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Flexible Operation of Water Distribution System for Economic Optimization

Strategies for Energy Efficient Pump Scheduling Reducing Operational Cost and Integrating Demand Side Management

Master's thesis in Sustainable Energy Systems

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Cover: Image created by AI, adobe firefly, visualizing a water distribution system consisting of a pumping station, a storage tank tank, demand curve representation variation in consumption over time and a clock symbolizing temporal flexibility in pump operation and demand management.

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Abstract

As the electrification of society expands and the share of variable renewable energy sources increases in the grid, the interest in exploring new sources of flexibility in the energy system is growing. One potential flexible resource being explored with the potential of supporting the energy system through load shifting and demand response is water distribution systems, as water utilities use a large amount of energy in pump operation. This thesis uses a MILP optimization model to evaluate the operational flexibility of water distribution systems under varying annual conditions in demand and price structures, as well as varying buffer storage requirements. The results show that reducing pump operation through flexible strategies can reduce both energy consumption and operational cost up to 19-30% under varying conditions, with overall savings dependent on seasonal price structures and physical system constraints. However, full participation in fast response flexibility markets is limited due to hydraulic constraints and storage requirements. Overall, water distribution systems show potential for energy optimization through flexible operation, but the practical role in support service action market remains restricted due to physical and operational constraints within water systems.

Keywords: Energy flexibility, Water distribution systems, demand response, load shifting, MILP optimization, renewable energy, pump scheduling, electricity markets

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Moa Karlsson, Gothenburg, June 2026

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis:

WDS	Water Distribution System
BEP	Best Efficiency Point
VRE	Variable Renewable Energy
TSO	Transmission System Operator
FCR	Frequency Containment Reserve
aFFR	Automatic Frequency Restoration Reserve
mFFR	Manual Frequency Restoration Reserve
VAT	Value Added Tax
MILP	Mixed-Integer Linear Programming
MIQP	Mixed-Integer Quadratic Programming
DCC	Disaggregated Convex Combination
SOS2	Special Ordered Sets of Type 2

Nomenclature

Below is the nomenclature of indices, sets, parameters, and variables that have been used throughout this thesis.

Indices

p	Indices for number of pump
t	Index for time step
s	Index for storage units/tanks
n	Index for nodes

Sets

$PUMP$	Set of number of pumps
T	Set of time steps (simulation)
$Storage$	Set of storage unit/tank
N	Set of nodes

Parameters

$resolution$	Time interval between consecutive data points
Δt	Time discretization step (time interval)
l_{min}	Minimum level inside tank
l_{max}	Maximum level inside tank
P_{min}	Minimum pump capacity
P_{max}	Maximum pump capacity
A_s	Cross sectional area of a storage unit/tank
V_{min}	Minimum volume in storage system

T_{buffer}	Required buffer storage duration
Δp	Pressure level
η_p	Pump efficiency
Q_{max}	Maximum flow of pump
Q_{BEP}	Pump flow at best efficiency point
$D_{n,t}$	Water demand
η_p	Pump efficiency
$\gamma_{p,t}^{sp}$	Spot prices
$\gamma_{p,t}^{gu}$	Grid utilization cost
$\gamma_{p,t}^{tax}$	Tax cost
$\gamma_{p,t}^{peak}$	Peak cost
P_{montly}	Highest peak in power operation each month
P_{peak}	Maximal measured power during each simulated day
$P_{previous}$	Previously observed monthly peak
h_0	Start hour of simulation
$l_{s,t}^{ref}$	Reference level profile
$Q_{p,t}^{ref}$	Reference flow profile

Variables

$Q_{p,t}$	Pump outflow at pump p and timestep t
$Q_{s,t}^{in}$	Tank inflow
$Q_{s,t}^{out}$	Tank outflow
$Q_{direct,t}$	Direct flow to the distribution network
$l_{s,t}$	water level at storage unit/tank
$V_{s,t}$	storage volume at each timestep t
$P_{p,t}$	Power consumption at pump p and timestep t
$Cost^{Pump}$	Pumping operation cost
$Cost^{Grid}$	Grid operation cost
$Cost_{ref}$	Operation cost from reference model
$Cost_{flex}$	Operation cost from flexible model
h_t	hours within the timeset T

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1

Introduction

Sustainability targets and upcoming local, national, and European climate and energy goals encourage increased electrification across many sectors in society. As energy systems become more dependent on renewable generation with variable patterns, the need for flexible consumption and production grows. This places greater emphasis on adaptability in electricity demand and supply to efficiently integrate rising loads while maintaining system reliability. As electricity prices have started to fluctuate and power tariff structures are introduced, motivation grows for many utilities to investigate the possibility of controlling their operation more energy efficiently, including the water utility sector [1].

1.1 Background

This section provides background information for the project.

1.1.1 The Transition of the Swedish Power System

Reducing nuclear power capacity in southern Sweden while wind power generation expands in the north will create significant challenges for system balance, particularly in the southern price areas (SE3 and SE4)[2]. Nuclear power provides stable, dispatchable generation and contributes to maintaining the real-time balance between electricity production and consumption. When nuclear power plants are no longer in use, the local power balance becomes more vulnerable, especially during periods of high demand. At the same time, a substantial share of new wind power capacity is being developed in northern Sweden (SE1 and SE2), where demand is comparatively lower. This geographical mismatch between production and consumption increases the reliance on long-distance transmission from north to south. However, the transmission network has limited capacity. When these limits are reached, bottlenecks arise, restricting the flow of electricity to southern regions. Hydropower, which is mostly located in northern Sweden, plays a crucial role in system regulation due to its flexibility and fast ramping capability. Transmission constraints can prevent this regulatory capacity from being fully utilized in the south when regional generation decreases. A larger share of hydropower capacity is used for energy generation rather than reserve and balancing services. This reduces the overall availability of flexible resources for system regulation[2].

When the electricity supply is insufficient in southern Sweden, electricity prices increase. These higher prices function as market signals, indicating scarcity and creating incentives for investment and structural adjustments. Increased transmission capacity to the area, increased production capacity within the area or increased demand flexibility within the area are examples of actions forward to solve the electricity issue. These actions vary in investments and costs. Flexibility actions of already existing infrastructure have the potential to be the most cost-effective ones. Facilities with adjustable electricity consumption, such as water treatment and wastewater treatment plants, can contribute to system stability by shifting or temporarily reducing load during peak price periods. By doing so, they help the regional power balance and support overall grid reliability.[2]

1.1.2 Energy flexibility and grid integration potential

The existing power must adapt as increased electrification of energy demand becomes a reality. The transition toward electrification of energy sectors and the investment in introducing renewable energies are driving the need for distributed energy resources [3]. However, the insertion of renewables into the grid is challenging due to their variable nature. In addition to having to expand the electricity production, the grid has to be operated more effectively for the transition to be both economic and environmentally successful[1]. In order to handle these challenges, the power system has to integrate more flexibility and have the ability to balance fluctuation in both production and consumption of electricity. Energy storage systems, demand-side management and the use of smart networks are technologies that increase in importance [4]. All these solutions have the possibility to improve energy efficiency, support grid stability and enable a higher share of renewable energy sources, while still being able to ensure reliability.

Water utilities are one of many industries that can adapt its consumption patterns to contribute both environmentally and gain economic advantages [5]. One of the most promising and low-cost instruments is demand response, which can reduce the cost of integrating more variable renewable energy generation to the grid [6]. Demand side management, using available energy more flexibly, can be carried out to support the new power system. A flexibility market can be imagined using knowledge of consumption patterns and price conditions, which gives the water utility power to plan pump operation, leading to stops without risking redundancy and safety [1]. Introducing flexible operation inside water utilities that accounts for electricity prices could lead to substantial cost savings. With the implementation of a power tariff, another parameter is added that could further enhance the benefits of flexible operation. From an environmental perspective, moving loads to low-price regions is beneficial, since low-price regions are typically characterized by a high share of renewable power, particularly wind and solar energy. These are technologies with very low marginal costs. Using electricity during these hours aligns consumption with periods of high renewable availability, reducing reliance on fossil-fuel-based generation and lowering associated greenhouse gas emissions.

1.1.3 Challenges in water infrastructure energy use

Most water and wastewater utilities consume a significant amount of electricity to pump both drinking water and wastewater. 90-95% of the total energy consumption comes from water pumps in water utilities, representing the main consumption of electric energy [7]. Currently, pumping is often controlled solely based on pressure and volume, without considering electricity prices[8]. As a result, energy consumption follows the same pattern every day. As the future energy system becomes more volatile and harder to predict due to the increasing share of intermittent renewable power in the market, the ability to control when electricity is consumed will become increasingly important. Optimized pump schedules can offer economic benefits due to variable price patterns, where higher prices are applied during periods of high demand and lower prices during periods of low demand within the same day [7]. The shift in load will allow the water utilities to save both energy and cost.

1.1.4 Trollhättan Energi

In the city of Trollhättan, the water treatment plant is run by Trollhättan Energi. Since the water sector represents a considerable share of electricity use in Trollhättan, it is of interest to investigate if water operations could benefit from flexible operation, but also provide a supporting service to the electricity grid. Adjusting pumping rates to help balance supply and demand and potentially receive economic compensation. Trollhättan is a typical medium-sized Swedish city and is large enough to have complex infrastructure, for example, multiple pumping stations, tanks and a network, while staying within acceptable limits to still make modeling and simulation manageable. The city has one treatment facility, a low reservoir, providing clean water to the entire town. Multiple water tanks, high reservoirs allowing storage possibilities, are vital for flexible operation. Since the city is located close to Göta älv river and the lake Vänern, Trollhättan has a strong connection to water management both historically and infrastructurally, making it a relevant case for research on water system operations and optimization. This can be achieved by examining energy use across water system utilities and collecting data from the electricity network company, which can then be used to evaluate future pricing models for energy consumption. Availability of operational data enables realistic modeling and validation of flexible pumping strategies. The scale and complexity of the water distribution network in Trollhättan provide a balance between realism and model tractability for optimization and flexibility studies.

1.2 Aim

The aim of the project is to evaluate whether pumps for water towers can be controlled flexibly to create an economic benefit, and simultaneously be a support service to the grid. By applying modeling and historical trend analysis, the study investigates different operational strategies based on various curve types. These strategies are used to optimize pumping by filling and releasing water in different patterns. Can the reservoir levels then be controlled with respect to electricity price and power tariffs is the question. The findings will provide a basis for assessing whether investments in flexible operation are justified by the potential economic gains.

1.3 Objectives & Research Questions

Following objectives have been set.

- Develop and validate a model for water tower pump operation.
- To evaluate the potential for flexible operation of water tower pumps to reduce electricity costs.
- To determine how electricity price variations can be integrated into pump control strategies.
- To assess the economic benefits of flexible pumping and power tariff impacts compared to traditional fixed operation.
- To investigate whether flexible pump operation can support grid stability through demand response.
- Provide recommendations for future implementation at Trollhättan Energi and other utilities.

The objectives have been turned into 3 research questions that will be investigated.

1. Can water infrastructure be energy optimized and also used to help balance the electricity demand in society?
2. How much economic benefits of flexible pumping and power tariff impacts is there compared to traditional fixed operation? Is further investments in flexible operation system significant?
3. Does the system size, pump capacity and storage volume affect the economic and support service benefits?

1.4 Limitations

Hydraulic effects in the pump system will be neglected due to complexity. Instead, the pump is seen solely as an electrical load that can be increased or decreased in time. Hydraulic effects cover flows, pressures and the physical behavior of the pump inside the system network. These effects define the operational limits of the pump and determine what adjustments can be made without disrupting system operation. Flow, pressure, resistance in the pipes, pump curve vs system curve, determine what flow the pump requires. Due to hydraulic interactions, the pump's electricity consumption is a function of the pressure and flow conditions across the entire network, not a static power value. Not including hydraulic effects can limit the results, since reducing system pressure can lower electricity consumption. For example, the model may predict that the pump should reduce it electricity consumption by 20%, as lowering the pressure may result in some customers not receiving water. Including hydraulic effects could add an important element for the real implementation of flexible operation. Furthermore, storage losses will be neglected, which will have an impact on the sensitivity of the model.

The company is currently building a new water facility, planned to be in use in 2029. The model will be based on the future planned system and the newly installed pumps, while data will come from the existing system. Since the water storage system will remain unchanged and the capacity of the new pumps is known, this approach is considered acceptable.

Trollhättan only has one water facility to provide the water demand to the entire city. However, this is not always the case in every city. In the largest cities like Gothenburg, two water facilities exist in order to be able to provide water for the entire city. In smaller cities where households are more remote from each other, a few smaller facilities exist. This study will focus on one water facility using one pumping station to feed a storage system for the entire city. This can be a limitation if using the model to compare different system sizes. Instead of being able to answer the profit and gain for different-sized cities, the model may be limited to different sizes of pumps.

2

Theory

In the following sections, relevant theory regarding the water distribution system (WDS) and its infrastructure is covered. Parts of the Swedish electricity system and market structures are described, however, the reader is presumed to have basic knowledge about energy systems and economic contents. The section also assesses the ideas of basic modeling structures.

2.1 Water Pumping and Storage System

A traditional water distribution network is a pressurized system consisting of a water source, water treatment plant, pumping stations, storage facilities, distribution pipes and control devices [9]. The purpose is to deliver clean water from the treatment plant to the consumers while upholding reliability and water quality. A simplified representation can be seen in Figure 2.1.

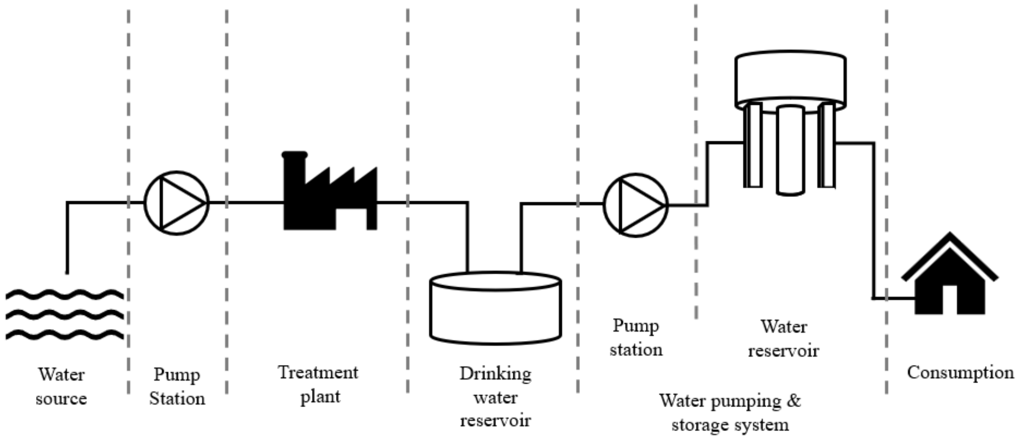


Figure 2.1: Simplified illustration of a typical water distribution system

The cycle begins by collecting water from a source, such as a lake or river. The water is processed in a water treatment plant and pump stations are used to distribute drinking water in the distribution system. Clean water is distributed in the pipe network to deliver water directly to consumers and households, or to fill up storage tanks [6].

2.1.1 Tanks and Reservoirs

Reservoirs and tanks serve similar functions in a water distribution system, however, some differences between them exist. Both storage units represent a large body of stored water for later use [10]. A water storage tank is used to improve the reliability and flexibility of the water supply system. It is a storage unit with limited volume and the amount of water in the tank changes depending on the flow in and out of the tank. Water is stored when the demand is low and supplied when the demand is high, and is a complement to the daily cycle balancing supply and demand [9]. Reservoirs are part of the water distribution network to maintain consistent pressure levels for all customers, to even out consumption variations and act as a reserve in case of outages [9].

2.1.2 Pressure Zones

In water distribution systems, pressure zones exist. A pressure zone is a defined area where the hydraulic pressure is maintained to ensure reliable service [11]. In order to accommodate variation in terrain elevation, different pressure zones can be established in the same WDS. Higher pressure zones supply water to elevated areas and lower pressure zones serve areas at lower elevations. A single pressure level would result in insufficient pressure for the system as a whole, multiple pressure zones often exist within a WDS. Reservoirs and tank storage can be placed in both zones, creating low-level reservoirs and high-level reservoirs. At the waterworks, clean drinking water is stored in low-level reservoirs, which are later used to pump out water into the network. High-level reservoirs are instead storage tanks positioned at a height sufficient for water to be distributed by gravity[9]. To fill the high-level reservoirs, water must be pumped up from the lower-level reservoirs between two pressure zones.

2.1.3 Water Demand Profile

Water demand in a distribution system changes both during the day and over the week. Fluctuations in water usage over the day create a diurnal demand pattern[12]. An example of a demand curve for water can be seen in Figure 2.2.

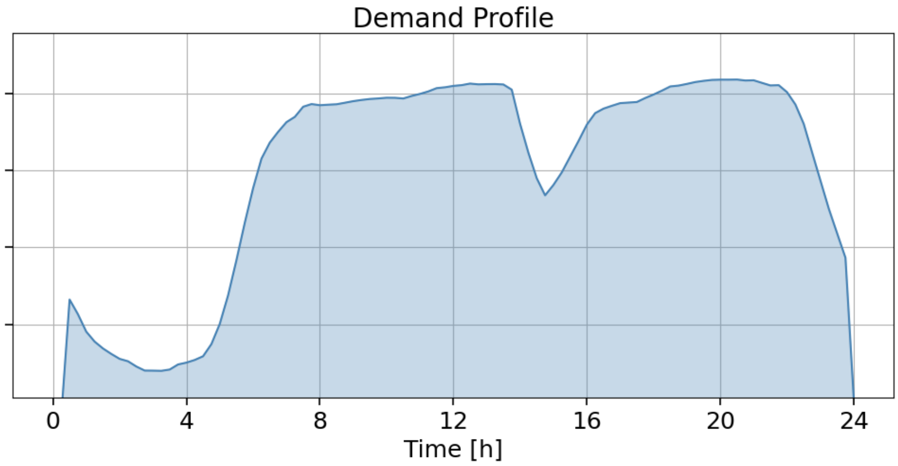


Figure 2.2: Hourly water demand profile smoothed using moving average to represent daily consumption pattern in a WDS

At night, between midnight and 5 AM, most people are asleep, resulting in the lowest demand. During this time, storage tanks are usually filled. Between 6 AM and 9 AM, the morning peak begins, where there is a sharp increase in water due to showers and cooking. Pumps and storage tanks are experiencing higher flow rates. During daytime, 9 AM to 3 PM, water usage usually drops since people are at work or school, but moderate demand still comes from commercial, institutional, and industrial activities. The evening peak begins from 3 PM to 9 PM, this occurs due to people coming home to their households, beginning cooking, laundry, and other household chores requiring water. Water levels in the storage tank are shrinking during this period of the day. Late at night, 9 PM to 12 AM, the demand gradually decreases, preparing to repeat the process the next day. At the weekends, the water use may shift due to morning peaks that may occur later due to different time schedules, as well as the overall consumption can increase since more time is spent at home and less industrial activity.

2.2 Energy consumption in water infrastructure

The largest electricity use for water utilities is the electricity required for the pumps to pump outgoing water from waterworks and pressure increase in the pipeline work [13]. Reservoirs are available to maintain pressure if the electricity supply for pumping is interrupted. This system setup creates a built-in redundancy that allows the system to operate for a limited time without full power input. In future energy systems, the ability to shift, reduce or increase electricity consumption in response to grid conditions will be highly important. Through digital tools that monitor and forecast water usage, combined with the redundancy in the infrastructure, the drinking water system can help provide flexibility to the power grid [4]. Since pumping accounts for the largest share of the total electricity consumption, reducing or postponing pumping could lower operating costs and contribute to improved energy efficiency. How much power that can reach depends on how the pumps are operated, whether they run steadily or vary over time.

There are different types of pump operations used in water distribution systems. The simplest type of pump control is called fixed-speed pumps. Fixed speed pumps either run at full speed when there is demand or are completely stopped. The other type of pump is called a variable speed pump. Variable speed pumps can adjust how fast they run to match the system demand[12]. This type of pumping is used in modern and all new installations since these pumps reduce mechanical stress and wear on the system. Every variable speed pump has a pump curve that describes how a pump performs at a given speed. It described the relationship between flow rate and head, which is the pressure or height the pump can deliver at that pressure[12]. When speed is changed, it affects flow rate, pressure and power. For variable speed pumps, efficiency is of importance because not all operating points are equally efficient based on the pump curve. Electrical energy can not be fully converted into flow. If a pump runs at a poor operating point, it wastes energy, leading to higher costs. Every pump has a Best Efficiency Point (BEP), which is where the pump runs most efficiently, with the lowest energy use per unit of flow and where the least mechanical stress appears. Pump performance starts to deviate when operated away from its BEP [14]. Approximately -30% to +20% of the flow rate at the BEP is described as the preferred operating region for pumps [15]. Operation outside of this region leads to both higher maintenance and operational costs.

2.3 Electricity market and Power tariffs

The Swedish electricity market consists of three main parts. The day-ahead market, the intraday market and the balancing market [16].

2.3.1 Day-Ahead Market

The day-ahead market trades electricity for delivery the next day and is run by Nord Pool, covering the northern and Baltic countries [17]. Most of the electricity is traded in this market. Actors submit bids for each hour of the next day, defining price, quantity and location. The prices are following the merit order principle, meaning the most expensive accepted offer sets the price, and prices are marginal. The price is what is referred to as spot prices. As of 2026, the electricity market has shifted from 60-minutes to 15-minute market time units, in order to accommodate the increased share of variable renewable energy (VRE) [18].

2.3.2 Intraday Market

The intraday market trades electricity closer to the delivery hour [19]. It is helpful to correct forecast errors in production or consumption. There can be several reasons why actors have to change positions, for example, weather changes, unforeseen demand changes, or unexpected amounts or prices. If a wind farm fails to produce its expected amount, a company can buy extra electricity on the intraday market.

Trading consists of both auction and continuous trading. Today, trading volumes are smaller than day-ahead, but as VRE shares increase, they may grow.

2.3.3 Balancing Market

In order to enable reliable and stable electricity production, support services are needed to provide stability to the power system. This is done through the balancing market. The balancing market is run by the transmission system operator (TSO), Svenska Kraftnät, and ensures real-time stability. This cannot be done only through the wholesale market. Some reserves used for balancing are FCR: frequency containment, aFFR: automatic frequency restoration and mFFR: manual frequency restoration, which is the main balancing tool [20]. mFFR handles imbalances and congestion, bids are submitted up to two weeks ahead and can be adjusted up to 45 minutes before delivery. Marginal pricing is used and only balancing responsible parties can submit bids. There is a minimum bid size of 10 MW on the mFRR market.

2.3.4 Flexible operation and demand response

Flexibility in the electricity market means the ability to adjust power production or consumption to balance supply and demand. Sweden has a lot of hydropower, which supports balancing services and historically, flexibility has not been problematic. However, when more VRE is introduced to the grid, due to its low marginal costs, it can result in extended periods of negative or near-zero marginal electricity prices. Especially during low net load events[21]. Most common flexible resources today, e.g., hydropower, batteries and gas turbines, are used to earn money by selling electricity through different markets when the system is lacking [4]. For example, when electricity prices are high, a hydropower plant can increase its generation and sell the power to the balancing market and is rewarded. Water utilities are not generators, but instead electricity consumers. However, flexibility and the electricity market are important in this aspect as well, but they work differently. Instead of earning revenue, the system reduces electricity cost by shifting when electricity is consumed. Due to the water distribution system often containing storage tanks or reservoirs, temporal decoupling between electricity consumption through pumping and water demand is allowed. Pumps can run during periods of low demand and low pricing, which creates load shifting and demand side flexibility.

Since electricity prices are determined one day in advance, operators have the opportunity to schedule run time when electricity is cheap and store water in tanks, in order to meet demand later. This creates savings and the market value of flexibility depends on the spot price and price volatility [21]. Higher price volatility creates greater cost-saving potential. Intraday market allows for adjustment when water demand forecast changes due to leakage, or when electricity prices change, pumping can be shifted again and respond to updated price signals. Theoretically, demand response and load reduction can contribute to the balancing market. During a grid shortage and high prices, pumping can reduce consumption. Often, large capacities are required to participate in this market and water utilities can be too small individually. However, aggregates combining multiple water systems could together be an asset to the flexibility market.

Demand response refers to when electricity users willingly adjust how much power they consume from the grid due to encouragement by some form of incentive, for example, price changes or financial rewards[22]. Being flexible with electricity consumption can be about cost-saving opportunities by avoiding peak prices, but can also include revenues by bidding the available flexibility onto a flexibility marketplace. Flexibility used for cost savings is often called implicit demand flexibility, while revenue-related operation is called explicit demand flexibility.

The ability to have flexible operation will be of high importance in order to avoid electricity costs not only for utilities, but also to try to reduce the electricity cost for users in the future. Flexible production, flexible demand and energy storage will only grow from today as most of the energy resources introduced through the electrification transition are considered behavioral loads, which enables the possibility for flexible operations. Shifting and reducing electricity consumption during certain times will be of importance to avoid peak load and maintain grid stability, but being able to increase electricity consumption to take advantage of when renewable electricity production creates abundance in the grid is of equal importance [4].

2.3.5 Consumer cost

The cost of the electricity system for the customer can be divided into three parts. The first being the electricity trade cost, including spot prices through day-ahead prices on the Nordpool marketplace. This gives flexible opportunities to the actors to avoid consuming electricity during high prices. The second one is the electricity grid cost, which is the cost of the grid transmission. This cost is company-specific for each grid company and therefore varies a lot depending on location and size. Taxes and government fees are the third part, covering energy tax, value-added tax (VAT) and additional charges from the state. During the year 2026, all electricity grid companies must introduce a power tariff. Before, this cost only existed during the coldest days when the grid was used to almost max capacity. This is an important tool for the electrification to be sustainable and to utilize most of the existing electricity grid[1].

2.3.6 Power tariff

The power tariff is a newly developed pricing model that encourages consumers to shift electricity use to off-peak hours, helping balance the grid, reduce cost, and support a reliable and sustainable energy supply [23]. The amount of power in kW that the utility has drawn from the electricity grid at the same time is the basis for the power tariff. The goal is to shift demand during peak hours. Peak hours are when the grid is heavily loaded due to many users using a large amount of power from the grid simultaneously. The pricing model does not generate any revenue, but is simply to redistribute electricity usage, favoring utilities that spread their usage more during off-peak hours.

2.4 Optimization techniques in energy systems

Most real-world systems are nonlinear, meaning linearization is needed. In detail, most power systems and mass balances include relationships of multiplication, squares and trigonometric functions when losses and all equations of physics are considered. These cannot be solved directly with linear programming and approximation techniques using linear equations are a powerful tool [24].

The meaning behind optimization is to find the best decision while respecting given constraints. This can be to either minimize cost or maximize profit. There are several different optimization techniques. One widely used method in optimization of energy systems is called Mixed-Integer Linear Programming (MILP).

2.4.1 Mixed Integer and Linear Optimization

Linear optimization is when the requirements of a model are represented by linear relationships to determine the objective. MILP is a special case of linear optimization where the model uses linear relationships, while some variables must be integers, whole numbers. Integer variables are needed because in real systems, some decisions are discrete, for example, if a pump is running or not, on or off. When binary variables become integrated in the model, it is often when a MILP approach is required instead of using linear programming[25].

The general standard MILP formulation is described in equation 2.1 [26].

$$\begin{aligned} \min_{x} \quad & c^T x \\ \text{subject to} \quad & A_{\text{ineq}} x \leq b_{\text{ineq}}, \\ & A_{\text{eq}} x = b_{\text{eq}}, \\ & 1 \leq x \leq u, \\ & x_i \in \mathbb{Z}, \quad \forall i \in \Upsilon. \end{aligned} \tag{2.1}$$

The formulation consists of

Objective	Minimize total cost:	$c^T x$
Inequality constraints	Physical or operational limits:	$A_{\text{ineq}} x \leq b_{\text{ineq}}$
Equality constraints	Conservation laws:	$A_{\text{eq}} x = b_{\text{eq}}$
Bounds	Min/Max constraints:	$1 \leq x \leq u$
Integer variables	on/off decisions:	$x_i \in \mathbb{Z}$

In order to solve a MILP, an optimization software is required, referred to as a solver. A solver can be described as an algorithm engine that systematically searches for an optimal or near-optimal solution for the objective function, while still accounting for constraints. The MIPgap or tolerance gap is a parameter that controls the minimal quality of the solution [27]. During an optimization, the solver searches for two values, the best objective, referring to the objective value for the best known feasible solution, and the best bound, which represents the objective value of the relaxed problem, for example, the lower bound for a minimization problem[28]. Tolerance gap is calculated as in Equation 2.2.

$$Tolerance\ gap = \frac{|best\ objective - best\ bound|}{|best\ objective|} \tag{2.2}$$

A lower value of the tolerance gap generates a more accurate solution. For example, in a minimization problem, if the best feasible solution cost 100 SEK and the best theoretical bound is 99 SEK, the gap is 0.01 or 1%. A complex model can be difficult to solve and take a great amount of time to solve completely. In most solvers, the tolerance gap is set to 0.01 as the default mode [27]. However, if a problem is taking too long to solve to perfection, the tolerance gap can be set manually to a higher value and force the model to find a solution within that tolerance.

2.4.2 MILP in water distribution system

Connecting MILP to water systems contains the explained building blocks of sets, variables, constraints and objective function. Capacity and tank limits are described using inequality constraints. Water levels in tanks are described using mass balances and equality constraints. Maximum and minimum flows and pressures are bounds in the system and integer variables are used as on/off decisions for pumps. The cost to operate the pumps becomes a variable energy cost or tariff, which is the objective to optimize the pumping cost.

The mathematical function must be linear in order to use MILP optimization. However, there are several relationships in water distribution systems that are not linear. Pump efficiency curves or head flow relationships. Piecewise linearization is a way to approximate in order to allow the model to solve, even if reality is nonlinear [24]. A common computer program used in water distribution network simulation is called EPANET. EPANET is a program used for simulation of water and hydraulic behavior in pressurized pipe networks [29]. The software includes different hydraulic models to represent real system behavior, including functions for head losses in pipes. These equations allow the simulation to account for frictional losses, which affect flow and pressure levels in the system network. EPANET models, therefore, provide a realistic assessment of system performance compared to simplified flow assumptions.

3

Method

The method used in this work was developed in order to determine if future actions in flexibility will be worth the investment, not only from the utility's economic perspective, but also from a system perspective, as it can contribute to grid optimization, as enhanced flexibility supports a more efficient utilization of the power system and overall system balancing. This section aims to describe the method in its entirety. AI such as ChatGPT and Copilot has been used in this project for troubleshooting code, grammar and spelling checks.

3.1 Method Overview

Mixed Integer Linear Programming (MILP), which is the optimization method used in this work, is a well-established approach for modeling energy systems and flexibility optimization [30]. MILP provides a globally optimal solution, given the model formulation, which makes it suitable for quantifying the economic value of operational flexibility. The objective function can be expressed linearly as $power \times price$. However, both objective and constraints must remain linear. Pump efficiency curves and flow–pressure relationships are typically nonlinear, implying that power consumption is often quadratically related to flow rate, requiring other more complex optimization methods. A limitation of the MILP approach is its reliance on a linear representation of system dynamics, which may require simplifications of nonlinear pump characteristics and hydraulic behavior.

Since the aim is to explore the future possibility of implementation and motivate continued research, this limitation is addressed by adopting reasonable linear approximations that preserve the overall system behavior while maintaining practical solvability. As the primary objective is to evaluate the economic potential of flexibility rather than to model detailed hydraulic dynamics, the degree of simplification is considered sufficient for the scope of this study. Figure 3.1 illustrates a block scheme of the optimization method.

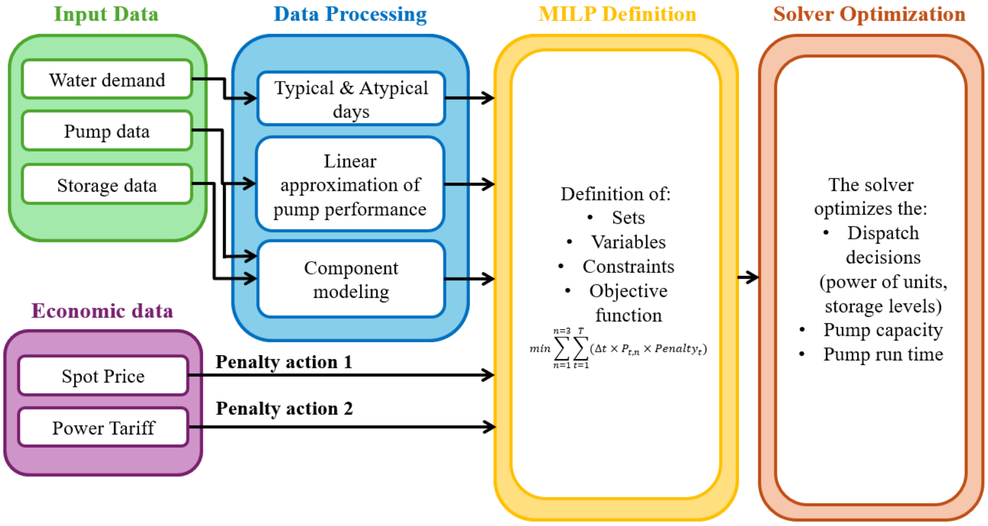


Figure 3.1: Block scheme of modeling optimization approach

Technical input data and demand profiles, together with economic price signals, will serve as inputs to the optimization model. Following data processing, the sets, variables, constraints and the objective function are described within the MILP definition. Finally, an optimization solver is used to solve the problem and generate the optimal operational schedule and corresponding results.

3.2 Software & Data Collection

Pyomo is an open source software package used to formulate, solve, and analyze optimization models [31]. It is Python-based and in combination with Visual Studio Code, the optimization model could be built following a clear structure and flexibility for data handling and model development. In this work, the solvers selected for solving the MILP models were HiGHS and Gurobi. These solvers are efficient and reliable for large-scale linear and mixed integer optimization problems. To support the company's future ambitions to continue the study and ensure reproducibility using open-source tools, HiGHS was primarily used as the default solver, while Groubi was applied during the study in order to reduce computation time and enable faster solutions of large problems. Real operational data were obtained from the SCADA system, a software used to monitor, gather and control industrial processes, in order to represent pump operation, water levels, and demand patterns, ensuring that the optimization results reflect realistic system behavior.

3.3 Mathematical Formulation of the Optimization Model

In this section, the mathematical formulation of the model setup is described.

To represent the physical behavior of the system, the problem consists of both linear and nonlinear equations. In order to reformulate the problem as a MILP model, linearization was applied. Perfect knowledge of the demand without considering unexpected outages was assumed. It was assumed that pumps could be turned off at different times throughout the day. However, no explicit constraint for how these start and stop cycles appeared was set.

The dataset for electricity price had varying resolution across months, since electricity pricing at a quarterly resolution was introduced in October 2025. The timestep in the model was defined as

$$\Delta t = \frac{1}{\text{resolution}},$$

where the resolution is defined as the number of time steps per hours. Thus

$$\Delta t = \begin{cases} 1, & \text{hourly data} \\ 0.25, & \text{quarter data} \end{cases}$$

The demand profile input data had a minute resolution. To align the demand profiles with the price signals and to reduce the computational load of the model, the data were resampled to a 15-minute resolution by averaging every 15 consecutive data points.

3.3.1 Mass Balance Constraints

The mass balance equation is given by equation 3.1

$$\sum_{p \in PUMP} Q_{p,t} - \sum_{s \in Storage} Q_{s,t}^{in} - Q_{direct,t} = \sum_{n \in Nodes} D_{n,t} - \sum_{s \in Storage} Q_{s,t}^{out} - Q_{direct,t} \quad (3.1)$$

where $Q_{p,t}$ is the flow rate leaving the reservoir from each pump, $Q_{s,t}^{in}$ and $Q_{s,t}^{out}$ are the inflow and outflow of the tank storage. $Q_{direct,t}$ is the flow that is directly pumped out in the network without passing through storage. The $D_{n,t}$ represents the demand in the network at time t. Figure 3.2 gives a visual overview of the mass balance in the WDS.

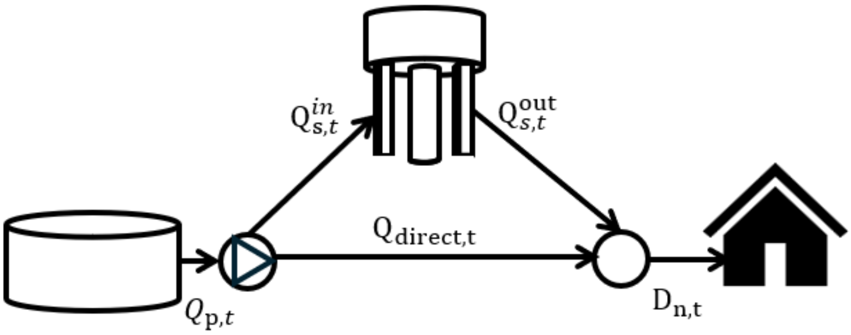


Figure 3.2: Mass balance representation of a water distribution system

Each tank in the model was assumed to have the geometry of a cylinder. Tanks have finite storage volume and the cross-sectional area limits flow rates. To describe the water level inside the tank, Equation 3.2 is used.

$$l_{s,t} = l_{s,t-1} + \frac{Q_{s,t}^{in} - Q_{s,t}^{out}}{A_s} \Delta t \tag{3.2}$$

Where $Q_{s,t}^{in}$ and $Q_{s,t}^{out}$ are the flow rate into and out from the tank and A_s is the cross-sectional area of the tank. Level is then used to calculate the volume using Equation 3.3.

$$V_{s,t} = l_{s,t} \times A_s \tag{3.3}$$

Tanks have a finite storage volume and the height is limited by a minimum and maximum value for each tank, explained in Equation 3.4.

$$l_{min} \leq l_{s,t} \leq l_{max} \tag{3.4}$$

Reservoirs have an infinite source of water and due to the large volume of water, the variation of water level inside is neglected.

The water level inside the tank is constrained by the physical height of the tower, which defines the maximum level (l_{max}). In addition, a minimum safety level is imposed based on demand requirements to ensure sufficient buffer capacity for handling periods of high demand or in case of leakage. To determine this minimum level (l_{min}), a buffer volume covering the most critical loads was identified. This was done by sorting the demand input, choosing the K largest values. Where K was defined using T_{buffer}, the buffer time in hours, the system was dimensioned to always be able to cover loads.

$$t = 1, 2, ..., N \tag{3.5}$$

$$T_{buffer} = [4, 12]\ hours \tag{3.6}$$

$$Sort : D_{(1)} \geq D_{(2)} \geq\ ...\ D_{(N)} \tag{3.7}$$

$$Select : \{D_{(N-K+1)}, ..., D_{(N)}\} \tag{3.8}$$

$$where : K = T_{buffer} \times resolution \tag{3.9}$$

The minimum volume required was then calculated using equation: 3.10.

$$V_{min} = (\sum_{i=1}^{K} D_i^{top}) \times \frac{3600}{resolution} \tag{3.10}$$

A safety margin for T_{buffer} was set to 8 hours, based on utility practice and engineering judgment. This parameter was later changed in order to study the impact of the minimum water level on cost.

3.3.2 Pump Constraints

The general pump equation was described as:

$$P = \frac{\rho g Q H}{\eta} \tag{3.11}$$

P is the power [W], where $\rho g H$ is the head related pressure, or pressure level. For a variable speed pump, the relationship between flow Q and head H is nonlinear, and the pump curve varies with rotational speed. In this work, H is assumed constant, resulting in a constant pressure level in the system. Under this assumption, the pump power P becomes linearly proportional to the flow rate. The pump must provide sufficient head to overcome the elevations to the highest point within the pressure zone.

The linearized power equation used in the MILP model is described in the equation 3.12

$$P_{p,t} = (\Delta p \times Q_{p,t})/\eta_p \tag{3.12}$$

where Δp is the highest pressure head in the system, $Q_{pump,t}$ is the flow rate from the pump, and η_{pump} is the efficiency.

Each pump is defined by a minimum and maximum capacity, defined in Equation 3.13

$$P_{min} \leq P_{p,t} \leq P_{max} \tag{3.13}$$

In a water distribution system, there is a head loss caused by friction along pipes. This head loss was neglected in this work since hydraulic losses were left outside the scope. However, to properly model variable speed pumps, the efficiency curve based on the flow outlet was considered using the defined pump curve.

The pump power equation is adopted into a linear model using a piecewise linear approximation based on discrete operating data. In Pyomo, a piecewise linear function can be implemented using the Piecewise component. q^k_{pump} is the flow breakpoints, spanning the expected operating range of each pump. Efficiency values are specified at each breakpoint. Pump power is then calculated at each breakpoint using equation 3.12, where efficiency is treated as a function of flow. The pump power was expressed as a convex combination of breakpoint values.

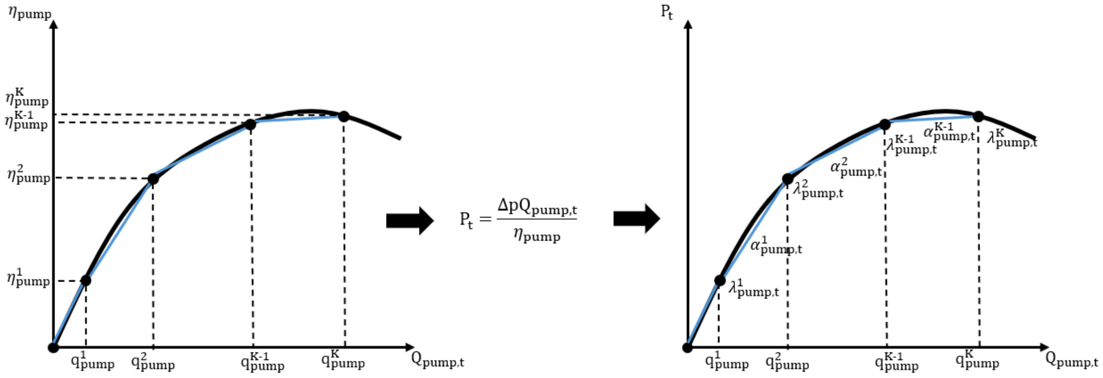


Figure 3.3: Piecewise linear approximation of pump efficiency and power consumption

To incorporate the non-linear curve into the MILP framework, the curve was approximated using Disaggregated Convex Combination (DCC). The DCC is a simulation of the Special Ordered Set of type 2 (SOS2) structure. The SOS2 uses straight-line segments to approximate nonlinear functions. The SOS2 constraint ensures that the solution lies between two neighboring breakpoints, resulting in a single segment of the piecewise linear function being used. When only two adjacent breakpoints are allowed to be non-zero, a valid linear interpolation of the operating point can be guaranteed. DCC introduces a binary variable for each segment. $\delta_s = 1$ if segment s is selected and 0 otherwise. Interpolation is then performed only on the active segment, making the segment selection explicit in relation to SOS2, where the segment is chosen implicitly. For larger models, piecewise using SOS2 and implicit segment selection becomes too slow. This solution enables an efficient solution using MILP solvers, while preserving some of the nonlinear behaviors of pump operation. However, the piecewise approximation increases the computational complexity of the model, generating longer simulation times.

Ramping constraints are introduced to limit the rate of change in pump flow between constructive time steps. It is important to ensure physically realistic and smooth pump operation, preventing abrupt changes in flow that would be infeasible due to mechanical and hydraulic limitations.

$$Q_{p,t} - Q_{p,t-1} \leq \frac{Q_{\max} \Delta t}{3600}, \quad \forall p \in \text{PUMP}, \ \forall t \in T \tag{3.14}$$

$$Q_{p,t-1} - Q_{p,t} \leq \frac{Q_{\max} \Delta t}{3600}, \quad \forall p \in \text{PUMP}, \ \forall t \in T \tag{3.15}$$

Equations 3.14 and 3.15 formulate the ramp-up and ramp-down constraints. These constraints ensure that pump flow remains within its maximum allowable variation per time step. The factor $\frac{Q_{max}\Delta t}{3600}$ allows the system to ramp up or down to full capacity in a period of 1 hour.

3.3.3 Pump Method Motivation

In this work, the investigation of the energy consumption of pump operation is part of the aim. Detailed hydraulic behavior of variable speed pumps has been neglected and the control simplified. In a real-world case, variable speed pumps do not operate at a constant head, which is assumed in this method. Head varies with flow and speed, creating a non-linear relationship in the pump equation 3.11. However, under certain assumptions, the power equation can be simplified, validating the method. These assumptions include that static head dominates and that the elevation difference between the reservoir and the tank is the main component. Friction losses from piping have been neglected in this work, also allowing this simplification.

The model is formulated using the perspective of system-level optimization and the main objective is to minimize energy cost through scheduling. The analysis aims to compare cost benefits under variable electricity prices, capturing energy consumption trends and pump run patterns. Determining exact hydraulic operating points is of secondary importance, motivating why simplification of the network hydraulics can be allowed. However, if accurate hydraulics simulations are needed, pump operating regions, non-linear head-flow interactions, or speed control behaviors are of interest, this simplification is not ideal. If the model were to be compared to an EPANET model, more accurate validation of the model could have been done. Since no EPANET model was available for this work, this also made the decision of simplification.

The formulation in Equation 3.11 is able to capture non-linear energy use in relation to flow, as well as recognizing bad operating points through efficiency penalties. This is required in order to enable optimizing against variable electricity prices. Questions covering how pumping should be scheduled during the day, how much flexibility reduces cost and how sensitive cost is to price volatility can still be answered without achieving a perfect hydraulic representation.

3.4 MILP Model

To compare the performance and operating cost of the pump system, several control strategies were implemented, each defined by a distinct objective function. The first strategy was cost-oriented, which aimed to minimize total operational cost. The aim of the second strategy was to minimize deviation from measured operational data, ensuring that simulated flow rates and storage volumes mimic observed system behavior.

3.4.1 Flexible Operation Model

The objective function in the flexible operation model is a minimization of cost, described in equation 3.16, using a cost-oriented objective.

$$f_1 = minCost^{Pump} \tag{3.16}$$

where

$$Cost^{Pump} = Cost^{grid} + Cost^{peak} \tag{3.17}$$

The cost of energy for all running pumps was minimized using the objective function. The cost of purchased electricity for pumping is the $Cost^{grid}$, $Cost^{Peak}$ is the cost from the electricity tariff. $Cost^{grid}$ are defined in Equation 3.18.

$$Cost^{grid} = \sum_{p \in PUMP} \sum_{t \in T} ((\gamma^{sp}_{p,t} + \gamma^{gu}_{p,t} + \gamma^{tax}_{p,t}) P_{p,t}) \Delta t \tag{3.18}$$

The index t refers to time step resolution of 15 minutes within the set T. The individual pumps are represented with index p and $PUMP$ is the set of all available pumps. The day-ahead spot price for electricity is the $\gamma^{sp}_{p,t}$. Grid utilization cost, consisting of transmission fee and subscription fee is the $\gamma^{gu}_{p,t}$. $\gamma^{tax}_{p,t}$ is the energy tax. The $P_{p,t}$ is the power of each pump p at time t.

The pricing model for peak hours was defined as a fee ($\gamma^{peak}_{p,t}$) charged during days from 07:00 to 20:00 from November to March. In practice, the power tariff is based on the average of the three highest power peaks during one hour within the peak hours of a month. Since the highest peaks are not known in advance when performing day-ahead optimization, simplification in modeling power tariffs has been made. For one, instead of using the average of the three highest monthly peaks, the model approximates using a single monthly peak (P_{montly}). This is justified because peak events are typically correlated, meaning reducing the highest peak also reduces the second-highest and the third.

In order to account for the time resolution, hours of the day were defined as

$$h_t = h_0 + t \times \Delta t \ mod \ 24 \tag{3.19}$$

where h_0 is the start hour. Then the maximal measured power during that day was recorded using:

$$P_{peak} \geq \sum_{p \in PUMP} P_{p,t}, \forall t \in T \ where \ 7 \leq h_t \leq 20 \tag{3.20}$$

The monthly peak power represents the maximum peak observed over time, including both current optimization and what has already happened earlier in the month. Therefore, it has to be greater than both the current peak and the previously observed monthly peak ($P_{previous}$).

$$P_{monthly} \geq P_{peak} \tag{3.21}$$

$$P_{monthly} \geq P_{previous} \tag{3.22}$$

The peak cost was determined based on the monthly peak power, scaled to a daily equivalent of the peak tariff γ^{peak}.

$$Cost^{peak} = \frac{\gamma^{peak}}{30}(P_{montly}) \tag{3.23}$$

Depending on which month was selected in the optimization, the $Cost^{Peak}$ could be turned on or off, using two setups of the objective function. Changing the condition from False to True in the model structure would activate the objective, including the term for peak cost.

3.4.2 Reference Operation Model

A reference orating model was created in order to compare flexible operation to current inflexible operation. This model contained the same constraints, but with a different objective function. Reference data for tank level and pump flow patterns were obtained from the SCADA system, representing actual system behavior. The objective was set to minimize the deviation from the reference data. This formulation allows the model to replicate a realistic baseline operation corresponding to when operation is only driven by demand satisfaction rather than cost optimization. Equation for the objective can be seen in Equations 3.24 and 3.25.

$$f_2 = minTracking \tag{3.24}$$

$$Tracking = \sum_{t \in T}(l_{s,t} - l_{s,t}^{ref})^2 + \sum_{t \in T}(\sum_{p \in PUMP} Q_{p,t} - \sum_{p \in PUMP} Q_{p,t}^{ref})^2 \tag{3.25}$$

The tracking formulation penalized both tank level and pump flow rate deviations over the entire simulation. A quadratic error term is used to ensure that both positive and negative deviations are penalized equally. Since quadratic terms were used in this function, this model is based on Mixed Integer Quadratic Programming (MIQP).

3.5 Water Distribution System: Case study

The WDS network used in the model represents a fictive town and is illustrated in Figure 3.4. The input data were based on guidelines from Svenskt Vatten's publication P114 [9]. The town has approximately 52,000 inhabitants, a total water storage capacity of 8600 m^3, and an average daily water consumption of about 14,000 m^3/day.

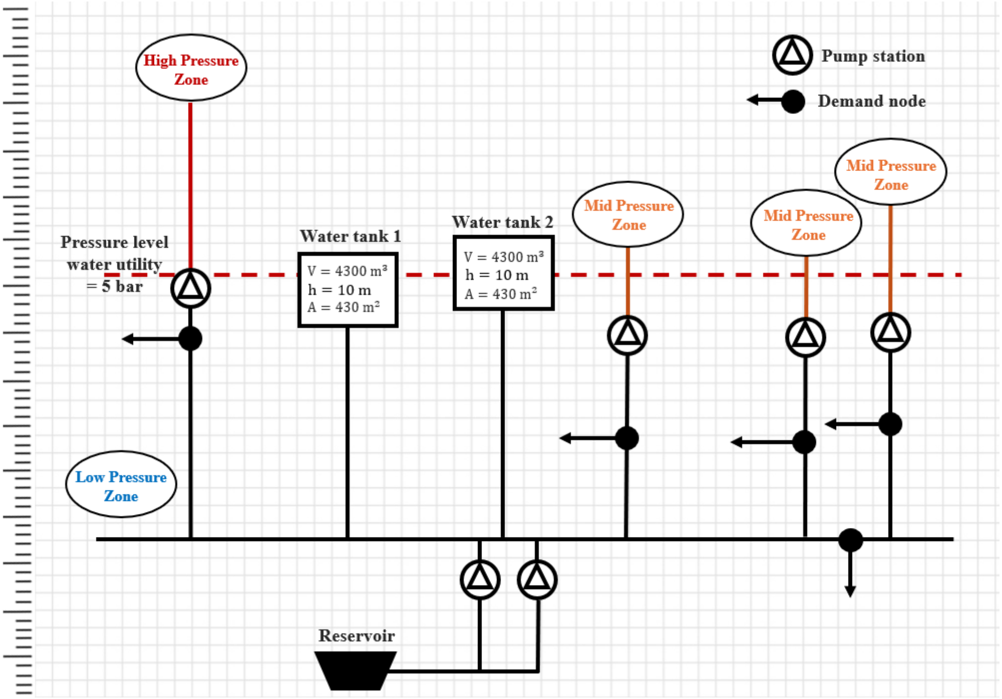


Figure 3.4: Schematic overview of the fictive town used in the case study, including reservoir, pump stations, tanks and pressure zones

The model consists of a reservoir, 2 pumps, 2 tanks and 5 demand nodes. The two tanks are interconnected by piping and function as communicating vessels, and can be seen as one storage system. However, to represent reality, the towers had a height difference of 1 m between the bottom of the towers. Since the towers are connected as communicating vessels, this created a dead space in one of the towers, since the height in tower 1 will limit tower 2. The total storage capacity was divided equally, creating two twin towers with 4300 m^3 each, a height of 10 m, and a surface area 430 m^2. Since hydraulic losses were neglected, the parameters of the pipe network were ignored. The water demand patterns were based on the city of Trollhättan. Pressure level was set to 5 bar for both towers. The study uses two pumps, where the pump curve and power relations were provided by the manufacturer. The maximum capacity for one pump was 160 kW and the best operating flow was at 600 m^3/h.

3.6 Load Shifting Quantification

In order to support the interpretation of the result. The method behind the quantification of load shifting is described. Load shifting in terms of energy [kWh] ($E = P\Delta t$) was calculated using the power consumption profiles of the flexible and reference operation models over time. The metric was defined as the sum of absolute differences in energy consumption at each time step, shown in Equation 3.26.

$$Shifted\ Load = \sum_{t \in T} | \sum_{p \in PUMP} (P_{p,t}^{flex} - P_{p,t}^{ref}) | \Delta t \tag{3.26}$$

This formulation captured the total magnitude of temporal redistribution of energy by flexible operation. The metric does not represent net energy savings, but the degree of temporal reallocation of pump load.

4

Results

This chapter presents the results of the optimization model. First, the input parameters and the scenario setup are described, followed by the simulation results. Lastly, the results include a sensitivity analysis of the model.

4.1 Scenario setup

The simulation was carried out using Groubi and Python in the Visual Studio Code environment. Computations were performed on an HP EliteBook computer with a 12th Gen Intel(R) Core(TM) i5-1235U processor and 16 GB RAM. The complexity of the implemented model increased the solution time when smaller tolerance gaps were used. In this study, the tolerance gap was set to 0.05 in the model. When the simulation was initiated at a lower tolerance gap closer to 0.01, the solver ran out of memory. Achieving smaller tolerance and more accurate solutions requires greater RAM capacity.

The scenario setup and input parameters are described in this section. The study is based on 4 scenarios, investigating the impact on flexibility under 4 different conditions throughout the year. In each of the seasons, summer, autumn, winter and spring, a period of one week was selected to study in order to catch yearly variation in both water demand and electricity price patterns. July and October were chosen for summer and autumn, so they represent months with no active power tariff structure. January and March were selected for winter and spring, having an active power tariff structure. General parameters equal in all simulations can be found in Table 4.1.

Table 4.1: Model parameters, costs and simulation settings used in the study

Category	Parameter	Value	Notes
Costs	Subscription fee	13909.17 SEK/month	
	Transmission fee	0.0517 SEK/kWh	
	Power tariff	34.4 SEK/kW	
	Energy tax	0.36 SEK/kWh	
System configuration	Number of pumps	2	Nonlinear efficiency model used (see Method)
	Number of tanks	2	Design based on case study (see Method)
Operational constraints	P_{max}	160 kW	
	Pressure level	5 bar	
	Q_{max}	900 m^3/h	
	Q_{BOP}	600 m^3/h	
Simulation configuration	Resolution	4	Different initial levels due to tanks at different heights
	Initial tank level 1	10 m	
	Initial tank level 2	9 m	
Simulation setup	Seasons	4	
	Duration	1 week	

Time-varying spot price and demand profiles were used as input parameters to the model. Profiles can be seen in Figures 4.1 and 4.2.

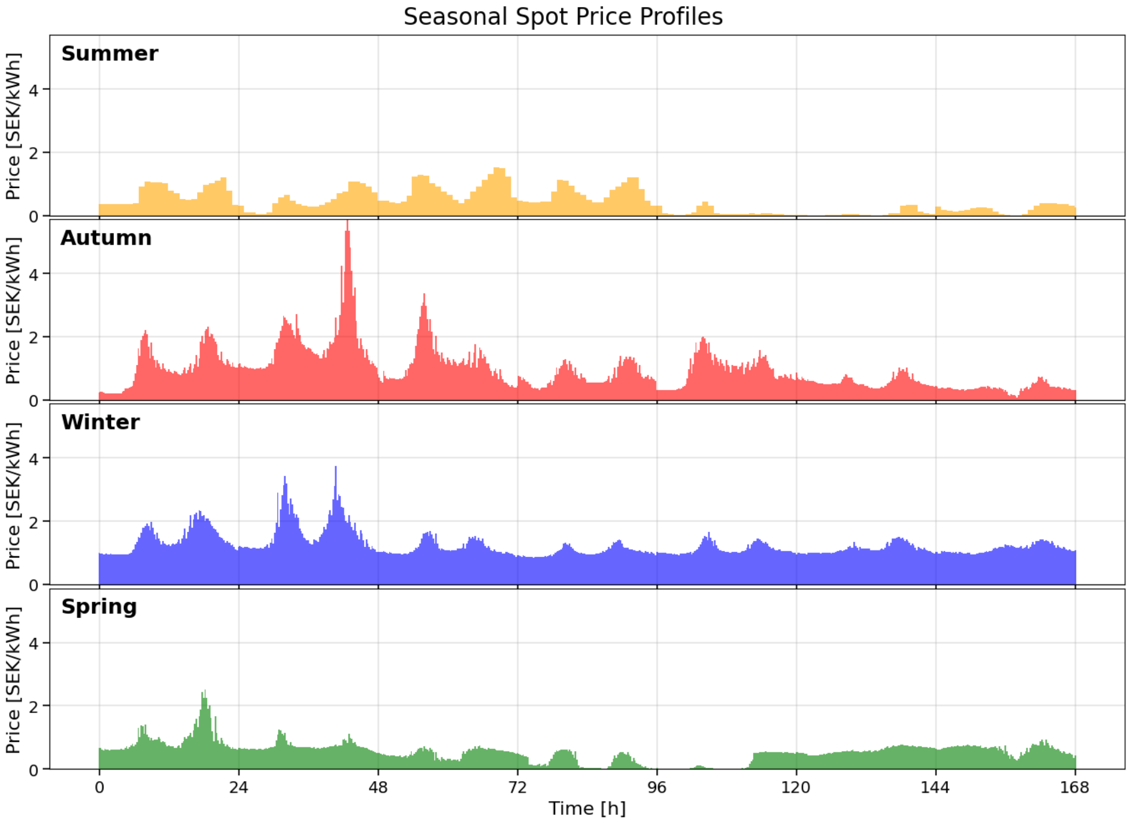


Figure 4.1: Seasonal variation in electricity spot prices illustrated though 15-minute resolution, showing variation in price patterns between summer, autumn, winter and spring

Clear differences in pattern can be seen in the spot price profiles during different seasons. Colder months in winter and autumn are characterized by higher mean prices and distinct price peaks reaching around and above 4 SEK/kWh. While the selected week in summer and spring has lower prices. Summer prices never reached above 2 SEK/kWh, and both seasons have periods with electricity prices close to 0 SEK/kWh. The summer and spring months experienced more stable price fluctuations, although summer is the most stable month, with generally low prices.

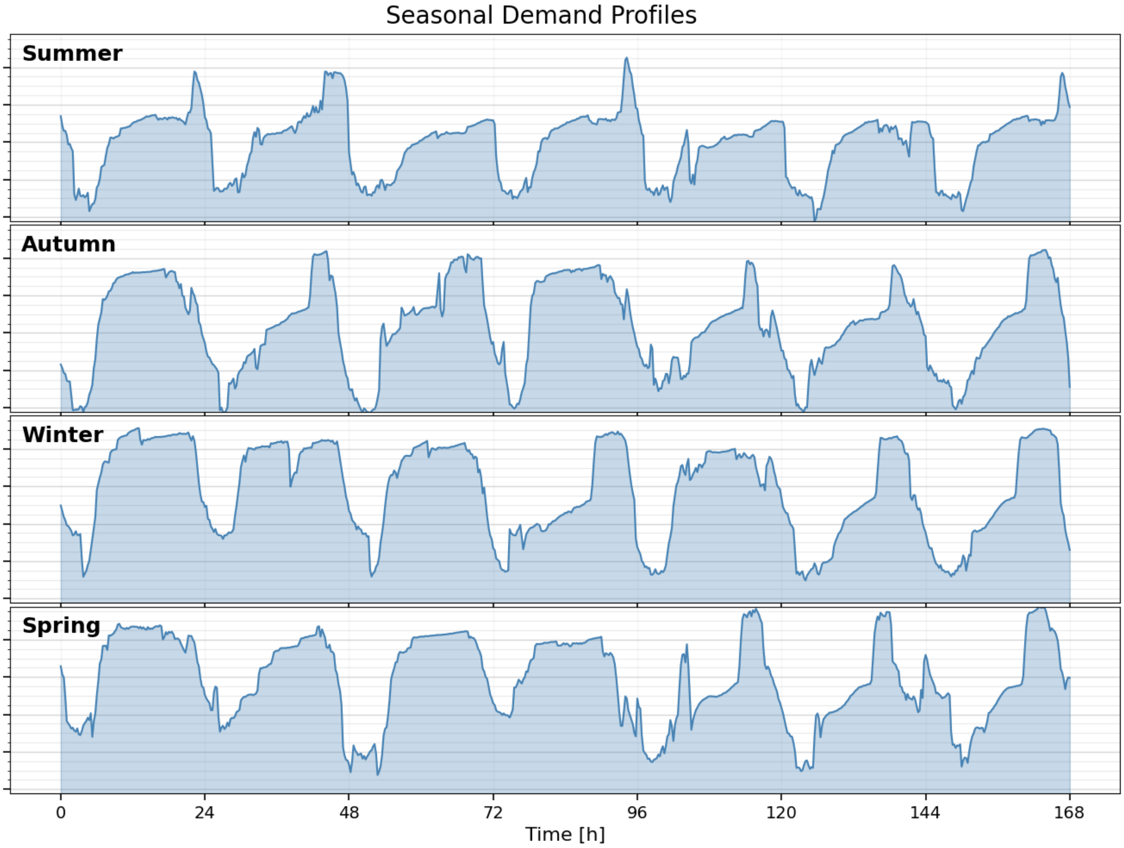


Figure 4.2: Seasonal variation in demand input profiles, illustrated though 15-minute resolution, showing variation water intensity between summer, autumn, winter and spring

Demand profiles are based on real-time data and the decision was made not to include numerical values due to data confidentiality. Differences between the seasons can be identified in demand patterns. The summer week experiences lower consumption in water demand in relation to the other three seasons. During winter and spring time, the demand is higher, while Autumn is in between in magnitude. The discussion is based on the contrasts in each case relative to one another, rather than on absolute numerical values. The shape of the demand curve is not always what is expected . This is most likely due to an underlying error in data measurements.

4.2 Simulation results

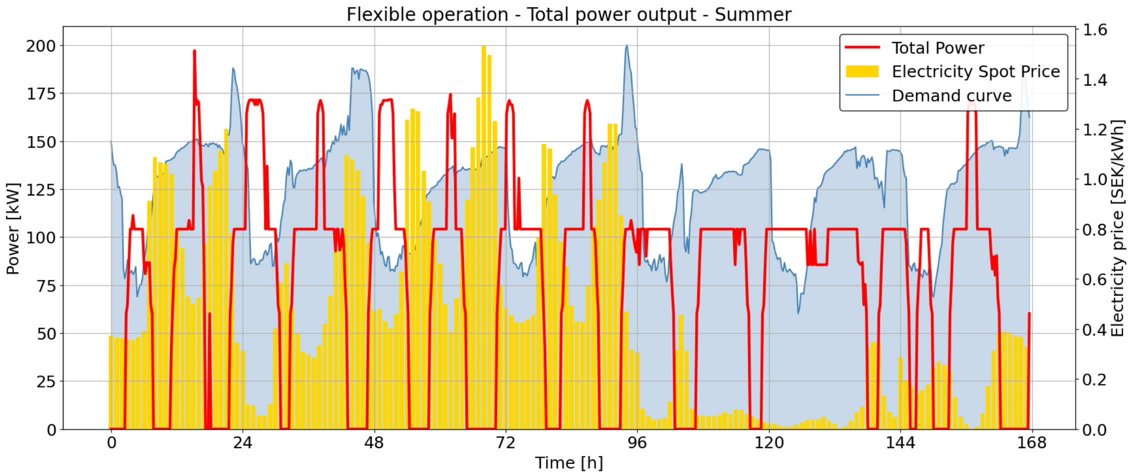
This section contains the results for the simulation model. Each simulation that was carried out had a run time of 180 hours, of which 168 hours were recorded in the analysis, which equated to 1 week. The additional 12 hours were chosen in order to include a full simulation over the horizon.

4.2.1 Comparison flexibility and reference model: Pump operation and price analysis

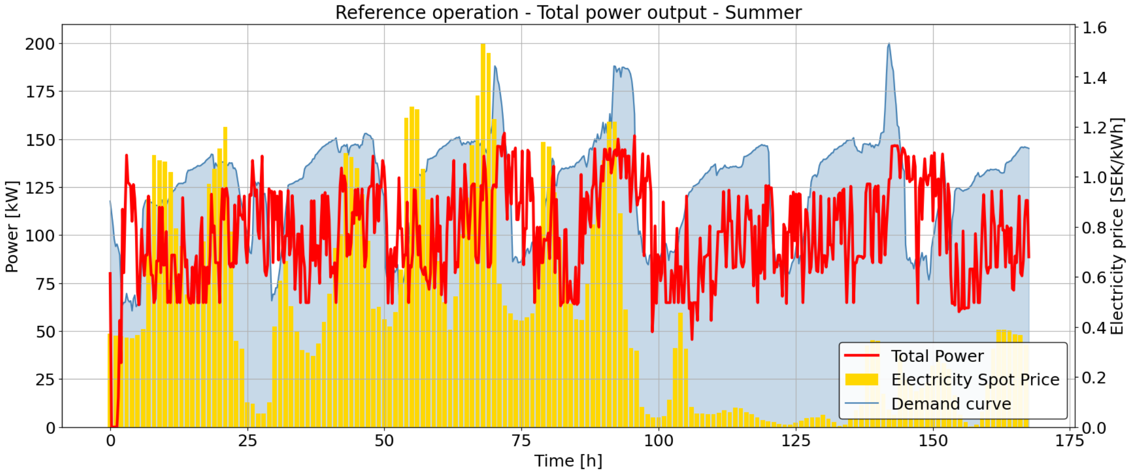
The following figures illustrate the optimal pump scheduling solution from the flexibility model and the reference model. The red line described the total power from both operating pumps. Yellow bars represent the spot price for electricity. The bars are compressed to display hourly prices to make a smoother graphical presentation, however, the simulations were performed using quarterly resolution. The blue-filled curve is the daily demand trend. Numerical values are not displayed due to data confidentiality. The minimum buffer limit was set to 8 hours in the tank in the flexible operation model.

4.2.1.1 Summer scenario

The results are based on a summer week in July 2025. Summer is characterized by lower stable prices with few high peak periods, due to reduced electricity demand. No power tariff structure is active. The results of the flexible operation model show that pumping is strategically shifted during price variations. Pumping is reduced or turned off during peak price periods and increased when electricity prices are lower. During longer periods of low stable prices, such as between time 96 and 144 hours in Figure 4.3a, no increased pumping is observed. An increase in pumping activity is observed in periods in which peak electricity prices are predicted.



(a) Flexible operation model: pump scheduling under summer conditions



(b) Reference operation model: pump scheduling under summer conditions

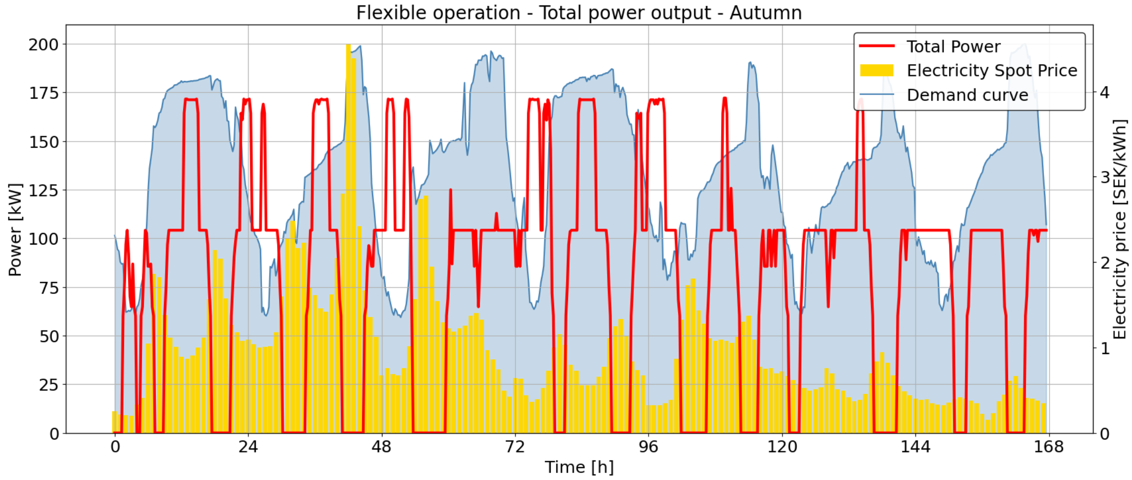
Figure 4.3: Simulation results of total power output for flexible and reference operation under summer conditions in price and demand patterns

Output from the reference model shows a different operational structure. The objective is not to minimize cost but rather to replicate current operational trends in storage levels and pumping patterns. This results in more stable pumping throughout the week, where pumping is not curtailed during higher price periods. During the first few hours in Figure 4.3b, no pumping occurs. This is explained by initial conditions in the model, where the volume in the tanks is set to its maximum value on day one. Since one objective of the model is to replicate a level pattern inside the tank, pumping is initially turned off until the storage level has been reached.

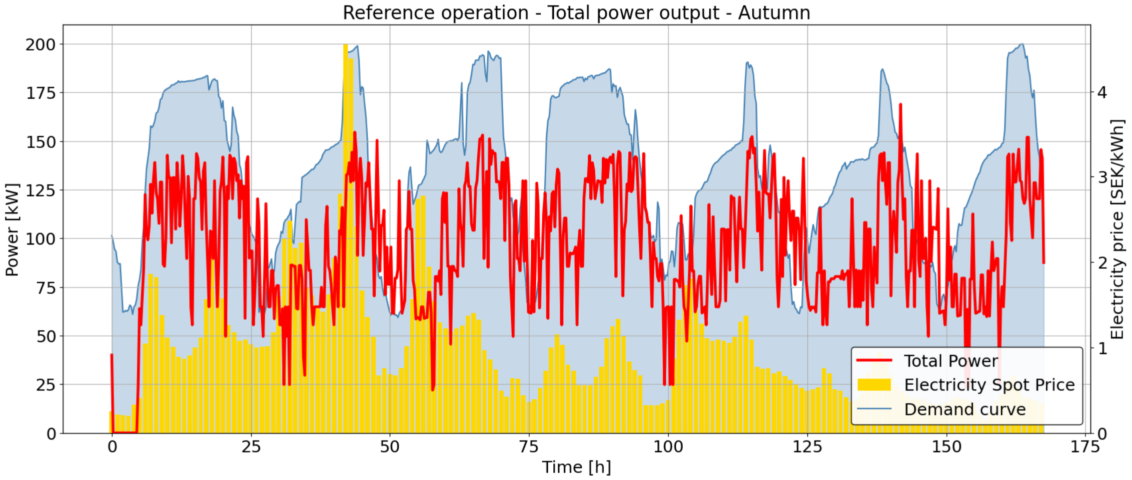
4.2.1.2 Autumn scenario

The results from the Autumn scenario are based on a week in October 2025. October 2025 was characterized by significant price peaks and high volatility due to shifting weather conditions and variable demand patterns in the energy system. No power tariff structure is active for the month of October.

The autumn week experiences patterns similar to those of a summer week. The flexible operating model shifts power and shifts operations away from high-price hours to lower-price periods. In this scenario, more peaking periods in operation occur, and more load hours have been shifted.



(a) Flexible operation model: pump scheduling under autumn conditions



(b) Reference operation model: pump scheduling under autumn conditions

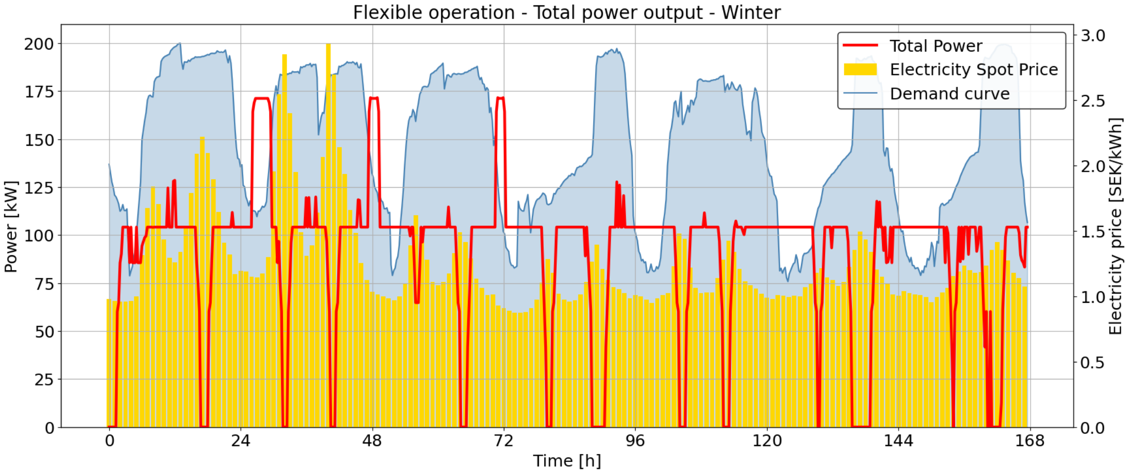
Figure 4.4: Simulation results of total power output for flexible and reference operation under autumn conditions in price and demand patterns

Figure 4.4b shows the results from the reference model in the investigated week. It can be observed that power output follows the demand curve and not the electricity price variation. The same initial value error appears in the first hours before the water level in the towers has stabilized to track the given input.

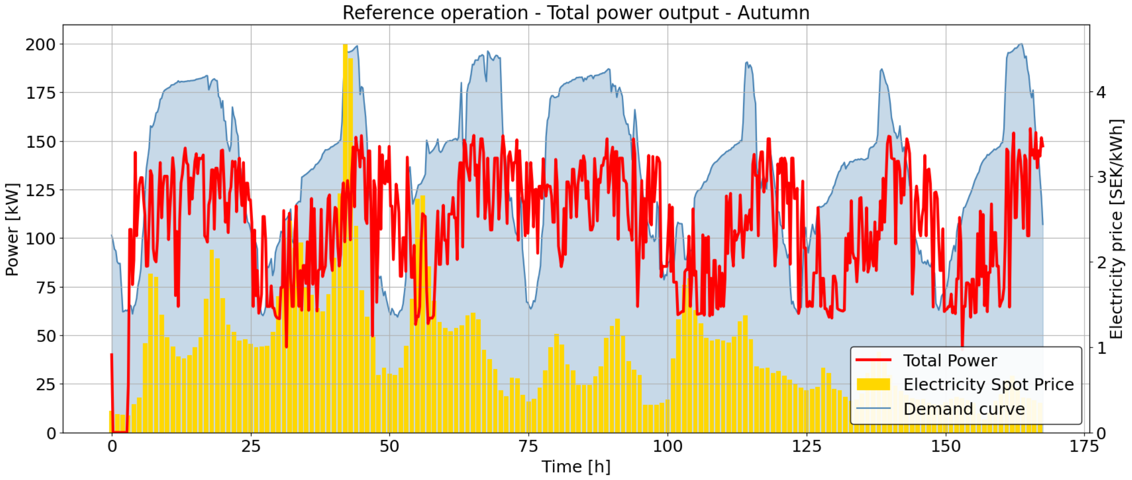
4.2.1.3 Winter scenario

The investigated winter week was selected in January 2026. Electricity prices in winter are characterized by a higher price level and volatility, driven by limited flexibility in the energy system. During the wintertime, the power tariff structure was active, and an extra cost was applied between the hours of 7 AM and 8 PM each day.

The output in total power from the flexible operation model differs compared to a week in summer or autumn. Figure 4.5a shows that, while pumping is still turned off during peak price periods, the allowed duration of time the pump is shut down is reduced compared to the previous scenarios. Less increased pumping during low price periods can also be observed.



(a) Flexible operation model: pump scheduling under winter conditions



(b) Reference operation model: pump scheduling under winter conditions

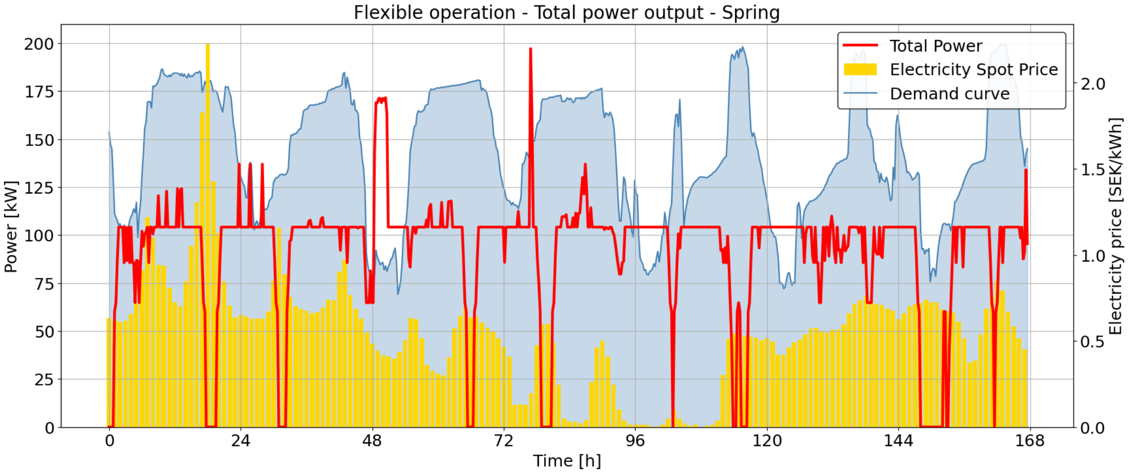
Figure 4.5: Simulation results of total power output for flexible and reference operation under winter conditions in price and demand patterns

The total pumping power from the reference operation model during the winter week closely follows the demand curve. The power output in Figure 4.5b is higher compared to the results from the reference model during the autumn and summer scenarios. The demand profile is greater in the winter scenario compared to the previous months, seen in Figure 4.2, which directly impacts the reference pumping operation.

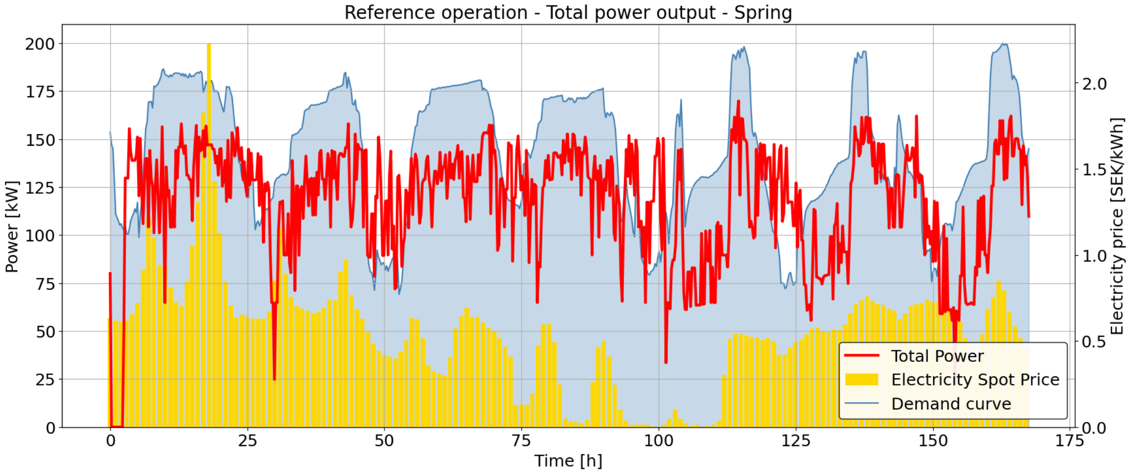
4.2.1.4 Spring scenario

A week in March 2026 was selected for the spring scenario. Electricity price levels were moderate with occasional price spikes, driven by the transition from winter demand to increased hydropower availability during springtime.

Power output during the springtime is similar to that during a winter week. The flexible operation case shows alignment with the electricity price signal. Pumping is curtailed when the electricity price peaks, but the allowed shutdown hours are lower compared to scenarios with no power tariff active.



(a) Flexible operation model: pump scheduling under spring conditions



(b) Reference operation model: pump scheduling under spring conditions

Figure 4.6: Simulation results of total power output for flexible and reference operation under spring conditions in price and demand patterns

The reference operation model follows the same demand-driven structure as in other scenarios.

4.2.1.5 Seasonal comparison: operational strategies

In all scenarios, the power output in the flexible operation model is oriented with electricity price signals. Pumping is reduced during high price periods and increased during low price events. Power is actively shifted in response to price fluctuation, in contrast to the reference model, which follows a demand-driven pattern. These results suggest a successful price-driven dispatch model compared to the reference operation, without impacting the weekly supply and demand balance in water.

Table 4.2 provides a summary of the total cost and energy calculated from each simulation. Cost per energy is the total cost divided by total energy, representing the average system cost per unit of energy consumed. The minimum volume is the minimum buffer of water stored as a percentage of the total storage the tanks need to keep at all times to provide security during the simulated week. Shifted load shows how many kWh could be shifted from high price periods.

Table 4.2: Comparison between cost and energy metrics for flexible and reference operation throughout different scenarios

Season	**Scenario**	**Cost [SEK]**	**Energy [kWh]**	**Cost per energy [SEK/kWh]**	**Shifted load [kWh]**
Summer	Flexible	28163.7	50020.3	0.563	4125.4
Summer	Reference	41249.3	67656.7	0.610	-
Autumn	Flexible	37779.3	53709.0	0.703	8826.3
Autumn	Reference	55187.7	71164.1	0.775	-
Winter	Flexible	51515.6	61049.7	0.844	3619.6
Winter	Reference	70841.0	81275.2	0.872	-
Spring	Flexible	38657.6	61511.4	0.628	3233.1
Spring	Reference	51186.7	79192.3	0.646	-

Table 4.3 provides insight into operational metrics. Pumped volume represents how much water has passed through the pump during the simulation in each scenario. The run time was how many hours of pumping had occurred during the simulation time of 168 hours. The optimal pumped volume is a theoretical value defined as the product of total operating time and the optimal pump flow rate at 600 m^3/h, representing a hypothetical case where pump operation always occurs at its best operating point. The utilization index is a ratio between the pumped volume and the optimal pumped volume, representing the operating efficiency relative to an ideal continuous operation at optimal flow.

Table 4.3: Comparison between volume metrics for flexible and reference operation throughout different scenarios

Season	Scenario	Min volume [%]	Pumped volume [m^3]	Run time [h]	Optimal pumped volume [m^3]	Utilization index [%]
Summer	Flexible	57.1	67724.9	118.5	71100.0	95.2
Summer	Reference	-	68751.8	165.25	99150.0	69.3
Autumn	Flexible	60.3	72195.0	121	72600.0	99.4
Autumn	Reference	-	68751.8	165.25	99150.0	69.3
Winter	Flexible	64.0	84678.2	147.5	88500,0	95.7
Winter	Reference	-	78313.5	165.25	99150.0	79.0
Spring	Flexible	66.5	85394.5	153	91800,0	93.0
Spring	Reference	-	80700.3	165.75	99450.0	81.1

Figure 4.7 and 4.8 help visualize the seasonal results. The flexible operation provides savings in cost, energy, and run time in all scenarios, since load can be shifted from expensive hours to lower price regions. Comparison results between reference operation and flexible operation across the seasons, savings are identified in bar charts in Figure 4.7.

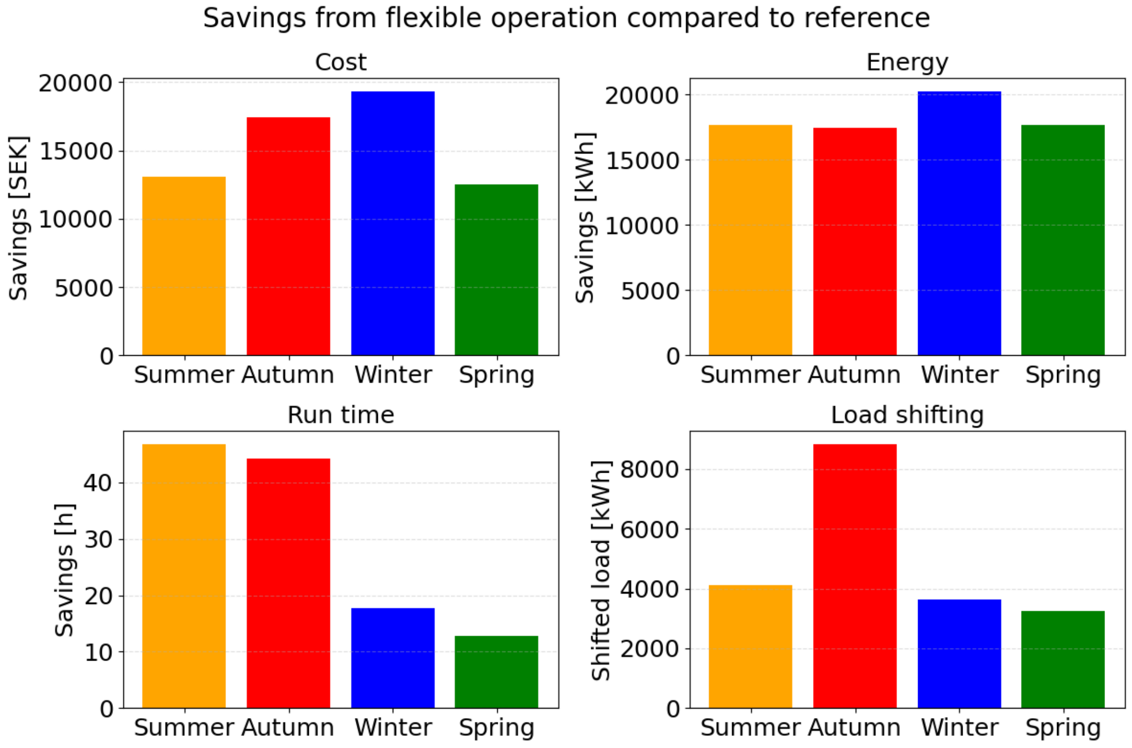


Figure 4.7: Bar chart representation of savings in cost, energy, runtime and potential of load shifting in each seasonal scenario

By implementing flexible operation, most money can be saved during winter conditions, at approximately 19,000 SEK, when the electricity price is high. Summer and spring weeks have similar savings at approximately 13,000 SEK, while autumn has the potential savings of approximately 17,000 SEK. In terms of energy consumption, energy savings are roughly the same in all investigated seasons, except for winter, which is a little elevated in relation to the seasonal cases. It is possible to turn off the pump for longer periods of time during summer and autumn, as clearly shown in the figure, since peaking consumption is not punished by power tariffs. Autumn has the highest potential for load shifting compared to the other seasons. Load shifting in the summer scenario is slightly higher than in the winter and spring weeks.

Figure 4.8 shows the system-level operational utilization based on runtime and assumed optimal flow.

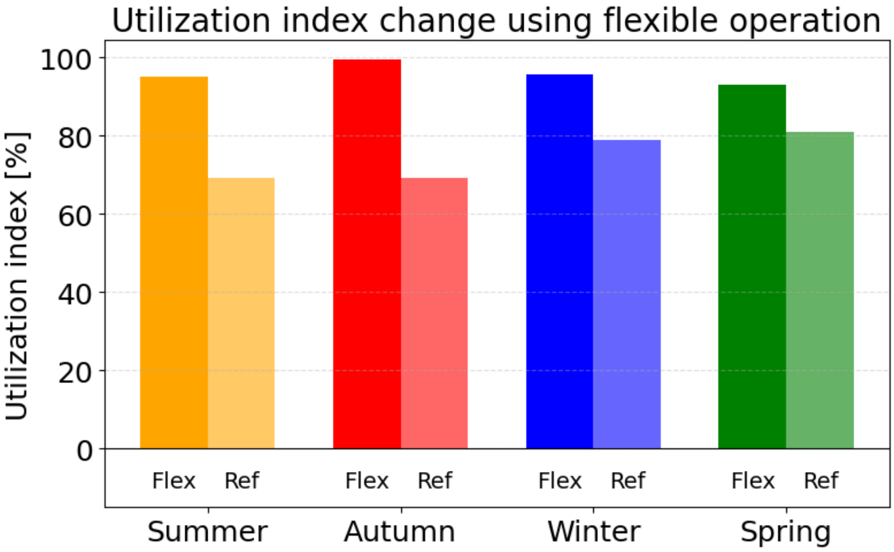


Figure 4.8: Bar chart representation of utilization index between the flexible and reference operation model in each seasonal scenario

The figure clearly indicates that using flexible operation, a higher utilization index can be reached in all seasons, reaching above 90% in all seasons. For the reference model, experience a lower utilization index in all cases, with summer being approximately 70%. This suggests the pump operation in the reference model is operating away from the best operating point. The utilization index in the reference aligns with the demand difference between the seasons explained in Figure 4.2, showing a correlation between demand and optimal flow rate in the reference model.

Further discussion can be found in Chapter 5.

4.2.2 Impact of reduced tank buffer on system operation and economic effects

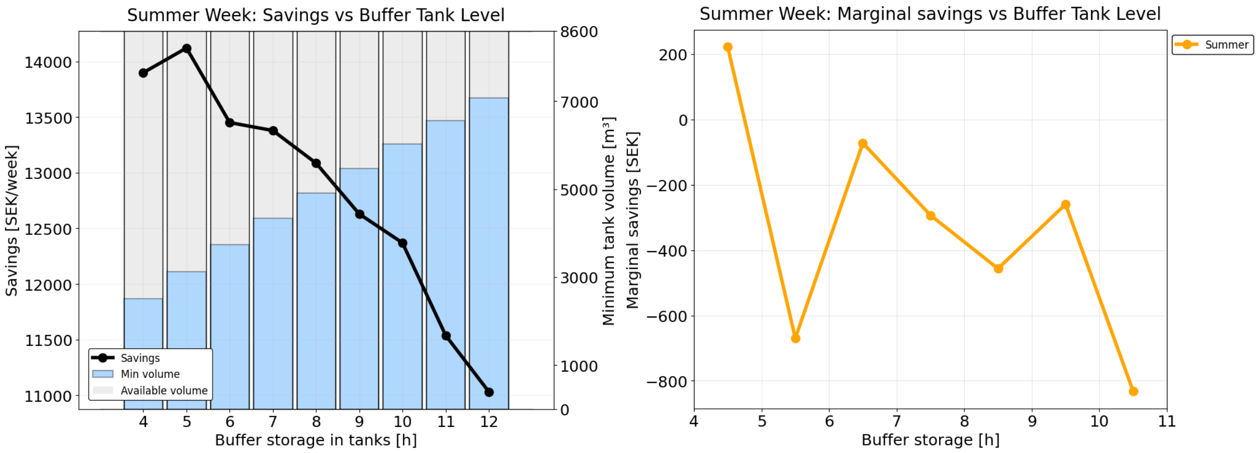
This section presents the analysis of how the reduced tank buffer impacts model results. The tank buffer level was decreased and increased by four hours relative to the original 8-hour buffer, resulting in a range between 4-12 hours of storage capacity being investigated. All four seasonal scenarios were analyzed. Four figures were produced and analyzed in each case. Savings represent the difference in total cost between the reference model and the flexibility model. The marginal savings between each buffer level, change in cost per energy, represent the average system cost per unit of energy consumed and the impact on the utilization index at different buffer levels. In this study, marginal savings refer to the change in cost between n progressing from one discrete buffer level to the next. Hence, the data point in that figure is illustrated between the two consecutive steps, corresponding to the marginal savings.

In this study, marginal savings refer to the change in cost between successive steps of the optimization process, such as between Step 4 and Step 5, Step 5 and Step 6, and so on.

4.2.2.1 Summer scenario

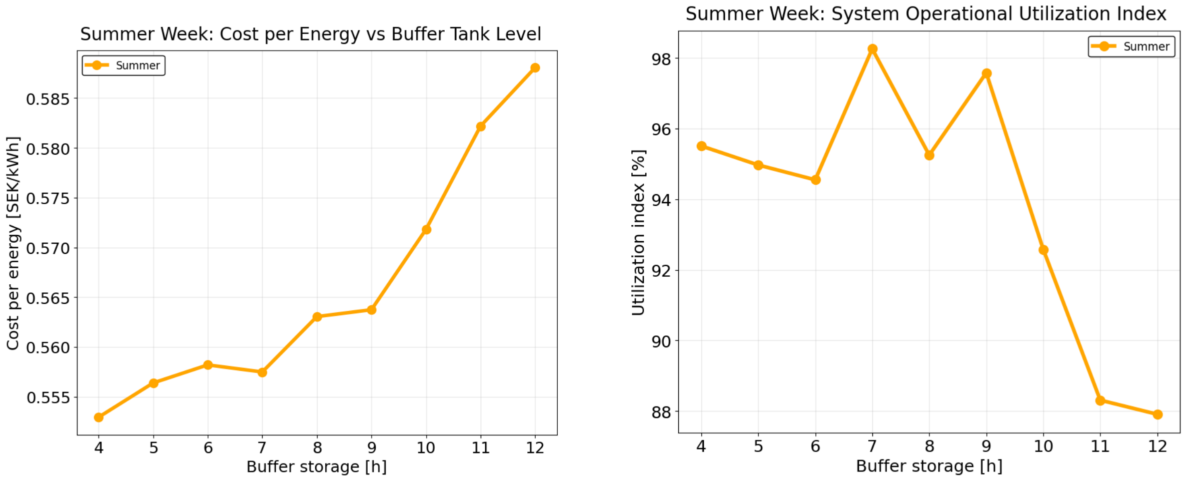
Figure 4.9 shows the results from the buffer analysis made during the summer week in July 2025. In the first graph, Figure 4.9a, savings per week are represented by the black dotted line. Each bar in the figure indicates the total available tank storage volume, while the blue shaded portion represents the minimum required volume to maintain in the tank to meet the buffer time requirement. When the desired buffer capacity increases, fewer savings can be made. The difference in savings between 4 and 12 hours buffer capacity is approximately 30%, spanning from 11,000-14,000. Between hours 4 and 5, the savings increase, showing an inconsistent trend. Expected results would be that marginal savings would decrease or remain constant since a larger buffer should not restrict the solution space. However, the model behavior may be influenced by the higher tolerance gap. Despite local fluctuation, the general trend indicates a reduction in savings with increased buffer capacity.

Observing the marginal savings in Figure 4.9b, the curve appeared irregular and exhibited fluctuation. Except between the first two data points, all marginal values are negative, indicating the observed trend. The fluctuation reveals that a reduction in savings is not strictly monotonic in magnitude for this scenario, meaning that while the difference remains negative, the size of the change varies between buffer levels.



(a) Savings in SEK per week as in relation to buffer tank storage hours during summer conditions, and bar chart visualization of available tank volume at varied buffer level

(b) Marginal saving trend in relation to buffer tank storage hours during summer conditions



(c) Cost per energy in relation to buffer tank storage hours during summer conditions

(d) Utilization index in relation to buffer tank storage hours during summer conditions

Figure 4.9: Comprehensive overview of cost savings and system utilization related to buffer tanks levels under summer conditions

Figure 4.9c illustrates how the average cost per energy for a simulated week increases with buffer level. A clear take-off point can be identified in the figure at buffer hour 9. After this threshold, the cost per unit energy increases at a gradually higher rate. Figure 4.9d shows how the system utilization index changes with increasing buffer level. The curve shows an irregular pattern, however, between buffer levels 4 and 9 hours, the utilization index is high at around 96 %, showing a significant drop in the higher storage requirements. At buffer levels 11 and 12 hours, the utilization is below 90%.

Table 4.4 presents numerical data for the analysis of the summer scenario.

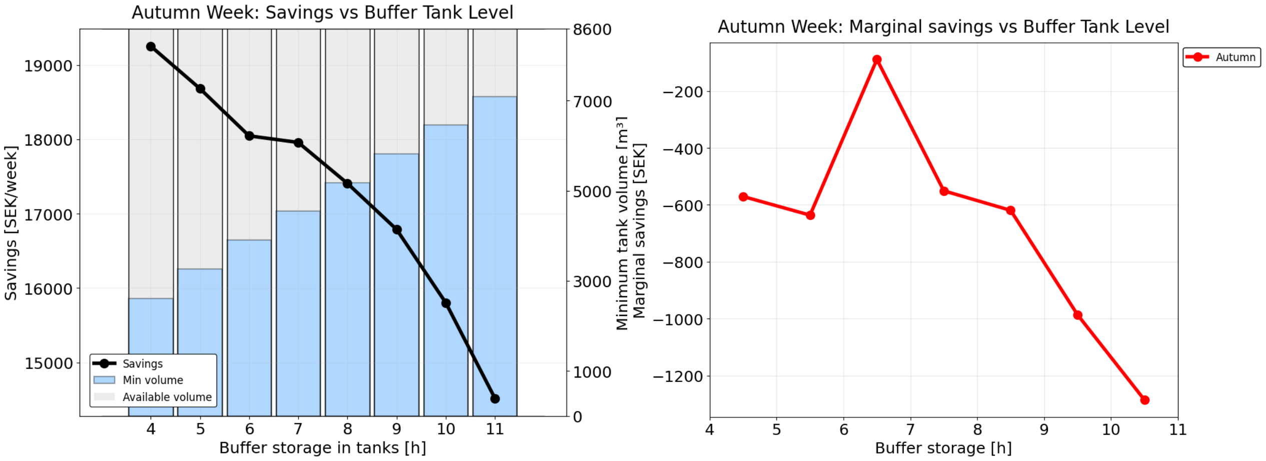
Table 4.4: Numerical data obtained in the summer scenario simulation

Buffert [h]	**Minimum tank volume** [m^3]	**Percent of max** [%]	**Cost** [SEK]	**Power** [kWh]	**Pumped Volume** [m^3]	**Run time** [h]
4	2514.6	0.292	27350.7	49464.1	67336.1	117.5
5	3129.9	0.364	27128.7	48759.1	66385.9	116.5
6	3738.7	0.435	27798.4	49800.7	67790.9	119.5
7	4333.0	0.504	27870.6	49993.6	67350.7	114.2
8	4912.6	0.571	28163.7	50020.3	67724.9	118.5
9	5475.3	0.637	28620.3	50769.1	68355.4	116.8
10	6023.0	0.700	28879.8	50506.7	68604.0	123.5
11	6554.2	0.762	29711.5	51034.9	69545.4	131.3
12	7076.1	0.823	30218.3	51387.2	69884.6	132.5
Reference	-	-	41249.3	67656.7	68751.8	165.25

4.2.2.2 Autumn scenario

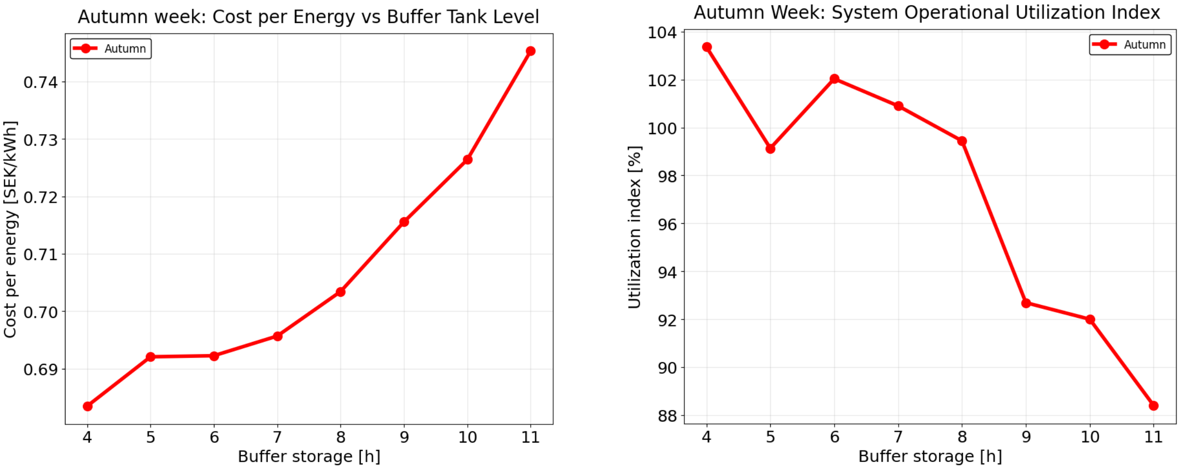
Results from the buffer analysis under autumn week conditions are shown in Figure 4.10. The buffer storage was varied from 4 to 12 hours, however, only storage up to 11 hours generated feasible solutions. Compared to the summer scenario, the higher demand during autumn increased the minimum level beyond tank storage capacity, preventing this system from covering 12 hours of demand at all time steps during the week.

Potential savings made during autumn conditions are higher than in the summer setup. Savings stretched between 14,500 - 19,000 SEK, seen in Figure 4.10a, having a difference of 32% between the lowest and highest buffer level. The savings curve in Figure 4.10a decreases gradually with increasing buffer capacity. This trend is also confirmed in Figure 4.10b as all data points are negative. Under autumn conditions, the marginal savings display a more monotonic trend, where savings are decreasing progressively as buffer capacity increases.



(a) Savings in SEK per week as in relation to buffer tank storage hours during autumn conditions, and bar chart visualization of available tank volume at varied buffer level

(b) Marginal saving trend in relation to buffer tank storage hours during autumn conditions



(c) Cost per energy in relation to buffer tank storage hours during autumn conditions

(d) Utilization index in relation to buffer tank storage hours during autumn conditions

Figure 4.10: Comprehensive overview of cost savings and system utilization related to buffer tanks levels under autumn conditions

In the graph for average cost per energy in Figure 4.10c, a take-off point can be observed around hour 8, indicating that cost per unit of energy increases more rapidly with additional buffer capacity after the 8-hour mark. In the Figure 4.10d, the trend of the utilization index is shown. Again, utilization is high before reaching 8 hours when the trend drops significantly below 90%. In this case, the index reaches a utilization level above 100%. The utilization index exceeds 100% because it is normalized against the flow rate of a single pump operating at its best efficiency point. Values above 100% indicate that the system was utilizing a pumping capacity greater than the reference capacity represented by one pump at its optimal operating conditions. In this autumn case, extensive load shifting was observed, leading the combined flow rates from the two operating pumps in the simulation to exceed the reference value. Values exceeding 100% should not be interpreted as a physical efficiency greater than 100% but as an indication that the pumping system is being utilized at a higher capacity than the reference.

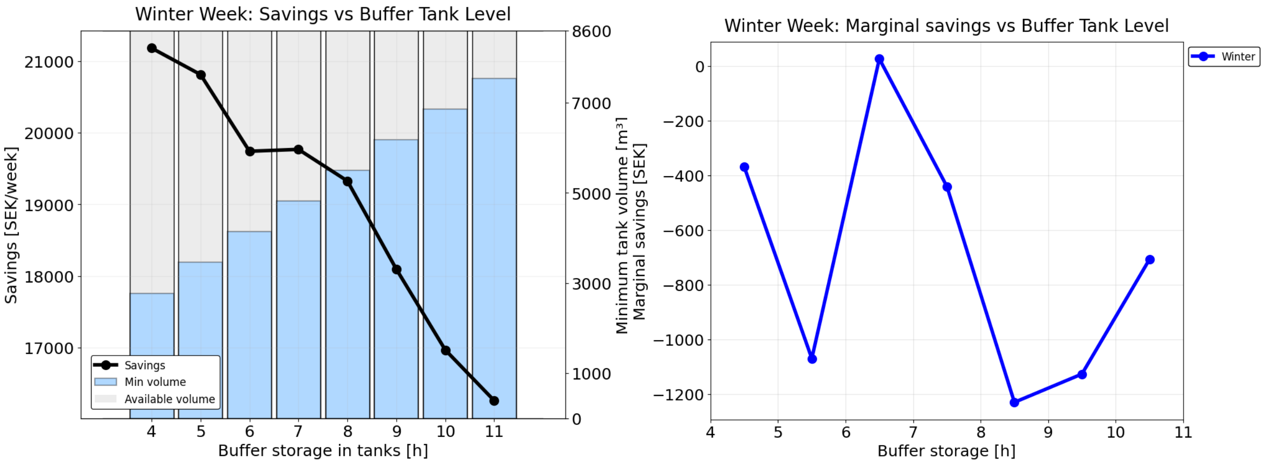
Numerical values for the analysis under autumn conditions can be found in Table 4.5.

Table 4.5: Numerical data obtained in the autumn scenario simulation

Buffert [h]	**Minimum tank volume** [m^3]	**Percent of max** [%]	**Cost** [SEK]	**Power** [kWh]	**Pumped Volume** [m^3]	**Run time** [h]
4	2611.1	30.4	35932.7	52575.7	69920.5	112.8
5	3257.3	37.9	36503.5	52747.4	70480.8	118.5
6	3901.2	45.4	37139.7	53652.1	71470.8	116.8
7	4542.1	52.8	37228.6	53515.6	71435.8	118.0
8	5181.6	60.3	37779.3	53709.0	72195.0	121.0
9	5819.2	67.7	38398.8	53664.4	72574.6	130.5
10	6455.3	75.1	39385.3	54221.0	73414.6	133.0
11	7089.7	82.4	40670.9	54568.6	74127.3	139.8
12	Infeasible	Infeasible	Infeasible	Infeasible	Infeasible	Infeasible
Reference	-	-	55187.7	71164.1	68751.8	163.5

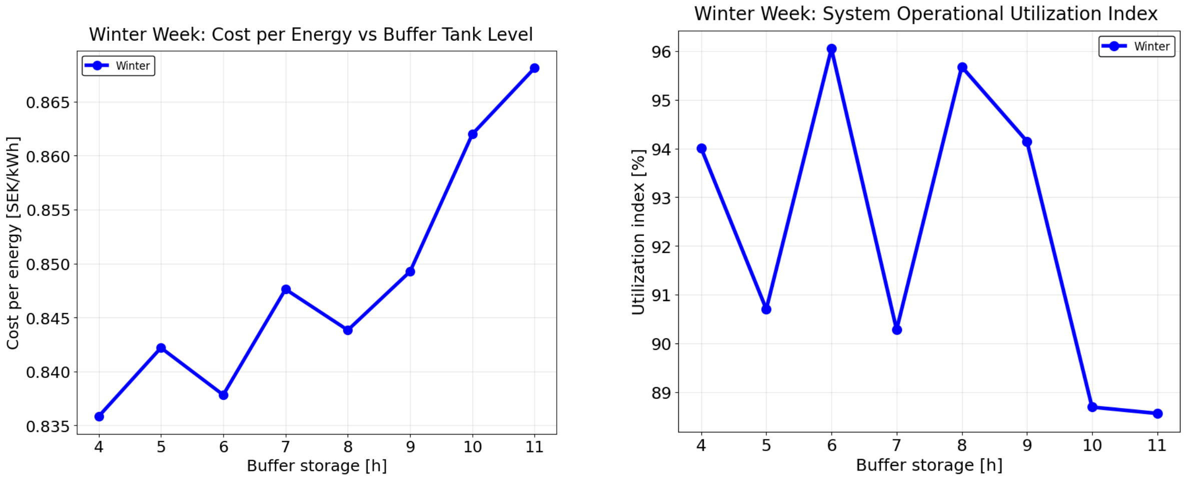
4.2.2.3 Winter scenario

Buffer analysis under winter conditions is illustrated in Figure 4.11. The analysis is done for a week in January 2026. Same trends in saving reduction can be seen in Figure 4.11a with a total reduction of approximately 23% between hours 4 and 11, with savings spanning from roughly 16,500 - 21,000 SEK. High demand during winter made the 12-hour solution infeasible. A small increase in savings can be identified between hours 6 and 7. This behavior was not expected and can be explained by the fact that the most optimal solution could not be found due to a high tolerance gap. This results in high fluctuations in Figure 4.11b showing the marginal savings. The difference in marginal savings under winter conditions is that at the higher end of storage capacity investigated, the total savings continue to decrease overall, but exhibit smaller variations between cases. The marginal effect of increasing storage capacity is not as uniform as in the autumn case, and becomes weaker at higher buffer levels.



(a) Savings in SEK per week as in relation to buffer tank storage hours during winter conditions, and bar chart visualization of available tank volume at varied buffer level

(b) Marginal saving trend in relation to buffer tank storage hours during autumn conditions



(c) Cost per energy in relation to buffer tank storage hours during winter conditions

(d) Utilization index in relation to buffer tank storage hours during winter conditions

Figure 4.11: Comprehensive overview of cost savings and system utilization related to buffer tanks levels under winter conditions

Average cost per energy increase in an irregular pattern before the take off point at hour 8 in figure 4.11c. In figure 4.11d, the trend for the utilization index appears to have an irregular pattern, but still keeps a high value before dropping down to below 90% after buffer level 9 hours. Similarities in variation of the trend can be found in both Figure 4.11c and 4.11d for the first data points in the buffer analysis.

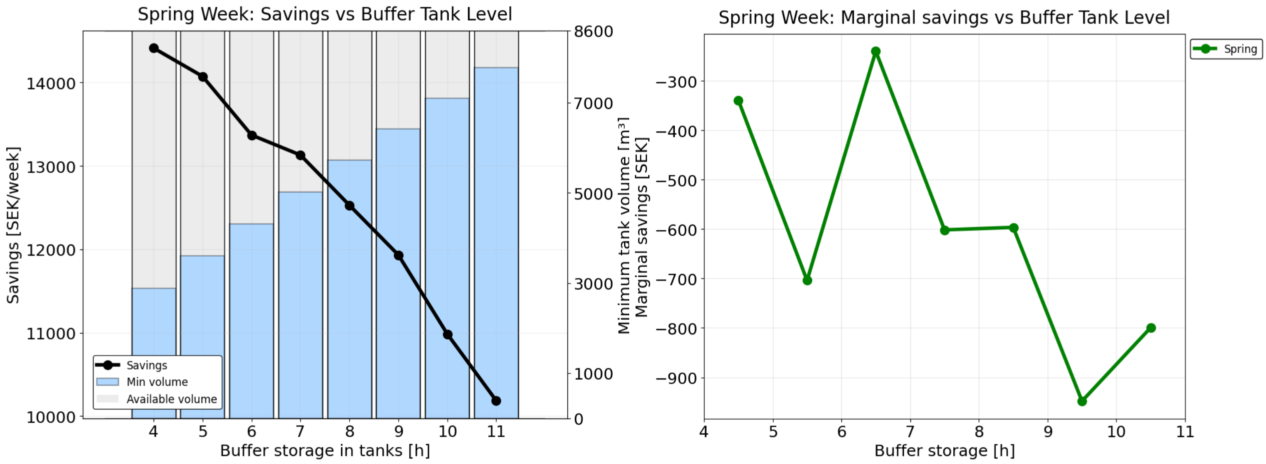
Table 4.6 shows numerical data for the winter scenario.

Table 4.6: Numerical data obtained in the winter scenario simulation

Buffer [h]	**Minimum tank volume** [m^3]	**Percent of max** [%]	**Cost** [SEK]	**Power** [kWh]	**Pumped Volume** [m^3]	**Run time** [h]
4	2768.8	32.2	49661.6	59415.5	82072.8	145.5
5	3455.1	40.2	50031.2	59405.8	82715.8	152.0
6	4138.3	48.1	51101.4	60992.6	83992.8	145.8
7	4819.9	56.0	51075.1	60257.1	83963.1	155.0
8	5500.0	64.0	51515.6	61049.7	84678.2	147.5
9	6179.2	71.9	52746.1	62108.1	85440.2	151.3
10	6857.3	79.7	53873.0	62498.0	86601.9	162.8
11	7534.7	87.6	54580.7	62872.2	86745.4	163.3
12	Infeasible	Infeasible	Infeasible	Infeasible	Infeasible	Infeasible
Reference	-	-	70841.0	81275.2	78313.5	165.5

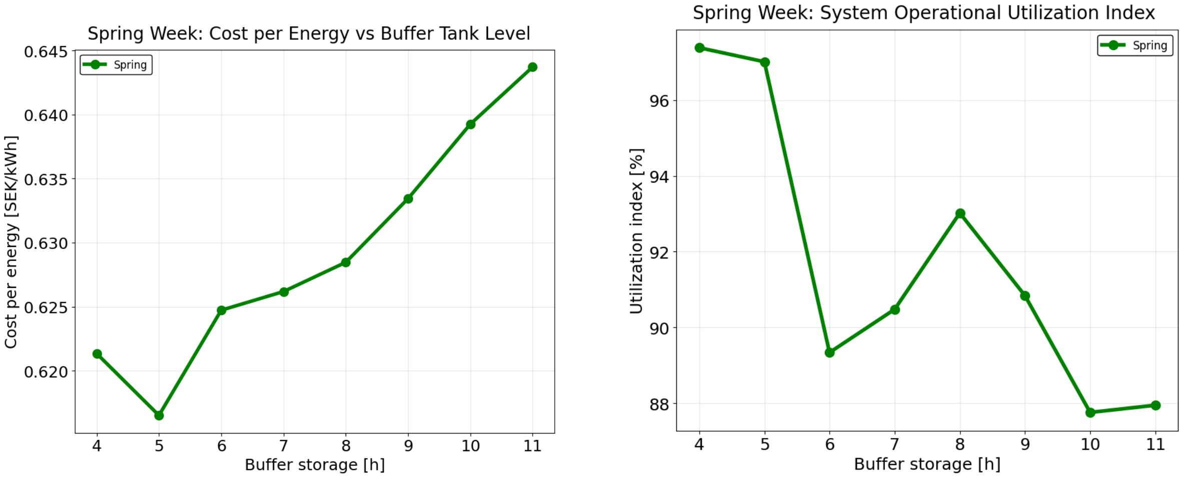
4.2.2.4 Spring scenario

Analysis of the selected spring week in March 2026 is presented in Figure 4.12. Cost savings under spring conditions have a similar quantity and trend as under autumn conditions. Savings stretched between 10,000 - 14,000 SEK, seen in Figure 4.12a, having a difference of 29% between the lowest and highest buffer level. In Figure 4.12b, all data points are negative values, indicating that under spring conditions, total savings decrease with increased buffer capacity. The range in margin is the lowest for this scenario, and no distinct monotonic behavior for the increase can be established. However, studying the savings curve in Figure 4.12a, the change in marginal cost is small and the general trend that buffer capacity has a big impact on potential savings is clear.



(a) Savings in SEK per week as in relation to buffer tank storage hours during spring conditions, and bar chart visualization of available tank volume at varied buffer level

(b) Marginal saving trend in relation to buffer tank storage hours during spring conditions



(c) Cost per energy in relation to buffer tank storage hours during spring conditions

(d) Utilization index in relation to buffer tank storage hours during spring conditions

Figure 4.12: Comprehensive overview of cost savings and system utilization related to buffer tanks levels under spring conditions

A slight take off at buffer level at hour 8 can be identified in Figure 4.12c, where the average cost per energy becomes greater in cases with higher desirable storage capacity. The curve presenting the utilization index in Figure 4.12d shows similar behavior to the other seasons, with the index dropping below 90% at buffer level 10.

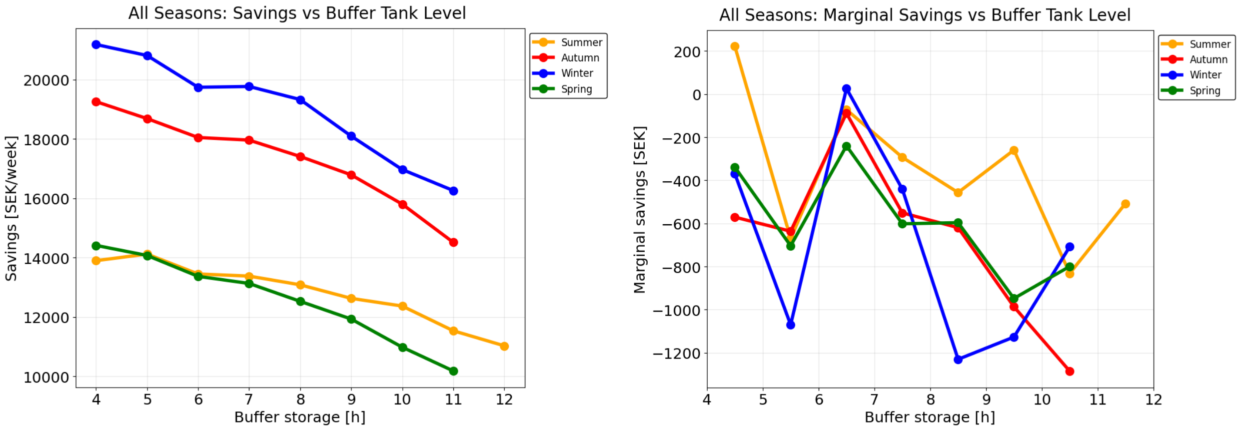
Numerical data for the analysis under spring conditions is found in Table 4.7.

Table 4.7: Numerical data obtained in the spring scenario simulation

Buffer [h]	**Minimum tank volume** [m^3]	**Percent of max** [%]	**Cost** [SEK]	**Power** [kWh]	**Pumped Volume** [m^3]	**Run time** [h]
4	2886.3	33.6	36773.5	59184.5	82671.5	141.5
5	3600.2	41.9	37112.3	60198.1	83383.4	143.3
6	4310.8	50.1	37816.2	60533.0	84028.3	156.8
7	5016.8	58.3	38056.2	60775.2	84691.7	156.0
8	5719.5	66.5	38657.6	61511.4	85394.5	153.0
9	6414.9	74.6	39254.0	61969.4	86115.9	158.0
10	7098.5	82.5	40202.1	62888.9	86885.1	165.0
11	7777.3	90.4	41001.5	63694.4	87469.8	165.8
12	Infeasible	Infeasible	Infeasible	Infeasible	Infeasible	Infeasible
Reference	-	-	51186.7	79192.3	80700.3	165.8

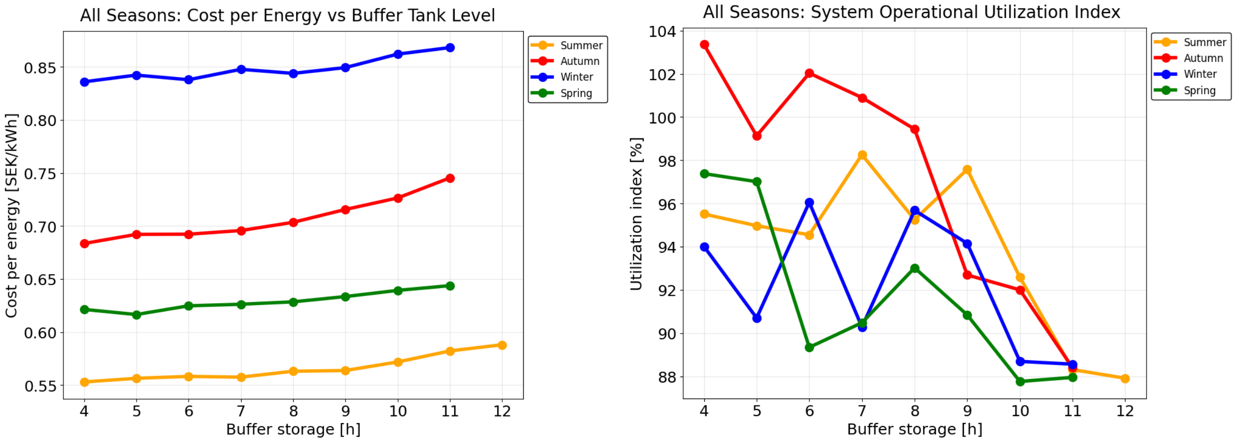
4.2.2.5 Seasonal comparison: Tank Buffer Level

In order to compare seasonal differences in the results from the four scenarios, Figure 4.13 visualizes the combination of the model outcome under seasonal variation. In terms of potential savings that can be achieved, Figure 4.13a shows that winter is the most favorable season. Autumn faces lower potential savings compared to the winter case, still reaching high levels. Summer and spring experience a similar amount of potential savings, being the lowest observed. Although differences in the absolute potential savings are observed, the marginal savings associated with a change in buffer security level follow similar trends across all seasonal conditions, causing the curves to overlap in Figure 4.13b. This outcome suggests that there is no significant relative effect of potential savings under varying seasonal conditions. Instead, the primary effect is of the magnitude of the savings.



(a) Seasonal comparison of savings in SEK per week as in relation to buffer tank storage hours

(b) Seasonal comparison of marginal saving trend in relation to buffer tank storage hours



(c) Seasonal comparison of cost per energy in relation to buffer tank storage hours

(d) Seasonal comparison of utilization index in relation to buffer tank storage hours

Figure 4.13: Seasonal overview of cost savings and system utilization related to buffer tanks levels

The average cost per energy trends, visualized in Figure 4.13c, follow the same magnitude of the electricity price profiles. Higher general prices in winter result in a high cost per unit of energy. During the summer, having low electricity prices results in the lowest cost per unit of energy. A small increase in all seasons can be observed after the 8-hour mark, indicating expenses increase with desired security. Figure 4.13d shows that under all seasons, the trend of the utilization index decreases with increased buffer storage level. Although the initial buffer level exhibits some irregular behavior, the overall trend remains clear, indicating a gradual reduction in utilization with increased buffer capacity.

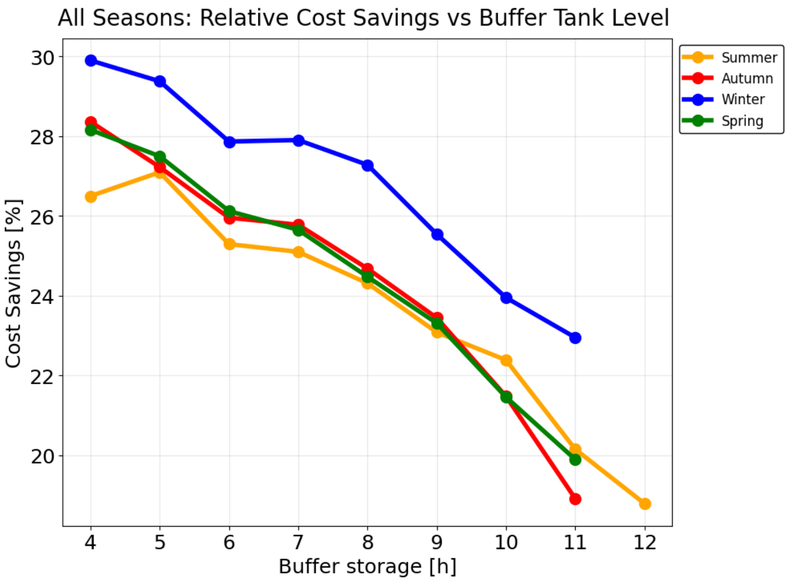


Figure 4.14: Seasonal comparison of relative savings in SEK per week as in relation to buffer tank storage hours

Figure 4.14 show the relative cost savings, calculated as $\frac{Cost_{ref} - Cost_{flex}}{Cost_{ref}}$, for the different scenarios. The model suggests that relative cost savings of between 19 - 30 % can be achieved throughout the year compared to the reference case.

4.2.3 Support service possibilities

An additional analysis was carried out in order to investigate the potential of flexible pump scheduling systems to participate in electricity support service markets. No additional simulation affecting pump behavior in response to market signals and potential revenue. Instead, the discussion is based on the state of charge in the tanks and the available power in the system. The top graph in Figure 4.15 shows how the tank level has varied under winter conditions in the flexible operation model. The red zone represents the minimum volume, the yellow is the operating region and the green field represents a possible increase of volume in the tank. The blue line is the state of charge. The graph below in Figure 4.15 is the power output in the simulation subtracted from the total maximum power allowed in the system (P_{max}). One pump had a maximum power of 160 kW, meaning if both pumps were running at full capacity, they would be using 320 kW. However, the power is limited due to flow restriction, only allowing a maximum flow of 900 m^3/h. This limit is marked in the figure as the red striped line. The green line represents the potential power that could have been added in this scenario.

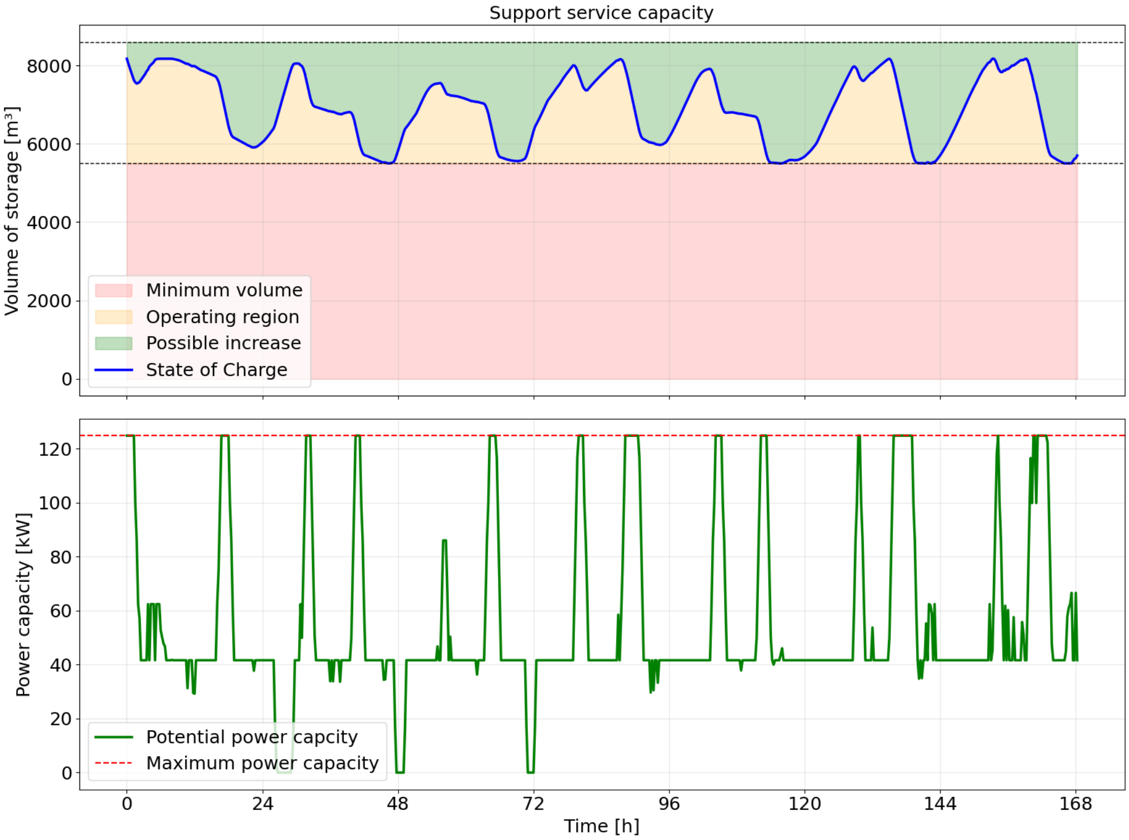


Figure 4.15: State of charge and possible available grid support capacity in the storage system. The upper graph show the storage volume over time with minimum and maximum bounds. The lower graph show the potential power capacity in the pump after daily consumption patterns.

Table 4.8 presents data for the winter scenario. Three tank buffer levels at 4, 8 and 11 hours were evaluated. 11 hours is the maximum storage level since 12 hours generated an infeasible solution. The maximum energy capacity was calculated based on the available volume in each case. Two different power assumptions were used based on the potential power curve in Figure 4.15. The first represents the maximum effect that could be achieved in the system. The second represents the average available flexible power under daily consumption, where a significant portion of the installed capacity is required for baseline operation. The number of hours represents the duration for which the system can sustain the corresponding power output given the available energy capacity.

Table 4.8: Impact of tank buffer level on energy and power flexibility metrics

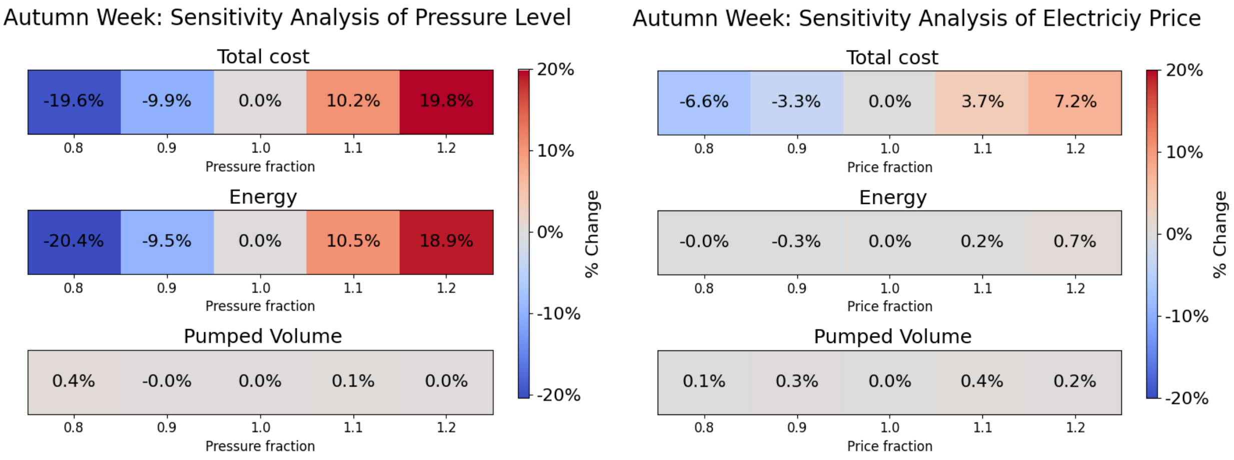
Tank buffer level [h]	Minimum volume [m^3]	Available volume [m^3]	Energy [kWh]	Effect [kW]	Hours [h]
4	2768.8	5831.2	809.75	124.85	6.5
				41.6	19.5
8	5500.0	3100.0	430.5	124.85	3.4
				41.6	10.3
11	7534.7	1065.3	147.93	124.85	1.2
				41.6	3.6

The table shows that the energy storage capacity is high compared to the available power, resulting in a long operation duration. It should be noted that the duration is based on a simplified steady state assumption and does not account for real-time fluctuation and system control. Dynamic response is also not included, which is a critical factor for ancillary services.

4.3 Sensitivity analysis

This section investigated how changes in pressure head level and price profiles affect the model results. Two scenarios were chosen in the sensitivity analysis, Autumn representing a scenario where no power tariff structure is active, and the winter scenario, which had an active power tariff structure. Original cases were the ones used in section Simulation Results 4.2. The Pressure head level was varied to assess the physical sensitivity of the system, while changes in electricity prices tested the economic sensitivity in the model. The analysis was performed scaling both pressure head level and price profiles using factors ranging from 0.8 to 1.2, testing sensitivity in both directions. By scaling the price profile, the absolute variation in prices was also amplified, meaning that high price peaks and low price periods were affected proportionally in magnitude, leading to increased sensitivity in the resulting cost fluctuations.

The results of the sensitivity analysis are shown in Figure 4.16. It can be concluded that changes in pressure level are directly linked to the required energy of the pump in a proportional pattern. Figure 4.16a shows that when the pressure level increased by a given factor, the energy consumption changed proportionally with the same factor. The pump energy is mainly determined by the pump equation in figure 3.11, since energy over time is the required power output. However, the pumped volume to the system was not affected by the change. This behavior is expected since the hydraulic energy is directly proportional to the pressure head level in the model. This result indicates that the system shows a high sensitivity in cost energy if the pressure head level i varied, but less sensitivity for the delivered volume. The system needs to always meet demand and deliver water to customers. Demand correlated constraints have stronger controls over the pumped water volume than the pressure level does.



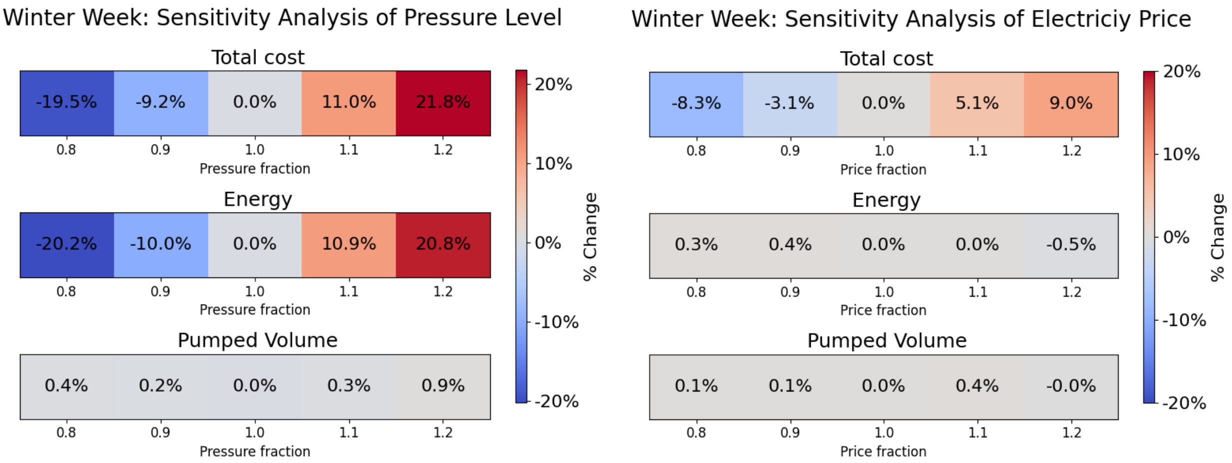
(a) System performance with respect to pressure level under autumn conditions

(b) System performance with respect to electricity price under autumn conditions

Figure 4.16: Sensitivity analysis of variation in key parameters affecting the flexibility model performance in the autumn scenario

Sensitivity analysis for price profiles is shown in Figure 4.16b. This result shows that energy and pumped volume are unchanged regardless of price level. Since demand profiles and hydraulic parameters are kept constant, this is expected in water distribution systems. The total cost is affected since the price profiles have changed. The reason why the sensitivity changes are not correlated with the scaled factor is that electricity prices are only a part of the total cost. Transmission cost and subscription cost are not affected by the sensitivity. The results show that the pump strategy is not affected by general scaling of electricity prices under the conditions used in the model, but instead is driven by supply and demand constraints.

Figure 4.17 shows the results for the sensitivity analysis made under winter conditions.



(a) System performance with respect to pressure level under winter conditions

(b) System performance with respect to pressure level under winter conditions

Figure 4.17: Sensitivity analysis of variation in key parameters affecting the flexibility model performance in the winter scenario

Figure 4.17a shows that the same results with scaling pressure level with varying factors, equal proportional results changes in energy and total cost. Pumped volume is not affected. Changing electricity price profiles under winter conditions does not affect energy or pumped volume output, shown in Figure 4.17b. The results are similar to the results presented for the autumn case, indicating consistent trends in the system response across the different scenarios.

5

Discussion

This chapter focuses on a more detailed discussion of the outcome of the model and findings in the results. The discussion seeks to answer the research questions of the thesis and to support the conclusion of the results.

5.1 Operational Shift and Economic Impact of Pumping Behavior using Flexibility Strategies

Findings in the results state that it is possible for water infrastructure to be energy optimized, creating both economic savings and energy savings in every season throughout the year, while still being able to provide a water supply in the system. However, the quantity of that saving and operational behavior differs depending on both price and demand structure, which varies a lot during different times of the year. In all scenarios in the year, economic signals create strong incentives to shift pump operation away from peaking to more favorable price periods, such as at night.

There are two main factors that influence operational behavior. The first factor influencing the pumping pattern is price volatility. The practical idea of load shifting is to move consumption from expensive hours with high demand to lower-cost periods and off-peak times. The model utilizes the price variations by redistributing the operation. If price volatility is lower or restricted, the motivation for the model to shift operation is reduced, resulting in more uniform operation behavior. The results show differences in pumping behavior between scenarios with an active power structure and those without. During winter and spring, peaks in power consumption occur less frequently and the pump experiences shorter shutdown periods. The shorter periods of shutdown are probably a consequence of water demand being higher in winter and spring in relation to autumn and summer. However, the reduced occurrence of high consumption peaks appears to be driven by the power tariff, as the same pattern is observed in both scenarios with an active tariff structure. High power peaks are penalized during daytime hours and as a result, the model favors more evenly distributed pumping rather than short periods of intense operation. These two factors together explain the differences in seasonal operation. High price levels drive savings in cost and energy, observed during winter when electricity prices remain elevated for longer time periods. High price volatility and a non-controllable power tariff structure increase optimal load shifting, as in the autumn scenario. Both the level and structure of electricity pricing affect the pumping behavior, determining the gained benefits from flexible pumping.

It is evident from the results that both cost and energy savings can be achieved by adopting a more flexible pump operating strategy. However, these benefits are associated with an increase in the total volume of water pumped from the reservoir. Although a larger cumulative pumped volume is observed in the flexible case, the total energy consumption is reduced. This is primarily due to higher flow rates during shorter operating periods, resulting in a faster turnover of water and allowing the pumps to operate under more favorable conditions. However, the increased pumped volume does not necessarily correspond to an increased water demand but rather reflects differences in operational strategy. This indicates an overall improved operational efficiency and the pumping system is operated during more favorable conditions. In this study, losses were neglected. Under a cost-minimizing operation, the importance of operating pumps near their optimal efficiency point increases. The flexible operating model seeks to maximize the utilization of a single pump at its best operating efficiency point and activates the second pump only when load shifting creates economic favor or demand requires increased pumping capacity. In contrast, the reference model follows existing operating patterns and does not explicitly consider either economic performance or energy efficiency. As a result, pumps may operate at lower efficiencies, leading to higher power consumption. In most water distribution systems, maintaining required pressure levels and volumes stored in the tanks is the primary control objective rather than minimizing energy consumption. Not only can a flexible strategy enable operation under more favorable conditions, but the strategy also allows the pumps to shut down during certain hours, reducing total operating time. Reduced runtime can contribute to reduced mechanical wear and potentially extend the pump's operational lifetime.

Beyond the demonstrated reduction in energy consumption and operating costs, pump performance can also be assessed using the utilization index. The utilization index reflects how effectively the pumping system uses its available capacity over time and should not be interpreted as a measure of the efficiency of any individual pump. The results in Figure 4.3 show that the utilization index in the flexible model exceeded 90 % in all seasonal scenarios. In contrast, the reference model, the utilization index spans from approximately 70% in the summer scenario to 80% in spring, consistently lower than those observed under flexible operation. These findings indicate that flexible operation alters the pumping pattern, which improves the utilization of the available pumping capacity. In practice, this means that the same installed pumping capacity is used more intensively during operation while remaining inactive for longer periods between pumping events, also leading the multiple start-stop cycles. However, the number of start-stop cycles remained well below the maximum limit recommended in the manufacturer's manual. The reference model is heavily influenced by the demand curve. During periods of lower demand, as for example in the summer scenario, pumps operate at reduced flow rates and also operate at lower flow. Since pump efficiency is related to the operating flow of the pump, lower flow rates generally result in reduced efficiency and consequently, lower utilization index. This correlation is visualized in Figure 4.8 when observing the reference model. Overall, the results suggest that operating the distribution pump with a flexible strategy can improve system-level utilization of available pump capacity while maintaining operational requirements.

In addition to the direct benefits associated with energy optimization and cost reduction, more effective pump operation may provide broader operational advantages. Economic savings achieved by flexible operation can be beneficial for the utilities in many aspects. Savings create opportunities to reinvest resources from operations to maintenance, infrastructure upgrades, replacement of aging equipment, leakage reduction measures, or other improvements within the water distribution system. Such investments may help offset any additional operational stress introduced by more dynamic pump scheduling and, at the same time, contribute to long-term reliability and resilience of the WDS.

5.2 Impact of Buffer Capacity and System Benefits

The results of the buffer capacity analysis indicate that the required level of storage security has a significant role in the operation of the water distribution system. Operational cost, energy consumption and water supply requirements are all affected parameters of security constraints. In this study, the buffer level represents the minimum storage volume requirement to ensure security of supply. Increasing the requirement reduces the feasible operation space of the optimization model, since a larger portion of the tank volume must be reserved for security purposes and is unavailable for operational flexibility. Consequently, pump scheduling becomes increasingly constrained and maintaining a high storage level becomes a more dominant factor in operational decision-making. Pump operation has to shift in both timing and intensity, which can affect the non-monotonic behavior in marginal savings. In theory, as buffer capacity increases, marginal savings would be expected to decrease or remain constant, since a larger buffer should not restrict the solution space of the model. However, the results indicate that in certain cases, the higher buffer levels lead to a minimum water stored, restricting operating space, which would generate greater savings. This behavior is not expected as increased storage security reduces the flexibility available to the optimization model. One possible explanation for this observation could be due to the numerical solver effect. It is already stated that the tolerance threshold is not optimal due to computer capacity. This can affect the optimal solution between nearby cases. Changing the tolerance gap to a smaller value would probably generate a more optimal solution, resolving the issues with the solution space being restricted.

Despite limitations associated with model accuracy and solver performance, the observed trends show that both cost and energy savings are strongly dependent on how much flexibility remains in the tank space after the minimum volume requirements are set. The results highlight a trade-off between operational efficiency and system security across all scenarios. However, the magnitude of achievable savings is not determined solely by the available flexibility. The absolute savings are strongly influenced by seasonal variation in electricity price structures. Results state that the greatest degree of load shifting appeared under autumn conditions, when the highest savings were achieved in winter. This finding suggests that increased load shifting capability does not necessarily translate directly into greater economic benefits. Although pump runtime was reduced during autumn and summer and load shifting abilities are greater, the economic value of shifting load was lower due to less favorable price dynamics. Winter conditions characterized by long, high-price periods provide stronger economic incentives for flexibility, even when desired buffer security increases. The interaction between buffer constraints and seasonal price dynamics interacts with system performance and optimal scheduling.

In all scenarios, a take-off point in average cost per unit of energy could be identified in the buffer capacity analysis, showing a non-linear change in system behavior beyond a certain storage level. Before reaching the take-off point, moderate changes in cost efficiency are observed when buffer capacity is increased, reflecting that the system is able to exploit operational flexibility to optimize pump scheduling. When reaching security level beyond the identified threshold, the cost per energy increases at a higher rate, suggesting a reduction in economic returns from additional storage capacity, which is also identified. When increasing the buffer requirement, a larger share of storage is allocated to maintain security, rather than contributing to operational optimization. The system's ability to shift pumping activities to periods of lower electricity prices is reduced. Although operational flexibility remains beneficial in terms of cost savings in all scenarios, the results suggest that a point is eventually reached where the additional security affects the operational efficiency improvements.

The analysis for the system utilization index further demonstrates that increasing buffer storage requirements leads to a reduction in the utilization of system operation in the flexibility model. This result is expected since a higher minimum storage level forces stricter operational constraints on the system, which reduces the available flexibility in pump scheduling. When a larger portion of the storage capacity becomes reserved for security purposes, the opportunities to shift pumping to favorable price periods become less frequent, resulting in more restricted control strategies showing a decline in utilization performance. The overall trend is clear and non-monotonic behavior can be observed across all scenarios. Similar irregularities correlate in the cost per energy analysis, indicating that small fluctuations between neighboring scenarios are probably caused by solver sensitivity and the selected optimal tolerance rather than physical system behavior. However, despite these local deviations, the overall trend highlights the relationship between storage flexibility and operational efficiency. Pump can be more strategically operated with lower buffer requirements, but when priority shifts toward increasing security levels, the ability to optimize pump operation to optimal strategies becomes limited, affecting the overall system performance.

5.3 WDS: a possible support service action to the grid

One of the research questions aims to investigate whether it is possible for a water distribution system to participate in the support services market. Due to the time limit of the project, a full-scale market participation analysis was not conducted. However, operational results from the cost-oriented flexibility model were used in this discussion. The flexible operation model was driven by spot price signals and represents an operational strategy focused on simple cost optimization, not active market bidding. If a water distribution network were to participate in the flexibility market, that would require different control strategies than the one suggested in this study. That strategy would aim to operate the pump so that it would be possible to both increase and decrease in intensity depending on market activation signals. The state of charge in the storage tanks and the available pump power in Figure 4.15 is not represent a scenario where support service action is used as a signal in operation. However, the figure still provides valuable insight.

Storage in water towers has the potential to contribute as a flexible energy resource through a combination of controllable pump load and stored potential energy. Two essential concepts in flexibility management are the system´s energy capacity [kWh] and the dispatchable power capacity [kW], where energy capacity is the total size of how much energy can be stored, and power capacity refers to how quickly that energy can be transferred. In Table 4.8, it is described that changing the minimum buffer level expands the total system size in terms of energy, creating a bigger energy storage in theory. However, the primary limit in the system is not the energy capacity but rather the power capacity and hydraulic dynamics. Flow limitation in pipes results in a maximum capacity of 125.85 kW power output. In Figure 4.15, although the maximum pump capacity is approximately 125 kW, a large portion of the capacity is required to maintain the required water supply in the system. As a result, the available power capacity left for flexibility is significantly lower at approximately 40 kW on average.

The available power decides how much support the utilities can provide to the grid and the flexibility market. Ancillary services value fast controllable power more than total energy storage, where the maximum controllable power determines the system’s potential to contribute to grid support services. The mean available power in this water distribution system of approximately 40 kW is relatively modest compared to the capacity of battery storage. Besides the maximum power capacity, how fast the system can respond is vital for acting in the flexibility market. Using a variable speed pump enables fast adjustments of motor rotational speed, resulting in rapid response in electrical control of the pump. However, when operating a water system, this is not the limiting factor. The real-time ramping of flow is limited by hydraulic conditions in terms of pressure requirements, cavitation risk, and overall system stability. Although frequency converters enable quick modification of motor speed, the effective operation of pumps is not only determined by electricity control, but also by the hydraulic response in the distribution network.

When evaluating different flexibility market options, the FCR market requires very fast response times, which will be challenging for the water distribution network due to hydraulic limitations. The aFRR operates on a minute-level response scale, which can also be difficult for the water utilities to achieve. In contrast, the mFFR market may represent a more realistic opportunity for a water distribution network to participate in. This ancillary service allows for longer activation periods that are better aligned with the slower dynamics of transporting water, which is suitable. for WDS. However, the minimum bid requirement of 1 MW may still exceed the achievable flexible power output of a single water distribution system. This study could deliver a maximum of 125 kW due to flow restriction. Increasing flow capacity could potentially generate higher available power output, but it is not necessarily the case since higher flow results in higher losses in the pipe system. Direct participation from an individual WDS is likely limited, but aggregation of multiple systems could potentially make participation more feasible. Without aggregating systems, flexible operation for an individual WDS is more relevant for energy optimization, load shifting and peak shaving and not as a support service to the grid.

5.4 Model Improvements and Recommendation of Future Work

The model provides insight into operational flexibility strategies of water distribution systems. However, heavy simplification limits its ability to accurately capture real-world system dynamics. The biggest model assumptions are the use of a constant pressure level and the neglect of hydraulic losses. Pressure conditions inside the pressurized system vary continuously with outgoing flow rates in a real-world system. Hydraulic losses have the same corresponding effect, since pipe friction influences the required pumping energy and overall system efficiency. The model simplifies the relationship between flow and energy consumption, which results in an underestimation of the physical constraints. The potential savings in both cost and energy presented in this study may be optimistic for real operating conditions. For example, in the sensitivity analysis, when the pressure level was varied, both total cost and energy consumption changed in proportion to the applied scaling factor. If hydraulic losses were considered in the model, the results would change, as losses increase with higher required pressure, making this relationship non-linear. Incorporating dynamic hydraulic behavior and friction losses in future studies would improve the model's physical realism and provide more accurate estimates of operational improvements in cost and efficiency.

The power tariff structure in the model represents a simplified approximation of how tariff structures are applied in practice, as tariffs are often added after operation. In this study, a single peak event was used to calculate the additional peak cost, in many real power tariff structures, the average of several peak values is used. Another difference is that power tariffs are only applied during weekdays, and not on weekends, which were not considered in the model. These aspects can affect the economic response of the model, as peak power reduction must be somewhat simplified. Another challenge is that the power tariff structures are currently under construction due to increased electrification and grid requirements. A result being that future power tariff structures may be different from the current implementation.

Always trying to predict the future, the level of uncertainty increases. Future demand patterns and electricity market conditions are hard to predict, affecting decision-making in pump operation. More complex modeling approaches could be of interest, for example, model predictive control, working in a 15-minute horizon prognosis, or other tools of machine learning. As already stated, the tolerance gap was set to a higher value in this study due to time limitations. Allowing the model to fully solve and generate the optimal solution would generate more accurate results.

6

Conclusion

The thesis set out to investigate the potential for flexible operation of water distribution pumps. Main findings can be summarized as follows:

- Water infrastructure can be energy-optimized through flexible rescheduling of pump operations away from peak-price periods.
- Significant reduction can be made in both cost and energy by implementing flexible operation throughout all seasons of the year. The magnitude of the savings depends on the structure and variation of electricity prices, which are affected by both the presence and duration of peak price periods. The results show that demand-side flexibility can reduce costs between 19-30%, while approximately 3,500-8,500 kWh of load can be shifted, depending on security level and season.
- Power tariff structures impact scheduling strategies of the pumping system and the potential for flexible operation in WDS by determining the economic benefit of load shifting and rescheduling pumping activities.
- Shifting from demand-based strategies to flexible operation impacts pump performance by altering operational scheduling, leading to improvement in utilization of optimal pump condition in terms of efficiency and power. Improvements in pump efficiency also reduce operational costs and maintenance requirements, as lower energy consumption directly translates into reduced electricity and operational load.
- The potential for an individual WDS to participate in flexibility markets is limited, however aggregation of multiple systems could increase the potential. Hydraulic constraints and operational limitations restrict the ability to use fast control signals required in certain ancillary service markets. Flexible operation of WDS shows is more suitable for energy optimization and load shifting, contributing to the reduction of electricity demand during peak load hours.
- Higher requirements for buffer safety margins lead to reduced operational flexibility, affecting both potential cost savings, optimal pump performance conditions, and the ability to provide support services.

In conclusion, this study has proved that WDS can provide operational flexibility through load shifting and storage utilization showing a measurable reduction in both energy consumption and operational cost. However, the extent of the flexibility is affected by hydraulic limitations, storage requirements, price structures, and market design, which also limit the suitability for fast-response ancillary services. Overall, WDS shows great potential for long-term energy optimization.

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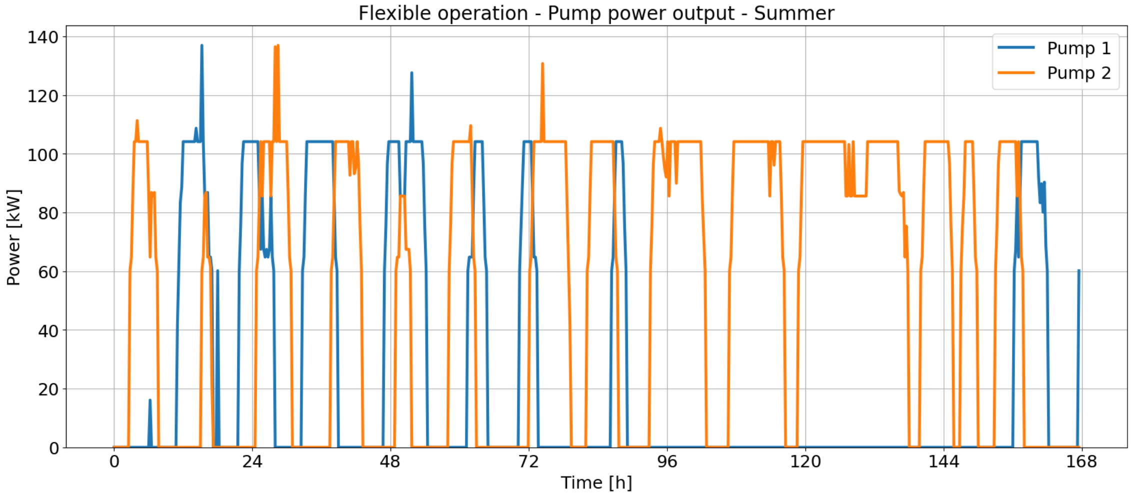
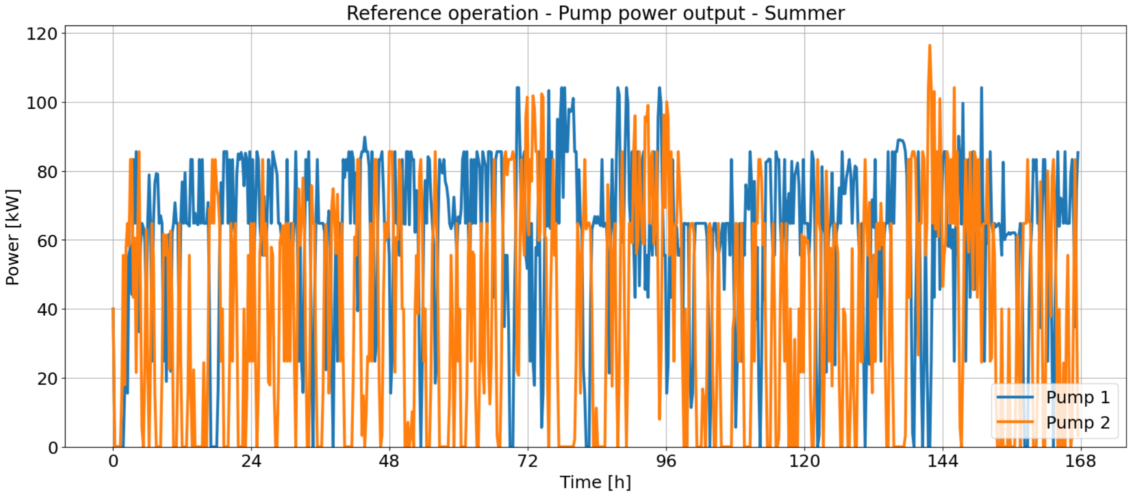
A

Appendix 1

This appendix include output data from individual pump operation the both the flexible and reference model. The same scenarios as in section 4.2 Simulation Results are represented in Figure A.1,A.2,A.3 and A.4.

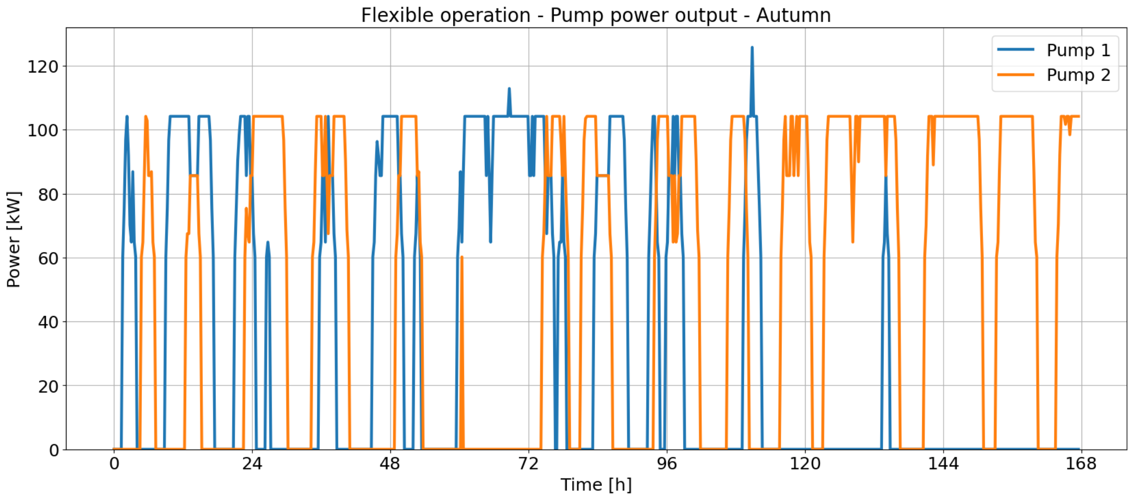


(a) Flexible operation model: pump scheduling under summer conditions

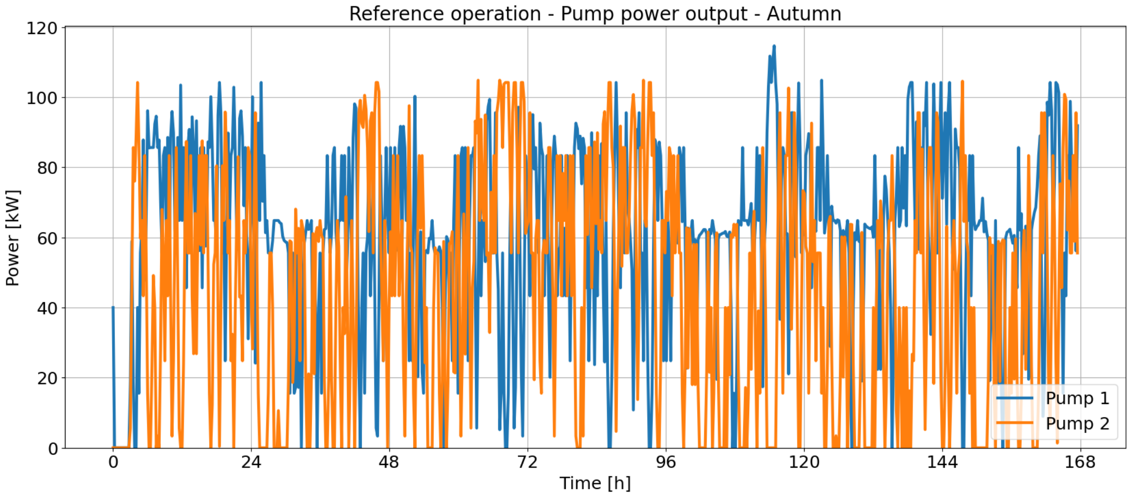


(b) Reference operation model: pump scheduling under summer conditions

Figure A.1: Simulation results of individual pump power output for flexible and reference operation under summer conditions in price and demand patterns

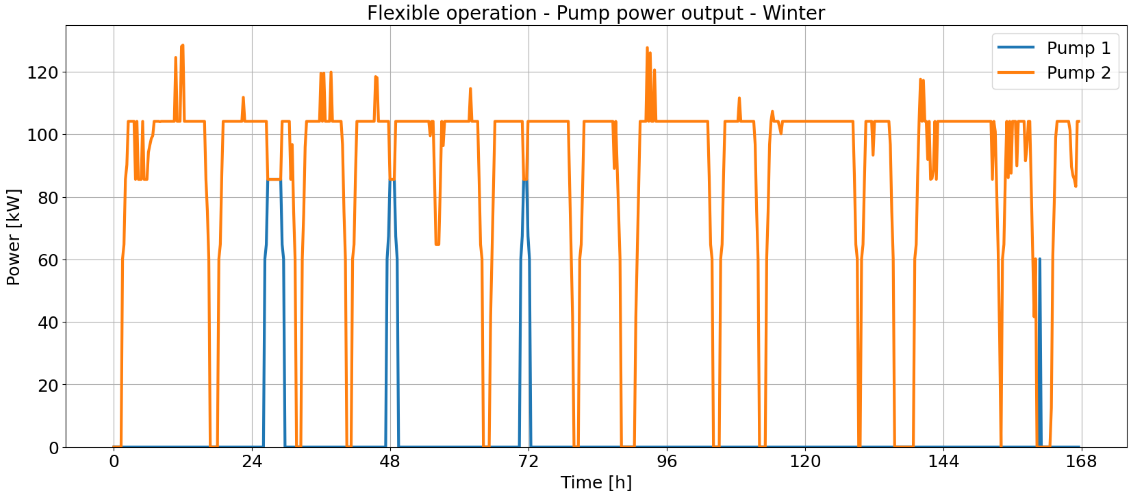


(a) Flexible operation model: pump scheduling under autumn conditions

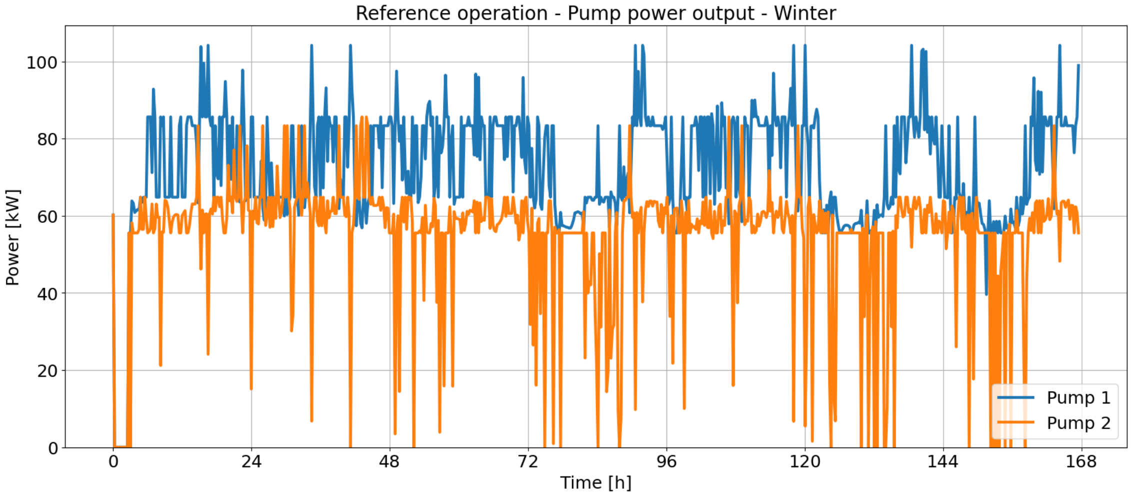


(b) Reference operation model: pump scheduling under autumn conditions

Figure A.2: Simulation results of individual pump power output for flexible and reference operation under autumn conditions in price and demand patterns

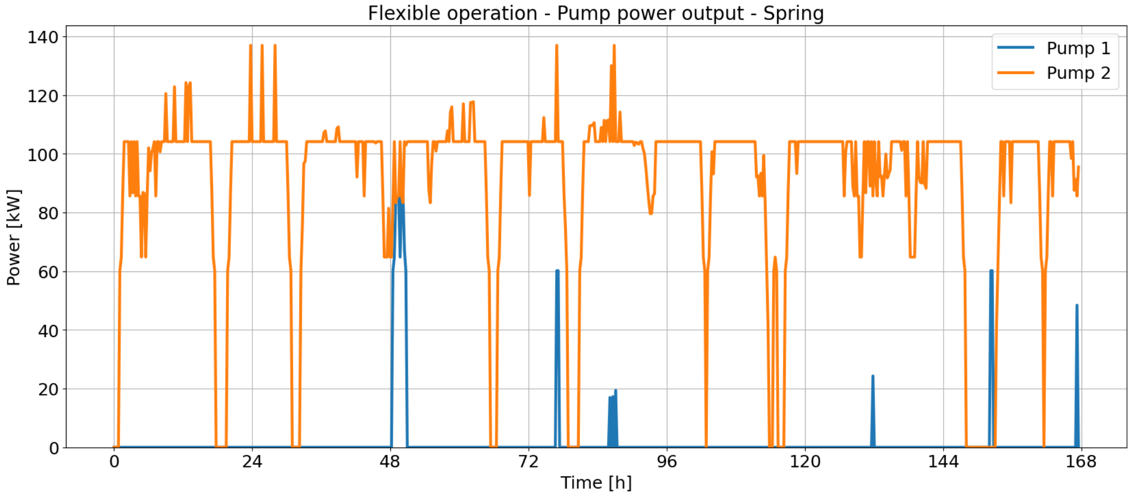


(a) Flexible operation model: pump scheduling under winter conditions

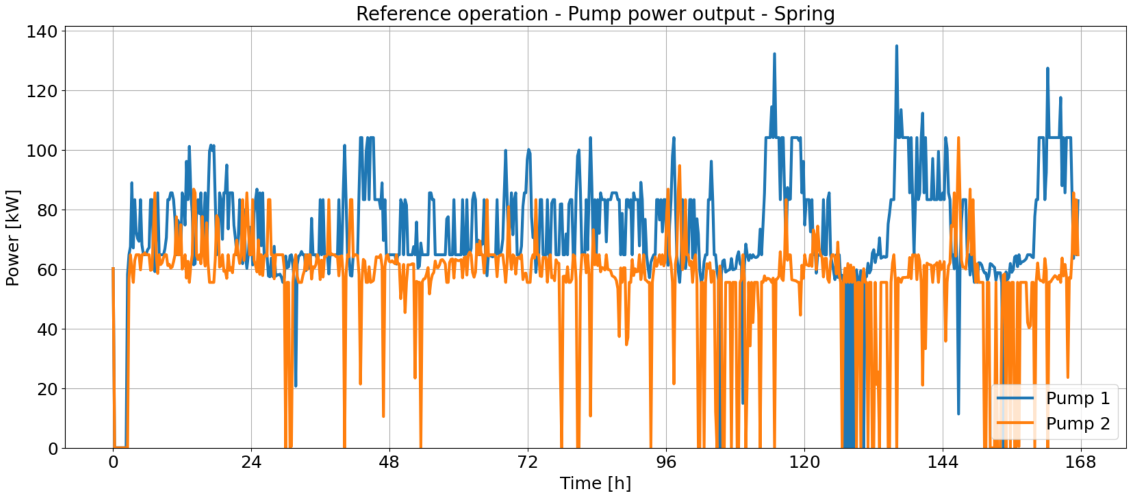


(b) Reference operation model: pump scheduling under winter conditions

Figure A.3: Simulation results of individual pump power output for flexible and reference operation under winter conditions in price and demand patterns



(a) Flexible operation model: pump scheduling under spring conditions



(b) Reference operation model: pump scheduling under spring conditions

Figure A.4: Simulation results of individual pump power output for flexible and reference operation under spring conditions in price and demand patterns

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