) is the most common assessment method across member states, but the thresholds and methodologies differ substantially, which means that comparable situations may be evaluated differently depending on the country. The difficulty of quantifying environmental benefits, which are often non-monetary and site-specific, adds further complexity to these assessments.

Evaluating whether the costs of environmental measures are disproportionate requires assessing both the ecological benefits of those measures and the costs of constraining hydropower operations. The costs include direct implementation costs (e.g., construction of fish passages and bypass channels) and indirect costs to the electricity system from reduced operational flexibility and capacity. The quantification of ecological benefits and direct implementation costs are outside the scope of this thesis. Paper D addresses the indirect, system-level costs: what constraining hydropower operations means for the electricity system. This is discussed further in Chapter 6.

In Sweden, the WFD is implemented through a water management process (*vattenförvaltning*) carried out in six-year cycles by the five county administrative boards that serve as regional water authorities, with guidance from the Swedish Agency for Marine and Water Management (HaV) [58]. In each cycle, all water bodies are mapped, monitored, and classified according to their ecological status. When the Swedish water authorities assess whether costs are disproportionate, a stepwise approach is used: the first step is qualitative, while the second step, a CBA, is not always conducted. The Swedish authorities apply a threshold where costs exceeding twice the estimated benefits are classified as disproportionate [57].

4.4.2 The Swedish National Plan

Of Sweden's roughly 2,000 hydropower plants, approximately 200 account for 93% of the country's average annual production [57]. The vast majority of these plants operate under environmental permits issued decades ago, most between 1920 and 1980, with minimal or no ecological requirements. These permits reflected the priorities and knowledge of the time and were not designed to accommodate the environmental standards now expected under the WFD. As of the most recent EU reporting, only 58% of Sweden's natural surface water bodies have achieved good ecological status, and only 2% of HMWBs meet good ecological potential [59].

WFD's environmental objectives are legally binding in individual permitting decisions [60]. The European Commission has pursued infringement proceedings, criticizing in particular the widespread use of permits that had never been updated with environmental requirements [57]. In response, the Swedish Government presented the Water Environment and Hydropower Bill (*Vattenmiljö och vattenkraft*, Government Bill 2017/18:243) in 2018 [61]. The bill introduced the concept of "modern environmental conditions," requiring that permit conditions be no older than 40 years. Since nearly all Swedish hydropower permits predate this threshold, the legislative change effectively triggered a comprehensive permit revision, and the government adopted a National Plan (*Nationell plan för moderna miljövillkor*) in 2020, which establishes a framework and timeline for revising the environmental permits of all Swedish hydropower plants through environmental courts [17].

The National Plan organizes the permit revision process by river system, with over 2,000 plants affected. For each water body, the process involves two linked steps. First, the regional water authorities classify the water body: designating it either as a natural water body (subject to GES) or as a heavily modified water body (subject to GEP), and determining whether less stringent environmental objectives apply. Both decisions involve the disproportionate costs criterion described in the previous subsection. Second, the water authorities determine which specific measures are needed for the water body to meet the requirements of its classification and applicable objectives. These measures may include construction of fish passages, minimum environmental flows in spillways or bypass channels, hydropeaking constraints, reservoir level variation restrictions, or removal of dams. The measures are tailored to each water body based on its ecological conditions, the type of hydropower infrastructure present, and the gap between the current status and the target. The classification and required measures then form the basis for the new environmental permits, which are decided by environmental courts on a case-by-case basis.

Implementation has been delayed repeatedly as Sweden awaited regulatory changes to enable full use of the WFD's exemption provisions. In 2024, the European Commission initiated a new infringement case in response to the delays [62]. The permit revision process commenced in July 2025 and is expected to span approximately 20 years [57].

The outcome of this process will directly affect the operational flexibility of Swedish hydropower and, consequently, the electricity system. The system-level implications of different regulatory outcomes are the subject of Paper D and are discussed further in Chapter 6.

4.4.3 Similar developments in other countries

The revision of hydropower environmental permits is not unique to Sweden. Norway is reviewing existing hydropower concessions through a process led by the Norwegian Water Resources and Energy Directorate (NVE) [63]. Finland, France, Germany, Italy, Spain, Romania, and several other European countries are also revising their hydropower regulations in response to the WFD [57].

A common challenge across these processes is how to determine when costs become disproportionate. Although cost–benefit analysis is the most widely used assessment approach, countries apply it with different methodologies and thresholds, which means that comparable plants may face different regulatory outcomes depending on the jurisdiction. The governance structures also differ: Sweden has adopted a comprehensive top-down legislative reform, whereas Finland, for example, has relied primarily on voluntary collaborative processes at the regional level [60]. The absence of harmonized EU-level guidance on how to evaluate disproportionate costs has resulted in substantial variation in national approaches [57].

CHAPTER 5

Modeling Hydropower

The previous chapter described the physical and technical characteristics of hydropower and the environmental constraints that affect its operation. This chapter turns to how these characteristics are represented in optimization models. Section 5.1 reviews the current approaches in the literature, from detailed hydropower scheduling models to aggregated capacity expansion representations. Section 5.2 presents Paper B, which systematically investigates how different levels of physical detail in the hydropower representation affect the modeled production. Section 5.3 extends this comparison to the energy system level, introducing the RAPID dispatch model and describing how both physical and environmental hydropower constraints are represented. Section 5.4 summarizes the chapter.

5.1 Current approaches in literature

As discussed in Chapter 4, the cascade network of plants and reservoirs in a river, the head-dependent production function, and the discharge-dependent turbine efficiencies all constitute challenges for modeling hydropower. These characteristics introduce nonlinearities and interdependencies that are computationally demanding to represent in optimization models. How and to what extent these characteristics are captured varies substantially across models. In many energy system models (both dispatch and capacity expansion models), hydropower is represented very simply: all capacity in a region is aggregated into a single plant and reservoir, with no river network, no head dependency, and no turbine efficiency curves [18, 19, 23, 35, 46]. The following paragraphs focus on models where dedicated effort has been made to capture these characteristics, reviewing the three types of optimization models introduced in Chapter 2: i) hydropower scheduling models, ii) energy system dispatch models, and iii) capacity expansion models. For all three types, the level of detail in the hydropower representation generally decreases with the modeled time horizon and system size.

Hydropower scheduling models

are dispatch models, often used for production planning, where only the hydropower production is optimized and the surrounding energy system is represented by exogenous electricity prices. These can roughly be categorized into short-term and long-term based on the time horizon. Short-term models typically consider time horizons of one day to one week with hourly resolution and are often the most physically detailed, capturing head-dependent production, nonlinear turbine efficiency curves, and the full river network [29, 64–77]. Long-term models consider one or several years, often with weekly or monthly resolution. Some are deterministic [78–81], and some stochastic [82–85]. Stochastic modeling is motivated by the significant uncertainties regarding future inflow and electricity prices over such horizons. However, the combination of a long time horizon and stochastic formulation makes these models computationally demanding, and as a result, head-dependent production and turbine efficiency functions are often more simplified in stochastic models than in deterministic models. To combine the long planning horizon with operational detail, a common strategy is to use the long-term model to establish reservoir boundary conditions, which are then passed as input to a short-term model for operational planning [31, 86]. In the Nordic system, this approach is exemplified by ProdRisk [31], a medium-term stochastic model based on stochastic dual dynamic programming (SDDP), which provides water values and reservoir targets for the short-term model SHOP [29, 30]; SHOP optimizes cascaded hydropower systems over one to two weeks with hourly or sub-hourly resolution.

Energy system dispatch models

optimize the operation of the full electricity system, including hydropower, given fixed installed capacities. Similarly to hydropower scheduling models, the level of detail in the hydropower representation depends on the time horizon. Short-term (days to weeks) energy system dispatch models applied to systems with large hydropower shares, such as the Nordic system, can include head-dependent production and turbine efficiency functions [87–96]. Long-term (one or several years) energy system dispatch models use less detailed hydropower representations than the short-term models, even when dedicated effort is made to capture hydropower characteristics [32, 97, 98]. This is partly because the longer time horizon itself increases the number of variables and constraints, and partly because many long-term models are stochastic, representing uncertainty in future inflows and electricity prices, which further consumes computational budget. Three long-term dispatch models illustrate different approaches to this trade-off. Härtel and Korpås [97] develop equivalent hydropower representations for

a deterministic European dispatch model, using aggregation methods that preserve cascade structure and hydraulic coupling while reducing computational cost. The EMPS model [32] and the FanSi model [98], both developed at SINTEF/NTNU for the Northern European system, are stochastic and take different approaches to the same challenge. EMPS uses planning horizons of three to five years with weekly time steps and computes water values via stochastic dynamic programming on an aggregated hydropower representation (one equivalent reservoir per area) using non-chronological load segments within each week, then disaggregates the area-level generation heuristically to individual plants and reservoirs in a final simulation step. FanSi operates directly on individual hydropower modules over a one-year rolling horizon, optimizing a two-stage stochastic linear program with chronological within-week time steps (typically three-hour resolution); it is often used in combination with EMPS for terminal water values at the end of the planning horizon. Both models handle inflow uncertainty through historical weather scenarios, but differ fundamentally in how hydropower detail enters the optimization: in EMPS, the optimization sees only the aggregated system, while in FanSi, the optimization is performed on the detailed plant-level representation. Even so, both EMPS and FanSi simplify relative to the short-term models cited above: neither includes nonlinear turbine efficiency curves or full head dependency within the optimization.

Capacity expansion models

optimize both investments in and operation of the electricity system, simultaneously determining the technology mix and the hourly dispatch over a full year or longer. The combination of investment decisions and operational detail across long time horizons makes these the most computationally demanding of the three model types. The hydropower representation is therefore typically the most simplified: all hydropower in a region is aggregated into one plant and one reservoir, with production constrained only by the aggregated installed capacity, the aggregated reservoir volume, and an inflow profile [18–20, 23, 46]. No cascade network, no head dependency, and no turbine efficiency functions are represented. These models effectively assume that hydropower can shift all of its energy freely between any hours (except perhaps restricted by minimum production constraints or ramp rate limitations), which overestimates the flexibility that hydropower can provide.

In summary, the level of detail in hydropower representations varies significantly across optimization models, reflecting a fundamental computational trade-off. Four properties emerge that can be desirable when modeling hydropower: stochastic treatment of uncertainty, detailed technical repre-

sentation, high temporal resolution, and long time horizons. These four properties are in tension with each other, and every model represents a trade-off among them. Long-term stochastic models such as EMPS and FanSi prioritize the representation of uncertainty, making some sacrifice on temporal resolution or hydropower detail within the optimization. Capacity expansion models prioritize simultaneous optimization of investments and hourly dispatch over long horizons, but use the most simplified hydropower representations. Short-term scheduling and dispatch models achieve the highest technical detail but are limited to horizons of days or weeks. Correctly assessing the value of flexibility in the electricity system requires chronological hourly representation over long time horizons [99], motivating models that retain these properties. Chronological resolution is necessary to capture within-day patterns such as hydropeaking constraints, the temporal correlation between variable renewable generation and demand, and the operation of storage; these phenomena cannot be represented in models that use non-chronological load segments within each time period, such as EMPS.

Several studies have attempted to improve the hydropower representation in deterministic, high time-resolution, long-term energy system models. Härtel and Korpås [97] develop aggregation methods that preserve cascade structure and hydraulic coupling for a European dispatch model. Liu et al. [100] include the network effect by modeling cascaded hydropower plants in a capacity expansion model for China. Ramírez-Sagner and Muñoz [101] model one head-dependent aggregated hydropower plant and find that ignoring head dependency leads to more wind and solar investments and a lower system cost, since excluding head dependency exaggerates hydropower's flexibility. Stevanato et al. [102] include the network effect and account for head dependency through iterative softlinking with an external head calculation. Baratgin et al. [103] couple a dispatch model with a hydrological model for the French system and find that the standard representation overestimates hydropower flexibility, leading to underestimated unsatisfied demand. These studies consistently show that simplified representations overestimate hydropower flexibility. However, each addresses a single aspect of the hydropower representation, and no systematic investigation of which physical characteristics to include, or the trade-offs between accuracy and computational effort, has been conducted for deterministic models combining high temporal resolution with long time horizons.

Among the models reviewed above, none combines turbine-level physical detail, hourly chronological resolution, and time horizons of one year or more. In Paper B, we address this gap by developing and comparing hydropower models spanning from fully aggregated to turbine-level detail for a single river. A deterministic formulation is chosen because it allows

the effect of each physical characteristic to be isolated, and the results directly connect to representing hydropower in deterministic dispatch and capacity expansion models. This does not imply that deterministic models are superior to stochastic approaches; the two are suited to different questions. Beyond model comparison, the detailed deterministic formulation is also well suited for examining hydropower's technical capabilities under realistic physical and technical constraints, which is the aim of Paper C. To examine the system-level impacts of environmental regulation (Paper D), the hydropower formulation is extended into RAPID, a dispatch model that optimizes the full Northern European power system with endogenous electricity prices. RAPID is also used for the comparison between detailed and aggregated hydropower representations in Section 5.3.

5.2 Paper B: Trade-offs between aggregated and turbine-level representations

In Paper B, we investigate how much the level of physical detail matters for the resulting hydropower production by developing a series of hydropower optimization models with varying levels of detail, all applied to a single river. All models maximize revenue given exogenous electricity prices and inflow, with hourly resolution over a full year and perfect foresight. The setup allows for a direct comparison of how including or excluding specific physical characteristics affects the resulting production profile.

5.2.1 The model spectrum from aggregated to turbine-level

Seven model variants are developed, spanning from the most aggregated representation (Model E) to the most detailed (Model A). Table 5.1 summarizes the key characteristics of each model.

Table 5.1: Overview of the seven hydropower model variants developed in Paper B. NLP = nonlinear program, MIQP = mixed-integer quadratic program, LP = linear program.

Model	Network effect	Head-dependent	Turbine efficiency	Aggregation level	Type
A	Yes	Yes	Nonconvex nonlinear	Turbine	NLP (nonconvex)
A:MIP	Yes	Yes	Nonconvex (multiple linear constraints)	Turbine	MIQP
B	Yes	Yes	Convex nonlinear	Turbine	NLP (nonconvex)
B:L	Yes	Yes (linearized)	Linear (multiple constraints)	Turbine	LP
C	Yes	No	Linear (multiple constraints)	Turbine	LP
D	Yes	No	Linear (single constant)	Turbine	LP
E	No	No	None	River	LP

Model E is designed to replicate the aggregated hydropower representation typical of capacity expansion models: one plant, one reservoir, maximum

capacity set to the aggregated theoretical maximum, and production constrained only by instantaneous capacity and reservoir content. No river network, no head, and no turbine physics are represented. Models A through D all represent the full river network, i.e., the cascade structure, delay times, and environmental constraints, at the turbine level. They differ in whether head-dependent production and turbine efficiency curves are included and how these are represented mathematically.

Model A aims to capture all the physical and technical characteristics described in Chapter 4: the cascade network with water travel times, head-dependent production, and nonconvex discharge-dependent turbine efficiency curves, all at turbine-level resolution with hourly time steps over a full year. It is the most physically detailed model in the comparison and serves as the benchmark against which the other models are evaluated. Model A differs from real-world hydropower operation in several respects. It is deterministic with perfect foresight, whereas real operators face uncertainty in future inflow and electricity prices. It assumes 100% plant availability, whereas actual plants experience scheduled maintenance and unplanned outages. It considers only day-ahead market revenue, whereas producers also respond to balancing market incentives. These differences mean that Model A does not replicate historical production (see Section 5.2.2), but it captures the physical constraints that shape hydropower's operational envelope, which is what the model comparison aims to isolate.

Mathematically, including the nonlinear efficiency curve while also allowing turbines to operate at zero discharge introduces a nonconvexity into Model A; the head-dependent power equation introduces a further nonconvexity through a bilinear product of head and discharge. Model A is therefore a nonlinear program (NLP). Model B uses a convex approximation of the efficiency curve, but remains nonconvex due to the bilinear power equation. Model C eliminates head-dependency by fixing head at its historical mean, making the model a linear program. Model D further simplifies by also fixing turbine efficiency at its maximum value.

Model B:L is a novel contribution of Paper B. It linearizes the bilinear head-times-discharge power equation of Model B using a first-order Taylor expansion around the historical mean head and mean effective discharge, and replaces the convex efficiency curve with ten linear constraints. The result is a fully linear program that approximates the physics of Model B without introducing any nonconvexity.

5.2.2 Key findings

Aggregated models overestimate flexibility

When all plants in a river are aggregated into a single unit without physical constraints (Model E), the model produces a characteristic optimization "flip-flop" pattern: in every hour, it either generates at full capacity or at zero, switching between the two extremes in direct response to hourly electricity prices. This behavior is optimal within the model's constraints but is entirely unrealistic. Physical river-based hydropower cannot operate this way due to the cascade dependencies, head dynamics, and turbine characteristics captured in Model A. Model A, by contrast, produces a generation profile substantially closer to the historical production data. The root-mean-square deviation (RMSD) of hourly production between Model E and Model A is 345 MWh/h, corresponding to 33% of the modelled installed capacity.

Each physical characteristic improves accuracy

Moving along the model spectrum from Model E toward Model A, each step adds a physical characteristic and improves accuracy. Adding the network effect alone (Model D) shifts the power duration curve roughly halfway from the all-or-nothing profile of Model E toward that of Model A, reducing the RMSD from 33% to 17% of installed capacity. Adding turbine efficiency curves (Model C) further reduces the RMSD to 9%, by reducing the incentive to produce at very high discharge levels. Adding head-dependency (Model B) reduces the RMSD to 5%, by making production depend on a variable that changes with reservoir drawdown. Finally, Model A adds the decreasing efficiency at low discharge levels, which shifts hours from near-zero to intermediate production.

The novel linearized model is both accurate and fast

The most practically significant result of Paper B is the performance of Model B:L. Despite being a linear program, it achieves an average RMSD of approximately 3% of installed capacity when compared to Model A, across all four modeled years. At the same time, Model B:L reduces the computation time by a factor of 60 relative to Model A: approximately one minute compared to one hour, both run on a modern desktop computer. Model A itself represents a significant advance over the prior literature, since deterministic hourly nonconvex hydropower models in the literature had previously been limited to time horizons of two weeks or less [69, 70].

5.3 Detailed vs. simplified hydropower modeling in full energy system context

Paper B isolates a single river and compares hydropower models with varying physical detail, demonstrating that the aggregated representation overestimates flexibility and distorts production profiles. A natural follow-up question is whether these differences at the river level propagate to system-level outcomes when the hydropower model is embedded in a full energy system dispatch model. If the surrounding system can compensate for the inaccurate hydropower representation without large additional costs, e.g., by adjusting thermal dispatch or cross-border trade, the system-level error may be modest. If not, the simplified representation may lead to biased electricity prices and underestimated system costs. This section presents an additional analysis, not included in any of the appended papers, that investigates this question.

Two configurations of the RAPID (River And Power System Integrated Dispatch) model are compared: one using the linearized detailed hydropower representation (Model B:L from Paper B) and one using a more standard aggregated representation (Model E from Paper B). RAPID is the same dispatch model used in Paper D to analyze the system-level impacts of environmental hydropower regulation. For the analysis in this section, however, the detailed hydropower representation has been extended to also cover Norway and Finland based on hydropower data from NVE (the Norwegian Water Resources and Energy Directorate) [104]. Below, the RAPID model is described in more detail.

5.3.1 The RAPID dispatch model

RAPID is a linear programming model that minimizes total power system operating cost across Northern Europe with hourly resolution. The model covers 19 bidding zones across 11 countries: Sweden (SE1–SE4), Norway (NO1–NO5), Finland (FI), Denmark (DK1, DK2), the Baltic states (EE, LV, LT), Germany (DE), Poland (PL), the Netherlands (NL), and the United Kingdom (UK). Figure 5.1 shows the modeled regions and transmission connections.

The objective function minimizes the sum of variable operation and maintenance costs, fuel costs (accounting for plant-specific efficiencies), CO_2 emission costs, and cycling costs for thermal units, across all regions and hours. Electricity prices emerge endogenously as the dual variables (shadow prices) of the regional hourly energy balance constraints.

Generation capacities are fixed at 2024 levels; no investment decisions are made. The model includes reservoir hydropower, pumped hydro storage,

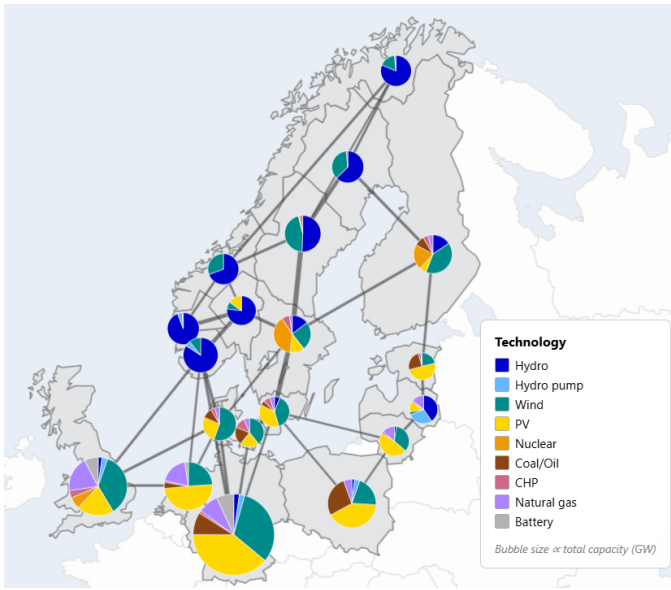

Figure 5.1: Map of the 19 bidding zones and transmission connections in the RAPID model. Pie charts show the installed generation capacity mix in each bidding zone based on 2024 data.

batteries, thermal generation (lignite, hard coal, oil, gas CCGT and OCGT, biomass and waste CHP), nuclear power, and variable renewable energy (wind onshore, wind offshore, and solar PV). Thermal plants are represented using a two-variable approach [105, 106] that captures start-up times, cycling costs, and part-load efficiency penalties without binary variables. Nuclear availability is constrained by reactor-specific unplanned outage patterns from the IAEA PRIS database and annual full load hours. Wind and solar capacity factors are derived from ERA5 reanalysis data using the GlobalEnergyGIS methodology [107, 108], scaled to match observed 2024 generation. Inter-regional transmission is represented using median historical weekly Net Transfer Capacity (NTC) values from the ENTSO-E Transparency Platform, with 5% losses per 1000 km. This approach does not capture internal bottlenecks within bidding zones, nor the physical laws of power flow, and may overestimate the ease with which generation in other regions can substitute for constrained generation within a zone. Only the day-ahead electricity market is represented; intraday markets, balancing markets, and ancillary services (frequency containment reserves, frequency restoration reserves) are not included. Since hydropower is a dominant provider of these services in the Nordic system, the full economic impact of changes in hydropower operations is likely larger than what the day-ahead representation captures.

5.3.2 Hydropower representation in RAPID

The distinguishing feature of RAPID is its dual-mode hydropower representation. In the detailed mode, hydropower in Sweden (SE1–SE4), Norway (NO1–NO5), and Finland (FI) is modeled at individual plant and turbine resolution using the FORSA (Flow Optimization for River Systems Analysis) framework, which builds on, and extends, the method in Paper B. This representation captures the cascade structure of each river system, including water travel times between plants, reservoir-specific level-to-volume relationships, head-dependent production functions, and turbine-specific efficiency curves. Each turbine's power output is computed using the linearized production equation from Model B:L: a first-order Taylor expansion of the bilinear head-times-discharge relationship around the mean head and mean effective discharge, combined with piecewise linear efficiency curve approximations. The water balance tracks multiple flow pathways (turbine discharge, fish passages, spillways) and enforces plant-specific environmental constraints where applicable. For Sweden, the detailed representation covers 9 major river systems with 219 plants, 421 turbines, and 33 reservoir-only facilities. The extension to Norway and Finland follows the same mathematical formulation but uses plant-level data from NVE [104].

In the aggregated mode, the same regions' hydropower is represented using a single-plant, single-reservoir approach corresponding to Model E from Paper B, scaled up to the regional level. All hydropower in each bidding zone is aggregated into one plant and one reservoir. No river network, no head dependency, and no turbine efficiency curves are represented. Generation is bounded only by aggregated capacity and reservoir content. This is the representation typical of many dispatch and capacity expansion models (see Section 5.1).

5.3.3 Modeling environmental constraints

The environmental impacts of hydropower described in Section 4.3 can be addressed through regulations that impose plant-specific operating conditions: minimum flows in bypassed reaches, limits on flow ramping rates, reservoir level variation restrictions, and seasonal variation requirements are some examples. The conditions needed to fulfill the water framework directive vary by plant, season, and river section, and are determined through environmental court rulings on a case-by-case basis. Translating this heterogeneous regulatory landscape into a consistent set of mathematical constraints across hundreds of plants and multiple river systems is a prerequisite for quantifying the system-level impacts of environmental regulation.

The FORSA framework, introduced in Section 5.3.2, is designed to han-

dle this diversity. Since Paper B, which focuses on the physical production characteristics (head dependency, turbine efficiency, cascade structure), the framework has been extended with a comprehensive representation of environmental constraints. This extension means that the detailed hydropower configuration compared against the aggregated representation in this section includes current environmental permits for all Swedish plants. It also enables the scenario analysis in Paper D, which investigates what happens when these constraints are tightened. Each constraint can be specified per plant, per river reach, and per time step, enabling representation of permit conditions that vary by location, season, and flow pathway. Constraints can be categorized by what they restrict: i) flow rates through different pathways, ii) rates of change and variation of flow, iii) reservoir water levels, and iv) rates of change and variation of water levels. All constraint types can additionally be made conditional on hydrological conditions. The following paragraphs describe each constraint category with examples. Throughout, p denotes a plant, p' a downstream connection, and t an hourly time step.

Flow bounds

As described in Section 5.3.2, the detailed hydropower representation tracks three flow pathways at each plant: turbine discharge, fish passage flow, and spillway flow. The sum of these constitutes the total flow $Q_{p,p'}(t)$ between plant p and a downstream plant p'. Bounds can be applied to the total flow or to any individual pathway. As an example, the bound on total flow is:

$$Q^{\min}_{p,p'}(t) \leq Q_{p,p'}(t) \leq Q^{\max}_{p,p'}(t) \tag{5.1}$$

where the bounds can vary by plant, downstream connection, and time step; analogous constraints apply to the turbine, fish passage, and spillway flows individually. Minimum environmental flow requirements are the most common type: a mandatory minimum flow through a fish passage or spillway. For bypassed reaches where water is diverted away from the turbine channel (see Figure 4.2), the water diverted produces no electricity.

Flow ramping constraints

Hydropeaking, i.e., the rapid downstream flow fluctuations caused by changes in generation (see Section 4.3), can be constrained by limiting the hourly rate of change of flow. As for flow bounds, ramping constraints can be applied to the total flow or to individual pathways. For total flow:

$$Q_{p,p'}(t-1) - \Delta Q^{\text{down}}_{p,p'} \leq Q_{p,p'}(t) \leq Q_{p,p'}(t-1) + \Delta Q^{\text{up}}_{p,p'} \tag{5.2}$$

where $\Delta Q^{\text{up}}_{p,p'}$ and $\Delta Q^{\text{down}}_{p,p'}$ are the maximum allowed hourly increase and decrease in flow (m^3/s per hour), respectively. These limits can differ between upward and downward ramping and can be set per plant connection. By limiting how rapidly flow can change, the frequency and severity of stranding events and habitat disruption downstream of the plant can be reduced.

Flow variation within periods

In addition to hourly ramping limits, the framework allows constraining the total range of flow variation within multi-day periods. For spillway flow, this is expressed as:

$$\max_{t \in \mathcal{T}_w} Q^{\text{spill}}_{p,p'}(t) - \min_{t \in \mathcal{T}_w} Q^{\text{spill}}_{p,p'}(t) \leq \Delta Q^{\text{spill,max}}_{p,p',w} \tag{5.3}$$

where $\mathcal{T}_w$ is the set of hours within period w. The framework also supports constraints that require flow to remain within a specified band around the level at the start of each period, applicable to total, passage, or spillway flows. These constraints limit how much the flow pattern can shift over days, complementing the hourly ramping limits.

Period-average flow constraints

Some regulations specify flow requirements averaged over multi-day periods rather than as instantaneous bounds. These can be represented as constraints on the mean flow over rolling windows of specified length (e.g., 3, 7, or 30 days):

$$\frac{1}{|\mathcal{T}_w|} \sum_{t \in \mathcal{T}_w} Q_{p,p'}(t) \geq Q^{\text{avg}}_{p,p'} \tag{5.4}$$

where $\mathcal{T}_w$ denotes the hours within the averaging window. Both minimum and maximum average flow constraints can be imposed, and they can be applied to total, passage, or spillway flows.

Water level bounds

Absolute upper and lower bounds can be imposed on both forebay and tailrace water levels:

$$L_p^{\min}(t) \leq L_p(t) \leq L_p^{\max}(t) \tag{5.5}$$

where the bounds can vary by plant and time step, enabling seasonal level requirements. Some permits specify level trajectories that change gradually over weeks or months, for example a minimum forebay level that rises linearly during the spring filling period; the framework accommodates such schedules through time-varying bounds.

Water level variation constraints

Reservoir water level fluctuations affect shoreline habitats and riparian vegetation, as described in Section 4.3. The variation of the forebay water level L_p within a day or week can be constrained:

$$\max_{t \in \mathcal{T}_d} L_p(t) - \min_{t \in \mathcal{T}_d} L_p(t) \leq \Delta L_{p,d}^{\max} \tag{5.6}$$

where $\mathcal{T}_d$ is the set of hours within day d (or, analogously, a week), and $\Delta L_{p,d}^{\max}$ is the allowed variation in meters. In addition, hourly level ramping constraints can be imposed on both forebay and tailrace levels, analogous to the flow ramping constraints described above. Such constraints can stabilize reservoir margins, enabling reestablishment of riparian vegetation and littoral zone productivity.

Conditionality

Any of the constraint types described above can be made conditional on hydrological conditions. In the framework, constraints can be set to apply only when the accumulated upstream inflow at the plant exceeds or falls below a specified threshold. This enables representation of permit conditions that vary with the hydrological situation, for example a minimum flow requirement that only applies during high-inflow periods, or a stricter ramping limit during low-flow conditions when ecological sensitivity is higher.

Implementation and scenarios

Current environmental permits for all 252 facilities in the 9 major Swedish river systems modeled in FORSA have been encoded as plant-specific constraint sets, based on existing environmental court rulings. These permits are heterogeneous: some plants have multiple flow pathway requirements with seasonal variation, while others have minimal or no environmental con-

ditions. This regulatory baseline constitutes the *Current* scenario in Paper D. These permits are also enforced in the detailed RAPID configuration used for the comparison in Section 5.3.4.

In Paper D, seven scenarios are analyzed, targeting the ecological stressor categories described in Section 4.3. In addition to the *Current* baseline and an unconstrained reference scenario, these include connectivity scenarios that add mandatory fish passage flows (1 or 5 m^3/s) at all plants, a hydropeaking scenario that limits daily flow variation to 50% of each plant's lowest recorded flow, and natural flow scenarios that require operations to follow natural inflow patterns within narrow bands (90–110% of instantaneous inflow), approximating run-of-river conditions. The system-level implications of these scenarios are discussed in Chapter 6.

5.3.4 Comparison setup

With the RAPID model and its two hydropower modes described, this subsection returns to the question posed at the beginning of this section: do the differences between detailed and aggregated hydropower representations, demonstrated for a single river in Paper B, propagate to system-level outcomes? The comparison is designed to isolate the effect of the hydropower representation. Two model runs are performed: one with the detailed FORSA hydropower representation (using the Model B:L formulation from Paper B) and one with the aggregated representation (Model E). All other model inputs, including installed capacities, demand, fuel prices, transmission constraints, and weather data, are identical between the two runs. The model is run for 2024.

The maximum hydropower capacity in the aggregated representation is set equal to the sum of maximum achievable power across all turbines in the detailed representation, so that total installed capacity is matched. Annual hydropower production in each region is also constrained to equal that of the corresponding detailed run. This isolates the effect of modeling detail on operational flexibility rather than on total energy and capacity availability.

The key metrics for comparison are: i) total system running cost, ii) hydropower production profiles, and iii) electricity prices. Differences in running cost between the two configurations reflect the economic value of the flexibility that the aggregated model incorrectly attributes to hydropower. Differences in electricity prices indicate how the hydropower representation propagates through the market equilibrium to affect prices.

5.3.5 Results

Running cost

The total system running cost is 0.5% higher in the detailed configuration than in the aggregated one. This number is, however, largely determined by the geographical scope: the detailed representation is applied only to Nordic hydropower, which constitutes roughly 8% of total installed capacity in the modeled system. The remaining 92% of the system is identical between the two runs, diluting the cost difference. In a Nordic-only model, the percentage would be correspondingly larger; in a model covering all of Europe with aggregated hydropower everywhere, it would be smaller still. The 0.5% therefore says more about the scope of the comparison than about the magnitude of the modeling error within the affected region. That said, the result indicates that in this model configuration, the flexible thermal fleet in the system can substitute for the overestimated hydropower flexibility at modest additional cost.

Hydropower production profiles

Figure 5.2 shows duration curves of hourly hydropower production for four bidding zones: SE2, SE3, NO1, and FI. These zones are selected to illustrate the pattern across a range of hydropower shares, from hydropower-dominated zones (SE2, NO1) to zones with a more mixed generation portfolio (SE3, FI); the same trend holds for all bidding zones where the detailed representation is applied. In all zones, the detailed representation leads to "smoother" hydropower production, producing fewer hours at high levels and more at low levels compared to the aggregated representation. This trend is consistent with the findings of Paper B at the river level.

However, the differences in production profiles are smaller than those observed in Paper B for isolated river systems. In the full system context, transmission constraints between bidding zones and limited demand within each zone dampen the extent to which the system can exploit the additional flexibility of the aggregated representation. Even if the aggregated model permits more hours at maximum capacity and rapid hydropower ramping, the broader system may not need or be able to absorb it.

Electricity prices

Consumption-weighted average electricity prices are 0.4% (on average for all bidding zones with detailed hydropower modeling) lower when the detailed hydropower representation is used compared to the aggregated representation. While this difference is small, the temporal variation of prices differs

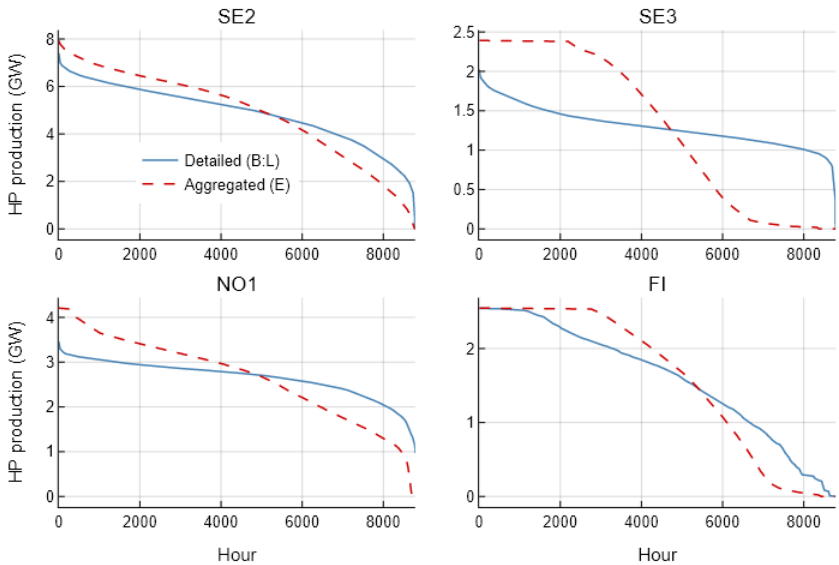

Figure 5.2: Duration curves of hourly hydropower production in the detailed (Model B:L) and aggregated (Model E) configurations for SE2, SE3, NO1, and FI.

more substantially. Figure 5.3 shows price duration curves for the same four bidding zones.

In SE2 and NO1, where hydropower constitutes a large share of total generation, prices are near-constant with the aggregated representation. This is consistent with Nycander and Söder [33], who observe that deterministic dispatch models produce nearly flat prices in hydropower-dominated areas because water is distributed over the year to even out price fluctuations. The mechanism is that unconstrained aggregated hydropower becomes the marginal (price-setting) unit in most hours, and since it faces no physical constraints that differentiate one hour from another, it sets a uniform price. With the detailed representation, hydropower's ability to respond is limited by head, efficiency, environmental permits and cascade constraints, causing the water value to differ and also other generators to set the price more often and introducing greater temporal variation.

To quantify this effect, the coefficient of variation (standard deviation divided by the mean) of hourly electricity prices within each bidding zone is computed for both configurations. Across all modeled bidding zones, the coefficient of variation increases by 6.4 percentage points on average when moving from the aggregated to the detailed representation. The choice of hydropower model thus has a more significant effect on price dynamics than on average price levels. Even so, the modeled price variation remains

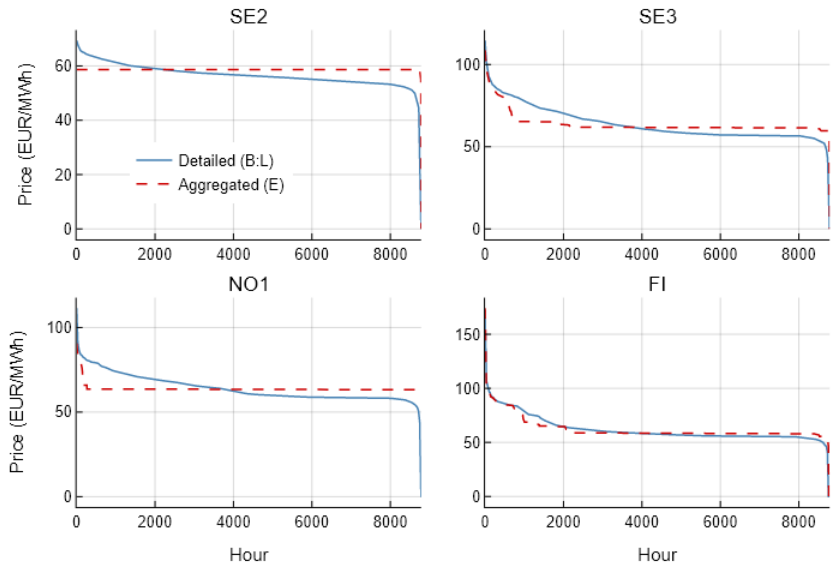

Figure 5.3: Duration curves of hourly electricity prices in the detailed (Model B:L) and aggregated (Model E) configurations for SE2, SE3, NO1, and FI.

lower than that observed in historical data. As discussed in Section 4.2, water values in reality depend on uncertain future inflows and prices, and the resulting uncertainty premiums contribute to price variation that a deterministic, perfect-foresight model cannot reproduce. This limitation is discussed further in Section 7.2.

5.4 Chapter summary

The literature review in Section 5.1 identified a gap: while some studies have shown that simplified hydropower representations overestimate flexibility, no systematic investigation had been conducted of which physical characteristics matter, what the trade-offs between accuracy and computational effort are, or how much the choice of representation affects energy system outcomes.

This chapter has addressed that gap in two steps. First, Paper B provides a systematic comparison of hydropower models spanning from fully aggregated to turbine-level detail, applied to a single river. The results show that each added physical characteristic (cascade network, turbine efficiency, head dependency) improves accuracy, and that the aggregated representation used in most energy system models produces an unrealistic all-or-nothing

production pattern with a 33% RMSD relative to the most detailed model. A key practical contribution is the linearized Model B:L, which achieves 3% RMSD at a fraction of the computational cost, making detailed hydropower modeling tractable within large-scale energy system models.

Second, the comparison in Section 5.3 extends the analysis to the energy system level by embedding both the detailed and aggregated representations in the RAPID dispatch model for Northern Europe. The system-level cost difference is 0.5%, though this number reflects the geographical scope of the comparison (the detailed representation covers only 8% of total installed capacity) as much as the modeling error itself. Average electricity prices are barely affected, but the effect on price dynamics is more substantial: the aggregated representation produces near-constant prices in hydropower-dominated zones, while the detailed representation yields greater temporal variation.

This chapter has compared detailed and aggregated hydropower representations at two levels: in isolated hydropower scheduling models (Paper B) and in a dispatch model of today's Northern European power system (Section 5.3). What remains unexplored is the effect of hydropower modeling detail in dispatch models of future systems with less thermal capacity and higher VRE shares, and in capacity expansion models where the hydropower representation may affect investment decisions. For example, Ramírez-Sagner and Muñoz [101] found that ignoring head dependency in a single aggregated plant led to higher wind and solar investments; whether a more comprehensive detailed representation, covering full river networks and environmental constraints across an entire country, would produce similar or larger effects on investment outcomes could be explored in future research (see Section 7.5).

The next chapter turns from how hydropower is modeled to what it can deliver. Using the detailed representation developed here, Papers C and D investigate hydropower's operational limits under realistic physical and environmental constraints, and the implications for the electricity system.

CHAPTER 6

Hydropower Output and the Cost of Environmental Regulation

The previous chapters established the technical characteristics of hydropower (Chapter 4) and the modeling approaches available for representing them in optimization models (Chapter 5). This chapter turns to the substantive questions: what can hydropower deliver when operated under real-world constraints, and what are the electricity system consequences when environmental regulations further limit hydropower operations? Section 6.1 presents Paper C, which quantifies the sustained output capability of Swedish hydropower during prolonged high-demand periods. Section 6.2 presents Paper D, which examines how different types of environmental constraints affect electricity system costs and the distribution of economic impacts across regions and market actors. Section 6.3 discusses the insights that emerge across the two papers.

6.1 Paper C: Sustained hydropower production through energy droughts

Electricity systems with high shares of wind and solar power face the risk of prolonged periods where supply falls short of demand, sometimes called energy droughts [109–111]. Reservoir hydropower could contribute to mitigating such shortfalls by sustaining high output over days or weeks. However, whether hydropower can maintain high output for extended periods depends on physical and regulatory constraints that are not captured in most energy system models. In Paper C, we investigate how much power Swedish hydropower can sustain during one to three weeks of high demand, and how flow limitations in rivers affect this capability.

The analysis uses the linearized hydropower scheduling model (Model B:L) developed in Paper B, extended to cover nine major Swedish rivers encompassing approximately 240 plants and 15 GW of installed capacity (92% of Sweden's total). The model represents cascade structures, head-dependent

production, turbine efficiency curves, and plant-specific environmental constraints. To simulate energy drought conditions, high electricity prices are introduced for periods of one, two, or three consecutive weeks within historical price profiles, creating strong economic incentives for maximum production. Each drought period is tested at different times of the year across four years (2016 to 2019), yielding more than 5,000 model runs. Three flow limitation scenarios are compared: i) the present regulatory regime, where the maximum flow at each plant is generally limited to the installed turbine capacity; ii) a reduced bottlenecks scenario, where flow limits are increased at identified bottleneck plants; and iii) an unrestricted scenario, where no upper limits on spillage are imposed. Two metrics are introduced to quantify the ability to sustain output: *sustained capacity* (the minimum hourly output maintained throughout the high-demand period, as a share of maximum capacity) and *sustained production* (total energy produced during the period, as a share of maximum possible production).

6.1.1 Key findings

Assuming full availability of all plants (i.e., no maintenance or unplanned outages), Swedish hydropower can sustain between 67% and 96% of its installed capacity for one to three weeks under the present regulatory regime, depending on the time of year and the duration of the high-demand period. On average, the sustained capacity is 84% for a one-week period and 78% for a three-week period. The range between the highest and lowest observed sustained capacity corresponds to approximately 4.5 GW, equivalent to the capacity of three to four Swedish nuclear reactors. This range underscores that hydropower's ability to sustain output varies considerably with conditions, and that treating hydropower as fully dispatchable overestimates what it can deliver.

The main factor limiting sustained output is river bottlenecks: locations where the maximum discharge capacity at one plant is lower than at plants upstream or downstream, preventing water from being transferred through the river network fast enough to keep downstream plants running at high output. These are technical constraints on maximum flow, not environmental maximum flow requirements. In the reduced bottlenecks scenario, where the maximum allowed discharge is increased at approximately 30% of plants identified as bottlenecks, the average sustained capacity increases to 90% for one week and 85% for three weeks. In the unrestricted scenario (no upper limits on discharge or spillage), sustained capacity exceeds 95% on average. The gains in these scenarios therefore reflect expanded physical throughput capacity at bottleneck locations.

The ability to sustain output also varies with the season. Sustained capacity

is highest during spring and early summer, when natural inflow is high and reservoirs are being replenished. It is lowest during the winter months (November to March), when reservoirs have been drawn down to meet winter demand and inflow is at its seasonal minimum. This seasonal pattern is notable because energy droughts in the European electricity system are most likely to occur during winter [110, 112, 113], precisely when hydropower's sustained output capability is weakest.

Sustaining high output comes at a cost in terms of annual energy production. The energy losses arise primarily from increased spillage at bottleneck locations, where water must bypass turbines to keep flows moving downstream. Under the present regulatory regime, the annual production loss is approximately 0.2% per week of sustained high output, increasing to approximately 0.8% per week in the unrestricted scenario where higher spillage enables higher sustained capacity.

6.1.2 Implications

The results of Paper C challenge a common assumption in energy system models: that hydropower can produce at its installed capacity as long as water is available in the reservoirs. The sustained capacity range of 67% to 96% means that, in the most constrained periods, Swedish hydropower can deliver approximately 10 GW of the 15 GW modeled capacity while sustaining output for up to three weeks. This corresponds to roughly 40% of peak electricity demand in Sweden. At the higher end, a sustained capacity of 96% (approximately 14.5 GW) can meet close to 60% of peak demand and nearly 100% of average demand. These numbers highlight that the distinction between peak capacity and sustained capacity is consequential for adequacy planning.

The findings also highlight the importance of flow limitations (both regulatory and technical constraints on maximum water flow) as a factor determining hydropower's contribution during periods of high net demand, or, high prices. In the context of Sweden's ongoing process of revising environmental permits (see Section 4.4), these results show that upper flow limits, not only minimum flow requirements, are consequential for hydropower's performance during energy droughts. The methodology developed in Paper C, based on systematic model runs across seasons, years, and flow limitation scenarios, provides a framework that can be applied to other regions with significant hydropower resources.

6.2 Paper D: Power system effects of environmental constraints

While Paper C quantified what hydropower can deliver in terms of sustained output, Paper D addresses the electricity system consequences of constraining hydropower operations for environmental purposes. Similar questions have been investigated for Norwegian hydropower [114, 115] and for Chilean hydropower [116]. In Paper D, we focus on the Swedish case and investigate how environmental constraints affect electricity system costs, electricity prices, and the distribution of economic impacts across regions and market actors. The analysis examines two categories of environmental measures currently under discussion in the Swedish permit revision process: i) connectivity measures, which require bypass flows at dam sites to enable fish passage, and ii) hydropeaking limitations, which constrain hourly and daily flow variations to reduce downstream ecological impacts. These two categories address fundamentally different ecological stressors (see Section 4.3) and affect hydropower operations in distinct ways.

The analysis uses the RAPID (River and Power System Integrated Dispatch) model, a dispatch model covering 19 bidding zones across 11 countries in Northern Europe with hourly resolution over three-year periods. Swedish hydropower in bidding zones SE1, SE2 and SE3 (approximately 98% of Sweden's hydropower capacity) is represented at individual plant and turbine level using the FORSA framework, which extends the methodology from Paper B to accommodate diverse types of environmental constraints. Hydropower in other regions uses an aggregated two-storage representation, where each region's hydropower is split into a long-term seasonal reservoir and a smaller short-term reservoir representing weekly regulation capability, with region-specific inflow splits calibrated to historical production patterns. This is a simplification compared to the plant-level FORSA representation used for Sweden; the extension of FORSA to Norway and Finland described in Section 5.3.2 was carried out after the analysis in Paper D. Electricity prices emerge endogenously from the optimization, which enables analysis of how constraints on Swedish hydropower propagate through the interconnected electricity system. Seven environmental constraint scenarios are compared, ranging from removing all existing environmental constraints to requiring operations that closely follow natural inflow patterns, which effectively eliminates storage and flexibility functions. The model is run for three different weather periods spanning 2016 to 2024 to capture variation in hydrological and meteorological conditions. One limitation of the current RAPID configuration is that inter-regional transmission is represented using aggregated Net Transfer Capacities, which does not capture intra-zonal bottlenecks or the

nonlinear behavior of power flows. Since the results are sensitive to transmission as a substitution pathway, a more refined transmission representation with linearization of DC power flow is planned before the final submission of Paper D.

6.2.1 Key findings

Two distinct mechanisms

The connectivity and hydropeaking scenarios affect hydropower through fundamentally different mechanisms. Connectivity constraints (mandatory minimum bypass flows of 1 or 5 m^3/s at all plants) reduce annual energy production by 0.7 to 3.1 TW h (1 to 4.5% of baseline production in SE1 to SE3) but preserve operational flexibility: the daily production range and hourly ramping capability remain essentially unchanged. The water diverted through fish passages bypasses the turbines entirely, reducing the total energy available, but the remaining water can still be timed as freely. By contrast, hydropeaking constraints (limiting daily flow variation to 50% of each plant's lowest recorded flow) have only a minor effect on annual production (approximately 0.3% reduction) but reduce the daily production range by approximately 75%. Since, under these constraints, generation is distributed roughly evenly across the hours of each day rather than being concentrated in high-demand periods.

Energy loss is more costly than flexibility loss

Despite the common emphasis on hydropower's flexibility value in the energy policy debate, connectivity constraints impose larger total system cost increases than hydropeaking constraints. The system cost increase is 51 to 236 M€/yr for the connectivity scenarios (depending on bypass flow magnitude) compared to 44 M€/yr for the hydropeaking scenario. The connectivity cost increase is approximately proportional to the bypass flow magnitude and, thereby, to the production loss. The explanation lies in the substitution options available in the current Northern European electricity system: energy lost through bypass flows must be replaced by thermal generators higher in the merit order, whereas the daily flexibility lost through hydropeaking constraints can be partially compensated by other flexible resources (Norwegian hydropower, gas turbines, batteries, and cross-border trade) at limited additional cost.

Each MWh of hydropower production lost to connectivity constraints costs the system approximately 77 €/MWh, regardless of the bypass flow magnitude. This consistent per-unit cost indicates that the system cost of connectivity measures is approximately proportional to the production loss.

The ranking between the total cost of energy loss and flexibility loss depends on the current system configuration, and could change as the electricity system evolves.

The economic burden falls locally and on hydropower producers

The economic impact of environmental constraints is concentrated geographically: the Swedish bidding zones where constraints are imposed (SE1 to SE3) bear the large majority of the net economic losses. Despite the lower total system cost increase for the hydropeaking scenario compared to the connectivity scenarios, Swedish regions experience higher net losses under hydropeaking constraints, indicating that flexibility constraints generate stronger cross-border redistribution effects than energy constraints of comparable system cost. When Swedish hydropower can no longer provide daily balancing, other regions increase their cycling of storage and flexible generation, benefiting from higher revenues. This redistribution, where flexibility constraints create gains in unconstrained regions at the expense of constrained regions, could not be captured by analyses that use exogenous electricity prices.

Among market actors, hydropower producers subject to the new constraints bear the largest economic loss in aggregate: 40 to 200 M€/yr in reduced profits, corresponding to up to 4% of their revenues. Consumers in the constrained regions face modest electricity price increases (up to 0.6% for the connectivity scenarios). Other generators, including wind and nuclear, benefit from the resulting higher prices.

The full cost spectrum

To contextualize these intermediate scenarios, the analysis also examines the extremes. Removing all existing environmental constraints (which in reality is not a realistic option, but serves as a reference) reveals that current regulations already impose a system cost of approximately 165 M€/yr relative to fully unconstrained operation. At the other end, requiring operations to follow natural inflow patterns (effectively converting reservoir hydropower to run-of-river) increases system costs by approximately 1,000 M€/yr, reflecting the high value of reservoir storage and operational flexibility.

6.2.2 Interpreting the results

The results above are based on a dispatch model with fixed installed capacities (see Section 2.2.2), meaning they represent the short-run impact on today's system if the scenarios were realized today. The system cannot adapt through new investments in the model. In practice, other bulk generation

and flexible resources could be deployed over time to partially offset lost hydropower, implying that the long-run cost increase would likely be smaller than the dispatch results suggest. At the same time, if the electricity system evolves, for example, toward higher wind and solar shares with less thermal generation and higher demand for electricity, hydropower generation and flexibility become more valuable, meaning that the long-run cost increase could be larger due to higher value of hydropower in a future system compared to today's system. Thus, the results are best interpreted as the operational cost increase of environmental constraints given the current generation fleet and demand, not as the long-run equilibrium cost. Extending the analysis to a capacity expansion framework is a direction for future research (see Section 7.5).

6.3 Chapter summary

Several overarching insights emerge from the analyses in Papers C and D.

First, the operational capabilities of hydropower under real-world constraints differ substantially from what simplified energy system models assume. Swedish hydropower can sustain between 67% and 96% of the available capacity over one to three weeks, not 100% as most energy system models effectively assume. This gap could have direct implications for the reliability of model-based assessments of future electricity systems (see also the discussion of modeling representations in Chapter 5).

Second, environmental constraints affect hydropower through two distinct mechanisms, energy loss and flexibility loss, with different cost implications depending on the type of measure (see Section 6.2.1). This distinction is useful for structuring the evaluation of different environmental measures and for understanding which aspects of hydropower's contribution are most consequential for the electricity system.

Third, the economic burden of environmental constraints is unevenly distributed. Hydropower producers in constrained regions absorb the largest share of the cost, while consumers face only modest price increases and generators in neighboring regions may benefit from higher prices. This uneven distribution is an important consideration for policy design, as it may affect the feasibility of implementing environmental measures in practice.

Fourth, the results suggest that significant environmental improvements can be achieved at moderate electricity system costs. The connectivity and hydropeaking scenarios tested in Paper D increase total system costs by 44 to 236 M€/yr, corresponding to 0.5 to 2.7% of consumer electricity expenditure in the affected regions. These costs are substantial in absolute terms, particularly for the affected hydropower producers, but are far below the

approximately 1,000 M€/yr cost of eliminating hydropower's storage and flexibility functions entirely through natural flow requirements.

It is important to note that the analyses in this chapter quantify the electricity system costs of environmental measures but not their ecological benefits. The ecological benefits depend on site-specific conditions and are the subject of ecological research beyond the scope of this thesis. Moreover, the costs quantified here are limited to effects on the electricity system. They do not include the direct implementation costs of the measures themselves, such as construction of fish passages or bypass channels, nor other societal costs, or benefits, such as effects on cultural heritage or recreational values. A complete cost-benefit assessment, as required under the EU Water Framework Directive's "disproportionate costs" criterion [57], could include all of these components.

CHAPTER 7

Conclusions, implications and future work

The main contributions of the thesis are synthesized below, organized around the three research questions, followed by method reflections, policy implications, and directions for future research.

7.1 Main contributions

Starting with Paper A, this analysis contributes with a systematic cross-regional comparison of how three politically contested factors, land availability for wind and solar power, the availability of nuclear power, and transmission expansion, affect the cost of low-carbon electricity systems. By applying the same model to both Europe and the MENA region, the analysis demonstrates that the cost impact of these factors is region-dependent: conclusions about which factors matter most cannot be transferred between regions with different resource endowments and demand characteristics. All three factors significantly affect system cost, with transmission expansion having the strongest and most consistent effect.

The remaining research questions examine hydropower, another key flexibility resource: how modeling choices affect the realism of its representation, what physical and regulatory constraints mean for its operational capabilities, and what the electricity system costs are when environmental regulations limit its operations.

7.1.1 RQ1: How does hydropower modeling detail affect the realism of modeled operations, and does the choice of hydropower representation affect electricity system model results?

Although the simplification of hydropower in energy system models has been widely acknowledged, no systematic investigation of which physical

characteristics matter most for operational realism had been reported in the literature. Paper B fills this gap by comparing five model formulations along the full continuum from turbine-level detail to full aggregation. The dispatch model comparison in Section 5.3 extends the assessment to the energy system level.

The standard aggregated hydropower representation used in most energy system models, where all plants and reservoirs in a region are combined into a single unit, significantly overestimates the flexibility of hydropower (see Section 5.2.2). The aggregated model assumes that hydropower can switch freely between zero and full output in every hour, a behavior that is prevented by physical cascade constraints, head dependency, and turbine efficiency characteristics. As shown in Paper B, each of these physical characteristics contributes measurably to the gap between the aggregated and the detailed representation, and a linearized formulation (Model B:L) can capture most of the accuracy at a fraction of the computational cost of the full nonlinear model.

The more important conclusion, however, concerns not the magnitude of the error but its consequences for different analyses: For aggregate system cost estimates in today's Northern European electricity system, the bias from aggregation is modest (approximately 0.5%, see Section 5.3.5), as thermal generation compensates for the overestimated hydropower flexibility, and the total cost remains close to correct. Energy system studies that use aggregated hydropower are therefore not necessarily wrong in their system cost estimates, at least not for the current system. Whether this modest cost bias persists in future systems with higher wind and solar shares, less thermal capacity, and greater reliance on hydropower flexibility is not yet known. If the surrounding system has fewer alternative flexibility sources, the overestimation of hydropower flexibility in aggregated models could translate into larger cost errors and potentially misleading conclusions about system adequacy. Extending the analysis to future system configurations and to capacity expansion models, where the bias could also affect investment decisions, is therefore an important direction for future research (see Section 7.5 and Section 7.5). Moreover, the aggregated representation distorts electricity price dynamics, because it allows hydropower to shift production between hours with a flexibility it does not physically have. This matters for any analysis where price patterns are part of the answer: assessments of revenue and profitability for generators and storage investors, evaluations of price volatility and extreme price events, and distributional analyses of who bears costs and who benefits from system changes.

For questions about hydropower's operational limits, a detailed representation was essential. The sustained output analysis in Paper C illustrates this: with detailed modeling (model B:L from Paper B), Swedish hydropower

can sustain between 67 and 96% of its capacity over one to three weeks depending on the season and hydrological conditions, whereas an aggregated representation would yield 100%. Without representing individual plants and cascade connections, there is no mechanism through which river bottlenecks are represented in the models, and such a limitation cannot be identified. Once identified, the sustained output limitation can in principle be approximated by simpler means, as demonstrated in [117], where we used hydropower equivalents derived from FORSA results.

Furthermore, evaluating how environmental constraints affect the electricity system required a detailed representation. Without representing individual plants, it is not possible to impose plant-specific environmental constraints or to quantify how different types of regulations affect hydropower operations differently. The entire analysis of environmental regulations in Paper D, including the energy-versus-flexibility distinction and the distributional cost analysis, requires the plant-level representation that the aggregated approach cannot provide.

7.1.2 RQ2: How do physical, technical and regulatory constraints affect hydropower's operational capabilities?

Hydropower's potential to sustain high output over week-long periods, the time scale relevant for energy droughts, was poorly explored in the literature, in part because historical data are insufficient: such prolonged high-demand situations have not been pressing enough to generate empirical evidence. Paper C addresses this gap using systematic model-based evaluation.

Swedish hydropower cannot sustain its full installed capacity over multi-week periods (see Section 6.1.1). The sustained output ranges from roughly two thirds to near-full capacity depending on the season and hydrological conditions. The binding constraint is not the availability of water in the reservoirs but rather physical and technical limitations such as river bottlenecks, i.e., flow limits at specific plants that prevent water from moving through the cascade fast enough to keep all plants running at high output. Moreover, sustained output capability is weakest during winter, precisely when energy droughts are most likely.

Previous studies of environmental hydropower constraints have typically assessed specific regulations on a case-by-case basis, without separating the mechanisms through which they affect hydropower operations. Paper D addresses this gap by distinguishing between energy and flexibility effects of environmental constraints. The analysis reveals two distinct mechanisms (see Section 6.2.1): connectivity measures (bypass flows for fish passage) reduce the total energy available while preserving operational flexibility,

whereas constraints that limit hydropeaking preserve most of the energy but largely eliminate intra-day flexibility. This distinction is important because it means that different types of environmental measures have qualitatively different consequences for the electricity system, and evaluating them requires understanding which dimension of hydropower's contribution, energy or flexibility, is affected.

Taken together, the analyses in Papers C and D illustrate two specific ways in which technical and regulatory constraints limit what hydropower can deliver: physical bottlenecks limit the sustained output level, and environmental regulations can reduce either the available energy or the operational flexibility, depending on the type of measure. These are examples of how constraints shape hydropower's operational capabilities; other dimensions, such as ramping capabilities over different timescales, remain to be systematically evaluated.

7.1.3 RQ3: What are the electricity system implications of regulatory constraints on hydropower?

Previous system-level assessments of environmental hydropower regulation have generally relied on exogenous electricity prices, which cannot capture how reduced hydropower availability alters the merit order and induces compensating responses from other generators. Moreover, no previous study had examined how the economic burden of such regulations is distributed across market actor groups. Paper D addresses both gaps by using endogenous price formation in a multi-country dispatch model and explicitly tracking the distribution of costs across consumers, hydropower producers, other generators, and transmission system operators.

Perhaps the most counterintuitive finding is that, in the current Northern European electricity system, the loss of energy from connectivity measures is more costly in aggregate than the loss of flexibility from hydropeaking constraints (see Section 6.2.1). This runs counter to the common emphasis on hydropower's flexibility value in the energy policy debate. The explanation is that the current system contains sufficient alternative flexibility resources to partially compensate for reduced Swedish hydropower flexibility at limited additional cost, whereas lost energy must be replaced by more expensive thermal generation. This ranking could shift as the system evolves toward higher wind and solar shares and less thermal backup.

A second important finding concerns the distribution of costs. The economic burden of environmental constraints falls primarily on hydropower producers in the constrained regions, while consumers face only modest price increases and generators in neighboring regions can benefit from

higher prices. This geographical and sectoral concentration of costs is relevant for policy design: even when the aggregate system cost increase is moderate, the concentrated losses may affect the political feasibility of implementing environmental measures.

The analyses also show that the tested environmental scenarios, which represent meaningful ecological improvements, impose electricity system costs that are far below the cost of eliminating hydropower's storage and flexibility functions entirely. These cost estimates, and the method used to derive them, are directly relevant to the assessment of environmental quality standards (*miljökvalitetsnormer*) within the Swedish water management process described in Section 4.4. The WFD requires that exemptions from environmental targets be justified by demonstrating that the costs of achieving them are disproportionate to the benefits (see Section 4.4), and quantifying the electricity system cost of specific environmental measures is one component of that assessment. The implications for the regulatory process are discussed further in Section 7.4.

7.1.4 Cross-cutting contribution: the models

Beyond the answers to the three research questions, a central contribution of this thesis is the development of the FORSA and RAPID models themselves. Both were developed as part of this thesis work to address gaps in available modeling tools identified in Chapter 5. FORSA (Flow Optimization for River Systems Analysis) is a hydropower scheduling model that represents individual plants and turbines at high technical detail, with a flexible system for specifying plant-specific environmental constraints. FORSA was motivated by the absence of detailed hydropower models capable of running at hourly resolution over a full year; prior nonconvex models in the literature were limited to time horizons of two weeks or less (see Section 5.2.2). RAPID (River And Power System Integrated Dispatch) is an electricity system dispatch model covering 19 bidding zones across 11 countries, with FORSA embedded as its hydropower module; it can also be configured as a capacity expansion model. RAPID was motivated by the lack of an openly available model combining plant-level hydropower detail with a multi-country electricity system context (see Section 5.3). The code is not publicly available at the time of writing, but the modeling approaches are documented in Papers B and D and in Chapter 5.

Together, FORSA and RAPID connect the hydropower-focused research questions in this thesis: FORSA provides the basis for examining trade-offs between computational effort and accuracy in hydropower modeling and for the sustained output analysis, while RAPID, with FORSA embedded as its hydropower module, provides the energy system context for evaluating

environmental constraints with endogenous price formation and system-wide interactions.

Since the appended papers, RAPID has been extended to cover Norwegian and Finnish hydropower at detailed resolution, which is the configuration used for the dispatch model comparison in Section 5.3. FORSA has also been adapted for use by the Swedish Energy Agency for assessing the effects of environmental measures on hydropower production and flexibility.

7.2 Method reflections

The analyses in this thesis are based on techno-economic optimization models that minimize system cost subject to technical and regulatory constraints. As discussed in Section 2.3, the results describe what is technically achievable at what cost under the specified conditions, not what will happen. Two assumptions are particularly consequential for interpreting the results: perfect markets and perfect foresight. The section concludes with a discussion of model validation.

7.2.1 Perfect markets

The perfect market assumption means that all actors are price-takers with competitive behavior, no transaction costs, and no barriers to trade across bidding zones beyond the specified transmission capacities. In the optimization models, this is equivalent to dispatching all generators to minimize total system cost (see Section 2.1). The assumption is most consequential for Papers A and D, which optimize entire multi-region systems with endogenous price formation: perfect markets implies that *all* generators across all regions are price-takers with perfect information and that trade between regions is frictionless up to the specified transmission capacities. The system cost minimum found by the model then corresponds to the competitive market equilibrium, and the resulting costs represent a lower bound on what would be achieved in practice: in Paper A, the cost-optimal capacity mix assumes idealized market conditions, and in Paper D, the cost of environmental constraints reflects the most efficient possible compensation by other generators and regions. Imperfect markets would reduce this efficiency, meaning that the models likely underestimate actual costs.

7.2.2 Perfect foresight

Perfect foresight means that the model has full knowledge of future inflows, demand, and wind and solar generation when making all dispatch decisions,

and operators never make suboptimal decisions due to uncertainty. The results therefore represent what is achievable under complete information, not predictions of how the system would actually perform. Uncertainties are particularly consequential for hydropower scheduling, where reservoir management requires forward-looking decisions over horizons spanning weeks to years: whether to store or release water depends critically on expectations about future inflows and electricity prices. As illustrated in Figure 4.1, Nordic hydropower reservoirs routinely shift tens of TWh between years, and how much water is stored or released in a given year is only partially explained by inflow variations. Thus, uncertainty affects not just short- or medium-term dispatch choices, but strategic water management over multi-year horizons. In practice, operators must maintain safety margins against the risk of reservoir levels breaching their upper or lower regulation limits due to incorrect inflow forecasts. Electricity prices are equally difficult to forecast over longer horizons, since they depend on generation technologies with other uncertainties (for instance variable wind and solar generation and nuclear generation subject to unplanned outages), and uncertain demand, all across an interconnected system. Suboptimal timing of production relative to price developments means that hydropower's stored energy is not always deployed when it is most valuable, and more expensive generation must compensate for the difference. Both effects lead to more conservative reservoir strategies than the deterministic optimum, and to higher total system costs than the model results suggest. Belsnes et al. [86] show that a stochastic hydropower model, compared to a deterministic, tends to shift production more toward the present rather than saving water for later, because deferring storage to an uncertain future is riskier than using water when it is available.

For Paper B, the assumption contributes to the discrepancy between modeled and historical production profiles (root-mean-square deviations of 23 to 36% of installed capacity), since real operators face uncertainty that the model does not represent. For Paper C, the sustained output estimates are upper bounds: the model plans water releases across the entire cascade knowing exactly when the high-demand period will occur and how long it will last, whereas a real operator facing an unfolding energy drought would manage reservoirs more cautiously. For Paper A, which uses a single-year capacity expansion model, perfect foresight means that the system is perfectly dispatched with no inefficiencies due to uncertainty, likely underestimating the capacity needed in a real system where planners face uncertainty. However, the comparative conclusions depend on relative differences between scenarios rather than on absolute cost levels, limiting the practical impact of this bias. For Paper D, the consequences of perfect foresight over a multi-year horizon are discussed below.

Multi-year horizons amplify the foresight problem

The inter-annual regulation capability of Nordic hydropower (see Section 4.1) means that meaningful analyses often require time horizons longer than a single year. Stochastic models that retain detailed hydropower representation in the optimization, such as FanSi [98], are limited to about one-year rolling horizon because the combination of plant-level detail, within-week chronology, and stochastic scenarios makes longer horizons computationally intractable. Aggregated stochastic models such as EMPS [32] can handle multi-year horizons by using weekly resolution and aggregated hydropower, but at the cost of the temporal and physical detail needed to capture, for example, hydropeaking constraints. In Paper D, we observed the need for multi-year horizons to allow for inter-annual balancing, which motivated running three consecutive years rather than separate single-year optimizations. RAPID's deterministic formulation makes multi-year runs computationally feasible, which is an advantage for capturing inter-annual regulation. However, three years of perfect foresight means that the model knows all future inflows and demand, and can shift water between years with a precision that no real operator can achieve. This leads to overly optimized hydropower production, underestimated use of flexibility from other generation technologies and flattened electricity prices. This effect is strongest with aggregated hydropower representations, where the model has full flexibility to trade water against the terminal value. With the detailed representation, physical constraints on individual plants distribute water use more realistically across hours, partially mitigating the problem (see Section 5.3.5).

Consequences for electricity prices

A consequence of deterministic optimization is that modeled electricity prices become unrealistically flat in hydropower-dominated regions, because the model distributes water to even out price fluctuations with perfect information. Nycander and Söder [33] observe this in a deterministic Nordic dispatch model, and the same effect is evident in Section 5.3. The detailed hydropower representation introduces substantially greater price variation than the aggregated one, but the model remains deterministic, and modeled price variation is still lower than historical price variation. In reality, forecast errors, unplanned outages, and the uncertainty premiums embedded in real market prices create variation that a deterministic model cannot reproduce.

7.2.3 Validation

As discussed in Section 2.3, even though the analyses are exploratory, validation is important for establishing that the models capture the relevant mechanisms well enough for the direction and relative magnitude of effects to be credible.

In Paper B, modeled production profiles are validated against one year of historical data for the Skellefte river. The resulting discrepancies (root-mean-square deviations of 23 to 36% of installed capacity) are attributable to the deterministic assumption discussed above, to the simplified market representation (only the day-ahead market is modeled), and to technical factors such as scheduled maintenance and unplanned outages, which reduce plant availability in reality but are not represented in the model. The work in Paper C exposed a limitation of validating models only against historical data. The model reproduces reasonable production profiles under historical conditions, but when used to investigate energy droughts through extended periods of high prices, the initial results showed unrealistically high sustained output, achieved by spilling enormous water flows at bottleneck points in the rivers. This revealed a missing model assumption: maximum flow limits, which was subsequently corrected. This error would not have been detected through validation against historical data, because under historical prices there was no incentive to push water through the bottlenecks at such rates. Validation against historical data can thus miss model errors that only manifest under novel conditions; in this case, the error was found through scenario analysis and validation of detailed results by discussion with hydropower operation experts.

For the RAPID electricity system model, used in Paper D and in the dispatch model comparison in Section 5.3, validation against historical data is both possible and important, since the baseline scenario in the analyses represent today's system. Systematic validation against historical generation and prices is in progress for Paper D, and will be presented before submission. Average generation volumes can be reproduced reasonably well, but reproducing historical price levels and price dynamics is challenging: the electricity price flattening discussed in the previous subsection is specific to this type of deterministic system model, and simplifications in the transmission representation also affect price formation across bidding zones. The scenario results in Paper D, i.e., the effects of environmental constraints that have not yet been implemented, cannot be validated against observations. Establishing that the model reproduces the baseline system reasonably well strengthens confidence that the mechanisms driving the scenario differences are correctly represented. Further confidence can be gained through sensitivity analysis and by comparing results with other studies in the literature.

7.3 Facts, values, and the researcher's role

The decision of how to regulate hydropower is not a purely techno-economic question. It involves a tension between two environmental objectives: decarbonization of the electricity system, which benefits from flexible hydropower, and the protection and restoration of aquatic ecosystems and biodiversity, which requires constraining hydropower operations. Resolving this tension requires weighing costs and benefits that are measured in different units and valued by different groups in society depending on their perspectives, and is fundamentally a question of priorities.

Consider the bypass flows analyzed in Paper D. A bypass flow of 5 m^3/s at all Swedish hydropower plants reduces annual hydropower production by approximately 3 TW h and increases system costs by approximately 236 M€/yr. These are quantifiable consequences. Whether this cost is acceptable in exchange for restoring connectivity for migratory fish in Swedish rivers is a value judgment that depends on how one weighs ecological restoration against electricity system costs. People who hold a "strong sustainability" perspective, in which ecosystem services cannot be substituted by man-made capital, are likely to value ecological restoration more highly than those who hold a "weak sustainability" perspective, in which such substitution could be considered more defensible [118].

Pielke [119] distinguishes four idealized roles a researcher can take when communicating results in policy-relevant fields. Two of them, the *pure scientist* who produces knowledge without regard for its application and the *science arbiter* who answers specific factual questions, can be sufficient to guide action when there is broad value consensus and the scientific evidence points directly toward a course of action. The hydropower regulation question is not such a case: as illustrated above, the same facts can support different conclusions depending on one's values, and no amount of additional scientific evidence can resolve the disagreement. In situations of value disagreement, the two remaining roles become relevant. An *issue advocate* combines factual knowledge with a normative standpoint to argue for a particular outcome. An *honest broker of policy alternatives*, by contrast, avoids imposing a normative standpoint and instead seeks to expand the range of options available to decision-makers, connecting scientifically grounded alternatives with the decision-makers' own values and leaving the choice to the democratic process.

This thesis and the appended papers provide factual input to a decision-making process in which the fundamental value judgments have, to a considerable extent, already been made by political and regulatory institutions. The EU Water Framework Directive establishes that good ecological status is the default objective, that exemptions require demonstrating disproportionate

costs, and in Sweden, the water authorities apply a threshold where costs exceeding twice the estimated benefits are deemed disproportionate (see Section 4.4). Within this institutional framework, the thesis contributes one specific piece of the factual basis: the electricity system cost of environmental measures on hydropower. In the terminology of Pielke [119], this places the work closest to the honest broker role, providing quantitative input that connects to the values and priorities already embedded in the regulatory framework, without advocating for a particular outcome.

Even within this framework, however, the factual basis is far from complete. The electricity system cost quantified in Paper D is only one component of the total cost of environmental measures. Direct implementation costs, such as constructing fish passages and bypass channels, are separate and are not addressed here. On the benefit side, monetizing the ecological gains from restoring river connectivity or reducing hydropeaking is inherently difficult: ecological benefits are site-specific, often non-monetary, and their valuation depends on the ethical framework applied. Furthermore, both costs and benefits unfold over long time horizons, raising questions about discounting and intergenerational equity that have no purely technical answers.

I believe that being transparent about these boundaries, about what the analysis covers and what it does not, and about the distinction between factual findings and the value judgments needed to act on them, is important for the credibility of the research and for the quality of the public debate.

7.4 Policy implications

The policy implications discussed here concern the findings from Papers C and D on hydropower's operational capabilities and the system-level effects of environmental regulation. The implications of hydropower modeling detail from Paper B and Section 5.3 are methodological in nature and were addressed in Section 7.1.1 and Section 7.1.4.

7.4.1 Informing the permit revision process

Sweden and other countries are undergoing a comprehensive process of revising environmental permits for all hydropower plants (see Section 4.4). The analyses in this thesis provide quantitative input that is directly relevant to this process in several ways.

First, the energy-versus-flexibility distinction identified in Paper D provides a useful framework for evaluating different types of environmental measures. Connectivity measures (bypass flows) and hydropeaking constraints affect the electricity system through fundamentally different mechanisms,

and their costs differ accordingly. Knowing that connectivity constraints primarily reduce energy while hydropeaking constraints primarily reduce flexibility allows regulators to anticipate the type of electricity system consequences for different categories of measures.

Second, the modeling approach used in Paper D, which quantifies the electricity system cost implications of specific environmental measures, could contribute to the development of methods for cost-benefit assessments within the Swedish water management process. The EU Water Framework Directive requires that exemptions from environmental targets be justified by demonstrating that the costs of achieving them are disproportionate to the benefits (see Section 4.4), and quantifying the electricity system cost component is one part of that assessment. The approach demonstrated here, combining plant-level hydropower modeling with system-wide dispatch optimization, provides one way to estimate this component for different types and magnitudes of environmental measures.

Third, the finding that a bypass flow of approximately 2 m^3/s at all modeled facilities would stay within the Swedish government's target of at most 1.5 TW h annual production loss provides a concrete reference point for the regulatory process.

7.4.2 Upper flow limits and energy droughts

The discussion of how environmental permits affect hydropower has largely centered on minimum flow requirements and ramping restrictions, which as shown in Paper D have measurable effects on electricity system costs. Maximum flow limits have received less attention in this context. Yet as Paper C demonstrates, river bottlenecks, where the maximum permitted or physically possible flow at individual plants is lower than at plants upstream or downstream, are the primary constraint on hydropower's ability to sustain high output during prolonged high-demand periods. For sustained output capability during energy droughts, upper flow limits are the binding constraint, not minimum flows. If the electricity system evolves toward higher wind and solar shares and greater reliance on hydropower during extended low-wind or low-solar periods, upper flow limits could become increasingly important also from a system cost perspective. If future systems place greater demands on sustained hydropower output, upper flow limits at identified bottleneck sites may warrant attention in the permit revision process alongside the more commonly discussed minimum flow requirements.

7.4.3 Distributional considerations

As discussed in Section 7.1.3, the economic burden of environmental measures on hydropower is not spread evenly across the electricity system. How the costs are distributed matters, because it affects who has incentives to support or oppose the measures, and ultimately the political feasibility of implementation.

For consumers, the price increases from the tested scenarios are modest. Stated preference studies cited in Paper D suggest that households are willing to pay considerably more than the estimated price increases for environmental improvements in regulated rivers, which could be taken as an indication that the consumer cost is acceptable. At the same time, electricity prices have become a politically charged issue in Sweden and elsewhere in Europe, and even small increases can be difficult to defend politically when they are framed as a cost imposed on households for ecological purposes. Willingness to pay varies across households, and the gap between what people state in surveys and what they accept as actual price increases on their electricity bills is not necessarily small.

The larger cost falls on hydropower producers in the constrained regions, through reduced revenues. This concentrated burden gives affected producers strong incentives to resist stricter environmental permits, which can make the legal proceedings in the ongoing permit revision process (see Section 4.4) slower and more expensive. If the goal is to accelerate the implementation of environmental measures, the distribution of costs is therefore not only a fairness question but also a practical one: how costs are allocated may affect the pace at which the process can proceed.

Other generators, including wind and nuclear producers, can benefit from the higher electricity prices that result from reduced hydropower production and flexibility. For companies with diversified generation portfolios that include both hydropower and other technologies, these gains can partially offset the losses on the hydropower side.

These observations do not lead to a specific policy recommendation, but they illustrate that information on how costs are distributed is a relevant input to the regulatory process, alongside the aggregate cost estimates. Understanding who bears the costs, and how those costs interact with the incentives of different actors, is relevant for anticipating how the regulatory process may unfold in practice.

7.5 Future research directions

Several directions for future research emerge from this work, concerning both method improvements and a better understanding of how model assumptions affect results, as well as transferability of methods and approaches to concrete use in policy and decision-making.

As we saw in Section 7.1.1, detailed hydropower modeling was essential for correctly assessing hydropower's ability to sustain high output during longer time periods. However, sustained output is only one of several operational characteristics that the aggregated representation misses. Systematically evaluating other aspects, such as ramp rate limitations on different timescales, is a natural direction for future research with the FORSA framework. Although FORSA has proven computationally tractable in dispatch models, it is data intensive: the required plant-level data may not be available for all regions, and the Swedish data used in this thesis are subject to confidentiality restrictions that prevent open sharing. Using the detailed model to identify which operational limitations matter most, and then capturing those in simpler representations could make the insights from detailed modeling accessible to a wider range of energy system studies.

A key open question is whether the modest system cost bias from aggregated hydropower representation persists in future systems with higher wind and solar shares, less thermal capacity, and greater reliance on hydropower flexibility (see Section 7.1.1). If the surrounding system has fewer alternative flexibility sources, the overestimation of hydropower flexibility could translate into larger cost errors. A related question is whether the bias also affects investment decisions in capacity expansion models, for example by underestimating the need for batteries or other complementary flexibility. All system-level analyses in this thesis use dispatch models with fixed installed capacities, and embedding detailed hydropower in a capacity expansion model is a natural next step.

The current analyses cover only the day-ahead electricity market at hourly resolution. Hydropower is the dominant provider of frequency containment and restoration reserves in the Nordic system, and environmental constraints that limit ramping capability or daily production range would directly affect the availability of these services. Extending the modeling framework to include ancillary service provision and balancing markets would capture a dimension of hydropower's system value that the current analysis does not address.

Beyond these method-oriented questions, there is a need for standardized methods to quantify the electricity system cost component of environmental measures. The approach demonstrated in Paper D provides one way to estimate such costs, but applying it requires detailed plant-level data and

a full system model. Currently, setting environmental quality standards (*miljökvalitetsnormer*) for individual water bodies in accordance with the WFD requires case-by-case analysis, and no established methodology exists for the electricity system cost component. Developing more systematic and transferable approaches to estimating these costs for different types and magnitudes of environmental measures could make the assessments more consistent, transparent, and accessible to the authorities responsible for the water management process.

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