SEASONAL AND TIME OF DAY DEPENDENT ELECTRICITY COSTS IN SRI LANKAN POWER SYSTEM, CONSIDERING WATER VALUE

Dimuthu Punsara Colambage

208040M

Master of Philosophy

Department of Electrical Engineering

Faculty of Engineering

University of Moratuwa

Sri Lanka

August 2024

SEASONAL AND TIME OF DAY DEPENDENT ELECTRICITY COSTS IN SRI LANKAN POWER SYSTEM, CONSIDERING WATER VALUE

Dimuthu Punsara Colambage

208040M

Thesis/Dissertation submitted in partial fulfilment of the requirements for the degree

Master of Philosophy

Department of Electrical Engineering

Faculty of Engineering

University of Moratuwa

Sri Lanka

August 2024

Declaration

I declare that this is my own work, and this thesis does not incorporate without acknowledgement any material previously submitted for a degree or diploma in any other University or Institute of higher learning and to the best of my knowledge and belief it does not contain any material previously published or written by another person except where the acknowledgement is made in the text. I retain the right to use this content in whole or part in future works (such as articles or books).

Signature: Date: 2024.08.30

The above candidate has carried out research for the MPhil thesis under our supervision. We confirm that the declaration made above by the student is true and correct.

Names of Supervisors:

1. Prof. W.D.A.S. Wijayapala
2. Dr. Tilak Siyambalapitiya

Signatures of the Supervisors: Date:

1.

2. 2024.08.30

Dedication

I dedicate this thesis to my parents and in memory of Emeritus Professor H.Y. Ranjit Perera, the initial supervisor of this research, who suddenly passed away.

Acknowledgement

It is with great pleasure that I acknowledge the assistance and contribution of all the people who helped me successfully finish this research. I am greatly indebted to my supervisors, who have been towers of strength throughout this project with their insight and guidance. I would like to acknowledge all the other academic staff members of the Department of Electrical Engineering, University of Moratuwa for their kind suggestions, feedback, and helping hand.

My appreciation goes to the members of the Progress Review Panel and the members of the Final Examination Panel for delivering their guidance and valuable comments, which have been instrumental in successfully continuing my research work. My heartfelt thanks go to the University of Moratuwa and the System Control Centre of the Ceylon Electricity Board for their guidance.

Moreover, I would like to extend my gratitude to my family for supporting me and encouraging me throughout this period. Finally, I would like to thank our colleagues who helped and motivated me during the research.

Abstract

Electricity generation costs fluctuate significantly due to seasonal, daily and hourly variations in electricity demand and powerplant availability. Utility providers prioritise optimising overall generation costs while ensuring continuous and high-quality electricity supply. The scheduling of power plant dispatches follows Stochastic Dual Dynamic Programming (SDDP) principles to maximise operational efficiency. Unlike thermal power plants, the evaluation of water value for hydropower plants introduces complexity in generation cost calculations. This research introduces novel approaches for estimating water value. These approaches include assigning a zero value to water, as well as proposing the generation cost of the most expensive thermal power plant in the daily load curve and the weighted average value of variable thermal power plants as optimal methods for water value estimation. The study accurately estimates seasonal and time-of-day-dependent electricity costs using advanced economic dispatch techniques and refined water value estimation methodologies. Furthermore, it explores the comparative water values between power generation and agriculture, enhancing decision-making processes. Focused on the Sri Lankan power system, this research contributes valuable insights into optimising electricity generation strategies amidst dynamic operational conditions.

Keywords: Generation Cost, Water Value, Economic Dispatch, SDDP, Optimise

Table of Contents

List of Figures

List of Tables

List of Abbreviations

Abbreviation	Description
CEB	Ceylon Electricity Board
DDDP	Discrete Differential Dynamic Programming
DDP	Differential Dynamic Programming
DP	Dynamic Programming
DPSA	Dynamic Programming with Successive Approximations
FCF	Future Cost Function
FSL	Full Supply Level
GT	Gas Turbine
ICF	Immediate Cost Function
IPP	Independent Power Producers
KCCP	Kelanitissa Combined Cycle Power Station
KPS	Kelanitissa Power Station
LKR	Sri Lankan Rupees
MCM	million cubic metre
METRO	Medium Term Reservoir Optimisation
MOL	Merit Order List
Mt	Metric ton
PUCSL	Public Utilities Commission of Sri Lanka
SDDP	Stochastic Dual Dynamic Programming
SLMA	Sri Lanka Mahaweli Authority
ST	Steam Turbine
WPS	Wimalasurendra Power Station

List of Appendices

1. INTRODUCTION

The cost of electricity generation varies among different power plants, and this difference can be attributed to various factors such as the conditions of the energy source, the country's location, the season, date, time and several other reasons. Specifically, the choice of energy source used for electricity generation plays a crucial role in determining the overall generation cost. Additionally, both natural and man-made factors in different countries can influence this cost.

Some country-specific reasons affecting electricity generation costs include the availability of the energy source, government economic policies, climate patterns and the economic and technical development levels of the country. It is common to consider the generation cost of a country as a constant in making technical and economic calculations, but this notion is not justified.

The generation cost depends on the chosen generation technology, whether it uses hydro or thermal methods, and the energy source, such as coal or diesel. As mentioned earlier, generation costs vary due to the availability of the energy source in a particular country; if the sources must be imported, the cost will increase. In the Sri Lankan scenario, hydropower is free, and the operating cost of hydropower plants is negligible, while thermal resources such as diesel and coal need to be imported. Other factors, including capital cost, operating cost and maintenance costs, are also relevant to this topic.

Tax policies, import and export regulations and various government policies can affect generation costs. Additionally, climate patterns have a direct relationship with generation costs, especially when weather conditions influence an increase in hydro power usage, such as when electricity demand rises due to the use of air conditioning machines in the winter season. Furthermore, the development level of a country is a crucial parameter in deciding electricity costs because well-developed and industrialised countries tend to use the latest technology, which requires more electricity. Moreover, if the economy is strong, the public is more inclined to use a greater number of electrical devices.

The primary responsibility of a power system is to produce continuous, high-quality power according to demand at a reasonable price. Power generation depends on consumer-side demand, which varies throughout the day. Therefore, it is essential to maintain generation according to demand and losses to maintain the stability of the system.

The utility side of the power system must decide on the best combination of power plants to meet the varying demand for electricity. The short-term optimisation problem involves scheduling generation to minimise the total generation cost over a study period, typically a day, subject to numerous constraints that must be satisfied. Power system owners aim to build new power plants to optimise the total cost of constructing and operating the generating system while phasing out old and less efficient power plants. If an electricity company is responsible for meeting the demand for electricity, the most critical constraint is that global generation must equal the quarter-hourly forecast demands. Two related short-term optimisation constraints are:

1. Unit Commitment
2. Economic Dispatch

Unit commitment is the process of deciding when and which generating units at each power station to start up and shut down. Economic dispatch involves deciding the individual power outputs of the scheduled generating units at each time point.

The primary objective of power system unit commitment is to schedule generation units to meet load demand at the minimum operating cost while adhering to all plant and system constraints. Generation scheduling involves determining startup and generation levels for each unit over a given scheduling period, subject to various system and unit constraints. The general unit commitment problem aims to minimise operation costs, including startup and shutdown costs. Throughout this process, it is evident that generation costs are influenced by the season and time of day.

1.1 Water Value Concept in Generation Planning

Food, water and air are identified as the bare necessities of living beings. Water, a natural resource, is available for free. More than 95% of the Earth is filled with water, but only 2-3% of that is usable. The demand for water is increasing day by day due to various reasons, including development, population growth and climate change. No other alternative is available for water. It is predicted that a water crisis will occur in the near future, and people are encouraged to preserve water. While water itself is free, it holds economic value. When water is not available to fulfil all needs, alternatives must be found to complete tasks. These alternatives come with a cost, and that cost is replaced by water when it is available. Alternatives might change from day to day and time to time, and their costs might vary according to date and time. This is the basic idea of the water value concept, which came into discussion in the 1960s with Swedish Power System Planning [1] [2].

Sri Lanka is a country with a tropical climate, and its annual rainfall comes from three different sources: two monsoonal (northeast and southwest), convectional and depressional origins. Large reservoirs have been built in the dry zone of the country to store water, and multi-purpose development projects such as Mahaweli manage the water resources to serve basic needs, agriculture, and power generation. The Laxapana and Samanala hydropower complexes store and manage water resources for hydropower generation, while approximately 201 mini hydropower plants (without sufficient water storage) operate in various locations [3]. Water is freely given by nature, so it can be said that the energy charge of water is zero for hydropower generation.

The availability of water is not constant throughout the year, emphasizing the need for protective and efficient water use. Reservoirs typically fill up during the rainy season and are unable to store more water. In such situations, hydropower plants operate at full-load conditions to avoid wasting water. In the dry season, water stored in reservoirs is used, and any shortage of water can disrupt the public's lifestyle, incurring additional costs to manage abnormal conditions.

The value added to water is not constant, changes from day to day and time to time due to various seasons. In dispatch decisions in a hydro-thermal power system, the water value concept is widely used. In extreme cases, operating a diesel thermal power plant may be cheaper than operating a hydropower plant when considering the value added to water. The marginal thermal generator is started when the water value exceeds the operating cost of the marginal hydro generator.

Water value in power generation is defined as the equivalent value of water in the reservoir, indicating the equivalent value of 1 kWh of electrical energy produced from hydropower. The water value is used in unit commitment to decide on switching generators on and off, with power plants dispatched according to their merit order.

When the water value crosses the next most expensive thermal generator, the corresponding next most expensive thermal generator is switched on.

When reservoirs are filled to spill level, the water value is effectively zero. In conditions of no rainfall, water draws down, and the value of remaining water increases. At one point where the water value crosses the operating cost of the cheapest thermal plant, if the first oil plant is not started, the water value continues to increase.

Contrary to common understanding, expensive thermal power plants are not necessarily used to serve peak demand. In practice, when oil power plants are started, they are operated at full load throughout the day because the water value is higher than the value of energy from the most expensive thermal power plant. Hydropower plants are utilised to serve the peak due to their fast response, availability in smaller capacities and upstream storage.

It's important to note that the water value concept deals with operational economics. Sometimes, calculations may show that power generation is cheaper than cultivating paddy fields in a particular area. These calculations and economic evaluations are done at the designing stage before finalising any multipurpose hydropower project. If the water value for power generation is cheaper, it may not be considered, as water should be released to fulfil basic human needs and other requirements, such as agriculture.

1.2 Importance of Calculating Seasonal and Time of Day Dependent Electricity Cost

Quantitative cost accounting methodologies are employed in accumulating, classifying, summarising and interpreting relevant information for operational planning, controlling and decision-making. The actual power generation cost holds significance in power generation, aiding in the formulation of tariffs, decision-making regarding new power plants, and dispatch power plants. The cost of generation is not constant; it fluctuates from day to day and time to time. Therefore, it is crucial to calculate the seasonal and time-of-day-dependent generation cost to ascertain the variation cost on a day-to-day and time-to-time basis. The water value concept serves as an intermediate output in the process of calculating the seasonal and time-of-use-dependent electricity cost.

This concept denotes the revenue that can be gained if 1 kWh of energy is saved from the most expensive power plant. In other words, when using the time-of-use costing method, it is necessary to convey to the customer the amount the system can save if they save 1 kWh. The water value concept can be applied to introduce a time-of-day tariff structure that provides an accurate estimation of time-of-use energy usage for electricity consumers. The results are valuable for enhancing current methodologies of tariff calculation, identifying ideal market conditions, estimating electricity prices at every quarter hour and making necessary predictions. As mentioned, this can serve as a guideline for establishing a time-of-use tariff for customers, where the time-of-use price concerning the average price is arbitrarily determined. These outcomes offer guidance on how the cost of electricity should be structured to communicate to customers at a particular date and time of the day, enabling consumers to respond by managing their energy utilisation [4] [5] [6].

1.3 Water Value in Agriculture

Currently, Sri Lanka's water management policy prioritises releasing water for basic needs before allocating it for agriculture and, subsequently, for electricity generation. Once water is used for agriculture, any remaining resources are directed towards electricity generation if available. The amount of water required varies by crop. For this analysis focus on the value of water in agriculture using rice as a reference, given its status as a staple food and its high-water demand. The water value in agriculture is determined based on two criteria: the amount of rice that can be produced per cubic meter of water and the cost of producing one kilogram of rice using that water. The water value in paddy cultivation varies with its growth stages. For instance, water levels are critical for paddy fields during the initial weeks but become less critical during the 8^{th} and 9^{th} weeks of growth. Additionally, seasonal factors impact water usage, as the two cultivation seasons—Yala and Maha—affect rainfall and other conditions.

1.4 Problem Statement and Objectives

The electricity generation cost has become a prominent topic in the Sri Lankan power system due to the increasing demand for electricity. The harnessing of almost all available hydropower sites has led to a transformation in the system, transitioning from a hydro-dominant system to a combination of coal and renewable energy dominance. This process has had political and economic impacts, resulting in financial losses for the utility side.

According to the current generation cost calculations in CEB, there are no seasonal and time-of-day cost considerations for generation, except for the calculation of the total generation cost per month. The present planning and dispatch analysis consider the energy charge for hydropower generation to be zero. It is crucial to calculate seasonal and time-of-day generation costs to determine how the generation cost varies throughout the day in different seasons. The primary objective of this research is to introduce a model to assess seasonal and time-of-day costing. The problem is examined in a general context, with Sri Lanka being taken as a case study for the issue. As partial objectives, the research examines different seasonal and time-of-day dependent parameters that influence the generation cost and determines the "water value" of power generation in Sri Lanka

Additionally, the water value for agriculture is calculated using paddy cultivation as a reference. This is then compared with the water value calculated for electricity generation. This comparison provides insights into the amount of electricity (kWh) produced per cubic meter of water and the amount of rice (kg) that can be produced per cubic meter of water, helping to determine which use yields more profit.

1.5 Project Scope

Generation costs are influenced by various constraints, fluctuating due to both natural and man-made conditions. The analysis of electricity data aims to examine the impacts of different conditions on the total energy cost.

The planning of a hydrothermal power system poses challenges due to the complexity of uncertainties arising from various conditions. Dynamic Programming (DP) techniques are employed to address sequential decision problems, breaking down the complex issue into subproblems based on mathematical principles. Optimal decisions for the current state are determined through a series of future decisions. The Stochastic Dual Dynamic Programming (SDDP), the latest DP method, is utilised to establish a methodology for assessing seasonal and time-of-day-dependent electricity costs. The current methodology employed by the CEB is based on SDDP and is notably complex. In this study, a simpler methodology is developed by avoiding intricate constraints. This model guides economic dispatch, and the electricity generation cost is calculated using three water value methods.

The main data sources for this research are pre-recorded and predicted data from the CEB. Some of this data is publicly available, while some is not. In addition, recorded data from the Department of Irrigation, Department of Agriculture Mahaweli Authority and Central Bank were also used.

Post-2020, the regular electricity consumption pattern in the country was disrupted due to the Covid-19 pandemic and the economic and political struggles in Sri Lanka in 2022. There were daily electricity interruptions from 2022 to 2023. Therefore, the year 2019 was selected as the sample year for this research. An overview of this thesis can be summarised as follows:

Chapter 02: Presents the effects of different factors on electricity generation costs.

Chapter 03: Expresses the literature review of the research. It describes applicable methodologies for the same scope and provides a local and international overview of the subject.

Chapter 04: In this chapter, A model is developed using the principles of SDDP.

Chapter 05: The analysis of data to present useful results in achieving the research goals is processed in this chapter.

Chapter 06: Conclusions and recommendations are presented in this chapter.

2. IMPACT OF VARIOUS FACTORS ON GENERATION COST

The Sri Lankan Power System operates as a hydro-thermal system, where natural effects contribute to fluctuations in hydro power generation. In contrast, the major resources for thermal generation are imported, there are no changes in thermal generation due to natural factors. When there are variations in demand, power plants with different unit costs must be dispatched in an optimal manner [7] [8]. Typically, low-cost thermal power plants are employed to handle the base load. As demand increases, higher-cost power plants need to be gradually dispatched, resulting in an escalation of unit costs [9].

However, in the Sri Lankan context, hydropower plants with lower generation costs are dispatched during peak times, specifically to address capacity needs at peak. The underlying reason for underutilising hydropower plants is the conservation of water for future needs, driven by an understanding of the value of water. Among the three major hydro complexes, the Mahaweli complex provides water for the basic needs of two-thirds of the country's population, including drinking and cultivation. Therefore, it is crucial to preserve water storage for the dry season, leading to irregular use of water for power generation.

The generation cost varies due to several factors, primarily driven by demand and the availability of power plants [10] [11] [12], which will be discussed in detail in this chapter.

2.1 Electricity Demand

To monitor factors influencing demand fluctuations, it is crucial to consider two significant parameters: the type of day and the time of day, both of which have a substantial impact on electricity demand. The typical pattern of a Daily Load Curve in Sri Lanka is illustrated in Figure 2.1 (Daily Load Curve for January 15, 2019). Daily Load Curves for January 2019 are plotted in a single graph (Figure 2.2) to identify the variation in electricity demand throughout the entire month. This figure illustrates the information on electricity demand variation on different dates and times within the same month, while the data for the remaining months is represented in Appendix F.

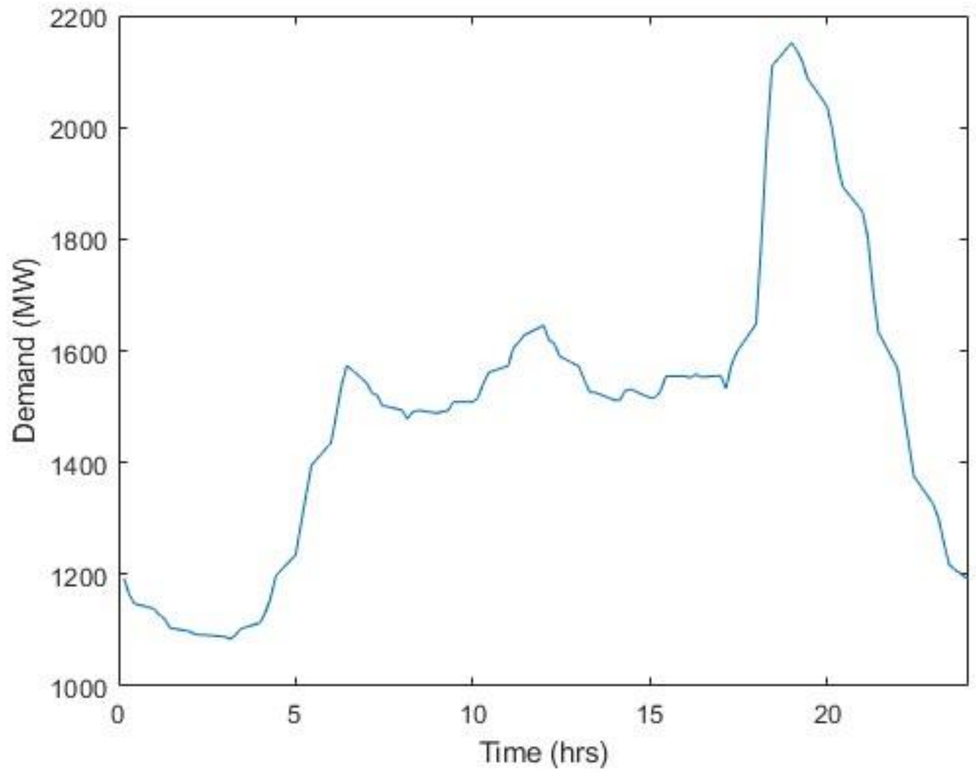


Figure 2. 1: Daily Load Curve of 2019.01.15

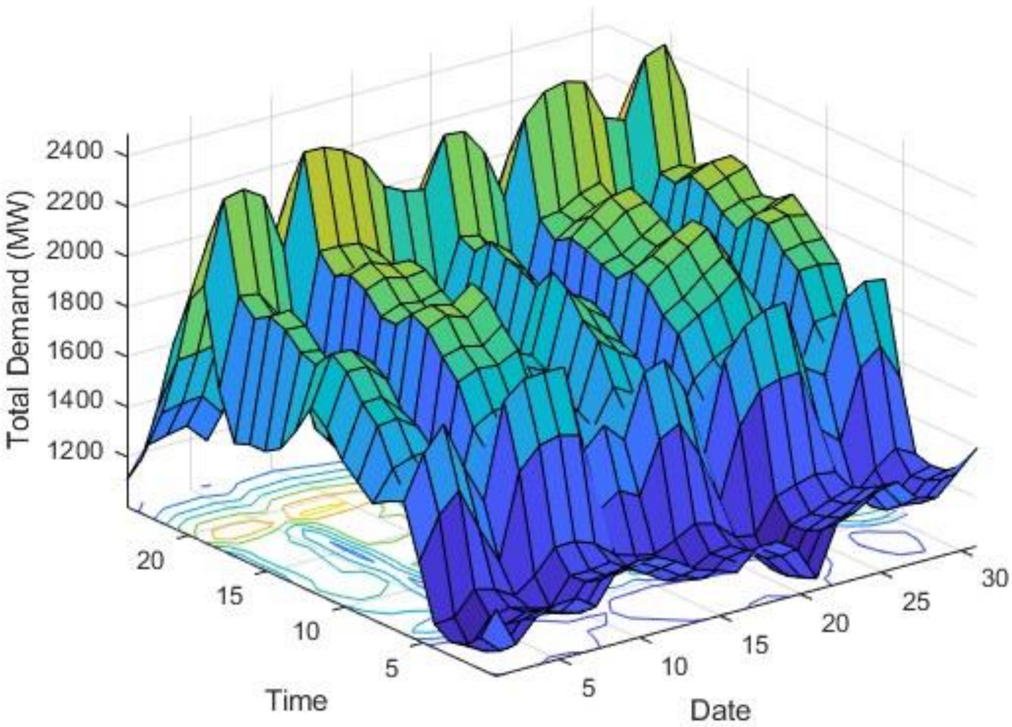
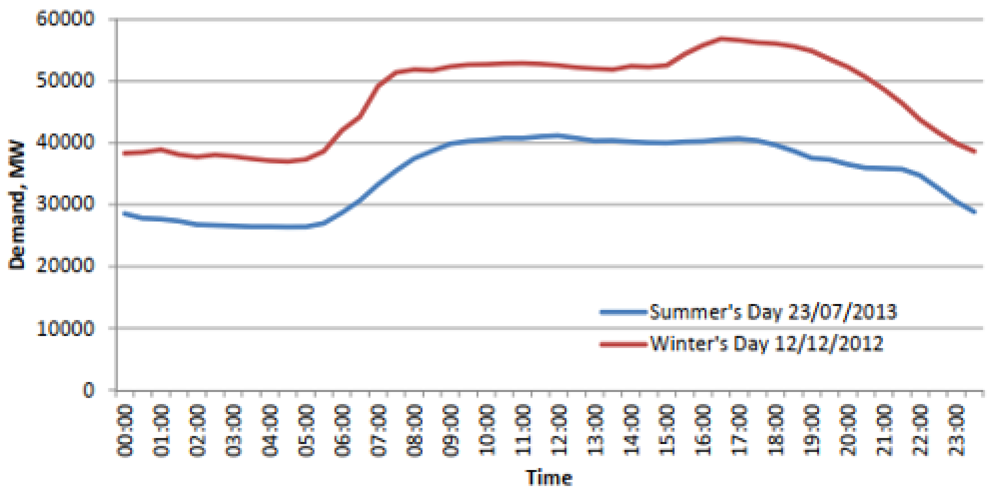


Figure 2. 2: Total Electricity Demand in January 2019

2.2.1 Type of Day

The demand for electricity varies based on the type of day, specifically whether it is a working day or a holiday. On holidays, including weekends and public holidays, many industries, offices and shops remain inactive, resulting in lower electricity consumption. Conversely, electricity consumption tends to be higher on working days.

Climatic and weather conditions also play a significant role in demand variation, particularly in countries with distinct seasons (spring, autumn, winter, summer). In regions with winters, there is an increased demand for electricity to operate heating systems. Figure 2.3 illustrates the Daily Load Curve of the UK on two days, one in summer and the other in winter. The winter demand is higher than the summer demand due to the need for heating during colder seasons.



Source: [13]

Figure 2. 3: Electricity Demand of UK in two selected days in Summer and Winter

Sri Lanka, situated between 5° 55' to 9° 51' North latitude and 79° 42' to 81° 53' East longitude, experiences a climate marked by distinct dry and wet seasons, rather than traditional four-season variations. The island's geographical location within the tropics, combined with diverse rainfall sources such as monsoonal, convectional, and depressional precipitation, contributes to a tropical climate.

The annual rainfall exhibits significant variability, ranging from less than 900 mm in the driest regions (southeastern and northwestern areas) to over 5000 mm in the wettest areas (western slopes of the central highlands). The topographical features and regional-scale wind patterns of the Southwest and Northeast monsoons play a key role in shaping Sri Lanka's climate. The island experiences four distinct climate seasons throughout the twelve-month period: the first inter-monsoon season (March - April), southwest monsoon season (May - September), second inter-monsoon season (October-November), and northeast monsoon season (December - February).

The variation of total electricity generation and peak demand in Sri Lanka throughout the year 2019 is depicted in Figures 2.4 to 2.7. The x-axis represents cumulative days of the year, starting from January 1st. The data visualisation provides insights into how climatic factors and seasonal variations impact the country's electricity generation and demand patterns.

Figures 2.5 and 2.7 indicate holidays, with Sundays marked by red stars, Poya days represented by purple circles, and special public holidays denoted by green stars. On certain days, two holidays coincide, and these instances are depicted with two marks at the same position. "The behaviour of total generation and peak demand in each month of 2019 is analysed in Appendix A and B, with special emphasis on holidays, which are specifically marked in the accompanying graphs.

As anticipated, both peak demand and total electricity generation exhibit a reduction on weekends and holidays. Clearly, the marked dates demonstrate a noticeable decrease in total generation, a trend that is mirrored in peak demand. Peak demand is consistently lower on Sundays and special holidays, including Poya and other occasions. The observed variation patterns in Figure 2.5 and Figure 2.7 underscore the influence of the type of day on the per unit cost of electricity.

Moreover, Figures 2.4 to 2.7 illustrate the impact of seasonality. With the influence of rainfall, total demand experiences a reduction in April-May and October-November compared to other months of the year.

For a comprehensive analysis, the same data is presented in Figures 2.8 to 2.11. The y-axis remains unchanged, consistent with Figures 2.3 and 2.7, while the x-axis is modified. Total electricity generation and peak demand are aggregated by each month and plotted according to the days of the week. (In this representation of the x-axis, we assign the value of 1 to the Monday of the first week. If the first date of the month falls on a Monday, the plot commences from 1 on the x-axis. However, if the first date of the month is a Tuesday, the plot begins from 2 on the x-axis. The clarity of the x-axis

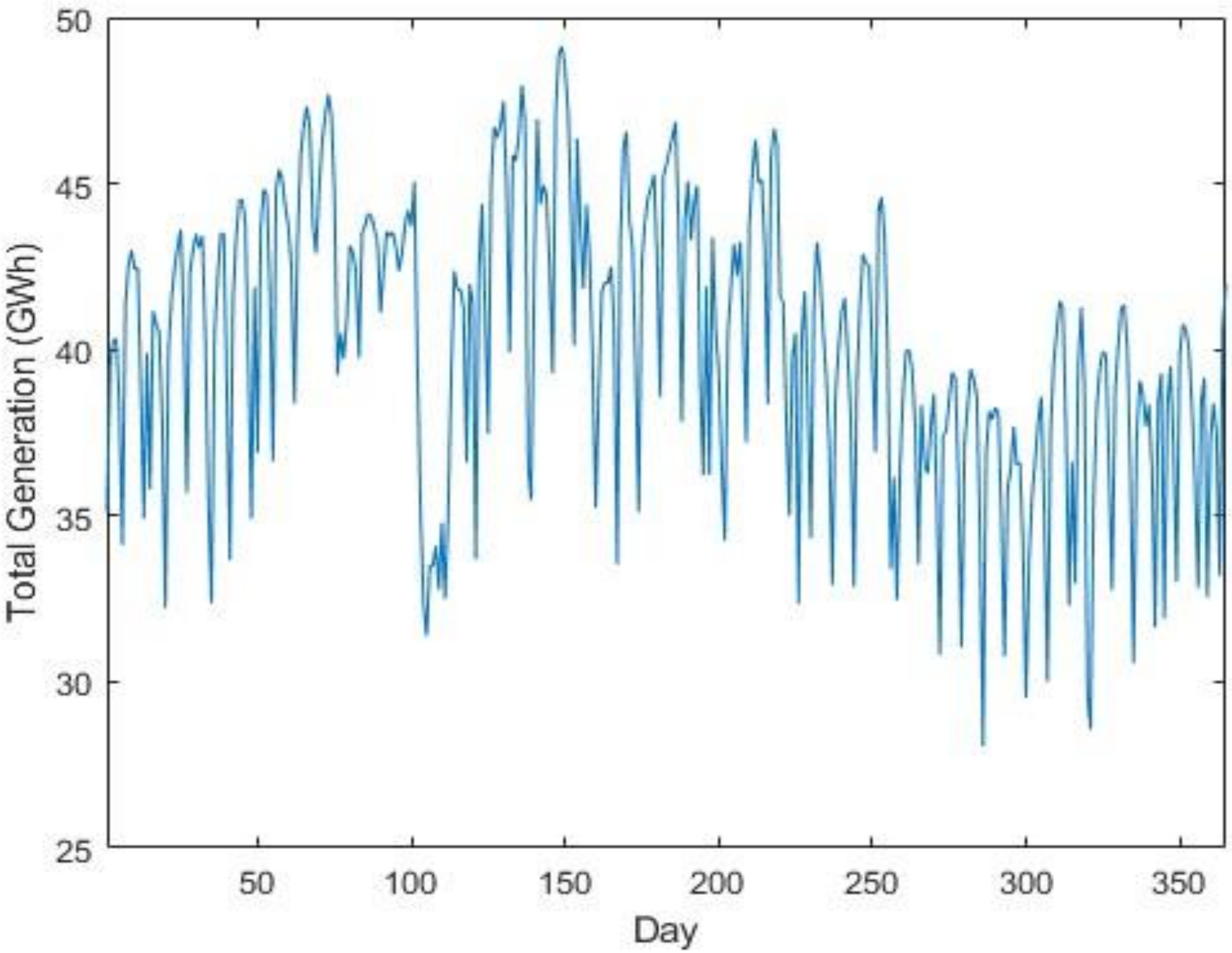


Figure 2. 4: Daily Electricity Generation of Sri Lanka in 2019

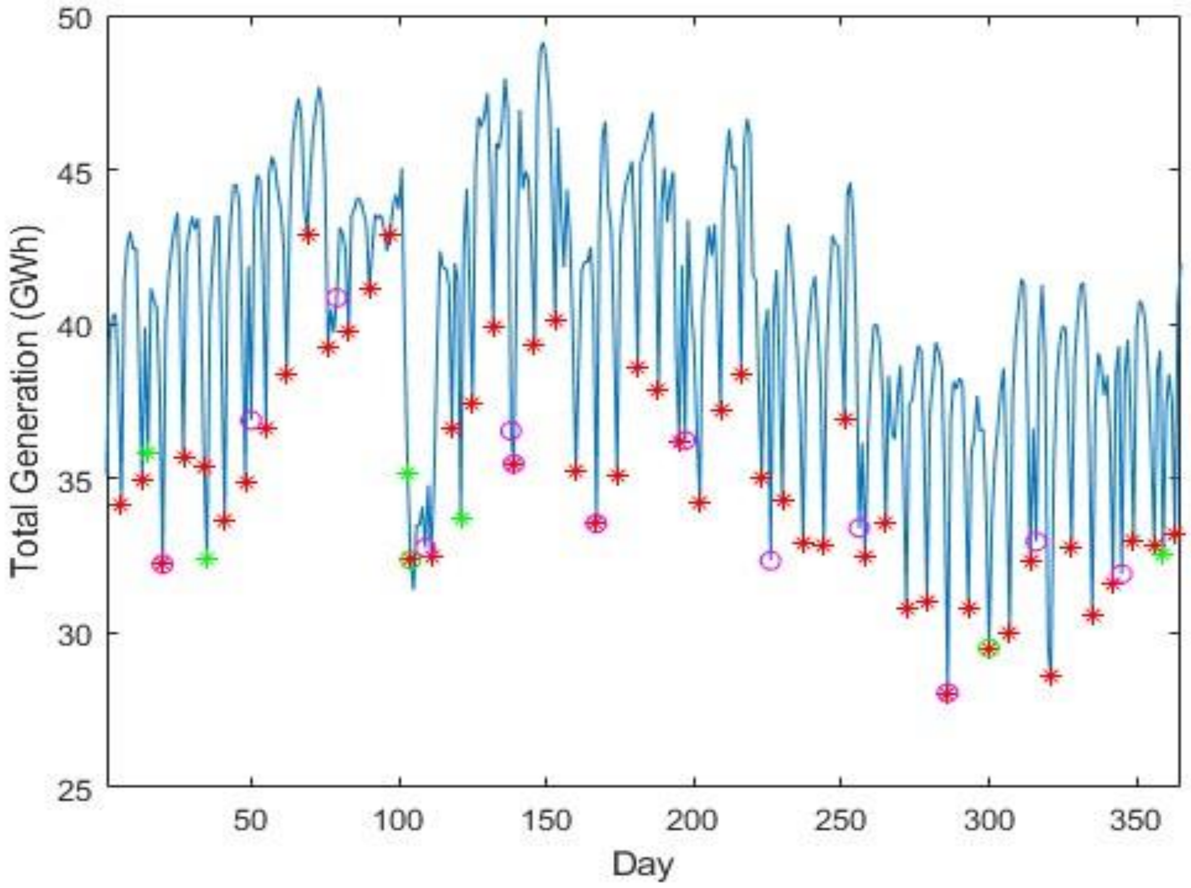


Figure 2. 5: Daily Electricity Generation of Sri Lanka in 2019 (Sundays are marked in red stars while other holidays are marked in different colours.)

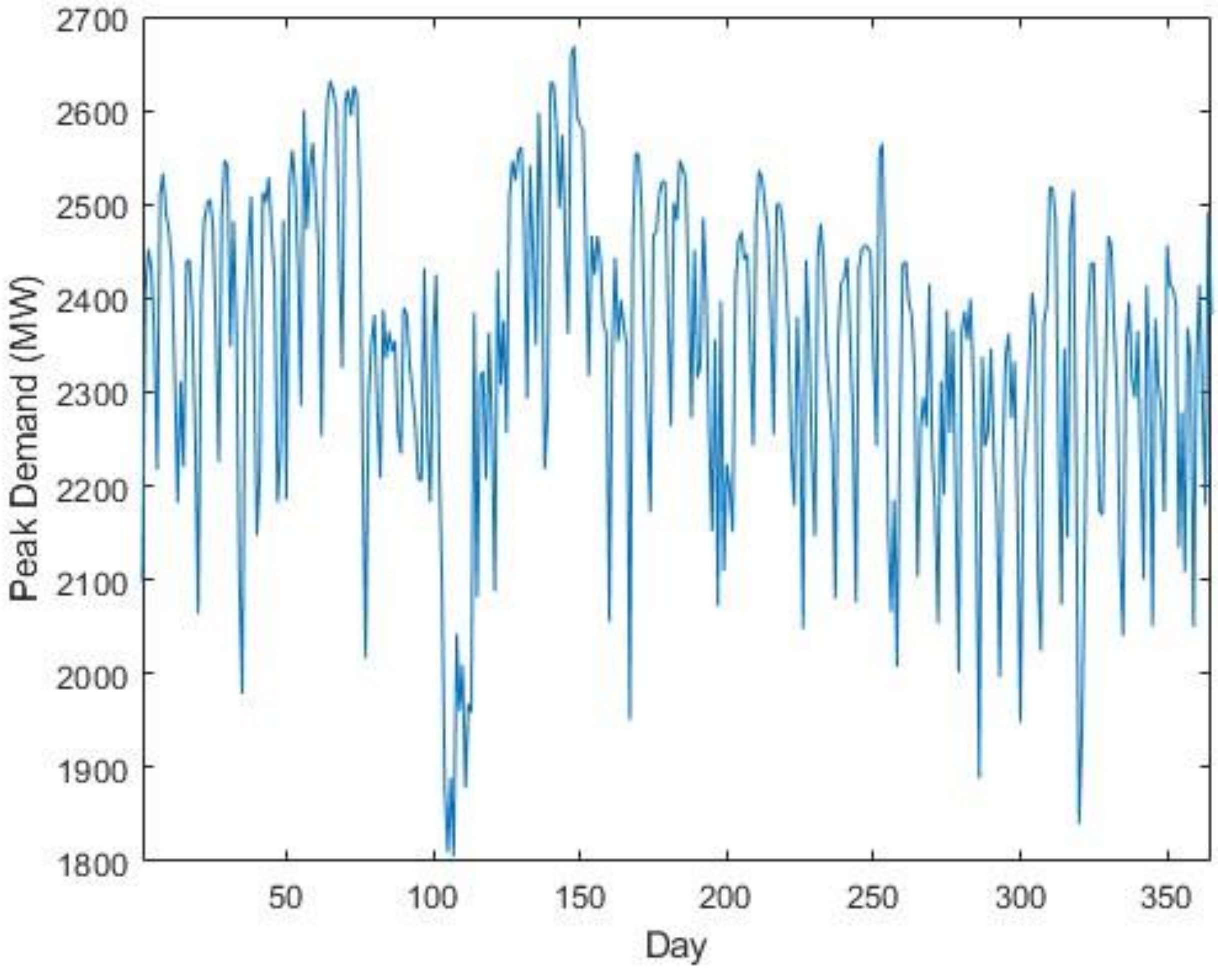


Figure 2. 6: Daily Peak Demand of Sri Lanka in 2019

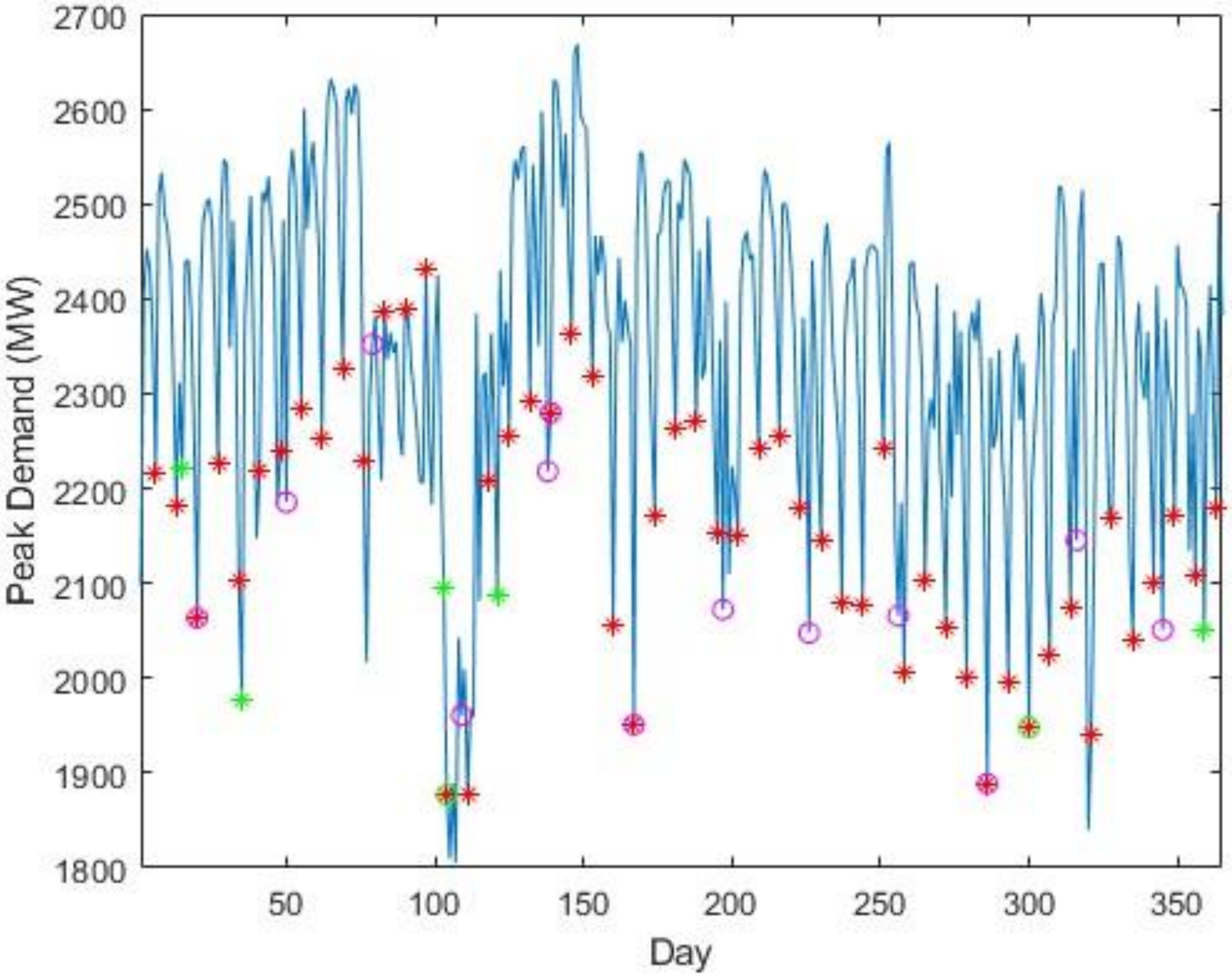


Figure 2. 7: Daily Peak Demand of Sri Lanka in 2019 (Sundays are marked in red stars while other holidays are marked in different colours.)

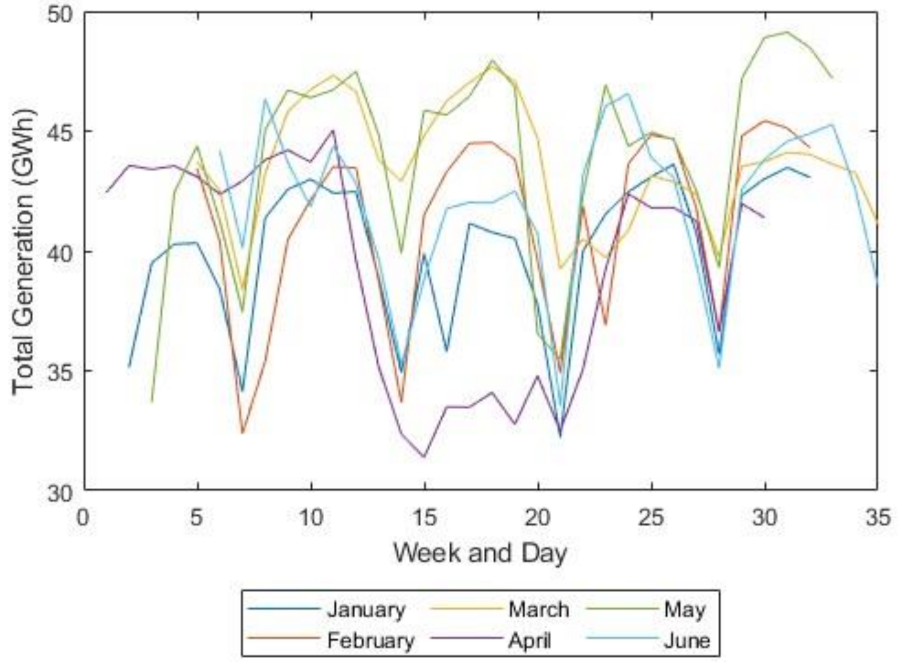


Figure 2. 8: Total Electricity Generation in first half of 2019

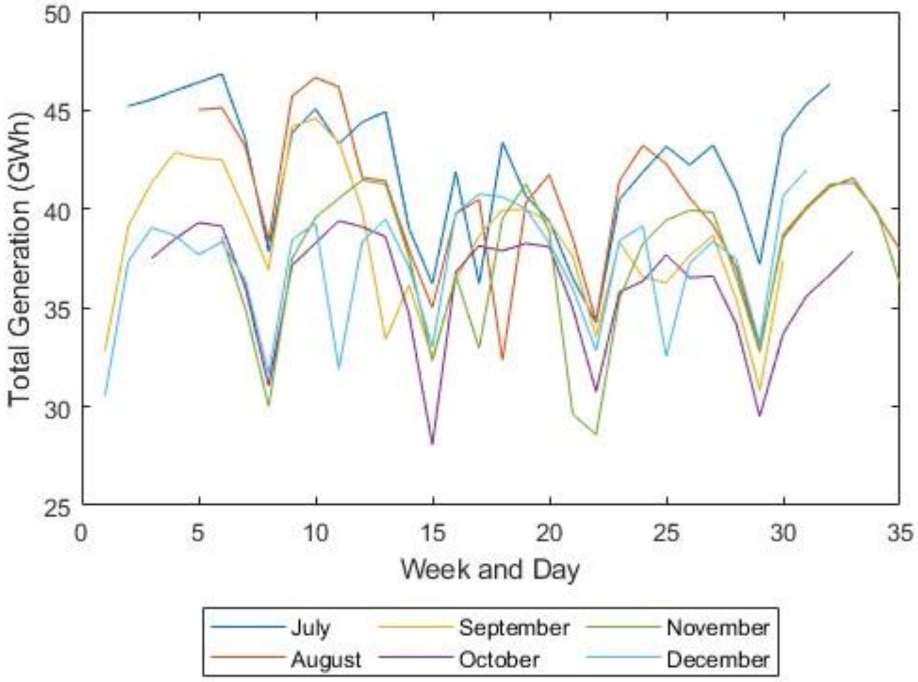


Figure 2. 9: Total Electricity Generation in second half of 2019

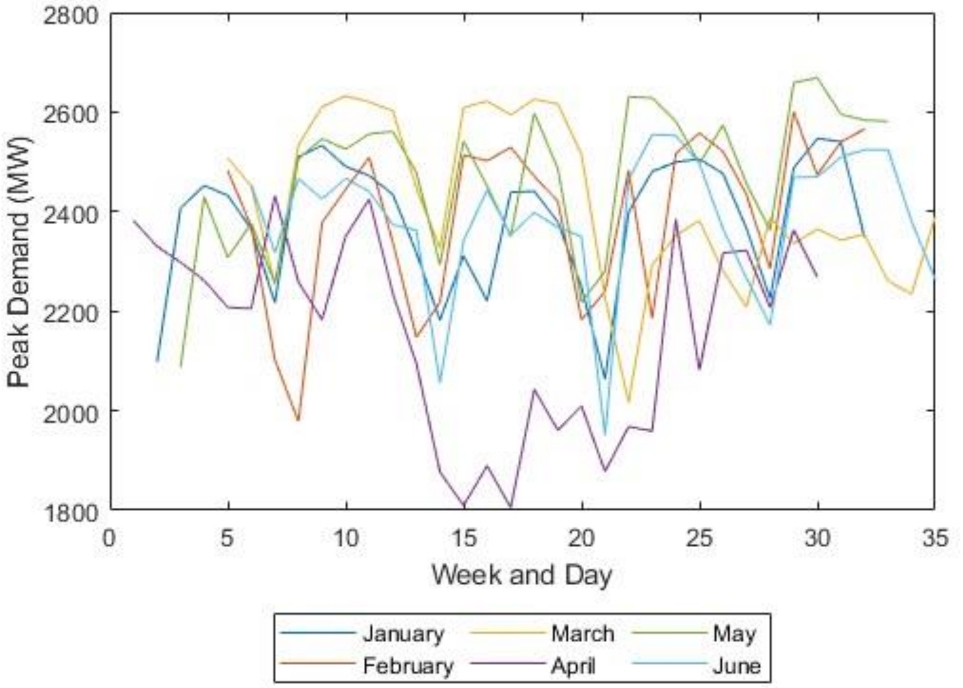


Figure 2. 10: Peak Demand in first half of 2019

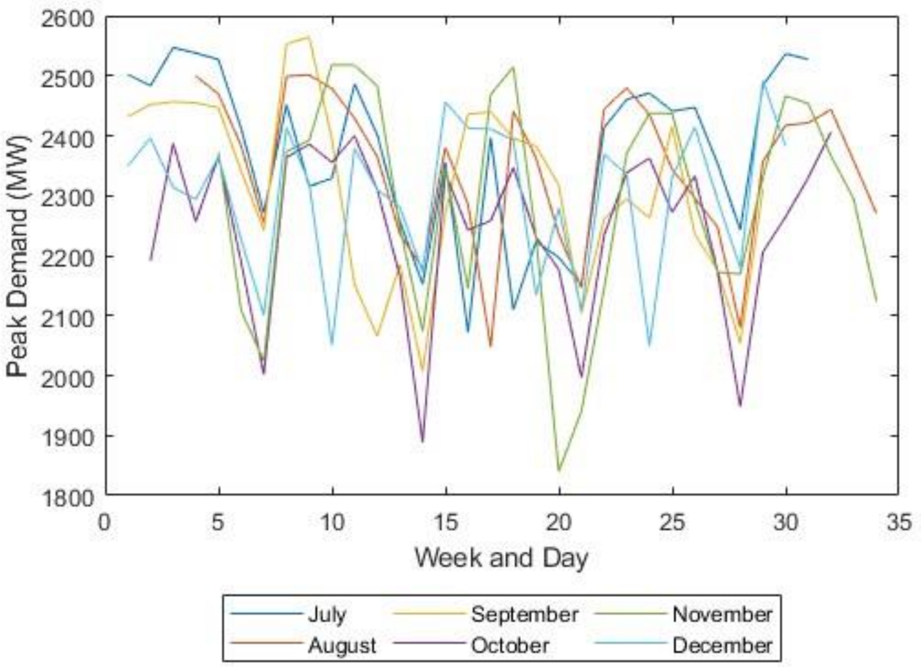


Figure 2. 11: Peak Demand in second half of 2019

naming on the graph is hindered by the limitations of the graph simulation software.) To simplify interpretation, the two halves of 2019 are plotted separately, offering a clearer depiction of the trends and avoiding complexity.

To simplify the x-axis naming in Figures 2.8 to 2.11, we can express it as follows: The graphs for January and March begin on 2 of the x-axes because the first dates of these months fell on Tuesdays. Similarly, the graphs for February, March, and November start on 5 of the x-axes as the first dates were Fridays. For April and July, the plots commence at 1 on the x-axis, reflecting that the first dates were Mondays. The x-axis ranges from 1 to 7, representing the first week of the month. Subsequently, 7 to 14, 15 to 21, and 22 to 28 represent the relevant weeks. However, the final week varies depending on the starting point of the graphs.

Figures 2.8 to 2.11 effectively illustrate the impact of the type of day on total electricity generation and peak demand. It is evident that both total generation and peak demand on weekends are consistently lower than on weekdays. Notably, a distinct decline in both parameters is observed during the Sinhala and Hindu New Year vacation period. This decline can be attributed to the non-operation of many industrial and commercial electrical consumers during weekends, resulting in a reduced peak on those days.

While total electricity generation and peak demand offer insights into load behaviour, they may not provide a comprehensive understanding of demand variation. To address this, a ratio is defined for convenience, providing a more nuanced perspective on the dynamics of electricity consumption.

$$Demand\ ratio = \frac{Peak\ Demand}{Average\ Demand}$$

In Figure 2.12, the peak-to-average demand ratio (inverse of Load Factor) of Sri Lanka is graphically represented for the year of 2019 while Figure 13 illustrates it by marking holidays. (Additional details for each month can be found in the provided Appendix D). The peak-to-average demand ratio serves as a valuable metric for understanding the relationship between the highest point of electricity demand and the overall average demand during a specific period. This ratio provides insights into the peak demand intensity relative to the average demand level, offering a nuanced perspective on the dynamics of electricity consumption throughout the given timeframe.

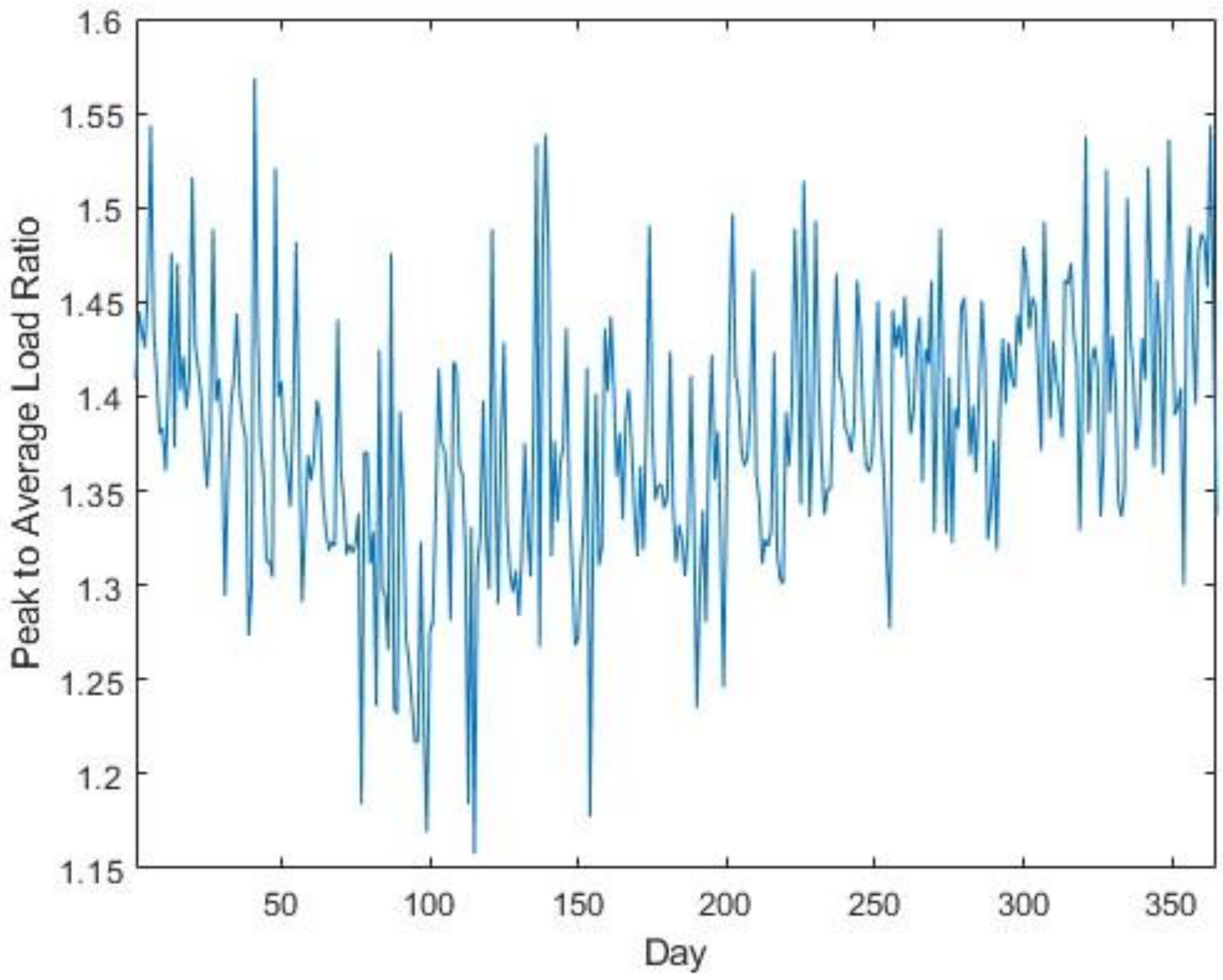


Figure 2. 12: Peak to Average Demand Ratio in 2019

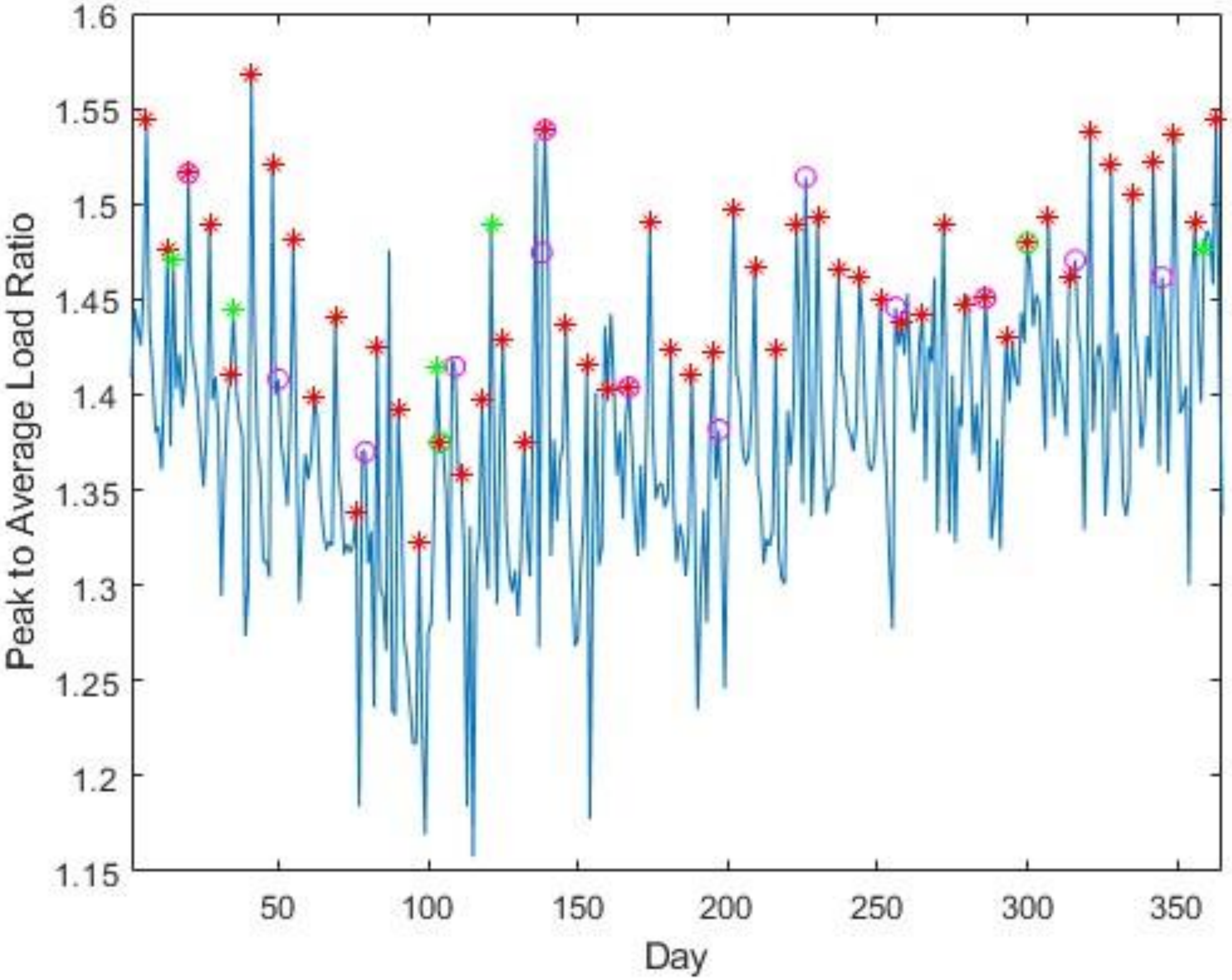


Figure 2. 13: Peak to Average Demand Ratio in 2019, marking holidays

The peak-to-average demand ratio is higher on Sundays and holidays compared to weekdays, even though the peak and average demand are lower than on weekdays. This is because the reduction in peak demand is less than the reduction in average demand. This result highlights an important aspect of Sri Lankan demand. The decrease in peak and total demand during holidays is attributed to industrial and commercial reductions. However, since the peak reduction is significantly less compared to the average reduction, it suggests that the contribution of industry and commercial demand to the peak is lower.

2.2.2 Time of Day

The demand for electricity undergoes fluctuations at different times, and these variations are captured by the Daily Load Curve, illustrating the electricity demand throughout the day. Given the non-constant nature of demand, power generation also experiences changes, leading to variations in the dispatch mix of power plants in response to the demand.

Another crucial factor influencing electricity demand is the changing duration of sunlight, as reflected in the times of sunrise and sunset. When sunlight is available, the usage of electricity for lighting tends to decrease, leading to an anticipated reduction in overall electricity demand.

Figure 2.14 illustrates the sunset time in the evening, while Figure 2.15 indicates the sunrise time in the morning for the year 2019. These figures provide insights into the relationship between natural light conditions and the corresponding impact on electricity demand throughout the day.

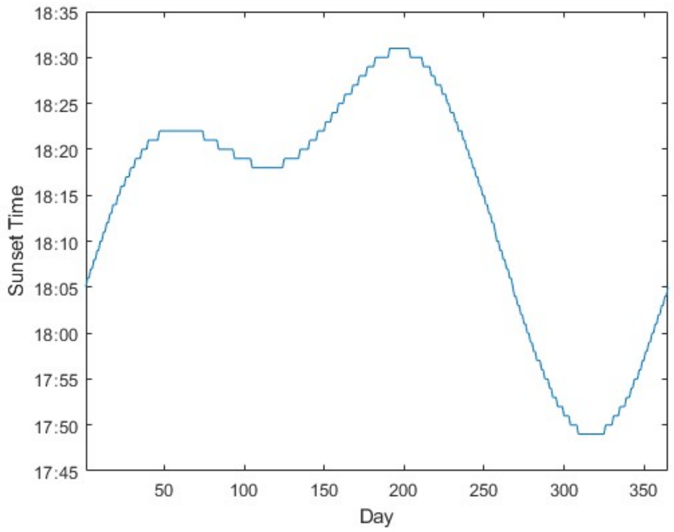


Figure 2. 14: Sunset Time in 2019

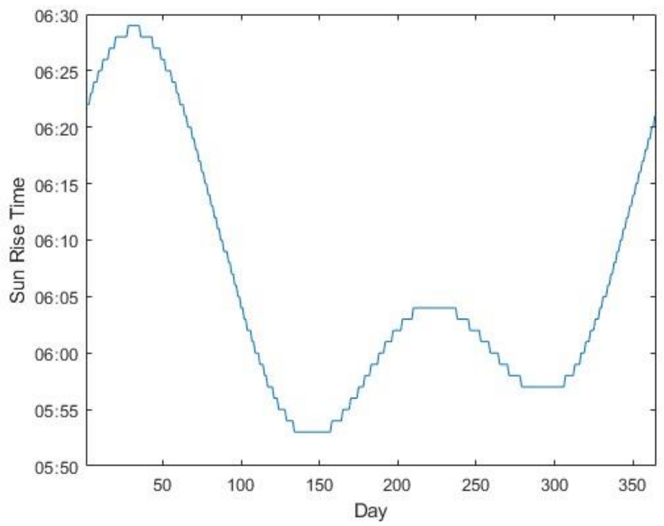


Figure 2. 15: Sun rise time in 2019.

The timing of sunset has a notable impact on electricity consumption patterns, particularly in influencing when the peak demand occurs. When sunset occurs earlier, electricity consumption tends to increase, and the peak demand arrives earlier in the evening. Conversely, if sunrise happens earlier, it tends to have a lesser impact on electricity consumption in the early morning due to lower utilisation during that time. Figure 2.16 provides a visual representation of the relationship between sunset times and evening peak demand, clearly illustrating that an early sunset lead to an earlier peak demand, and vice versa.

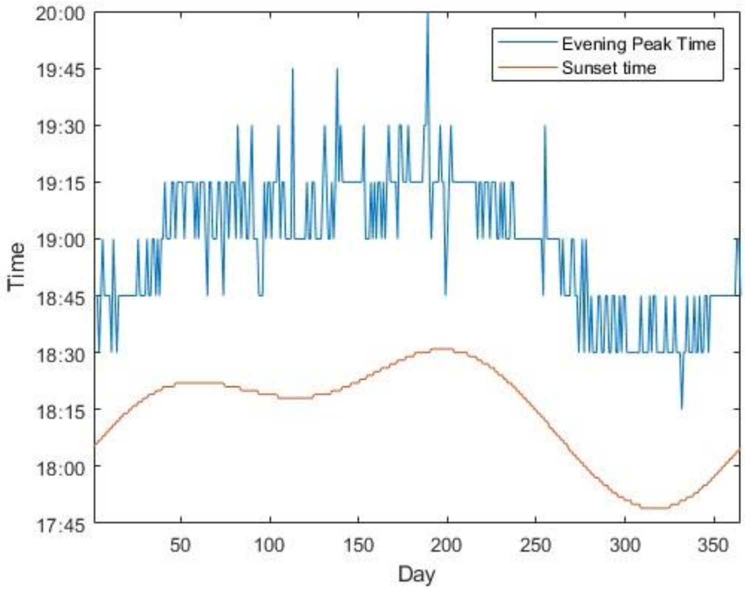


Figure 2. 16: Sunset time and evening peak occurring time in 2019.

To facilitate decision-making, especially in the implementation of a Time-of-Use tariff structure, the variation in sunset time has led to the introduction of two main time slots: daytime, morning peak, night peak and off-peak. Table 2.1 outlines these different time slots, which play a crucial role in shaping electricity consumption patterns and are essential considerations for tariff structures. The seasonal differences between time slots are highlighted in bold in Table 2.1.

Table 2. 1: Time Slots

January to September	**October to December**	**Description**
10.00 pm – 4.00 am	10.00 pm – 4.00 am	Off peak (Night)
4.00 am- 5.30 am	4.00 am- 5.30 am	Ascent of morning peak
5.30 am – 6 .00 am	5.30 am – 6 .00 am	Peak (morning)
6.00 am – 7.30 am	6.00 am – 7.30 am	Off peak (morning)

7.30 am – **5.30 pm**	7.30 am – **5.00 pm**	Day time
5.30 pm – 6.30 pm	**5.00 pm – 6.00 pm**	Ascent of night peak
6.30 pm – 8.30 pm	**6.00 pm** – 8.30 pm	Peak (night)
8.30 pm – 10.00 pm	8.30 pm – 10.00 pm	Descent of night peak

In this analysis, the Daily Load Curves of randomly selected dates are scrutinised to gain insights into the electricity consumption patterns. A detailed compilation of all the Daily Load Curves for the first month of 2019 is provided in the appendix G, offering a comprehensive overview of the variations in electricity demand throughout the first month of the year. This examination allows for the identification of specific trends, peak demand periods, and fluctuations in consumption on different days. By studying these load curves, a more nuanced understanding of the factors influencing daily electricity demand can be achieved, contributing to informed decision-making in the management and planning of power generation and distribution.

Figures 2.17 to 2.19 illustrate a consistent pattern in the Daily Load Curve for all the analysed days. The demand for selected days in February is plotted on the same axes (Figure 2.17), revealing a consistent pattern of variation with slight differences in magnitudes. Figure 2.18, focusing on the month of October characterised by heavy rainfall, shows a maximum peak reaching 2000 MW. In contrast, Figure 2.17 depicts the data for February, where the maximum peak rises to the range of 2400-2600 MW. These variations highlight the impact of seasonal factors, such as rainfall, on the electricity demand, with different months exhibiting different peak levels.

Furthermore, Figures 2.17 and 2.18 emphasise that the Load Curve on Sundays tends to be lower compared to other days. This observation aligns with the general trend of reduced electricity consumption on weekends. Analysing these load curves across different months and days provides valuable insights into the dynamic nature of electricity demand, aiding in the development of effective strategies for power management and distribution.

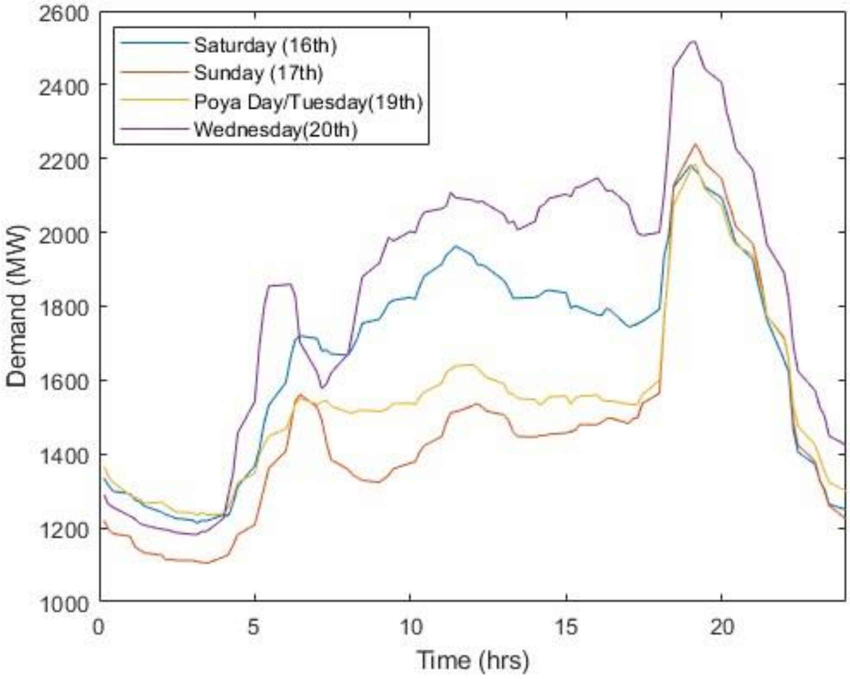


Figure 2. 17: Daily Load Curves of four selected dates in the same week of February 2019

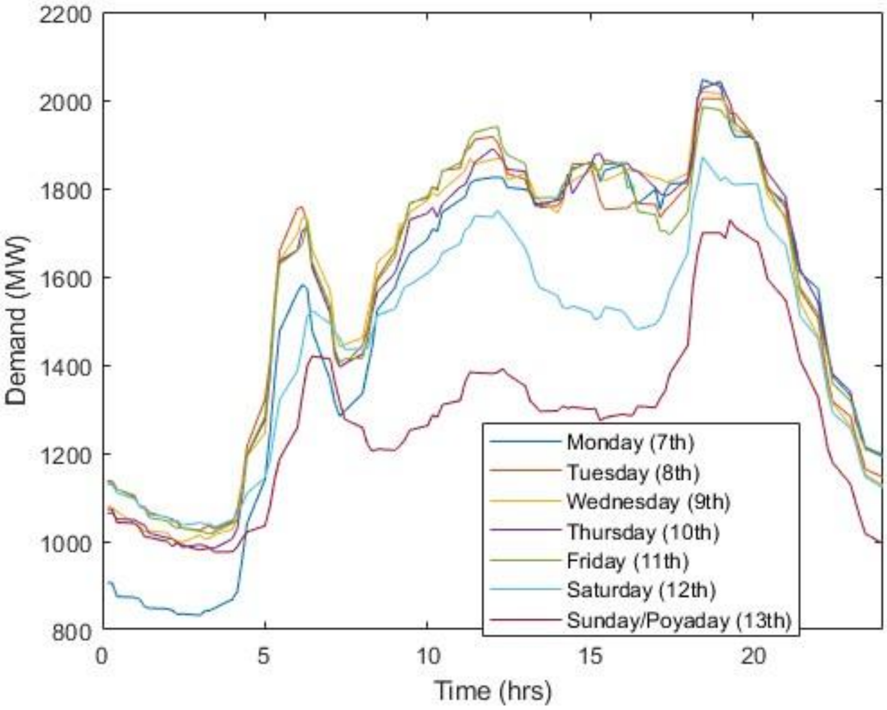


Figure 2. 18: Daily Load Curves of one week in October 2019

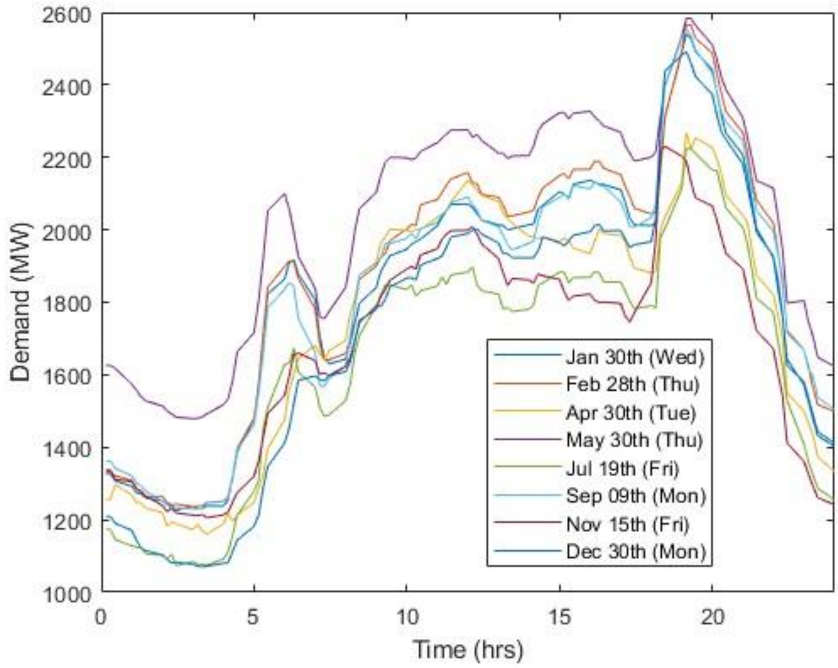


Figure 2. 19: Daily Load Curves for randomly selected dates in different months

2.2 Availability of Power Plants

The availability of power plants plays a crucial role in the dispatch process, particularly when aiming to optimise generation costs. If power plants with lower generation costs are unavailable, it becomes necessary to resort to more expensive alternatives. In this context, the examination of hydropower plant availability is of particular significance due to its potential to contribute to a reduction in the overall generation cost.

The concept of "water value" is explored further in Section 1.1, shedding light on its relevance in understanding and managing hydro power plant availability. This concept likely delves into the value derived from the efficient utilisation of water resources in hydroelectric power generation, emphasising its impact on the economic and operational aspects of the power system. The detailed discussion in Section 1.1 is anticipated to provide a comprehensive understanding of how water value influences decision-making in the dispatch of power plants, especially in the context of managing costs and optimising power generation.

The fluctuation of water levels in reservoirs is influenced by diverse climate and weather conditions. When water levels reach the spill level, it allows for the release of water to sustain continuous operations of hydropower plants. Conversely, during the dry season, as water levels decrease, water is conserved for essential needs and agriculture, and higher-cost thermal power plants become the primary dispatch choice. This seasonal variation in hydropower plant availability results in lower generation costs during the wet season, where hydropower contributes significantly to power generation.

Unlike hydropower plants, the unit costs of thermal power plants generally remain constant throughout the seasons. If the unit cost is the primary consideration in the dispatch decision, it would recommend maximising the use of hydropower plants due to their lower costs. However, this decision-making process is complex. While it may be cost-effective in the short term, the ability to meet future demand must be carefully considered. Inability to meet future demand can lead to increase overall power generation costs in subsequent planning periods. Therefore, the dispatch decision involves a balancing act between current cost-effectiveness and future demand projections to ensure the sustainability and efficiency of the power generation system.

The availability of hydropower is intricately tied to factors such as rainfall, catchment area and environmental conditions. Relying solely on rainfall data to assess power plant availability poses a significant challenge due to the limited scope of available data. This narrow margin restricts the accuracy of such assessments, necessitating a more comprehensive approach that incorporates additional factors influencing power plant availability. The factors contributing to low accuracy can be attributed to several reasons. Firstly, the available precipitation data cover only a limited region, which may not adequately represent the specifically designed catchment area of reservoirs. Additionally, rainfall, while a significant factor, is not the sole determinant of water availability; other contributing factors exist, albeit less prominently. Despite this, rainfall is generally considered the primary factor influencing water availability.

To address this, a more refined approach involves determining water inflow by aggregating the water utilised for power generation and considering the variance between the initial and final available water amounts for the specific period. This methodology, when appropriately adjusted for factors like evaporation, allows for a more precise evaluation of hydropower availability, contributing to more accurate decision-making in power plant dispatch and overall system management.

In the context of Sri Lanka, dispatch decisions treat all reservoirs equally, but the focus is primarily on six large upstream reservoirs. These reservoirs, Victoria, Kotmale, Randenigala, Maussakele, Castlereigh, and Samanala Wewa are crucial for decision-making processes, while smaller downstream reservoirs and ponds accumulate water based on upstream generation. As a result, assessing the availability of power plants requires consideration only of these upstream reservoirs.

The inflow of water into an upstream reservoir is calculated by determining the difference between the available water amount at the end and beginning of the specified period, supplemented by the quantity of water utilised for power generation.

For example, the inflow data of the Victoria reservoir is depicted in Figure 2.20, showcasing fluctuations from year to year. This section focuses on identifying variations in water availability in reservoirs on a monthly and seasonal basis, distinguishing between dry and wet seasons.

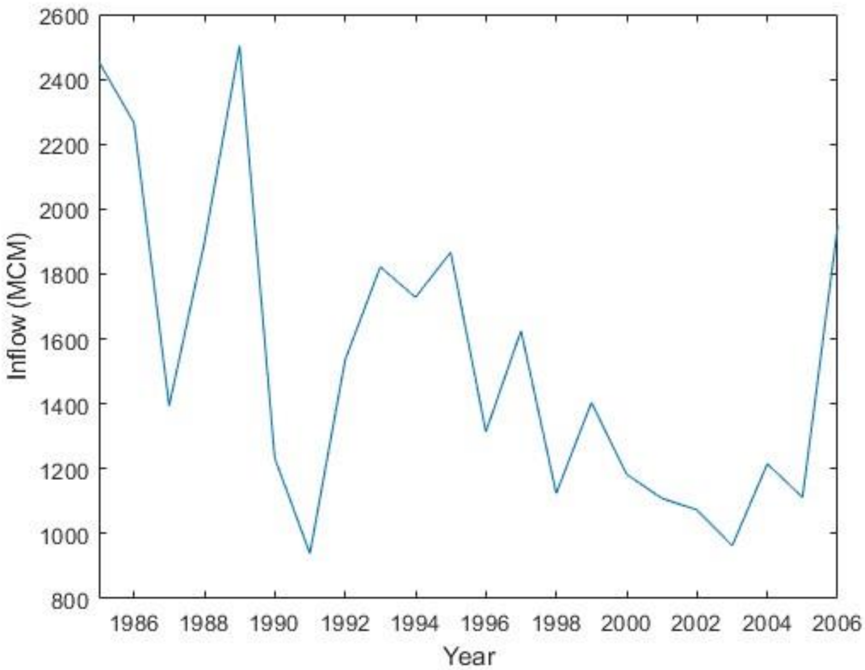


Figure 2. 20: Annual Inflow of Victoria Reservoir (1985-2006)

The primary objective is to analyse how the inflow varies within each month compared to other months within the same year. While Figure 2.20 provides an overview of the yearly fluctuations, understanding the monthly variation is crucial. To analyse the monthly variation, each month's inflow is normalised by dividing it by the net inflow of the entire year. This calculation yields the monthly inflow ratio, which allows for a more granular examination of how inflows fluctuate throughout the year.

$$Monthly\ inflow\ ratio = \frac{Inflow\ of\ the\ month}{Annual\ inflow}$$

Figure 2.21 depicts the average monthly inflow ratio for the period 1986-2010, while Figure 2.22 illustrates the median and standard deviation of monthly inflow ratio for each year within the same timeframe. In the graphs, the x-axis is labelled from 1 to 12, where 1 represents January, 2 represents February, and so forth.

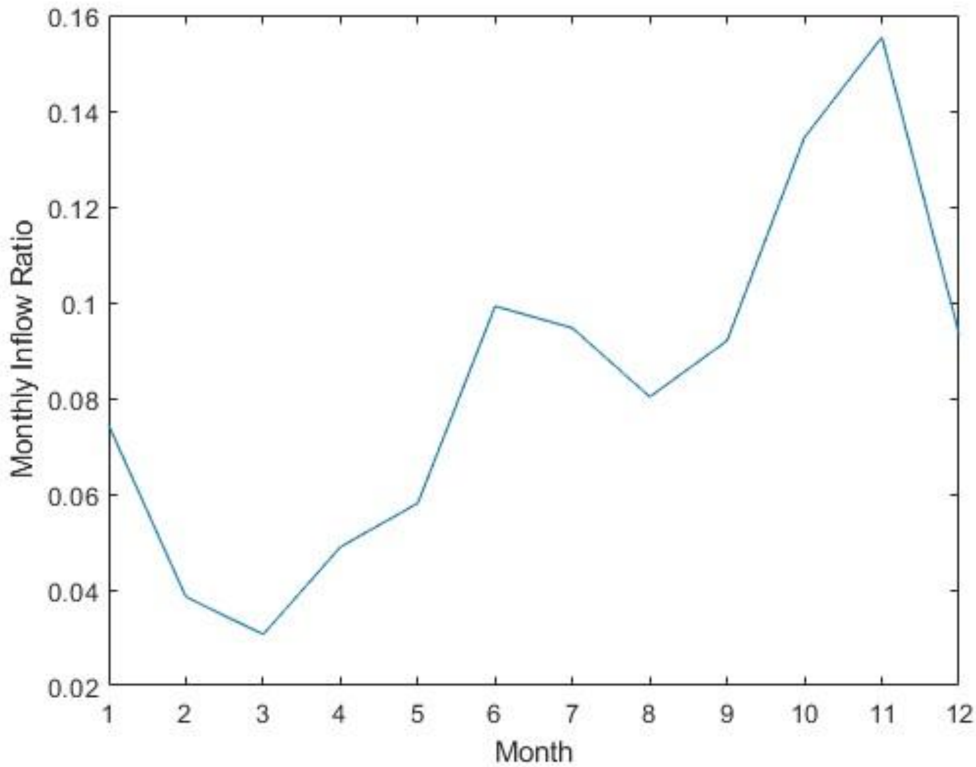


Figure 2. 21: Average Monthly Inflow Ratio of Victoria Reservoir (1985-2006)

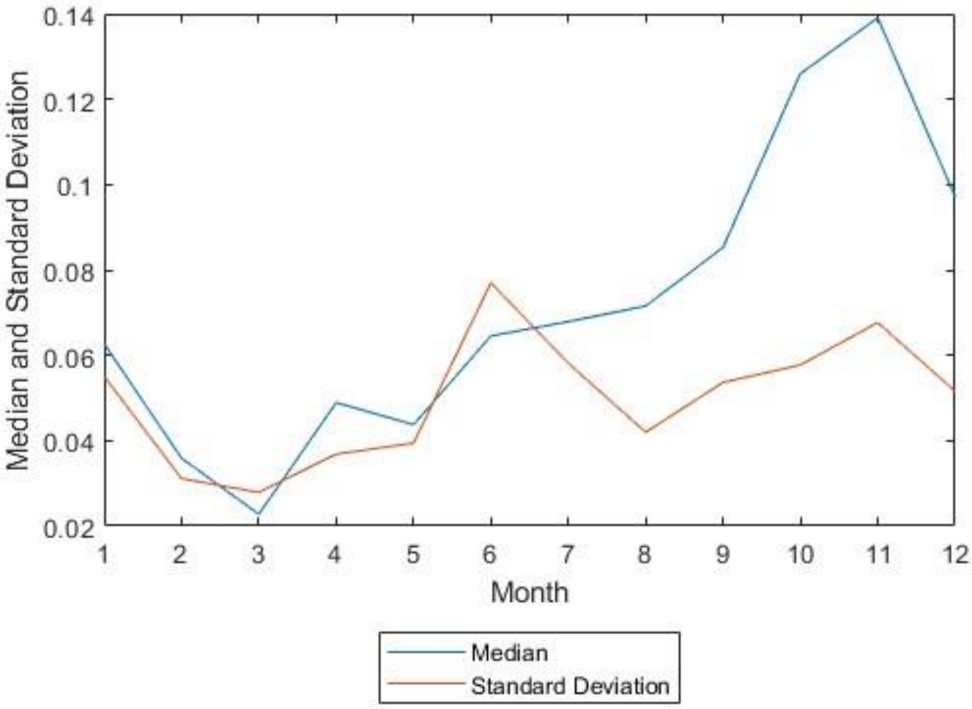


Figure 2. 22: Median and Standard Deviation of Monthly Inflow Ratio (1985-2006)

The average monthly inflow ratio of Victoria Reservoir reaches its trough in March and February. Therefore, these two months can be considered as dry months.

To simplify calculations and focus on more significant factors, the impact of evaporation is neglected. This decision is informed by historic data, which indicates that the maximum water reduction due to evaporation recorded throughout history is less than 1 mm. Therefore, for the purpose of evaluating reservoir water levels and availability, evaporation is deemed negligible, allowing for a more streamlined and practical approach to decision-making in power plant dispatch.

The power plant dispatch schedule in Sri Lanka follows a strategy where coal power plants serve as the base load. When it becomes necessary to initiate variable thermal (oil) power plants, they are operated at full load, regardless of whether they run continuously throughout the day or operate in a start-stop manner. Considering energy charges, the preference is for oil plants during peak demand periods due to their responsiveness, but this becomes impractical as peak load is primarily managed by hydropower plants to conserve water resources. Instead, the strategy involves preserving water by operating diesel power plants.

Hydropower plants are deemed efficient for handling peak demand due to their fast response times, smaller capacities, and the ability to maintain daily storage. This approach not only optimises the use of available water resources but also ensures a practical and effective dispatch schedule that balances the characteristics of different power plants in the Sri Lankan context.

3. LITERATURE REVIEW

The research aims to develop a model for calculating electricity costs that vary with seasons and time of day, concurrently evaluating the value of water. To accomplish this objective, it is crucial to delineate the methodologies of economic dispatch, as they provide the optimal future cost function.

In essence, addressing power system optimisation poses a significant challenge due to its capacity to encompass diverse technical, economic intricacies, and uncertainties. Attempting to incorporate all these elements into a single problem becomes computationally infeasible. Consequently, a typical approach involves considering a hierarchy of problems that tackle various time scales and perspectives. These include short-term dispatch (spanning a few days or weeks), mid-term operational planning (covering 1-2 years), and long-term operational planning (spanning 3-5 years). The outcomes derived from a long-term model can then be integrated into a model with a shorter horizon, but with more detailed considerations in other aspects of modelling.

Dynamic programming (DP) proves to be a potent method for addressing optimisation issues characterised by overlapping subproblems and optimal substructure. The enhanced forms of Dynamic Programming, namely Differential (or incremental) Dynamic Programming (DDP) and Discrete Differential Dynamic Programming (DDDP), contribute to achieving more precise outcomes in problems with overlapping subproblems and optimal substructure [14] [15] [16] [17]. Various literature sources propose distinct methodologies; however, this discussion focuses on several successful and applicable approaches, while describing theoretical concepts of DP, DDP etc. One of these mathematical techniques were employed by a Sri Lankan Engineer, P.J. Perera, in the 1980s to establish a methodology for water resources planning [18] [19].

3.1 Analysis of P.J. Perera's model

3.1.1 Dynamic Programming Techniques in Water Resources Planning

Dynamic Programming (DP) techniques which are based on Bellman's Principle of Optimality might be conveniently used in water resource optimisation due to stage-by-stage applicability. The basic idea of Bellman's Principle states that in a decision policy, whatever the initial states and the initial decisions are, the remaining decisions must constitute an optimal policy regarding the states resulting from the initial decision.

Strengths:

- Effective in breaking down complex, multi-stage problems into manageable subproblems.
- Provides a systematic approach to finding the optimal solution by considering all possible stages.

Weaknesses:

- Computationally intensive, especially for large-scale problems.
- Requires precise formulation of the problem and accurate input data.

Limitations:

- May not be feasible for real-time applications due to computational demands.
- Limited by the curse of dimensionality, where the state space grows exponentially with the number of variables.

Application to the Problem Statement:

In the context of electricity cost calculation and water resource evaluation, DP can optimise the operation of hydroelectric plants by determining the optimal water release schedule to minimise costs while meeting electricity demand. This approach is relevant to the problem statement as it directly addresses the need for efficient resource allocation over varying time scales.

3.1.2 Basic derivation for the deterministic case

$$C = Optimise\ f[R_1(S_1, U_0), \dots\dots\dots\dots\dots\dots\dots\dots., R_N(S_N, U_{N-1})]$$

Where,

C – Objective function

$U_n \in W_n, S_n \in V_n$

f – function representing the combined effect of the system transformations succeeding from an initial state vector S_0 to a final state vector S_N, resulting from a series of decision vectors $U_o, U_1, \dots\dots\dots\dots\dots\dots., U_{N-1}$

$R_N(S_N, U_{N-1})$ – the return at stage n with respect to the state vector S_n and the decision vector U_{N-1}

V_n, W_n – The administrative domains for decision vector U_n

S_n - State vector for stage n respectively

A cost minimisation, additive properties prevail in the function can be expressed as,

$$f[R_1(S_1, U_0), \dots \dots \dots \dots \dots \dots \dots \dots ., R_N(S_N, U_{N-1})] = \sum_{n=1}^{N} R_n(S_n, U_{n-1})$$

Where,

S_n - reservoir storage at stage n and

U_{N-1} – release of this storage at stage n

$F_N(S_N)$ – Minimum Cost for operating the system from an initial state S_0 to some final state S_N

$$F_N(S_N) = min \sum_{n=1}^{N} R_n(S_n, U_{n-1})$$

$$F_N(S_N) = min[R_N(S_N, U_{N-1})] + min\left[\sum_{n=1}^{N-1} R_n(S_n, U_{n-1})\right]$$

By the definition,

$$F_{N-1}(S_{N-1}) = min\left[\sum_{n=1}^{N-1} R_n(S_n, U_{n-1})\right]$$

$$\therefore F_N(S_N) = min[R_N(S_N, U_{N-1}) + F_{N-1}(S_{N-1})] \quad (1)$$

Equation (1) represents the Dynamic Programming recursive algorithm, from an initial state vector S_0, to a final state S_N. Depending on whether the initial state or the final state is known, the algorithm could be applied in a forward or backward manner. If both states are known, it could be applied either way.

Basic derivation for stochastic case

The stochastic element in reservoir operation is streamflow, and once this effect is introduced, the return function becomes dependent upon both storage (S_n) and inflow (I_n), in addition to the decision variable U_{n-1}.

Equation (1) can be revised as,

$$F_N(S_N) = \min\left[\int_{-\propto}^{+\propto} P(I_N)R_N(S_N, I_N, U_{N-1}) + P_{N-1}(S_{N-1})\right]$$

Where,

$P(I_N)$ – The probability density function of I_N for a discrete probability distribution of I_N

$$F_N(S_N) = \min\left[\sum_{i=1}^{K} P(I_N^1). R_N(S_N, I_N^1, U_{N-1}) + F_{N-1}(S_{N-1})\right]$$

Where,

I_N^1 - i^{th} discretisation of the streamflow at stage N

$P(I_N^1)$ – Probability of occurrence

k – Total number of discretisation

3.1.3 Markov Chains and Serial Correlation

Markov Chains provide a way to model the stochastic nature of inflows by considering the conditional probabilities of streamflow events based on previous observations.

A Markov Chain of the first order is defined as a sequence of events $x_0, x_1, x_2, \ldots\ldots\ldots.., x_{n+1}$ of discrete random variables, with the property that the conditional distribution of x_{n+1}, given $x_0, x_1, x_2, \ldots\ldots\ldots.., x_n$, depends only on the value of x_n, but not further $x_0, x_1, x_2, \ldots\ldots\ldots.., x_{n-1}$. For any state values of $h, j, \ldots\ldots., k$ belonging to the discrete state space,

$$Prob.[X_{n+1} = k \mid X_0 = h, \ldots\ldots\ldots, X_n = j] = Prob.[X_{n+1} = k \mid X_n = j]$$

When a streamflow of a certain month is independently analysed using recorded previous data, a certain probability distribution could be derived for its representation. However, this distribution is usually conditional upon the actual streamflow of the previous month, as in the case of the occurrence in a first order Markov Chain. The basic derivation for the stochastic case with the introduction of this serial correlation is as follows.

$$F_N(S_N, I_{N+1}^1) = min\left[\sum_{i=1}^{K} P(I_N^1 I_{N+1}^1).\{R_N(S_N, I_N^1, U_{N-1}) + F_{N-1}(S_{N-1}, I_N^1)\}\right]$$

Where,

$P(I_N^1 I_{N+1}^1)$ – The conditional probability of streamflow at stage N falling into the discretisation I, given I_{N+1}^1 inflow at stage $N+1$

It is evident that no unique optimal trajectory exists when serial correlation is considered.

Strengths:

- Captures the dependency of current states on previous states, reflecting real-world processes.
- Useful for modelling systems with inherent randomness and uncertainty.

Weaknesses:

- Requires extensive historical data for accurate probability estimation.
- Assumes that future states depend only on the current state, which may not always be true.

Limitations:

- May oversimplify complex dependencies between variables.
- Effectiveness depends on the accuracy of the estimated transition probabilities.

Application to the Problem Statement:

By using Markov Chains to model streamflow, the research can incorporate the stochastic nature of water inflows into the optimisation model. This approach allows for more realistic and robust planning of water and electricity resources, aligning with the goal of the thesis.

3.1.4 Differential Dynamic Programming (DDP)

Differential (or incremental) Dynamic Programming is a successive approximation technique, where the optimality of the objective function is considered locally, unlike in the conventional DP technique, where it is considered globally. DDP applies the principle of optimality about a nominal, possibly non-optimal trajectory. It is in effect, limiting the admissible domain of U_n and S_n to W_n and V_n respectively, which define the immediate neighborhood of U_n and S_n. These domains are successively updated in an iterative sequence to approach at an optimal solution.

3.1.5 Discrete Differential Dynamic Programming (DDDP)

Discrete Differential Dynamic Programming is an extension of DDP, in which the recursive equation of DP is used to search for an improved trajectory among discrete states within a neighbourhood (corridor) of a trial trajectory instead of the whole domain as in the case of conventional DP.

Strengths:

- Reduces computational complexity by focusing on local optimality.
- Suitable for problems where a good initial approximation of the solution is available.

Weaknesses:

- May converge to a local rather than global optimum if the initial trajectory is not well-chosen.
- Requires iterative adjustments and fine-tuning of parameters.

Limitations:

- Limited to problems with well-defined and convex cost functions.
- Effectiveness decreases for highly non-linear or non-convex problems.

Application to the Problem Statement:

DDP and DDDP can be used to refine the operational strategies for hydroelectric plants, ensuring more accurate and efficient scheduling of water releases to balance electricity generation and water conservation. These techniques help in minimising the overall cost function, making them directly relevant to the research objective.

Let,

$$\Delta_j S_n(k), j = 1,2, \dots \dots \dots \dots \dots, I; k = 1,2, \dots\dots, M; n = 1,2, \dots \dots, N$$

be the j^{th} increment of the state variable $S_n(k)$ at stage n in an Mdimentional vector space with a total of I possible increments. In the DDDP algorithm $\Delta_j S_n(k)$ can take any one value for j from 1 to I, from a set of assumed incremental values of the state domain.

Each of the M components of $\Delta_j S_n(k)$ can have I values, making the total number of combinations of $\Delta_j S_n(k)$ vectors at stage n equal to I. To have an accurate result, $\Delta_j S_n(k)$ must be sufficiently small. If the domains of the state variables span up to their entire extent, I will be very large, which is the main setback of conventional DP. In DDDP, the value of I is limited to 3 or 4 only. Defining a subdomain ($\overline{D}_n$) of the main domain such that,

$$\overline{D}_n = \bar{S}_n + \overline{\Delta}_j \bar{S}_n \ , j = 1,2, \dots \dots, I$$

Where,

$\bar{S}_n$ – The state vector at stage n represents a trial trajectory

All subdomains $\overline{D}_n$, $n = 1,2, \dots\dots, N$ together are called the corridor around the trial trajectory.

3.1.6 Procedure of DDDP

1. Select a trial trajectory as close as possible to the optimal trajectory. This may be done with some insight into the actual operation of the system. It will ensure convergence on the global optimum rather than on a local optimum.
2. Open corridors on state variables around this trial trajectory.
3. Obtain the updated trajectory using the conventional DP technique within the corridor.
4. Repeat steps (2) and (3) successively until the updated trajectory remains the same as the previous trajectory. They will be the optimum trajectory for that discretisation of the state variables within the corridor.
5. If added accuracy is required, narrow down the corridor by having the same number of discretisation, but with a smaller increment of the state variable. Repeat steps (2), (3) and (4).

6. If the accuracy is not sufficient, repeat step (5)

The return function in the problem under study is the thermal operating cost of the system. This is elevated as a function of the control variable which is equivalent to the hydro generations from the various plants. It is easily seen that the cost functions resulting from these generations are convex. The objective function, which is the sum of these convex functions is also convex, thus eliminating multiple optima. The optimal trajectory, therefore, becomes independent of the initial trial trajectory and this will be ensured by DDDP by selecting any arbitrary initial trajectory.

3.1.7 Dynamic Programming with Successive Approximations (DPSA)

DPSA optimises state variables one by one in a cyclic process, freezing the values of non-optimised variables at their previous semi-optimal values. This method is combined with DDDP to achieve fast and optimal results.

DPSA can only be used where a unique optimal trajectory exists for the state variables. Since this is the basic requirement for DDDP too, both methods can be combined to give a fast-optimal result. In DPSA, the state variables are optimised one by one in a cyclic process, and the state variables which are not under optimisation at a particular time instant are frozen at their previous semi-optimal values. It can be proven as in DDDP, that if the return functions are convex, the result will converge to the global optimum.

Strengths:

- Efficient in handling large-scale problems by breaking them down into smaller subproblems.
- Accelerates convergence to the optimal solution.

Weaknesses:

- May require several iterations to achieve convergence.
- Performance depends on the initial approximations and the accuracy of the optimisation routine.

Limitations:

- Limited to problems where a unique optimal trajectory exists.
- May not perform well for highly non-linear or complex systems.

Application to the Problem Statement:

DPSA can be applied to fine-tune the scheduling of hydroelectric plants by iteratively optimising water releases and electricity generation. This technique supports the research objective by enhancing the precision and efficiency of the proposed model.

3.1.8 Data Analysis

The main component of the stochasticity introduced to the problem is that due to inflows. A certain amount of statistical data processing is required to represent the inflows in an acceptable form to be input in the DP routine. It has been observed that streamflow patterns confirm to either normal or log-normal distributions with a high goodness- of- fit index. The log- normal distribution is useful in representing the skewness of the distribution, as is prominent in the case of daily inflow patterns whereas in the monthly patterns this skewness is damped to a certain degree. A chi-squared goodness of fit test will determine the suitability of the selected distribution.

When the proper distributions are obtained, discretisation is done with equal probability intervals. Five inflow conditions have been used in the study and hence each has a 20% probability of occurrence. Once discretisation is done, it is convenient to available the discrete conditional probabilities for the transition probabilities (or the transition probabilities) rather than the conditional distribution when treating the flow pattern of the year as events of a first order Markov Chain.

If I is the occurrence of the streamflow in month n within the class interval p,

$$Prob.\left(I_n^p \middle| I_{n-1}^q\right).m_p/m_q$$

Where,

m_q – number of occurrences of the streamflow in month $n-1$ within the class interval q

m_p – within the set of occurrences of m_q, the subset of occurrences of streamflow in month n within the interval p

For k inflow intervals, the expectation of the inflow I_n for a certain month $\boldsymbol{n}$, given the actual inflow interval of the previous month as q is,

$$I_n = \sum_{i=1}^{k} I_n^1 \,.\, prob(I_n^1 I_{n-1}^q)$$

Which may be quite different from the unconditional expectation,

$$I_n^0 = \frac{1}{k} . \sum_{i=1}^{k} I_n^1$$

for equal probability intervals.

A transition probability matrix can be defined for the streamflow of any two adjoining months n and $n + 1$ such that,

$$M = \left[P_{ij}\right], i = 1,2, \ldots \ldots, k \,; j = 1,2, \ldots \ldots, k$$

Where,

$$P_{ij} = Prob(I_{n+1}^j | I_n^i)$$

3.1.9 The Mid-Term schedule with deterministic inflows

This is implemented either on a monthly or weekly basis. The inflow regimes at various dam sites are found for various hydro-conditions using probability analysis and are classified under various dry-conditions. For example, 60%- dry would mean that the inflow will be greater or equal to the corresponding value for 60% of the time. It is illustrated by F in the inflow- duration curve given below.

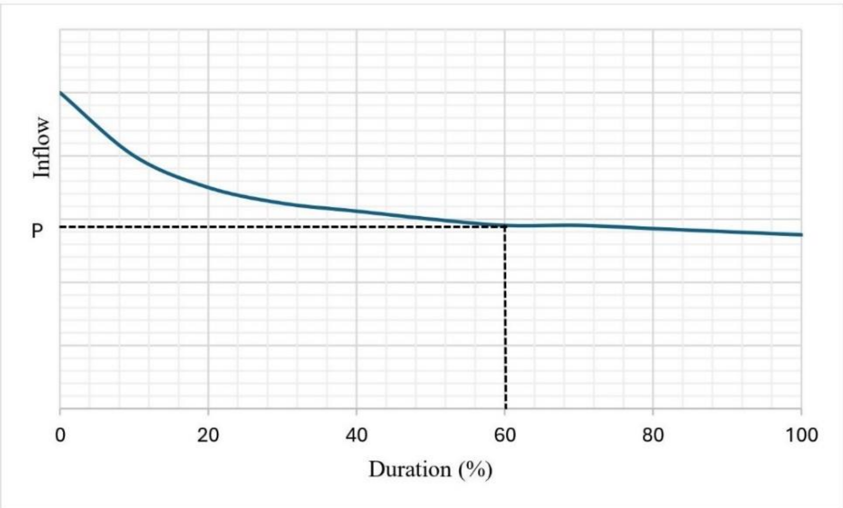


Figure 3. 1: Inflow Duration Curve

The input of inflows to the model can be given as a combination of these dry conditions for 12 months. The model uses DDDPSA to arrive at the optimal trajectories for the reservoirs.

3.1.10 Evaluation of the return function

To obtain the thermal plant costs for each trajectory of the state variables, the load duration curve for that month is probabilistically simulated with the corresponding hydro energy included. The hydro components groups into the two basins of Mahaweli and Kelani rivers are fitted using Jacoby's method with zero outages are assumed. For thermal plants, forced and scheduled outages are considered, and the plants are probabilistically stacked on the load duration curve in the order of their increasing operating cost.

3.1.11 Irrigation requirements

Irrigation only exists in the Mahaweli basin, at Polgolla and Minipe. The irrigation requirements off Polgolla are specified at three sites of Bowatenna, Elahera and Angammedilla. These requirements are given monthly at these sites. If an irrigation deficit is to be affected at Polgolla in an annual basis, there are numerous combinations possible in the adjusted diversions at these sites, and it should be initially investigated as to which distribution of the actual diversions are more realistic in actual practice. The DP routine can be made sensitive to irrigation diversions by the introduction of a penalty cost in the case of an irrigation deficit. The form of this penalty should incorporate not only the limitation of the total diversion deficits, but also how these deficits are distributed within the year.

For example, a total annual deficit of 100 MCM at Polgolla can give rise to a deficit at Bowatenna of 50 MCM in January and 50 MCM in December (leaving aside Elehera and Amgammedilla) or a 25 MCM deficit in January and a 75 MCM deficit in December. Since the diversion requirements at Bowatenna are 75 MCM for all months, the former case seems more appropriate in a practical sense as the optimising model does not consider the diversion storages as state variables. The introduction of a linear irrigation penalty can give rise to inappropriate monthly irrigation diversions because the results can exhibit insensitivity to the diversion pattern within the year. What is essentially required is the capability of the model to meet the requirements within the constraints imposed by the inflows, such that if there should be any deficits, these to be allocated monthly rather than in an annual basis. This is accomplished by introducing an exponential irrigational penalty rather than a linear penalty. For the example considered earlier, a linear penalty will give rise to identical irrigation penalty costs for the two cases, whereas the introduction of an exponential penalty of the form,

$$cost = EXP(deficit\ each\ month)$$

will minimize the penalty for the former case. The following expression illustrates this,

$$EXP(50) + EXP\ (50) = EXP(25) + EXP(75)$$

even though,

$$50 \quad + \quad 50 \quad = \quad 25 \quad + \quad 75$$

This penalty cost of course will have no physical meaning, but when added to the thermal costs for the various reservoir trajectories in the DP exercise, the resulting optimal trajectories will satisfy the irrigation in the most appropriate way monthly. This exponential irrigation penalty factor can also be used to enforce the trade-off between irrigation and power. A very low penalty will enforce negligible influence on irrigation deficits and in effect will optimise for the power only, whereas with a high penalty, the vice-versa will occur. Since quantification of actual irrigation losses are quite complex and inaccurate, under normal running the model is made to assume a very high penalty factor for irrigation deficits whereby the thermal cost is minimised only after meeting the irrigation requirements within the constraints of the inflows.

3.1.12 The mid-term schedule with stochastic inflows

A composite basin representation is used in the study due to the excessive number of state variables existent in the system. The composite representation agglomerates the reservoirs in each basin into one equivalent energy storage entity and an associated generating plant. The composite model is based on a single measure of potential energy which is indicative of the system ‘s generating capability. The one-dam representation of the multi-reservoir system in effect receives, stores and releases potential energy when operative in the DP routine. The inflows also should be represented by the potential energy input into the system. The dependence between the potential energy outflow and the electrical energy generated is given by the generation function of each composite basin.

The composite model is most applicable when the sequence of monthly decisions on the total hydro generation is of greater economic significance than the allocation of these among the various hydro plants. The decomposition of this total generation to those of the individual plants depends on the initial derivation of the generation function. Therefore, it is of basic importance to maintain as far as possible a consistent approach to this problem with that applied for achieving the main objective of the study.

3.1.13 Generation Functions

The power generation of a hydro plant as a function of the released water depends on the plant head and the overall plant efficiency. This is given by,

$$P = e.Q.H \qquad (2)$$

With,

$$P < P_{max} = e.Q_{max}.M_{max}$$

Where,

P – Power generated

Q – water flowrate through the turbine

H – Plant head

e -plant efficiency

Q_{max} is determined by the maximum turbine capacity, and H_{max} occurs when the reservoir level is at its maximum. If $Q > Q_{max}$, there will be no further contribution to the generation.

Equation (2) can be considered as the generation function for a single plant in the composite basin. The generation function of the composite model is an aggregate of the generation functions and spill characteristics of many similar plants. Its characteristics will depend on how the individual plants are operated integrally within the basin.

3.1.14 Operational curves for the generation function

The generation function for each basin and its inflow energy are obtained by a system simulation in a specific set of operational curves. In establishing these curves, it is necessary to consider that,

a) The optimisation routine within each basin must aim for similar goals as in the final scheduling programme, which is the system cost minimisation.
b) Serial correlation of the monthly inflows cannot be considered as a unique trajectory, which is essential for the simulation of the plants cannot be obtained that way.

With the above considerations in view, the most appropriate way of obtaining these curves would be a system cost minimisation using DDDPSA using the actual inflows of the available inflow regime. The system demands of the actual year of interest can be used as being incurring repetitively for every year for the available inflow period.

3.1.15 The short-term model with deterministic inflows

After the development of the mid-term models, a deterministic short-term model has been developed to operate daily. This is in fact an optimal dispatch model, to be used to recommend to the operators the optimal way to meet the demand on an hourly basis. Unlike in the mid-term case, the water transport time delays must be considered here as well as the true operational characteristics of the hydro and thermal machines. The operation of the Kotmale and Mahaweli complex ponds become significant in this case, and they must be introduced as state variable along with Ukuwela and Bowatenna. Victoria can be hydraulically decoupled from the system as the discharges from Polgolla would not make any significant changes in the Victoria storage when operating on an hourly basis.

The optimisation routine used here is DDDPSA. However, a major modification had to introduced into the conventional DDDPSA technique to fit it to the short-term problem. In normal DDDPSA technique to fit it to the short-term problem. In normal DDDPSA the state variables which are not under optimisation are frozen at their semi-optimal values. When relating this concept to the actual case under study the following problem arises,

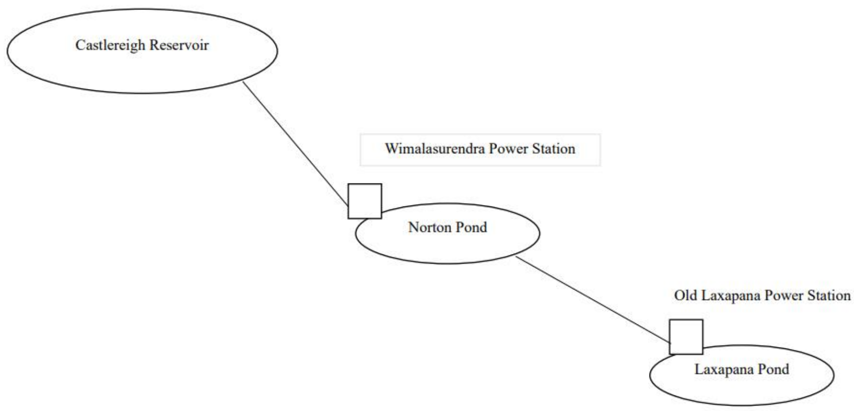


Figure 3. 2: A part of Laxapana Cascade

Consider the cascade of Castlereigh, Norton and Laxapana reservoirs (Figure 3.2). The Wimalasurendra power plant has been designed for peak operation whereas the Old Laxapana plant is running practically at baseload. When using conventional DDDPSA to these two plants, first the Castlereigh reservoir is optimised using the energy of the Wimalasurendra power plant while the Norton Pond trajectory is frozen. This means that all the water discharged through the Wimalasurendra power plant is forced through the Old Laxapana plant as well, thereby disabling the Norton Pond to act as a buffer to accommodate the highly irregular discharges of Wimalasurendra plant. Hence the feasible space of trajectories of the Norton Pond is severely curtailed due to the operation of the Old Laxapana plant. In the modified DDDPSA technique developed, the plant generations are frozen rather than the reservoir storages. In the example considered above when optimisation is done on the Castlereigh reservoir. The Old Laxapana generation is frozen, rather than the Norton Pond storage so that limitations on the Castlereigh discharge are not imposed by the operation of the Old Laxapana plant. After the optimisation of the Castlereigh reservoir, the Norton Pond trajectory is updated with the optimised discharges of the Wimalasurendra plant and used in the subsequent optimisation.

3.2 Analysis of METRO Model

METRO is applied for operations planning of integrated hydro, thermal, irrigation system. This uses the water value concept in deriving an operation policy for the power reservoirs of the system and uses optimal reservoir balancing factors to balance the reservoir drawdown (maintaining an optimal mix) on simulation of the operating policy. Water value is the incremental long-term replacement cost of hydro in storage by thermal and is a well proven concept used in medium term operational planning [20]. [21]

Strengths of METRO

- **Holistic Approach**: METRO integrates hydro, thermal and irrigation systems, providing a comprehensive solution for managing water and energy resources. This integration is crucial for optimising resource use across different sectors.
- **Water Value Concept**: By evaluating the opportunity cost of water in storage, METRO enables a more accurate assessment of the trade-offs between using water for energy generation versus other uses like irrigation. This helps in deriving optimal operation policies.
- **Thermal Switching Curves**: METRO can identify optimal switching points for thermal plants based on hydrological conditions, which is valuable for ensuring reliable base load operation during dry periods.
- **Maintenance Planning**: The inclusion of maintenance schedules and the treatment of forced outages as random events allows for more realistic planning and minimises the operational impact, improving system reliability.
- **Daily Operational Guidelines**: The system provides daily generation schedules, which aids in the practical management of plants and helps in adjusting operations in response to changing conditions.
- **Long-term and Medium-term Planning**: METRO can project system performance and budget fuel costs up to a year ahead, aiding in strategic planning and resource allocation.
- **Quantitative and Qualitative Reliability Analysis**: The tool offers a detailed analysis of system reliability, which is essential for understanding potential risks and making informed decisions.
- **Adaptability**: METRO can incorporate upcoming expansions and changes in the system, ensuring that the planning tool remains relevant and up to date.

Weaknesses and Limitations

- **Complexity and Data Requirements**: The detailed modelling of various systems and their interactions requires comprehensive and accurate data. This can be challenging to obtain and maintain, particularly in regions with limited data availability.

- **Sensitivity to Assumptions**: The accuracy of METRO's outputs depends on the assumptions made regarding hydrological conditions, fuel costs and other factors. Inaccurate assumptions can lead to suboptimal policies.
- **Focus on Medium and Long-term Planning**: While METRO is effective for medium and long-term planning, it may not be as responsive to short-term fluctuations and sudden changes in system conditions.
- **Computational Intensity**: The detailed simulations and optimisations conducted by METRO require significant computational resources, which can be a limitation for its use in real-time or near-real-time decision-making.
- **Opportunity Cost Estimation**: The concept of water value, while useful, relies on the estimation of incremental thermal costs, which can vary significantly with market conditions and fuel prices. This variability can affect the accuracy of the operation policies derived from METRO.
- **Integration Challenges**: While METRO integrates various components of the system, the actual implementation can be challenging due to differing operational requirements, priorities, and regulatory frameworks across the hydro, thermal and irrigation sectors.

Application to the Problem at Hand

In the context of developing a mathematical model for seasonal and time-of-day electricity costing, METRO offers valuable insights, particularly in the valuation of water resources and the optimisation of hydro-thermal coordination. However, its reliance on long-term projections and complex data requirements might limit its applicability for real-time or short-term decision-making. Additionally, while METRO focuses on minimising thermal operation costs and managing water resources, it may not fully account for the dynamic nature of electricity markets, where prices can fluctuate significantly based on demand and supply conditions. Integrating METRO's principles with other methods like SDDP, DPSA or DDDP could enhance its capability to handle such complexities.

3.2.1 Capabilities of METRO

- Optimising the operation of the hydro power resources in the system to minimise thermal operation costs and the expense associated with unserved energy in the long and medium term, considering varying hydrological conditions.
- Identifying thermal switching curves for the base load operation of thermal plants specifically designed for dry hydrological conditions.
- Integrating the complete irrigation system in conjunction with the power station.

- Evaluating the opportunity cost of water in storage (water value) by assessing incremental thermal costs.
- Establishing reservoir operating policies (rule curves) that delineate reservoir drawdown philosophy based on reservoir storage and time, accounting for diverse hydrological conditions.
- Incorporating maintenance schedules for all hydro and thermal plants.
- Optimising maintenance planning to minimise the impact of planned forced outages, treating them as truly random events rather than relying on capacity de-rating methods.
- Providing daily operational guidelines in the form of recommended generation schedules for all plants.
- Projecting expected system performance for one year ahead by simulating the past hydrological sequence and fuel cost budgeting.
- Conducting a quantitative and qualitative analysis of power system reliability.
- Analysing Mahaweli irrigation reliability and examining power/irrigation trade-offs.
- Incorporating all forthcoming expansions of the system through data file updates.

The precision of the short-term dispatch model is crucial, particularly since short-term economic dispatch can extend from 24 to 168 hours. During this timeframe, the variability in water inflow and fuel prices does not significantly impact the accuracy of the short-term model's output. However, the accuracy of the model can be influenced by factors such as:

1. Addition and retirements of power plants
2. Varied shapes of load duration curves
3. Differing unit prices of thermal power plants

3.2.2 Mathematical modelling of Economic Dispatch

The subsequent notations are employed in the formulation of the dispatch algorithm model.

t	Time interval (hour) index
T	Total number of time intervals (scheduling horizon)
D_t	Total Demand (MW)

D_t^{Th}	Total Thermal Power Supply
D_t^{Hy}	Total Hydro Power Supply
I	Number of available thermal plants
N_i	Number of units in ith thermal plant
M_j	Number of units in jth thermal plant
u_{it}	Commitment state of ith thermal plant, $if\ u_{it} = 1\ committed; u_{it} = 0\ reserved$
S_{nit}	Status of ith thermal plant, nth unit at tth state
S_{nit}^D	Discrete status of ith thermal plant, nth unit $if\ 0 < S_{ni,t-1} \leq 1\ then\ S_{nit}^D = 1$ $if\ -1 < S_{ni,t-1} \leq 0\ then\ S_{nit}^D = 0$
Mt_{nit}	Maintenance state of ith thermal plant, nth unit $if\ Mt_{nit} = 1\ , available;\ Mt_{nit} = 0, offline$
Pt_{nit}	Power output of ith thermal plant, nth unit (MW)
Ph_{jt}	Power output for the reservoir j during the t hour
$C_i(..)$	Cost function of ith thermal plant in LKR/hr; a function of P_{it}
Pt_{ni}^{max}	Maximum power output of ith thermal plant, nth unit (MW)
Pt_{ni}^{min}	Minimum power output ith thermal plant, nth unit (MW)
Ph_j^{max}	Maximum power output of the hydro unit j
Ph_j^{min}	Minimum power output of the hydro unit j
ΔP_{ni}	Ramp rate of ith thermal plant, nth unit (MW/hr)
T_{ni}^{up}	Minimum up time of ith thermal plant, nth unit (hrs)
T_{ni}^{dn}	Minimum down time ith thermal plant, nth unit (hrs)
T_{ni}^{SD}	Reserved hours of ith thermal plant, nth unit (hrs)
St_{nit}	Start-up cost of ith thermal plant, nth unit (LKR)
Sd_{ni}	Shutdown cost of ith thermal plant, nth unit (LKR)
$C_t(Pt_{nit})$	Total Thermal Cost of ith thermal plant, tth hour
$Dc_{1,t}^{l-1}$	Total demand when $l - 1$ units are dispatched in tth hour.
$Rd_{l+1,t}^{l}$	Remaining demand when $I - (l + 1)$ units to be dispatched in tth hour.
x_{nit}	Consecutive time that ith thermal plant, nth unit has been down at time t
α	Maximum capacity limit percentage

3.2.3 Objective function

The goal of resolving the economic dispatch problem in an electric power system is to ascertain the generation levels for all active units that both minimise the overall cost and adhere to a defined set of constraints.

$$Total\ cost = min \sum_{t=0}^{T}\{\sum_{i=0}^{I-1}\sum_{n=1}^{Ni}|S_{nit}|Mt_{nit}(a_i Pt_{nit} + c_i) + St_{nit}S_{nit}^{D}\big(1 - S_{ni,t-1}^{D}\big) + Sd_{nit}S_{ni,t-1}^{D}(1 - S_{nit}^{D})\}$$

System Constrains

Several constraints of the system influence the unit commitment and economic dispatch.

Demand satisfaction for each hour t

$$Total\ Demand = Hydro\ generation + Thermal\ Generation + Losses$$

$$D_t = D_t^{Hy} + D_t^{Th} + Losses$$

$$D_t = \sum_{j=1}^{J} Ph_{jt} + \sum_{i=1}^{I}\sum_{n=0}^{Ni}|S_{nit}|Mt_{nit}Pt_{nit} + Losses$$

Technical operation limits of each unit

$$Pt_{ni}^{min} < Pt_{nit} < Pt_{ni}^{max} \qquad \forall t \in [1, \mathrm{T}], \forall \mathrm{i} \in [1, \mathrm{I}], \forall \mathrm{n} \in [1, \mathrm{Ni}]$$

$$Ph_{j}^{min} < Ph_{j} < Ph_{j}^{max} \qquad \forall t \in [1, \mathrm{T}], \forall \mathrm{j} \in [1, \mathrm{J}]$$

Startup/ Shutdown Cost

$$St_{nit} = \begin{cases} St_{ni}^{c} & if\ x_{nit} > t_{cold} \\ St_{ni}^{w} & if\ t_{hot} < x_{nit} < t_{cold} \\ St_{ni}^{h} & Otherwise \end{cases}$$

$$startup\ cost = St_{nit}S_{nit}^{D}\big(1 - S_{ni,t-1}^{D}\big)$$

$$shutdown\ cost = Sd_{nit}S_{nit}^{D}(1 - S_{ni,t-1}^{D})$$

Spinning reserve requirement

$$Spining\ reserve = Total\ amount\ of\ generation\ available\ from\ all\ synchrounous\ units - (present\ loads + losses)$$

$$\sum_{i=1}^{I}\sum_{n=0}^{Ni}|S_{nit}|(Pt_{ni}^{max} - Pt_{nit}) + \sum_{j=1}^{J}\big(Ph_{j}^{max} - Ph_{jt}\big) \geq \beta t$$

For Sri Lankan context, $\beta = 0$

Every hydropower system exhibits distinctive hydraulic limitations, primarily dictated by geographical and hydrological factors. Occasionally, the release of water from one reservoir can impact the availability of water in another reservoir, referring to them as hydraulically coupled units.

Minimum uptime and downtime

Combined cycle power plants, coal power plants, and nuclear power plants exhibit variable minimum up times, contingent on the duration of the plant shutdown. In contrast, other thermal plants have distinct minimum up and down times.

Minimum startup time of a thermal power plant:

$$if\ \left(S_{ni,t-1} = 0\ and\ S_{nit} > 0\right)\ then\ S_{ni,t+\tau} = 1\ ;\ \tau\ \leq\ T_{ni}^{up}$$

$$T_{ni}^{up} = \begin{cases} T_{ni}^{upC} & if\ x_{nit} >\ t_{cold} \\ T_{ni}^{upW} & if\ t_{warm} <\ x_{nit} <\ t_{cold} \\ T_{ni}^{upH} & otherwise \end{cases}$$

Minimum downtime of a thermal power plant:

$$if\ \left(S_{ni,t-1} = 1\ and\ S_{nit} < 0\ \right)then\ S_{ni,t+\tau} = 0\ ;\ \tau\ \leq\ T_{ni}^{dn}$$

$$Pt_{nit} = \begin{cases} m\tau + K & if\ (\tau < T_{ni}^{up}) \\ Pt_{nit} & otherwise \end{cases}$$

Hydropower plants are characterised by rapid startup and shutdown capabilities. Therefore, the minimum startup and shutdown times are not constraints for hydropower plants.

Ramp rate.

$$\Delta P_{in} = |Pt_{nit} -\ Pt_{ni,t+1}|$$

It is assumed that rate of decrease in power is same as the rate of increase in power.

Status of the thermal plant

$$S_{nit} = \begin{cases} \dfrac{Pt_{nit}}{Pt_{ni}^{min}} & if\ (\tau <\ T_{ni}^{up}) \\ 1 & if\ (\tau \geq\ T_{ni}^{up}) \end{cases}$$

$$S_{nit} = \begin{cases} -\dfrac{Pt_{nit}}{Pt_{ni}^{min}} & if\ (\tau <\ T_{ni}^{dn}) \\ 0 & if\ (\tau \geq\ T_{ni}^{dn}) \end{cases}$$

Maximum Capacity Unit

$$\alpha D_t \ \geq \ Pt_{nit} \ and \ \alpha D_t \ \geq \ Ph_{nit}; \ \alpha = 0.2$$

Thermal Plant Cost Function

$$C_t(Pt_{nit}) = \ aPt_{nit} + \ bPt_{nit}^2 + c$$

Sri Lankan system does not contain with second order of cost function.

$$\therefore \ C_t(Pt_{nit}) = \ aPt_{nit} + \ c$$

3.2.4 Algorithm of Metro for economic dispatch of Thermal Power plants

Input

- Half an hour demand curve of thermal and total demand
- Available plants and cost details
- Maintenance schedule
- Initial status of the plants (ON/OFF, Number of Units running, Number of hours stopped)

Step 1

- Generate initial schedule.
- Sort the power plants ascending order to unit cost.
  - Combined cycle power plant consists of no-load cost per hour. Therefore, the average cost of the plant is taken as $\frac{aPt_{ni}^{max} - C}{Pt_{ni}^{max}}$

Step 2

- Generate option for the next schedule (Number of Options = 2^I)
- Remove infeasible options by considering total minimum load and total maximum load (total minimum load < Load < total maximum load)

$$\sum_{i=1}^{I}\sum_{n=1}^{Ni} u_{it}Mt_{nit}Pt_{ni}^{min} < \ D_t^{Th} < \ \sum_{i=1}^{I}\sum_{n=1}^{Ni} u_{it}Mt_{nit}Pt_{ni}^{max}$$

Step 3

- Options are generated for the plants but not for the plants' units. Therefore, if a plant is committed that does not mean that all the available units are up running. But if a plant is reserved no units will be running.
- Even though it is a Merit Order List (MOL) all the committed power plant of an option should be dispatched regardless of the cost. Therefore, at least its operational minimum power will be dispatched.

- $Plant\ Capacity\ \leq (Demand - Dispatched\ Capacity -$
  $Minimum\ capacity\ of\ total\ remaining\ power\ plants)$
- $Dispatched\ Capaticy = \sum_{i=1}^{l-1}\sum_{n=1}^{Ni}|S_{nit}|Mt_{nit}Pt_{nit}$
- $Total\ mimimun\ load\ of\ remaining\ plants =$
  $\sum_{i=1+1}^{I}\sum_{n=1}^{Ni}|S_{nit}|Mt_{nit}\,Pt_{ni}^{min}$
- $\sum_{n=1}^{Ni}|S_{nit}|Mt_{nit}Pt_{nit} \leq (D_t^{Th} - \sum_{i=1}^{l-1}\sum_{n=1}^{Ni}|S_{nit}|Mt_{nit}Pt_{nit} -$
  $\sum_{i=1+1}^{I}\sum_{n=1}^{Ni}|S_{nit}|Mt_{nit}\,Pt_{ni}^{min})$
- Four transitions can occur in a step change.
  - Transition 1
    - $if\ \ u_{i,t-1} = 0\ and\ S_{ni,t-1} = 0\ then$
      - $if\ u_{it} = 1\ then$
        - $if\ (Pt_{nit} \leq \left(D_t^{Th} - Dc_{0,t}^{l-1} - Rd_{l+1,t}^{I}\right))\ then$
          - $if\ \left(\tau < T_{ni}^{up}\right)then, 0 < S_{nit} < 1$
          - $if\ \left(\tau \geq T_{ni}^{up}\right)then, S_{nit} = 1$
        - $if\ \left(Pt_{nit} > \ \left(D_t^{Th} - Dc_{0,t}^{l-1} -\right.\right.$
          $\left.\left.Rd_{l+1,t}^{I}\right)\right)\ then$
          - $S_{nit} = 0$
      - $if\ u_{it} = 0, then\ S_{nit} = 0$

  - Transition 2
    - $if\ \ u_{i,t-1} = 1\ and\ S_{ni,t-1} = 1\ then$
      - $if\ u_{it} = 1\ then$
        - $if\ \left(Pt_{nit} \leq \left(D_t^{Th} - Dc_{0,t}^{l-1} -\right.\right.$
          $\left.\left.Rd_{l+1,t}^{I}\right)\right)\ then,\ S_{nit} = 1$
        - $if\ (Pt_{nit} > \left(D_t^{Th} - Dc_{0,t}^{l-1} - Rd_{l+1,t}^{I}\right))\ then$
          - $if\ \left(\tau < T_{ni}^{dn}\right)then, -1 < S_{nit} < 0$
          - $if\ \left(\tau \geq T_{ni}^{dn}\right)then, S_{nit} = 0$
      - $if\ u_{it} = 0, then$
          - $if\ \left(\tau < T_{ni}^{dn}\right)then, -1 < S_{nit} < 0$
          - $if\ \left(\tau \geq T_{ni}^{dn}\right)then, S_{nit} = 0$

- Transition 3
  - $if\ u_{i,t-1} = 1\ and\ 0 < S_{ni,t-1} < 1\ then\ u_{nit} \neq 1$
    - $if\ u_{nit} = 1\ then,$
      - $if\ (\tau < T_{ni}^{up})\ then, 0 < S_{nit} < 1$
      - $if\ (\tau \geq T_{ni}^{up})\ then\ S_{nit} = 1$
- Transition 4
  - $if\ u_{i,t-1} = 0\ and -1 < S_{ni,t-1} < 0\ then\ u_{nit} \neq 1$
    - $if\ u_{nit} = 0\ then$
      - $if\ (\tau < T_{ni}^{dn})\quad then -1 < S_{nit} < 0$
      - $if\ (\tau \geq T_{ni}^{dn})\quad then, S_{nit} = 0$

- Total cost of one option consists of energy cost and transition cost.

$$Total\ cost\ for\ hour = Energy\ Cost + Transition\ Cost$$

$$Transition\ Cost = St_{nit}S_{nit}^{D}\left(1 - S_{ni,t-1}^{D}\right) + Sd_{nit}S_{ni,t-1}^{D}(1 - S_{nit}^{D})$$

$$Energy\ Cost = \sum_{i=0}^{l-1}\sum_{n=1}^{Ni} |S_{nit}| Mt_{nit}(a_i Pt_{nit} + c_i)$$

$$\therefore\ Total\ cost\ for\ hour$$

$$= \sum_{i=0}^{l-1}\sum_{n=1}^{Ni} |S_{nit}| Mt_{nit}(a_i Pt_{nit} + c_i) + St_{nit}S_{nit}^{D}\left(1 - S_{ni,t-1}^{D}\right) + Sd_{nit}S_{ni,t-1}^{D}(1 - S_{nit}^{D})$$

- After completion of scheduling one option,

$$Full\ Total\ Cost = Previous\ Total\ Cost + Total\ Cost\ for\ hour$$

3.3 Short term power system planning

There are several methods of short-term forecasting including,

Classical time series and regression method

Time series models

Artificial intelligence and computational intelligence methods

Hybrid approaches [22]

Absolute mean percentage error (MAPE) is used to measure the performance of these models.

$$MAPE = \frac{100}{T}\sum_{t=1}^{T}\frac{y_t - f_t}{y_t}\ (\%)$$

Where,

y_t = real value at time t

f_t = forecast at time t of period T

3.3.1 Water value models

Cost of fuel is the main component that is deciding the operation cost of a thermal power plant.

$$\therefore \textit{thermal plants are representing according to the operating cost}$$

$$:\ c_j \left(\frac{\$}{MWh}\right)$$

Where, $j = 1,2, \ldots \ldots, n$

Generation Limits,

$$g_t(j) \leq G(j)$$

Where,

$g_t(j)$= energy production of plant j in stage t (MWh)

$G(j)$ = maximum generation capacity of plant j

Determining the power plant combination to achieve the required load with minimizing the fuel cost.

$$z_t = min \sum_{j=1}^{J} c_j g_t(j)$$

$$\sum_{j=1}^{J} g_t\,(t) = \ d_t$$

Where,

$z(t)$ – the system operating cost in stage t

c – unit operation costs

$d(t)$ – system load

$g(t)$ – Power production

g – generation capacities

3.3.2 Immediate Cost Function (ICF) and Future Cost Function (FCF)

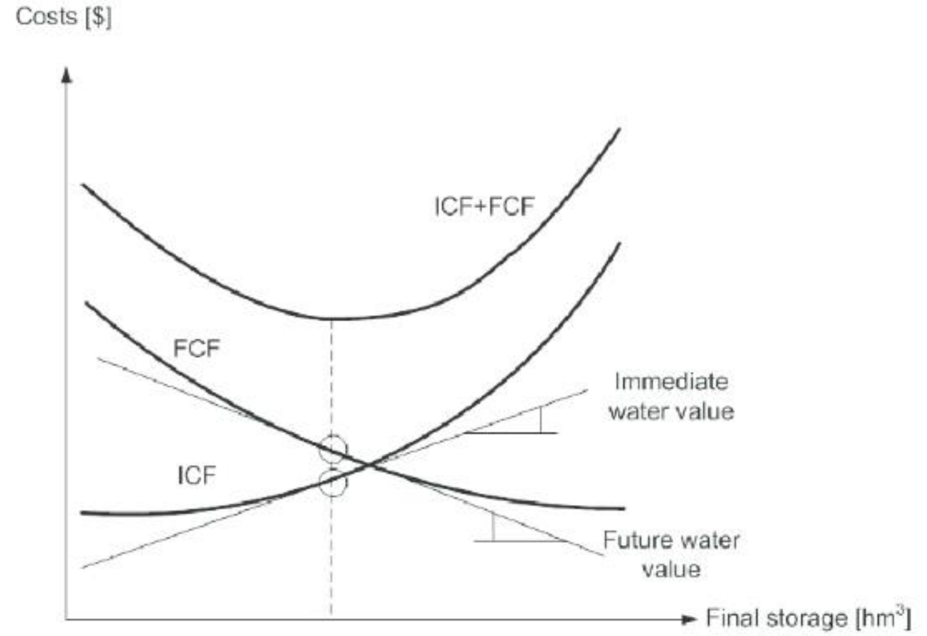


Figure 3. 3: Immediate Versus Future Cost Function

Source: [22]

Figure 3.3 illustrates a Supply-Demand curve for Immediate Costs versus Future Cost Functions. As final storage capacity increases to accommodate more water, future operating costs are expected to decline. However, if additional storage is needed, it becomes essential to utilise thermal power plants to conserve water, which results in an increase in immediate costs. The upper curve represents the sum of FCF and ICF, and it is likely to have a minimum at the point where reservoirs are being operated. An interesting feature of the total graph is that the gradients of ICF and FCF indicate the water value. At this minimum point, the gradients of both ICF and FCF are equal.

3.3.3 Optimisation Algorithm

$$p_k(k+1) = \alpha_p(k)p_n(k) + \epsilon(k)$$

Where,

p_k – average short price in the week

$p_n(k)$ – normalised value of p_k

$\alpha_p(k)$ – auto correction coefficient determined from the future function

$\epsilon(k)$ – normal random variable

Principle of mass production Theory

When the utilised capacity is increasing, fixed cost is declined and increasing the variable.

$$tc = \frac{FC}{x} + vc$$

tc – total average cost

FC – total fixed cost

X – production quantity

vc – total variable cost

To obtain the variable cost of a thermal power plant, specific heat rate curve is used. Specific heat curve provides information on the necessary heat energy required for generating one unit of electrical energy $H(P)$

$$H(P) = \frac{\alpha}{p} + \beta + \gamma P \qquad [\frac{kJ}{kWh}]$$

$$F(P) = P * H(P) \qquad [\frac{MJ}{h}]$$

$$C(P) = k * F(P) = a + bP + cP^2 \qquad [\frac{\$}{h}]$$

P – Thermo power plant production

α, β, γ – coefficient

$F(P)$ – input – output curve

$C(P)$ – fuel cost function

k – fuel cost coefficient

Water value deterministic function

$$f_c(P)\begin{cases} R_l(t) = R_{pl}(t), f_c(P) = 0 \\ R_l(t) < R_{pl}(t), f_c(P) = A \\ R_l(t) > R_{pl}(t), f_c(P) = B \end{cases}$$

$f_c(P)$ – function cost curve for water value

P – power needed in system

R_l – reservoir level

R_{pl} – planned reservoir level

System production optimisation

$$min\sum c(j)g_t(j) + \sum \rho(k, v_{t+1})\alpha_{t+1}(k)v_{t+1}(k) \pm E_i$$

Where,

$min\sum c(j)g_t(j)$ - immediate cost of thermal power plants Operating cost in stage t

$\sum \rho(k, v_{t+1})\alpha_{t+1}(k)v_{t+1}(k)$ - future cost of hydro power plant

$\rho(k, v_{t+1})$ – production coefficient of reservoir k

$\alpha_{t+1}(k)$ – water value function of the reservoir

$v_{t+1}(k)$ – reservoir volume at the end stage t

E_i – power exchange

For the easiness of understanding, the function can be modified as:

$$\min F = \sum_{i=1}^{5} c_i(TPP) + \sum_{i=1}^{6} c_i(HPP) \pm c(PEX)$$

Where,

$c_i(TPP)$ – cost of thermal power plant i

$c_i(HPP)$ - cost of hydro power plant i

$c(PEX)$ – energy sold or brought on power exchange

$$c_i(HPP) = \rho_i \approx V_{t+1}$$

Summation of power production and energy exchange must be equal with the planned load for each period.

$$\sum_{i=1}^{5} c_i(TPP) * P_i + \sum_{i=1}^{6} C_i(HPP) * P_i \pm c(PEX) * P = L$$

To achieve the maximum financial benefits,

$$C_i(HPP) + C_i(TPP) \le \min[c(EPEX), c_i(TPP)]$$

4. METHODOLOGY

The primary goal in optimising a power system based on hydro-thermal conditions is to formulate an optimum strategic plan for each stage of its planning period. This plan, contingent on the system's state at each stage, should determine expected power generation in different power plants. The overarching target is reducing the anticipate operation cost throughout corresponding period. This price encompasses fuel expenses and penalties for failing to meet load demand. The challenge lies in managing the limited hydroelectric energy stored in reservoirs, as this creates a complex interplay between present decisions and their future consequences.

The unpredictability of future inflow sequences due to imperfect forecasts makes the operational problem inherently uncertain. The presence of large number of cascade reservoirs and necessity of optimisation in different time durations contribute to the multi-scale nature of the problem. The nonlinearity of the objective function stems from both thermal costs and the product of outflow and head in the hydroelectric production function. Additionally, the worth of energy generated in a hydro plant is not directly quantifiable based solely on the plant state; instead, it is evaluated in terms of expected fuel savings from avoiding thermal generation. This non separability introduces further complexity into the objective function. In managing this complex problem, it is crucial to strike a balance between hydro and thermal generation, consider uncertainties in future inflow sequences, and navigate the trade-off between preventing energy wastage and minimising operating costs. Solutions often involve advanced optimisation algorithms tailored to address the stochastic, large-scale, and nonlinear aspects of the optimisation challenge.

To accomplish the stated objective SDDP technique can be employed [1] [23] [24] [25] .

SDDP, is an algorithm developed to address large-scale multi-stage optimisation problems under uncertainty. Unlike SDP, SDDP offers a distinctive approach by eliminating the need to enumerate combinations of reservoir levels. Instead, it approximates the future cost function through a Benders decomposition scheme. SDDP has proven effective in handling probabilistic models, such as those involving hydro inflows, renewable intermittency, demand variations and fuel price uncertainties.

SDDP serves as a model of stochastic dispatch, designed for electrical systems finds application in long, medium, and short-term operational activities. The model exhibits a high degree of flexibility concerning both temporal and spatial intricacies. It can effectively portray extended decision horizons, spanning into decades and includes by week or month. Furthermore, it offers intra-stage resolution, allowing for the representation of hours and minutes.

Hydroelectric Plants and Thermoelectric Plants are intricately represented in the optimisation framework. Each reservoir undergoes a detailed depiction, encompassing factors like water storage, flowrate, spilling, infiltration etc. The inclusion of a stochastic inflow model accounts for the seasonality, time and spatial correlations in inflow patterns.

The primary target of utilising SDDP approach is to reduce overall cost associated with hydro & thermal plants. The model aims to determine the cost-effective operating policy for the entire power system. Several constraints have been considered, including the parallelisation of SDDP to enhance computational efficiency. By decomposing the original problem into smaller-size sub-problems with one stage, the parallel version allows simultaneous solving by multiple computers connected through a local network or in a multi-task computer setup.

Although hydroelectric plants do not incur direct operating costs, their position in the merit order curve is influenced by uncertainties related to future inflows, as depicted in the figure 4.1. While one might assume that the absence of direct operating costs would prioritise hydro plants, the fluctuating nature of future inflows introduces a level of uncertainty that impacts their standing in the merit order. This uncertainty stems from factors such as variations in weather patterns and precipitation, which directly influence water inflows and subsequently impact the optimal utilisation of hydroelectric resources. Consequently, the interplay between the absence of direct operating costs and the unpredictability of future inflows adds complexity to the strategic placement of hydro plants in the merit order curve.

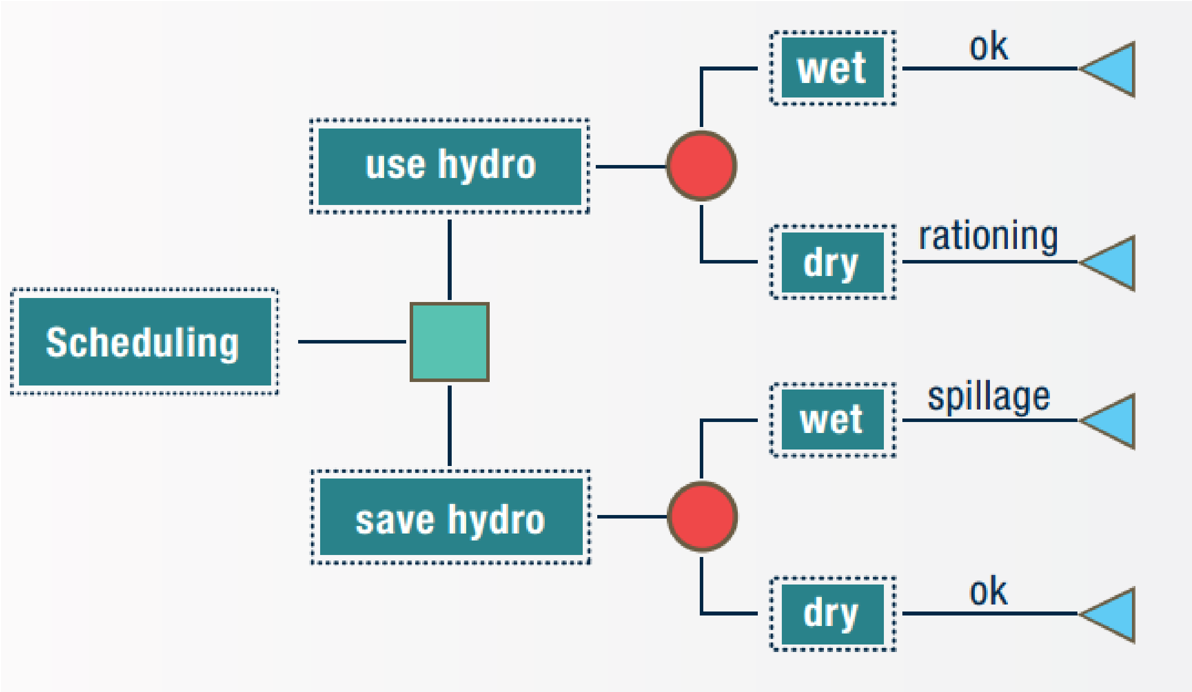


Figure 4. 1: Economic Dispatch of Hydropower plants

While hydro plants may not incur direct operational costs, they do have an opportunity cost associated with them. This opportunity cost represents the benefits derived from potential future production of energy. The determination of these parameters relies on consequence analysis linked to decisions regarding the storage or utilisation of water in various future scenarios. In the Stochastic Dual Dynamic Programming (SDDP) framework, this is reflected in the cost functions, where the immediate cost function addresses the present operational considerations, while the future cost function incorporates the opportunity cost associated with decisions related to storing or using water in different scenarios. This dynamic interplay involves scheduling the use of hydro resources, considering varying conditions such as wet and dry periods, to optimise overall system performance and minimise costs.

4.1 Strengths, Weaknesses and Limitations of SDDP in the Context of Electricity Costing

4.1.1 Strengths

- **Handling Uncertainty**: SDDP excels in managing uncertainties, such as fluctuating hydro inflows, renewable energy generation, and varying fuel prices. This is crucial for electricity systems where such uncertainties are prevalent.

- **Scalability and Computational Efficiency**: By using Bender's decomposition, SDDP can efficiently solve large-scale problems, which is essential for complex systems like power grids. The parallelisation capabilities further enhance its computational efficiency, making it suitable for long-term planning.

- **Flexibility**: SDDP allows for modelling both long-term and short-term decision-making processes, with the ability to incorporate intra-stage resolution. This flexibility is beneficial for accurately capturing seasonal and daily variations in electricity demand and supply.

- **Economic Dispatch Optimisation**: SDDP can optimise the dispatch of hydro and thermal power plants, balancing operational costs and opportunity costs. This ensures cost-effective operation while considering the complexities introduced by the variability of future inflows.

4.1.2 Weaknesses and Limitations

- **Complexity and Assumptions**: The SDDP method requires careful modelling of the system's stochastic processes, such as inflow patterns and demand variations. Incorrect assumptions can lead to suboptimal policies.

- **Computational Resources**: While SDDP is efficient compared to other methods, it still requires significant computational resources, especially when dealing with very large systems or high-resolution time steps.

- **Accuracy of Future Predictions**: The effectiveness of SDDP depends on the accuracy of the stochastic models used for future predictions. Inaccurate models can result in suboptimal decisions, especially in systems with high variability.

4.2 Mathematical Modelling for Seasonal and Time of Day Electricity Costing using SDDP Principles

To develop a mathematical model using SDDP principles, along with DPSA, DDDP, Markov Chains and serial correlation, it can be outlined:

4.2.1 State Variables and Decision Variables

- **State Variables**: These include the storage levels in hydro reservoirs, generation capacity of thermal plants and possibly renewable generation availability.
- **Decision Variables**: These include the amount of water released from reservoirs, the amount of electricity generated by each type of plant and the allocation of generation to meet demand.

4.2.2 Objective Function

The objective is to minimise the total cost over a planning horizon. This includes operational costs, opportunity costs, and penalties for unmet demand or excessive use of expensive resources.

$$\min E\left[\sum_{t=1}^{T} C_t(x_t, u_t, \omega_t)\right] \quad (1)$$

Where:

C_t - Cost function at time t

x_t - state vector

u_t - Control vector (decision variables)

ω_t - represents the uncertainties.

4.2.3 Dynamic Programming Recursion

The value function at time $t, V_t(x_t)$, can be expressed as:

$$V_t(x_t) = min_{u_t}\{C_t(x_t, u_t) + E[V_{t+1}(x_{t+1}|x_t, u_t]\} \quad (2)$$

To handle large-scale problems, Bender's decomposition splits the problem into a master problem and subproblems. The master problem determines the decision variables, and the subproblems (one for each scenario) are used to approximate the value function. Uncertainties such as inflows can be modelled using Markov Chains, capturing the probabilities of transitions between different states. Serial correlation can be incorporated to model temporal dependencies in the stochastic processes. DDDP can be used to refine the decision-making process by solving a series of linearised subproblems, improving the approximation of the value function. DPSA techniques can be used to iteratively improve the decision policy, starting from an initial guess and converging to an optimal policy.

Operation of hydrothermal electric system is not simple due to the characteristics of two generation methods. Stochastic programming techniques are used to model hydrothermal systems owing to the uncertainty.

4.2.4 Constraints

Neglecting the losses,

$$Total\ Electricity\ Demand = Total\ Hydro\ generation + Total\ Thermal\ Generation \quad (3)$$

Water storage of a reservoir at a particular state (t),

$$x_{t+1} = x_t + y_t - (u_t + s_t) \quad (4)$$

Where,

x_{t+1} - water storage at the end of state t

x_t - water storage at the beginning of state t

y_t - water inflow (increment) volume

u_t - water discharge volume

s_t - water spillage volume

Due to the practical knowledge, evaporation is neglected.

And,

$$\underline{x}_{t+1} \leq x_{t+1} \leq \bar{x}_{t+1} \quad (5)$$

Where,

$\underline{x}_{t+1}$ - minimum storage of the reservoir

$\bar{x}_{t+1}$ - maximum storage of the reservoir

$$u_t \leq \bar{u}_t \tag{6}$$

Where,

$\bar{u}_t$ - maximum allowable outflow of the turbine

4.2.5 Integrated Equations

Since water is free, the aim of the optimisation is to minimise the cost of thermal power generation. The objective function is a recursive function, which is a summation of immediate operation cost and future operation cost. Equation (7) serves as a building block for dynamic programming, defining how costs propagate over time, which is more focused on a single stage t and its immediate successor $t+1$, providing a local view of the cost structure.

$$A_t(X_t) = E[\min(C_t) + \gamma A_{t+1}(X_{t+1})] \tag{7}$$

Where,

$A_t(X_t)$ - Expected operation cost at state X_t

$A_{t+1}(X_{t+1})$ - Expected operation cost at state X_{t+1} (future operation cost)

$E(.)$ - Expected Value function

C_t - Generation cost at stage t

γ – Discount factor (weighting constant for future costs)

Using (1), (2) and (7) equations new equations can be integrated for optimising the hydrothermal electric system.

The 4.2 section introduces an iterative algorithm to minimise the overall cost.

$$minimise: Total\ Cost_{dispatch} = Sum\ of\ Costs\ over\ 2^I\ Options \tag{8}$$

4.3 Algorithm for Economic Dispatch

This algorithm introduces a methodology to economic dispatch, which is used to optimise processing speed as well as main memory usage since the algorithm involved in huge amount of data. Parallel processing method is used for finding the economic dispatch data.

Inputs

- Economic Dispatch Inputs
  - Quarter hour electricity demand
  - Existing Power Plant Details
  - Irrigation release agreements
- Initial State Variables
  - x_o: initial water storage levels in reservoirs
  - Capacities of existing hydro and thermal power plants and their per unit generation cost details
- State Transition Parameters
  - y_t: Water inflows into the reservoirs at each time step
  - s_t: Water spillage at each time step
  - u_t: Water released from reservoir at each time step
- Constraints
  - $\underline{x}_{t+1}, \bar{x}_{t+1}$: Minimum and Maximum storage limits of reservoirs
  - $\bar{u}_t$ Maximum allowable outflow from the turbines
  - P_{min}, P_{max}: Minimum and Maximum Power Generation Capacities of each power plant
- Uncertainties and Stochastic Elements
  - ω_t: Probability distribution for uncertainties like inflow and demand

Step 1

- Generate initial schedule.
- Sort thermal power plants according to the ascending order of unit cost.

Step 2

- Generate options for next schedule. (Number of options = 2^I) [1]

If m - number of discretised intervals of state vectors, then m^{2n} discretised states are there.

Let, $m = 20$,

Table 4. 1: Number of discretised States

Number of reservoirs	States
1	20^2
2	20^4
3	20^6

- Remove the impossible conditions of loads.

  e.g. - $P_{min} < P < P_{max}$

- Compare the different conditions of each power plants and choose/ ignore them according to the conditions/ constraints.

Step 3

- Employ all the options available.

Step 4

- Sort options of quarter-hour total cost in ascending order and computation time.
- Take first 100 options as the current option. (100 options are chosen due to the conditions of computation)

Step 5

- Repeat 2,3,4 steps until the time finish. (Figure 4.2)
- Form a tree structure.

Step 6

- Find minimum total cost at t=T.
- Reach the backward till it reaches initial position. ($t = 0$)

The path from initial position to final least cost position provides optimum dispatch schedule.

Output: An optimal economic dispatch schedule for each 15 min.

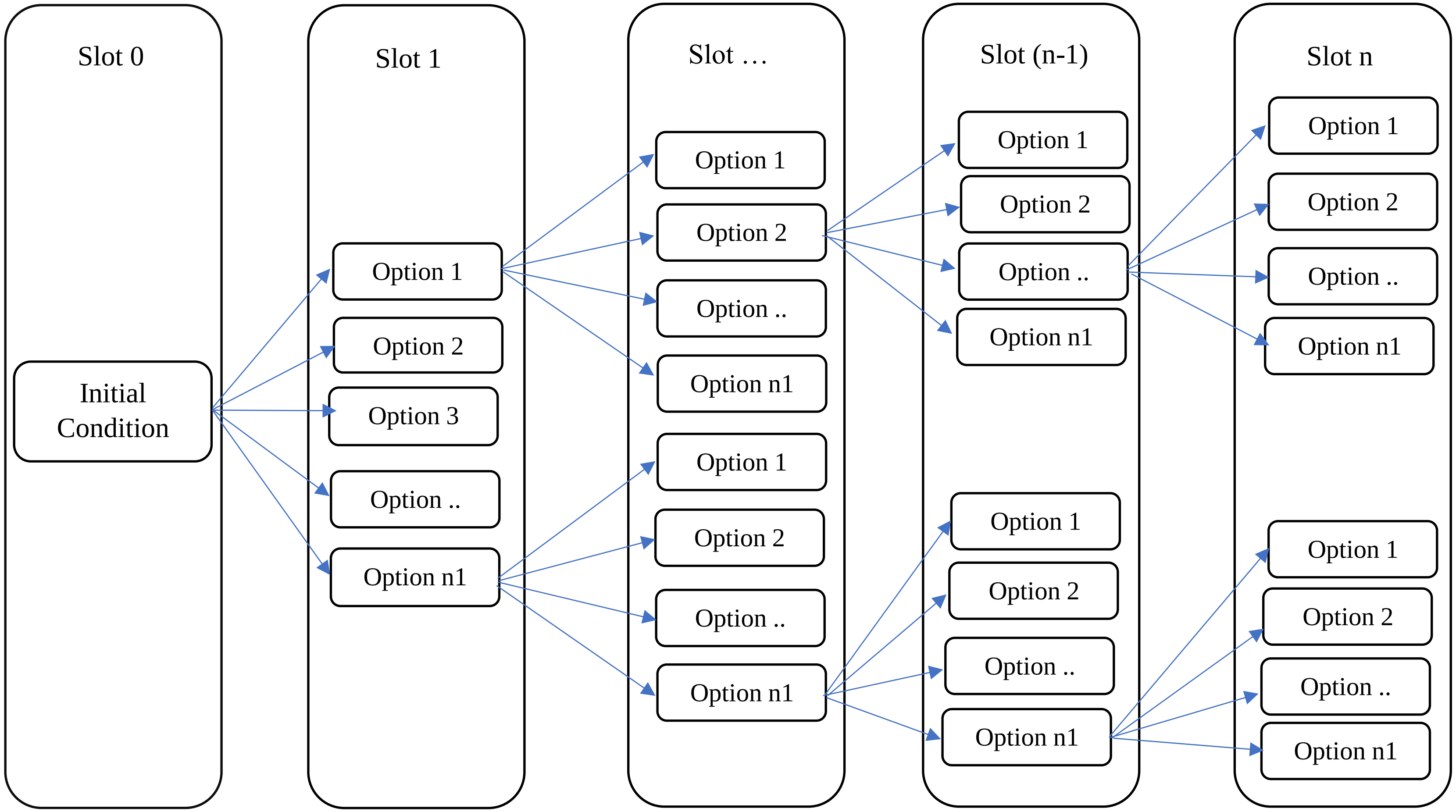
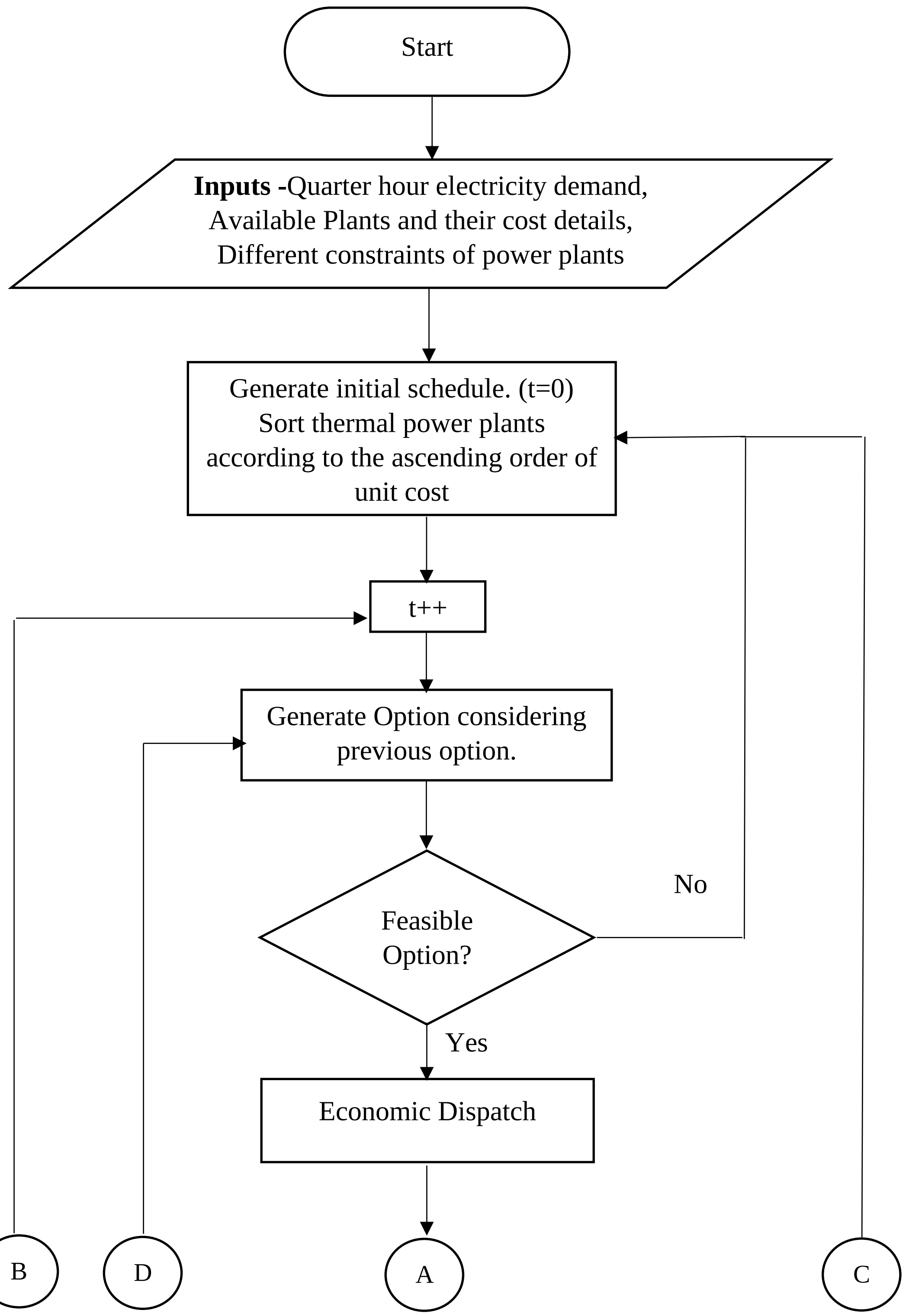
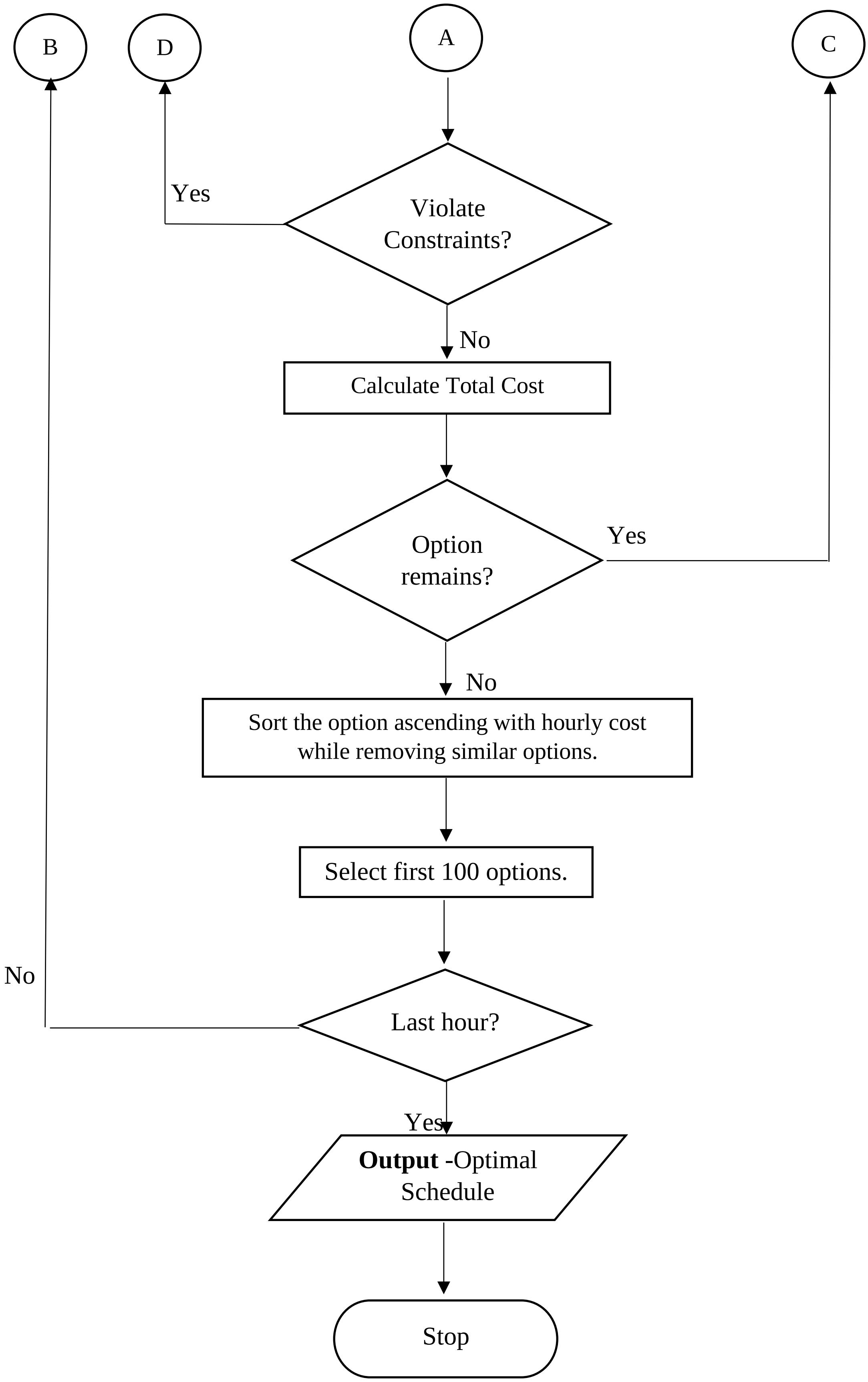


Figure 4. 2: Tree Structure Obtained for feasible options

4.1 Flowchart of the algorithm for economic dispatch




B
D
A
C
Yes
Violate
Constraints?
No
Calculate Total Cost
Yes
Option
remains?
No
Sort the option ascending with hourly cost
while removing similar options.
Select first 100 options.
No
Last hour?
Yes
Output -Optimal
Schedule
Stop

4.2 Calculating Seasonal and Time of Day Dependent Electricity Cost

Following the computing of dispatch schedule, three distinct methods are employed for the computation of Seasonal and Time of Day Dependent Electricity Cost. These methods rely on three approaches to estimate the water value. The water value was not provided in sections 4.2 and 4.3 because dispatching is centred on thermal power plants, with hydropower plants included based on their availability, as discussed in Chapter 02. The three distinct methods of calculating the water value are:

1. Assigning fuel cost for hydro is zero (water value is zero)
2. Assigning the per unit generation cost of the most expensive thermal power plant in the load curve as water value.
3. Assigning the weighted average generation cost of variable thermal power plants as the water value

Moving forward, these methods involve calculating the weighted average of the generation costs of all power plants ($A_{i,r}$) in the dispatch schedule for each quarter hour. The weights are typically based on contribution to total electricity generation. The water value is assigned as the per unit generation cost of hydropower plants while thermal power plants are assigned their per unit cost, mainly depending on the fuel cost. The Total Generation Cost of r^{th} generator unit of i^{th} power plant ($A_{i,r}$) can be calculated by,

$$A_{i,r} = \frac{\sum P_{i,r} Y_{i,r} \times 0.25}{\sum P_{i,r} \times 0.25} \qquad (5)$$

Where,

$P_{i,r}$ - Power Output of r^{th} generator unit of i^{th} powerplant in 15 minutes

$Y_{i,r}$ - The unit cost of the same unit an average unit cost

To calculate $A_{i,r}$ in LKR/kWh, it is essential to substitute $P_{i,r}$ in kW rather than MW. The factor 0.25 in Equation (5) corresponds to quarter-hour intervals (0.25 hrs). The reason for using quarter-hour intervals is that it has become the standard at CEB in this era. Prior to 2018, intervals were half an hour, but since 2018, all short-term dispatches have aligned with 15-minute durations. CEB forecasts economic dispatch patterns for each quarter-hour throughout the day, resulting in four dispatch schedules per hour and a total of 96 schedules per day (4 per hour × 24 hours = 96). To comprehensively analyse the dispatch schedule for a specific time slot, the application of SDDP is warranted.

The capacity cost for both hydro and thermal power plants is omitted from consideration, as this cost is applicable regardless of the power plant's operational status. Capacity cost is not factored into the merit order dispatch, as it remains constant and is independent of seasonal or time-of-day variations.

A detailed description of each method, along with their respective pros and cons, will be provided in Chapter 05 when analysing the results of each method.

5. ANALYSIS AND RESULTS

The chapter 4 underscores the significance of Systematic Dynamic Dispatch Programming (SDDP) within this research, employing a simplified structure to mitigate complexity. It delves into the analysis of the Seasonal and Time of Day Dependent Electricity Cost and water value using the economic dispatch schedule of the CEB, grounded in SDDP and NCP. By extracting the dispatch schedule from the CEB's timetable, this chapter facilitates the examination of the specified parameters. Given the accuracy and real-world applicability of SDDP output, its inclusion in this context is deemed appropriate. Moving forward with the methodology introduced in Chapter 4, it is crucial to follow each step diligently.

In this sample calculation, the varying states of the reservoirs are not considered to avoid unnecessary complexity. It is assumed that all reservoirs meet the conditions required to release water during the specified time. For the recursive calculation, the time horizon is set to conclude at the end of the corresponding period, which is 8 pm.

5.1 Obtaining Economic Dispatch Schedule

Inputs:

Table 5.1 represents the predicted electricity demand from 7 to 8 pm on January 15, 2019, and Table 5.2 illustrates the existing power plants and their rated power generation. After presenting tables 5.1 and 5.2, specific constraints for this day and time are mentioned.

Table 5. 1: Quarter Hour Predicted Electricity Demand of 7 - 8 pm, 2019.01.15

	Time			
	7:00 pm	7:15 pm	7:30 pm	7:45 pm
Predicted Quarter Hourly Electricity Demand (MW)	**2,220**	**2,207**	**2,187**	**2,157**

Source: PUCSL

Table 5. 2: Existing Power Plants with their Rated Capacity and Generation Cost Details

Type	Complex	Power Station and Generator Unit	Capacity (MW) [3]	Per Unit Generation Cost (LKR/ kWh) [26]	Remarks
Hydro	Mahaweli	Victoria 01	70		
		Victoria 02	70		
		Victoria 03	70		
		Randenigala 01	61		
		Randenigala 02	61		
		Rantabe 01	24.5		
		Rantabe 02	24.5		
		Kotmale 01	67		Out of work
		Kotmale 02	67		
		Kotmale 03	67		Out of work
		Nillabe	1.61		
		Ukuwela 01	19.3		
		Ukuwela 02	19.3		
		Bowathenna	40		
		Upper Kotmale 01	75		
		Upper Kotmale 02	75		
		Moraghakanda	10		
	Laxapana	New Laxapana 01	50		
		New Laxapana 02	50		
		Polpitiya 01	45		
		Polpitiya 02	45		
		Old Laxpana 01	9.6		

Type	Complex	Power Station and Generator Unit	Capacity (MW) [3]	Per Unit Generation Cost (LKR/ kWh) [26]	Remarks
		Old Laxpana 02	9.6		
		Old Laxpana 03	9.6		
		Old Laxpana 04	12.5		
		Old Laxpana 05	12.5		
		Canyon 01	30		
		Canyon 02	30		Out of work
		WPS 01	25		Out of work
		WPS 02	25		
	Samanala	Samanalawewa 01	60		
		Samanalawewa 02	60		
		Kukule 01	37.5		
		Kukule 02	37.5		
		Udavalawa	3.2		
		Inginiyagala	0		Out of work
Thermal	Kelanitissa	KPS GT 01	20	46.07	
		KPS GT 02	20		Out of work
		KPS GT 04	20		Out of work
		KPS GT 05	20		
		KPS GT 07	115	36.09	
	KCCP	KCCP_GT	165	21.88	
		KCCP_ST			
	KCCP	Sapugaskanda 01	20	22.26	Out of work
		Sapugaskanda 02	20		

Type	Complex	Power Station and Generator Unit	Capacity (MW) [3]	Per Unit Generation Cost (LKR/ kWh) [26]	Remarks
		Sapugaskanda 03	20		Out of work
		Sapugaskanda 04	20		Out of work
		Sapugaskanda 05	10		
		Sapugaskanda 06	10		
		Sapugaskanda 07	10		Out of work
		Sapugaskanda 08	10		
		Sapugaskanda 09	10		
		Sapugaskanda 10	10		
		Sapugaskanda 11	10		
		Sapugaskanda 12	10		
	Barge	Barge	62.4	18.14	
	Uthurujanani	Uthuru Janani	26.7	21.61	
	Lakvijaya	Lakvijaya 01	300	7.95	
		Lakvijaya 02	300		
		Lakvijaya 03	300		Out of work
	IPP	EMC Thulhiriya	0	22.44	Out of work
		Asia Power	51	22.48	Out of work
		Sojitz	163	22.44	Out of work

Type	Complex	Power Station and Generator Unit	Capacity (MW) [3]	Per Unit Generation Cost (LKR/ kWh) [26]	Remarks
		ACE-Matara	25	22.06	Out of work
		ACE-Embilipitiya	100	22.06	
		West Coast GT1	270	22.01	
		West Coast GT2			
		West Coast Steam			

It is crucial to consider the storage levels of the reservoir in the economic dispatch process. Table 5.3 presents the storage details of several reservoirs within the context.

Table 5. 3: Storage Levels of Different Reservoirs on 2019.01.15

Reservoir	Storage at FCL (MCM)	Storage of the Day (MCM)	Active Storage (%)	
			MCM	%
Mahaweli				
Kotmale	170.9	139.3	94.4	74.9
Victoria	721.2	582.6	310.6	69.2
Randenigala	801.5	608.8	256.4	57.1
Rantembe	7.0	6.2	2.5	74.8
Bowatenna	23.5	14.8	4.0	31.6
Moragahakanda	557.9	270.3	133.6	70.6
Laxapana				
Castlereigh	48.3	35.3	14.7	53.2

Moussakele	123.3	105.6	99.7	85.0
Samanala				
Samanalawewa	278.0	122.6	122.6	60.2
Udawalawe	268.7	141.4	141.4	73.7

Different constraints of power plants

- Hydropower plants are utilised during this time of day, which corresponds to peak hours when these plants are heavily engaged. No contradictions with the equations of (4) to (6).
- Some power plants are not operating due to maintenance work, as indicated in the Remarks column of Table 5.2 with the note 'Out of service'.
- The Lakvijaya Coal Power Complex will serve as the baseload.
- This is nighttime, so there is no contribution from solar power plants.
- Contribution of wind power plants is neglected.
- Operational Constraints (starting time/ shut down time etc) are not considered.

A Sample Calculation for the Steps 1 to 5

Initial Setup and Sorting

Sorted Thermal Power Plants by Unit Cost (ascending order):

i Lakvijaya 7.95 LKR/kWh (baseload)

ii Barge 18.14 LKR/kWh

iii Uthuru Janani 21.61 LKR/kWh

iv KCCP 21.88 LKR/kWh

v Sapugaskanda 22.26 LKR/kWh

vi KPS GT 07 36.09 LKR/kWh

vii KPS small GTs 46.07 LKR/kWh

Calculate the Schedule

1. **7:00 pm - Demand: 2,220 MW**
   - Lakvijaya 01: 300 MW
   - Lakvijaya 02: 300 MW
   - Additional plants needed: 1,620 MW

2. **7:15 pm - Demand: 2,207 MW**
   - Lakvijaya 01: 300 MW
   - Lakvijaya 02: 300 MW
   - Additional plants needed: 1,607 MW

3. **7:30 pm - Demand: 2,187 MW**
   - Lakvijaya 01: 300 MW
   - Lakvijaya 02: 300 MW
   - Additional plants needed: 1,587 MW

4. **7:45 pm - Demand: 2,157 MW**
   - Lakvijaya 01: 300 MW
   - Lakvijaya 02: 300 MW
   - Additional plants needed: 1,557 MW

Optimising the Dispatch Schedule

To minimise the cost, the next plants will be chosen based on their cost-effectiveness until the demand is met.

Optimal Dispatch Schedule for Each 15-Minute Interval:

7:00 pm
- Lakvijaya 01: 300 MW
- Lakvijaya 02: 300 MW
- Barge: 62.4 MW

- KCCP_GT: 165 MW
- Uthuru Janani: 26.7 MW
- Remaining demand: 1,365.9 MW
- Next in order: Sapugaskanda 02, 05, 06, 08, 09, 10, 11, 12 (total: 80 MW)
- Remaining demand: 1,285.9 MW
- Next: KPS GT 07 (115 MW), KPS GT 01 (20 MW), KPS GT 05 (20 MW)
- Remaining demand: 1,130.9 MW
- Use additional plants as necessary to meet the remaining demand.

7:15 pm
- Repeat the same process with 2,207 MW demand, adjusting for the slightly lower requirement.

7:30 pm
- Repeat with 2,187 MW demand.

7:45 pm
- Repeat with 2,157 MW demand.

7:00 pm - Demand: 2,220 MW

- **Lakvijaya 01**: 300 MW
- **Lakvijaya 02**: 300 MW
- **Barge**: 62.4 MW
- **KCCP_GT**: 165 MW
- **Uthuru Janani**: 26.7 MW
- **Sapugaskanda 02**: 20 MW
- **Sapugaskanda 05**: 10 MW
- **Sapugaskanda 06**: 10 MW
- **Sapugaskanda 08**: 10 MW
- **Sapugaskanda 09**: 10 MW
- **Sapugaskanda 10**: 10 MW
- **Sapugaskanda 11**: 10 MW
- **Sapugaskanda 12**: 10 MW

- **KPS GT 07**: 115 MW
- **KPS GT 01**: 20 MW
- **KPS GT 05**: 20 MW

Remaining Demand: 1,143.9 MW

Continuing with hydro plants in the specified order:

- **Samanalawewa 01**: 60 MW
- **Samanalawewa 02**: 60 MW
- **New Laxapana 01**: 50 MW
- **New Laxapana 02**: 50 MW
- **Old Laxapana 01**: 9.6 MW
- **Old Laxapana 02**: 9.6 MW
- **Old Laxapana 03**: 9.6 MW
- **Old Laxapana 04**: 12.5 MW
- **Old Laxapana 05**: 12.5 MW
- **Mahaweli (Victoria 01)**: 70 MW
- **Mahaweli (Victoria 02)**: 70 MW
- **Mahaweli (Victoria 03)**: 70 MW
- **Mahaweli (Randenigala 01)**: 61 MW
- **Mahaweli (Randenigala 02)**: 61 MW
- **Mahaweli (Rantabe 01)**: 24.5 MW
- **Mahaweli (Rantabe 02)**: 24.5 MW
- **Mahaweli (Kotmale 02)**: 67 MW

Summing the above capacities:

- **Samanalawewa**: 120 MW
- **New Laxapana**: 100 MW
- **Old Laxapana**: 53.8 MW
- **Mahaweli (Victoria)**: 210 MW
- **Mahaweli (Randenigala)**: 122 MW
- **Mahaweli (Rantabe)**: 49 MW
- **Mahaweli (Kotmale)**: 67 MW

Total Hydro Capacity: 721.8 MW

7:15 pm - Demand: 2,207 MW

- **Lakvijaya 01**: 300 MW
- **Lakvijaya 02**: 300 MW
- **Barge**: 62.4 MW
- **KCCP_GT**: 165 MW
- **Uthuru Janani**: 26.7 MW
- **Sapugaskanda 02**: 20 MW
- **Sapugaskanda 05**: 10 MW
- **Sapugaskanda 06**: 10 MW
- **Sapugaskanda 08**: 10 MW
- **Sapugaskanda 09**: 10 MW
- **Sapugaskanda 10**: 10 MW
- **Sapugaskanda 11**: 10 MW
- **Sapugaskanda 12**: 10 MW
- **KPS GT 07**: 115 MW
- **KPS GT 01**: 20 MW
- **KPS GT 05**: 20 MW

Remaining Demand: 1,130.9 MW
Continuing with hydro plants in the specified order:

- **Samanalawewa 01**: 60 MW
- **Samanalawewa 02**: 60 MW
- **New Laxapana 01**: 50 MW
- **New Laxapana 02**: 50 MW
- **Old Laxapana 01**: 9.6 MW
- **Old Laxapana 02**: 9.6 MW
- **Old Laxapana 03**: 9.6 MW
- **Old Laxapana 04**: 12.5 MW
- **Old Laxapana 05**: 12.5 MW

- **Mahaweli (Victoria 01)**: 70 MW
- **Mahaweli (Victoria 02)**: 70 MW
- **Mahaweli (Victoria 03)**: 70 MW
- **Mahaweli (Randenigala 01)**: 61 MW
- **Mahaweli (Randenigala 02)**: 61 MW
- **Mahaweli (Rantabe 01)**: 24.5 MW
- **Mahaweli (Rantabe 02)**: 24.5 MW
- **Mahaweli (Kotmale 02)**: 67 MW

Total Hydro Capacity: 721.8 MW

7:30 pm - Demand: 2,187 MW

- **Lakvijaya 01**: 300 MW
- **Lakvijaya 02**: 300 MW
- **Barge**: 62.4 MW
- **KCCP_GT**: 165 MW
- **Uthuru Janani**: 26.7 MW
- **Sapugaskanda 02**: 20 MW
- **Sapugaskanda 05**: 10 MW
- **Sapugaskanda 06**: 10 MW
- **Sapugaskanda 08**: 10 MW
- **Sapugaskanda 09**: 10 MW
- **Sapugaskanda 10**: 10 MW
- **Sapugaskanda 11**: 10 MW
- **Sapugaskanda 12**: 10 MW
- **KPS GT 07**: 115 MW
- **KPS GT 01**: 20 MW
- **KPS GT 05**: 20 MW

Remaining Demand: 1,110.9 MW
Continuing with hydro plants in the specified order:

- **Samanalawewa 01**: 60 MW

- **Samanalawewa 02**: 60 MW
- **New Laxapana 01**: 50 MW
- **New Laxapana 02**: 50 MW
- **Old Laxapana 01**: 9.6 MW
- **Old Laxapana 02**: 9.6 MW
- **Old Laxapana 03**: 9.6 MW
- **Old Laxapana 04**: 12.5 MW
- **Old Laxapana 05**: 12.5 MW
- **Mahaweli (Victoria 01)**: 70 MW
- **Mahaweli (Victoria 02)**: 70 MW
- **Mahaweli (Victoria 03)**: 70 MW
- **Mahaweli (Randenigala 01)**: 61 MW
- **Mahaweli (Randenigala 02)**: 61 MW
- **Mahaweli (Rantabe 01)**: 24.5 MW
- **Mahaweli (Rantabe 02)**: 24.5 MW
- **Mahaweli (Kotmale 02)**: 67 MW

Total Hydro Capacity: 721.8 MW

7:45 pm - Demand: 2,157 MW

- **Lakvijaya 01**: 300 MW
- **Lakvijaya 02**: 300 MW
- **Barge**: 62.4 MW
- **KCCP_GT**: 165 MW
- **Uthuru Janani**: 26.7 MW
- **Sapugaskanda 02**: 20 MW
- **Sapugaskanda 05**: 10 MW
- **Sapugaskanda 06**: 10 MW
- **Sapugaskanda 08**: 10 MW
- **Sapugaskanda 09**: 10 MW
- **Sapugaskanda 10**: 10 MW
- **Sapugaskanda 11**: 10 MW
- **Sapugaskanda 12**: 10 MW

- **KPS GT 07**: 115 MW
- **KPS GT 01**: 20 MW
- **KPS GT 05**: 20 MW

Remaining Demand: 1,090.9 MW

Continuing with hydro plants in the specified order:

- **Samanalawewa 01**: 60 MW
- **Samanalawewa 02**: 60 MW
- **New Laxapana 01**: 50 MW
- **New Laxapana 02**: 50 MW
- **Old Laxapana 01**: 9.6 MW
- **Old Laxapana 02**: 9.6 MW
- **Old Laxapana 03**: 9.6 MW
- **Old Laxapana 04**: 12.5 MW
- **Old Laxapana 05**: 12.5 MW
- **Mahaweli (Victoria 01)**: 70 MW
- **Mahaweli (Victoria 02)**: 70 MW
- **Mahaweli (Victoria 03)**: 70 MW
- **Mahaweli (Randenigala 01)**: 61 MW
- **Mahaweli (Randenigala 02)**: 61 MW
- **Mahaweli (Rantabe 01)**: 24.5 MW
- **Mahaweli (Rantabe 02)**: 24.5 MW
- **Mahaweli (Kotmale 02)**: 67 MW

Total Hydro Capacity: 721.8 MW

Sample Calculation for Step 06

Let γ = 0.9

	t	t+1	t+2	t+3
	7.00 pm	7.15 pm	7.30 pm	7.45 pm
C_t(LKR)	18,085,673.00	18,085,673.00	18,085,673.00	18,085,673.00
$A_t(X_t)$ (LKR)	62,196,629.00	49,012,174.00	34,362,779.00	18,085,673.00

Output

The optimal economic dispatch schedule for each 15-minute interval, using the order of Samanala, Laxapana, and Mahaweli hydro plants to meet the remaining demand, is as follows:

1. **7:00 pm**
   - Lakvijaya 01: 300 MW
   - Lakvijaya 02: 300 MW
   - Barge: 62.4 MW
   - KCCP_GT: 165 MW
   - Uthuru Janani: 26.7 MW
   - Sapugaskanda 02: 20 MW
   - Sapugaskanda 05: 10 MW
   - Sapugaskanda 06: 10 MW
   - Sapugaskanda 08: 10 MW
   - Sapugaskanda 09: 10 MW
   - Sapugaskanda 10: 10 MW
   - Sapugaskanda 11: 10 MW
   - Sapugaskanda 12: 10 MW
   - KPS GT 07: 115 MW
   - KPS GT 01: 20 MW
   - KPS GT 05: 20 MW
   - Remaining demand to be met by Hydro Plants 1,143.9 MW.

2. **7:15 pm**
   - Same configuration as above, with remaining demand: 1,130.9 MW to be met by Hydro Plants.

3. **7:30 pm**
   - Same configuration as above, with remaining demand: 1,110.9 MW to be met by Hydro Plants.

4. **7:45 pm**

- Same configuration as above, with remaining demand: 1,090.9 MW to be met by Hydro Plants.

The algorithm generates similar options, but several practical constraints must be considered to obtain an accurate output. One of the main constraints is that power plants do not always operate under full load conditions and may not run at their rated power. Additionally, the dispatch schedule might not require the rated power; often only a portion of the power is needed to meet the demand for a given quarter-hour period. Furthermore, the cascaded structure of hydropower plants must be considered. For example, the water used for power generation at the Victoria Reservoir will subsequently flow to the Randenigala and Rantembe reservoirs. Initially, reservoirs located upstream of the river release water, followed by the downstream reservoirs coming into operation. The actual dispatch schedule for the corresponding period is presented in Table 5.3.

Table 5. 4: Economic Dispatch Schedule of 7 - 8 pm, 2019.01.15

Power Station and Generator Unit	Quarter Hourly Power Generation (MW)			
	7:00 pm	7:15 pm	7:30 pm	7:45 pm
Victoria 01	63.36	66.49	60.34	59.94
Victoria 02	59.68	36.92	40.77	44.43
Victoria 03	69.76	55.00	54.86	64.38
Randenigala 01	56.72	56.72	56.72	56.72
Randenigala 02	56.45	56.45	56.45	56.45
Rantabe 01	25.1	25.15	25.15	25.28
Rantabe 02	24.31	24.34	24.45	24.25
Kotmale 01	0.00	0.00	0.00	0.00
Kotmale 02	63.00	63.00	63.00	63.00
Kotmale 03	0.00	0.00	0.00	0.00
Nillabe	3.20	3.20	3.20	3.20
Ukuwela 01	18.50	18.53	18.52	18.52
Ukuwela 02	17.3	17.33	17.31	17.31
Bowathenna	27.48	23.33	10.01	12.13
Upper Kotmale 01	74.73	74.75	74.63	74.84
Upper Kotmale 02	74.83	74.81	74.67	74.73
Moraghakanda	9.47	9.31	9.22	9.33
New Laxapana 01	42.72	40.09	40.23	40.27
New Laxapana 02	40.34	40.27	40.44	40.35
Polpitiya 01	16.12	20.88	21.62	21.95
Polpitiya 02	6.84	19.72	20.53	20.77
Old Laxpana 01	3.08	3.08	3.08	3.09

Power Station and Generator Unit	Quarter Hourly Power Generation (MW)			
	7:00 pm	7:15 pm	7:30 pm	7:45 pm
Old Laxpana 02	1.01	1.01	0.99	0.99
Old Laxpana 03	1.01	1.01	1.00	1.01
Old Laxpana 04	4.13	4.13	4.13	4.13
Old Laxpana 05	4.23	4.23	4.23	4.23
Canyon 01	30.06	30.06	30.06	30.06
Canyon 02	0.00	0.00	0.00	0.00
WPS 01	0.00	0.00	0.00	0.00
WPS 02	25.07	25.12	25.14	25.11
Samanalawewa 01	59.65	59.84	59.46	59.47
Samanalawewa 02	59.46	59.49	59.46	60.86
Kukule 01	37.50	37.50	37.50	0.00
Kukule 02	37.50	37.50	37.50	26.00
Udavalawa	3.20	3.20	3.20	3.20
Inginiyagala	0.00	0.00	0.00	0.00
KPS GT 01	0.00	13.12	15.4	16.88
KPS GT 02	0.00	0.00	0.00	0.00
KPS GT 04	0.00	0.00	0.00	0.00
KPS GT 05	15.00	15.00	15.00	15.00
KPS GT 07	110.87	110.9	110.56	110.66
KCCP_GT	84.26	88.55	87.89	87.14
KCCP_ST	41.55	41.45	41.39	41.26
Sapugaskanda 01	0.00	0.00	0.00	0.00
Sapugaskanda 02	16.03	15.93	15.65	15.98
Sapugaskanda 03	0.00	0.00	0.00	0.00
Sapugaskanda 04	0.00	0.00	0.00	0.00
Sapugaskanda 05	7.96	8.09	7.91	7.99
Sapugaskanda 06	8.35	8.52	8.51	8.50
Sapugaskanda 07	0.00	0.00	0.00	0.00
Sapugaskanda 08	8.86	9.06	8.91	9.02
Sapugaskanda 09	7.87	7.90	8.00	8.07
Sapugaskanda 10	8.30	8.62	8.47	8.52
Sapugaskanda 11	9.08	8.94	9.15	8.84
Sapugaskanda 12	8.90	9.02	9.00	8.90
Barge	44.93	49.25	44.86	44.86
Uthuru Janani	22.52	22.18	22.25	22.25
Lakvijaya 01	204.83	203.5	204.33	204.5
Lakvijaya 02	271.93	272.11	273.02	272.66
Lakvijaya 03	0.00	0.00	0.00	0.00
EMC Thulhiriya	0.00	0.00	0.00	0.00
Asia Power	0.00	0.00	0.00	0.00
Sojitz	0.00	0.00	0.00	0.00
ACE-Matara	0.00	0.00	0.00	0.00
ACE-Embilipitiya	86.21	83.85	84.02	83.67

Power Station and Generator Unit	Quarter Hourly Power Generation (MW)			
	7:00 pm	7:15 pm	7:30 pm	7:45 pm
West Coast GT1	84.89	85.50	85.32	85.32
West Coast GT2	0.00	0.00	0.00	0.00
West Coast Steam	45.69	46.06	45.69	45.59
Total Generation	**2,220.39**	**2,206.81**	**2,187.27**	**2,156.69**

Source: CEB (Daily Dispatch Schedule)

5.1 Method 01: Assigning zero for hydro fuel cost.

Utilising the information provided in Tables 5.1 and 5.2, the generation cost for each time duration is computed by attributing a zero value to the fuel cost of hydropower plants. This assumption stems from considering hydro as cost-free, given its perceived lack of financial value. Consequently, in this approach, the water value is set to zero.

Table 5. 5: Generation Cost of 7 - 8 pm, 2019.01.15 (Using method 1)

Power Station and Generator Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
Victoria 01	0.00	0.00	0.00	0.00	0.00
Victoria 02	0.00	0.00	0.00	0.00	0.00
Victoria 03	0.00	0.00	0.00	0.00	0.00
Randenigala 01	0.00	0.00	0.00	0.00	0.00
Randenigala 02	0.00	0.00	0.00	0.00	0.00
Rantabe 01	0.00	0.00	0.00	0.00	0.00
Rantabe 02	0.00	0.00	0.00	0.00	0.00
Kotmale 01	0.00	0.00	0.00	0.00	0.00
Kotmale 02	0.00	0.00	0.00	0.00	0.00
Kotmale 03	0.00	0.00	0.00	0.00	0.00
Nillabe	0.00	0.00	0.00	0.00	0.00
Ukuwela 01	0.00	0.00	0.00	0.00	0.00
Ukuwela 02	0.00	0.00	0.00	0.00	0.00
Bowathenna	0.00	0.00	0.00	0.00	0.00
Upper Kotmale 01	0.00	0.00	0.00	0.00	0.00
Upper Kotmale 02	0.00	0.00	0.00	0.00	0.00
Moraghakanda	0.00	0.00	0.00	0.00	0.00
New Laxapana 01	0.00	0.00	0.00	0.00	0.00
New Laxapana 02	0.00	0.00	0.00	0.00	0.00
Polpitiya 01	0.00	0.00	0.00	0.00	0.00
Polpitiya 02	0.00	0.00	0.00	0.00	0.00
Old Laxpana 01	0.00	0.00	0.00	0.00	0.00
Old Laxpana 02	0.00	0.00	0.00	0.00	0.00
Old Laxpana 03	0.00	0.00	0.00	0.00	0.00

Power Station and Generatior Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times 10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
Old Laxpana 04	0.00	0.00	0.00	0.00	0.00
Old Laxpana 05	0.00	0.00	0.00	0.00	0.00
Canyon 01	0.00	0.00	0.00	0.00	0.00
Canyon 02	0.00	0.00	0.00	0.00	0.00
WPS 01	0.00	0.00	0.00	0.00	0.00
WPS 02	0.00	0.00	0.00	0.00	0.00
Samanalawewa 01	0.00	0.00	0.00	0.00	0.00
Samanalawewa 02	0.00	0.00	0.00	0.00	0.00
Kukule 01	0.00	0.00	0.00	0.00	0.00
Kukule 02	0.00	0.00	0.00	0.00	0.00
Udavalawa	0.00	0.00	0.00	0.00	0.00
Inginiyagala	0.00	0.00	0.00	0.00	0.00
KPS GT 01	46.07	0.00	151.16	177.41	194.37
KPS GT 02	46.07	0.00	0.00	0.00	0.00
KPS GT 04	46.07	0.00	0.00	0.00	0.00
KPS GT 05	46.07	172.76	172.76	172.76	172.76
KPS GT 07	36.09	1 000.36	1 000.59	997.55	998.44
KCCP_GT	21.88	460.93	484.34	480.76	476.63
KCCP_ST	21.88	227.29	226.71	226.41	225.68
Sapugaskanda 01	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 02	22.26	89.23	88.66	87.09	88.91
Sapugaskanda 03	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 04	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 05	20.46	40.7	41.37	40.47	40.87
Sapugaskanda 06	20.46	42.71	43.59	43.54	43.49
Sapugaskanda 07	20.46	0.00	0.00	0.00	0.00
Sapugaskanda 08	20.46	45.34	46.35	45.58	46.16
Sapugaskanda 09	20.46	40.27	40.39	40.93	41.28
Sapugaskanda 10	20.46	42.46	44.08	43.33	43.58
Sapugaskanda 11	20.46	46.47	45.7	46.81	45.19
Sapugaskanda 12	20.46	45.53	46.15	46.04	45.53
Barge	18.14	203.75	223.34	203.42	203.42
Uthuru Janani	21.61	121.65	119.84	120.21	120.21
Lakvijaya 01	7.95	407.11	404.45	406.11	406.44
Lakvijaya 02	7.95	540.45	540.81	542.63	541.9
Lakvijaya 03	7.95	0.00	0.00	0.00	0.00
EMC Thulhiriya	22.44	0.00	0.00	0.00	0.00
Asia Power	24.48	0.00	0.00	0.00	0.00
Sojitz	22.44	0.00	0.00	0.00	0.00
ACE-Matara	22.06	0.00	0.00	0.00	0.00
ACE-Embilipitiya	22.06	475.46	462.45	463.35	461.43

Power Station and Generatior Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost (×10^3 LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
West Coast GT1	22.01	467.09	470.49	469.49	469.49
West Coast GT2	22.01	0.00	0.00	0.00	0.00
West Coast Steam	22.01	251.43	253.43	251.43	250.83
Total Cost (LKR)		**4,720.99**	**4,906.66**	**4,905.34**	**4,916.63**
Total Generation (MW)		**2,220.39**	**2,206.81**	**2,187.27**	**2,156.69**
Per unit Cost (LKR/kWh)		**8.50**	**8.89**	**8.97**	**9.12**

Figure 5.1 depicts the generation cost for the specific day, computed through the approach of setting hydro fuel cost to zero. Typically, the peak electricity demand in Sri Lanka occurs between 6-10 pm in the evening. However, in this representation, costs are reduced during that period. This anomaly arises from strategically deploying hydropower plants during peak hours to address the high load, thereby lowering the overall electricity generation cost. Conversely, during off-peak times, where no hydro power plants are in use, costs escalate considerably.

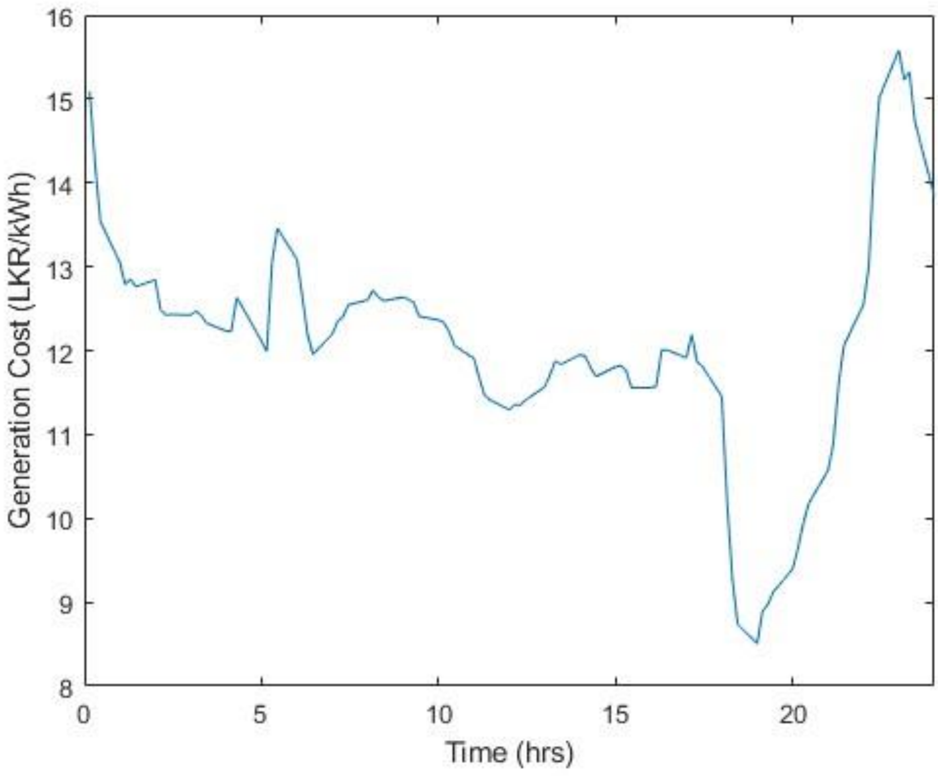


Figure 5. 1: Generation Cost of 2019.01.15, Calculated using method 01.

The calculation of generation costs for January 2019 is illustrated in Figure 5.2, using method 01 while remaining months are presented in Appendix E.

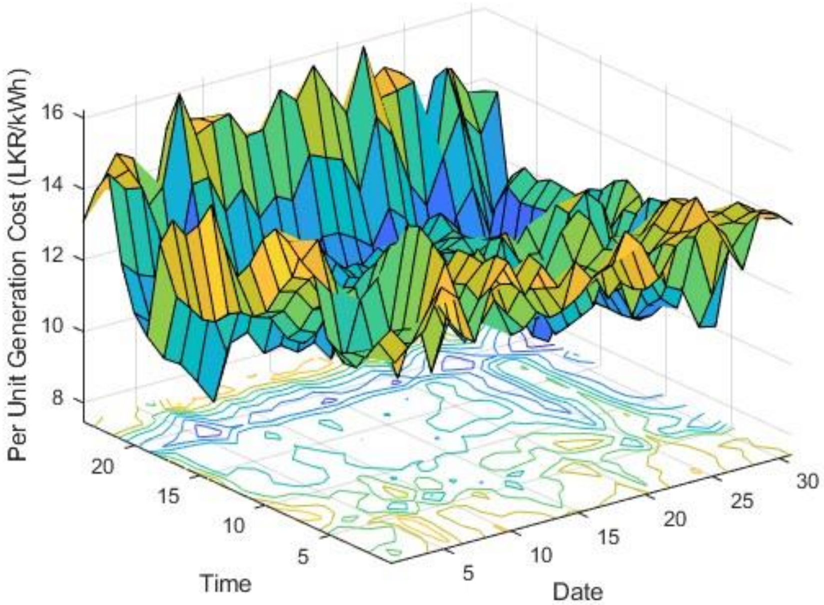


Figure 5. 2: Variation of Generation Costs in January 2019

5.2 Method 02: Assigning the per unit generation cost of the most expensive thermal power plant in the Load Curve

This method employs a graphical approach for power plant dispatch on a given date, relying on an avoided cost-based methodology. In determining the position of a power plant in the merit order during dispatch, the primary consideration is the energy cost associated with the plant. While the fundamental criterion for thermal power plants is cost, practical constraints exist for hydropower plants.

In the conventional scheme, a power plant with lower energy costs is allocated to the lower segment of the Daily Load Curve, and conversely for higher costs. However, practical considerations, such as power plant availability, can alter the dispatch sequence. In specific scenarios, hydropower plants with lower energy costs may be strategically placed higher in the load curve. In such cases, the water value for the corresponding hydropower plant is set equal to the unit cost of the adjacent thermal power plant located underneath it, which typically has the highest cost.

Increasing hydropower generation reduces the equivalent amount of thermal energy for a given demand, and vice versa. If a hydropower plant is positioned between two thermal power plants in a Daily Load Curve, limitations on capacity may prevent an increase in hydro contribution. In this scenario, decreasing hydropower generation increases the share of thermal energy at the top of the Daily Load Curve. The water value in this case is determined by taking the unit cost of the thermal power plant located higher than the hydropower plant.

The rationale for using the marginal cost of the thermal power plant in the margin is to select the thermal power plant with the highest operating cost. This approach, is an avoided cost method, considers the highest marginal cost among all thermal units currently in operation—that is, the cost of producing an additional unit under existing conditions. When hydropower is utilised, the savings come from shutting down or reducing the output of the most expensive generator in operation, which, by definition, is the thermal unit with the highest cost. Therefore, the cost savings from using hydropower at that moment equate to the cost of the most expensive unit. Thus, it is justifiable to use this method to assign a value to the water used for hydropower generation.

Figure 5.3 illustrates the Daily Load Curve for January 15th, 2019, chosen as a sample, with the understanding that the same methodology can be applied for any date. The curve is constructed based on cumulative power plant dispatch for the day, following a merit order approach. For simplicity, power plant complexes like Mahaweli and Laxapana are amalgamated, not considering each unit or plant individually. The merit order is determined not solely by the per unit generation cost but also by operational constraints.

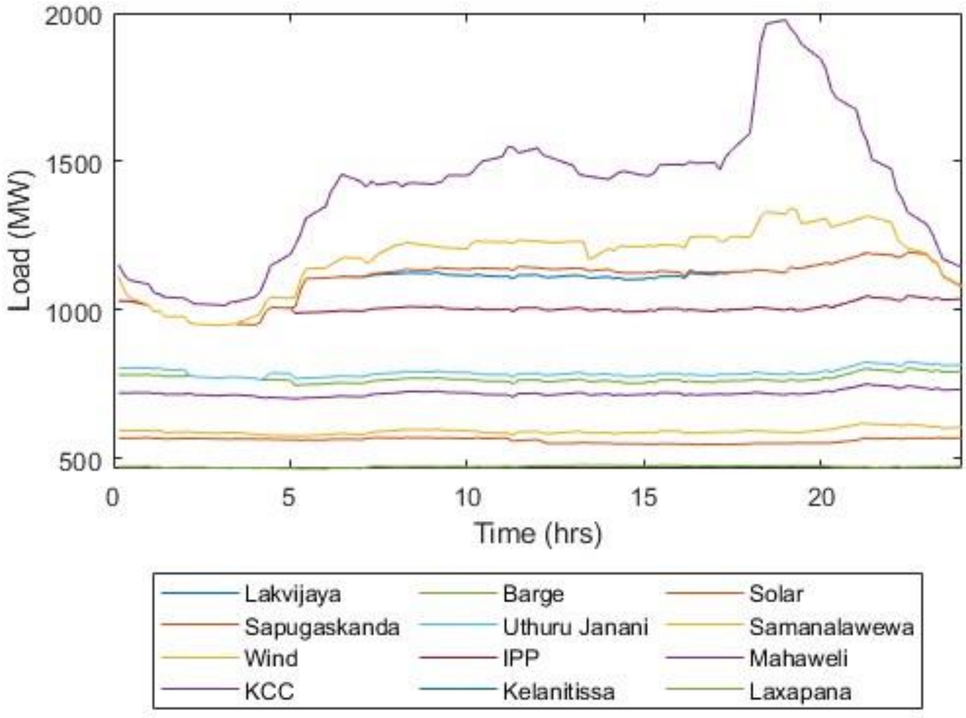


Figure 5. 3: Load Curve for January 15th, 2019

Figure 5.3 depicts the contribution of each power plant to meet the daily electricity demand on January 15th, 2019. According to the graph, the small GTs of Kelanitissa Power Station (KPS) emerges as the thermal complex positioned at the most expensive segment of the Daily Load Curve. In this method, the unit cost of the KPS complex is adopted as the water value for the date, which is 46.07 LKR/kWh [26]. Consequently, the water value for 7-8 pm time slot of January 15th, 2019, is determined to be 46.07 LKR/kWh.

It's important to note that the statement "the value of the renewable generator is equal to the marginal renewable generator" does not hold true when renewable energy constitutes a significant share in power plant dispatch. In instances of high renewable energy share, the thermal generator assumes the marginal value.

To maintain uniform generation costs, this water value is substituted as the per-unit cost of hydro power plants, while all other calculations remain consistent with method 01.

Table 5. 6: Generation Cost of 7 - 8 pm, 2019.01.15 (Using method 2)

Power Station and Generatior Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times 10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
Victoria 01	**46.07**	844.91	765.78	694.99	690.36
Victoria 02	**46.07**	687.39	425.27	469.53	511.69
Victoria 03	**46.07**	803.43	633.49	631.84	741.47
Randenigala 01	**46.07**	653.28	653.28	653.28	653.28
Randenigala 02	**46.07**	650.21	650.21	650.21	650.21
Rantabe 01	**46.07**	289.14	289.62	289.71	291.2
Rantabe 02	**46.07**	280.02	280.31	281.6	279.35
Kotmale 01	**46.07**	0.00	0.00	0.00	0.00
Kotmale 02	**46.07**	725.6	725.6	725.6	725.6
Kotmale 03	**46.07**	0.00	0.00	0.00	0.00
Nillabe	**46.07**	36.86	36.86	36.86	36.86
Ukuwela 01	**46.07**	213.12	213.44	213.35	213.35
Ukuwela 02	**46.07**	199.3	199.58	199.39	199.39
Bowathenna	**46.07**	316.45	268.73	115.27	139.7
Upper Kotmale 01	**46.07**	860.74	860.93	859.6	862.03
Upper Kotmale 02	**46.07**	861.83	861.59	859.98	860.7
Moraghakanda	**46.07**	109.08	107.2	106.24	107.51
New Laxapana 01	**46.07**	491.97	461.7	463.37	463.83
New Laxapana 02	**46.07**	464.6	463.78	465.71	464.77
Polpitiya 01	**46.07**	185.64	240.43	249.04	252.75
Polpitiya 02	**46.07**	78.76	227.16	236.48	239.16
Old Laxpana 01	**46.07**	35.49	35.5	35.5	35.54
Old Laxpana 02	**46.07**	11.59	11.61	11.41	11.45
Old Laxpana 03	**46.07**	11.58	11.63	11.53	11.67
Old Laxpana 04	**46.07**	47.58	47.58	47.58	47.56
Old Laxpana 05	**46.07**	48.67	48.67	48.67	48.67
Canyon 01	**46.07**	346.17	346.17	346.17	346.17
Canyon 02	**46.07**	0.00	0.00	0.00	0.00
WPS 01	**46.07**	0.00	0.00	0.00	0.00
WPS 02	**46.07**	288.79	289.32	289.52	289.25
Samanalawewa 01	**46.07**	687	689.21	684.78	684.97
Samanalawewa 02	**46.07**	684.78	685.15	684.88	700.91
Kukule 01	**46.07**	431.91	431.91	431.91	0
Kukule 02	**46.07**	431.91	431.91	431.91	299.46
Udavalawa	**46.07**	36.86	36.86	36.86	36.86
Inginiyagala	**46.07**	0.00	0.00	0.00	0.00
KPS GT 01	46.07	0.00	151.16	177.41	194.37
KPS GT 02	46.07	0.00	0.00	0.00	0.00
KPS GT 04	46.07	0.00	0.00	0.00	0.00
KPS GT 05	46.07	172.76	172.76	172.76	172.76

Power Station and Generatior Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times 10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
KPS GT 07	36.09	1 000.36	1 000.59	997.55	998.44
KCCP_GT	21.88	460.93	484.34	480.76	476.63
KCCP_ST	21.88	227.29	226.71	226.41	225.68
Sapugaskanda 01	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 02	22.26	89.23	88.66	87.09	88.91
Sapugaskanda 03	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 04	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 05	20.46	40.7	41.37	40.47	40.87
Sapugaskanda 06	20.46	42.71	43.59	43.54	43.49
Sapugaskanda 07	20.46	0.00	0.00	0.00	0.00
Sapugaskanda 08	20.46	45.34	46.35	45.58	46.16
Sapugaskanda 09	20.46	40.27	40.39	40.93	41.28
Sapugaskanda 10	20.46	42.46	44.08	43.33	43.58
Sapugaskanda 11	20.46	46.47	45.7	46.81	45.19
Sapugaskanda 12	20.46	45.53	46.15	46.04	45.53
Barge	18.14	203.75	223.34	203.42	203.42
Uthuru Janani	21.61	121.65	119.84	120.21	120.21
Lakvijaya 01	7.95	407.11	404.45	406.11	406.44
Lakvijaya 02	7.95	540.45	540.81	542.63	541.9
Lakvijaya 03	7.95	0.00	0.00	0.00	0.00
EMC Thulhiriya	22.44	0.00	0.00	0.00	0.00
Asia Power	24.48	0.00	0.00	0.00	0.00
Sojitz	22.44	0.00	0.00	0.00	0.00
ACE-Matara	22.06	0.00	0.00	0.00	0.00
ACE-Embilipitiya	22.06	475.46	462.45	463.35	461.43
West Coast GT1	22.01	467.09	470.49	469.49	469.49
West Coast GT2	22.01	0.00	0.00	0.00	0.00
West Coast Steam	22.01	251.43	253.43	251.43	250.83
Total Cost (LKR)		**16,740.94**	**16,544.07**	**16,359.71**	**16,009.72**
Total Generation (MW)		**2,220.39**	**2,206.81**	**2,187.27**	**2,156.69**
Per unit Cost (LKR/kWh)		**30.16**	**29.99**	**29.92**	**29.69**

The profitability of an organisation or business is intrinsically linked to its revenue. The tariff structure, formulated based on generation costs, plays a pivotal role in determining the utility's revenue within the realm of power economics. When considering power plant dispatch, hydropower plants are often favoured as the cheapest and optimal choices if solely assessed based on generation cost. However, such a decision-making approach is inadequate, as relying solely on hydro power may prove insufficient to meet future demands, potentially leading to increased generation costs in subsequent periods. Therefore, it becomes essential not only to ascertain the generation cost but also to determine the water value associated with the generation.

Figure 5.4 illustrates the variation in water value for January 15th, 2019, and Figure 5.5 shows the per unit generation cost calculated using method 02. This is followed by Figures 5.6 and 5.7, which depict the variation in water value and generation cost for January 2019, respectively, determined using the same method.

Referring to Figure 5.4, it is observed that the variation in water value remains consistent compared to the other two methods. On this day, the small GTs of KPS (GT 01, 02, 04, and 05) were positioned at the highest point of the Daily Load Curve among variable thermal power plants. Consequently, their per unit cost (=46.07 LKR/kWh [26]) was considered as the water value for all periods except for the timeframe between 01:15 and 05:00 hours, during which IPPs were operational. IPPs, a combination of power plants belonging to the private sector, were analysed within the economic dispatch schedule to ensure the total demand was met on time. Thus, the per unit generation cost of ACE-Embilipitiya (=22.06 LKR/kWh [26]) was deemed as the water value for the corresponding period.

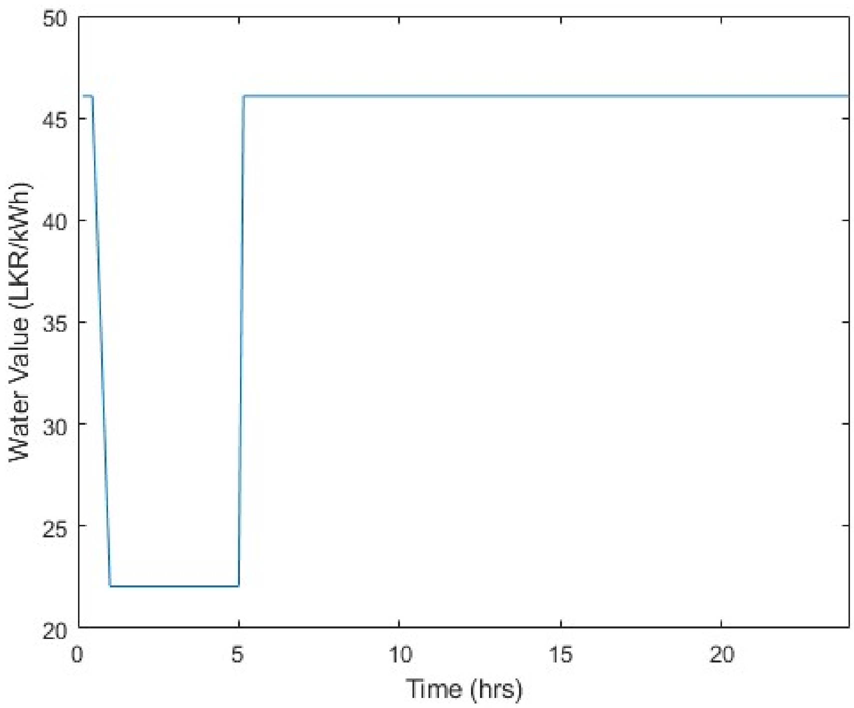


Figure 5. 4: Water Value of 2019.01.15, Calculated by method 02.

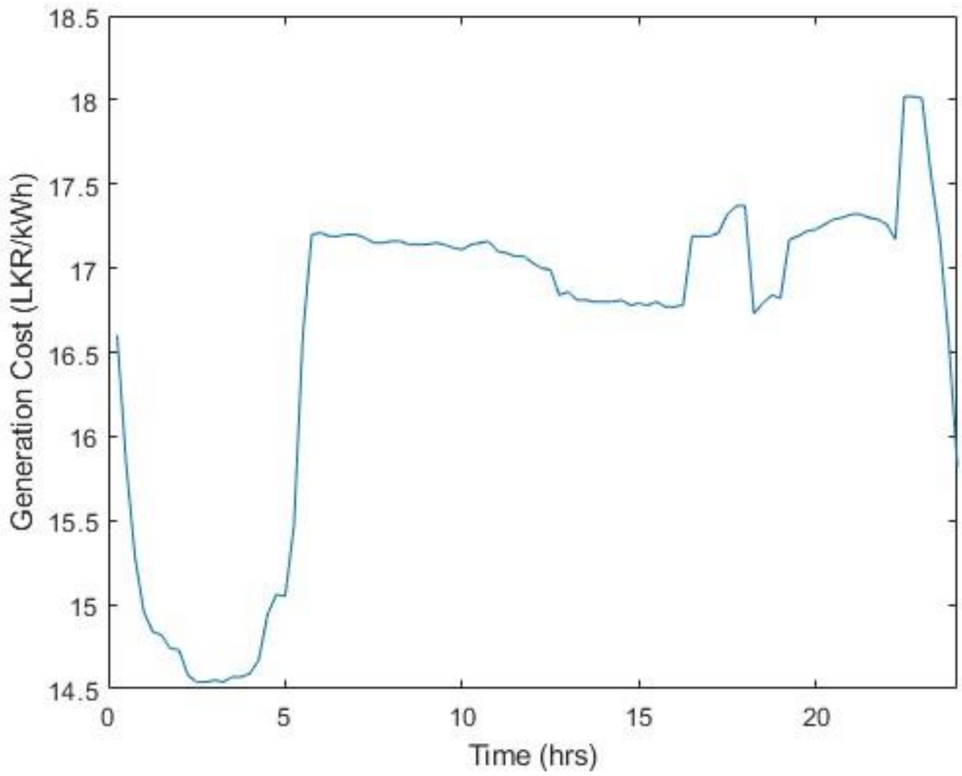


Figure 5. 5: Generation Cost of 2019.01.15, calculated by Method 02.

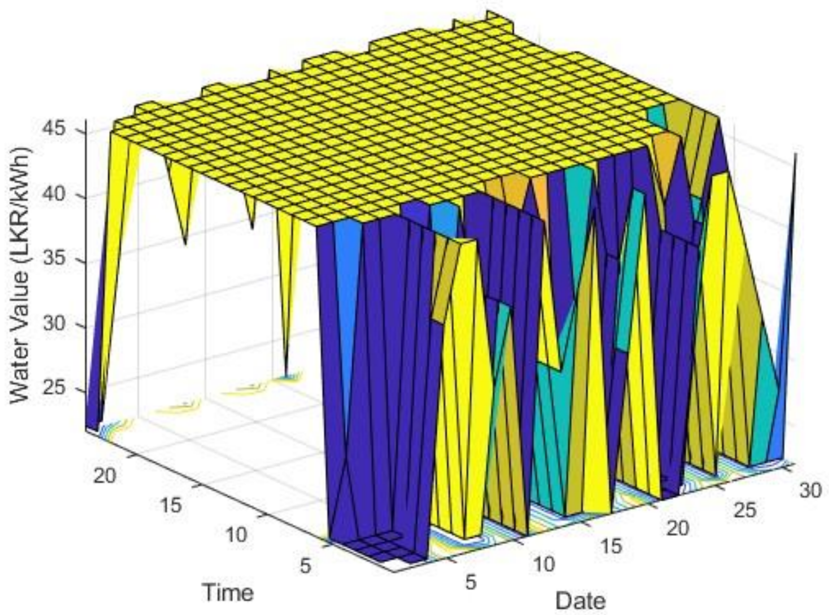


Figure 5. 6: Water Value of January 2019 Calculated by Method 02.

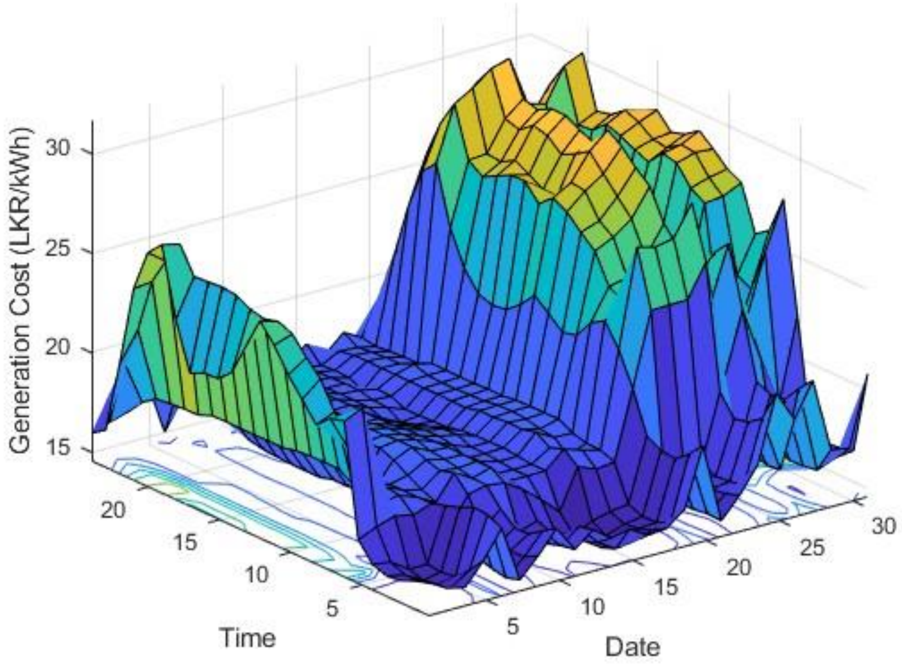


Figure 5. 7: Generation Cost of January 2019 Calculated by Method 02.

Appendices H and I depict the results of Method 02 by month. Figure 5.8 illustrates the generation costs calculated using Method 2, while the costs obtained through Method 1 are concurrently presented on the same graph for January 15th, 2019.

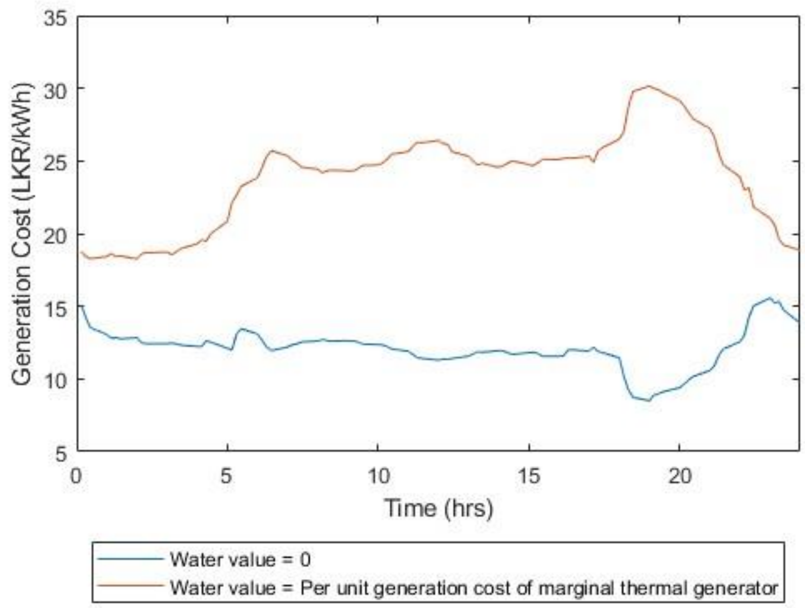


Figure 5. 8: Generation Cost of 2019.01.15, Calculated using method 01 and 02.

5.3 Method 03: Assigning the weighted average generation cost of variable thermal power plants as the water value.

Weighted Average cost of variable thermal power plants for water value calculation stands out as a more acceptable approach, as it incorporates the concept of assessing the cost of alternatives utilised in the absence of water resources. This method equates the water value to the cost of alternatives, which would be employed when water resources are unavailable. While water may not be perceived as having economic value when readily available, its absence necessitates significant investment in alternatives. Notably, these alternatives often involve variable thermal power plants (such as those powered by diesel and heavy fuel), which rely on imported fuel subject to escalating prices in the global market. The power plant designated to handle the baseload is excluded from the calculation due to its inability to operate independently without the baseload.

Indeed, the energy charges for thermal power plants are primarily contingent on factors such as fuel costs and variable operation and maintenance charges. These elements play a crucial role in determining the overall cost of electricity generation for thermal power plants. The capacity cost, encompassing investment, fixed operation, and maintenance, remains constant regardless of the season and time. As such, it is not factored into the calculation at this stage. The focus is on variables like fuel costs and operational and maintenance charges that directly impact energy costs.

Table 5.5 details the water value calculation for the period from 7-8 pm on January 15th, 2019. Concurrently, Figure 5.9 provides a visual representation of the water value's fluctuation throughout the entire day.

The water value, obtained by averaging the weighted thermal values over time, is utilised to calculate the total generation cost for each time slot (Table 5.6). Unlike previous methods, the on-time water value is specifically applied to each respective time slot.

Table 5. 7: Water Value Calculation Using Weighted Average Thermal Generation Cost on January 15th, 2019, from 7-8 pm

Power Station and Generator Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times 10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
KPS GT 01	46.07	0.00	151.16	177.41	194.37
KPS GT 02	46.07	0.00	0.00	0.00	0.00
KPS GT 04	46.07	0.00	0.00	0.00	0.00
KPS GT 05	46.07	172.76	172.76	172.76	172.76
KPS GT 07	36.09	1 000.36	1 000.59	997.55	998.44
KCCP_GT	21.88	460.93	484.34	480.76	476.63
KCCP_ST	21.88	227.29	226.71	226.41	225.68
Sapugaskanda 01	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 02	22.26	89.23	88.66	87.09	88.91
Sapugaskanda 03	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 04	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 05	20.46	40.70	41.37	40.47	40.87
Sapugaskanda 06	20.46	42.71	43.59	43.54	43.49
Sapugaskanda 07	20.46	0.00	0.00	0.00	0.00
Sapugaskanda 08	20.46	45.34	46.35	45.58	46.16
Sapugaskanda 09	20.46	40.27	40.39	40.93	41.28
Sapugaskanda 10	20.46	42.46	44.08	43.33	43.58
Sapugaskanda 11	20.46	46.47	45.70	46.81	45.19
Sapugaskanda 12	20.46	45.53	46.15	46.04	45.53
Barge	18.14	203.75	223.34	203.42	203.42
Uthuru Janani	21.61	121.65	119.84	120.21	120.21
EMC Thulhiriya	22.44	0.00	0.00	0.00	0.00
Asia Power	24.48	0.00	0.00	0.00	0.00
Sojitz	22.44	0.00	0.00	0.00	0.00
ACE-Matara	22.06	0.00	0.00	0.00	0.00
ACE-Embilipitiya	22.06	475.46	462.45	463.35	461.43
West Coast GT1	22.01	467.09	470.49	469.49	469.49
West Coast GT2	22.01	0.00	0.00	0.00	0.00
West Coast Steam	22.01	251.43	253.43	251.43	250.83
Total Cost (LKR)		3,773.43	3,961.40	3,956.60	3,968.28
Thermal Generation (MW)		611.29	631.93	628.00	628.43
Weighted Thermal Average Value (LKR/kWh)		**24.69**	**25.07**	**25.20**	**25.26**

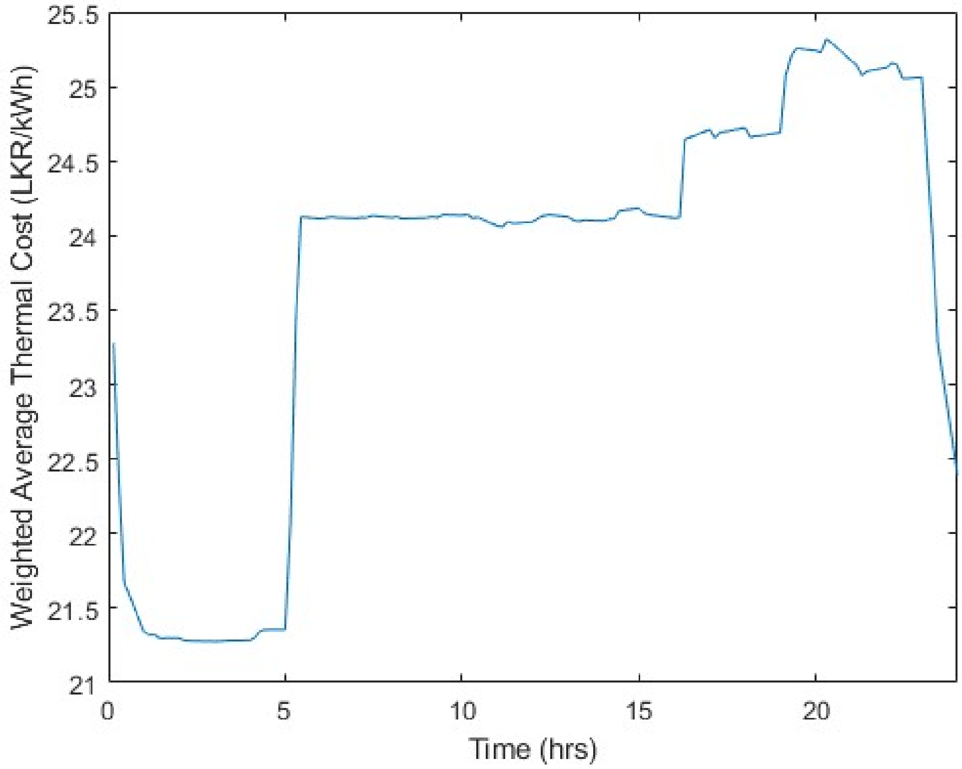


Figure 5. 9: Variation of Weighted Thermal Average Value throughout the day on January 15th, 2019

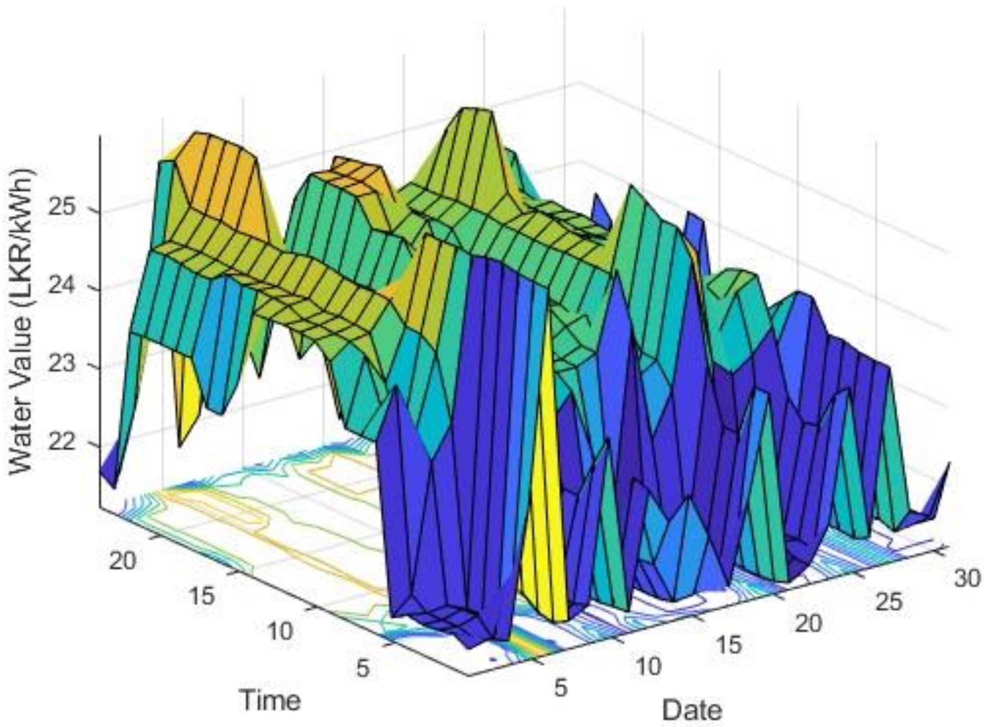


Figure 5. 10: Water Value of January 2019, Calculated by Method 03.

Table 5. 8: Generation Cost of 7 - 8 pm, 2019.01.15 (Using method 3)

Power Station and Generator Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times 10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
On time Water Value		**24.69**	**25.07**	**25.20**	**25.26**
Victoria 01	On time water value is substituted.	452.83	416.79	380.17	378.49
Victoria 02		368.41	231.47	256.84	280.54
Victoria 03		430.6	344.79	345.63	406.52
Randenigala 01		350.13	355.57	357.36	358.17
Randenigala 02		348.48	353.89	355.68	356.48
Rantabe 01		154.96	157.63	158.48	159.65
Rantabe 02		150.08	152.56	154.04	153.15
Kotmale 01		0.00	0.00	0.00	0.00
Kotmale 02		388.89	394.93	396.92	397.82
Kotmale 03		0.00	0.00	0.00	0.00
Nillabe		19.75	20.06	20.16	20.21
Ukuwela 01		114.22	116.17	116.71	116.97
Ukuwela 02		106.81	108.62	109.07	109.32
Bowathenna		169.61	146.26	63.05	76.59
Upper Kotmale 01		461.31	468.58	470.22	472.61
Upper Kotmale 02		461.9	468.94	470.43	471.89
Moraghakanda		58.46	58.35	58.11	58.94
New Laxapana 01		263.67	251.29	253.47	254.3
New Laxapana 02		249.01	252.42	254.75	254.81
Polpitiya 01		99.49	130.86	136.23	138.57
Polpitiya 02		42.21	123.64	129.36	131.12
Old Laxpana 01		19.02	19.32	19.42	19.49
Old Laxpana 02		6.21	6.32	6.24	6.28
Old Laxpana 03		6.20	6.33	6.31	6.4
Old Laxpana 04		25.5	25.9	26.03	26.07
Old Laxpana 05		26.09	26.49	26.63	26.69
Canyon 01		185.53	188.41	189.36	189.79
Canyon 02		0.00	0.00	0.00	0.00
WPS 01		0.00	0.00	0.00	0.00
WPS 02		154.78	157.47	158.37	158.58
Samanalawewa 01		368.2	375.12	374.59	375.54
Samanalawewa 02		367.01	372.91	374.64	384.28
Kukule 01		231.48	235.08	236.26	0.00
Kukule 02		231.48	235.08	236.26	164.18
Udavalawa		19.75	20.06	20.16	20.21
Inginiyagala		0.00	0.00	0.00	0.00
KPS GT 01	46.07	0.00	151.16	177.41	194.37
KPS GT 02	46.07	0.00	0.00	0.00	0.00
KPS GT 04	46.07	0.00	0.00	0.00	0.00

Power Station and Generator Unit	Per Unit Generation Cost (LKR/kWh)	Generation Cost ($\times 10^3$ LKR)			
		7:00 pm	7:15 pm	7:30 pm	7:45 pm
KPS GT 05	46.07	172.76	172.76	172.76	172.76
KPS GT 07	36.09	1 000.36	1 000.59	997.55	998.44
KCCP_GT	21.88	460.93	484.34	480.76	476.63
KCCP_ST	21.88	227.29	226.71	226.41	225.68
Sapugaskanda 01	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 02	22.26	89.23	88.66	87.09	88.91
Sapugaskanda 03	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 04	22.26	0.00	0.00	0.00	0.00
Sapugaskanda 05	20.46	40.7	41.37	40.47	40.87
Sapugaskanda 06	20.46	42.71	43.59	43.54	43.49
Sapugaskanda 07	20.46	0.00	0.00	0.00	0.00
Sapugaskanda 08	20.46	45.34	46.35	45.58	46.16
Sapugaskanda 09	20.46	40.27	40.39	40.93	41.28
Sapugaskanda 10	20.46	42.46	44.08	43.33	43.58
Sapugaskanda 11	20.46	46.47	45.7	46.81	45.19
Sapugaskanda 12	20.46	45.53	46.15	46.04	45.53
Barge	18.14	203.75	223.34	203.42	203.42
Uthuru Janani	21.61	121.65	119.84	120.21	120.21
Lakvijaya 01	7.95	407.11	404.45	406.11	406.44
Lakvijaya 02	7.95	540.45	540.81	542.63	541.9
Lakvijaya 03	7.95	0.00	0.00	0.00	0.00
EMC Thulhiriya	22.44	0.00	0.00	0.00	0.00
Asia Power	24.48	0.00	0.00	0.00	0.00
Sojitz	22.44	0.00	0.00	0.00	0.00
ACE-Matara	22.06	0.00	0.00	0.00	0.00
ACE-Embilipitiya	22.06	475.46	462.45	463.35	461.43
West Coast GT1	22.01	467.09	470.49	469.49	469.49
West Coast GT2	22.01	0.00	0.00	0.00	0.00
West Coast Steam	22.01	251.43	253.43	251.43	250.83
Total (Wind)	21.88	231.7	237.19	220.69	227.87
Total (Solar)	46.07	0.00	0.00	0.00	0.00
Total Cost (LKR)		11,284.79	11,365.16	11,287	11,118.14
Total Generation (MW)		2,220.39	2,206.81	2,187.27	2,156.69
Per unit Cost (LKR/kWh)		**20.33**	**20.6**	**20.64**	**20.62**

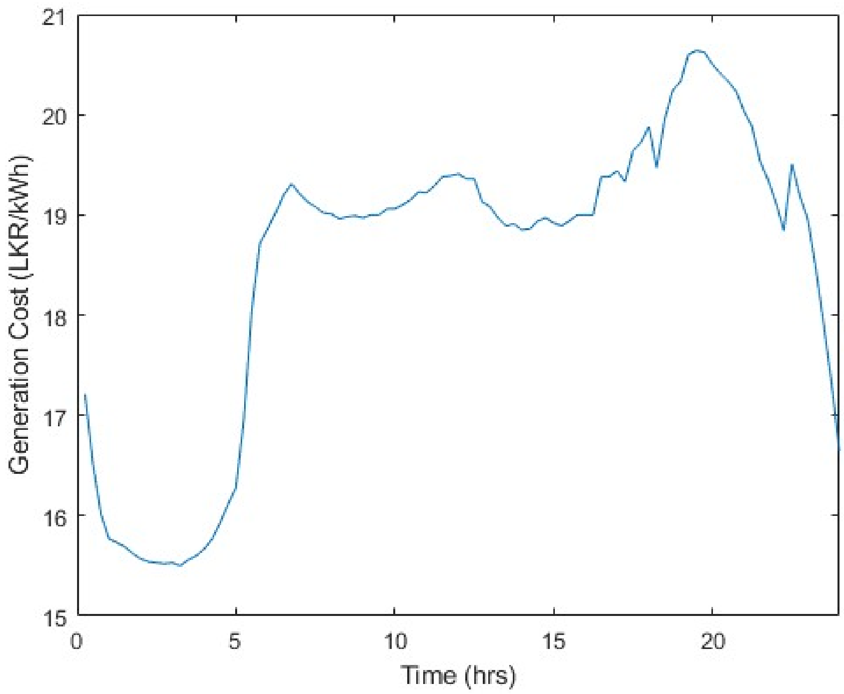


Figure 5. 11: Generation Cost 2019.01.15, Calculated by Method 03.

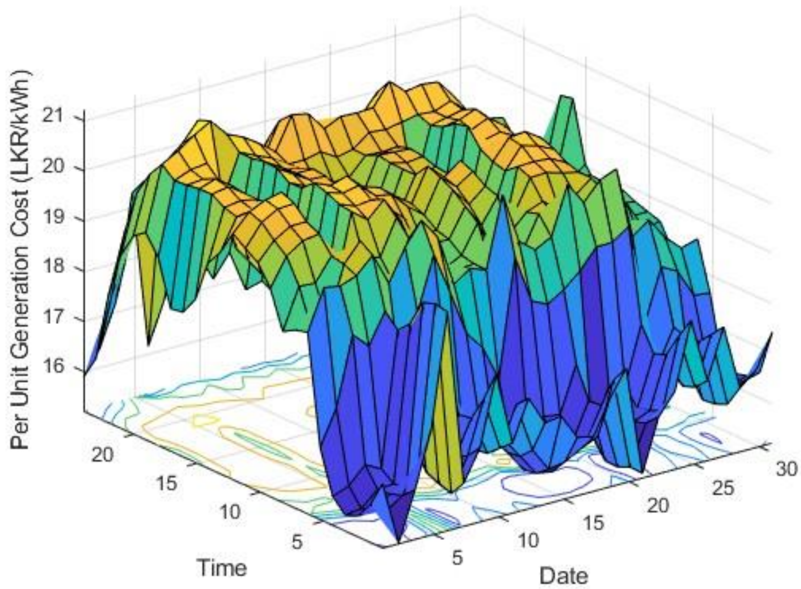


Figure 5. 12: Generation Cost of January, Calculated by Method 03

The results obtained for water value and generation cost for every month of 2019 is presented in Appendices J and K.

The results of the generation cost calculation using this method are depicted in Figure 5.13, concurrently displaying the outcomes of the previous two methods in the same graph while Appendix L provides the analysis for each day in the month of January 2019

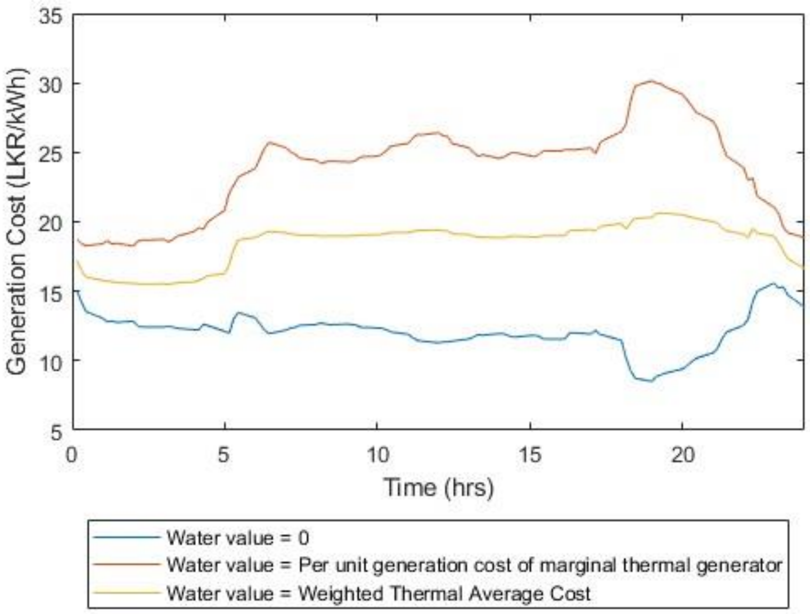


Figure 5. 13: Generation Cost Calculation for January 15th, 2019 (Using three methods)

5.4 Water Value in Agriculture

The water management policy of the Sri Lankan government prioritises the allocation of stored water in irrigation systems based on a merit order, ensuring the fulfilment of basic needs, agricultural requirements and power generation. Notably, Sri Lanka is often characterised as a nation with a high-water usage for rice cultivation, reflecting its agricultural practices deeply rooted in the cultivation of this staple crop.

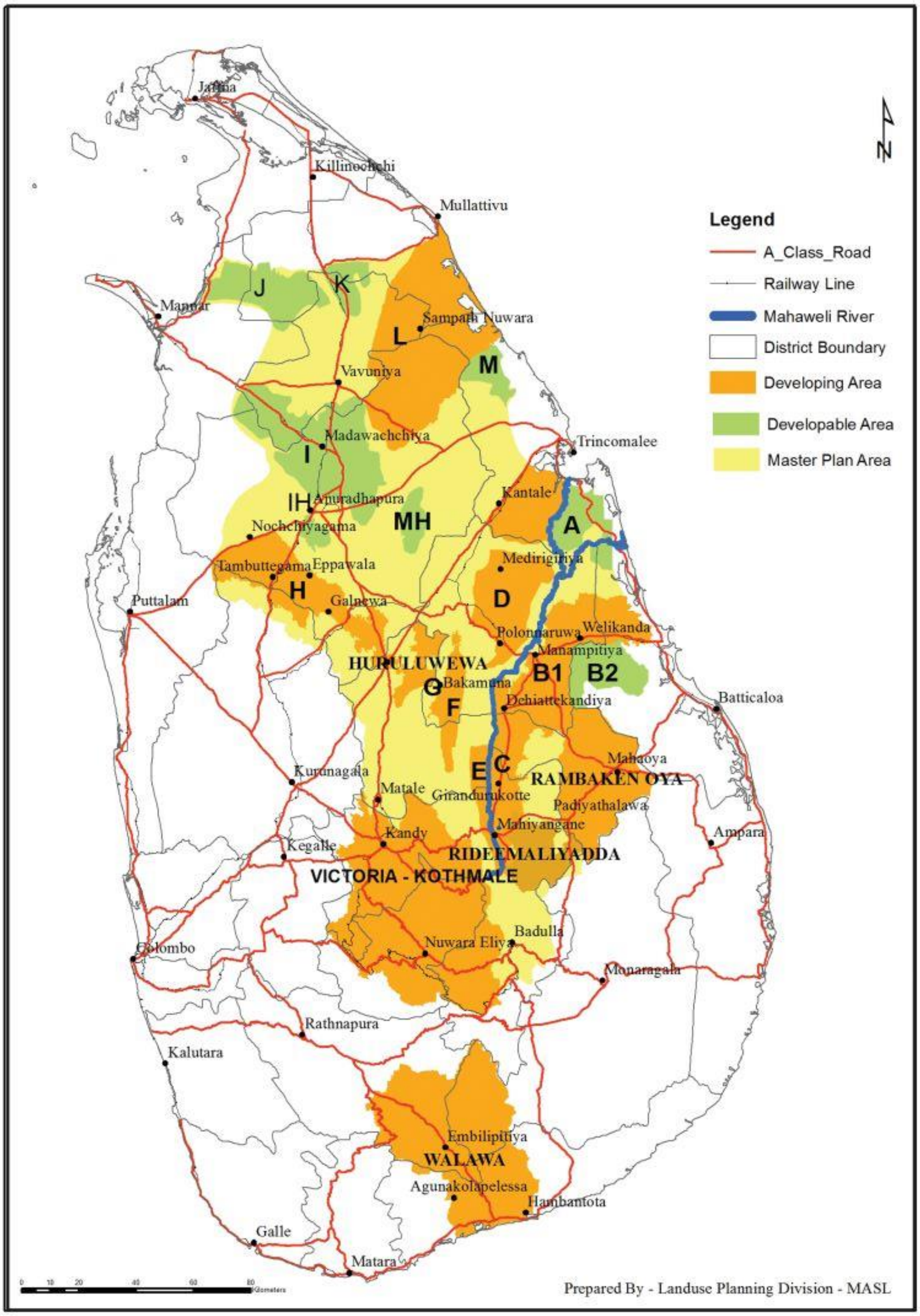
While real-time water valuation is effectively implemented in power generation, a similar approach is lacking in assessing the value of water in agriculture. It's imperative to acknowledge that rice cultivation isn't the sole beneficiary of reservoir-stored water; however, given Sri Lanka's historic context and dietary habits, rice holds paramount importance as a staple food in the local community. Therefore, for the purpose of this discussion, the rice production serves as a pertinent case study.

It's essential to recognise the inherent variability in water consumption associated with rice cultivation. There is no fixed value for water consumption; rather, it spans a range influenced by numerous factors such as soil type, paddy variety and environmental conditions. Typically, the water footprint of rice falls within a broad spectrum, ranging from 3,000 to 4,000 litres per kilogram. This variability underscores the complexity of water management in agriculture and emphasises the need for comprehensive assessment and sustainable practices [27].

Similarly, water duty, which refers to the amount of water allocated per unit area, varies between irrigation schemes. Factors such as agricultural practices and local conditions contribute to this variability. The Kaltota scheme, managed by the irrigation department, reports the highest water duty, reaching 7 feet per acre for a season. In contrast, other schemes typically range between 4 to 5 feet per acre. This diversity underscores the challenge in establishing a fixed and reliable value across different contexts. From 1 kilogram of paddy, approximately 700 grams of rice can be obtained. [28] [29].

Additionally, the cost of rice production is computed as 23.17 LKR/kg for paddy fields associated with irrigation systems and 32.38 LKR/kg for rain-fed systems [30]. This cost includes labour, fertiliser, and various other associated expenses, but does not account for the value of water. More than 80% of the gross paddy production of Sri Lanka comes from the irrigation system based cultivation areas [30]. Sri Lankan paddy cultivation yields two cultivation seasons, known as Yala and Maha.

It is calculated that the per capita rice consumption in Sri Lanka is 107 kg/year [30], with the country's population approximately 22 million. When domestic rice production falls short of meeting the food demand, rice is imported. Various statistics indicate that the overall process of rice importing is more cost-effective than producing it domestically [31].



Source: Land Use Planning Division, Mahaweli Authority of Sri Lanka

Figure 5. 14: Mahaweli Development Zones of Sri Lanka

The Water value in paddy cultivation varies with the weeks of growth. During the initial weeks, water supply is crucial; if adequate water is not provided in the first two weeks, the entire crop can be jeopardised. However, by the 9th or 10th week, the importance of water supply diminishes [27]. Unlike in power generation, the value of water in agriculture must be assessed throughout the crop's growth stages. The impact of water requirements changes weekly in agriculture. This research discusses the water value for both power generation and agriculture, based on the Mahaweli complex. The Mahaweli project has divided the country's lands into various zones, as illustrated in Figure 5.14.

The irrigation system in Sri Lanka is not solely dependent on the reservoirs that contribute to power generation. For instance, if the water from the Mahaweli River were not diverted for agriculture, would it affect 100% of the crops and fields? The answer is no, because existing reservoirs have some stored water and rainfall also contributes. Thus, not all agriculture is supported solely by the Mahaweli reservoirs.

The initial use of Mahaweli water occurs at the Kotmale and Upper Kotmale power plants for power generation. After this, a portion of the water is diverted at the Polgolla barrage to the northern part of the country. The Upper Kotmale and Kotmale power plants are located upstream of Polgolla, and the water is utilised there before being diverted. The water directed to the northern region supports agricultural development in the Mahaweli H, L zones and Huruluwewa, with Ukuwela and Bowatenna power plants also aligned along this route.

Water not diverted northward flows through the Victoria, Randenigala and Rantembe reservoirs. It is then used for agricultural purposes at the Minipe anicut, with the remaining water utilised at the Moragahakanda reservoir. Annually, it is estimated that 11,016 MCM of water flow out to the sea from the Mahaweli reservoir system [32].

The reservoirs are interconnected, and water is not released for irrigation at every point but at specific locations. This system is also integrated with local irrigation networks. Water at the initial stages of the river or canal holds greater value because it is used multiple times as it moves downstream. Each drop of water can be utilised at several stages and is eventually returned to the river due to the incremental flow structure.

For example, Table 5.8 presents data on annual rice production by zone and season, while Table 5.9 shows the amount of water released for irrigation activities. It should be noted that the water release pattern varies by season; the Maha season primarily relies on rainfall, whereas the Yala season depends on irrigation systems.

Table 5. 9: Annual Rice Production of Mahaweli Zone 2019

Mahaweli Zone	Rice Production (Mt)		
	Yala	Maha	Total
B	79,731	56,583	136,313
C	82,725	78,200	160,925
D	3,930	5,391	9,321
E	70	3,275	3,345
G	23,418	22,761	46,179
H	51,672	71,672	123,344
Huruluwewa	23,481	33,248	56,729
L	5,454	11,598	17,052
Udawalawe	61,300	57,736	119,036
Rambaken Oya	4,536	3,926	8,462
Total	336,316	344,388	680,704

Source: Sri Lanka Mahaweli Authority [33]

Table 5. 10: Supply of water to Agricultural Activities 2018

Serial No	Reservoir		Capacity of Water Supplied (MCM)
1	Polgolla Diversion (To Bowatenne Reservoir)		1,110.176
2	Minipe Canal	Left Bank	19.40
		Right Bank	911.976
3	Moragahakanda Reservoir		652.07
4	Udawalawe	Left Bank	453.287
		Right Bank	467.787
Total			**3,614.696**

Source: Sri Lanka Mahaweli Authority [32]

According to the data illustrated in Figure 5.14, it is evident that the Mahaweli H, L and Huruluwewa zones receive water through the Polgolla Diversion, which directs water northward to where the Ukuwela and Bowatenna power stations are located. Based on the information in Table 5.8, the annual rice production in this region is 197, 125 Mt, with water supplied under serial number 1 of Table 5.9. By excluding factors such as incremental flow, rainfall and existing reservoir storages, an average value for the amount of rice can be produced by $1m^3$ of water for this zone can be calculated as 0.178 kg/m³.

Moving forward, the Mahaweli B, C, D, E, G and Rambaken Oya zones are located along the direction of the Victoria, Randenigala and Rantambe reservoirs. Water is released at two main points: Minipe and Moragahakanda, as detailed in Table 5.9. The total rice production in these zones, summed up, amounts to 398,393 Mt, with a cumulative water release of 1,583.446 MCM at Minipe and Moragahakanda. The average value for the amount of rice can be produced by $1m^3$ of water here is 0.252 kg/m³. Using the data from Table 5.8, the cost of rice production can be estimated for each zone and presented in Table 5.10.

However, it should be noted that these calculations are based on several assumptions. First, it is assumed that the entire rice production is dependent on the irrigated water from the Mahaweli River. In other words, if the water were not diverted to the Northern direction at Polgolla, there would be no rice production in the region. This implies that the country would lose 197,125 metric tons of rice, which represents the total production from the Mahaweli H, L, and Hurulu Wewa zones. This assumption is made to avoid the complexity of accounting for other factors such as rainfall, existing reservoir storage (both Mahaweli and ancient reservoirs), and incremental inflows.

The second assumption is that the cost of rice production is equated with the value of water in calculating the overall production cost. In reality, the cost includes labour, machinery, fertiliser, and other associated expenses, but it does not incorporate the value of water. Additionally, the paddy-to-rice conversion ratio is disregarded in these calculations.

Table 5. 11: Annual Rice Production Cost of Mahaweli Zones 2018

Mahaweli Zone	Rice Production Cost (LKR million)		
	Yala	Maha	Total
B	1,847.37	1,311.03	3,158.37
C	1,916.74	1,811.89	3,728.63

D	91.06	124.91	215.97
E	1.62	75.88	77.5
G	542.6	527.37	1,069.97
H	1,197.24	1,660.64	2,857.88
Huruluwewa	544.05	770.36	1,314.41
L	126.37	268.73	395.09
Udawalawe	1,420.32	1,337.74	2,758.06
Rambaken Oya	105.1	90.97	196.06
Total	**7,792.44**	**7,979.47**	**15,771.91**

Sources: Sri Lanka Mahaweli Authority [33]

The Mahaweli zone contributes only a portion of Sri Lanka's overall rice supply. The comprehensive statistics for rice production across Sri Lanka are presented in Table 5.11 [34].

Table 5. 12: Total Rice Production and Cost Details of Sri Lanka

Year	Rice Production (Mt x 1000)			Rice Production Cost (LKR million)		
	Yala	Maha	Total	Yala	Maha	Total
2018	1,533	2,397	3,930	45,990	71,910	117,900
2019	1,519	3,073	4,592	45,570	92,190	137,760

Source: Central Bank of Sri Lanka [34]

Generally, the internal production of rice in Sri Lanka is sufficient to meet the country’s demand, making it crucial to maintain an adequate rice stockpile. However, in some years, national rice production has declined due to natural disasters and various other factors. In response, the government takes necessary actions to ensure food security, which sometimes includes importing rice. Table 5.12 provides information on rice import data.

Table 5. 13: Rice Import Details of Sri Lanka

Year	Amont of Rice (Mt × 1000)	Expenditure (LKR million)	Unit Cost (LKR/kg)
2015	275.4	17,486.9	63.51
2016	28.3	1,828.3	64.62
2017	669.3	41,744.0	62.37

2018	200.4	14,115.8	70.43
2019	23.9	2,274.9	95.05

Source: Hansard Report of Sri Lanka Parliament [31]

For a robust quantitative analysis, the most appropriate approach is to compare the costs with those of alternative resources utilised when the primary resource is unavailable. This is akin to equating the value of water to the weighted average cost of variable thermal power plants. In scenarios where water release is constrained by irrigation demands, one must consider the incremental cost of electricity generation. Conversely, if water is released without constraint, it's essential to evaluate the corresponding loss in agricultural value—specifically, the trade-off between increased agricultural imports and the value of additional hydroelectric generation (i.e., thermal energy avoided and fuel saved).

Table 5.13 points out the rice importing cost is 95.05 LKR/kg for 2019. If the Mahaweli was not released water for the irrigation, 680,704 Mt of rice would not be produced in Sri Lanka (Table 5.9) and that amount should be imported. In that case, 64.7 billion LKR cost will be added for rice importing, which can be considered as the water value of agriculture.

Sometimes, there is a debate on whether importing rice is more profitable than producing it locally. This notion cannot become a reality due to socio-economic considerations. Food security is a crucial concern for the country. As rice is a staple food in Sri Lanka, maintaining an adequate supply is essential. In a scenario where imports and exports are halted, a food crisis could arise if an extraordinary stock of rice is not maintained. All nations prioritise food security rather than relying solely on low-cost imports. Additionally, unemployment could increase due to the loss of agricultural jobs.

5.5 Expanding the water value into reservoir levels

The water value for power generation can also be assessed at the reservoir level, like how it is evaluated for agriculture. Water stored in the Kotmale and Upper Kotmale reservoirs holds more value compared to other reservoirs because it flows through the entire reservoir network. This cascade structure results in incremental flow contributions to each downstream reservoir.

To further analyse the water value across different reservoirs, it's important to recognise that they are interconnected in a cascade system. The outflow from Victoria becomes the inflow for Randenigala, and similarly, the outflow from Randenigala feeds into Rantembe. Thus, the water value at these reservoirs is not equal, as the storage in Victoria directly influences the inflows to both Randenigala and Rantembe, and Randenigala's storage affects Rantembe's inflow. Consequently, the water value tends to be higher at upstream reservoirs compared to downstream ones, given that a single drop of water from Victoria is used for power generation at both Randenigala and Rantembe.

Additionally, these reservoirs receive water from various sources, including rainfall, groundwater and their catchment areas. However, to simplify this analysis, the incremental flow is not considered; instead, the focus is on the electricity generation rates of each power plant.

The water consumption necessary to produce 1 kWh of energy is contingent upon the discharge rate of the generators within a hydropower plant. Table 5.13 presents the discharge rates of generators across various hydropower stations, alongside their corresponding electricity generation rate per unit volume of water.

Table 5. 14: Discharge rates and Electricity Generation rates of different Hydropower Stations

Hydropower Plant	Discharge rate of generators (MCM/GWh)	Discharge rate of generators (m^3/MW/s)	Electricity generation rate (kWh/m^3)
Canyon	2.24	0.62	0.45
Wimalasurendra	1.98	0.55	0.51
Old Laxapana	0.94	0.26	1.06
New Laxapana	0.82	0.23	1.22
Polpitiya	1.60	0.44	0.63
Broadlands	7.20	2.00	0.14
Ukuwela	5.40	1.50	0.19
Bowatenna	8.10	2.25	0.12
Kotmale	1.80	0.50	0.56
Victoria	2.00	0.56	0.50

Randenigala	5.10	1.42	0.20
Rantembe	12.70	3.53	0.08
Samanala Wewa	1.30	0.36	0.77
Kukule	2.10	0.58	0.48

Source: CEB [35]

Undoubtedly, the value of water is higher upstream due to its significant impact downstream. Various factors, such as irrigation system requirements, rainfall, existing storage, incremental inflow and others, influence the water value at the reservoir level. The challenge lies in finding the optimal balance between the water values for electricity generation and agriculture since the same amount of water is used simultaneously for both purposes during release.

6. CONCLUSION AND DISCUSSION

Electricity demand varies by season, day and time and electricity generation depends on consumer demand and availability of power plants. Utilities strive to provide continuous, high-quality power at a reasonable price to their customers and economic dispatch models are prepared by the utility to achieve this goal. The cost of electricity is not the same at every time due to demand variation and the economic dispatch model. Currently, generation cost variation is not considered in decision-making due to a lack of data available on the scope.

6.1. Research Contribution

The contributions of this research to advancing knowledge can be summarised as:

- Introduced an innovative approach for economic dispatch and calculating seasonal and time-of-day dependent electricity costs using Stochastic Dual Dynamic Programming (SDDP) principles.
- Offered two novel approaches for assessing the real time value of water, challenging the traditional practice of assigning a zero value or a constant value.
- Pioneered the evaluation of water value for each reservoir individually, rather than using a single national value.
- Initiated both quantitative and qualitative comparisons of the water value for agricultural use versus power generation.

6.2. Conclusions

This research explored the impact of various factors on generation costs. Chapter 2 highlights the fluctuations in electricity demand by season, day and time with a focus on the year 2019. Electricity demand directly affects generation costs, as it influences the number of power plants required for dispatch. The findings can inform the development of a more accurate tariff structure to meet future needs. Additionally, the availability of power plants is crucial to generation costs, as it involves reserving resources for future demands.

The primary objective of this research was to introduce a new methodology for calculating seasonal and time-of-day dependent electricity costs, while also assessing the value of water as an intermediate result. In this research, DP and its implemented technologies (SDDP) were used to optimise the scheduling of water releases from hydroelectric plants to minimise electricity generation costs while meeting demand. The stage-by-stage decision-making process of DP is well-suited for this problem as it allows for the consideration of various time scales and operational constraints.

In this research, the water value is analysed using three methods, each approach has its advantages and limitations, and the choice of method depends on factors such as the availability of data, the specific context of power generation, and the objectives of the analysis.

Method one, which assumes a water value of zero, is founded on primary assumptions that contradict the concept of water valuation. The discussion regarding the economic value of water is disregarded when assigning it a value of zero. Moreover, it raises the question of how to generate revenue for the maintenance of the power station if electricity, a product of the station's operations, is considered to have zero value. When considering a water value of zero, it neglects other variable operating costs, such as the cost of spares and staff salaries This prompts consideration of whether the power station can generate sufficient profits to sustain its operations and maintenance when the generation cost is deemed to be zero.

Method 02, which is an avoided cost-based method, the water value is determined based on the generation cost of the most expensive thermal power plant in the daily load curve. This approach reflects the idea that the cost of generating electricity from the most expensive power plant represents the opportunity cost of using water for power generation during that period. It assumes that if water is used for power generation, it could have been used elsewhere, and the cost of using the most expensive alternative represents the value of water. This method also accepted.

It is recommended to utilise the third approach, which calculates the collective cost of power generation from thermal plants and assigns it as the water value. By using this method, decision-makers can make more informed choices regarding water allocation for power generation, considering both the economic implications and the efficiency of thermal power plants in the dispatch schedule.

The distinction between the novel approach and existing methodologies in the context of operations planning for integrated hydro and thermal systems can be summarised as follows:

Novel Approach: Dynamic Calculation of Generation Costs and Water Value

- **Dynamic Calculation:** The novel approach focuses on dynamically calculating generation costs and water value based on real-time or near-real-time conditions. This involves updating these values continuously or at frequent intervals to reflect changing hydrological conditions, fuel prices, and operational statuses.
- **Adaptive Policies:** By calculating generation costs and water value on-the-fly, the novel approach can adapt operational policies more effectively to current conditions, potentially leading to more efficient and cost-effective management of the energy system.
- **Improved Decision-Making:** This dynamic approach allows for more precise decision-making by incorporating up-to-date information. It enhances the ability to respond to short-term fluctuations in electricity demand, fuel prices, and water availability.
- **Real-Time Optimisation:** The ability to adjust operational strategies in real time can improve the integration of hydro and thermal resources, optimise water use, and minimise operational costs more effectively than static models.

Existing Methodologies: Static Values for Generation Costs and Water Value

- **Static Calculation:** Traditional methodologies often rely on fixed or constant values for generation costs and water value over the planning horizon. These values are typically based on historical data or assumed conditions and do not account for real-time changes.
- **Less Adaptability:** Static values can lead to less responsive and flexible operation policies. They may not adequately reflect the impact of sudden changes in hydrological conditions, fuel prices, or unexpected operational issues.
- **Potential Inefficiencies:** By not updating cost and value calculations dynamically, existing methodologies may miss opportunities for optimization and cost reduction. They may also fail to adequately address short-term variations and uncertainties.

- **Long-Term Focus:** Many existing methods are designed for long-term planning and may not incorporate mechanisms for real-time adjustments. This can result in suboptimal management of resources and costs.

The key difference between the novel approach and existing methodologies lies in the ability to dynamically calculate and update generation costs and water value. The novel approach offers enhanced adaptability and precision by continuously incorporating real-time information, leading to potentially more efficient and responsive operational strategies. In contrast, existing methodologies often use static values, which may limit their ability to address short-term fluctuations and dynamic conditions effectively.

6.3. Discussion

The profitability of an organisation or business is intrinsically linked to its revenue. The tariff structure, formulated based on generation costs, plays a pivotal role in determining the utility's revenue within the realm of power economics. When considering power plant dispatch, hydropower plants are often favoured as the cheapest and optimal choices if solely assessed based on generation cost. However, such a decision-making approach is inadequate, as relying solely on hydropower may prove insufficient to meet future demands, potentially leading to increased generation costs in subsequent periods. Therefore, it becomes essential not only to ascertain the generation cost but also to determine the water value associated with the generation.

Table 2.1 highlights the seasonal Time of Use (ToU) tariff structure for five different time slots. However, there are some practical difficulties associated with this structure. It is suggested that ToU slots be changed twice per year, but this poses challenges such as the need for frequent meter changes, making it complex to implement in practice.

The year 2019 has been selected as the reference point for this research due to its representation of regular economic and social conditions in Sri Lanka. In contrast, the years 2020-2021 were marked by the impacts of the COVID-19 pandemic, while 2022-2023 were dominated by the effects of a severe economic crisis. These events significantly disrupted the usual functioning of the country.

It is important to note that the standard of living in Sri Lanka has changed since 2019, leading to altered lifestyles and electricity consumption patterns. Specifically, there have been notable changes in daily load curves, peak demand, total electricity generation and demand ratios in 2024. Therefore, it is essential to consider these time-varying changes in Sri Lankan society when interpolating the research results into the future.

Moving forward with the obtained results, it is essential to discuss the applicability of these findings in the planning process. Initially, it is important to consider how to use these electricity costs, which are dependent on both season and time of day, to formulate a pricing methodology.

Currently, electricity consumers receive a time-of-day production cost, as capacity-related costs (including generation, transmission, and distribution costs) and energy-related costs are separated in the pricing structure. In consumer pricing, fixed costs are accounted for based on their connection to the grid, which is proportional to their measured demand. Once the fixed cost is paid, the focus shifts to producing electricity and delivering it to customers over the network.

The energy component of the cost directly reflects production adjusted for losses. For simplification, it is assumed that losses are consistent throughout the network at any time of the day. Alternatively, a sophisticated loss assignment policy could be introduced to allocate losses in different time slots, such as assigning a 12% loss during peak times and a 4% loss during off-peak times. Additionally, different loss levels could be introduced for various consumers based on their voltage level, especially providing low loss allocation for bulk customers.

While some countries incorporate sophisticated loss allocation policies in their electricity pricing methodology, it may not be explicitly visible in the Sri Lankan electricity pricing scheme but could be included as a background cost.

This analysis embodies a quantitative cost accounting method pivotal for accumulating, classifying, summarising, and interpreting information crucial in decision-making, controlling, and operational planning processes. Its outcomes are paramount in policy-making tasks such as tariff formulation, determining the initiation of new power plants, and optimising total generation costs.

Moreover, this research delves into several critical thinking points, integral for policy implementation activities. It contemplates the achievable revenue when conserving 1 kWh of energy from the thermal power plant with the highest per-unit cost. Furthermore, it scrutinises the profit gained by the power system through conserving 1 kWh of energy at the consumers' end.

Guiding the accurate estimation of seasonal and time-of-use electricity costs and water values, this research facilitates identifying market conditions and provides real-time energy and cost predictions. Beyond merely shaping a time-of-use tariff structure, this concept serves as a 'bridge of communication' between demand and utility sides, aiming to minimise electricity usage during periods of high generation costs. Ultimately, it advocates for load-shifting and Demand Side Management, fostering energy conservation among consumers.

Comparing with water value of agriculture and power generation, it can be argued that Sri Lanka's water management policy should prioritise releasing more water for power generation, as allocating a significant portion of water for agriculture proves to be less economically efficient. Conversely, when available water resources are not utilised for power generation, costly alternatives such as variable thermal power plants must be employed to meet the targeted power generation, which again imposes a financial burden on the economy.

However, there are several constraints to consider regarding this notion. Relying entirely on imported food directly impacts the food security of the country. Additionally, rice cultivation is a fundamental occupation in many Asian countries, including Sri Lanka, with a history spanning more than 25 centuries. It is challenging to alter this deeply entrenched social and economic structure.

Moreover, the expected agricultural and power generation output of a hydro complex is determined during the project's design stage. Altering the schedule of water release midway through the project can adversely affect the overall profitability and outcomes. As discussed in Chapter 1, the water value concept serves as an operational economic parameter.

REFERENCES

[1] M. Pereira and L. Pinto, "Multi-stage Stochastic Optimization Applied to Energy Planning," *Mathematical Programming 52, North- Holland*, pp. 359-375, 1991.

[2] I. D. Wangsa, T. M. Yang and H. M. Wee, "The effect of Price-Dependent Demand on the Sustainable Electrical Energy Supply Chain," *Energies,* no. 11, 2018.

[3] "Long Term Generation Expansion Plan 2022-2041," Transmission and Generation Planning Branch of Ceylon Electricity Board, Colombo, 2021.

[4] S. Sandagiri, "Water Value for Hydro Generation Reserviors," Department of Electrical Engineering, University of Moratuwa, Moratuwa , 2011.

[5] A. Philpott, "On the Marginal Value of Water for Hydroelectricity," in *Advances and Trends in Optimization with Engineering Applications*, Auckland, New Zealand, Society for Industrial and Applied Mathematics, 2017, pp. 405-425.

[6] V. Pillai N, "Modeling Optimal Time-Differential Pricing of Electricity Under Uncertinity: Revisiting the Welfare Foundations," Kerala, India, 2012.

[7] A. Takada, H. Ijuin, M. Matsui and T. Yamada, "Seasonal Analysis and Capacity Planning of Solar Energy Demand-to-Supply Management: Case Study of a Logistics Distribution Center," *Energies* , vol. 17, no. 191, 2014.

[8] J. Li, L. Shi and H. Fu, "Multi-Objective Short-Term Optimal Dispatching of Cascade Hydro–Wind–Solar–Thermal Hybrid Gen-eration System with Pumped Storage Hydropower," *Energies,* vol. 17, no. 98, 2024.

[9] C. Terrier, J. Loustau, D. Lepour and F. Maréchal, "From Local Energy Communities towards National Energy System: A Grid-Aware Techno-Economic Analysis," *Energies*, vol. 17, no. 910, 2024.

[10] Dharmawangsa, Ivan, T. M. Yang and H. M. Wee, "The effect of Price-Dependent Demand on the Sustainable Electrical Energy Supply Chain," *Energies,* vol. 11, no. 1645, p. 10.3390, 2018.

[11] J. Andruszkiewicz, J. Lorenc and A. Weychan, "Seasonal Variability of Price Elasticity of Demand of household using zonal tariffs and its impact on hourly load of the Power System," *Energy,* vol. 190, no. 117175, 2020.

[12] C. Eid, E. Koliou, M. Valles, J. Reneses and R. Hakvoort, "Time-based Pricing and Electricity Demand Response: Exixsting Barriers and Next Steps," *Utilities Policy,* vol. 40, pp. 15-25, 2016.

[13] C. Gavin, "Seasonal variations in electricity demand," 2014. [Online]. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/295225/Seasonal_variations_in_electricity_demand.pdf. [Accessed 20 February 2024].

[14] Dias, B.H., A. Marcato, R. Souza, M. Soares, I. Silva(jr), E. Oliveira, R. Brandi and T. Ramos, "Stochastic Dynamic Programming Applied to Hydrothermal Power Systems Operation Planning Based on the Convex Hull

Algorithm,” *Mathematical Problems in Engineering,* vol. 10.1155, no. 390940, 2010.

[15] M. Pereira and L. Pinto, “A Decomposition Approach to the Economic Dispatch of Hydrothermal Systems,” *PER OCT,* p. 3851, October 1982.

[16] S. Masache and C. Barrera-Singana, “Short-Term Hydrothermal Economic Dis[atch Applied on Hydraulic Coupled Power Plants Using Dynamic Programming,” in *IEEE ANDESCON,* Quito, Ecuador, 2020.

[17] H. Dai, N. Zhang and W. Su, “A Literature Review of Stochastic Programming and Unit Commitment,” *Journal of Power and Energy Engineering,* vol. 3, pp. 206-214, 2015.

[18] Perera, P.J;, “Dynamic Programming Techniques in Water Resource Planning,” Hand Written Document, Colombo, 1980.

[19] P. Perera and A. Seneviratne, “Medium Term Hydro-Thermal Scheduling in Sri Lanka,” in *Third Regional Symposium on Long-Term Power System Planning,* 1988, 1988.

[20] S. Sandagiri, M. Madurapperuma, H. Malraj and M. Nafas, “Seasonal and Time of Day Dependent Electricity Costs in Sri Lankan System,” Department of Electrical Engineering, University of Moratuwa, Moratuwa, 2011.

[21] M. El-Hawary, “An Overview of Economic Dispatch for General Hydro-Thermal Electric Power Systems,” St John's Memorial University of Newfoundland, Newfoundland, Canada.

[22] M. Cerjan, D. Marcic and M. Delimar, “Short Term Power System Planning with water value and Energy Trade Optimisation,” in *8th International Conference on the European Energy Market (EEM),* Zagreb, Croatia, 2011.

[23] “PSR Software and Consultants,” [Online]. Available: https://www.psr-inc.com/en/software/. [Accessed 10 February 2024].

[24] I. Cruz, M. Badaoui and M. Palomino, “Medium- Term Hydrothermal Scheduling of Infiernillo Reservoir Using Stochastic Dual Dynamic Programming (SDDP): A Case Study in Mexico,” *Energies,* vol. 16, no. 6288, 2023.

[25] D. Golembiovsky, A. Pavlov and S. Daniil, “Experimental Study of Methods of Scenario Lattice Construction for Stochastic Dual Dynamic Programming,” *Scientific Research Publishing,* vol. 10, pp. 47-60, 2021.

[26] “Statistical Digest 2019,” Ceylon Electricity Board, Colombo, 2019.

[27] “Efficient agricultural water use and management in Paddy Fields in Sri Lanka - National Outlook,” Food And Agriculture Organization of The United Nations, Rome, 2022.

[28] B. Kamaladasa, Interviewee, *Water Value in Agriculture.* [Interview]. 17 02 2024.

[29] D. Perera, A. Dissanayake, U. Udari and W. Wickremasinghe, “Policies that Matter or Are Forgettable The Evaluation of Paddy Policies in Sri Lanka: 1998 to 2018,” Hector Kobbekaduwa Agrarian Research and Training Institute , Colombo, 2021.

[30] “Department of Agriculture, Sri Lanka,” [Online]. Available: https://doa.gov.lk/rrdi_rice_introduction-2/. [Accessed 15 08 2024].

[31] "Hansard Report," Sri Lankan Parliament , 2021, 2020.

[32] "Annual Report 2019," Sri Lanka Mahaweli Authority, Colombo, 2020.

[33] "Mahaweli Statistical Hand Book 2019," Mahaweli Authority of Sri Lanka, Colombo, 2020.

[34] "Annual Report 2019," Central Bank of Sri Lanka, Colombo, Sri Lanka, 2020.

[35] "Annual Report of Generation Planning 2019," Ceylon Electricity Board, Colombo, 2020.

[36] J. Andruszkiewicz, J. Lorenc and A. Weychan, "Demand Price Elasticity of Residential ELectricity Consumers with Zonal Tariff Settlement Based on Their Load Profiles," *Energies,* no. 12, 2019.

[37] "Sales and Generation Data Book 2019," Ceylon Electricity Board, Colombo, Sri Lanka, 2020.

[Appendix A- Total Electricity Generation in 2019]

January

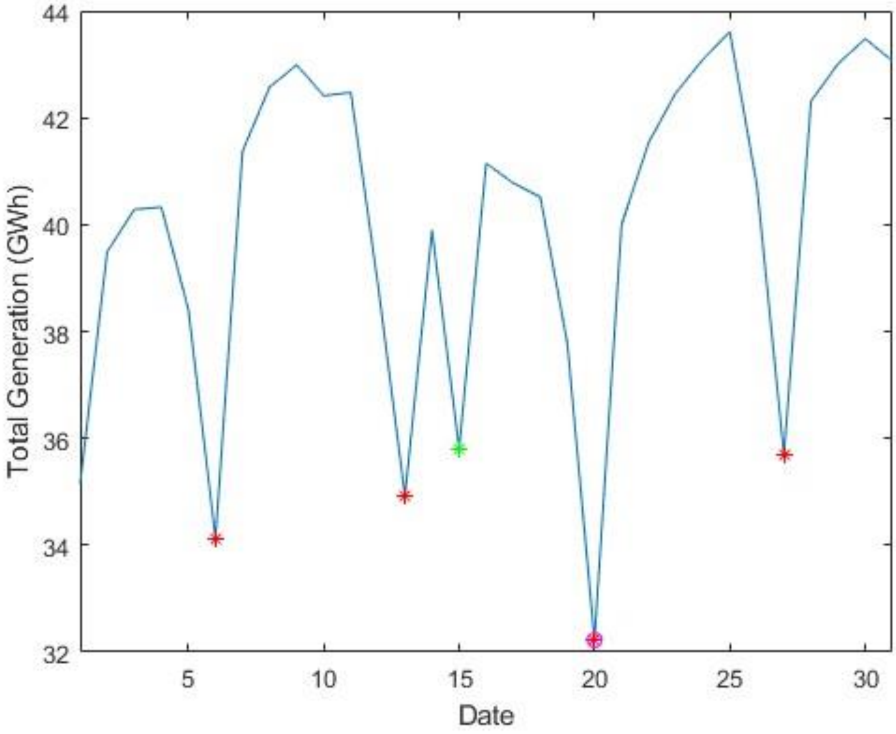


Figure A. 1: Total Electricity Generation in January 2019

February

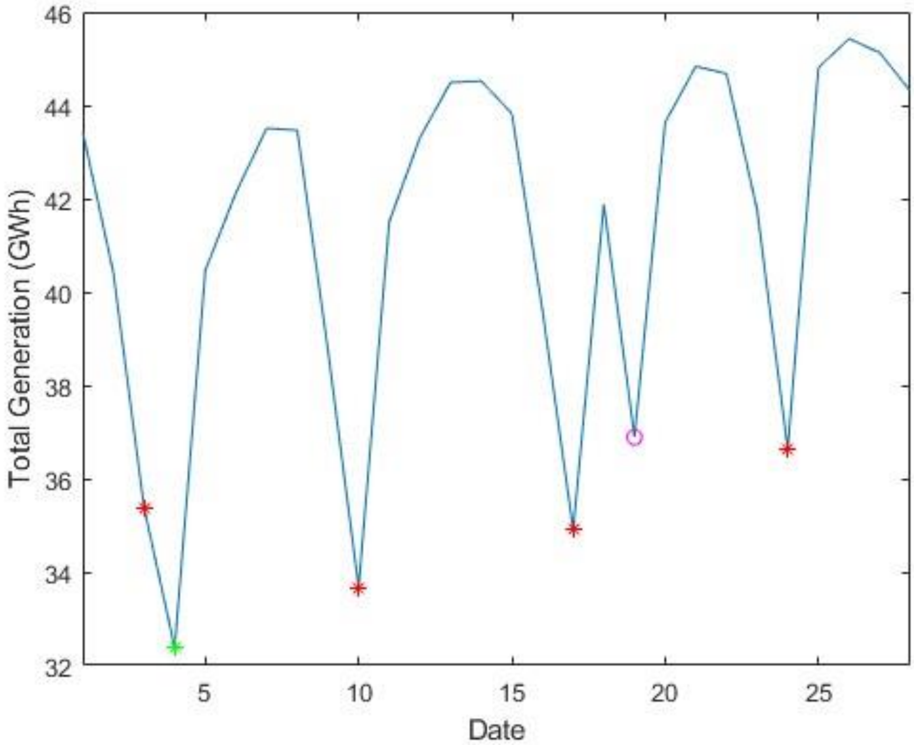


Figure A. 2: Total Electricity Generation in February 2019

March

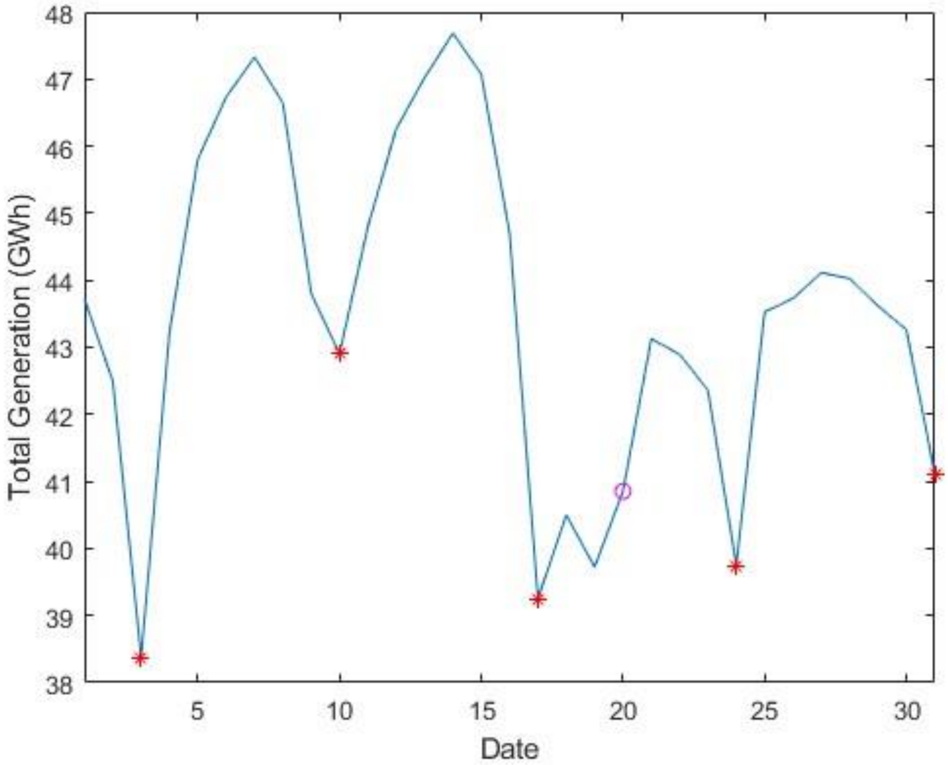


Figure A. 3: Total Electricity Generation in March 2019

April

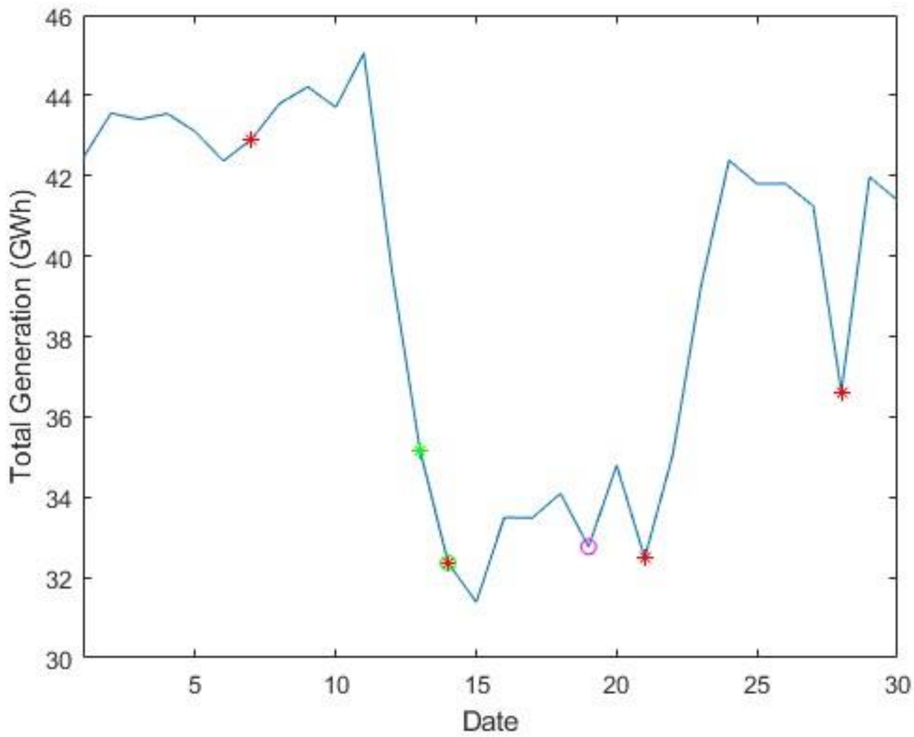


Figure A. 4: Total Electricity Generation in April 2019

May

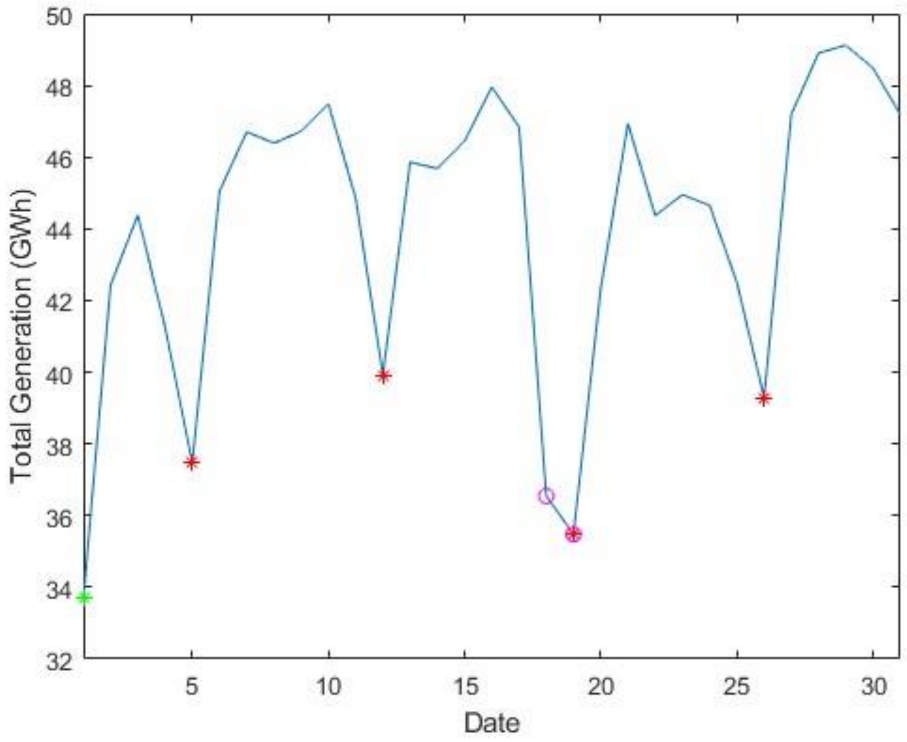


Figure A. 5: Total Electricity Generation in May 2019

June

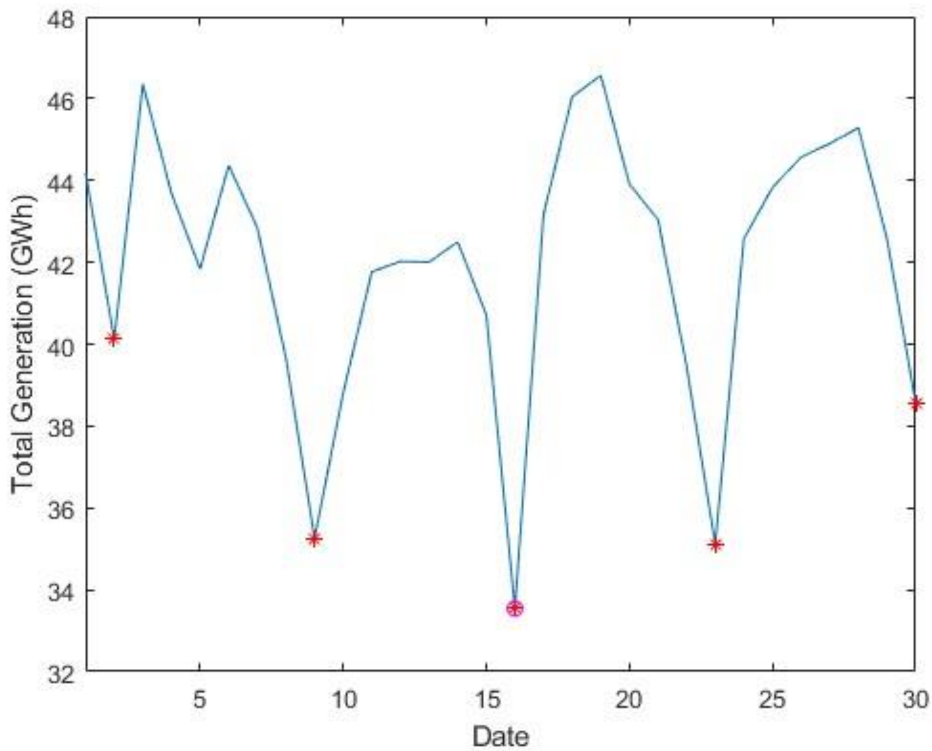


Figure A. 6: Total Electricity Generation in June 2019

July

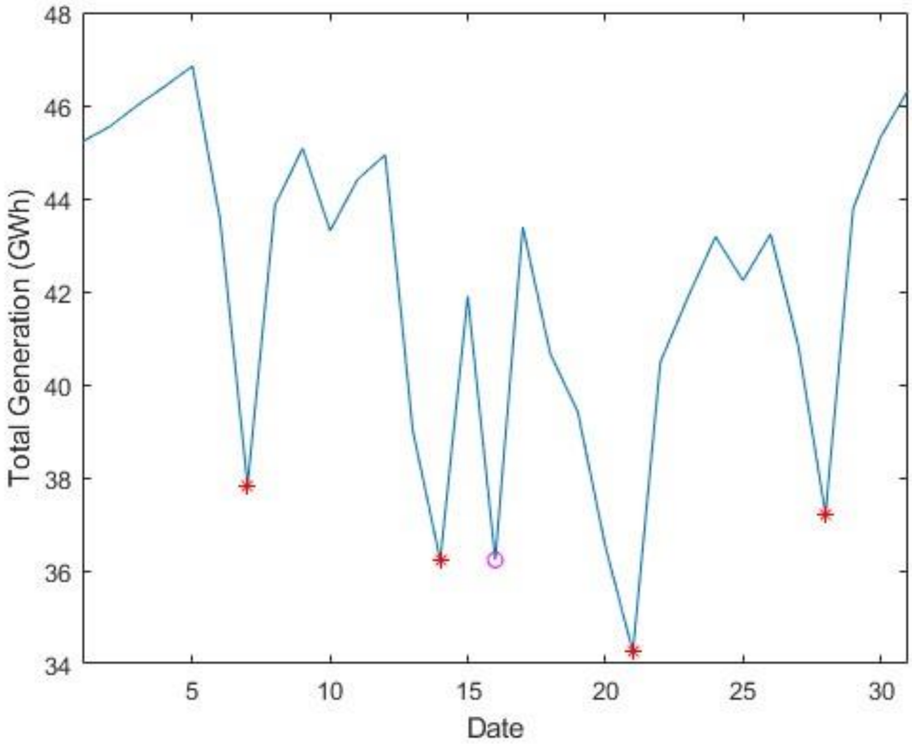


Figure A. 7: Total Electricity Generation in July 2019

August

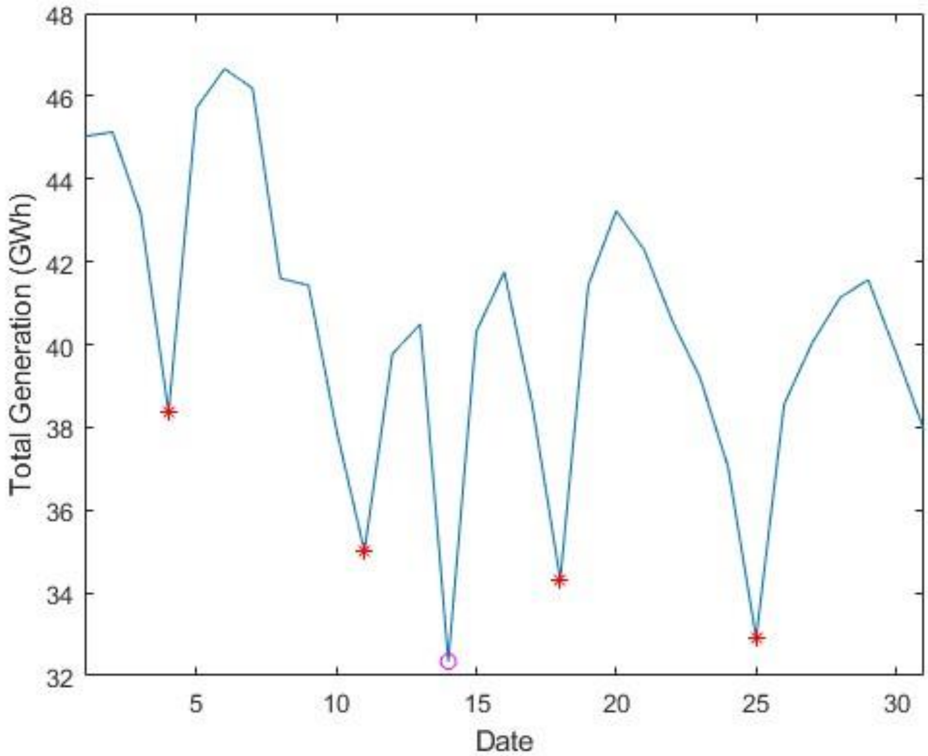


Figure A. 8: Total Electricity Generation in August 2019

September

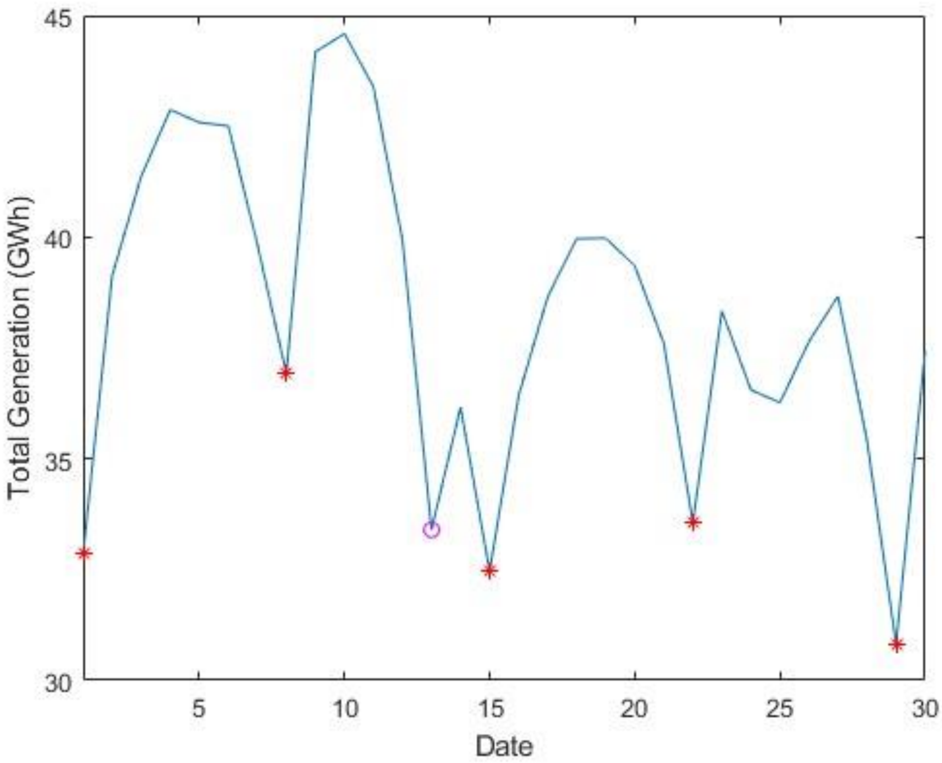


Figure A. 9: Total Electricity Generation in September 2019

October

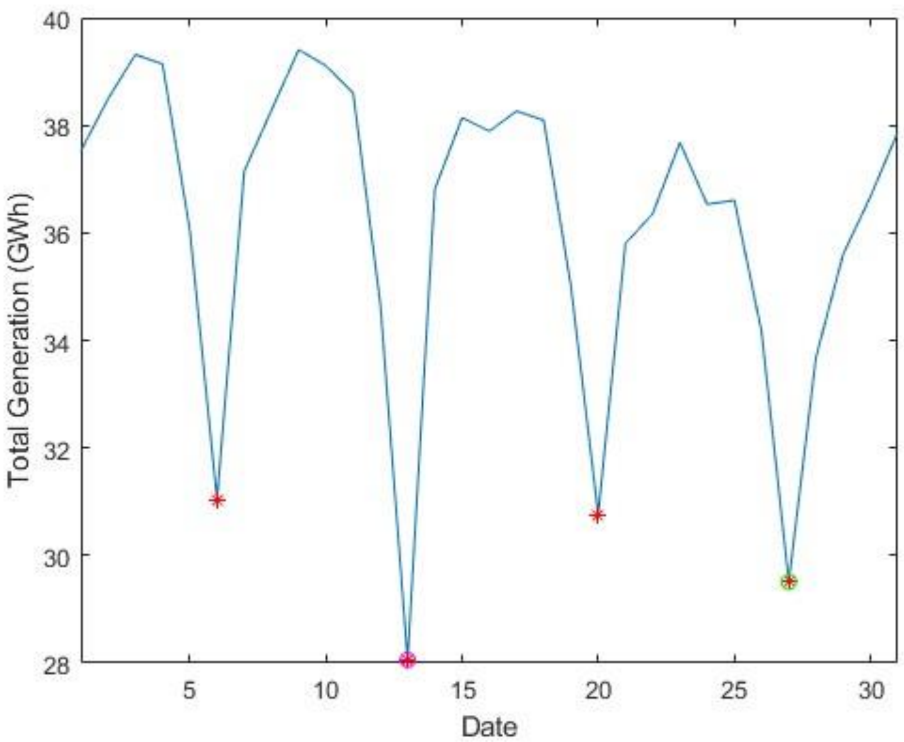


Figure A. 10: Total Electricity Generation in October 2019

November

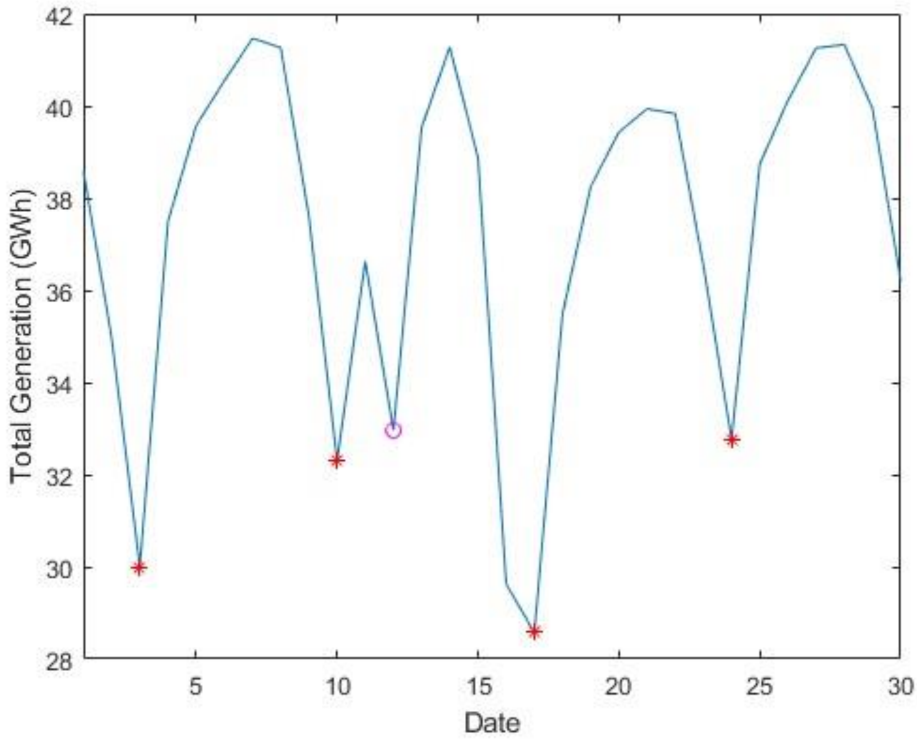


Figure A. 11: Total Electricity Generation in November 2019

December

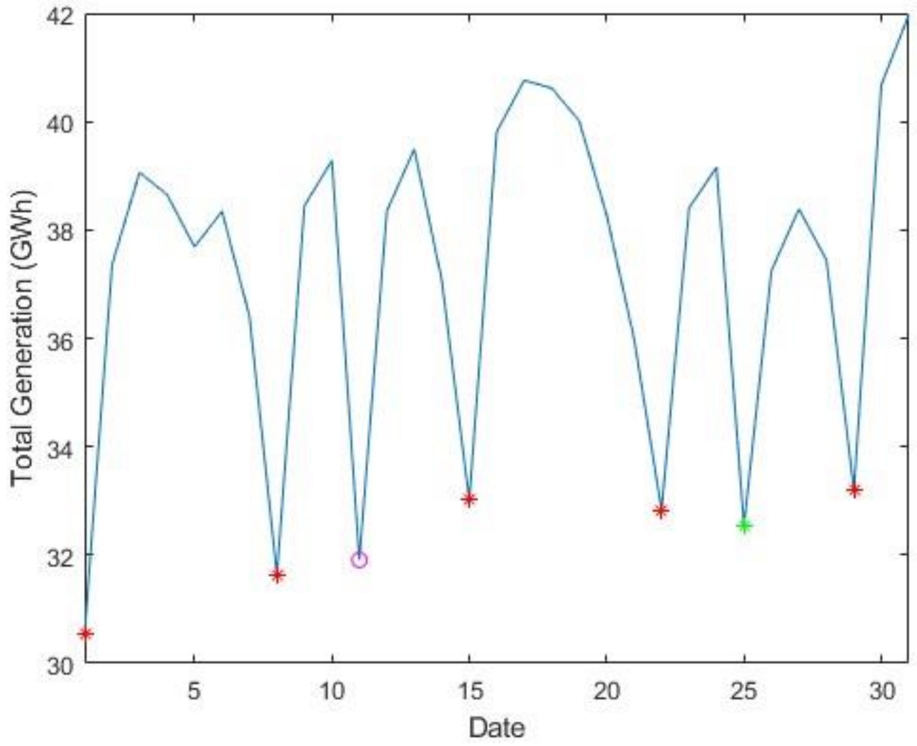


Figure A. 12: Total Electricity Generation in December 2019

[Appendix B- Peak Demand in 2019]

January

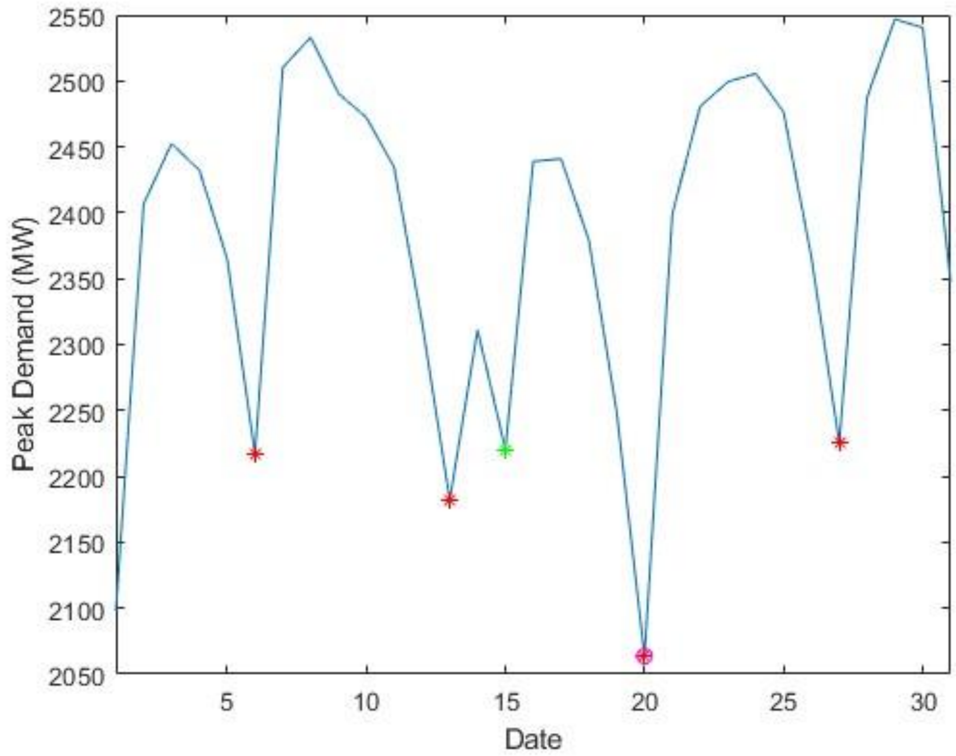


Figure B. 1: Peak Demand in January 2019

February

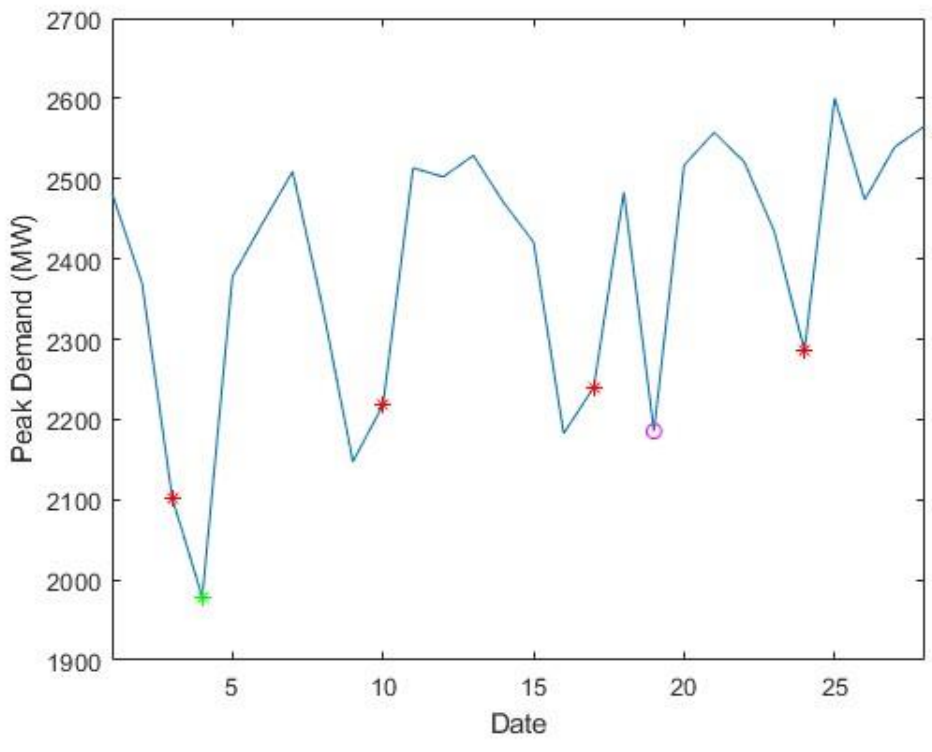


Figure B. 2: Peak Demand in February 2019

March

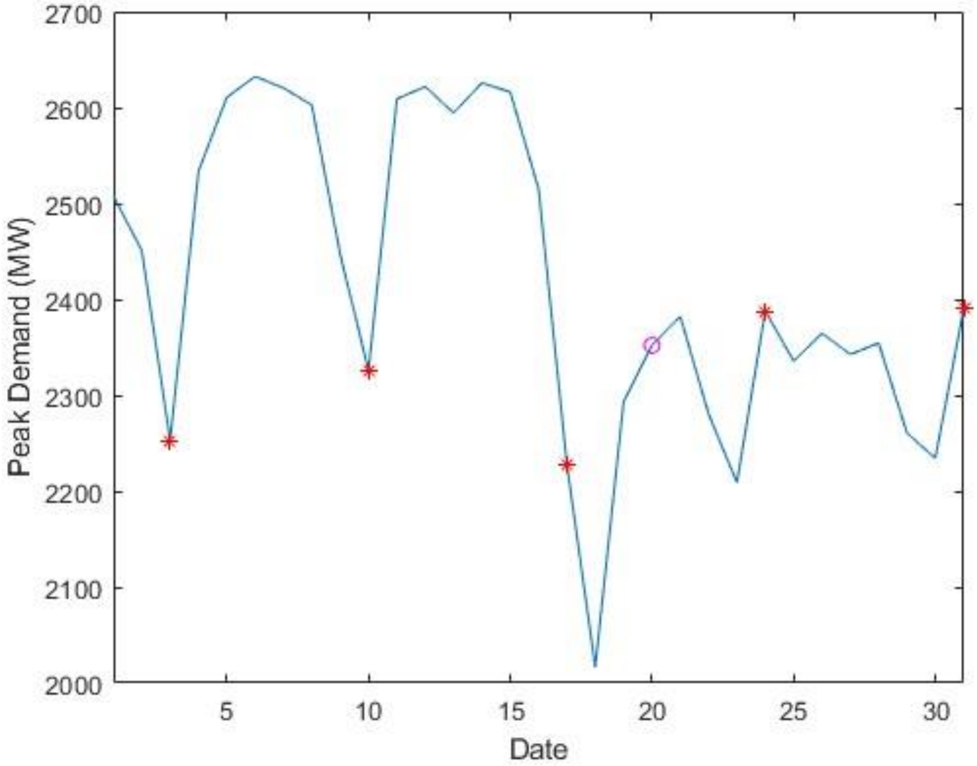


Figure B. 3: Peak Demand in March 2019

April

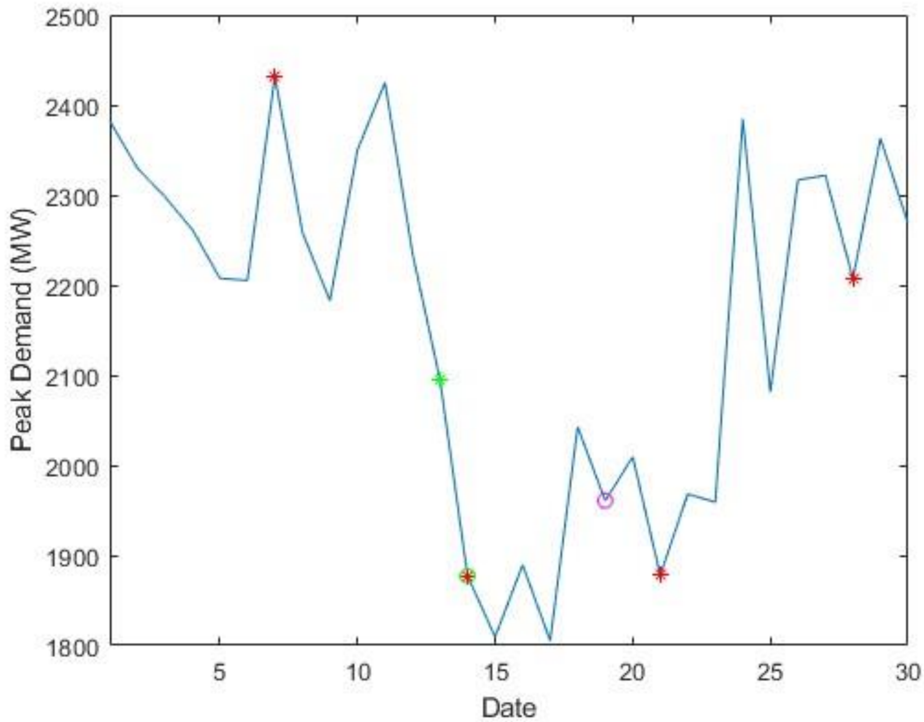


Figure B. 4: Peak Demand in April 2019

May

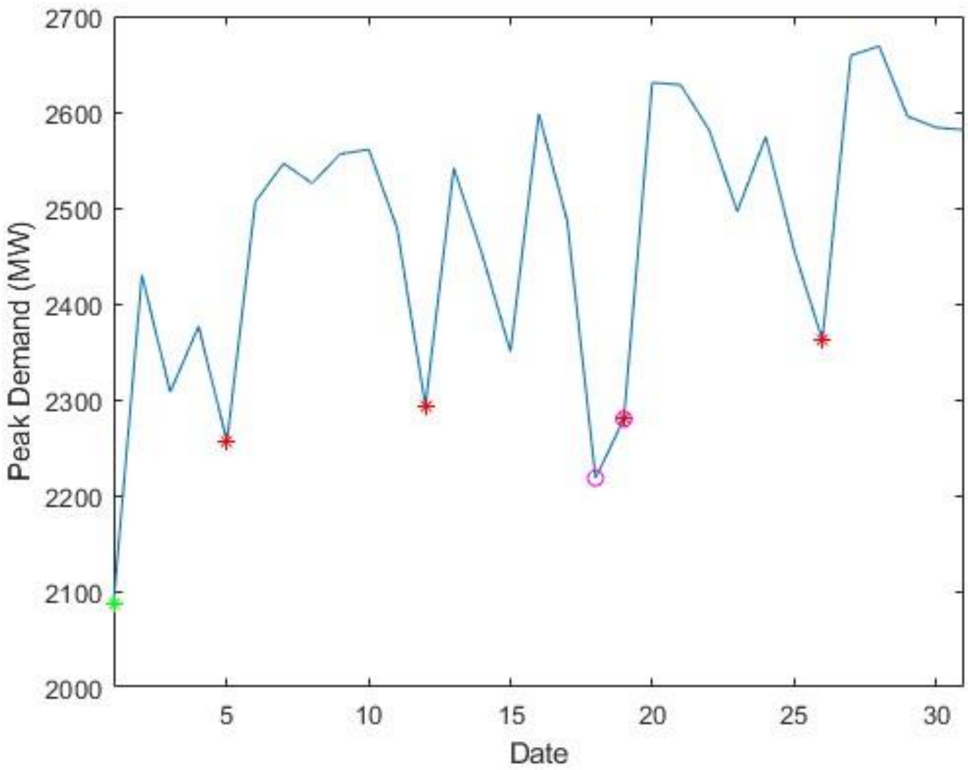


Figure B. 5: Peak Demand in May 2019

June

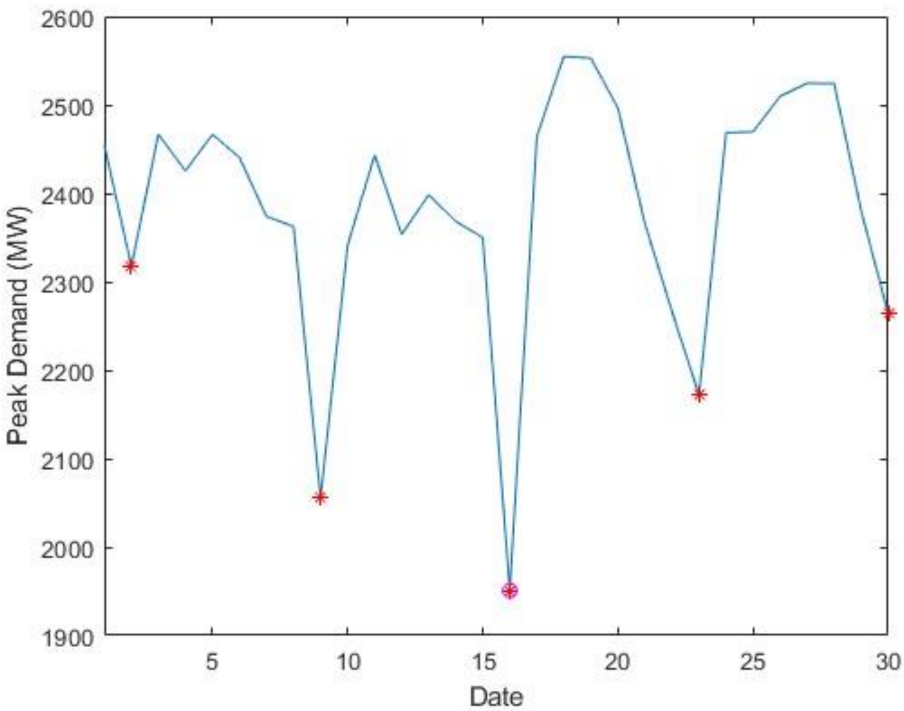


Figure B. 6: Peak Demand in June 2019

July

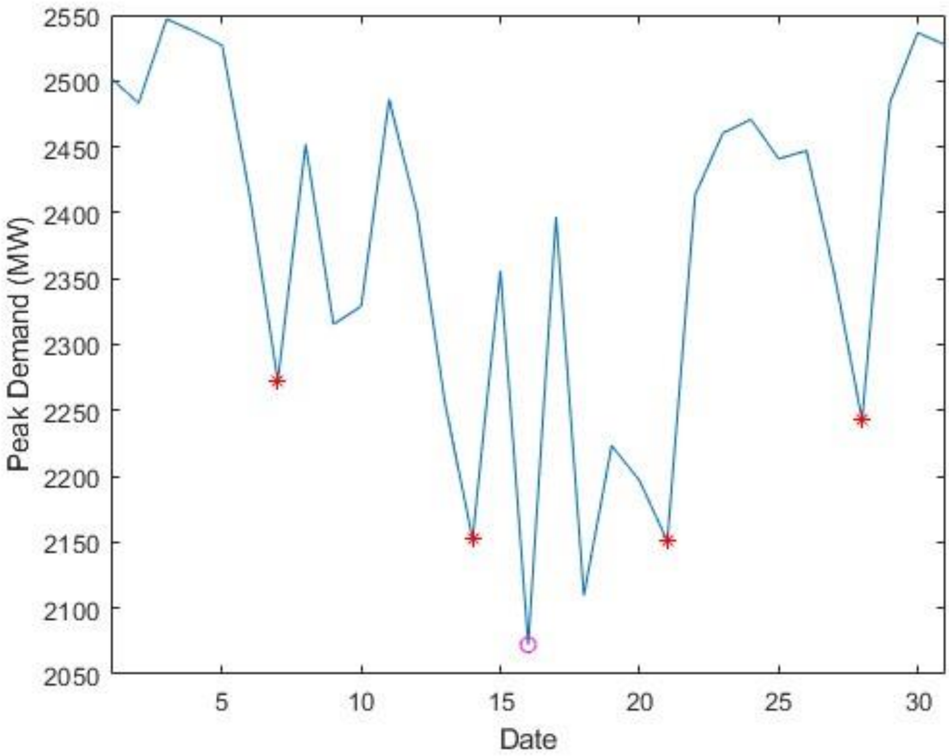


Figure B. 7: Peak Demand in July 2019

August

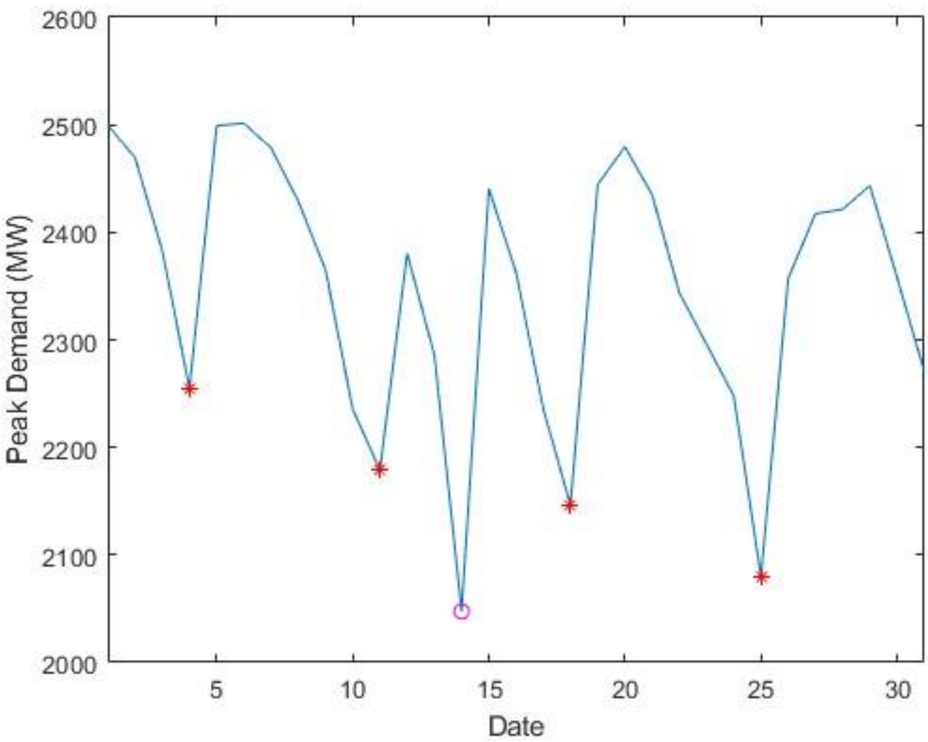


Figure B. 8: Peak Demand in August 2019

September

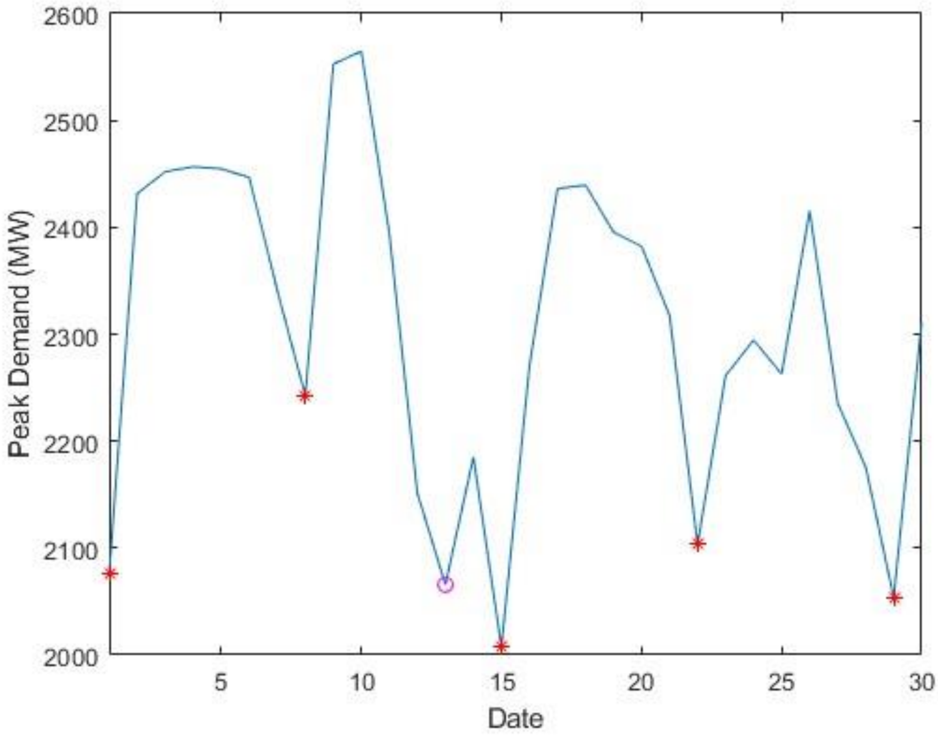


Figure B. 9: Peak Demand in September 2019

October

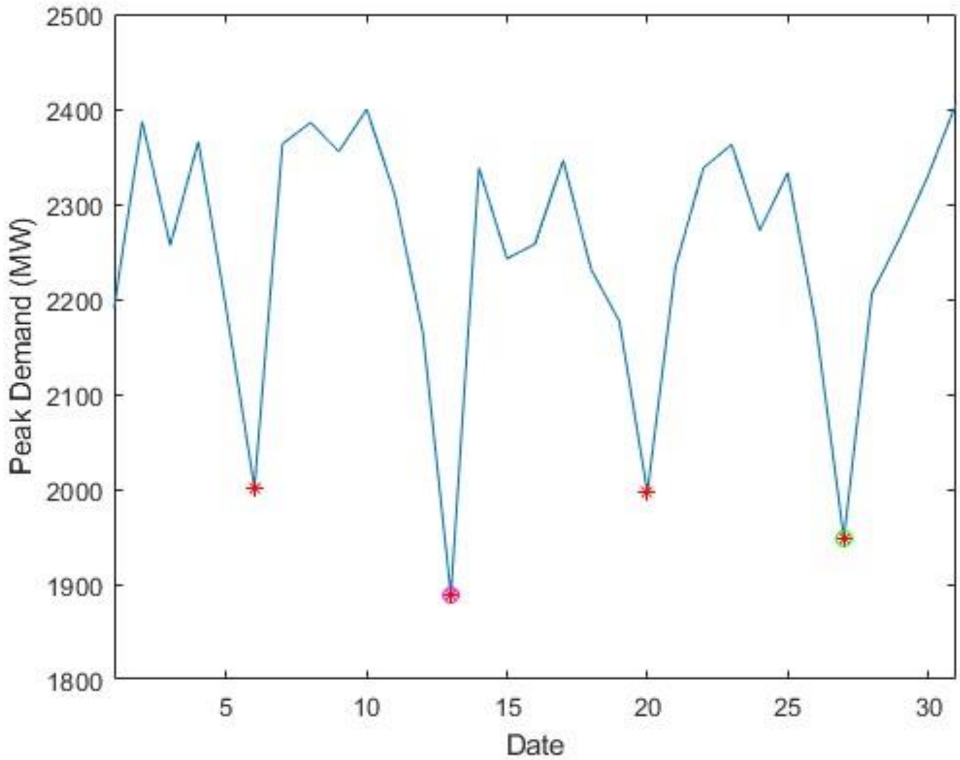


Figure B. 10: Peak Demand in October 2019

November

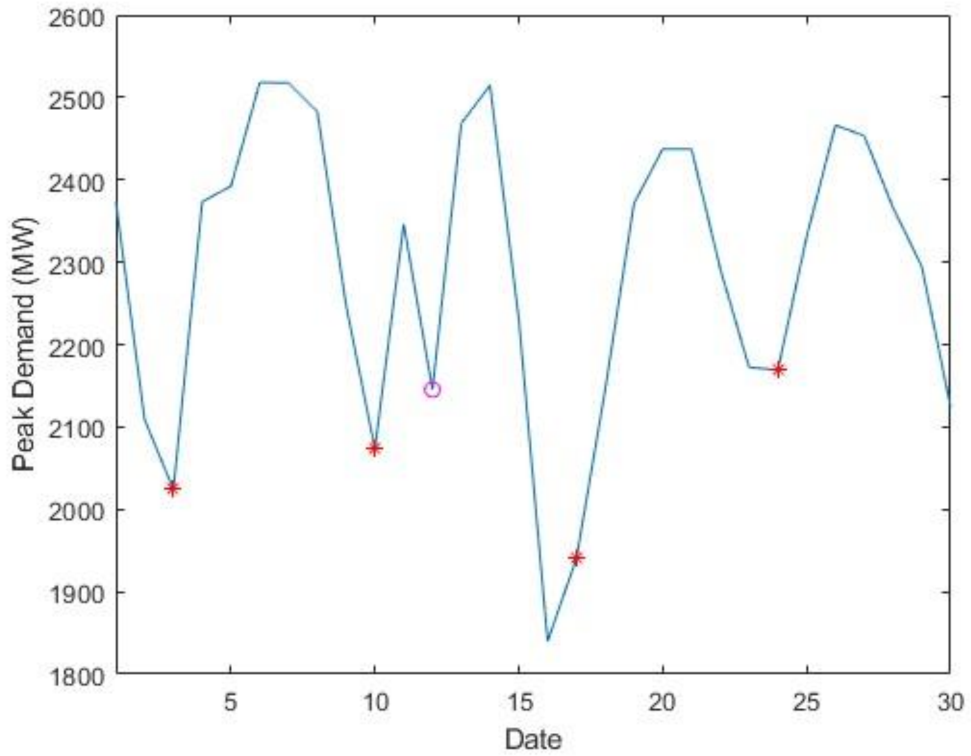


Figure B. 11: Peak Demand in November 2019

December

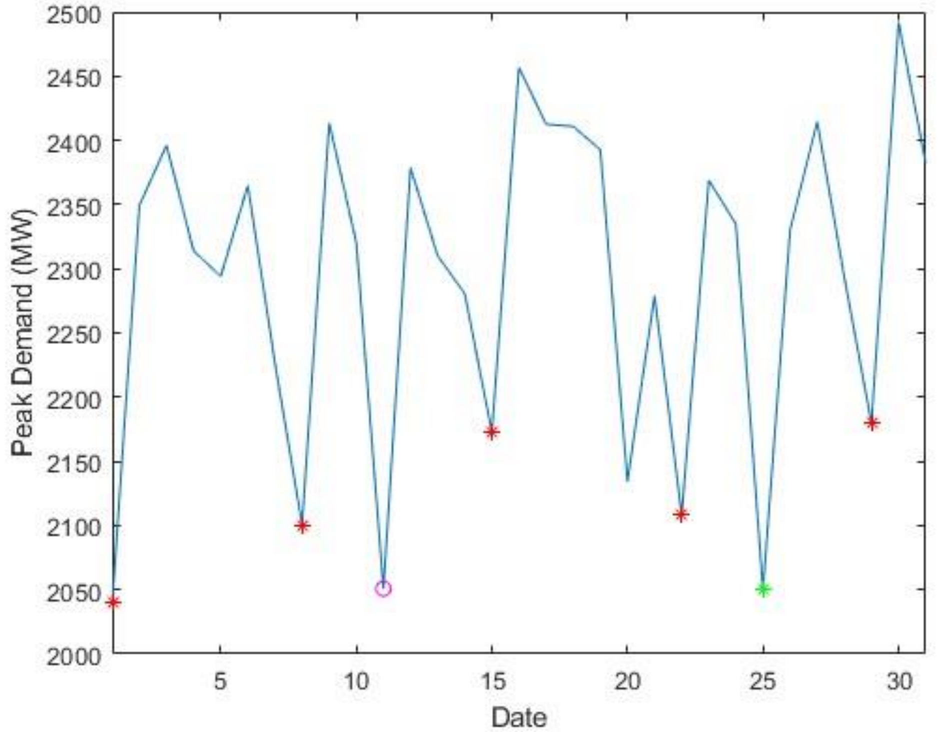


Figure B. 12: Peak Demand in December 2019

[Appendix C- Average Load in 2019]

January

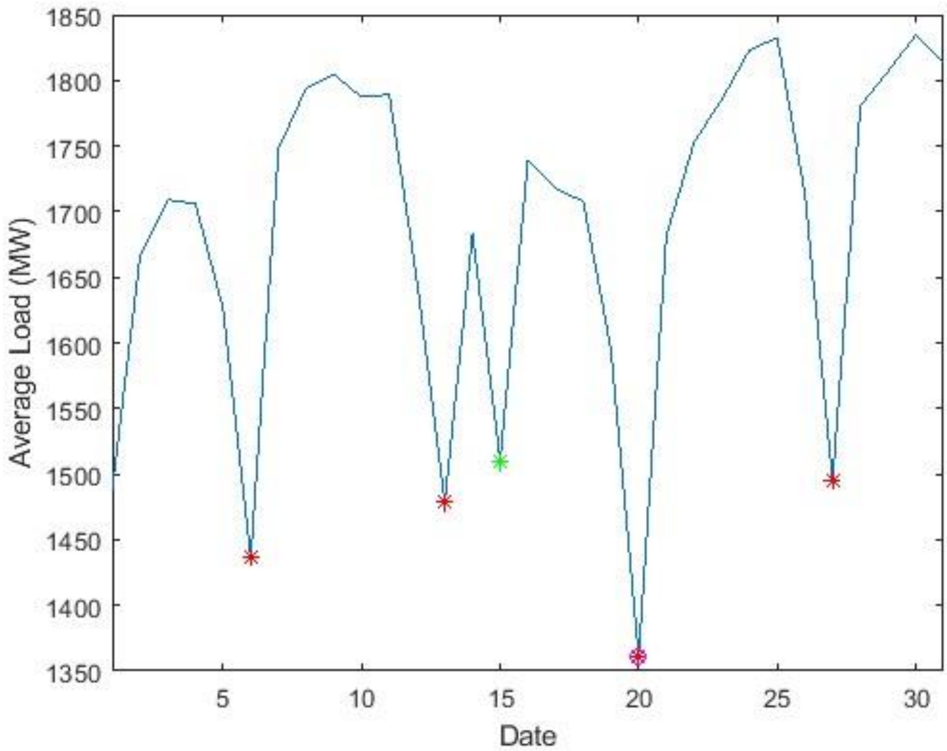


Figure C. 1: Average Load in January 2019

February

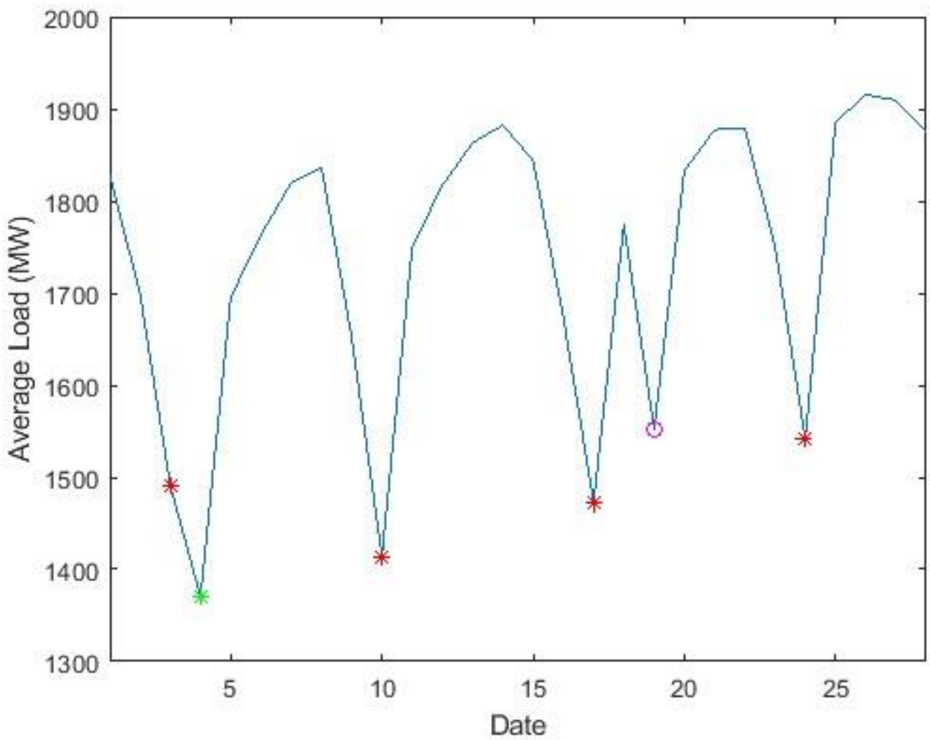


Figure C. 2: Average Load in February 2019

March

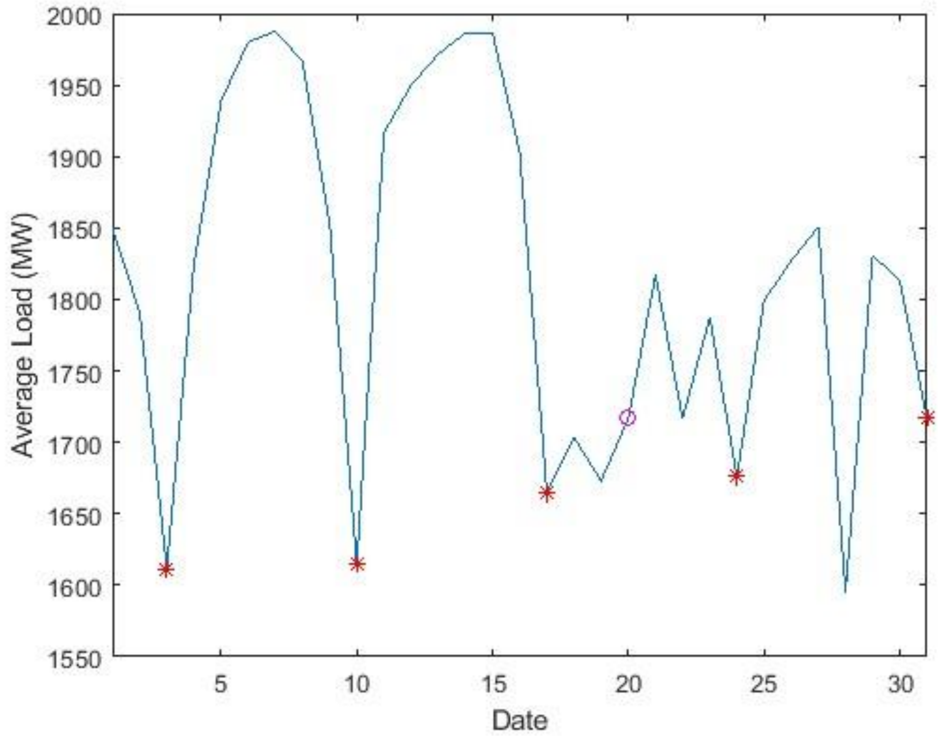


Figure C. 3: Average Load in March 2019

April

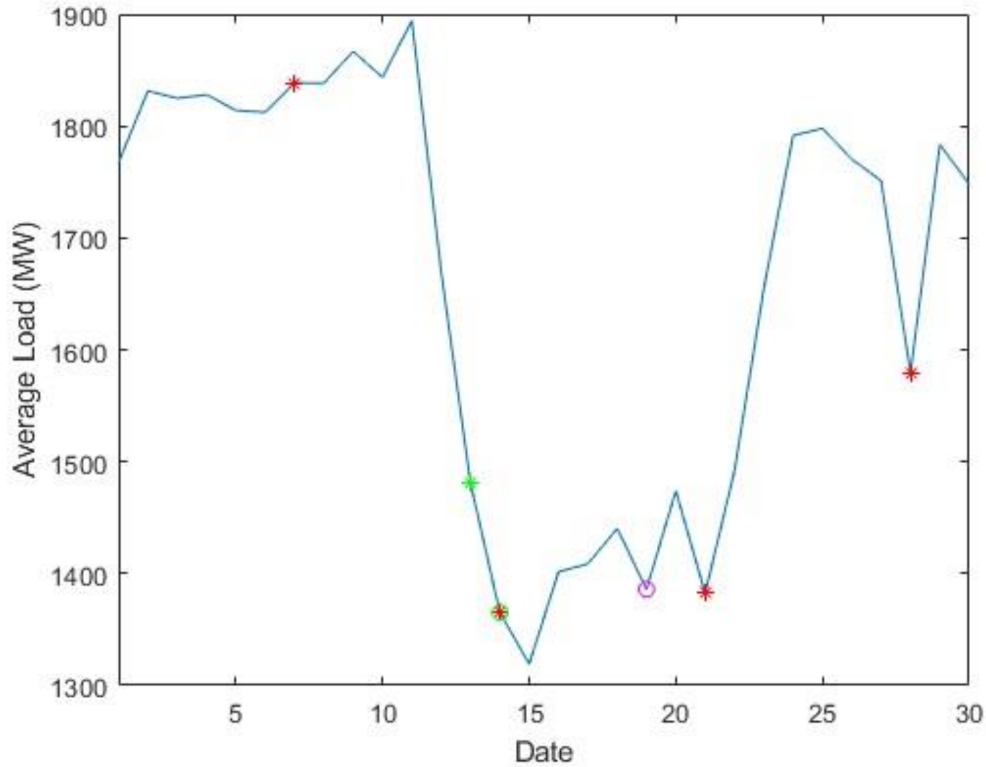


Figure C. 4: Average Load in April 2019

May

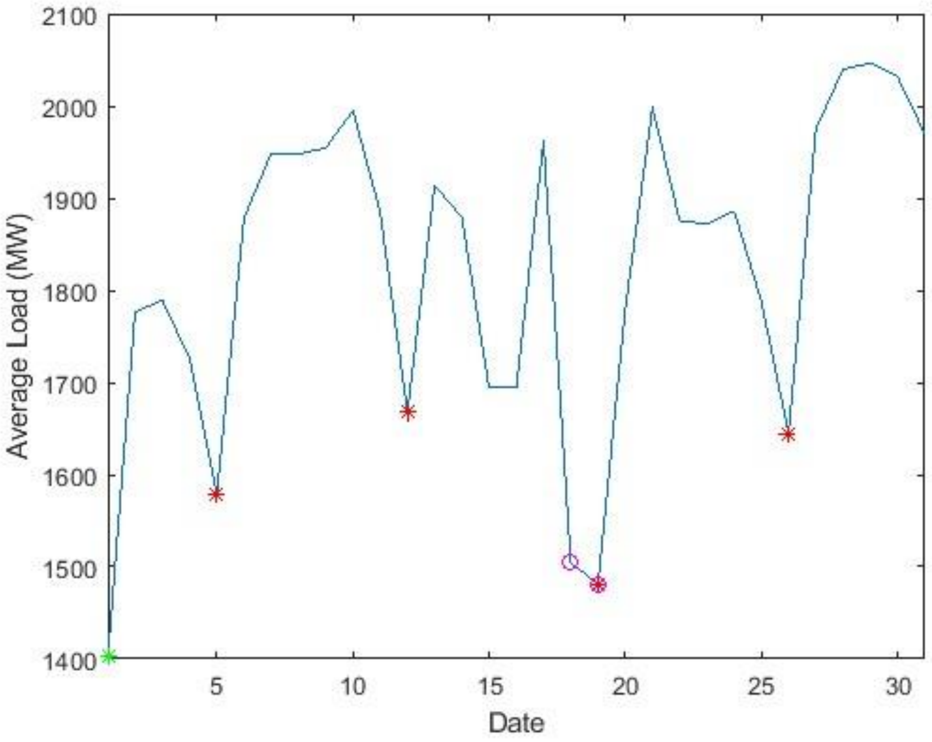


Figure C. 5: Average Load in May 2019

June

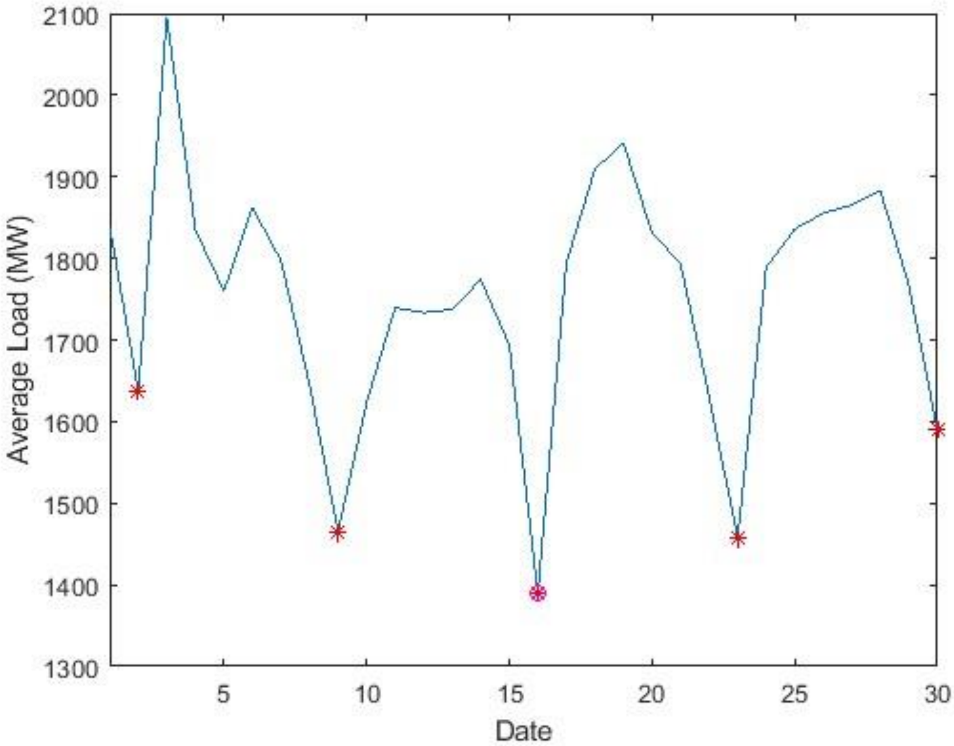


Figure C. 6: Average Load in June 2019

July

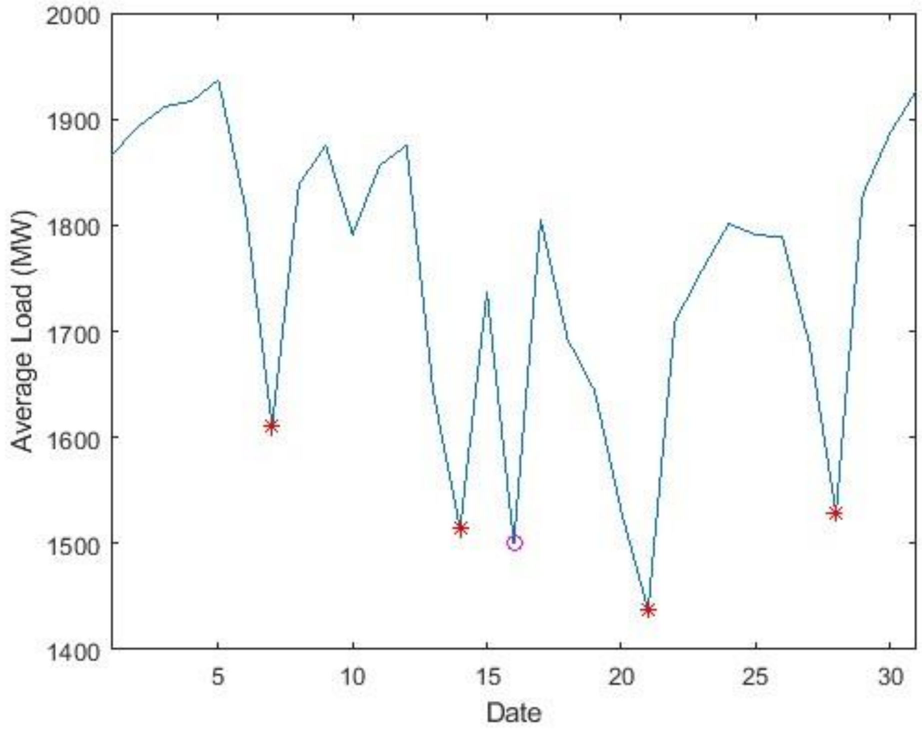


Figure C. 7: Average Load in July 2019

August

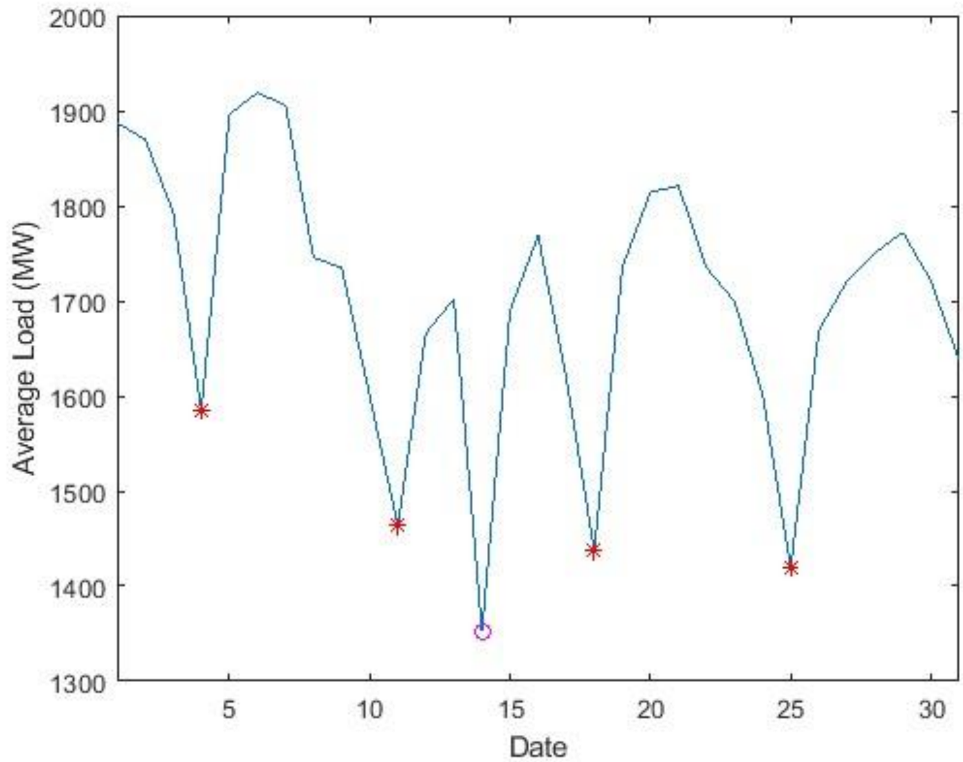


Figure C. 8: Average Load in August 2019

September

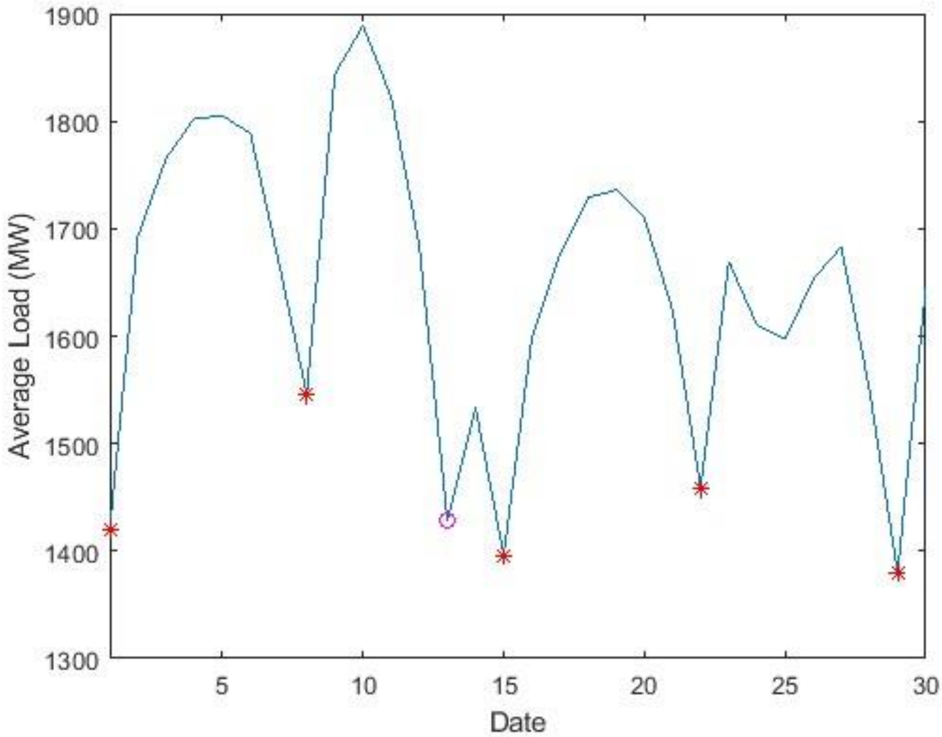


Figure C. 9: Average Load in September 2019

October

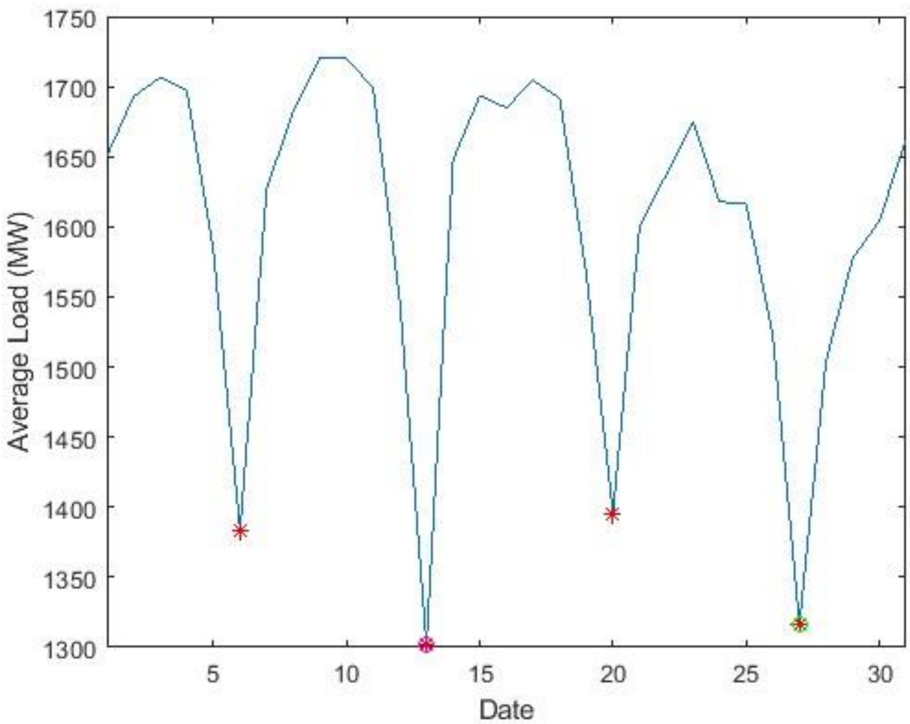


Figure C. 10: Average Load in October 2019

November

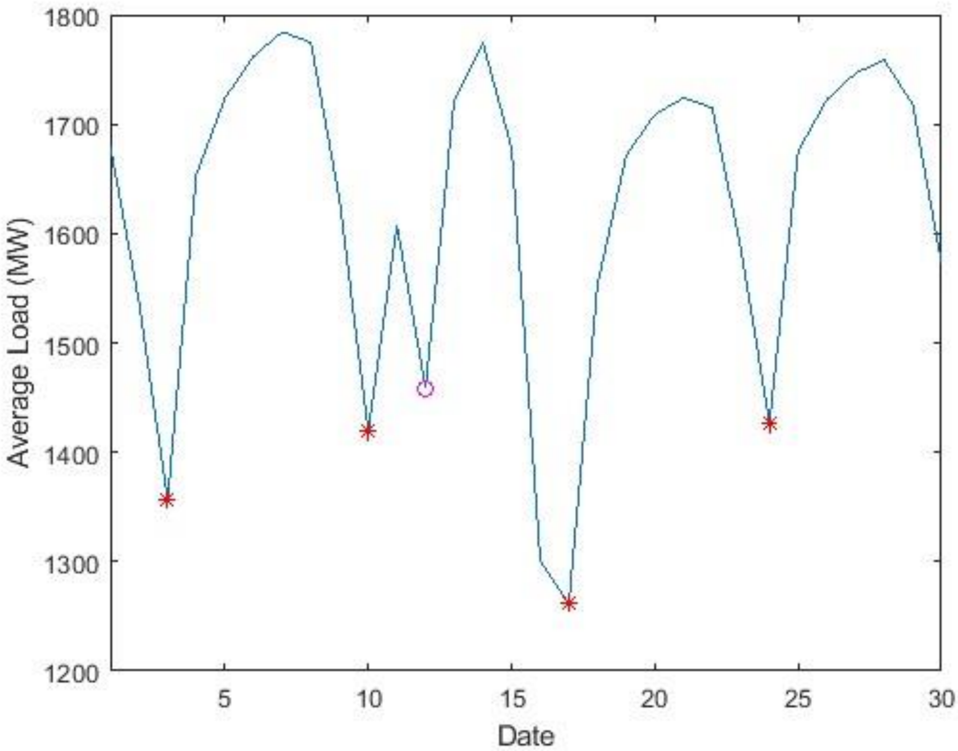


Figure C. 11: Average Load in November 2019

December

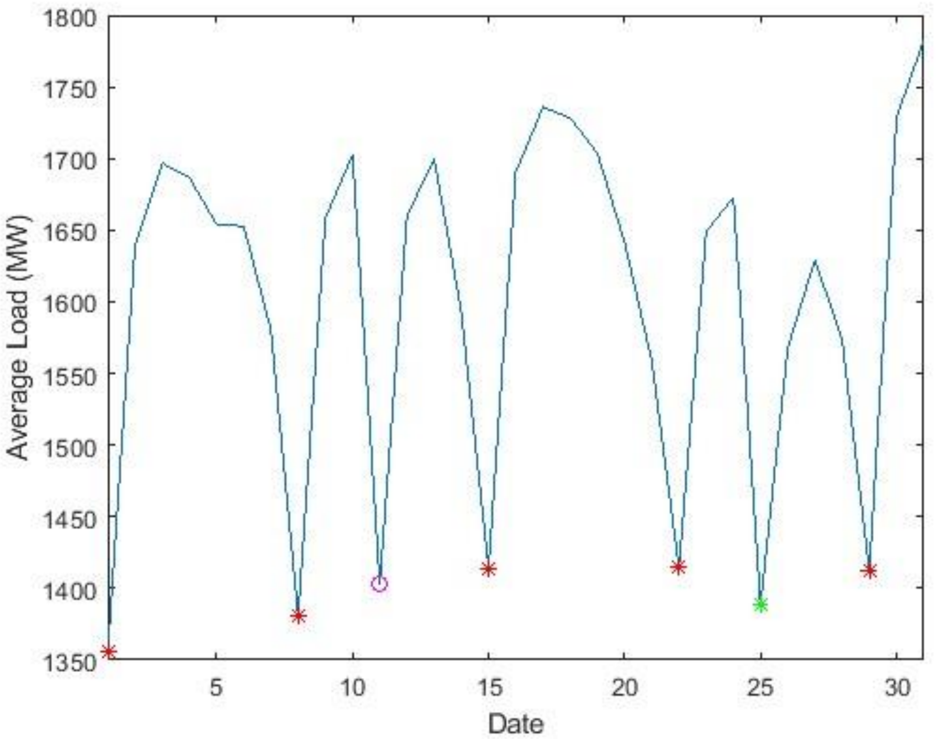


Figure C. 12: Average Load in December 2019

[Appendix D- Peak to Average Demand Ratio in 2019]

January

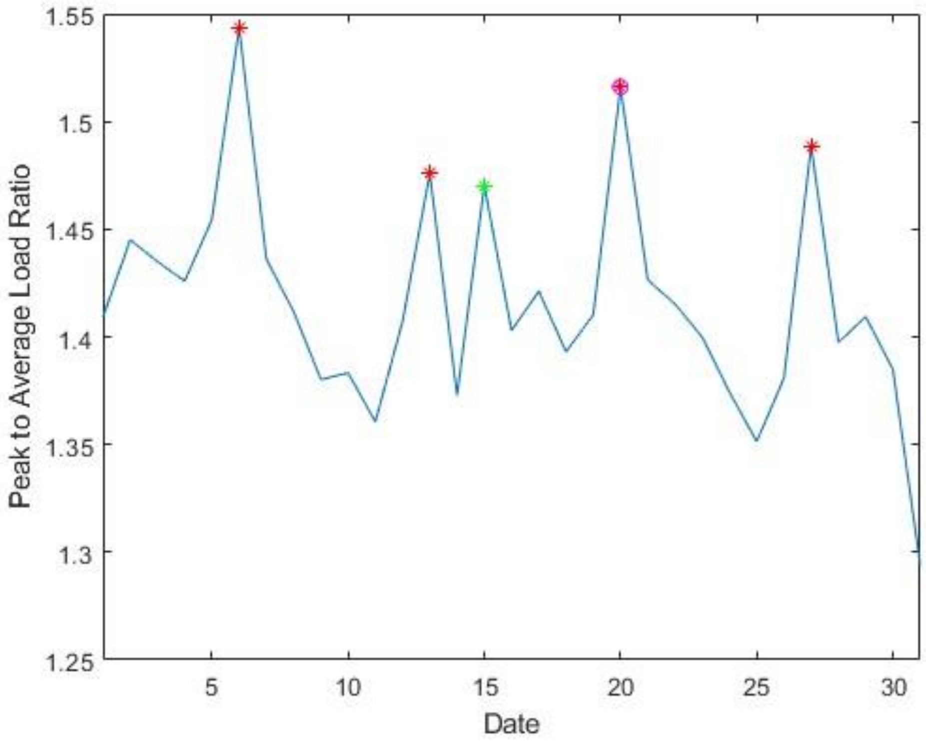


Figure D. 1 : Peak to Average Demand Ratio in January 2019

February

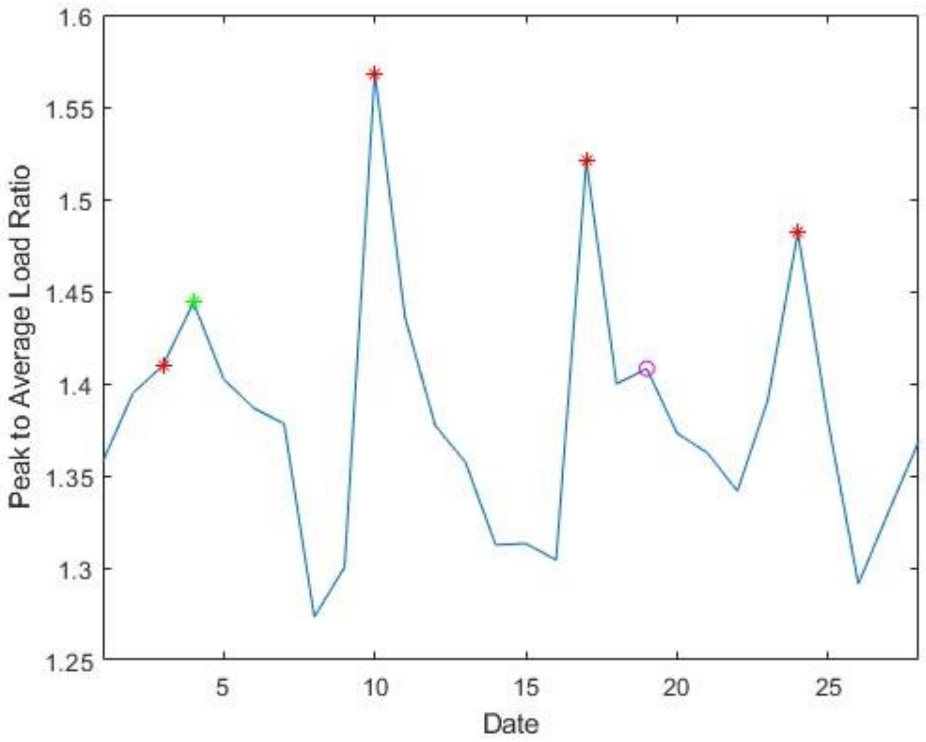


Figure D. 2: Peak to Average Demand Ratio in February 2019

March

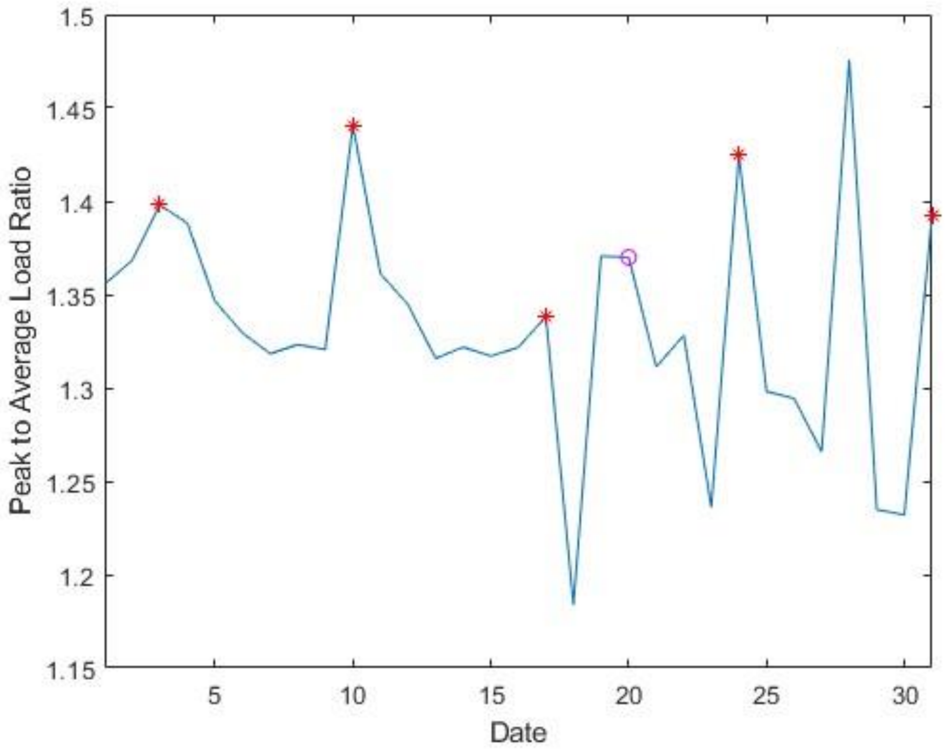


Figure D. 3: Peak to Average Demand Ratio in March 2019

April

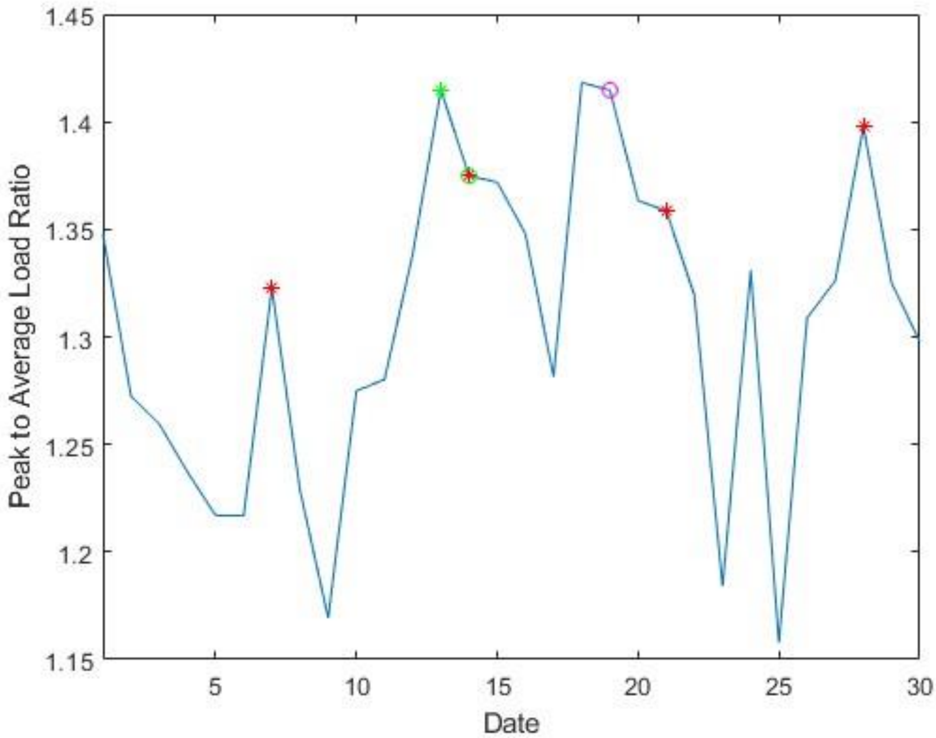


Figure D. 4: Peak to Average Demand Ratio in April 2019

May

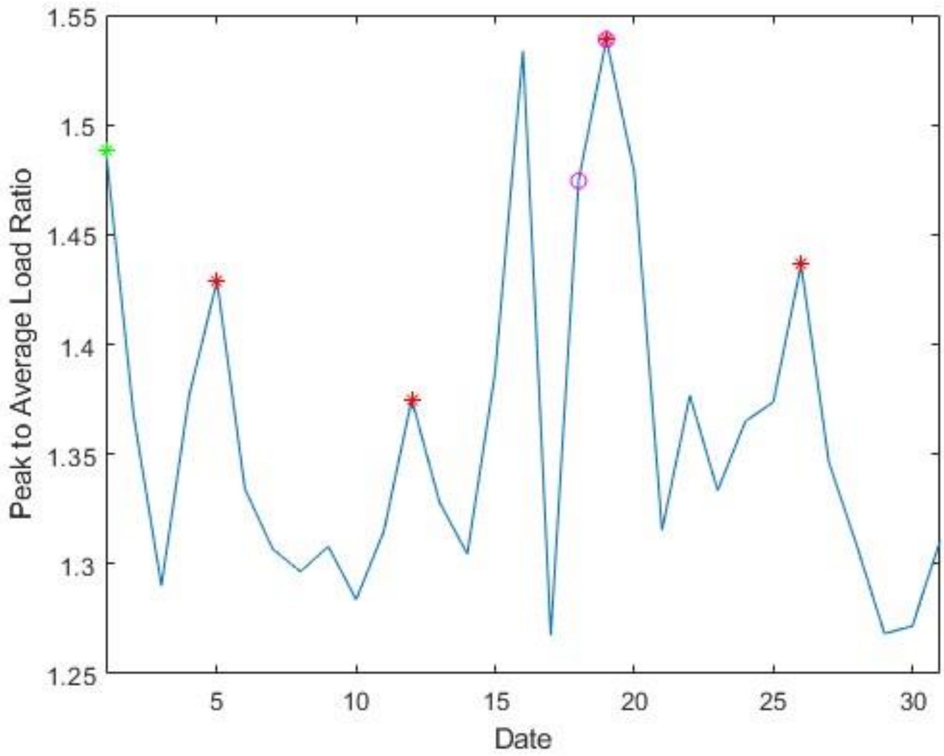


Figure D. 5: Peak to Average Demand Ratio in May 2019

June

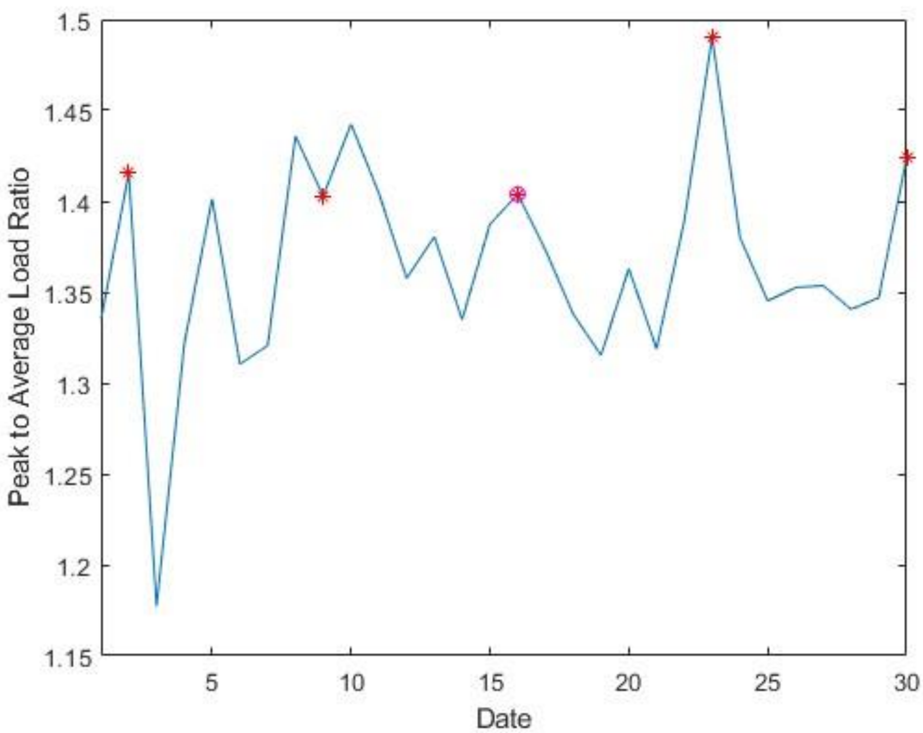


Figure D. 6: Peak to Average Demand Ratio in June 2019

July

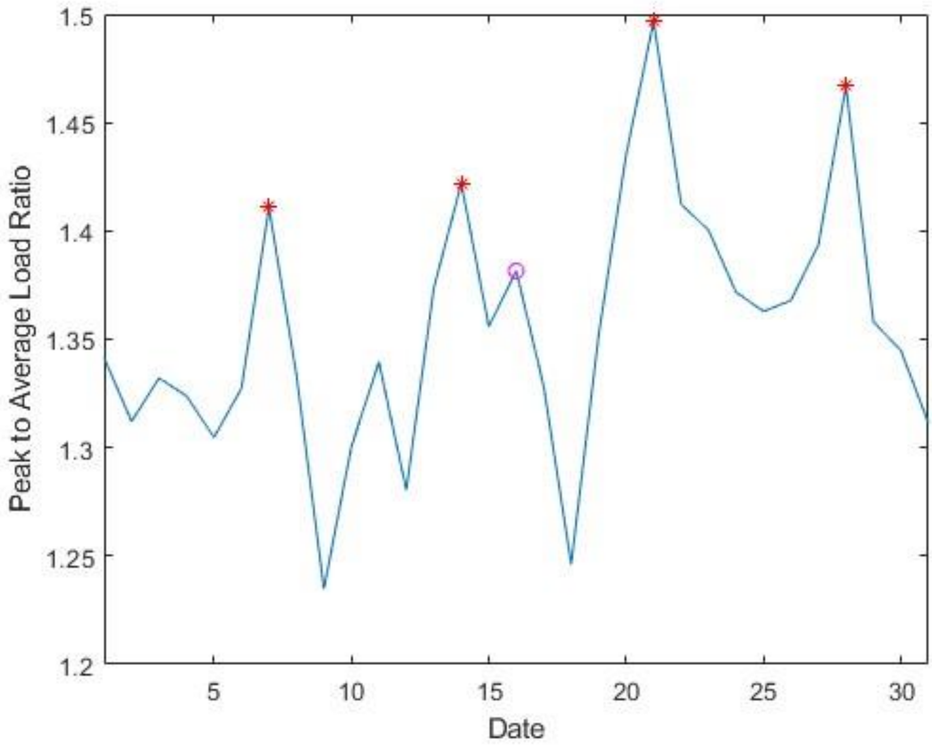


Figure D. 7: Peak to Average Demand Ratio in July 2019

August

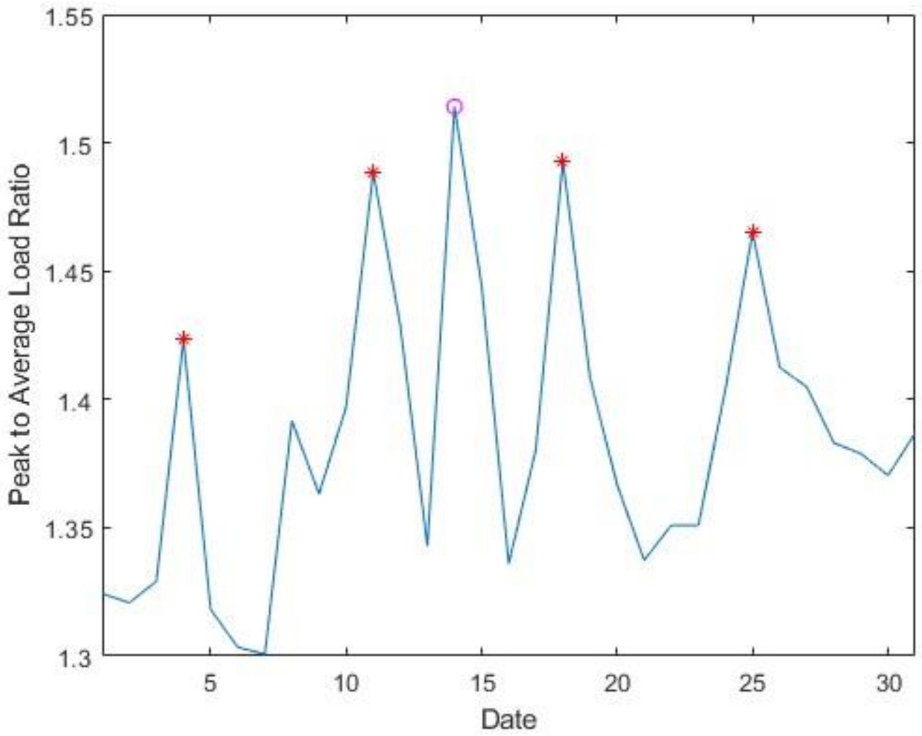


Figure D. 8: Peak to Average Demand Ratio in August 2019

September

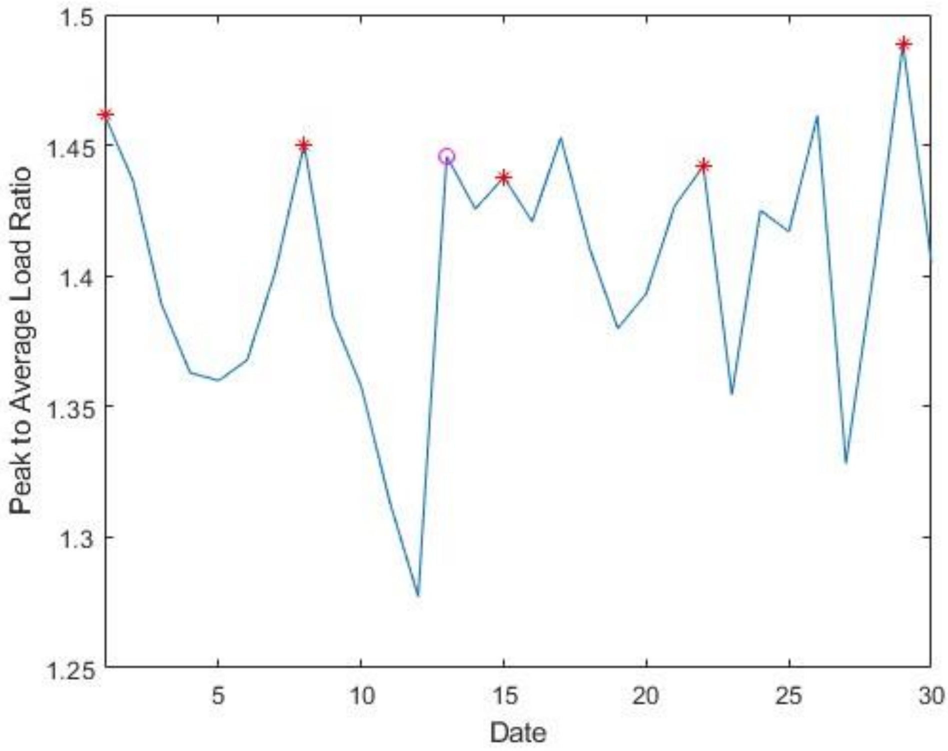


Figure D. 9: Peak to Average Demand Ratio in September 2019

October

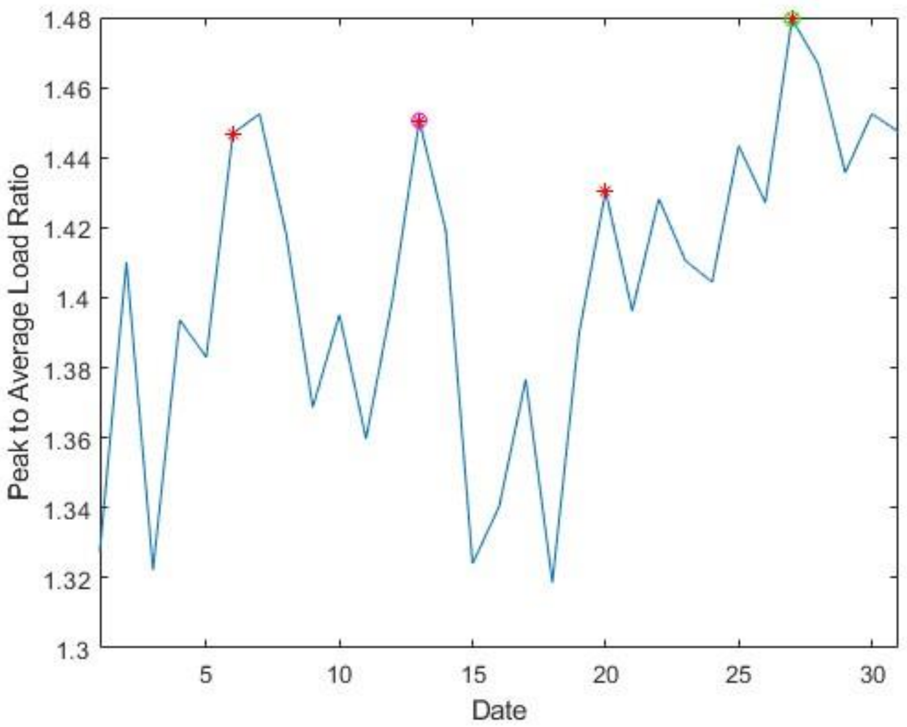


Figure D. 10: Peak to Average Demand Ratio in October 2019

November

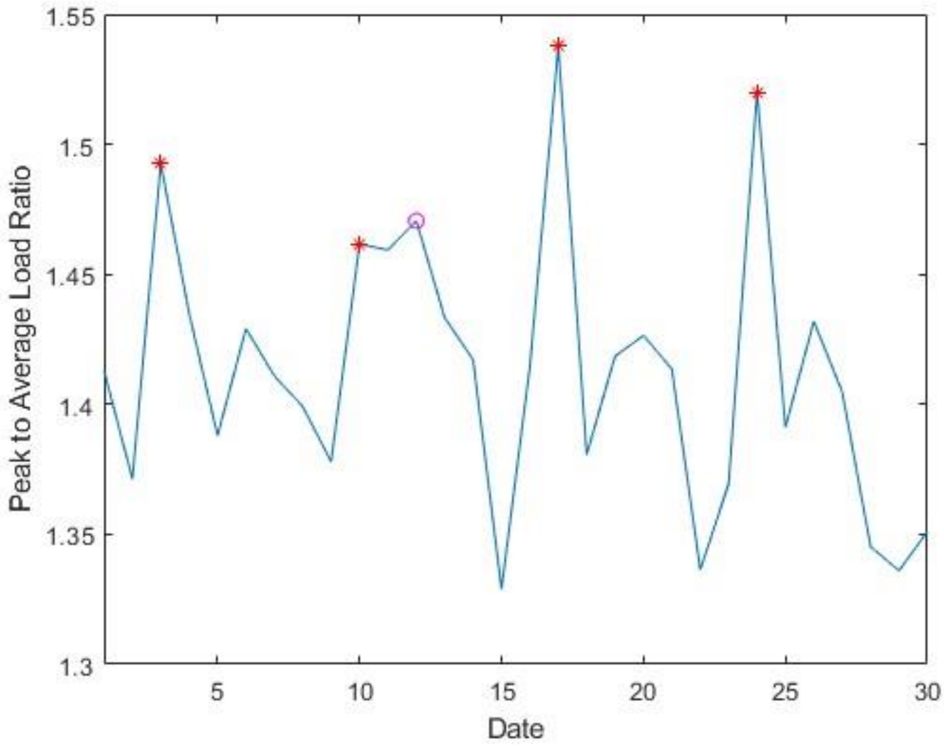


Figure D. 11: Peak to Average Demand Ratio in November 2019

December

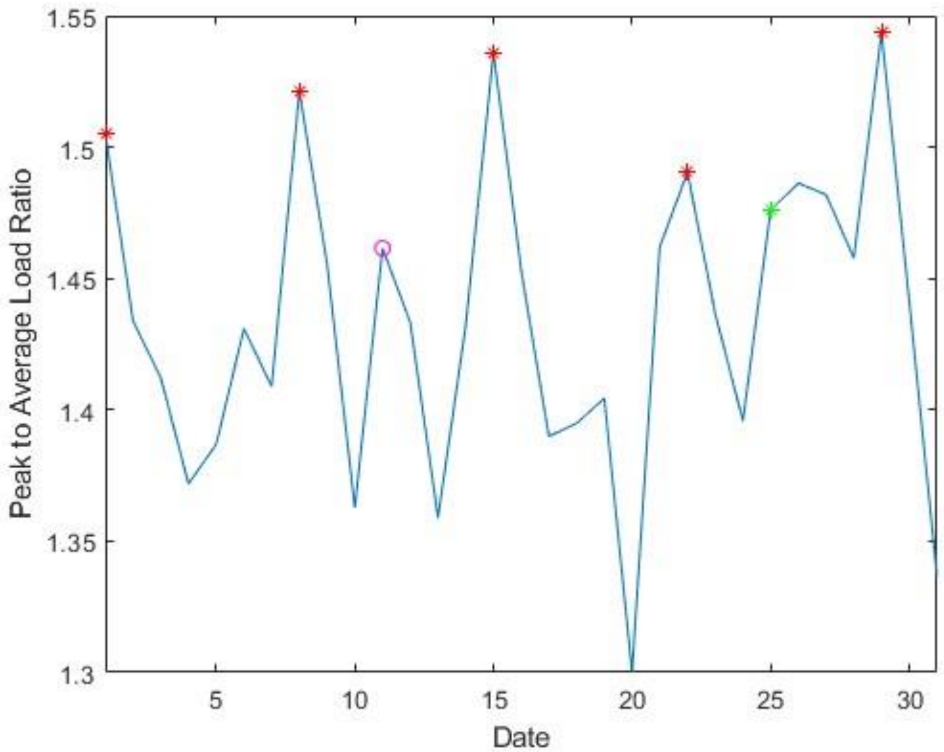


Figure D. 12: Peak to Average Demand Ratio in December 2019

[Appendix E- Monthly Generation Cost of 2019: Calculated by method 01]

January

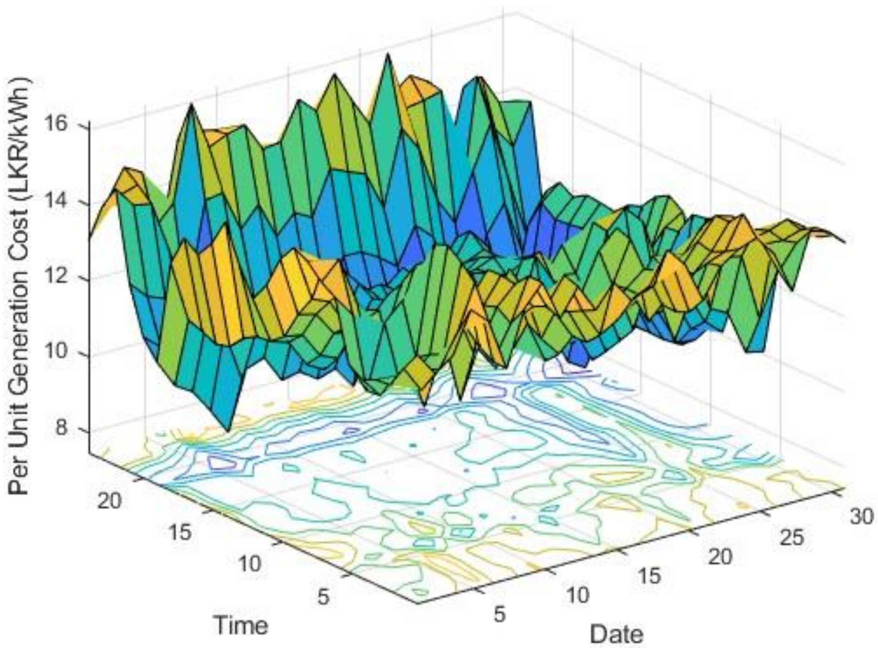


Figure E. 1: Generation Cost of January 2019 with zero water value.

February

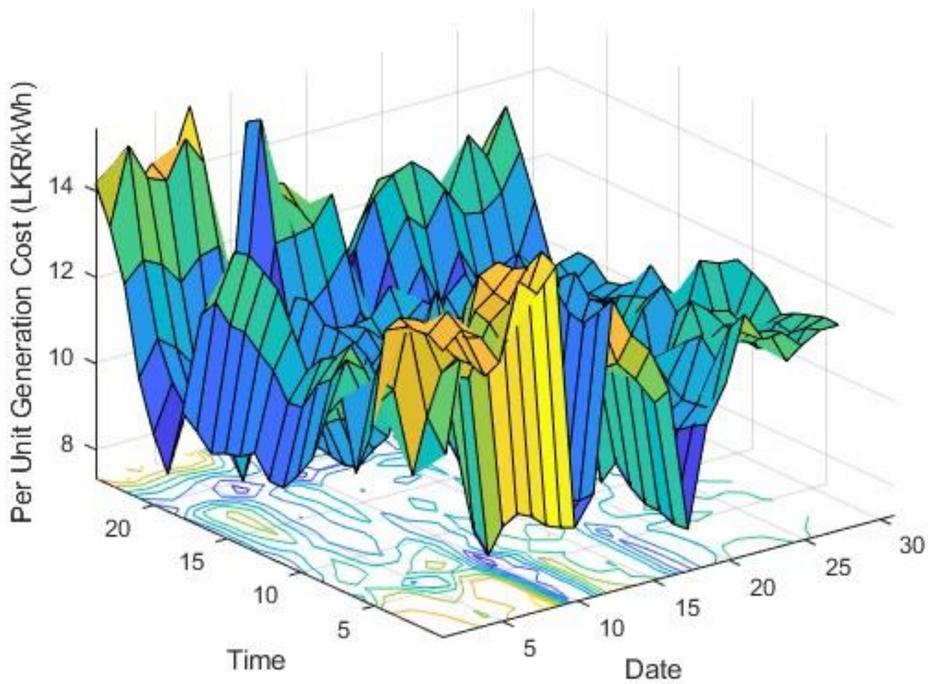


Figure E. 2: Generation Cost of February 2019 with zero water value.

March

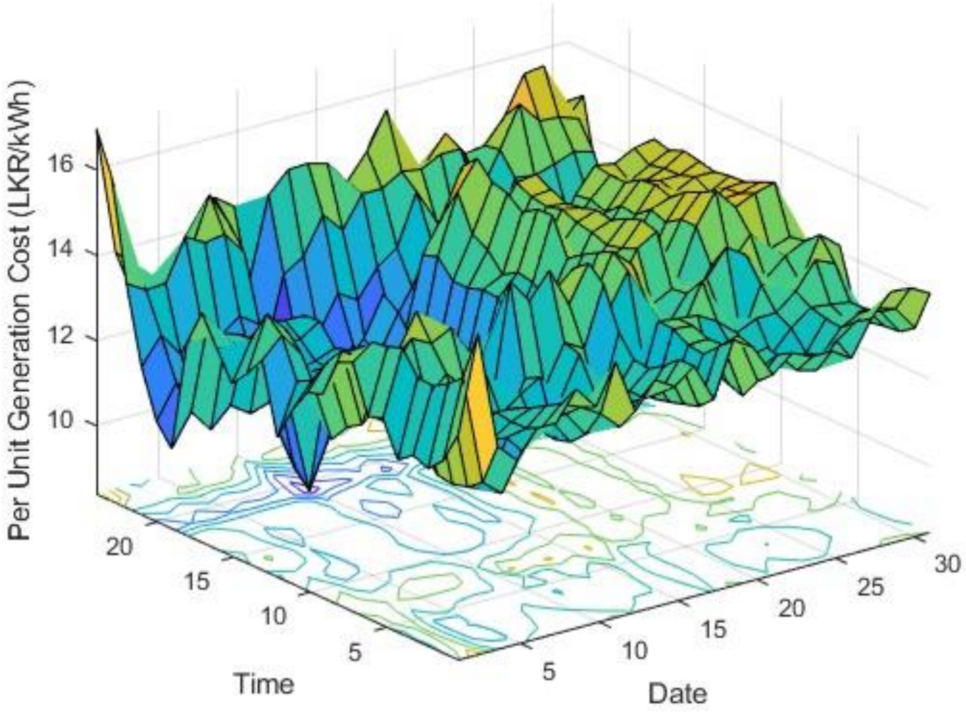


Figure E. 3: Generation Cost of March 2019 with zero water value.

April

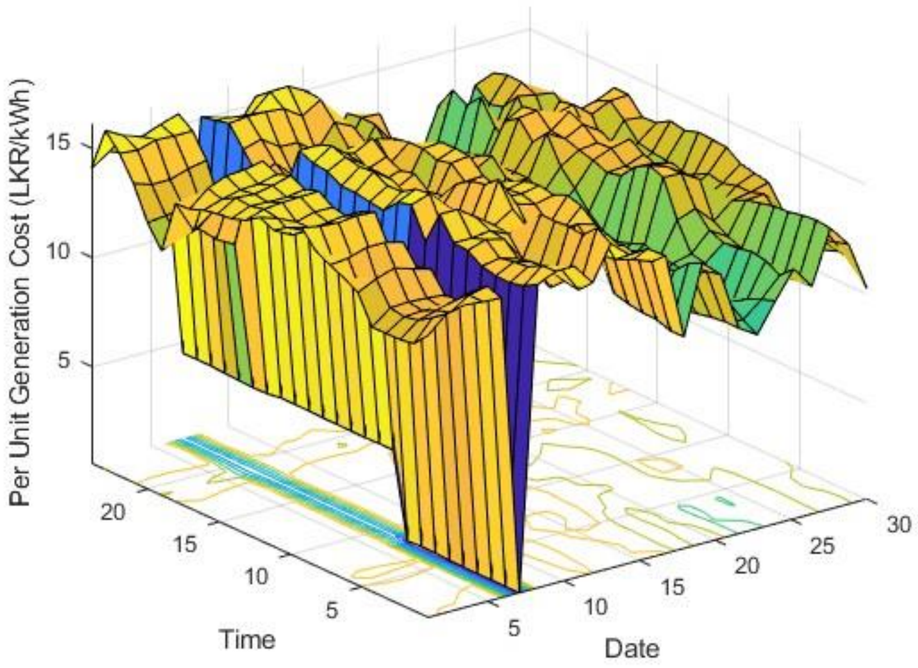


Figure E. 4: Generation Cost of April 2019 with zero water value.

May

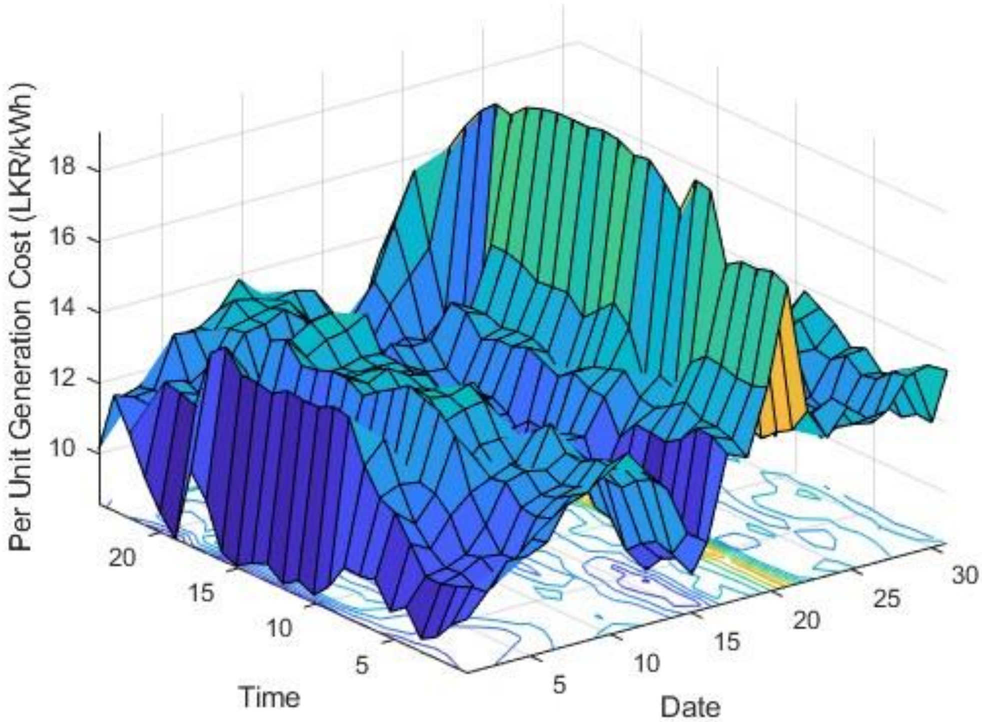


Figure E. 5: Generation Cost of May 2019 with zero water value.

June

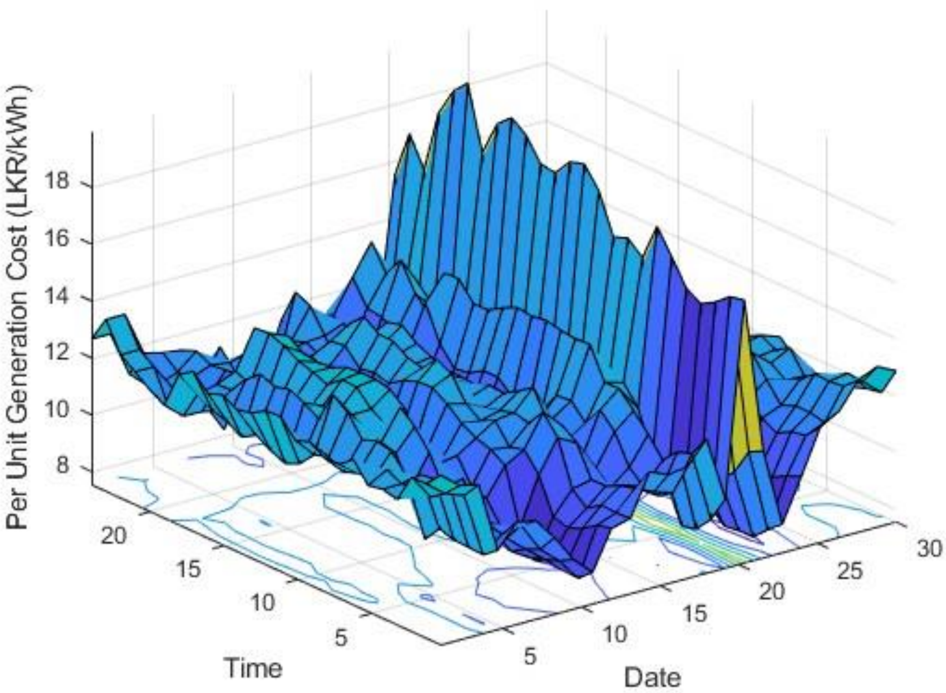


Figure E. 6: Generation Cost of June 2019 with zero water value.

July

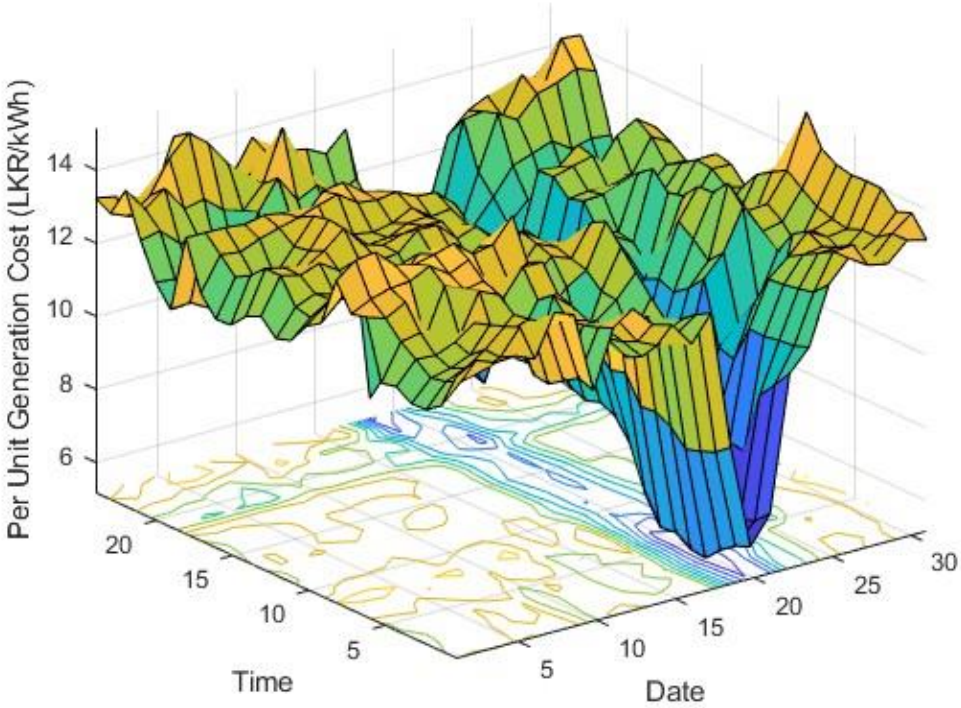


Figure E. 7: Generation Cost of July 2019 with zero water value.

August

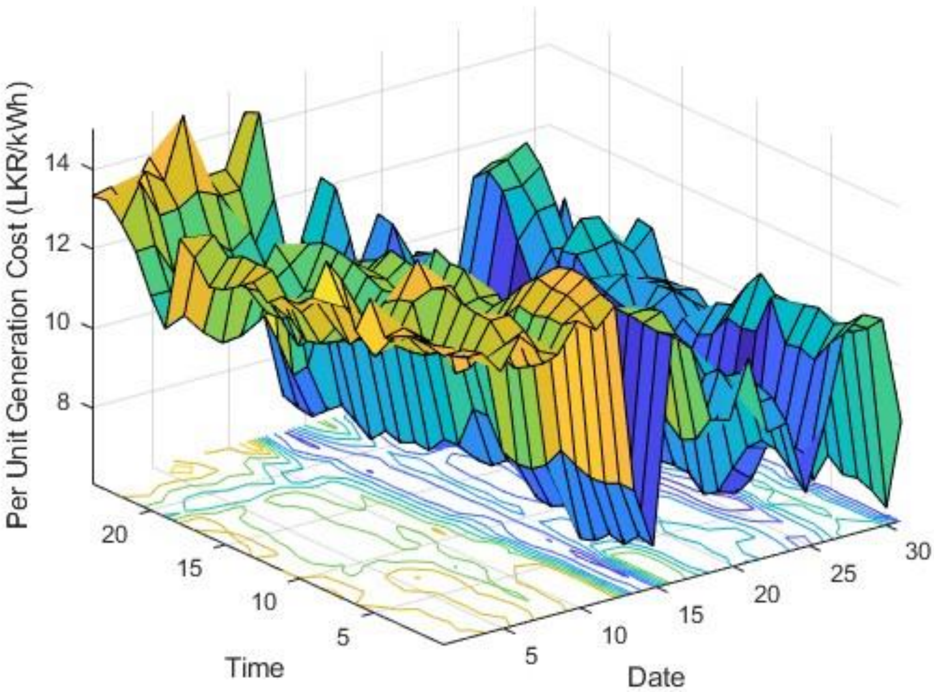


Figure E. 8: Generation Cost of August 2019 with zero water value.

September

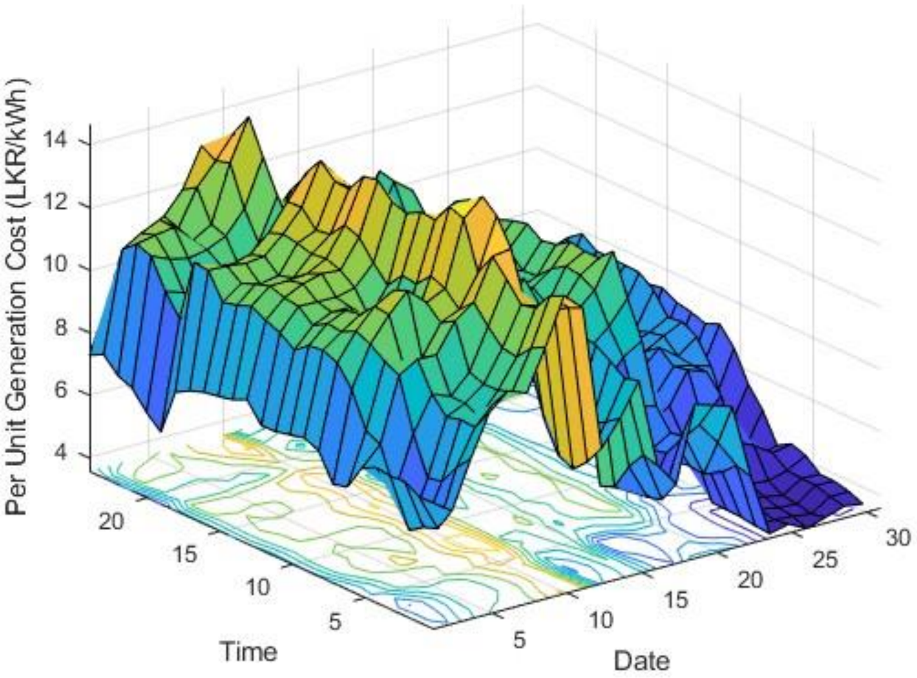


Figure E. 9: Generation Cost of September 2019 with zero water value.

October

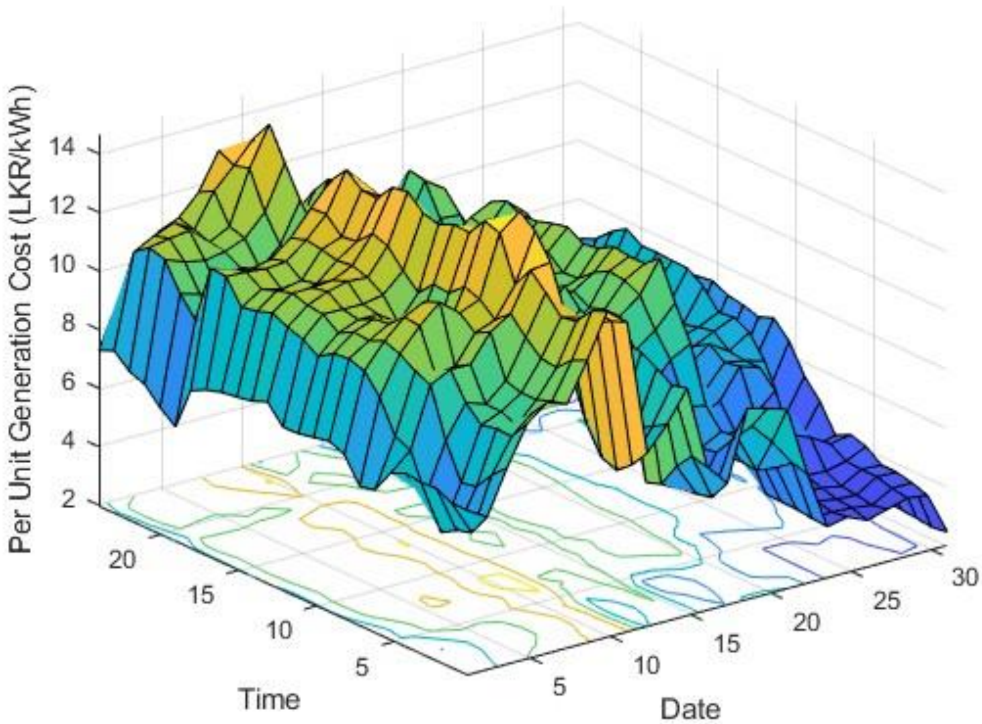


Figure E. 10: Generation Cost of October 2019 with zero water value.

November

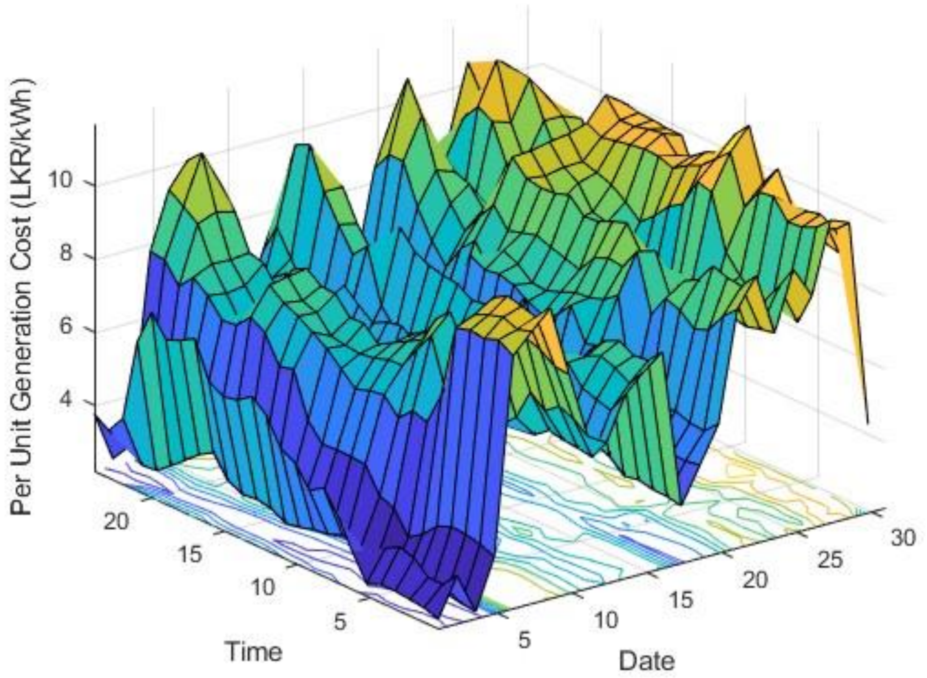


Figure E. 11: Generation Cost of November 2019 with zero water value.

December

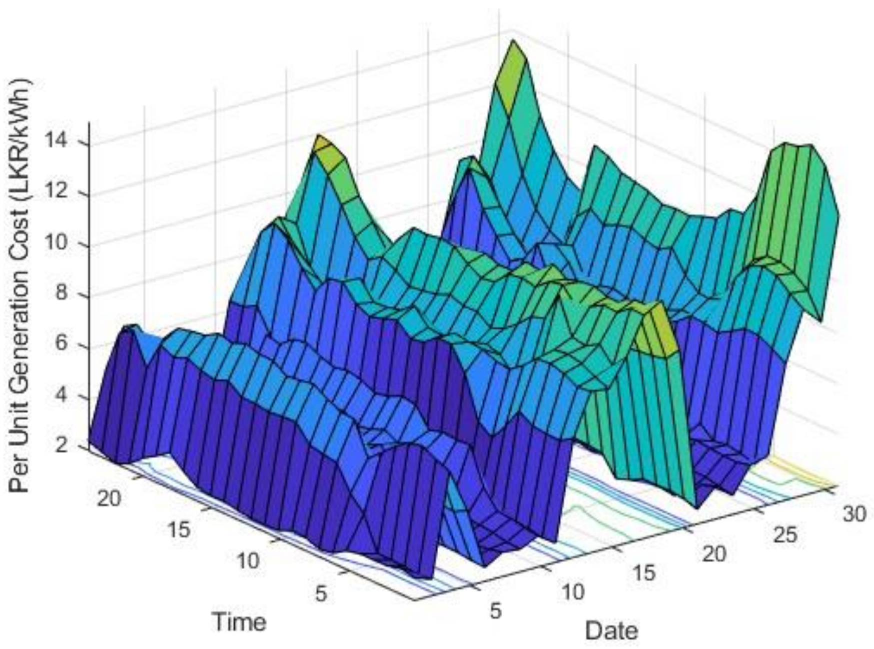


Figure E. 12: Generation Cost of December 2019 with zero water value.

[Appendix F- Total Demand in 2019]

January

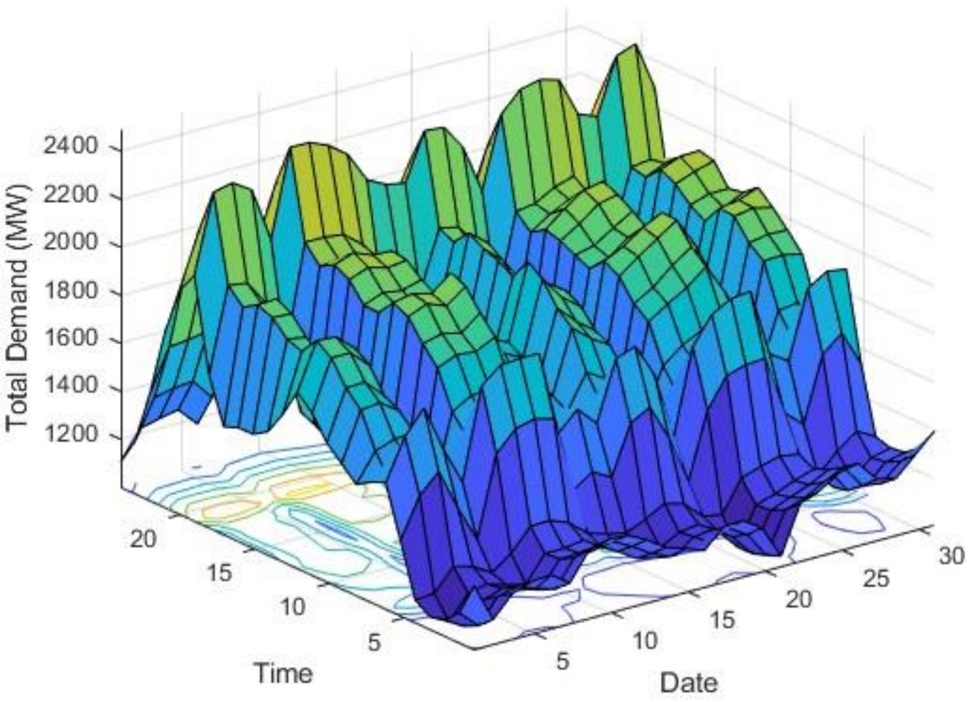


Figure F. 1: Total Demand in January 2019

February

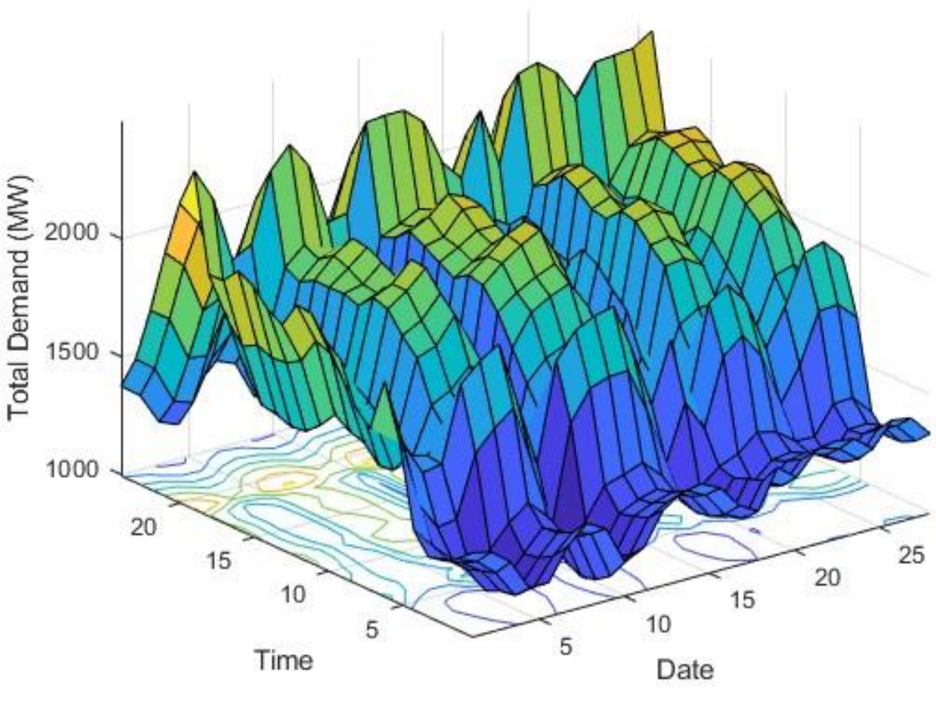


Figure F. 2: Total Demand in February 2019

March

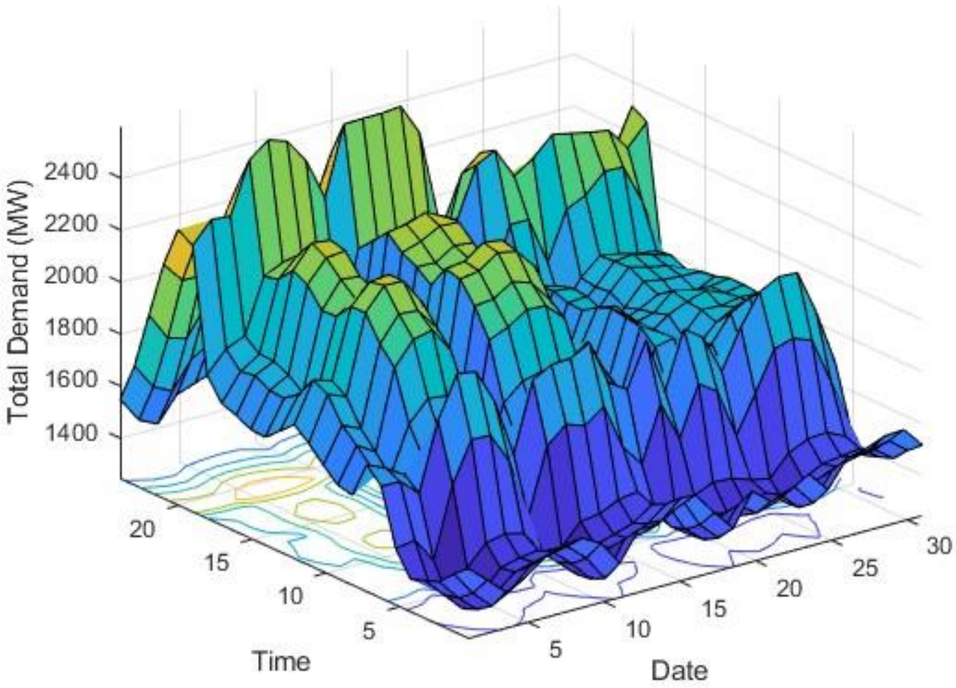


Figure F. 3: Total Demand in March 2019

April

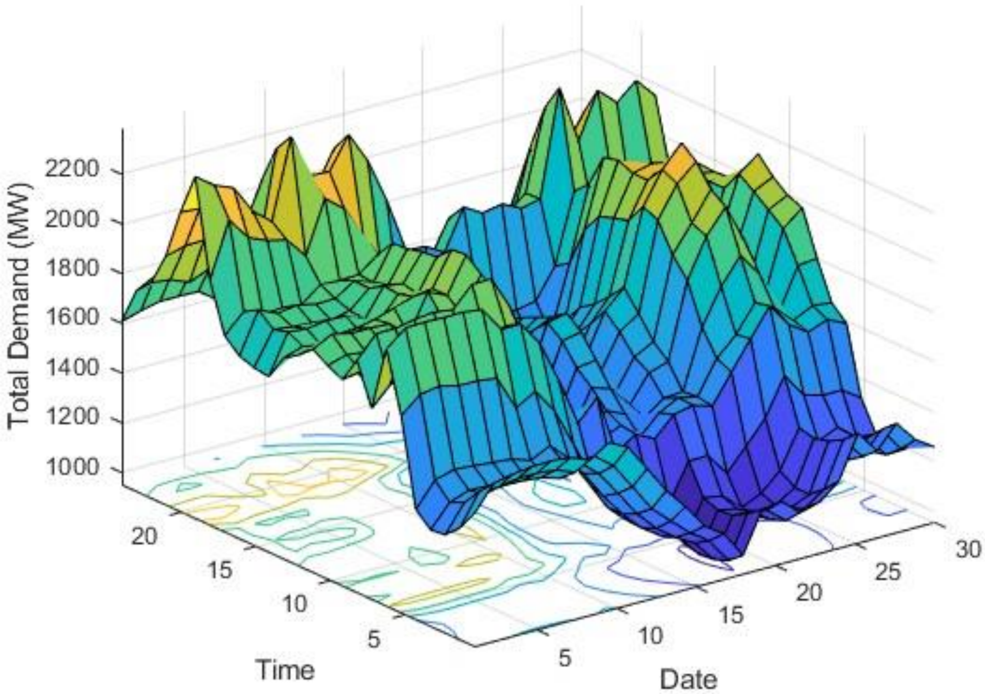


Figure F. 4: Total Demand in April 2019

May

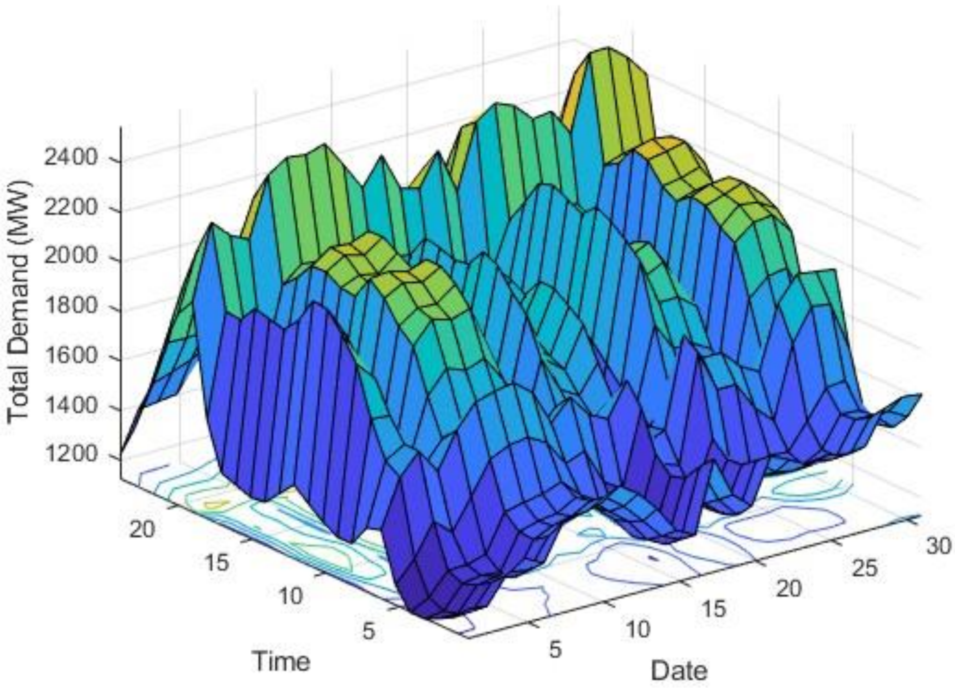


Figure F. 5: Total Demand in May 2019

June

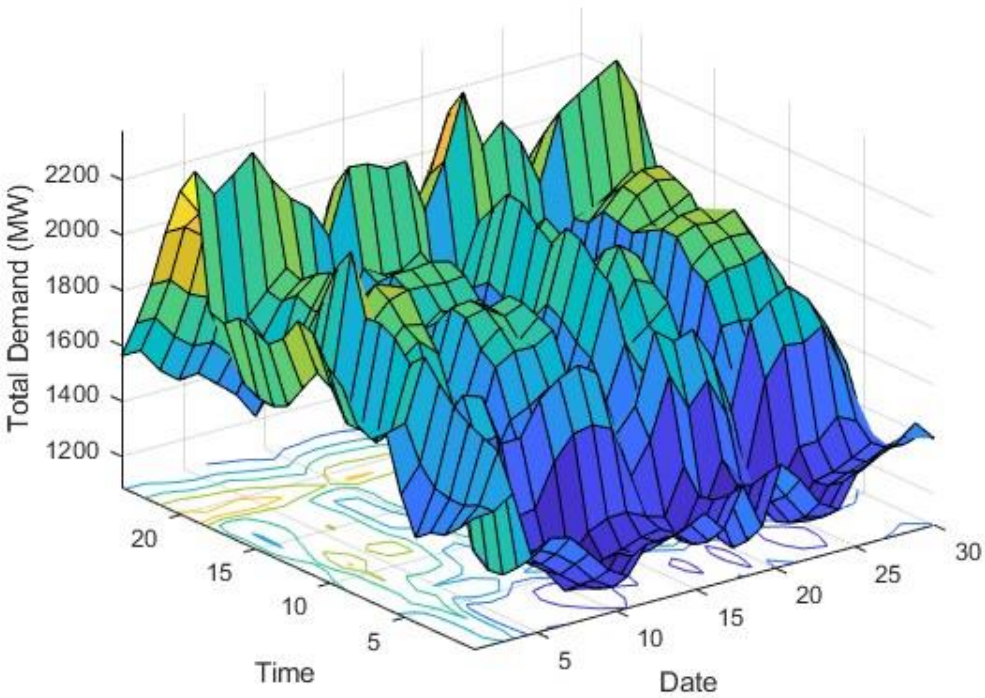


Figure F. 6: Total Demand in June 2019

July

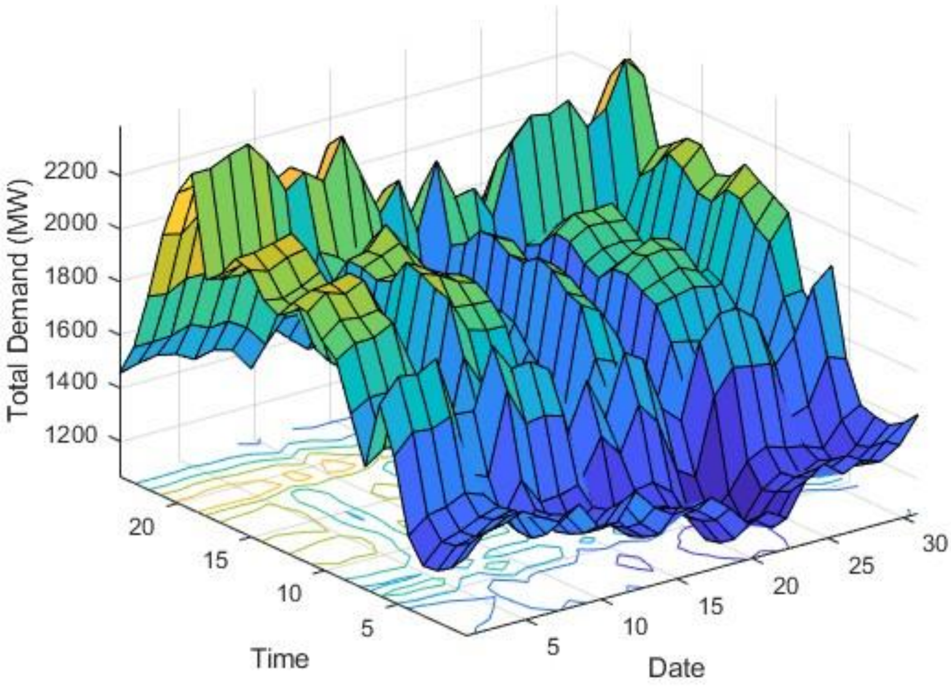


Figure F. 7: Total Demand in July 2019

August

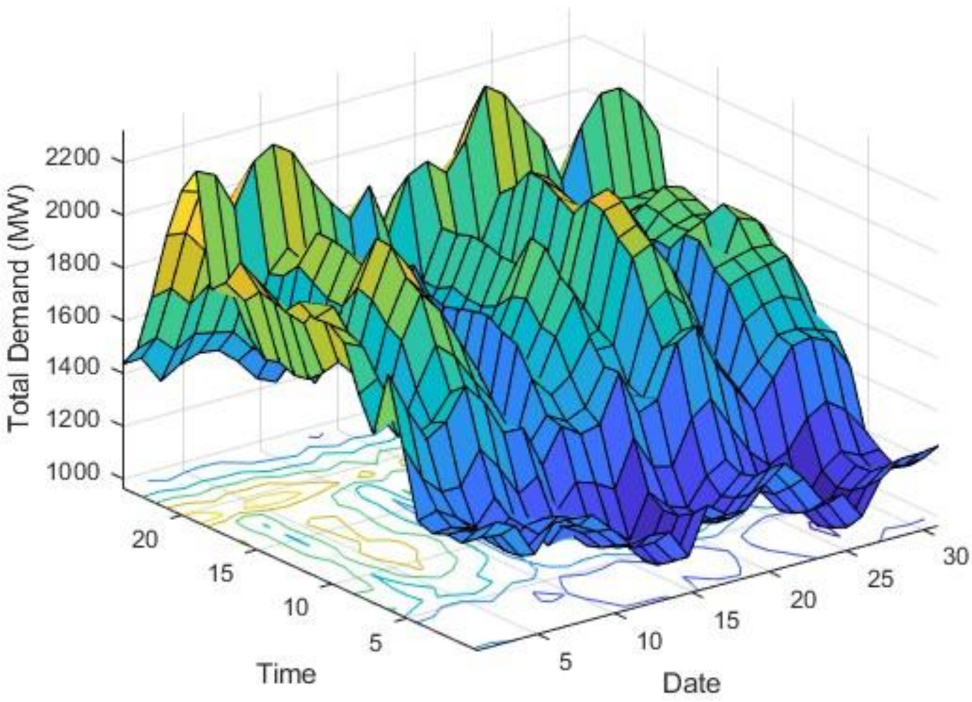


Figure F. 8: Total Demand in August 2019

September

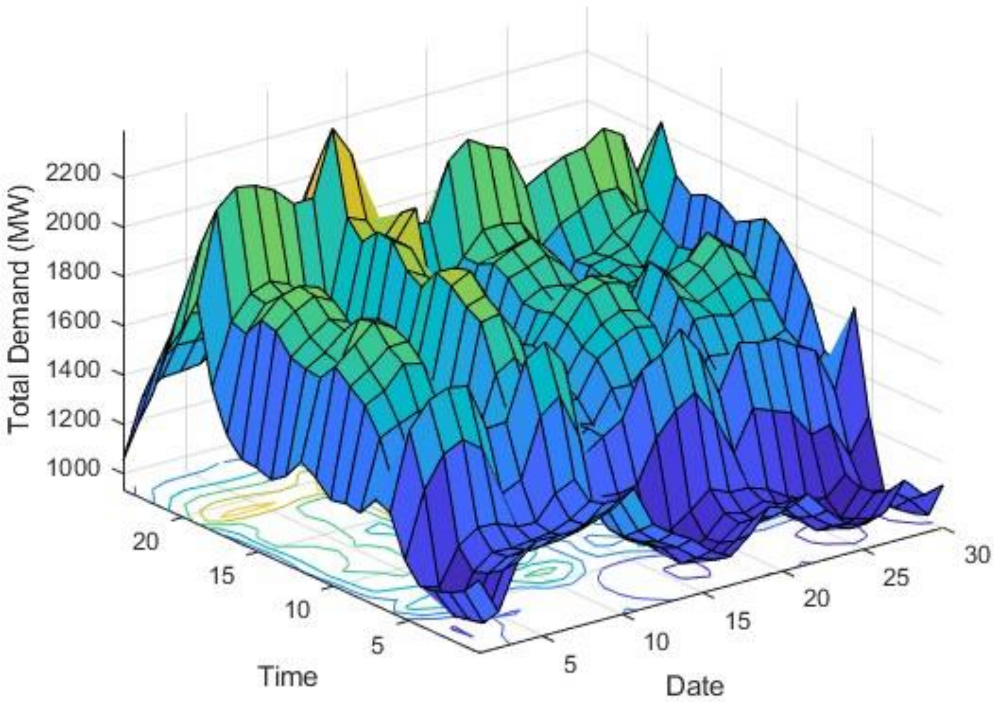


Figure F. 9: Total Demand in September 2019

October

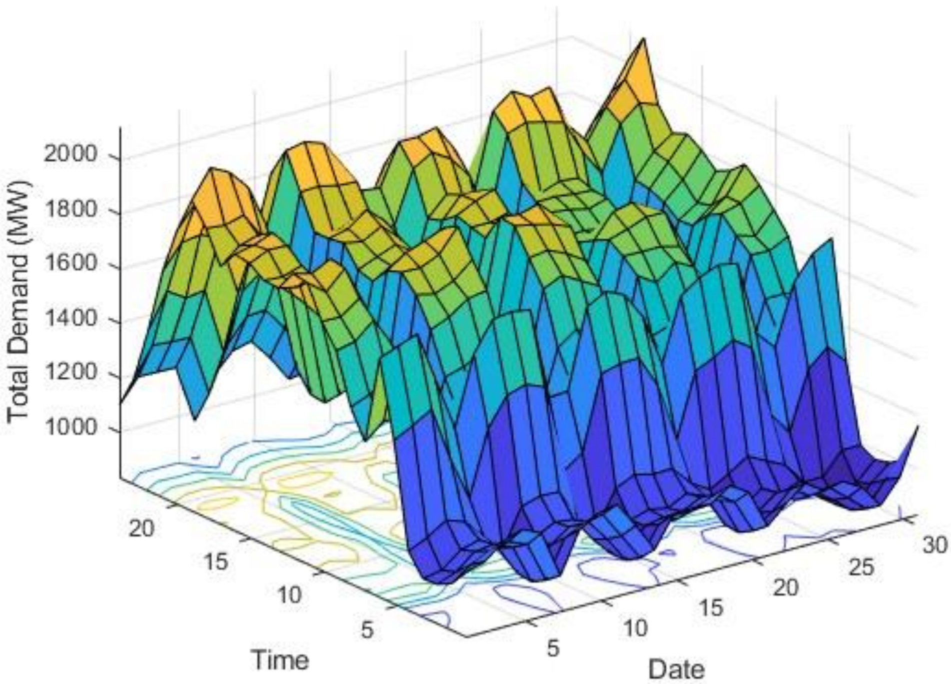


Figure F. 10: Total Demand in October 2019

November

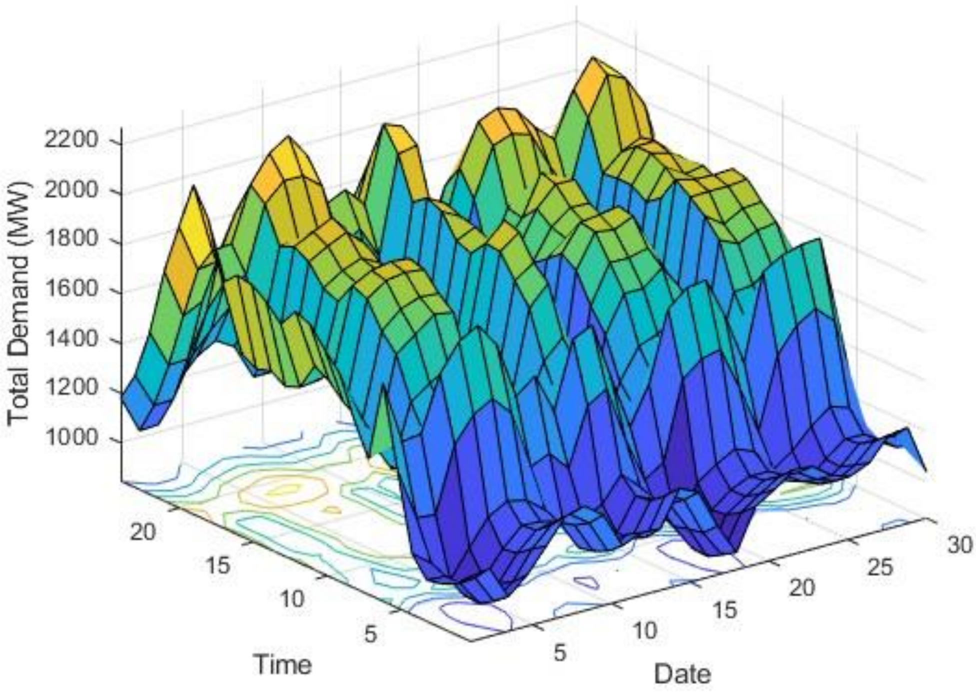


Figure F. 11: Total Demand in November 2019

December

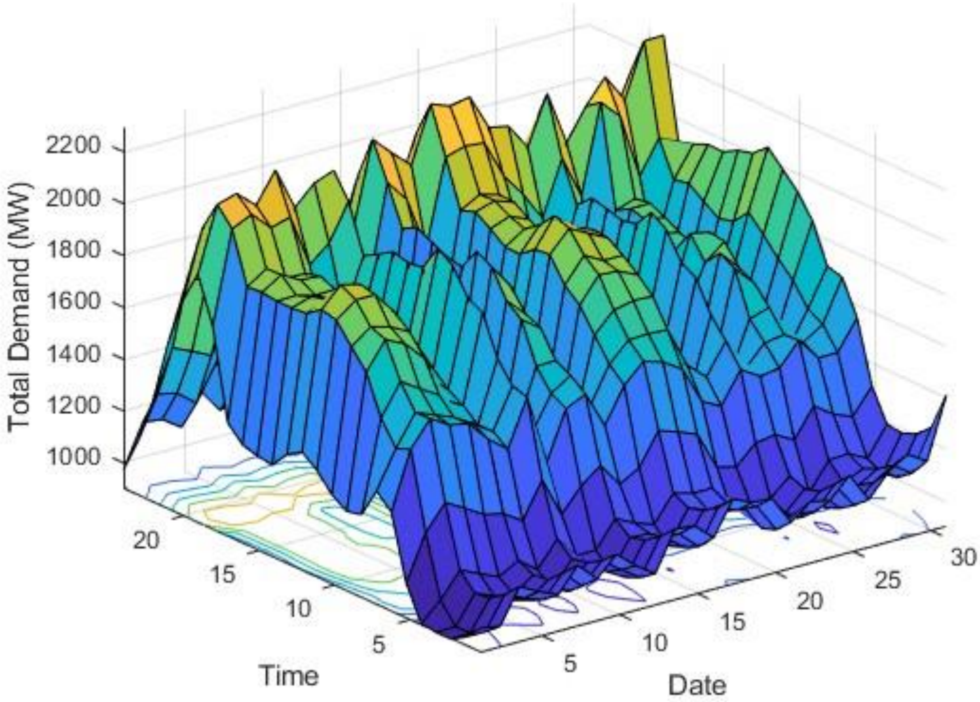


Figure F. 12: Total Demand in December 2019

[Appendix G- Daily Load Curves in January 2019]

Tuesday 1st of January 2019

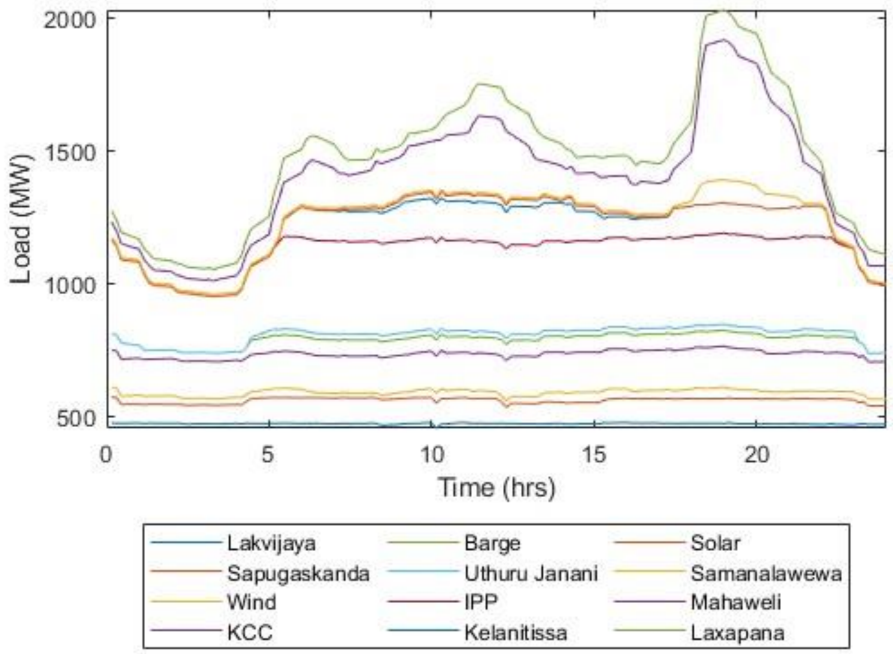


Figure G. 1: Daily Load Curve of 2019.01.01.

Wednesday 2nd of January 2019

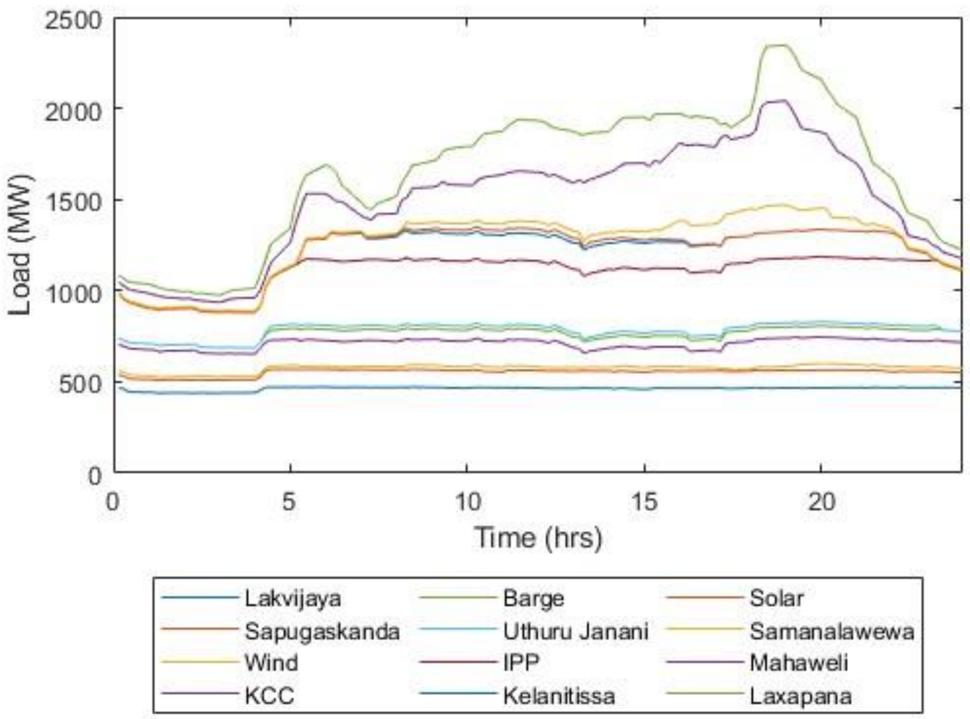


Figure G. 2: Daily Load Curve of 2019.01.02.

Thursday 3rd of January 2019

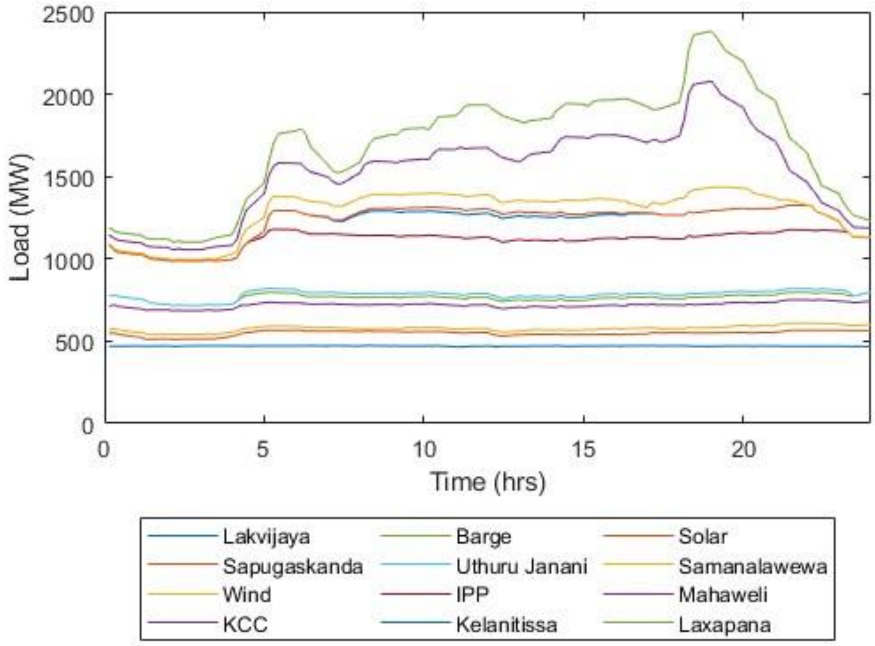


Figure G. 3: Daily Load Curve of 2019.01.03.

Friday 4th of January 2019

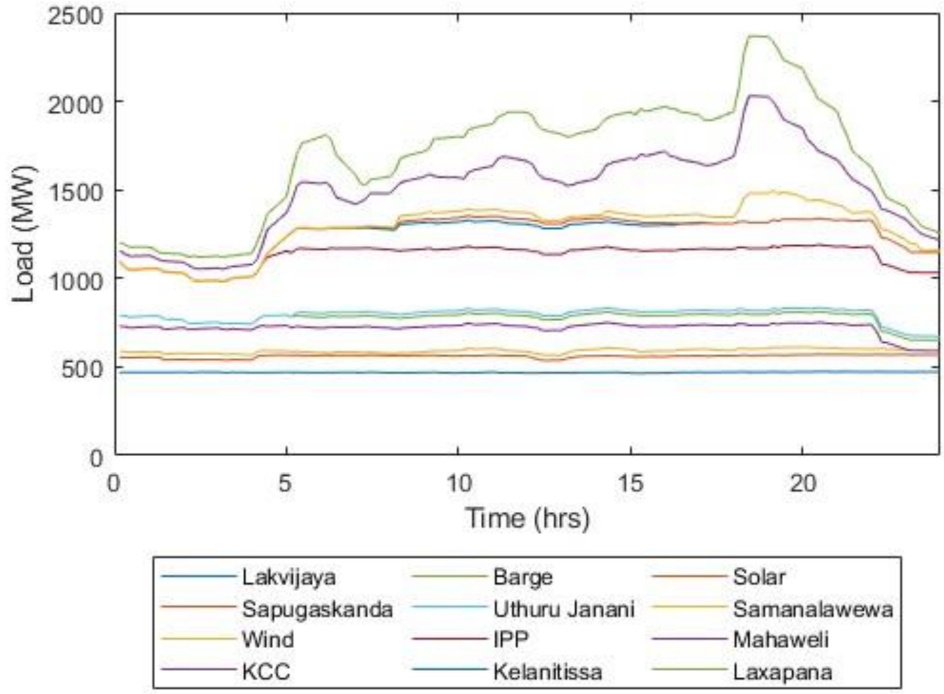


Figure G. 4: Daily Load Curve of 2019.01.04.

Saturday 5th of January 2019

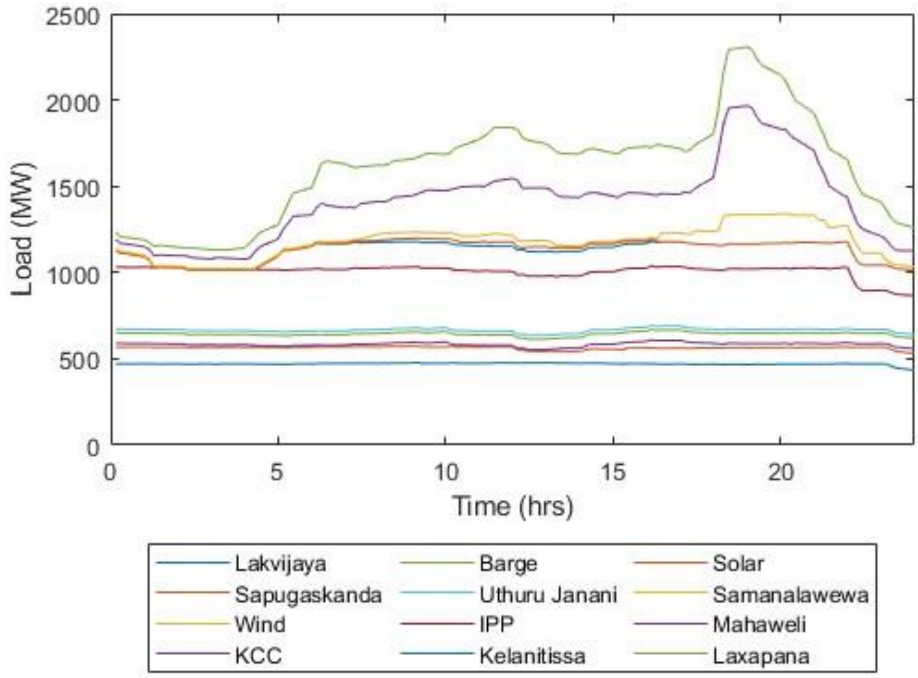


Figure G. 5: Daily Load Curve of 2019.01.05.

Sunday 6th of January 2019

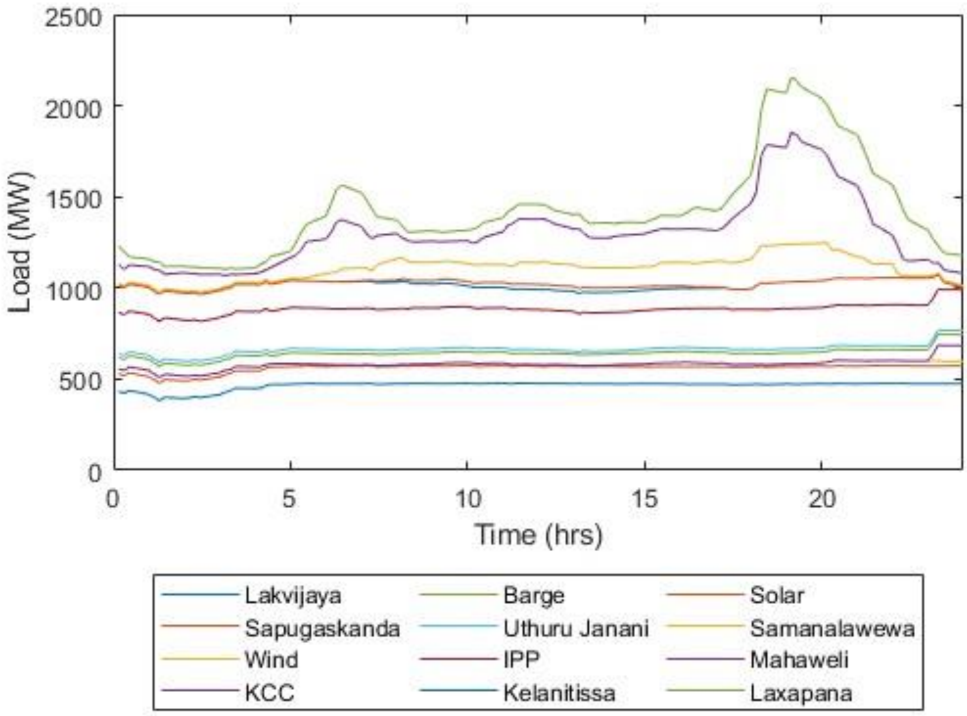


Figure G. 6: Daily Load Curve of 2019.01.06.

Monday 7th of January 2019

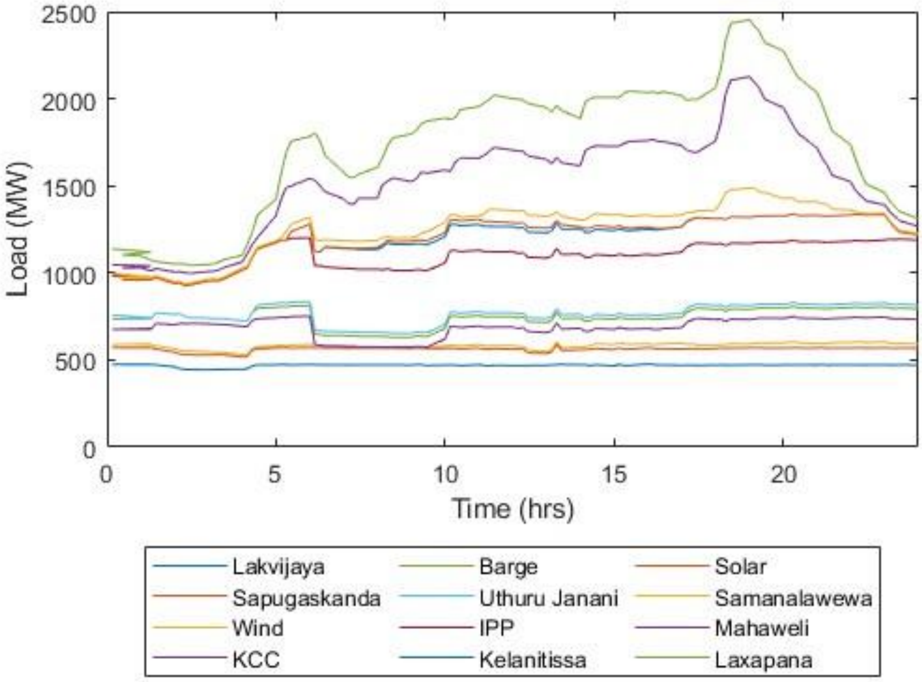


Figure G. 7: Daily Load Curve of 2019.01.07.

Tuesday 8th of January 2019

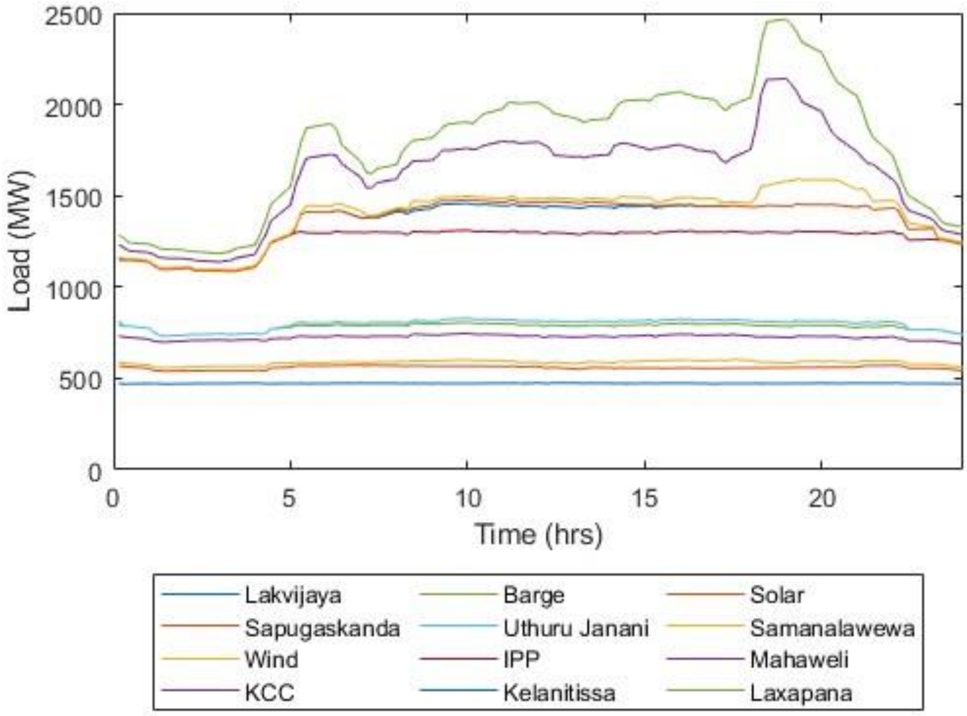


Figure G. 8: Daily Load Curve of 2019.01.08.

Wednesday 9th of January 2019

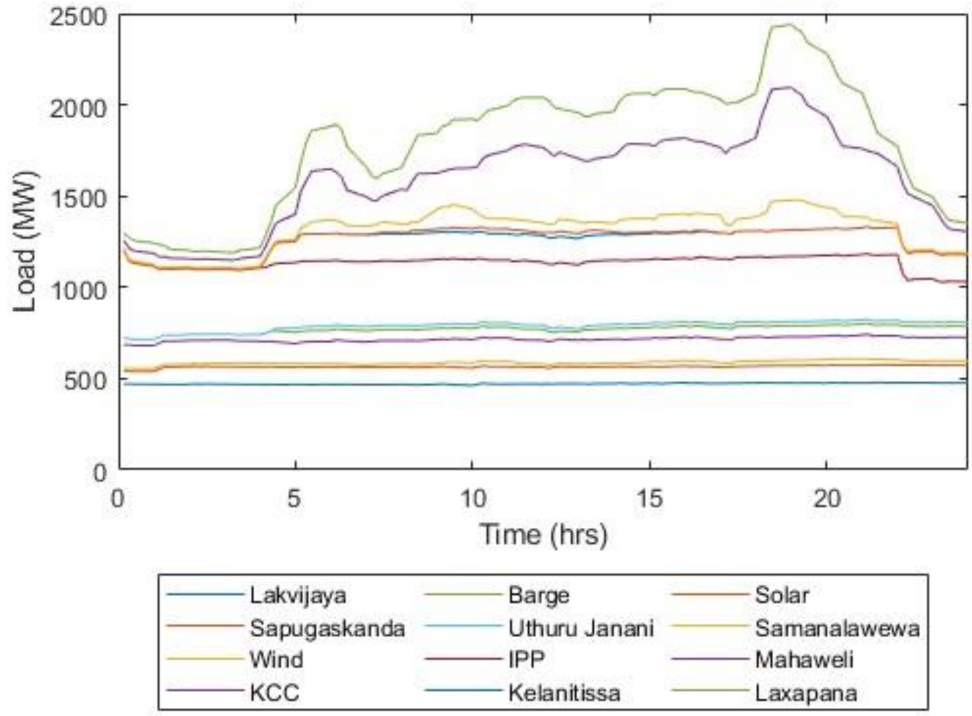


Figure G. 9: Daily Load Curve of 2019.01.09.

Thursday 10th of January 2019

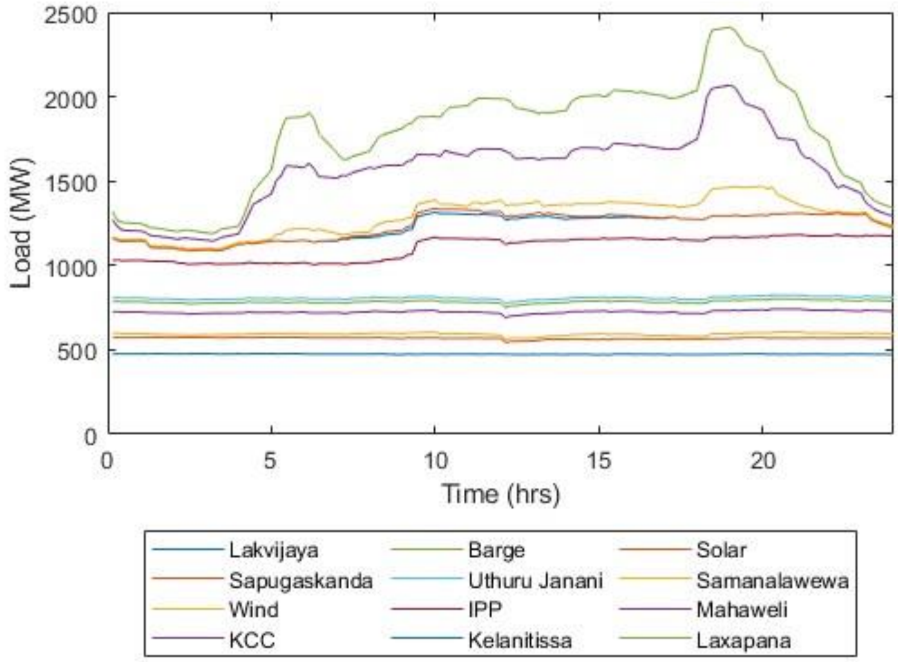


Figure G. 10: Daily Load Curve of 2019.01.10.

Friday 11th of January 2019

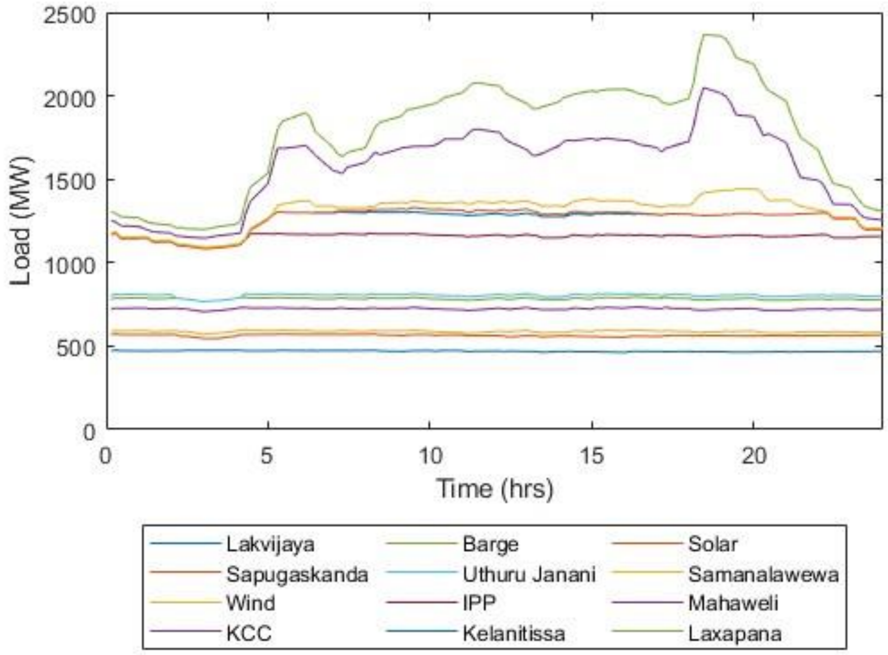


Figure G. 11: Daily Load Curve of 2019.01.11.

Saturday 12th of January 2019

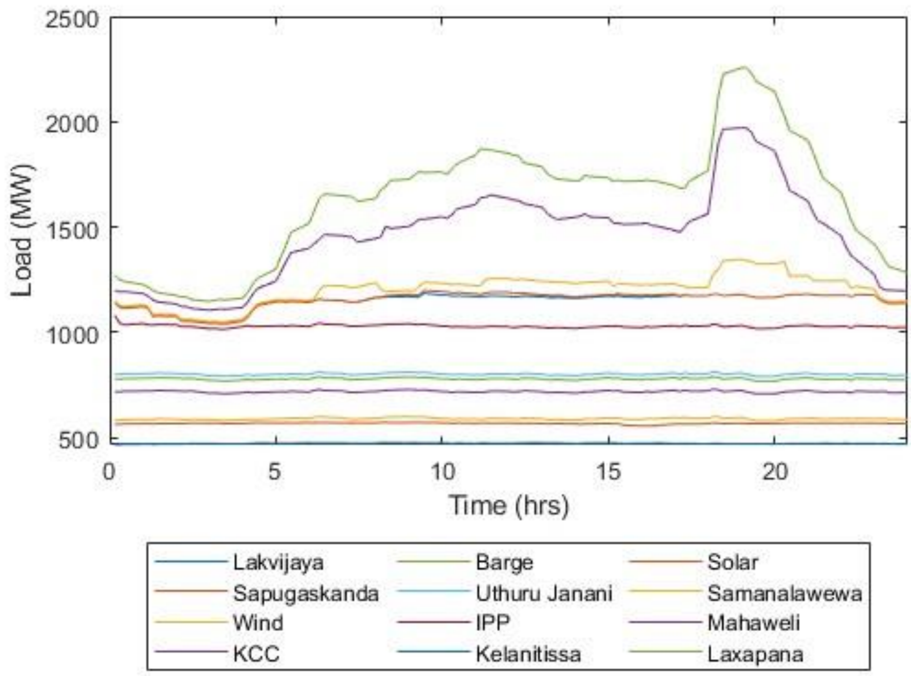


Figure G. 12: Daily Load Curve of 2019.01.12.

Sunday 13th of January 2019

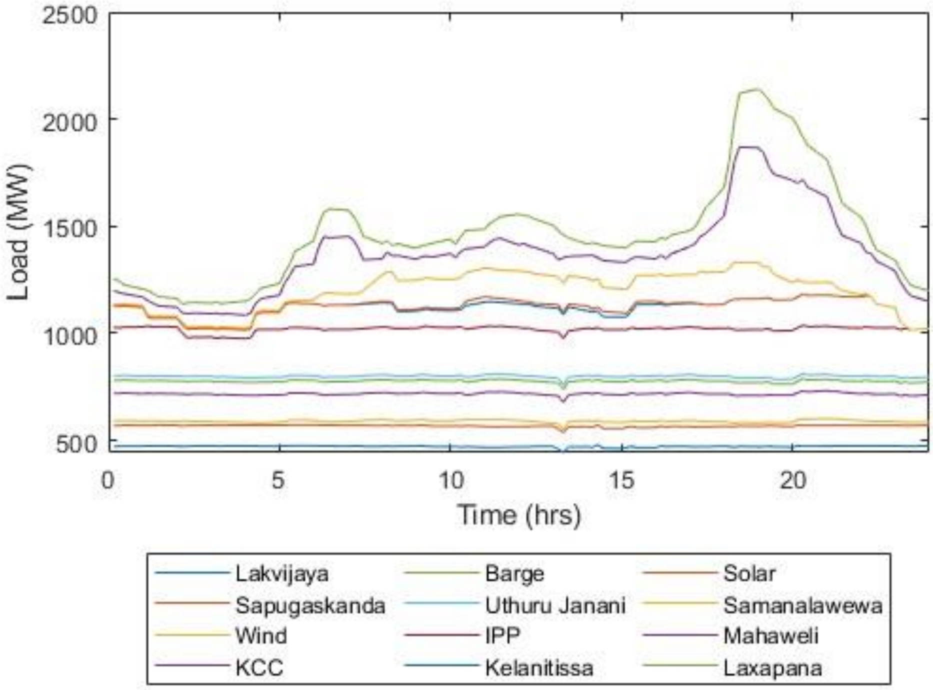


Figure G. 13: Daily Load Curve of 2019.01.13.

Monday 14th of January 2019

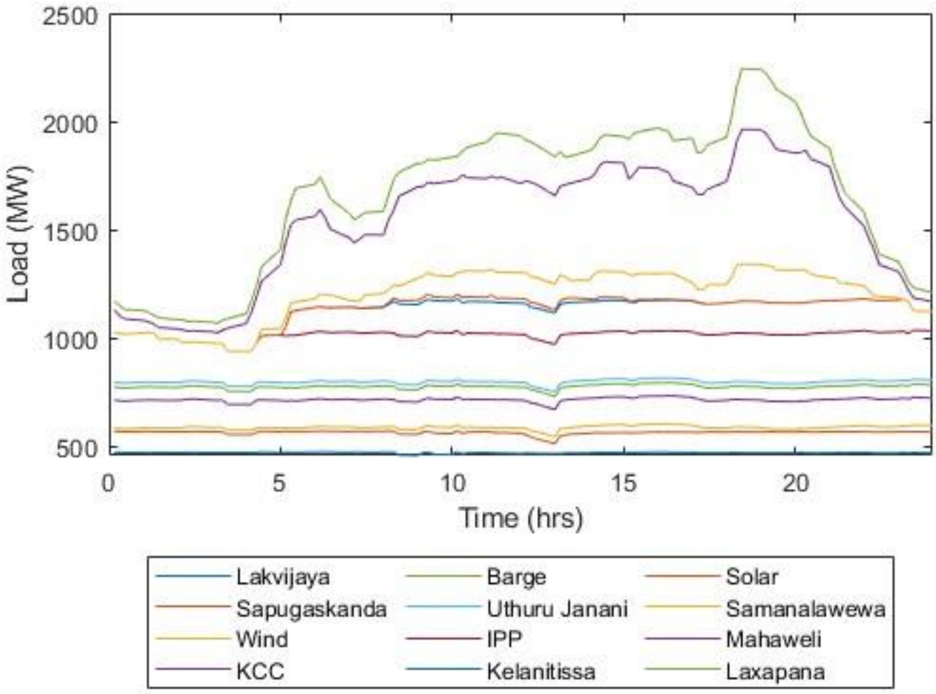


Figure G. 14: Daily Load Curve of 2019.01.14.

Tuesday 15th of January 2019

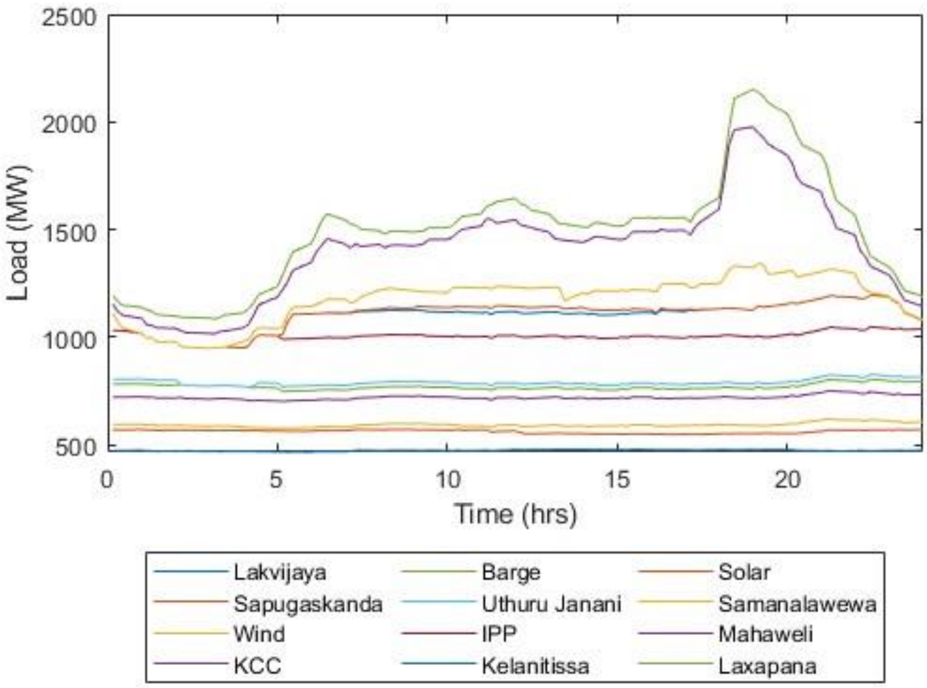


Figure G. 15: Daily Load Curve of 2019.01.15.

Wednesday 16thof January 2019

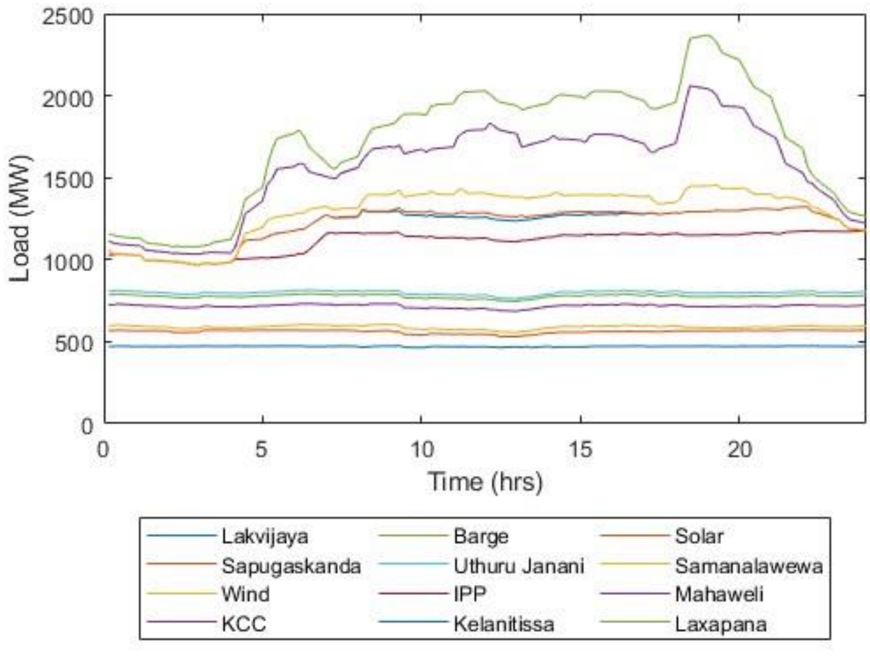


Figure G. 16: Daily Load Curve of 2019.01.16.

Thursday 17th of January 2019

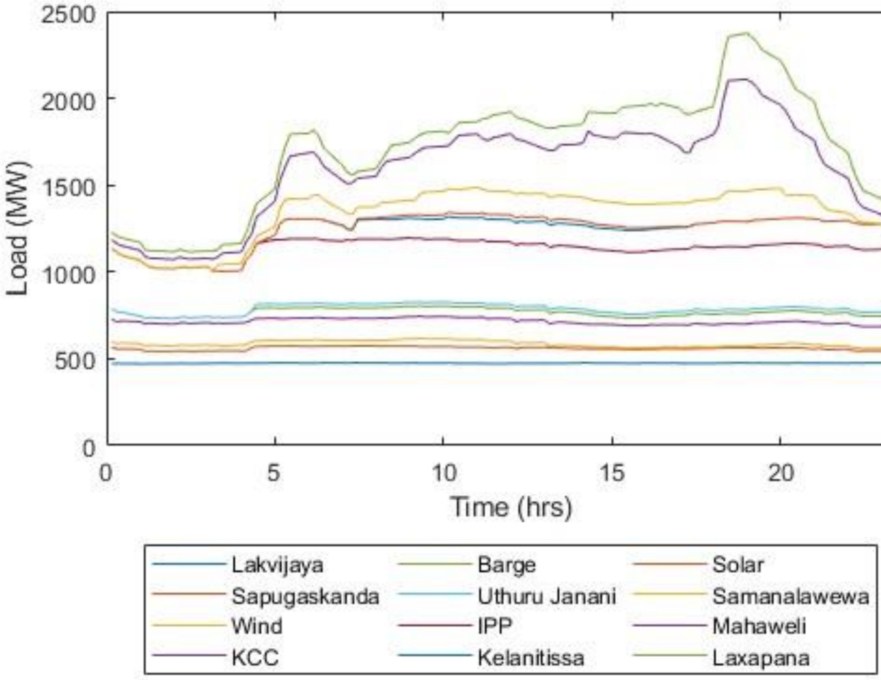


Figure G. 17: Daily Load Curve of 2019.01.17.

Friday 18th of January 2019

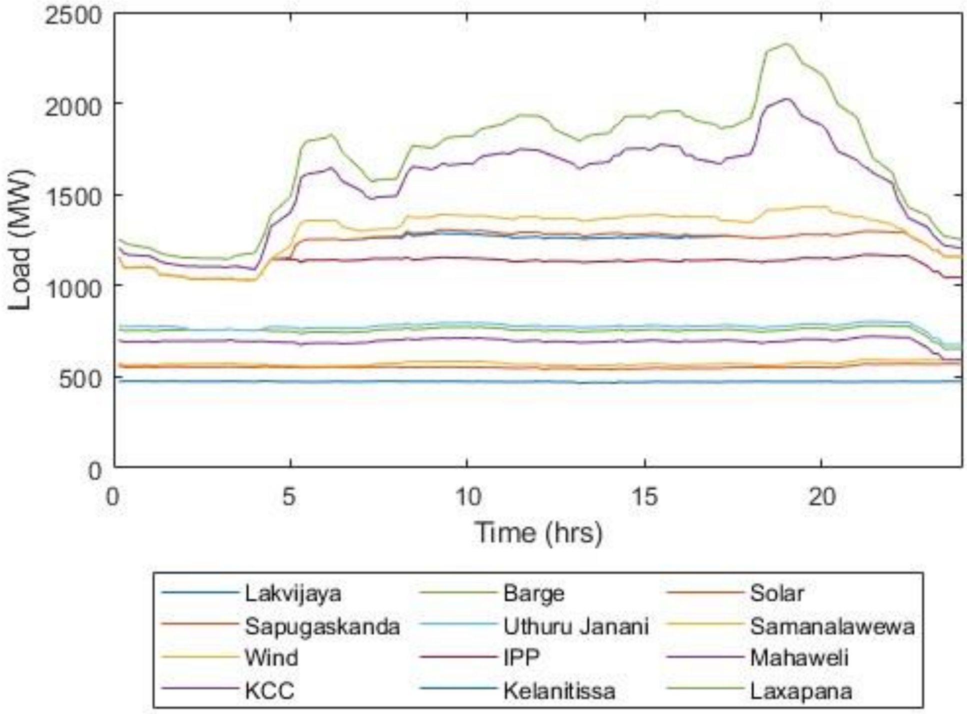


Figure G. 18: Daily Load Curve of 2019.01.18.

Saturday 19th of January 2019

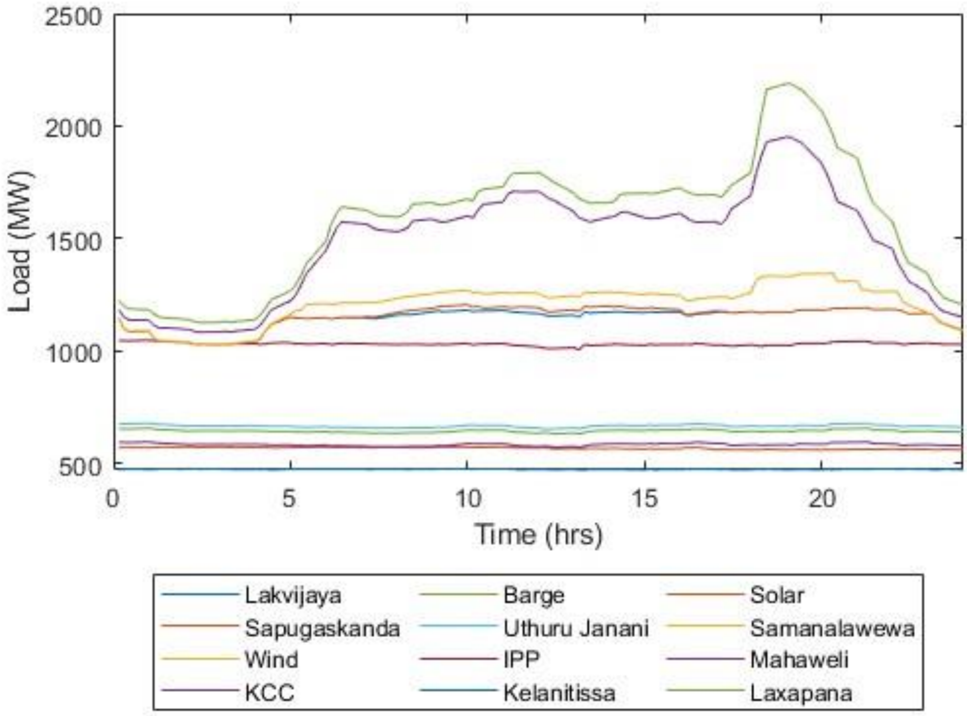


Figure G. 19: Daily Load Curve of 2019.01.19.

Sunday 20th of January 2019

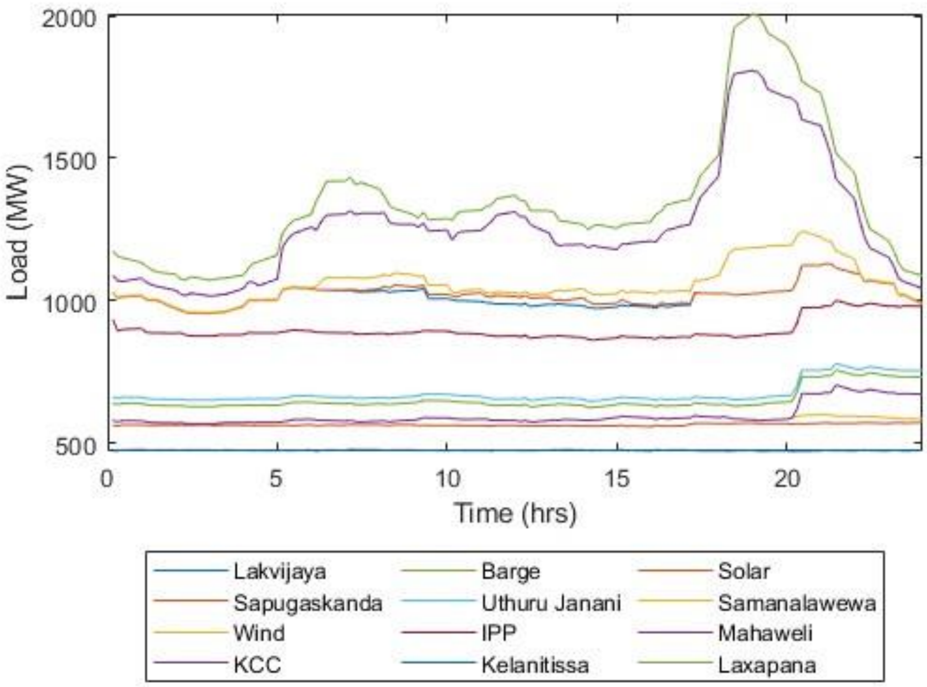


Figure G. 20: Daily Load Curve of 2019.01.20.

Monday 21st of January 2019

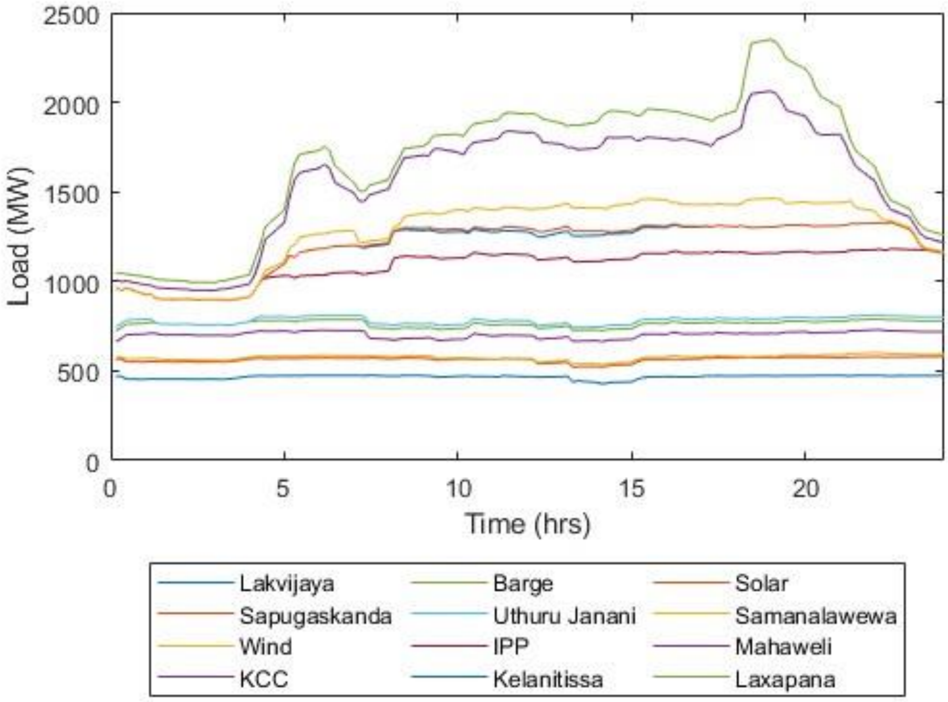


Figure G. 21: Daily Load Curve of 2019.01.21.

Tuesday 22nd of January 2019

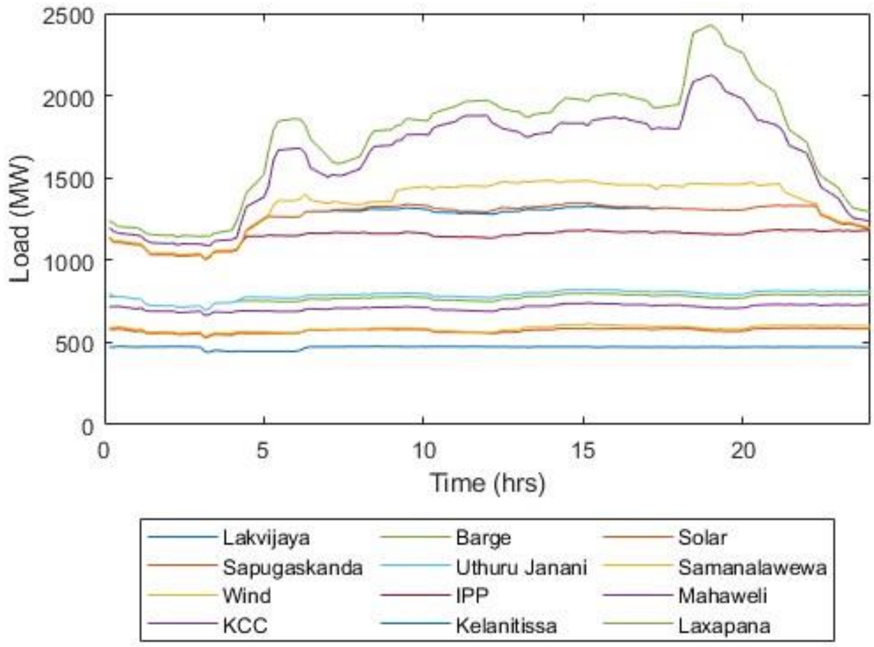


Figure G. 22: Daily Load Curve of 2019.01.22.

Wednesday 23rd of January 2019

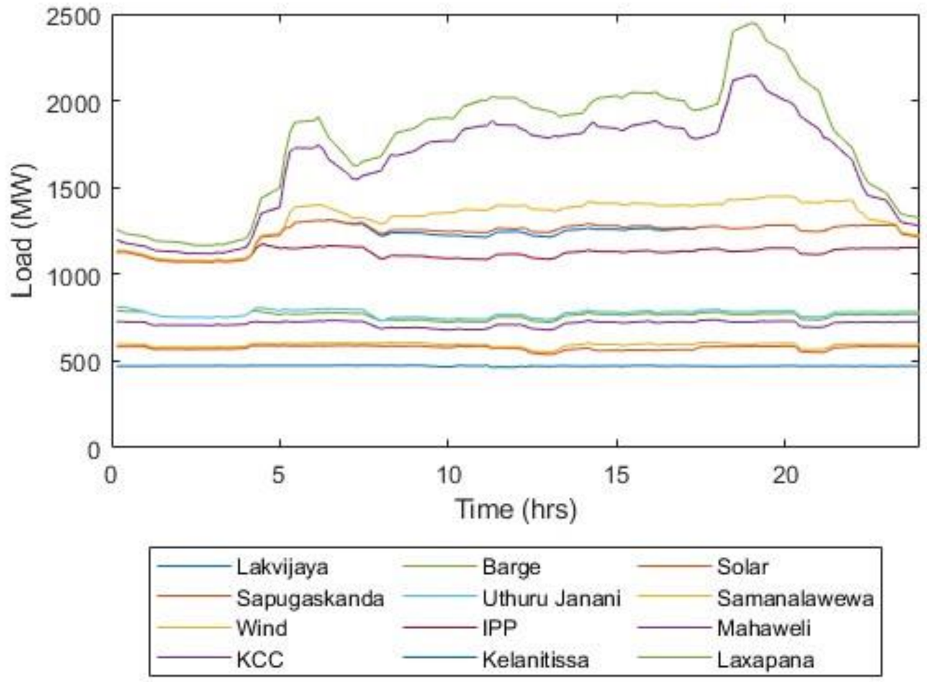


Figure G. 23: Daily Load Curve of 2019.01.23.

Thursday 24th of January 2019

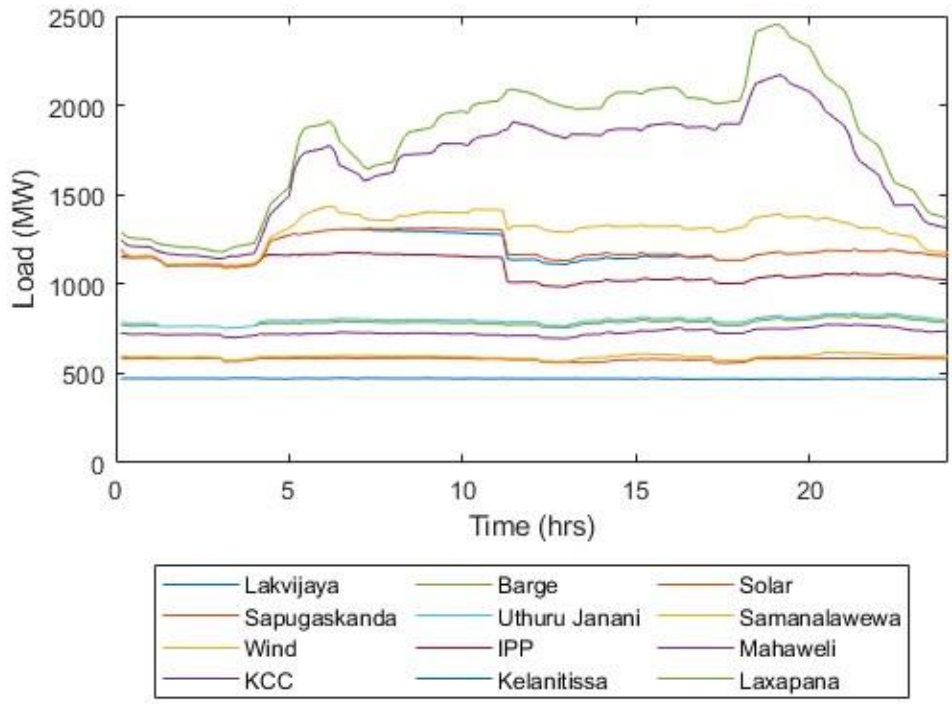


Figure G. 24: Daily Load Curve of 2019.01.24.

Friday 25th of January 2019

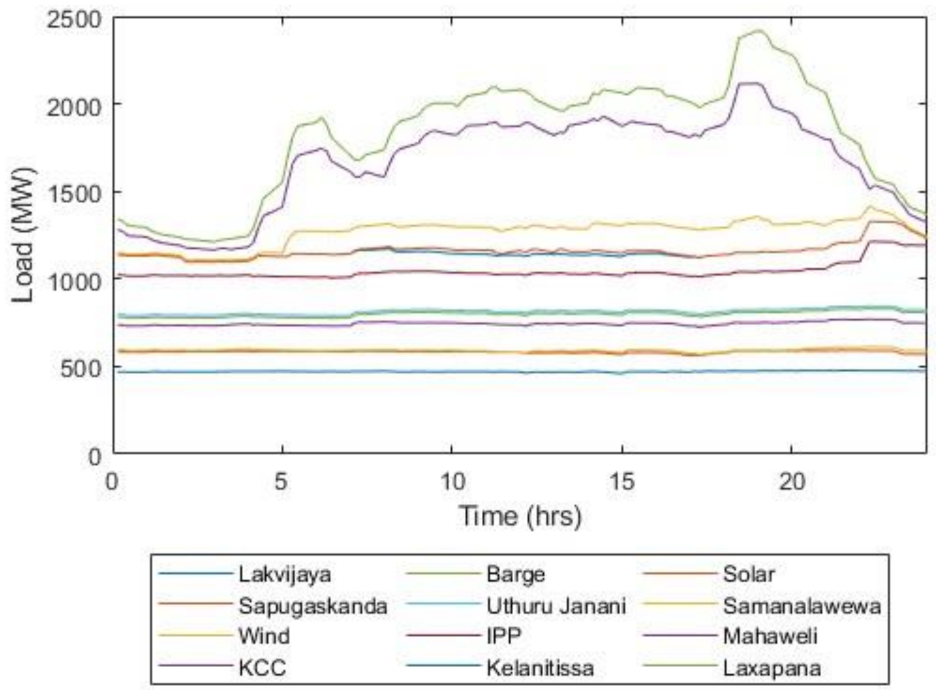


Figure G. 25: Daily Load Curve of 2019.01.25.

Saturday 26th of January 2019

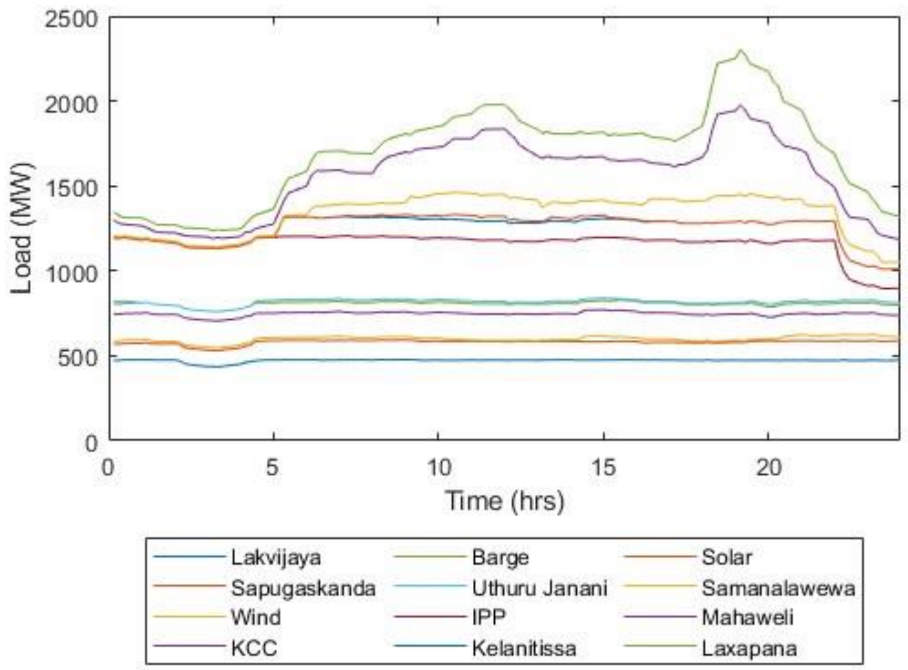


Figure G. 26: Daily Load Curve of 2019.01.26.

Sunday 27th of January 2019

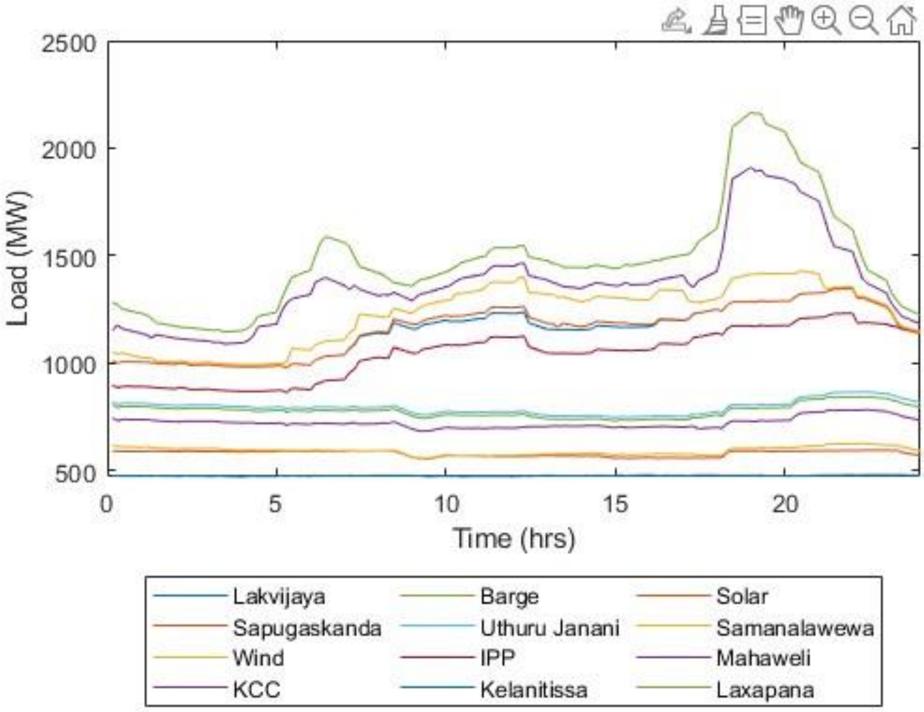


Figure G. 27: Daily Load Curve of 2019.01.27.

Monday 28th of January 2019

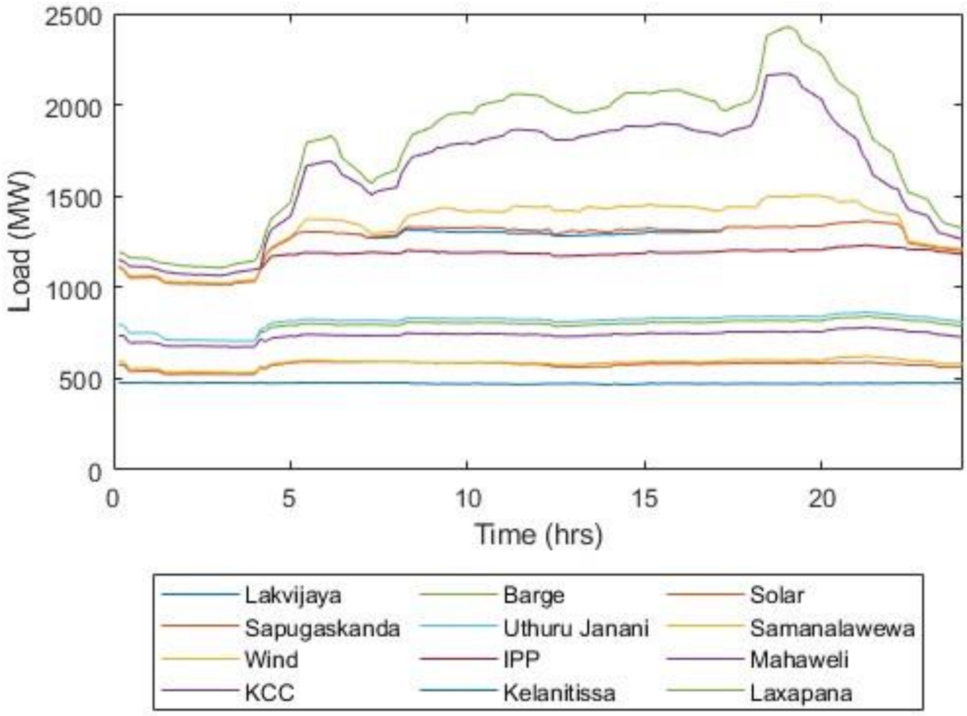


Figure G. 28: Daily Load Curve of 2019.01.28.

Tuesday 29th of January 2019

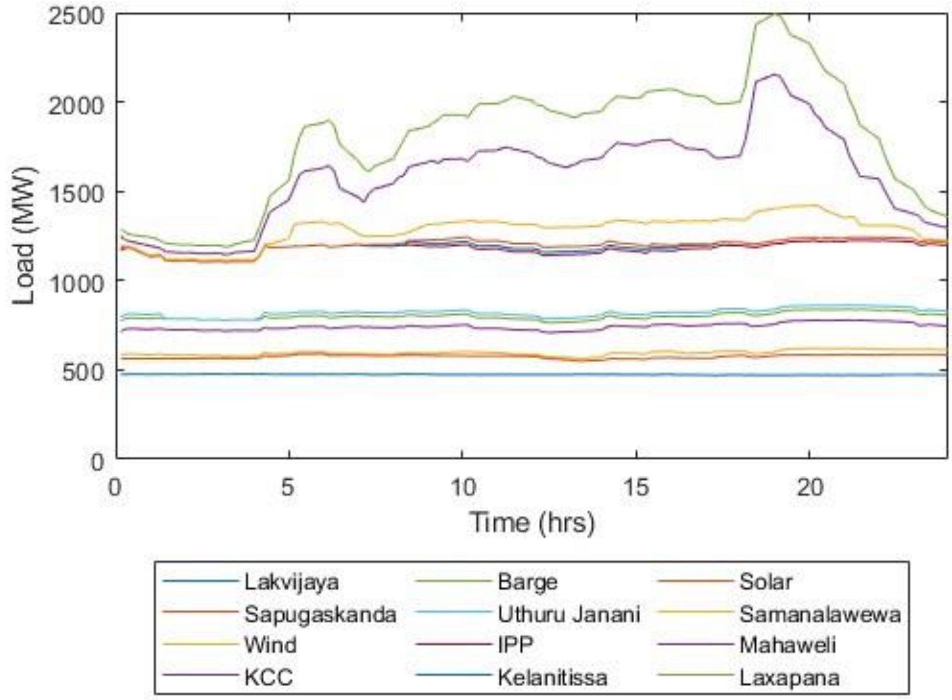


Figure G. 29: Daily Load Curve of 2019.01.29.

Wednesday 30th of January 2019

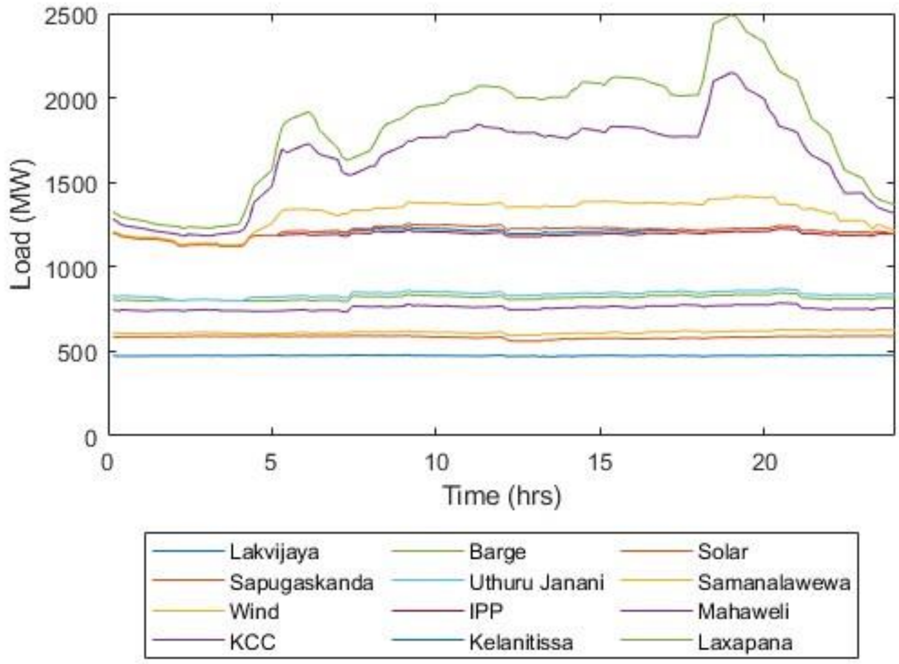


Figure G. 30: Daily Load Curve of 2019.01.30.

Thursday 31st of January 2019

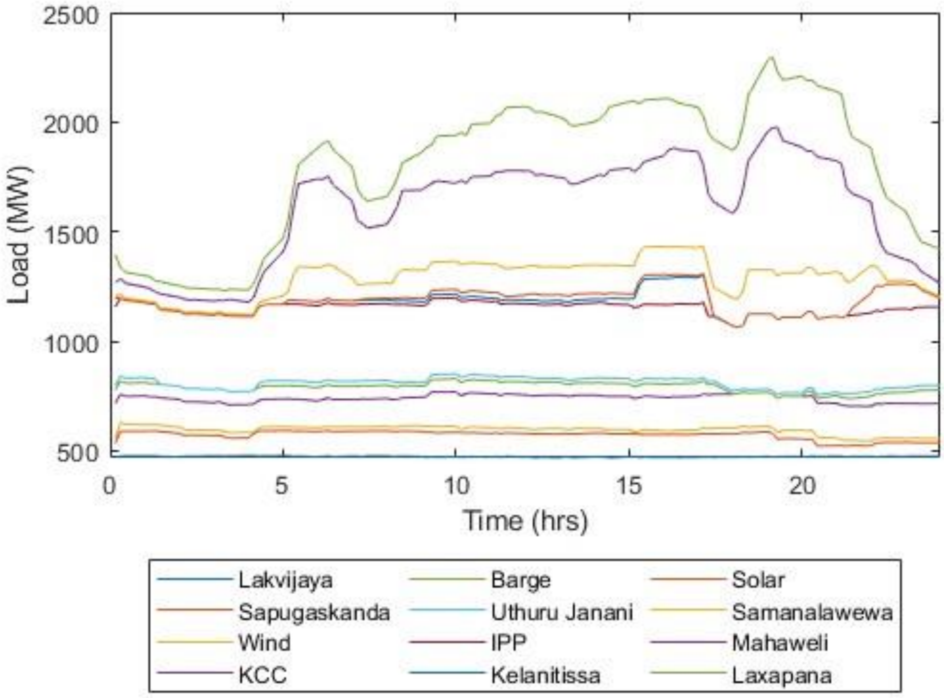


Figure G. 31: Daily Load Curve of 2019.01.31.

[Appendix H- Monthly Water Value of 2019 calculated by Method 02]

January

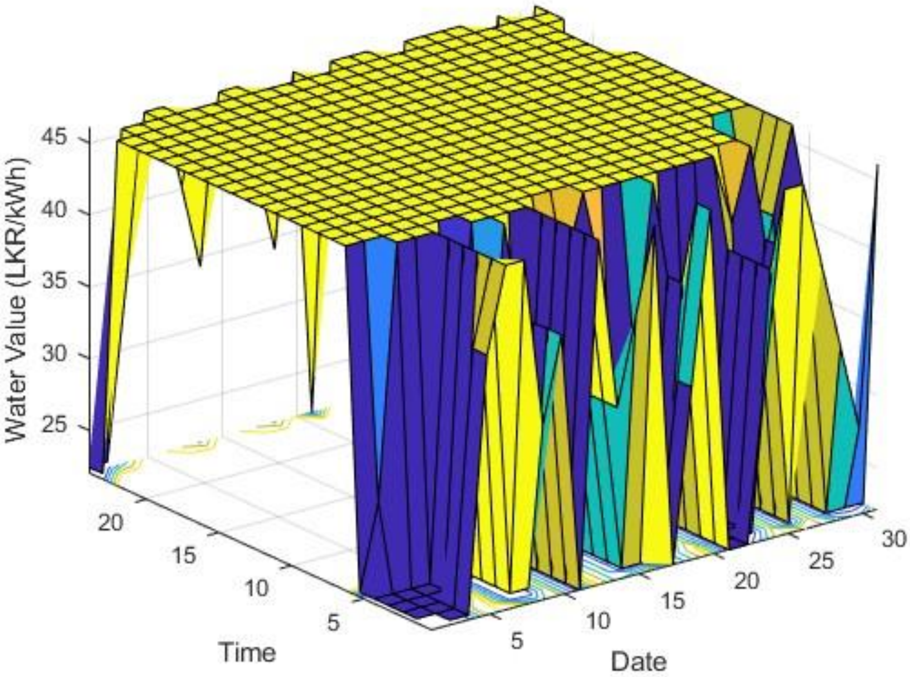


Figure H. 1: Water Value of January 2019, Calculated by Method 02

February

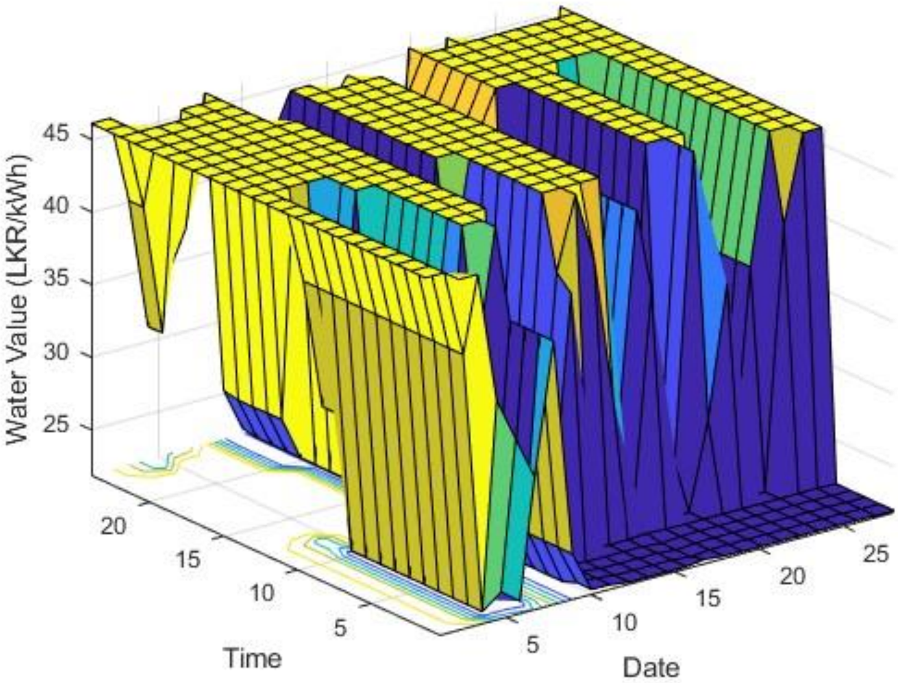


Figure H. 2: Water Value of February 2019, Calculated by Method 02

March

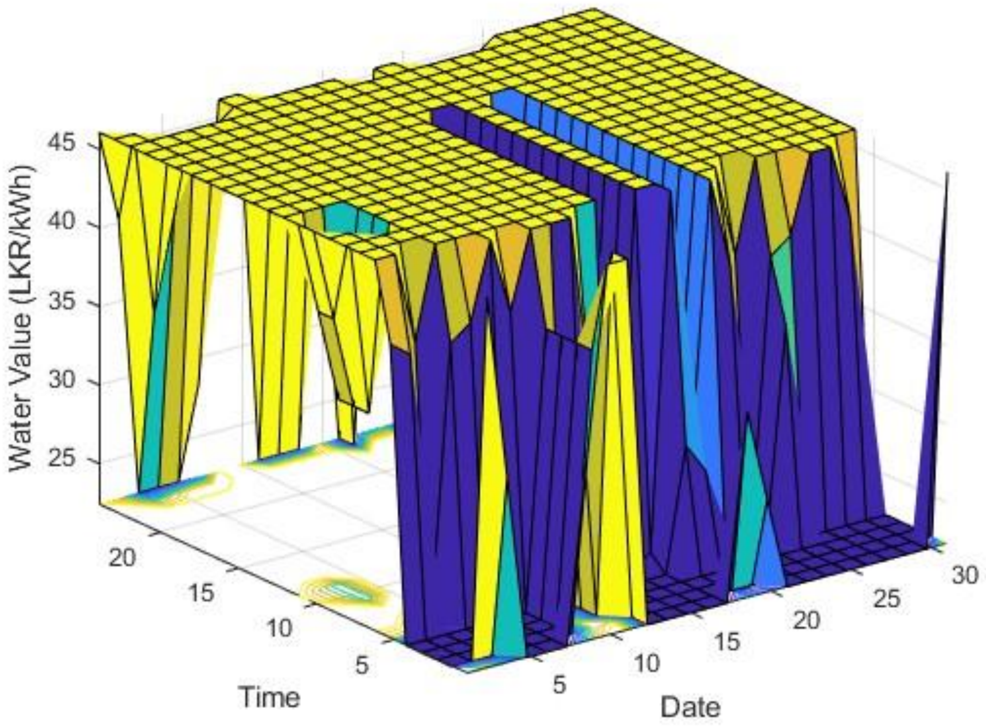


Figure H. 3: Water Value of March 2019, Calculated by Method 02

April

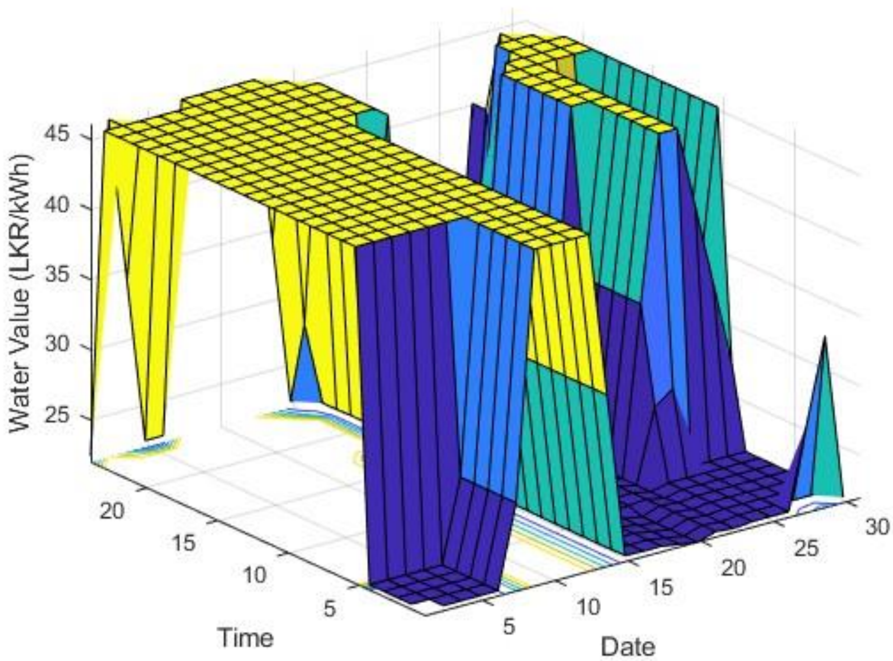


Figure H. 4: Water Value of April 2019, Calculated by Method 02

May

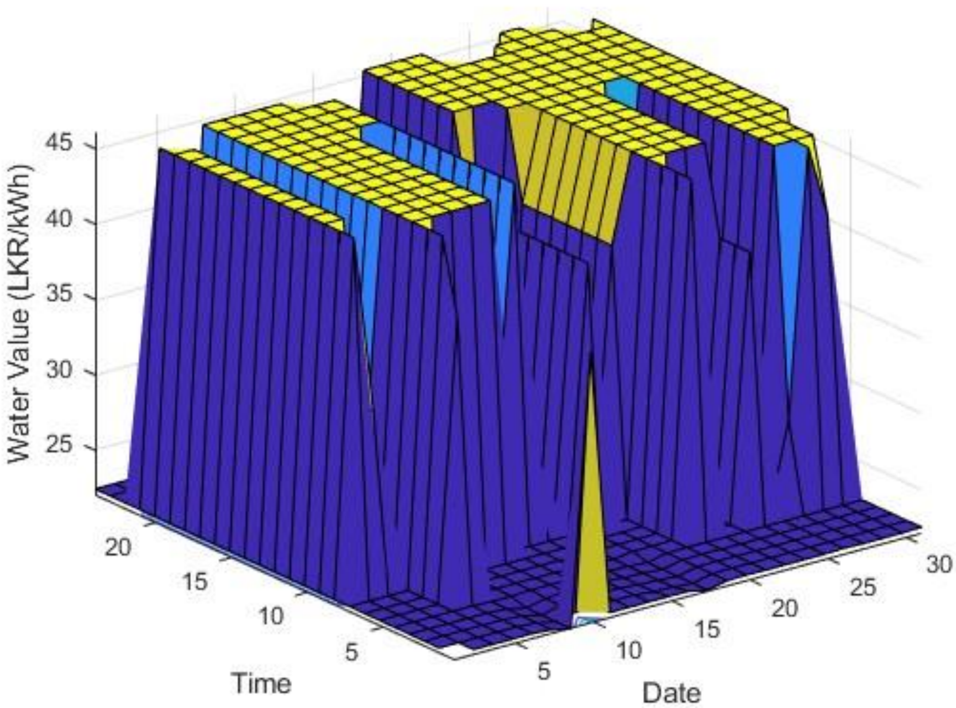


Figure H. 5: Water Value of May 2019, Calculated by Method 02

June

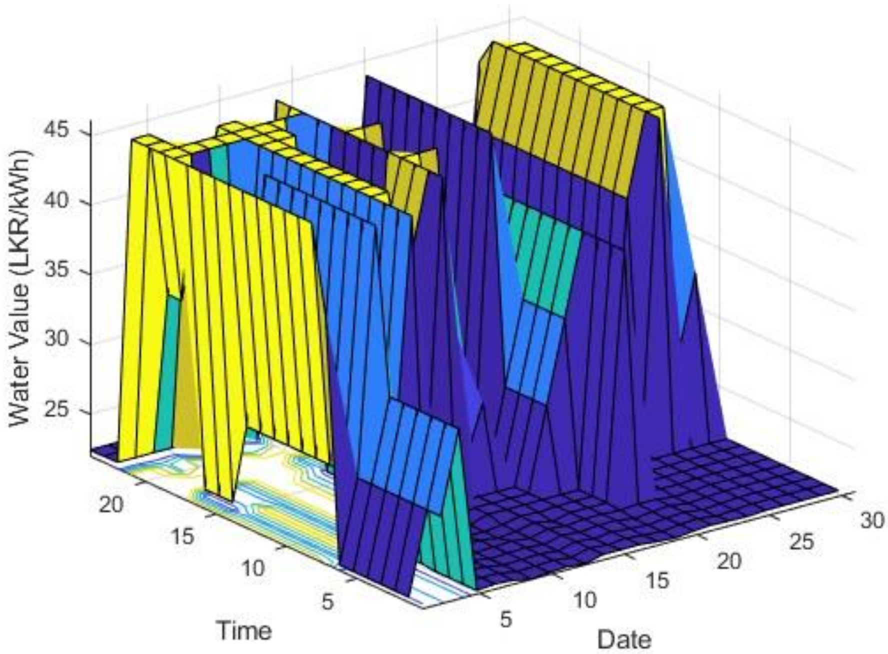


Figure H. 6: Water Value of June 2019, Calculated by Method 02

July

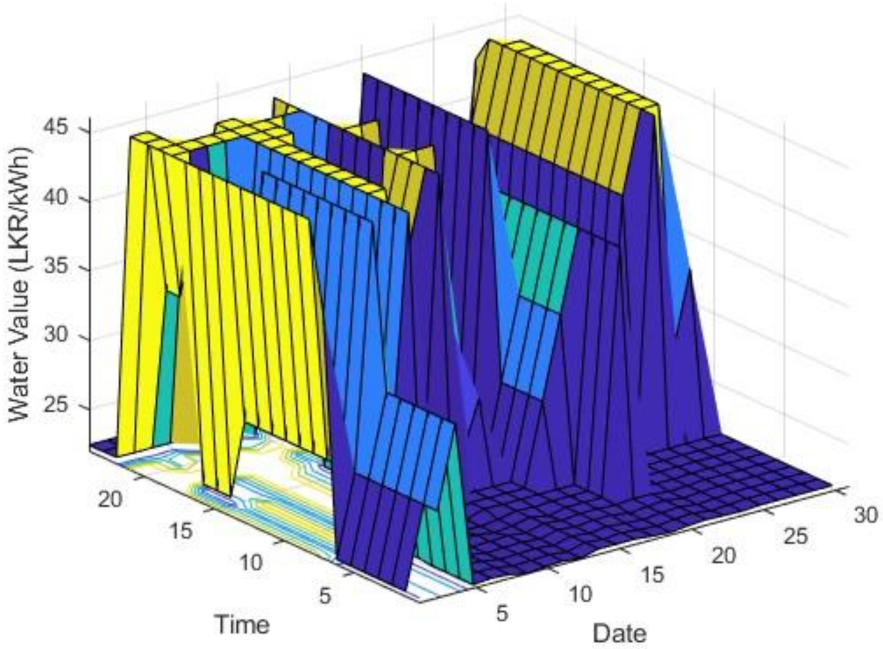


Figure H. 7: Water Value of July 2019, Calculated by Method 02

August

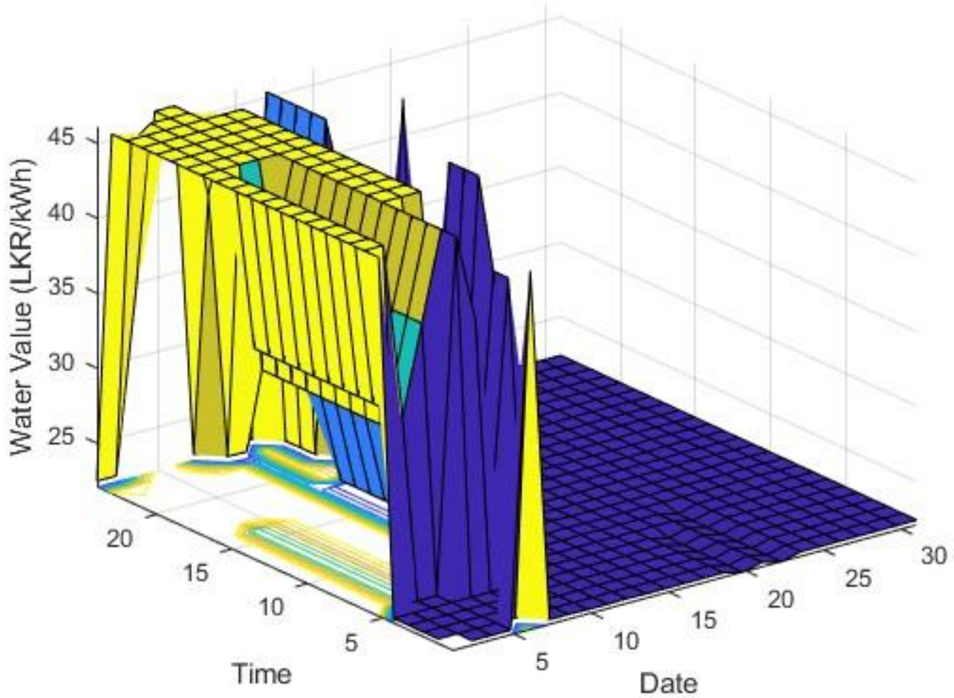


Figure H. 8: Water Value of August 2019, Calculated by Method 02

September

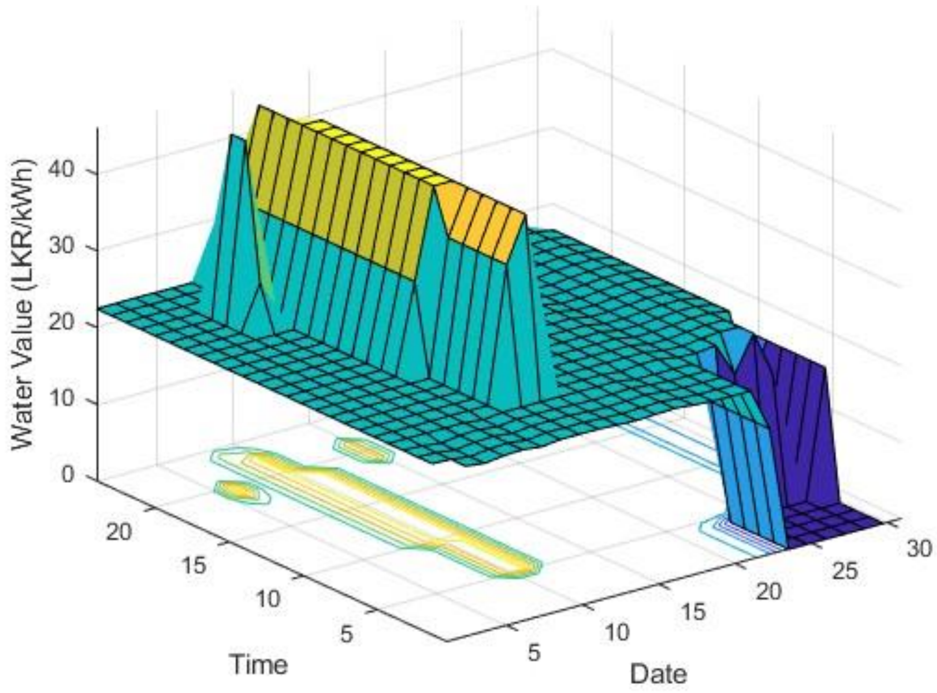


Figure H. 9: Water Value of September 2019, Calculated by Method 02

October

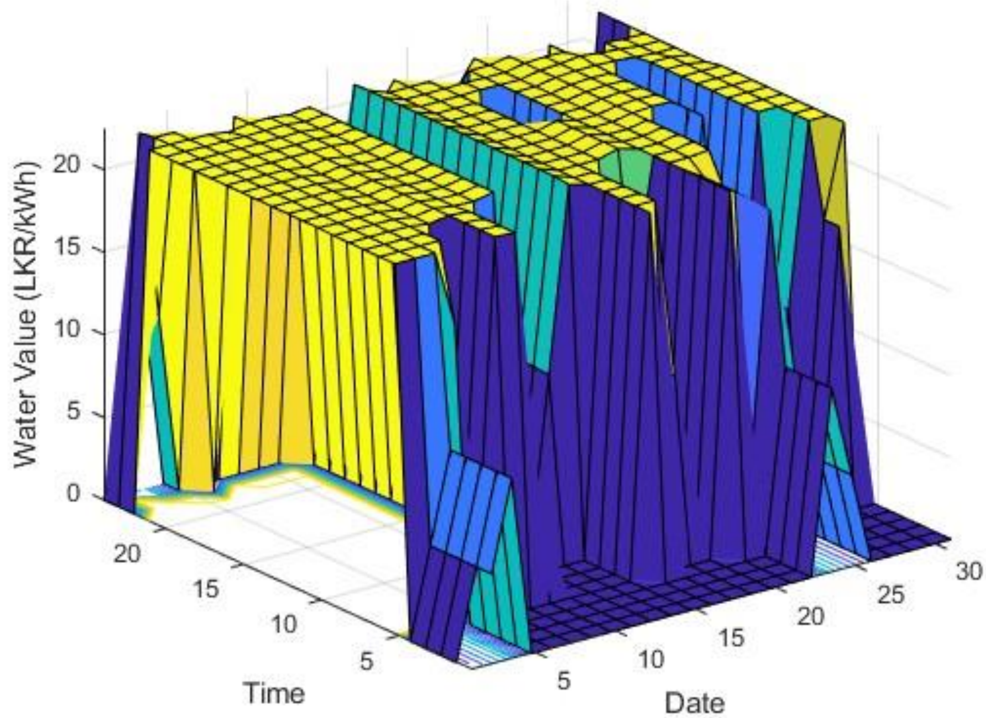


Figure H. 10: Water Value of October 2019, Calculated by Method 02

November

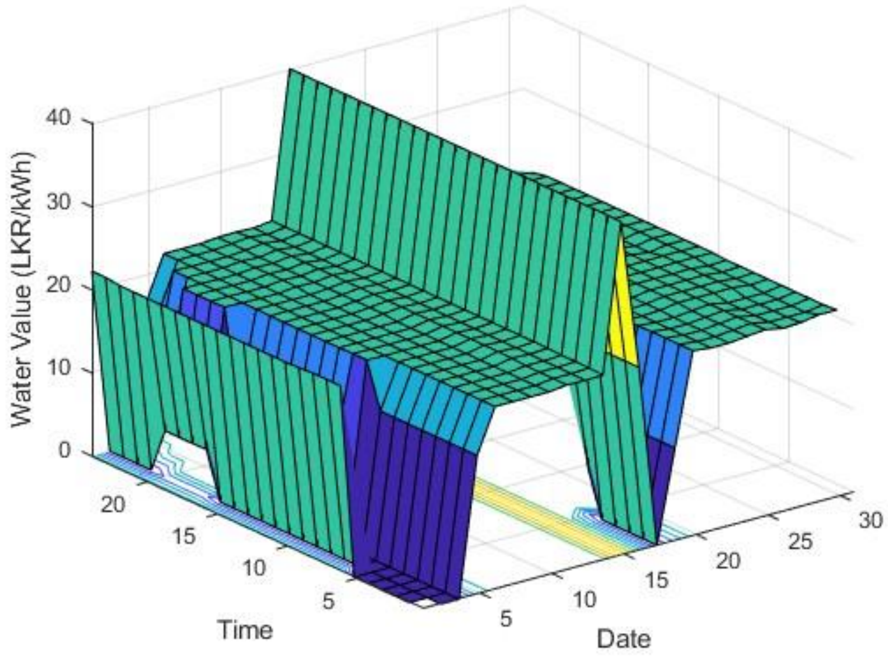


Figure H. 11: Water Value of November 2019, Calculated by Method 02

December

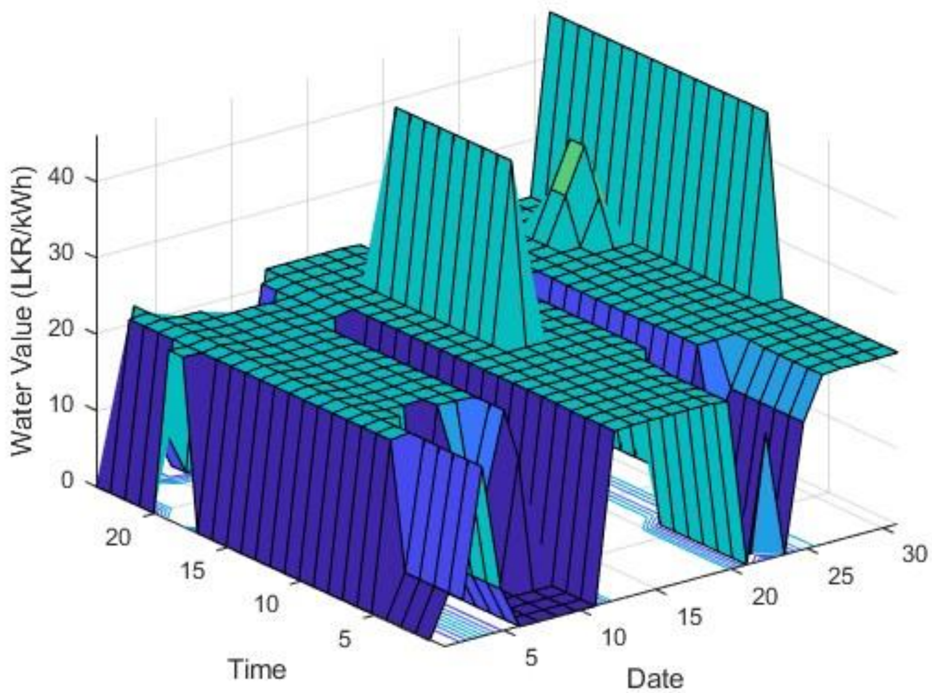


Figure H. 12: Water Value of January 2019, Calculated by Method 02

[Appendix I- Monthly Generation Cost of 2019: Calculated by Method 2]

January

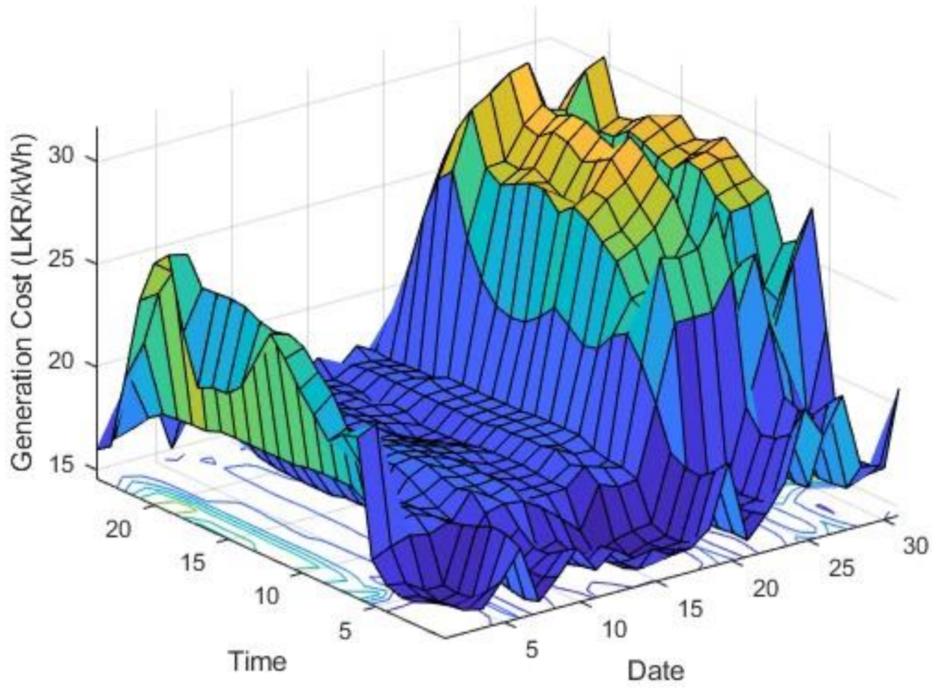


Figure I. 1: Generation Cost of January 2019, Calculated by Method 02

February

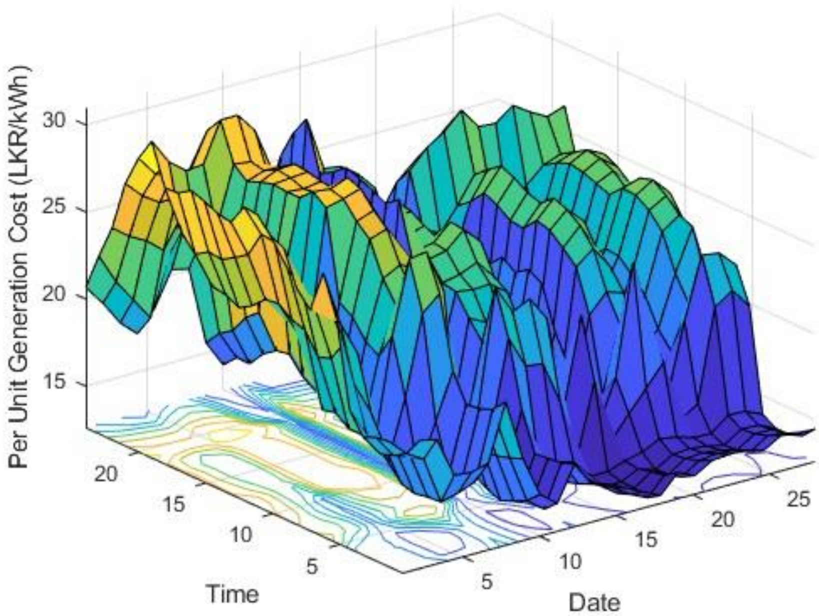


Figure I. 2: Generation Cost of February 2019, Calculated by Method 02

March

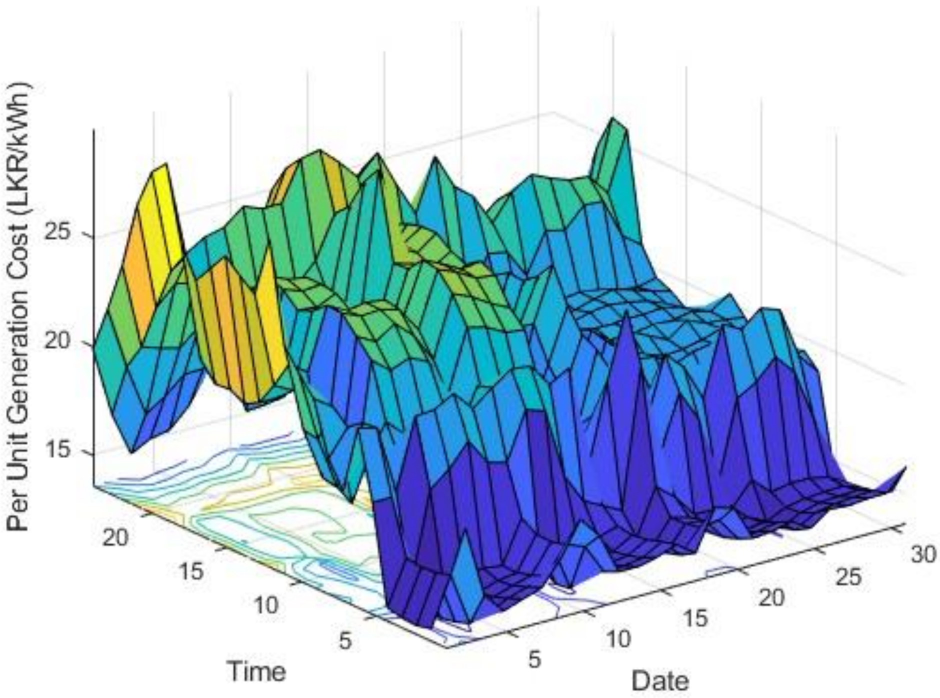


Figure I. 3: Generation Cost of March 2019, Calculated by Method 02

April

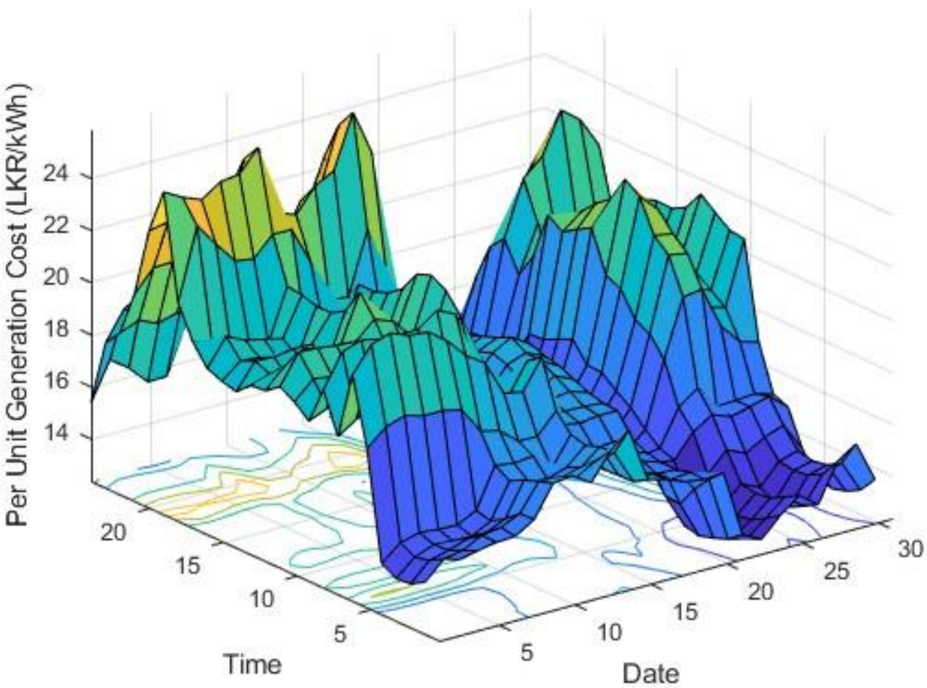


Figure I. 4: Generation Cost of April 2019, Calculated by Method 02

May

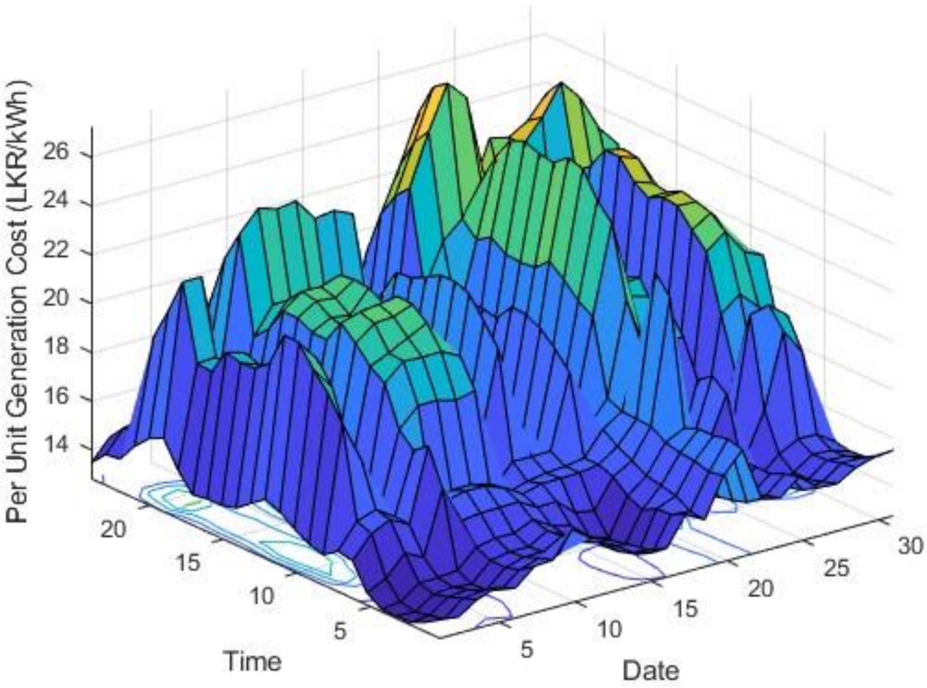


Figure I. 5: Generation Cost of May 2019, Calculated by Method 02

June

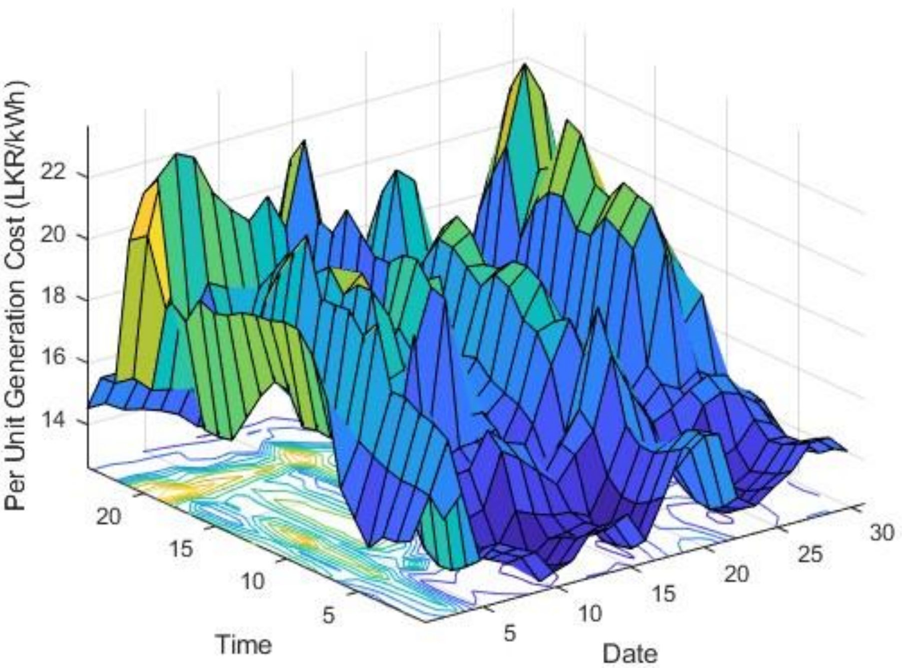


Figure I. 6: Generation Cost of June 2019, Calculated by Method 02

July

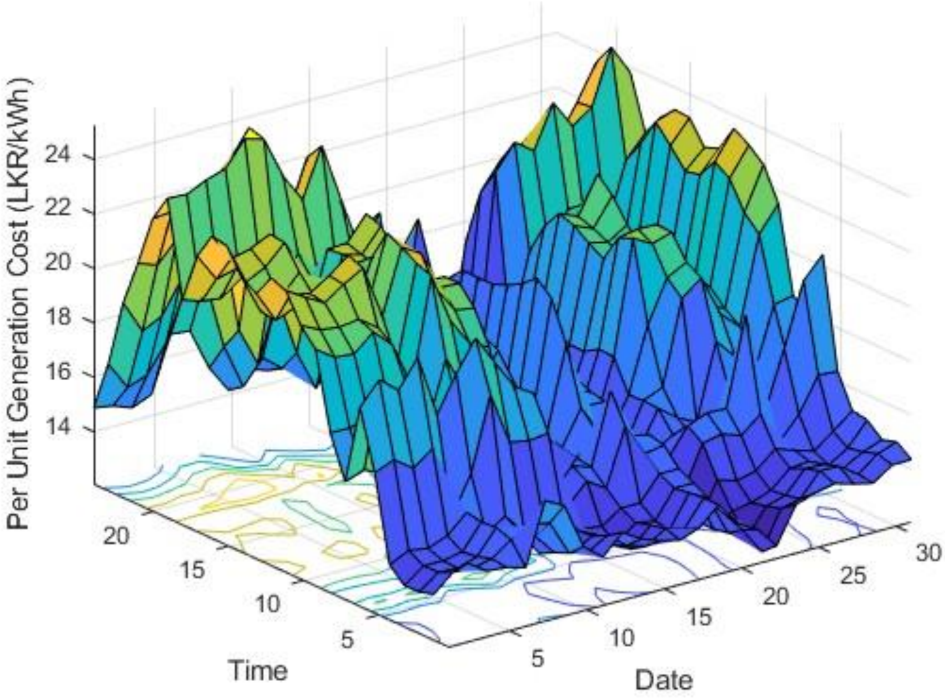


Figure I. 7: Generation Cost of July 2019, Calculated by Method 02

August

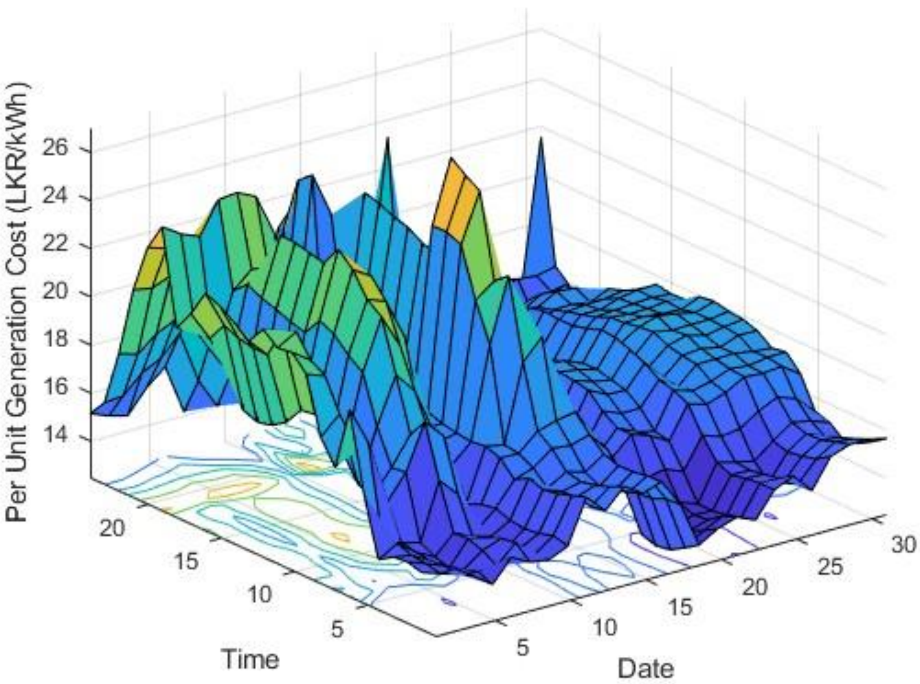


Figure I. 8: Generation Cost of August 2019, Calculated by Method 02

September

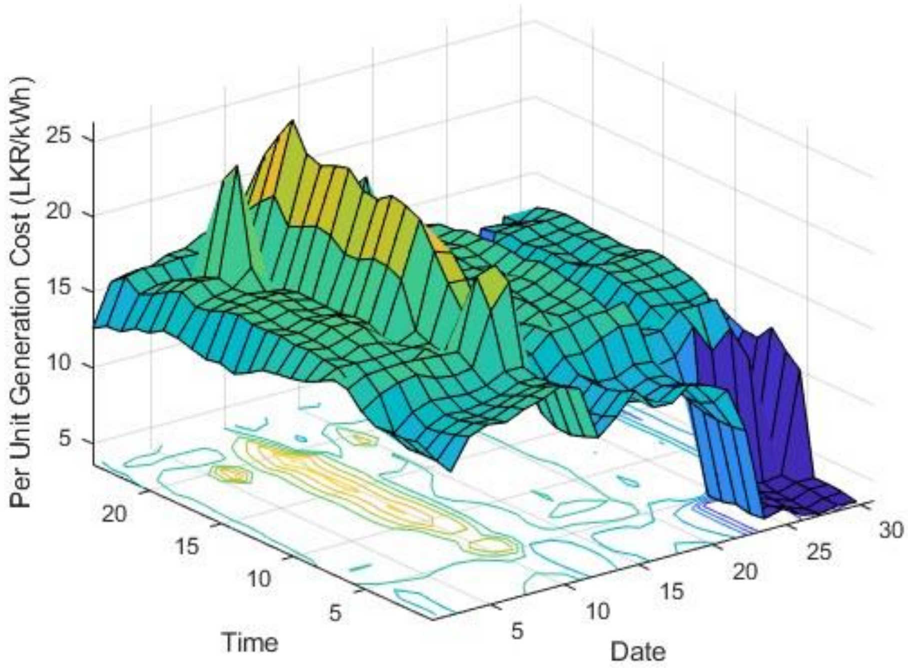


Figure I. 9: Generation Cost of September 2019, Calculated by Method 02

October

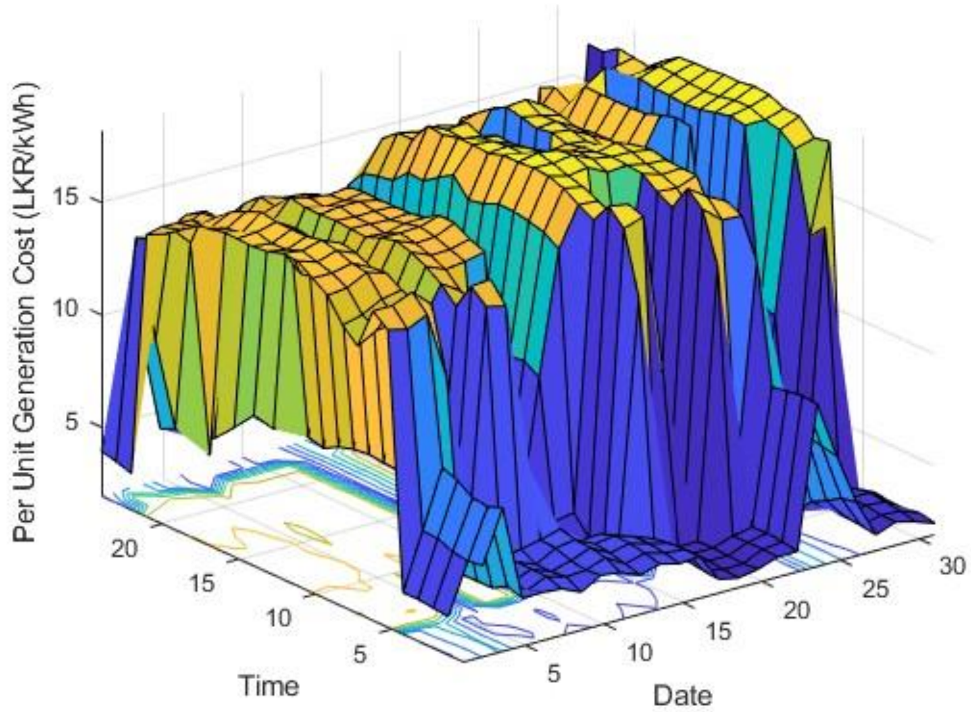


Figure I. 10: Generation Cost of October 2019, Calculated by Method 02

November

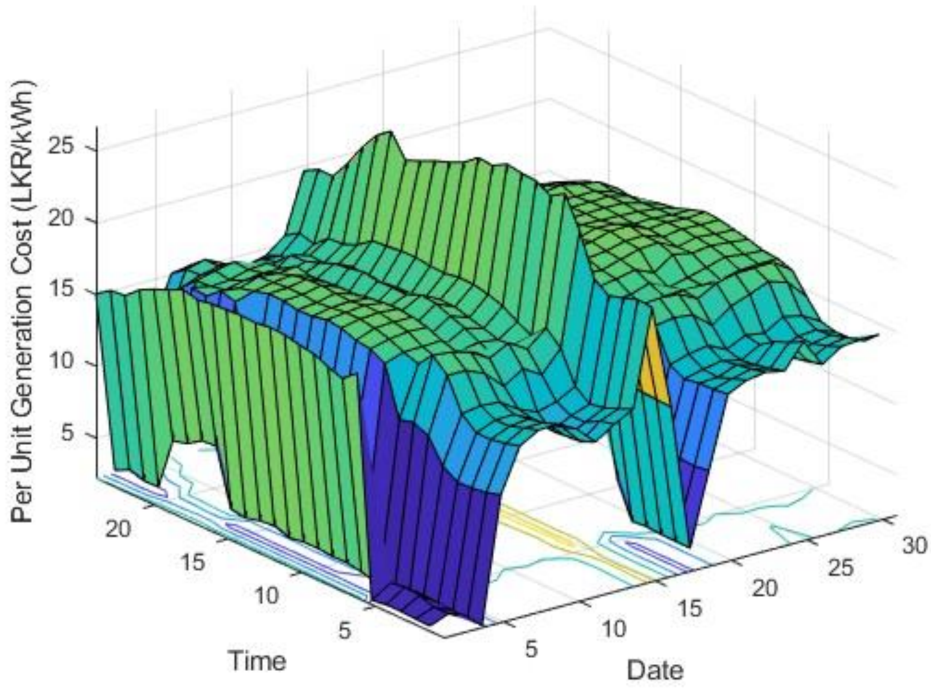


Figure I. 11: Generation Cost of November 2019, Calculated by Method 02

December

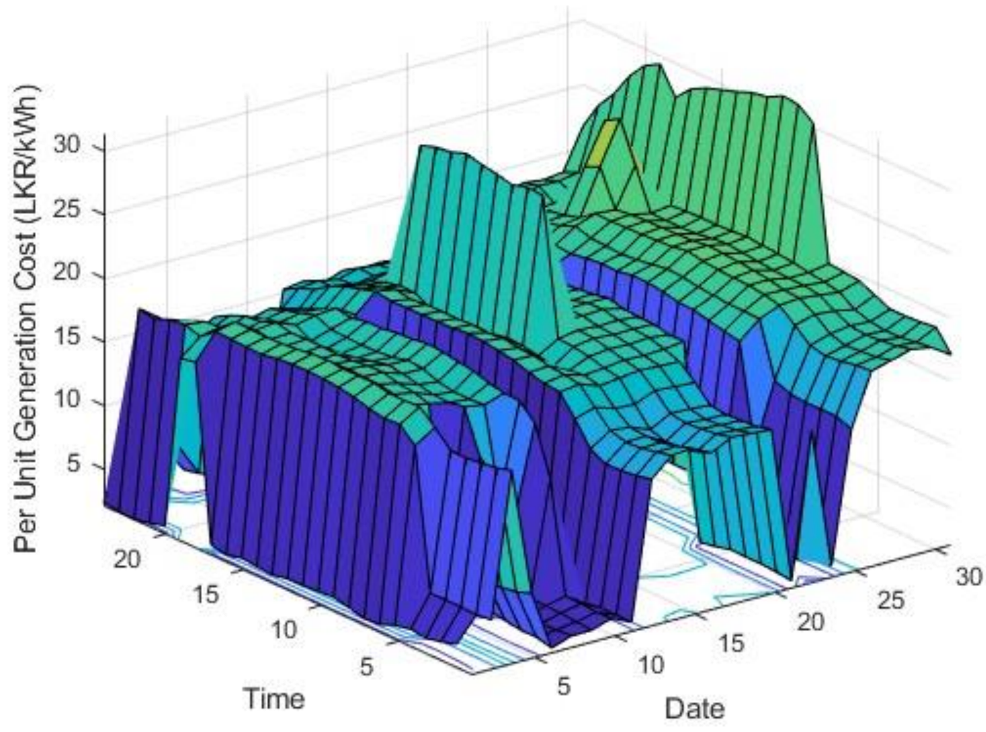


Figure I. 12: Generation Cost of December 2019, Calculated by Method 02

[Appendix J- Monthly Water Value of 2019, Calculated by Method 03]

January

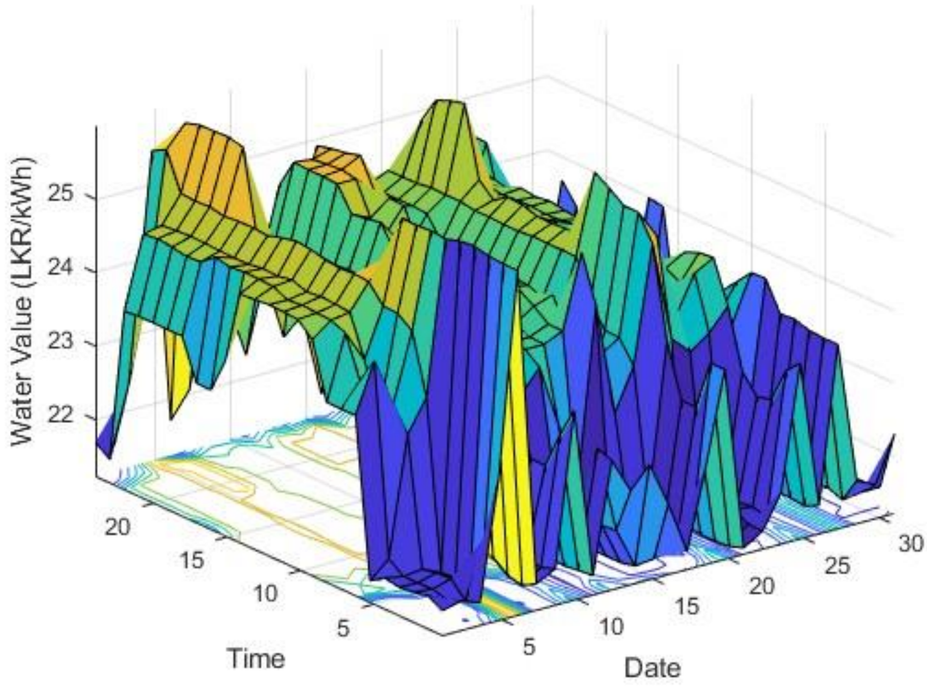


Figure J. 1: Water Value of January 2019, Calculated by Method 03

February

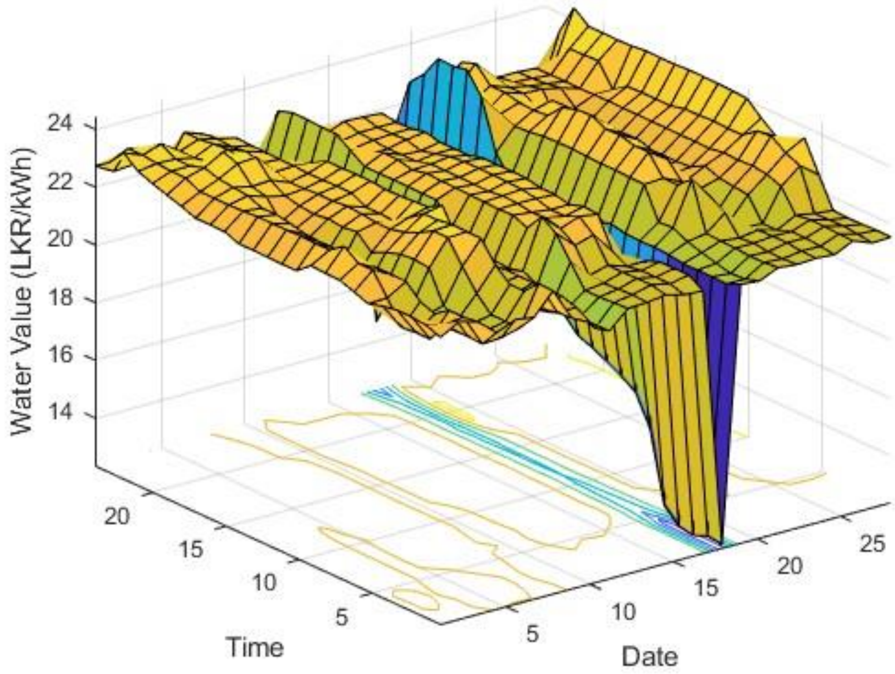


Figure J. 2: Water Value of February 2019, Calculated by Method 03

March

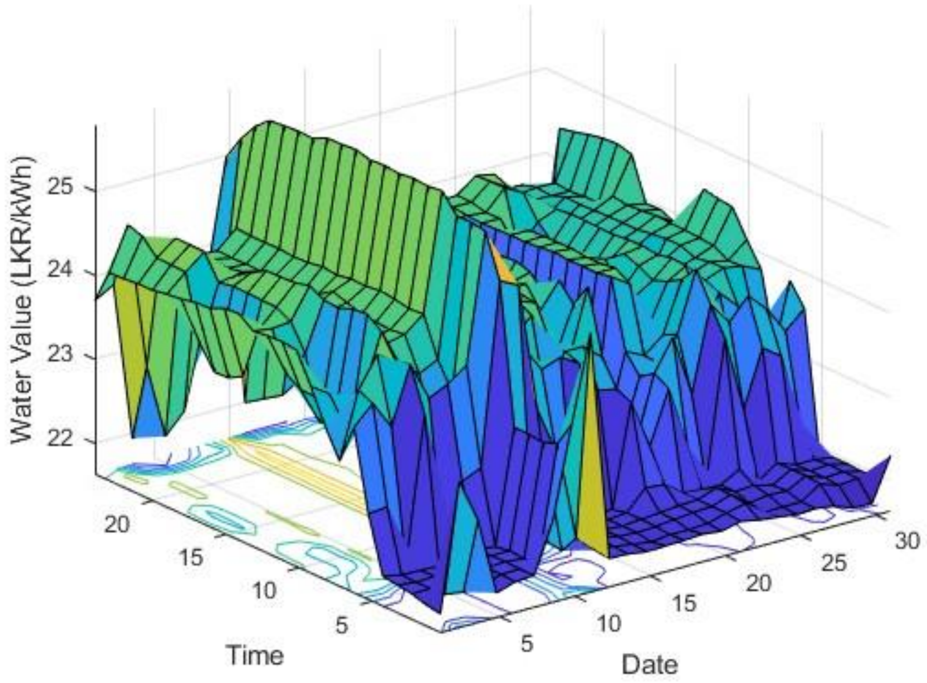


Figure J. 3: Water Value of March 2019, Calculated by Method 03

April

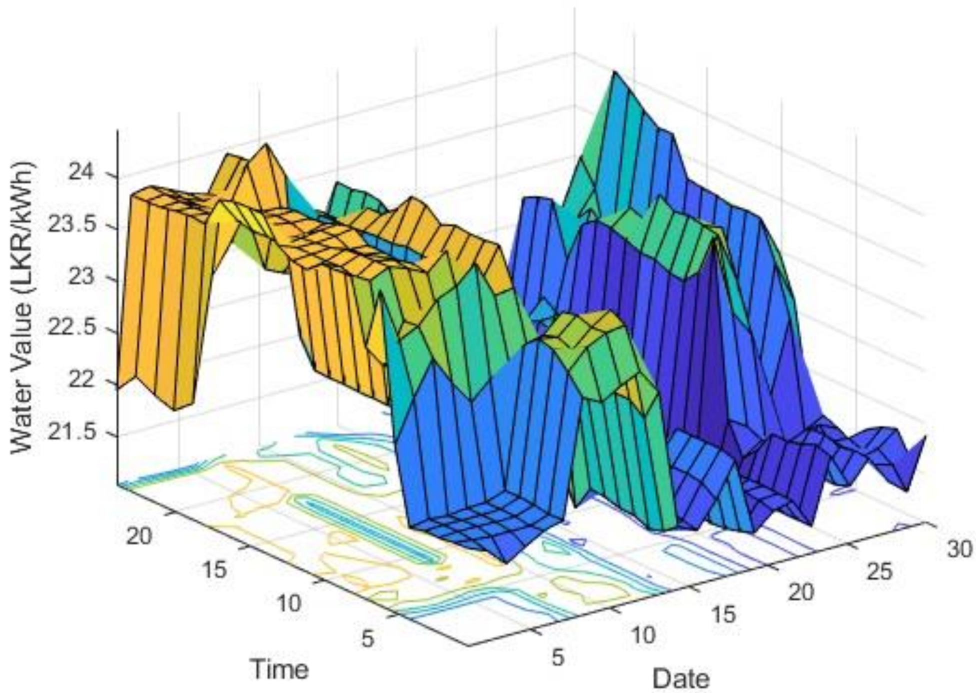


Figure J. 4: Water Value of April 2019, Calculated by Method 03

May

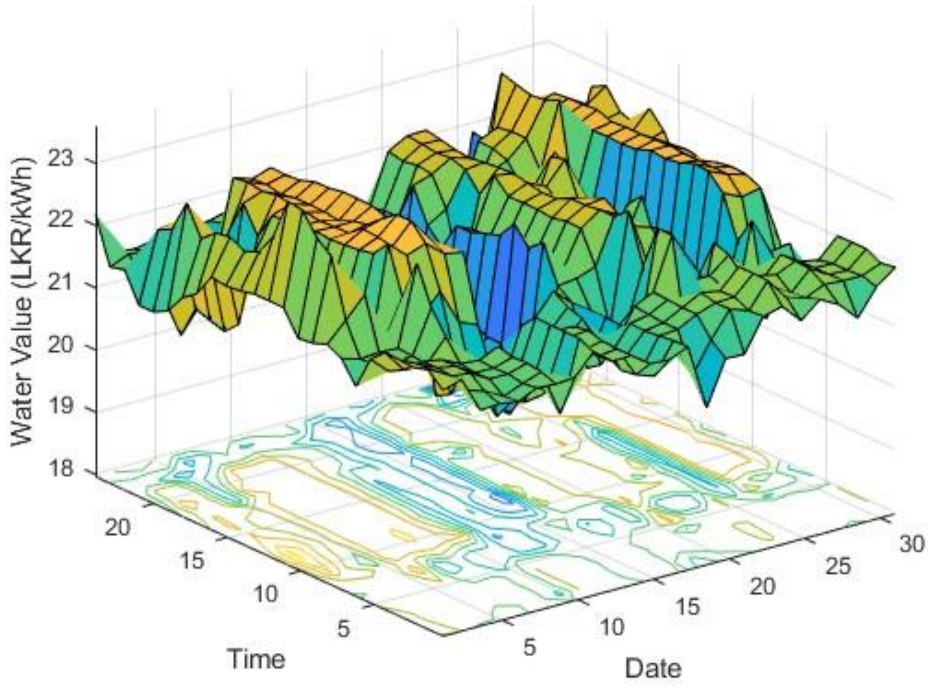


Figure J. 5: Water Value of May 2019, Calculated by Method 03

June

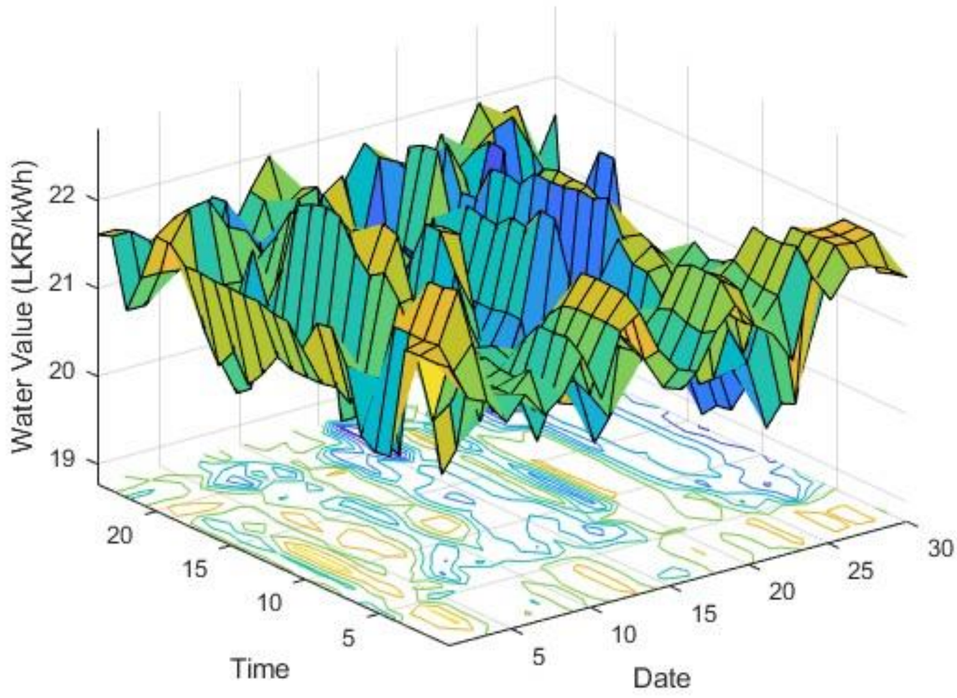


Figure J. 6: Water Value of June 2019, Calculated by Method 03

July

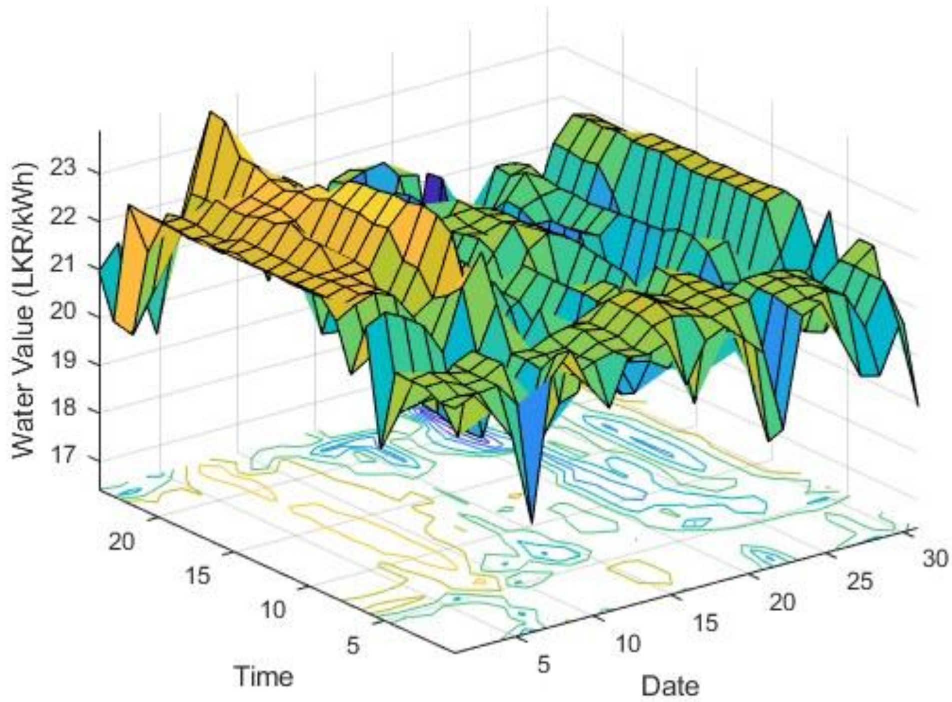


Figure J. 7: Water Value of July 2019, Calculated by Method 03

August

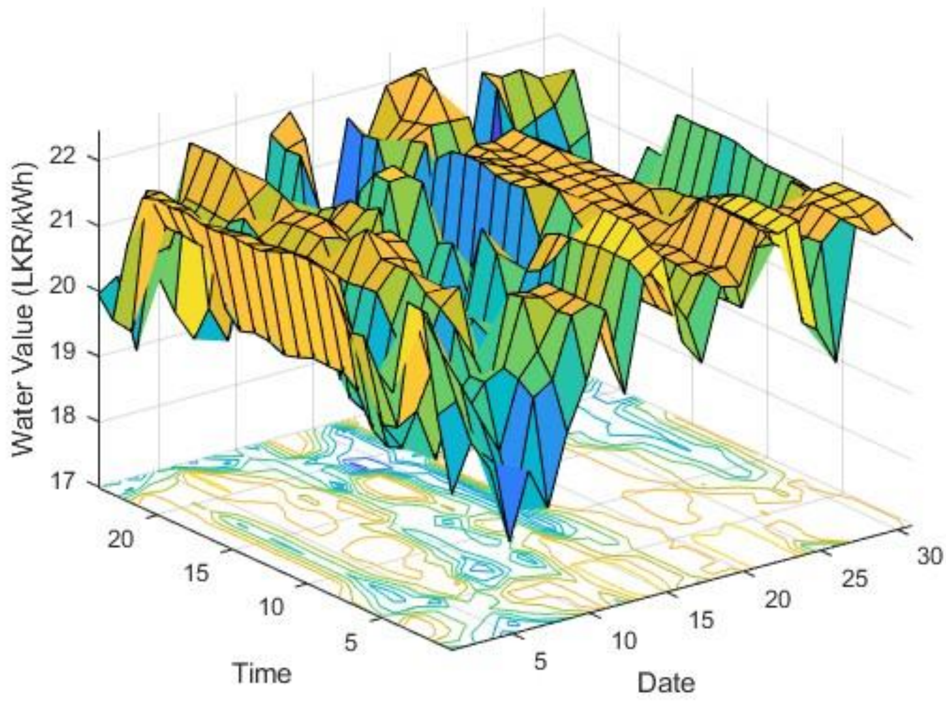


Figure J. 8: Water Value of August 2019, Calculated by Method 03

September

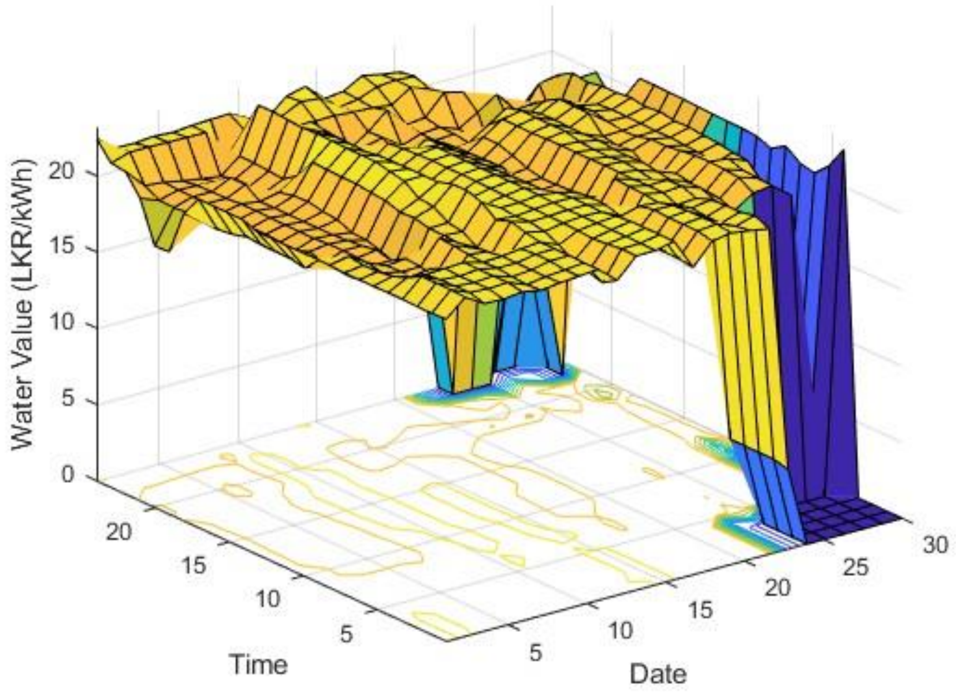


Figure J. 9: Water Value of September 2019, Calculated by Method 03

October

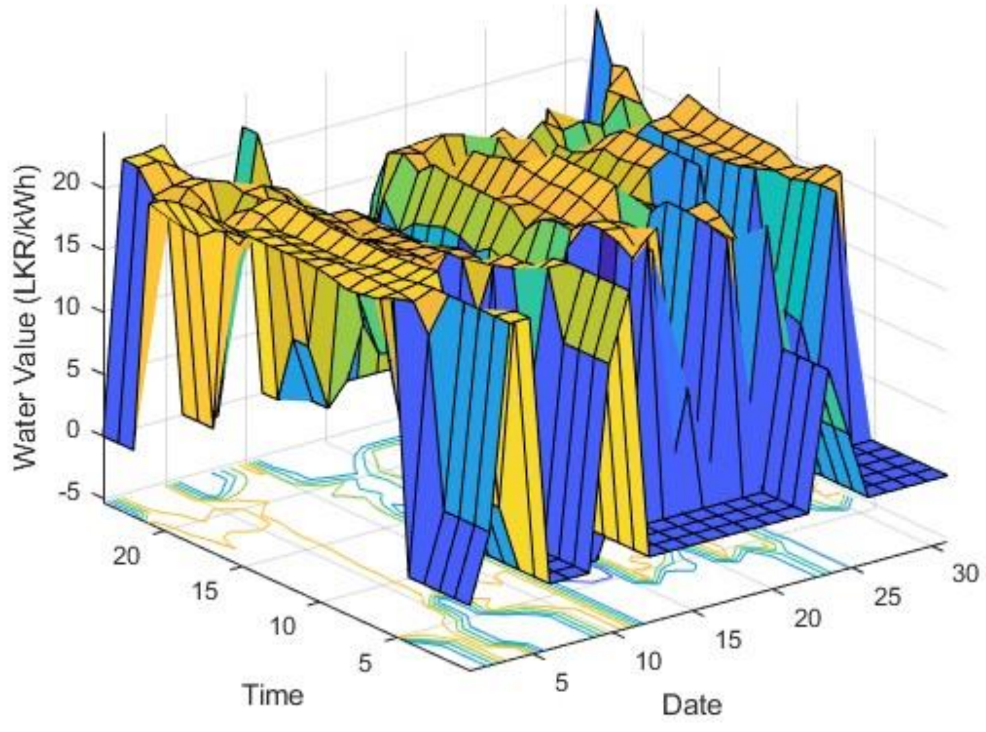


Figure J. 10: Water Value of October 2019, Calculated by Method 03

November

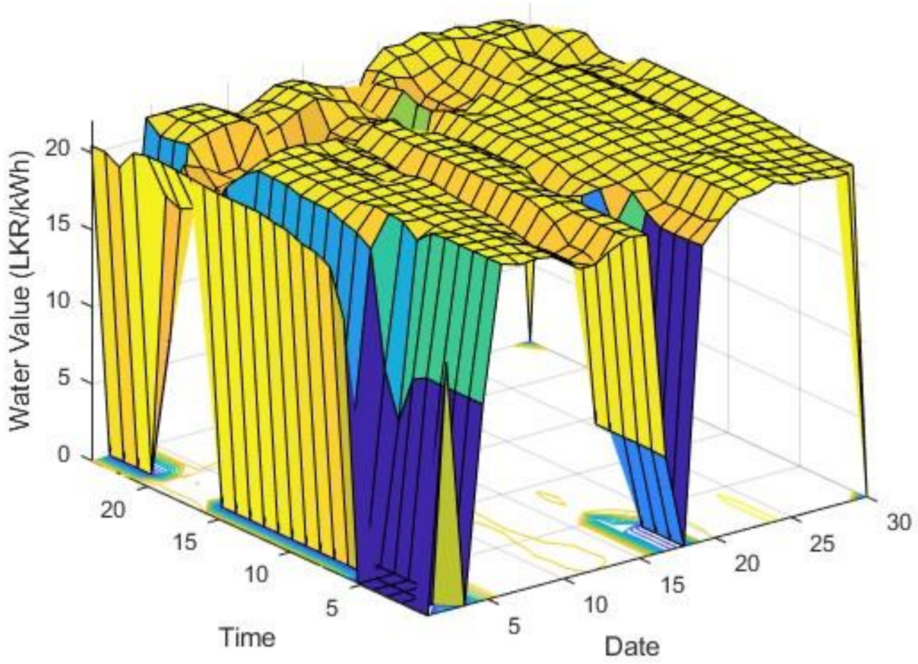


Figure J. 11: Water Value of November 2019, Calculated by Method 03

December

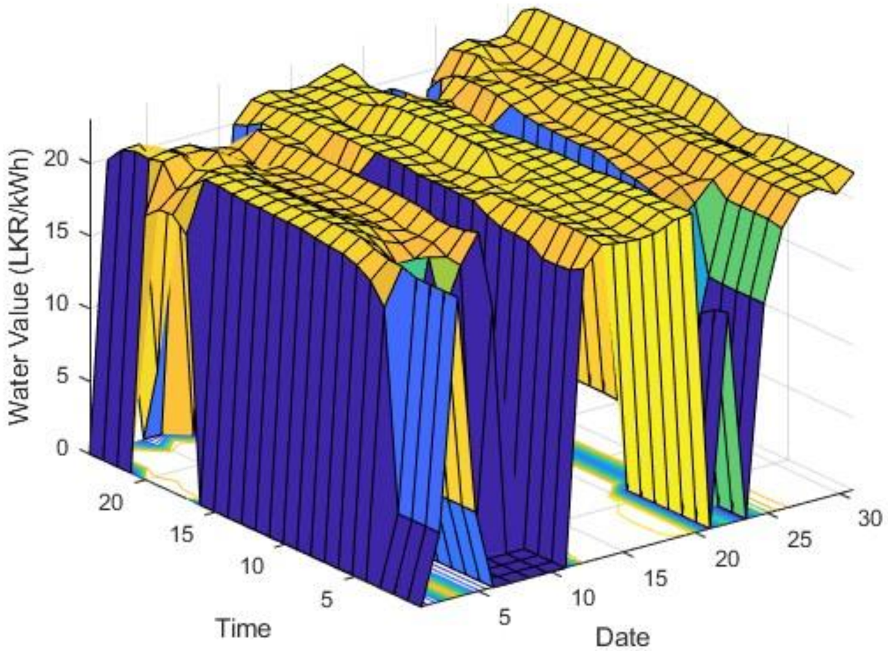


Figure J. 12: Water Value of December 2019, Calculated by Method 03

[Appendix K- Monthly Generation Cost of 2019: Calculated by method 3]

January

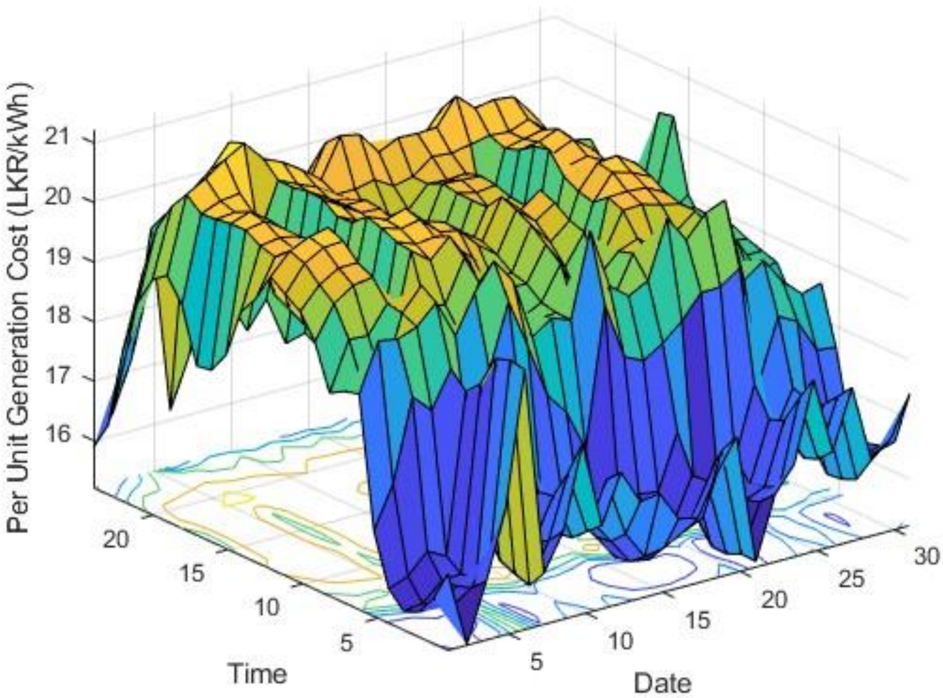


Figure K. 1: Generation Cost of January 2019, Calculated by Method 03

February

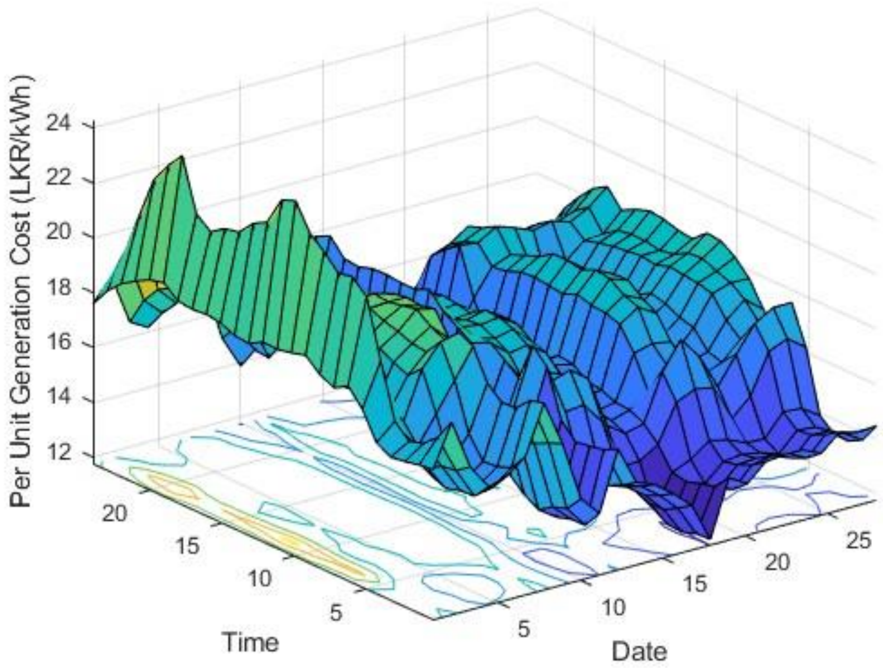


Figure K. 2: Generation Cost of February 2019, Calculated by Method 03

March

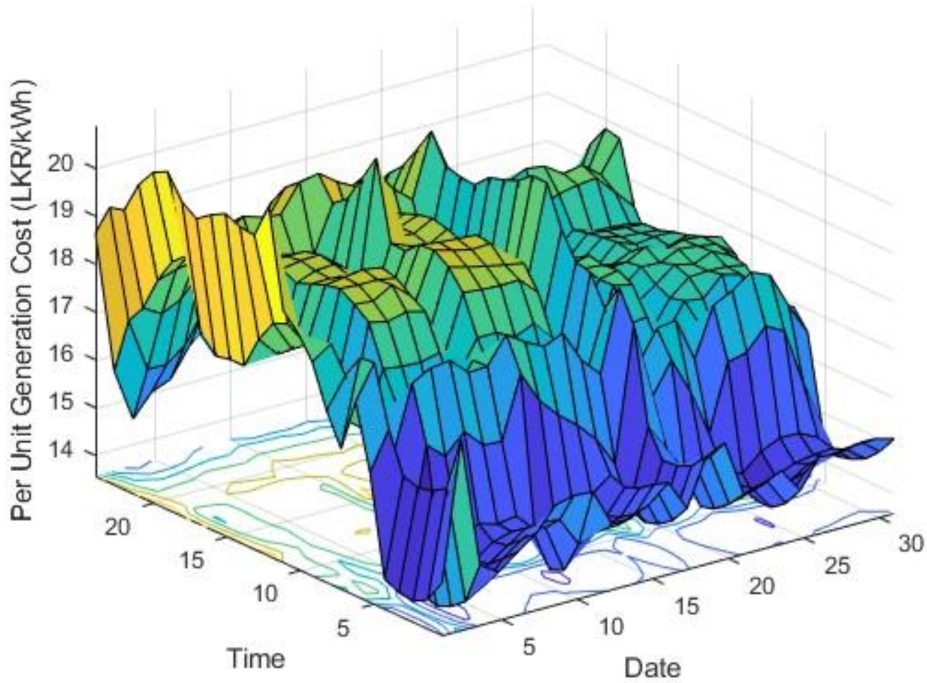


Figure K. 3: Generation Cost of March 2019, Calculated by Method 03

April

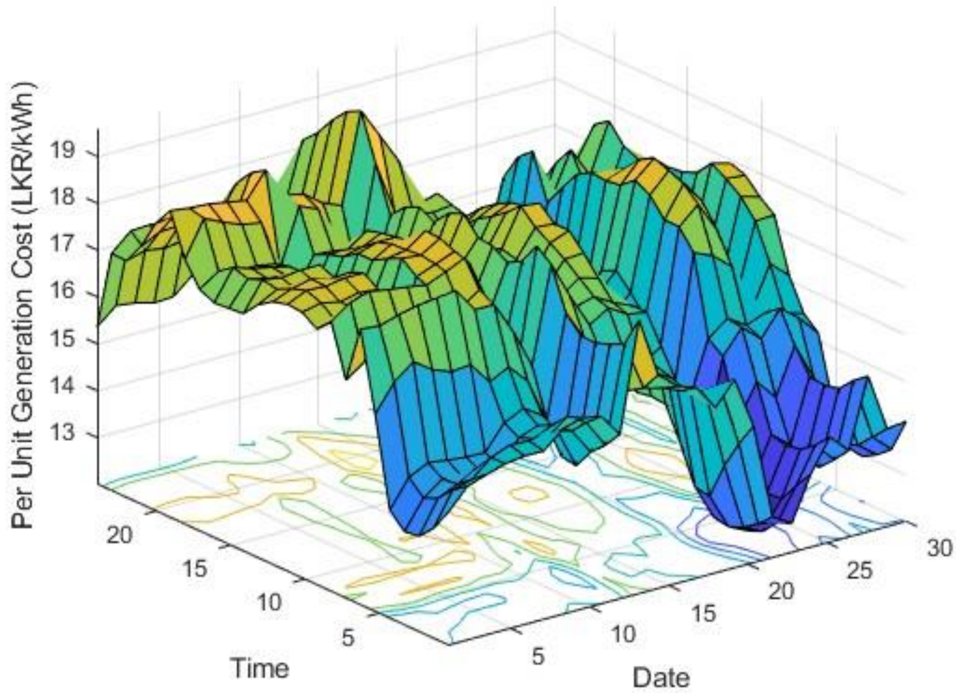


Figure K. 4: Generation Cost of April 2019, Calculated by Method 03

May

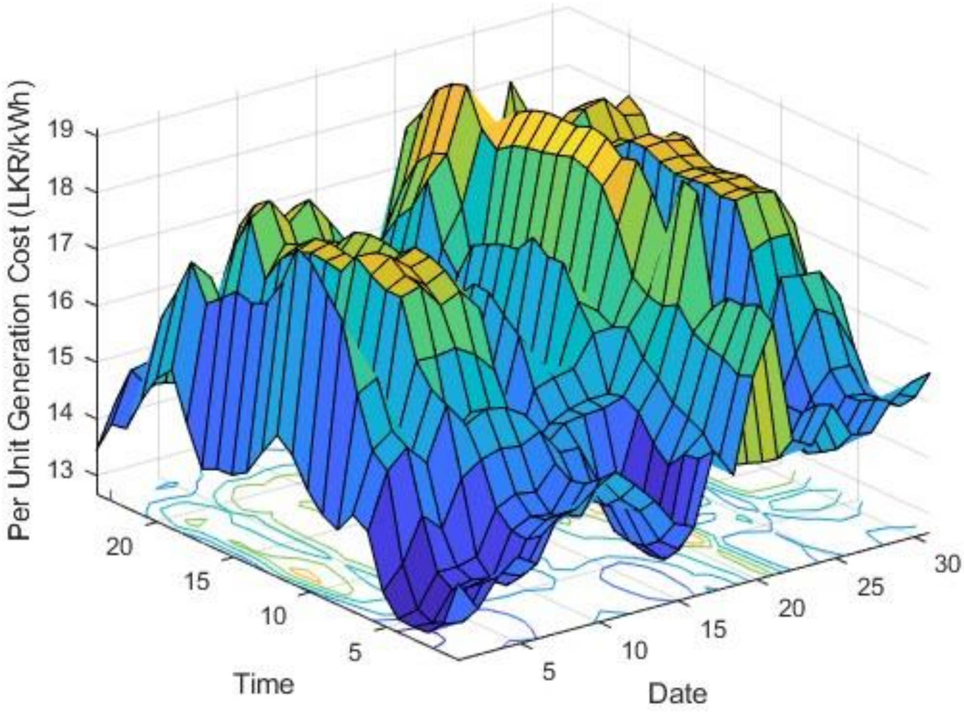


Figure K. 5: Generation Cost of May 2019, Calculated by Method 03

June

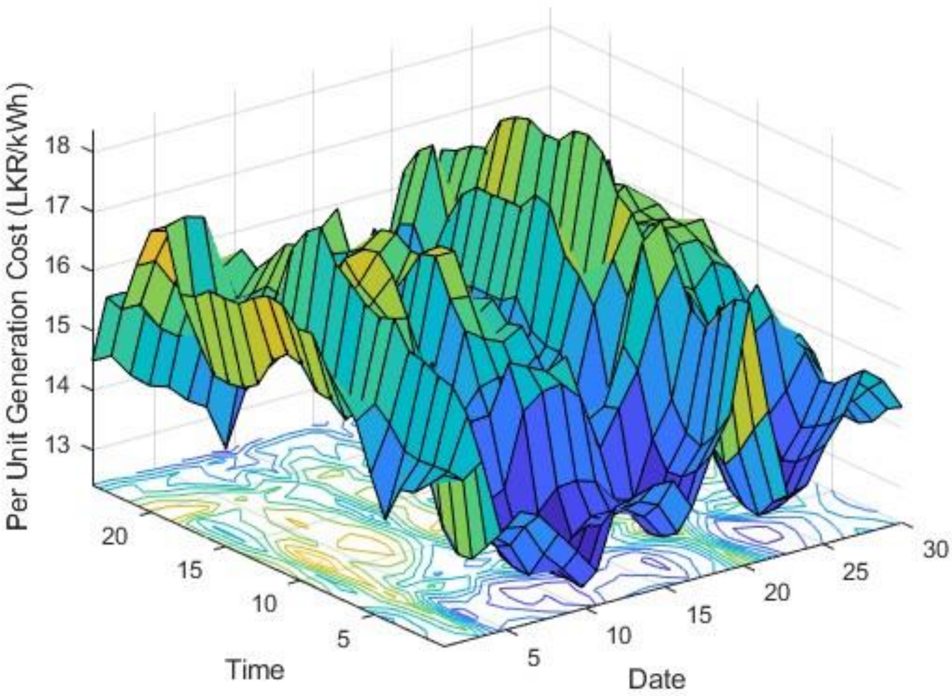


Figure K. 6: Generation Cost of June 2019, Calculated by Method 03

July

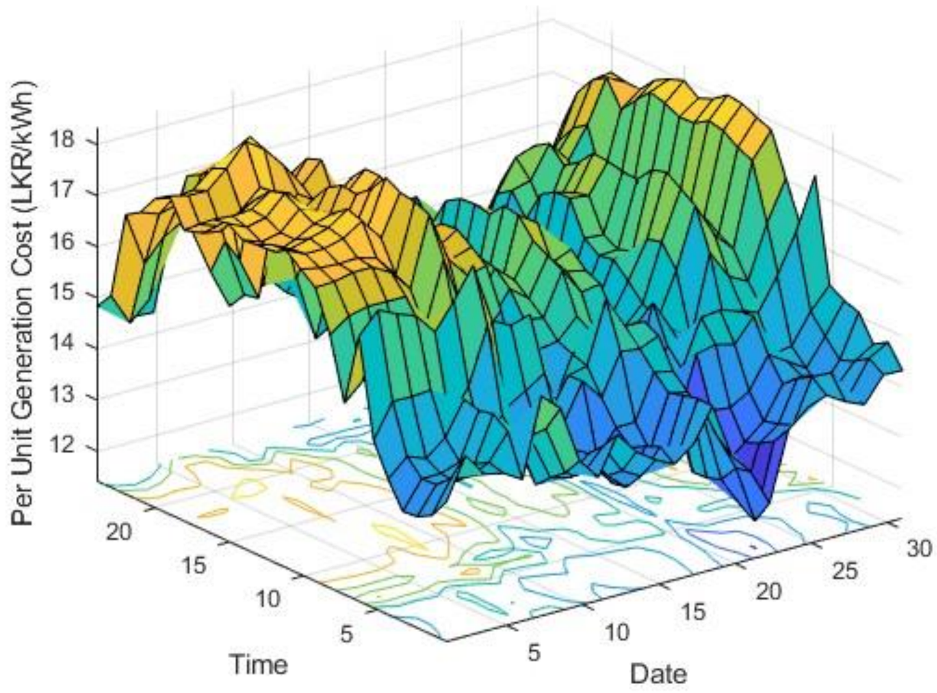


Figure K. 7: Generation Cost of July 2019, Calculated by Method 03

August

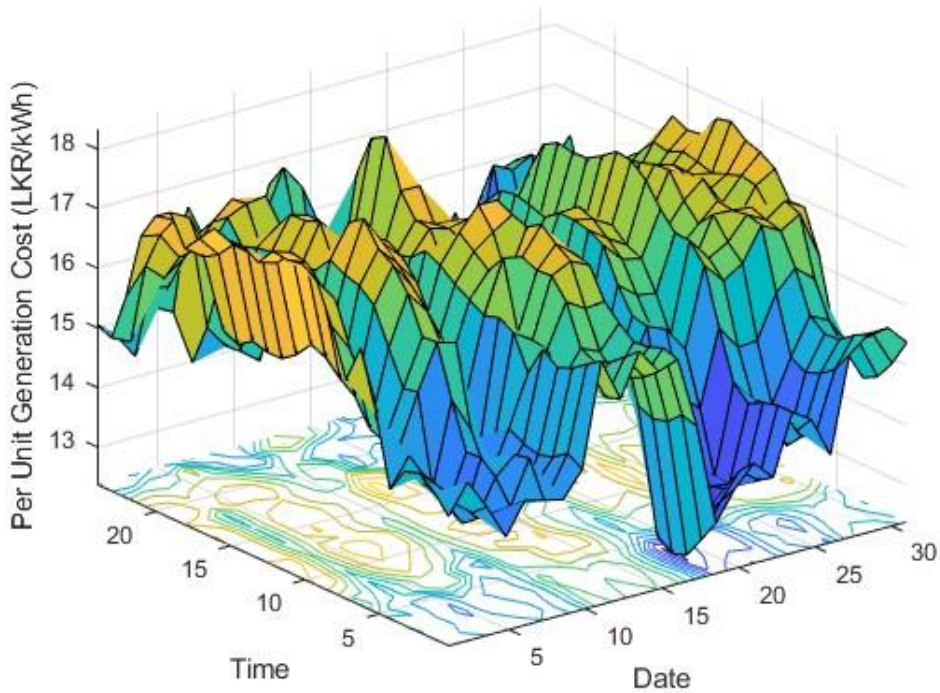


Figure K. 8: Generation Cost of August 2019, Calculated by Method 03

September

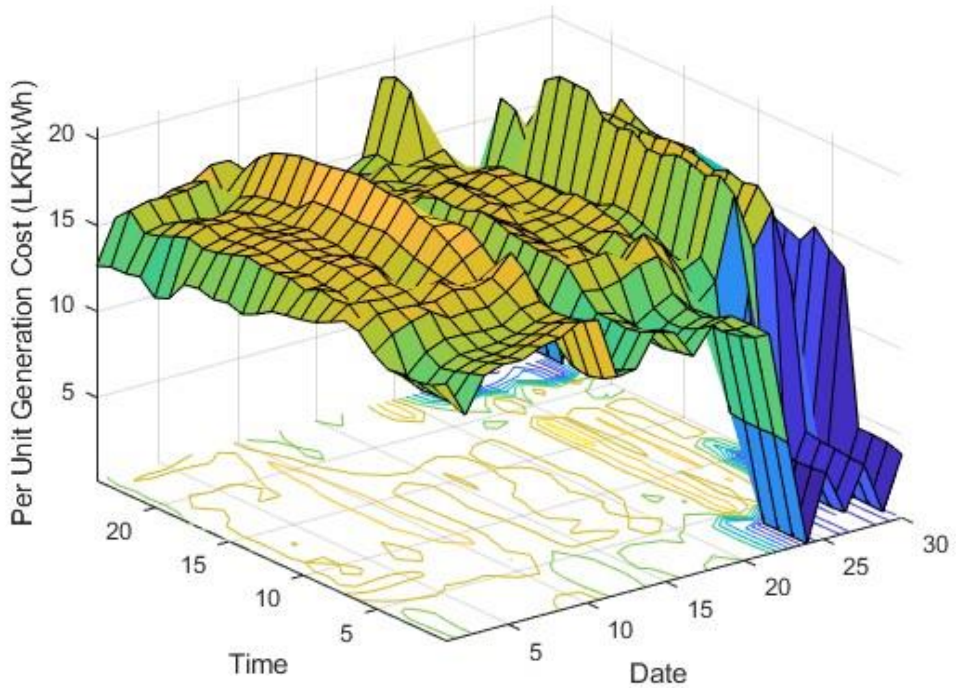


Figure K. 9: Generation Cost of September 2019, Calculated by Method 03

October

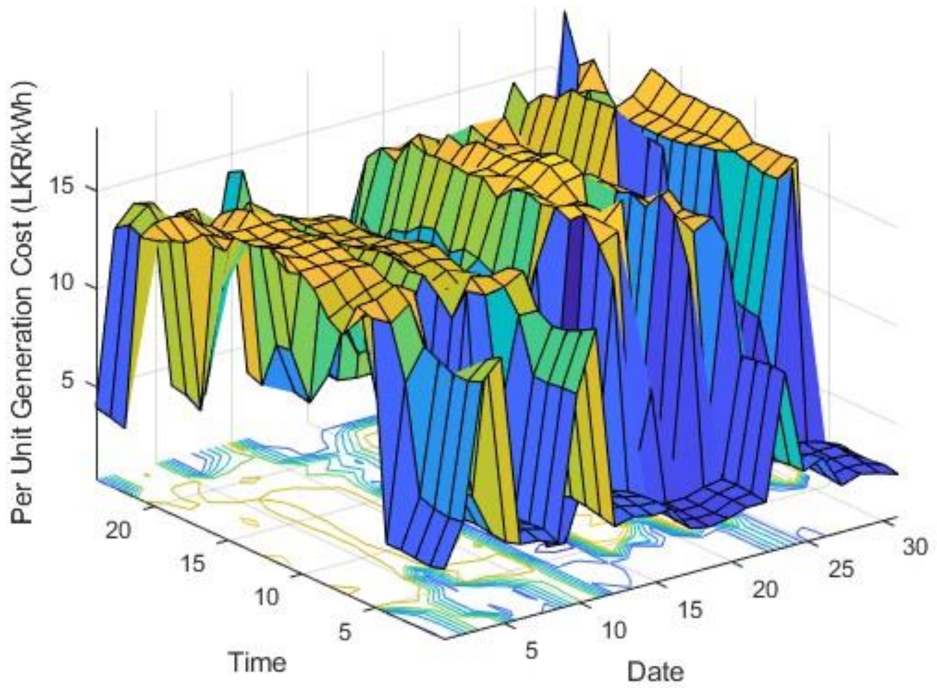


Figure K. 10: Generation Cost of October 2019, Calculated by Method 03

November

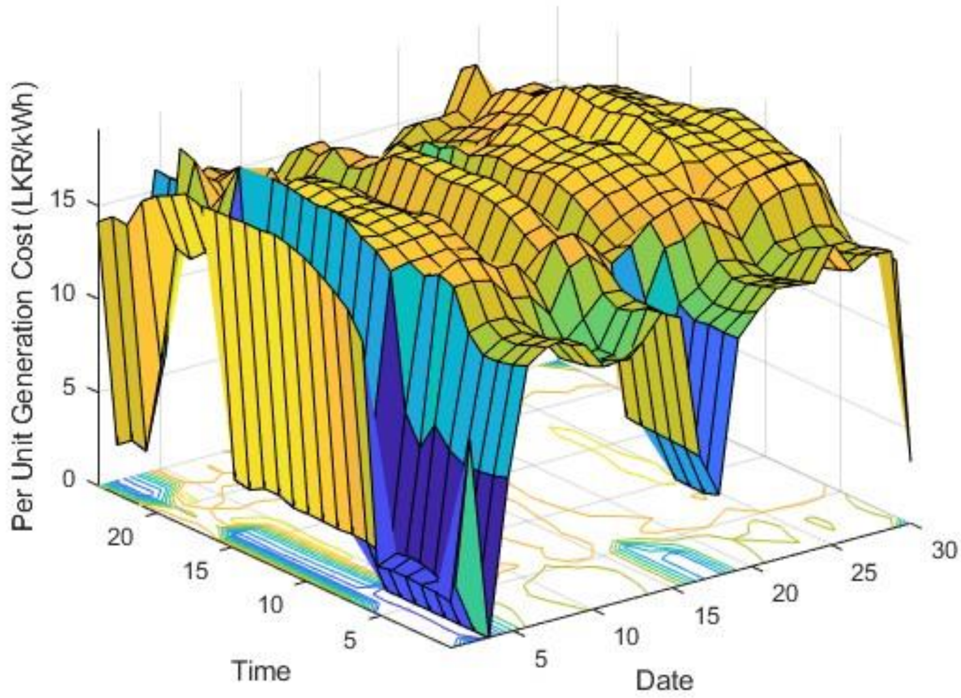


Figure K. 11: Generation Cost of November 2019, Calculated by Method 03

December

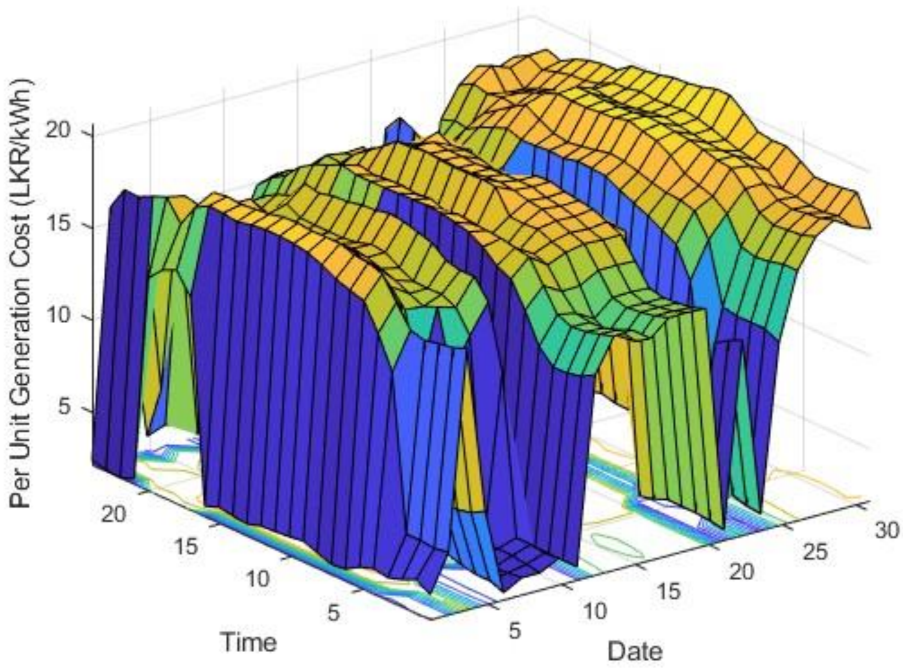


Figure K. 12: Generation Cost of December 2019, Calculated by Method 03

[Appendix L- Generation Cost of January 2019: Comparison of the results of three methods]

Tuesday 1st of January 2019

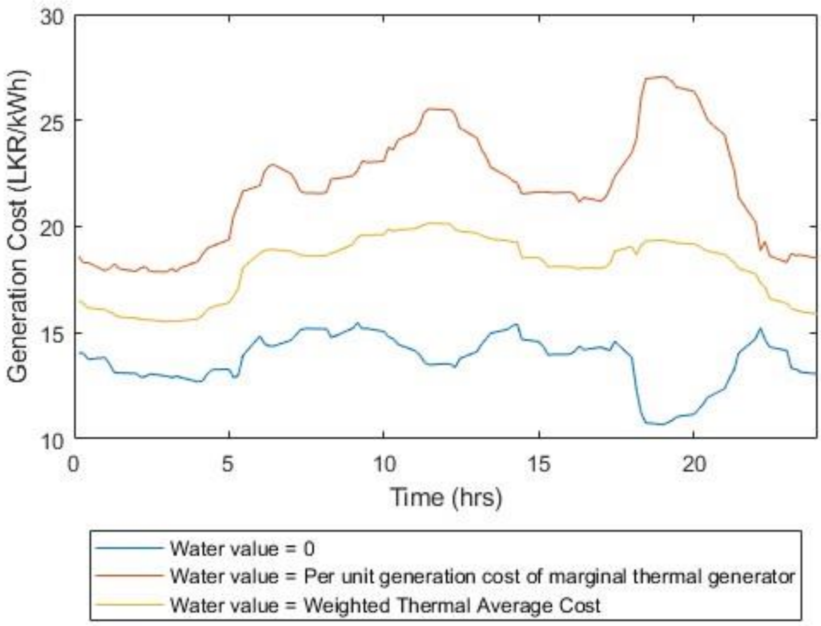


Figure L. 1: Generation Cost of 2019.01.01.

Wednesday 2nd of January 2019

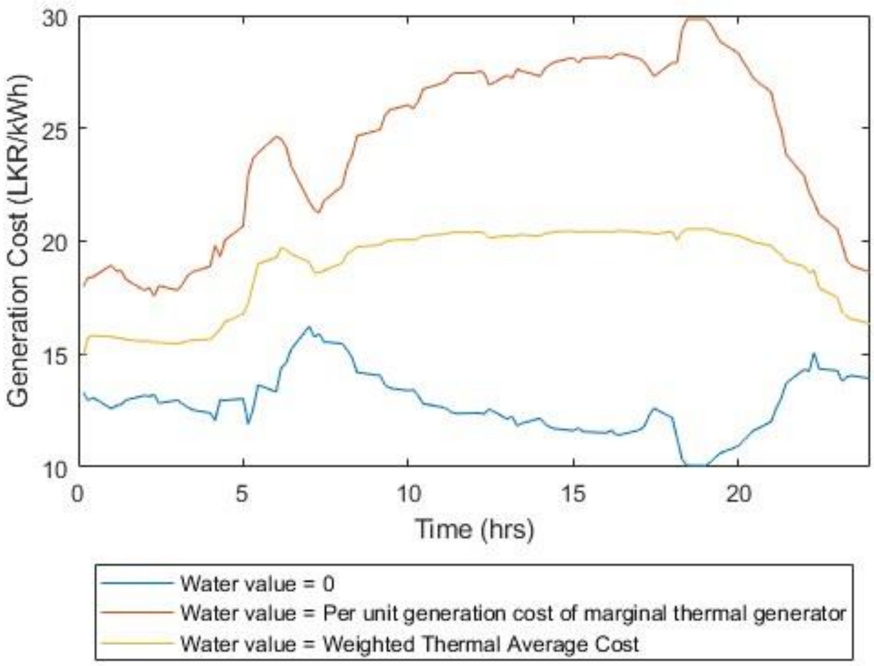


Figure L. 2: Generation Cost of 2019.01.02.

Thursday 3rd of January 2019

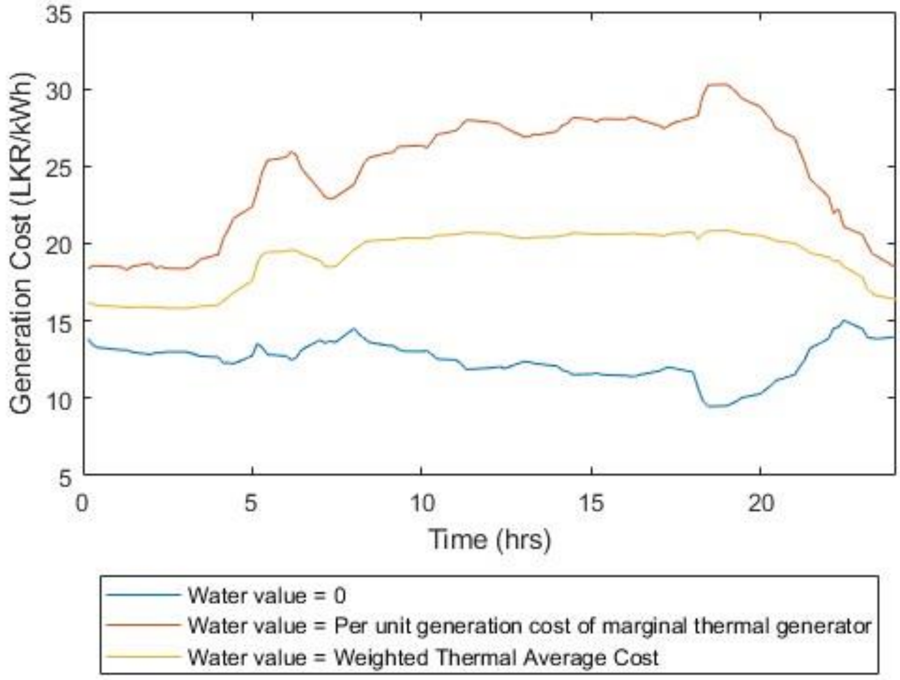


Figure L. 3: Generation Cost of 2019.01.03.

Friday 4th of January 2019

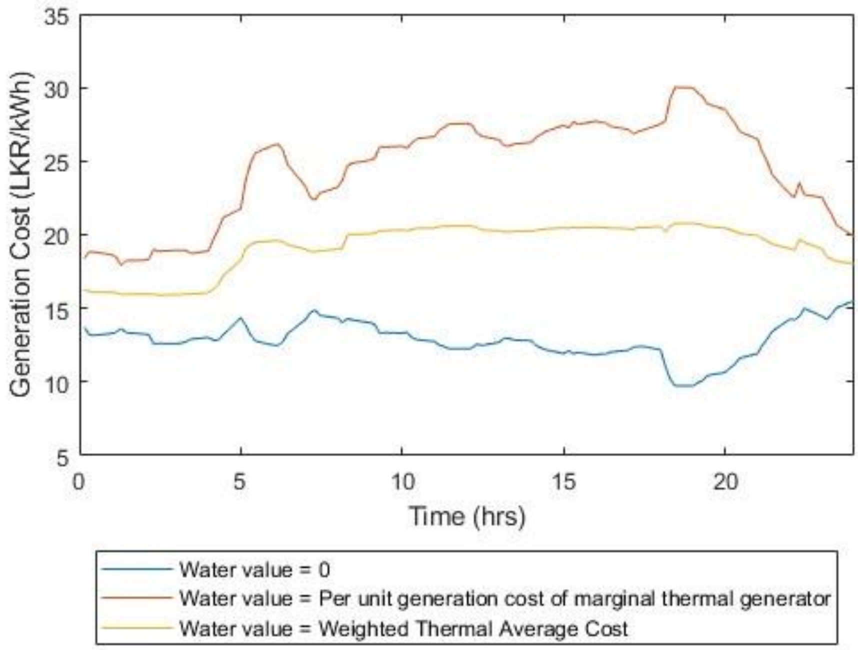


Figure L. 4: Generation Cost of 2019.01.04.

Saturday 5th of January 2019

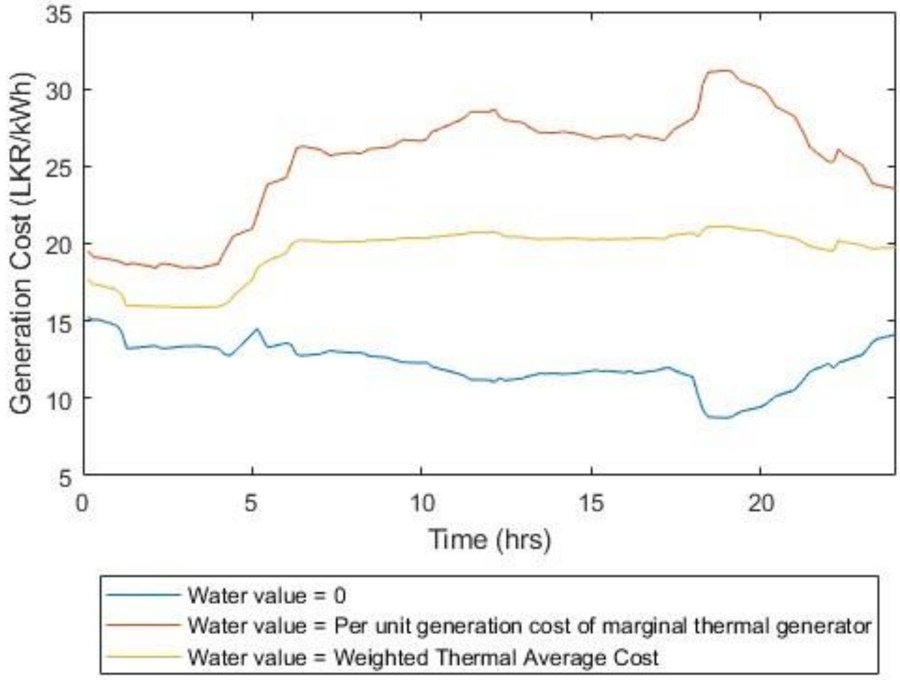


Figure L. 5: Generation Cost of 2019.01.04.

Sunday 6th of January 2019

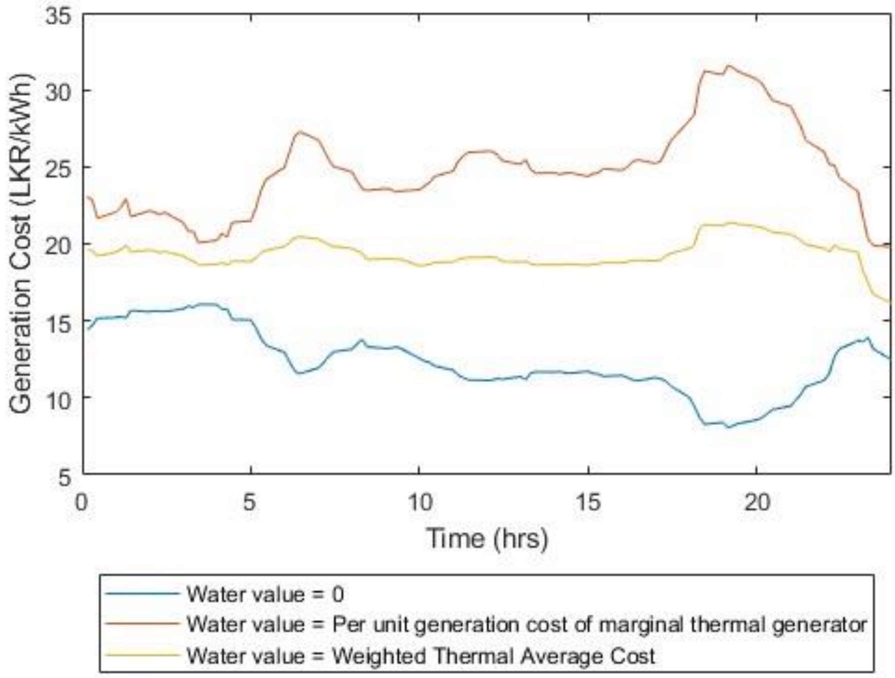


Figure L. 6: Generation Cost of 2019.01.06.

Monday 7th of January 2019

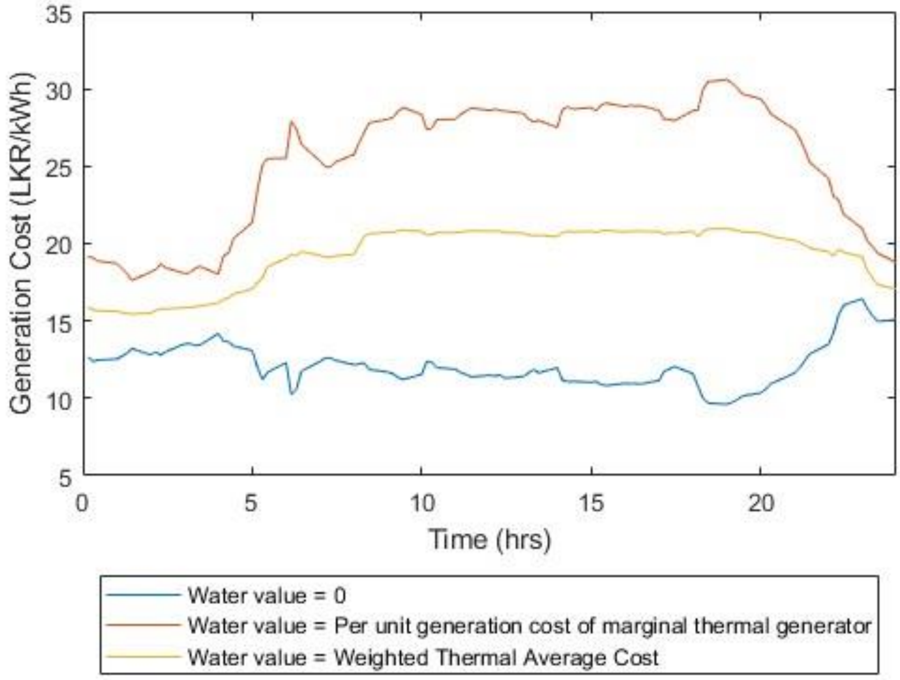


Figure L. 7: Generation Cost of 2019.01.07.

Tuesday 8th of January 2019

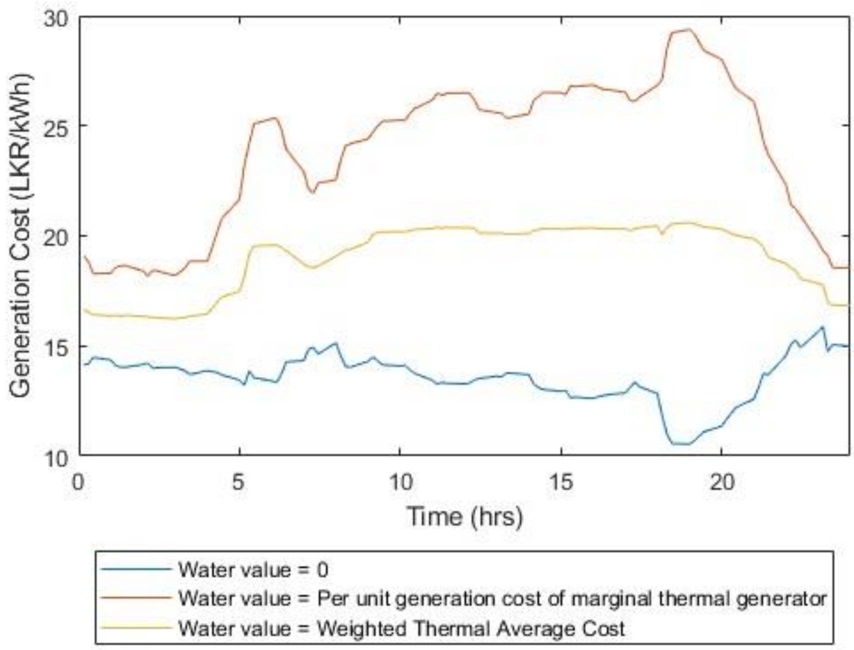


Figure L. 8: Generation Cost of 2019.01.08.

Wednesday 9th of January 2019

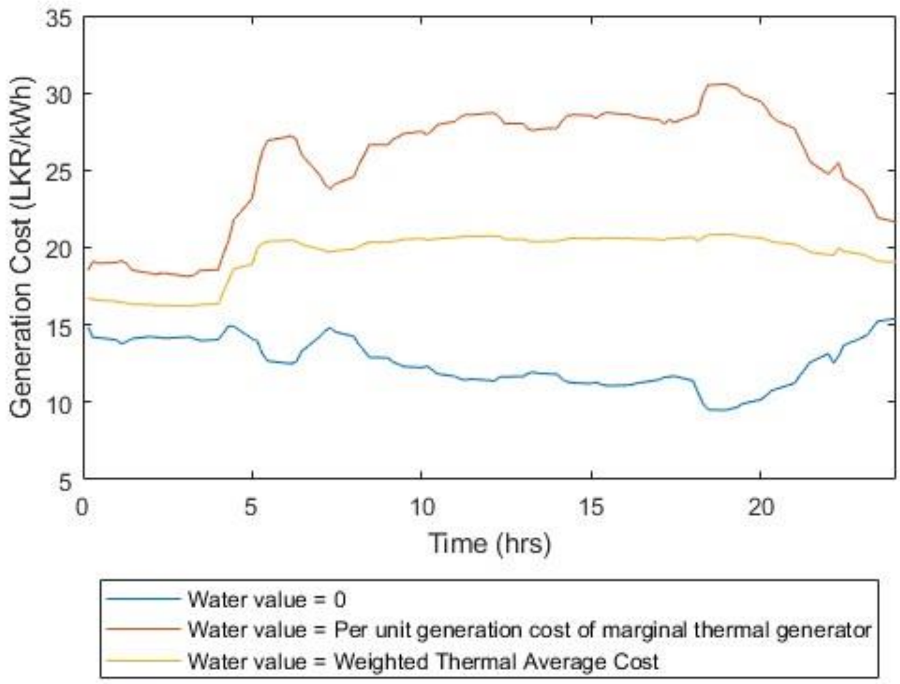


Figure L. 9: Generation Cost of 2019.01.09.

Thursday 10th of January 2019

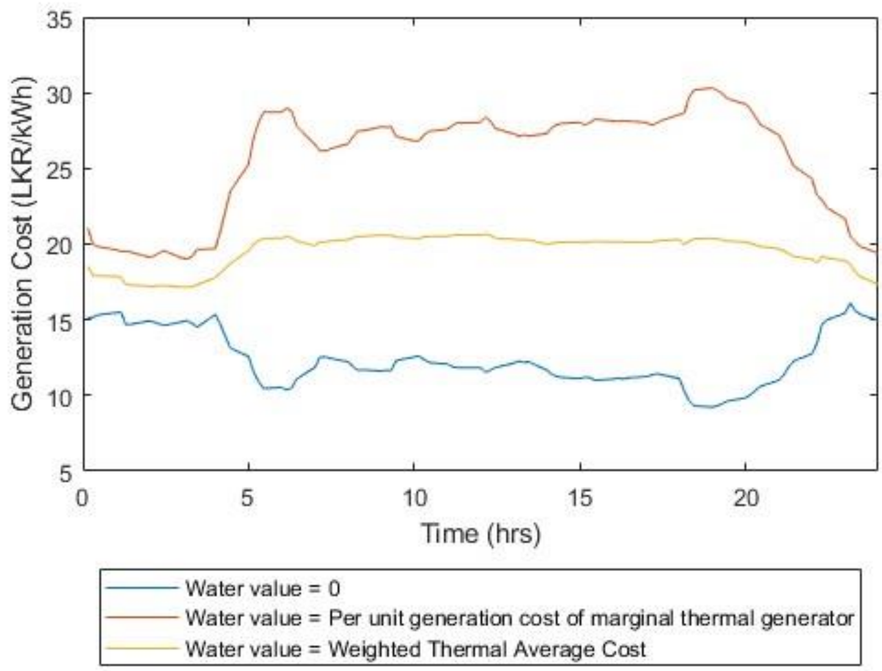


Figure L. 10: Generation Cost of 2019.01.10.

Friday 11th of January 2019

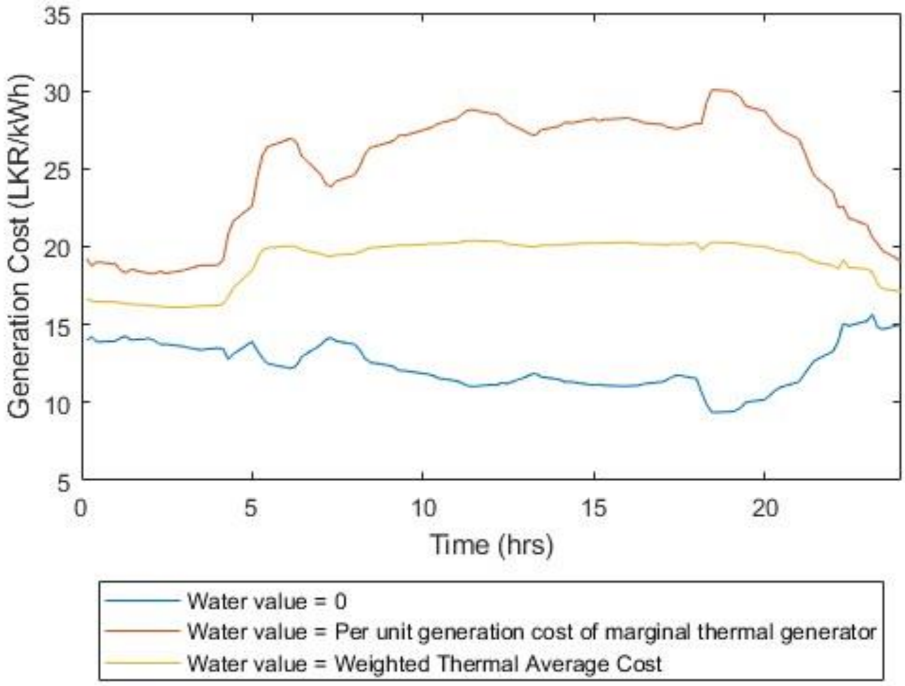


Figure L. 11: Generation Cost of 2019.01.11.

Saturday 12th of January 2019

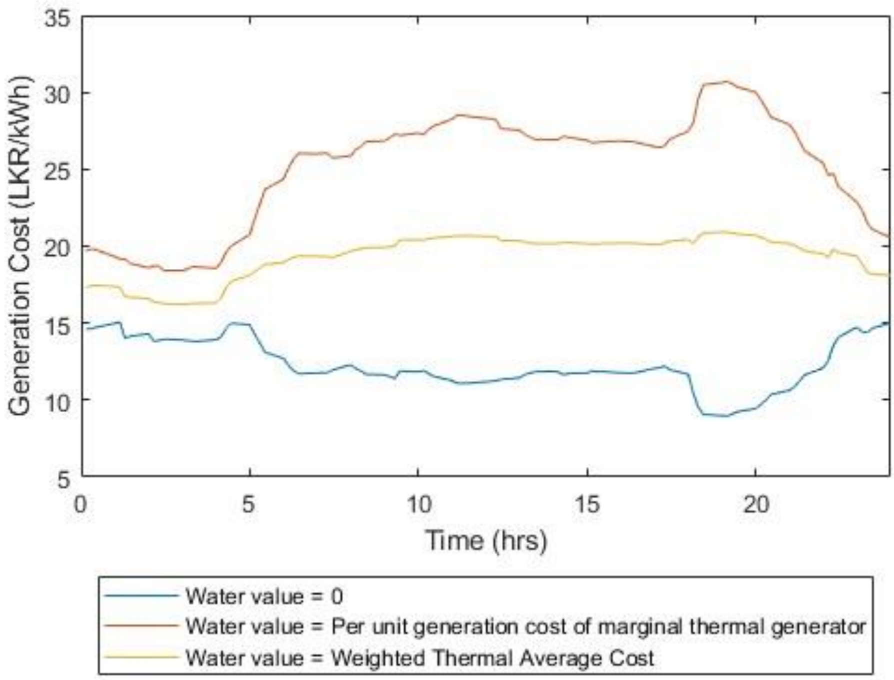


Figure L. 12: Generation Cost of 2019.01.12.

Sunday 13th of January 2019

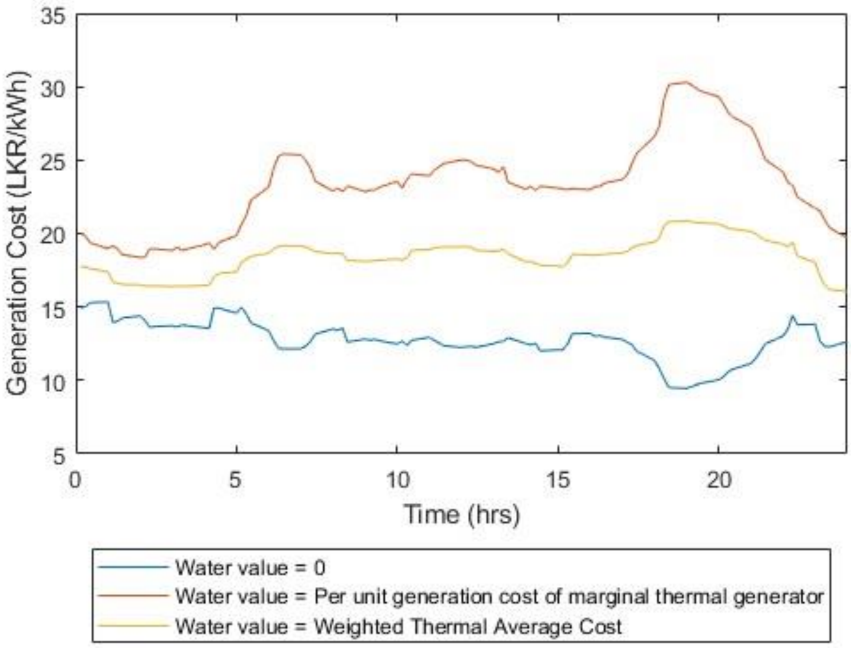


Figure L. 13: Generation Cost of 2019.01.13.

Monday 14th of January 2019

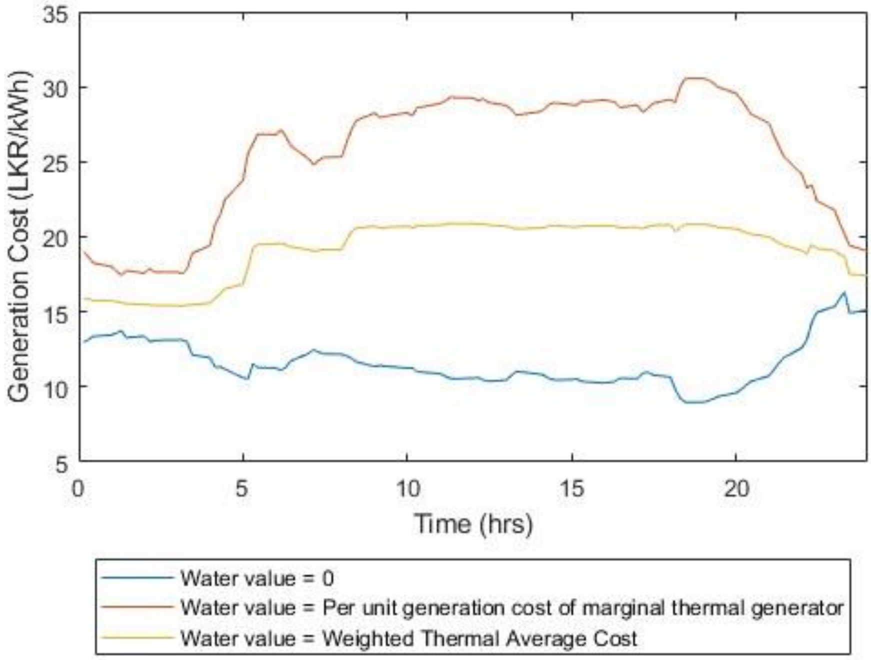


Figure L. 14: Generation Cost of 2019.01.14.

Tuesday 15th of January 2019

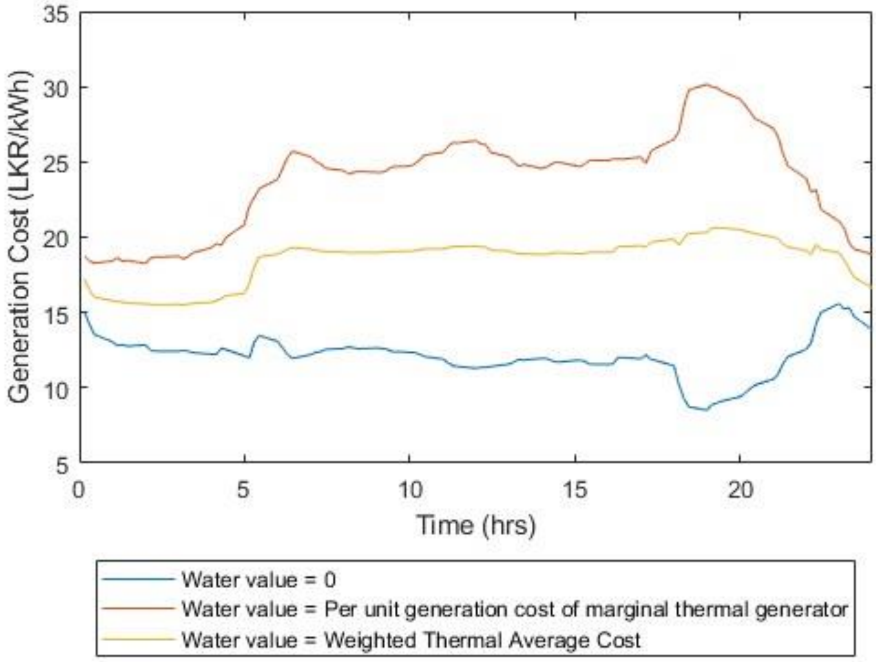


Figure L. 15: Generation Cost of 2019.01.15.

Wednesday 16thof January 2019

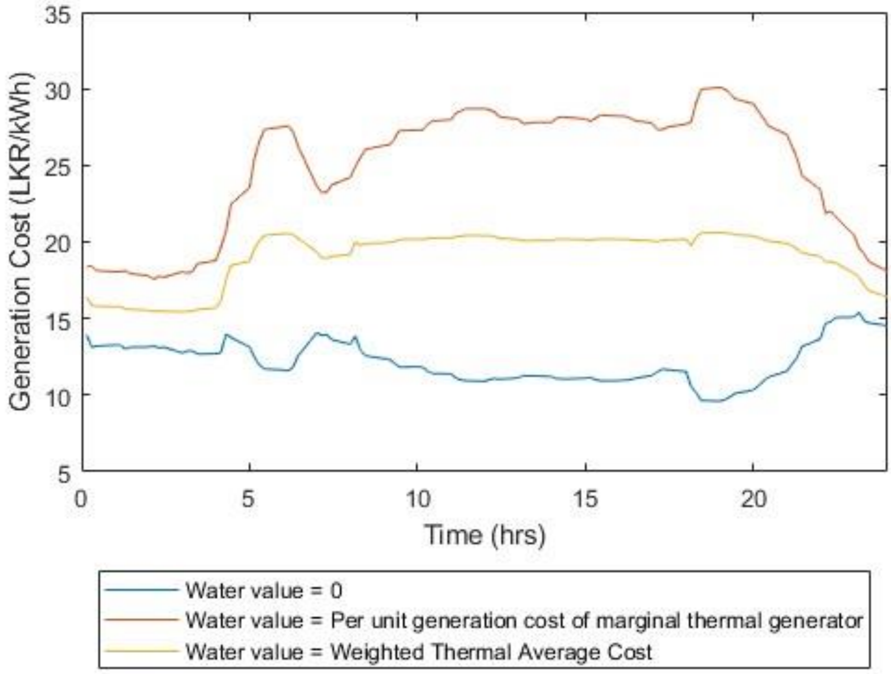


Figure L. 16: Generation Cost of 2019.01.16.

Thursday 17th of January 2019

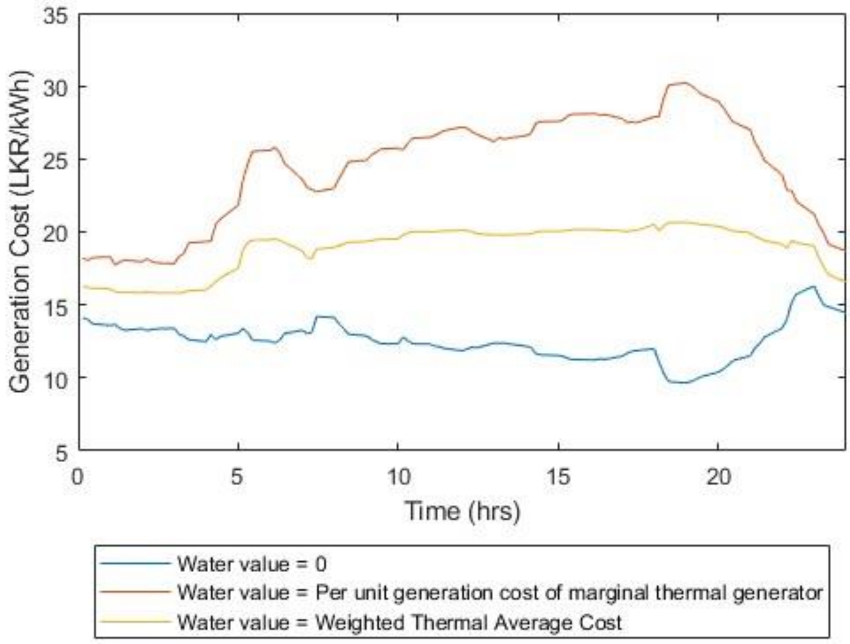


Figure L. 17: Generation Cost of 2019.01.17.

Friday 18th of January 2019

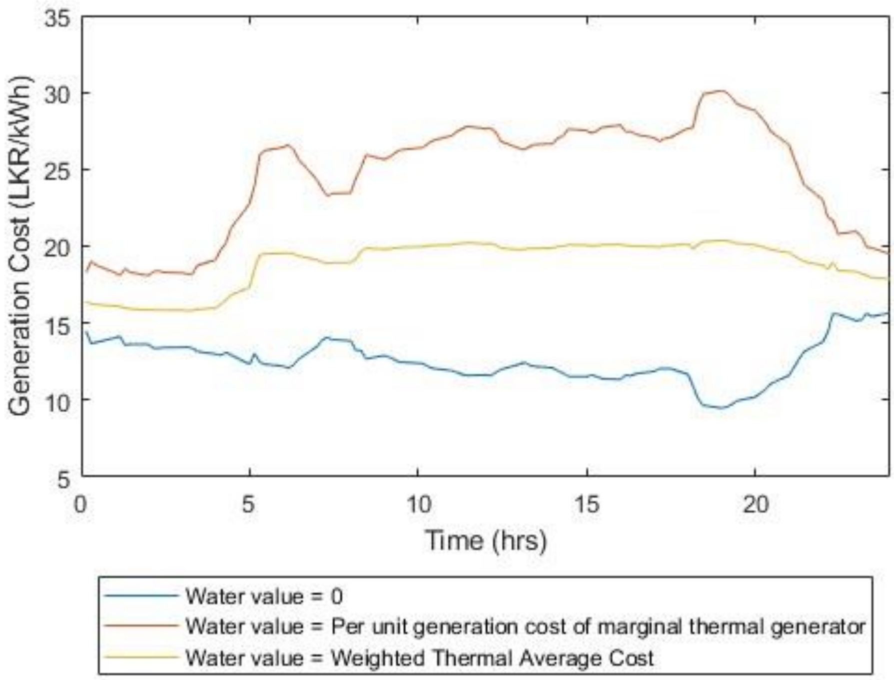


Figure L. 18: Generation Cost of 2019.01.18.

Saturday 19th of January 2019

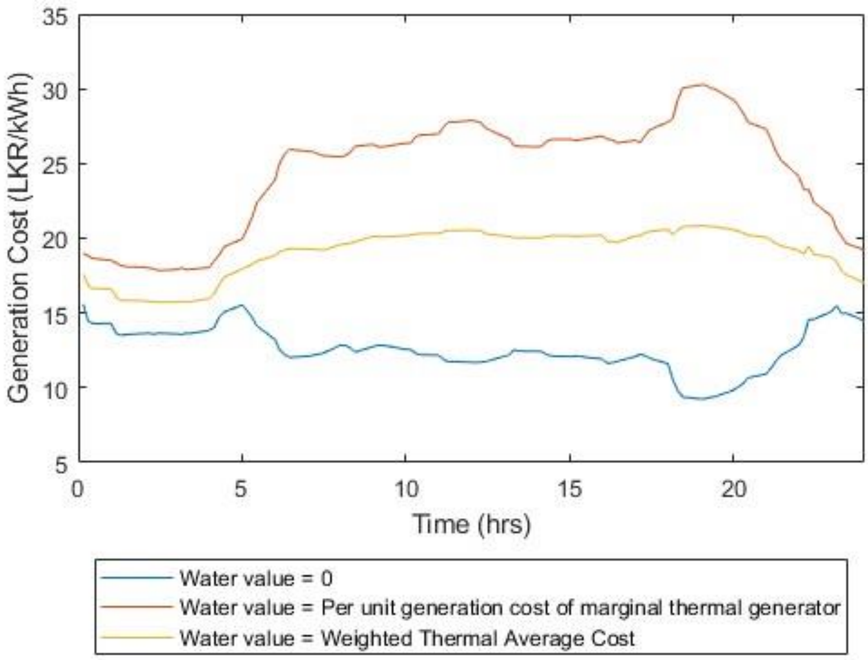


Figure L. 19: Generation Cost of 2019.01.19.

Sunday 20th of January 2019

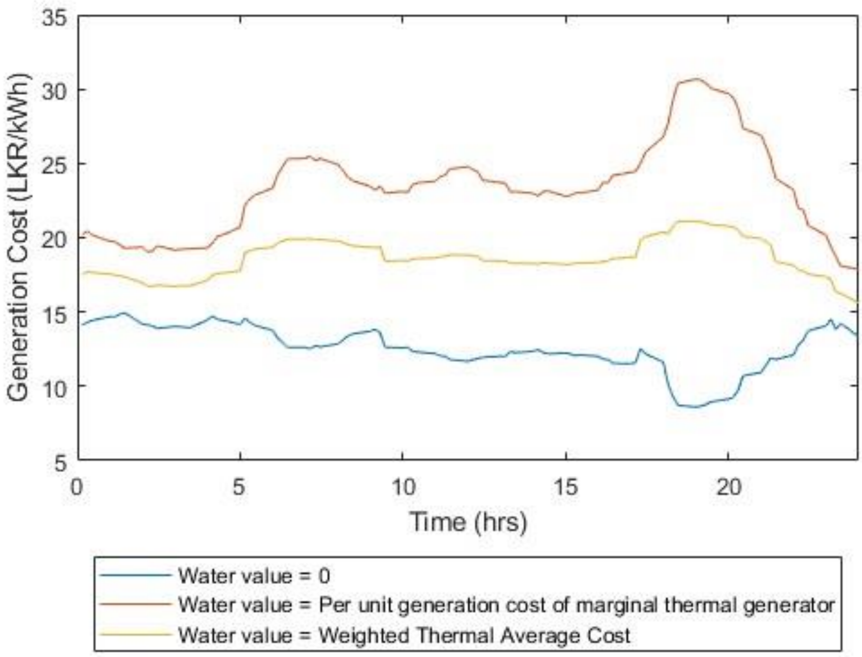


Figure L. 20: Generation Cost of 2019.01.20.

Monday 21st of January 2019

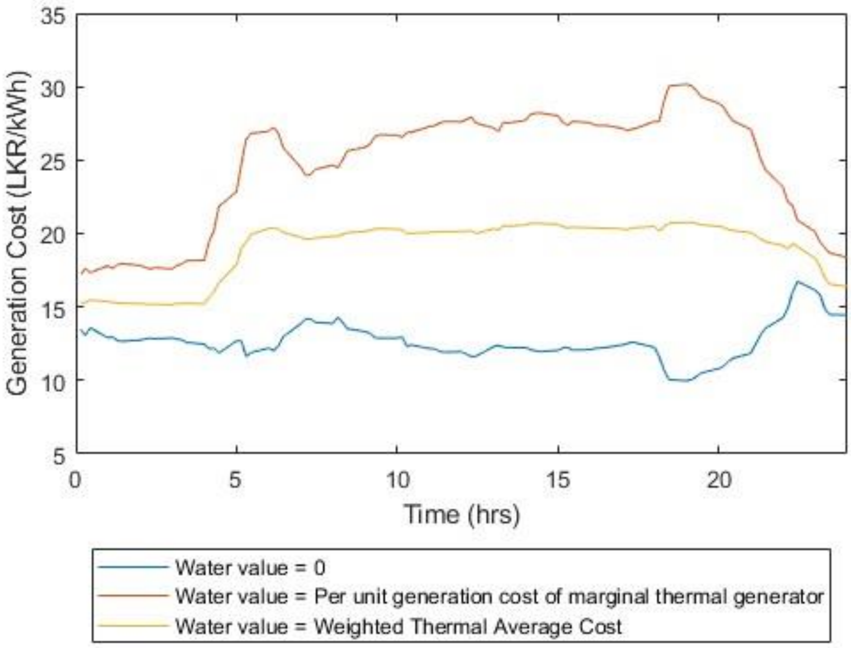


Figure L. 21: Generation Cost of 2019.01.21.

Tuesday 22nd of January 2019

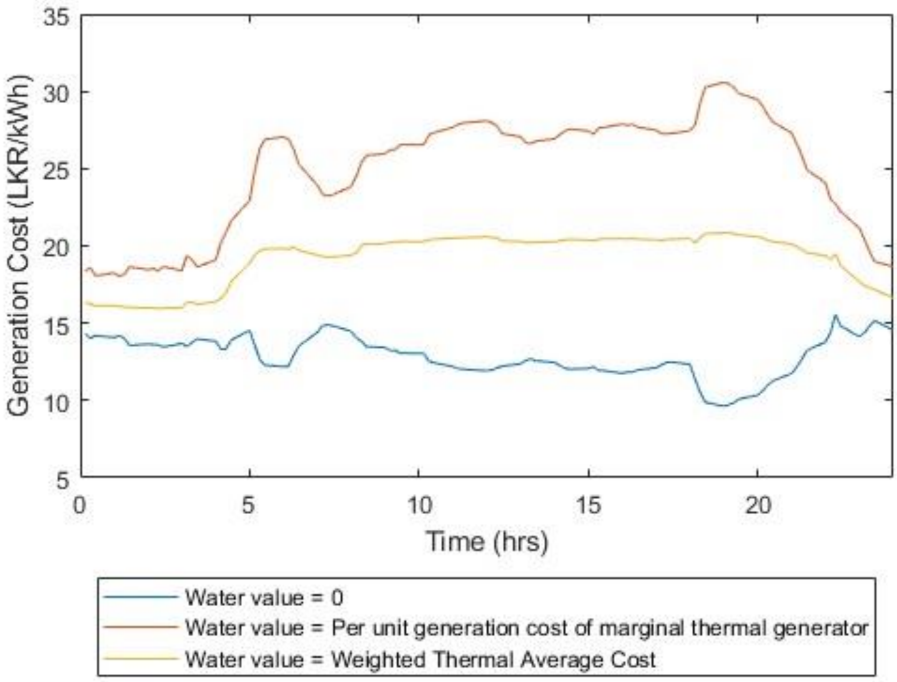


Figure L. 22: Generation Cost of 2019.01.22.

Wednesday 23rd of January 2019

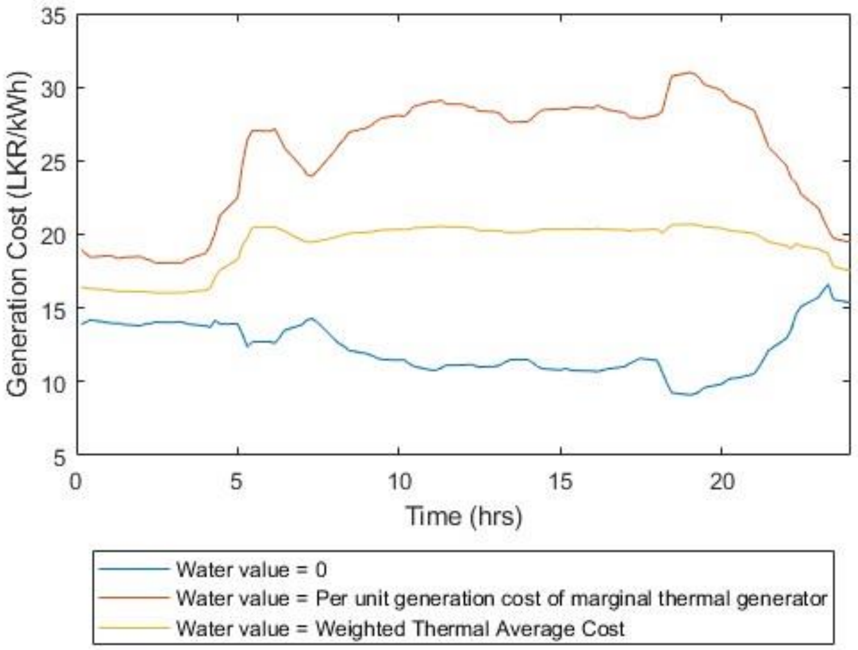


Figure L. 23: Generation Cost of 2019.01.23.

Thursday 24th of January 2019

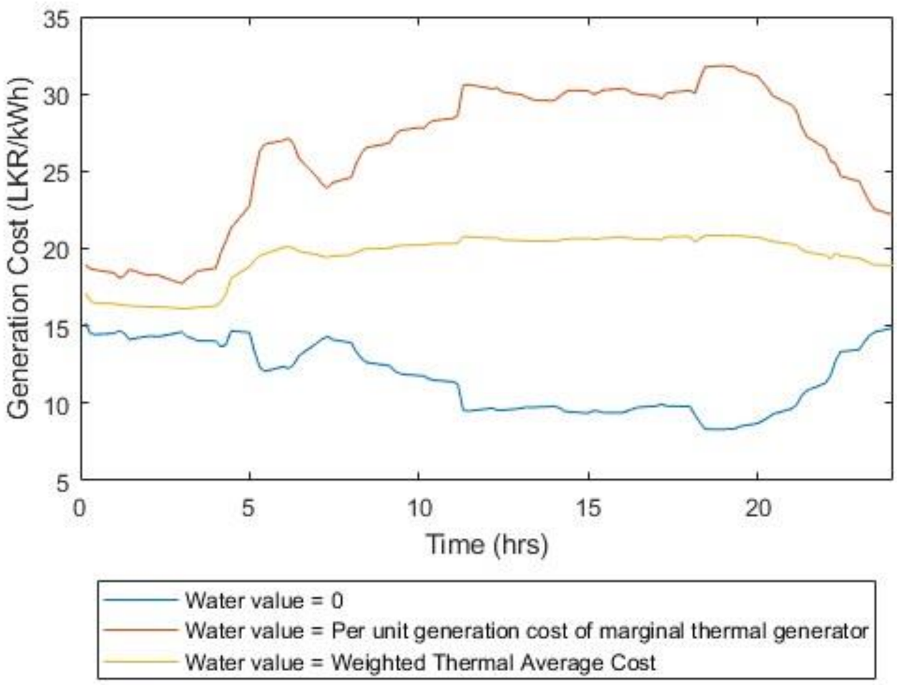


Figure L. 24: Generation Cost of 2019.01.24.

Friday 25th of January 2019

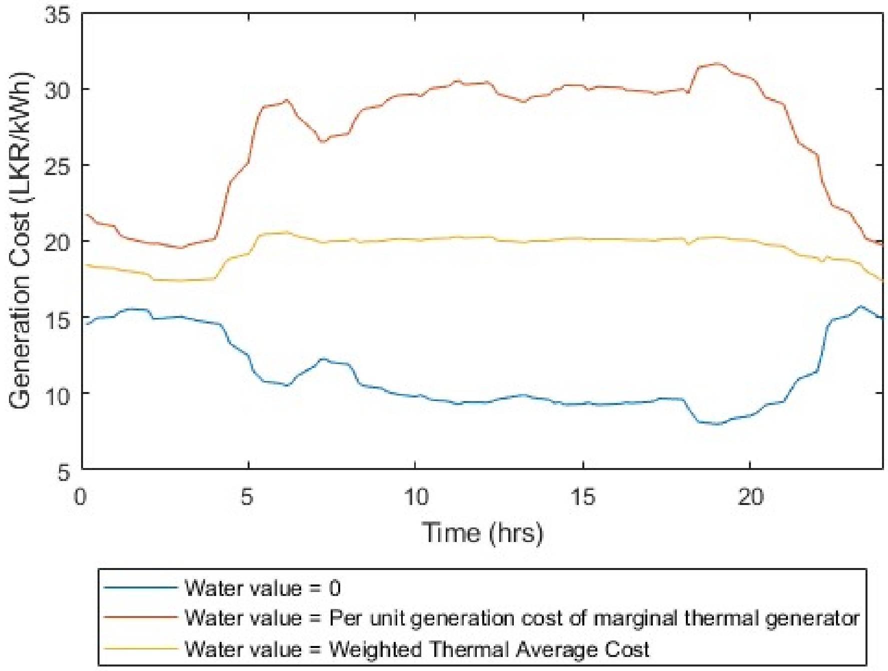


Figure L. 25: Generation Cost of 2019.01.25.

Saturday 26th of January 2019

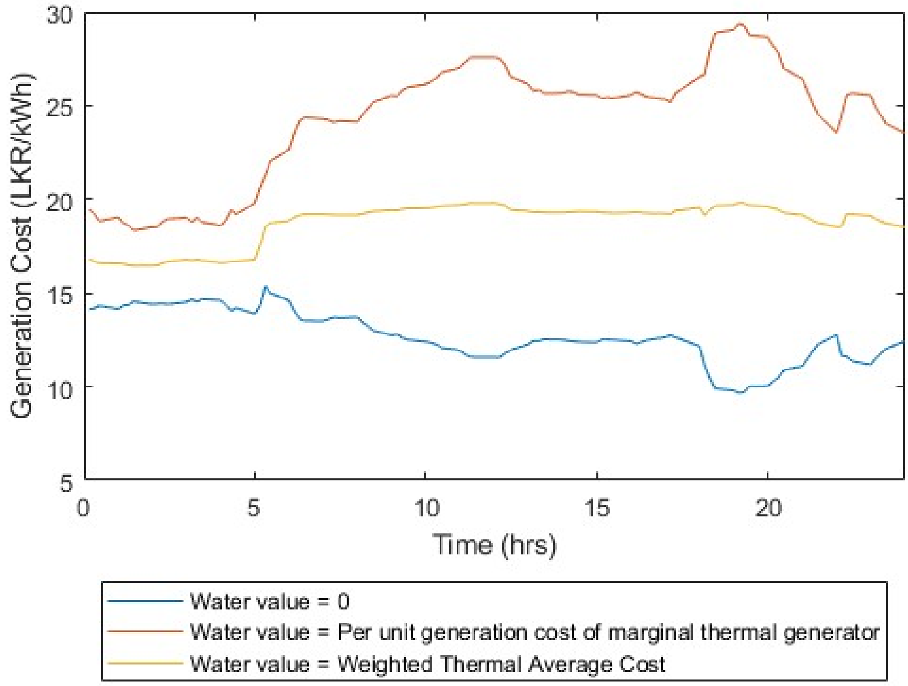


Figure L. 26: Generation Cost of 2019.01.26.

Sunday 27th of January 2019

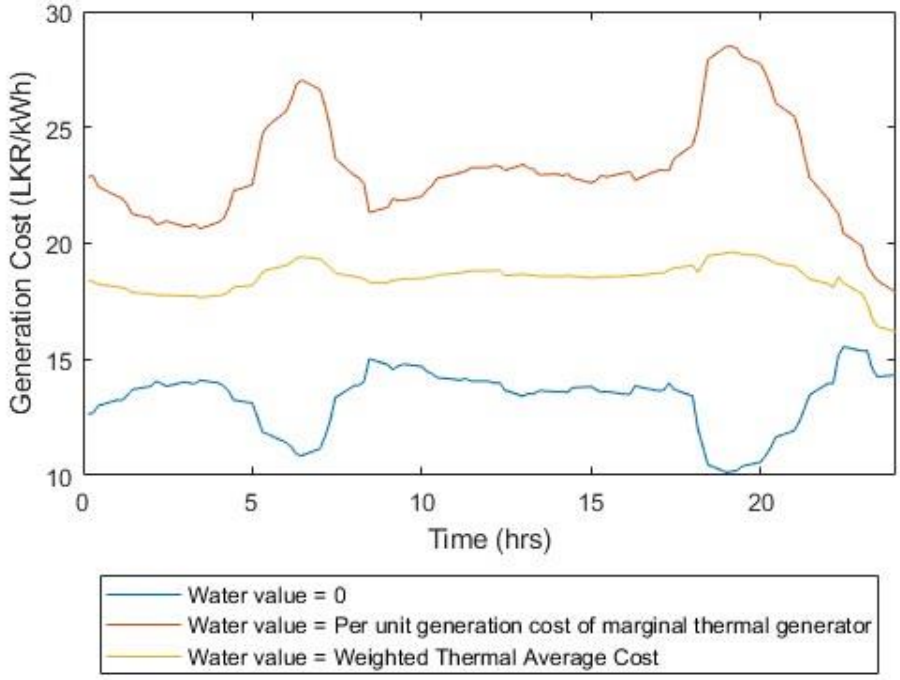


Figure L. 27: Generation Cost of 2019.01.27.

Monday 28th of January 2019

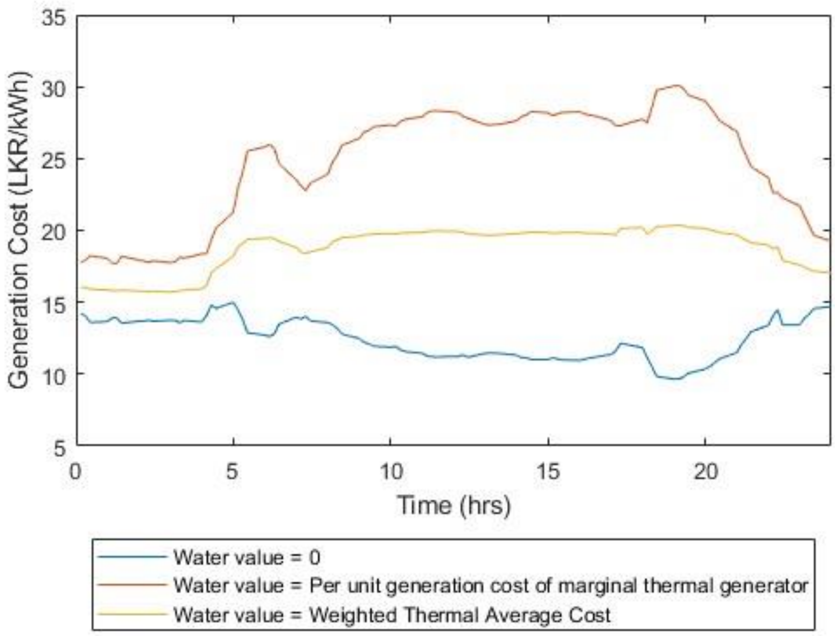


Figure L. 28: Generation Cost of 2019.01.28.

Tuesday 29th of January 2019

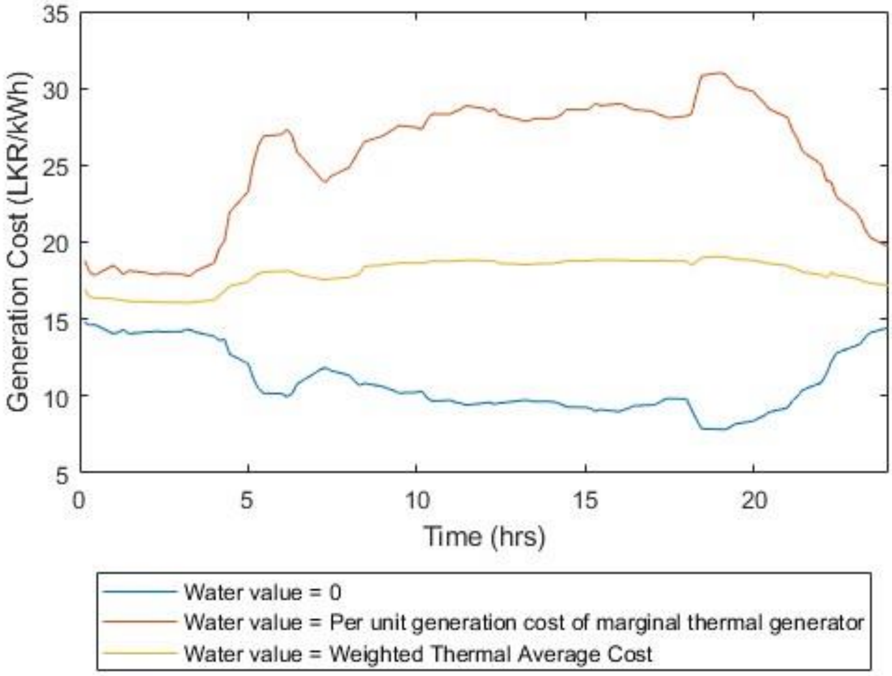


Figure L. 29: Generation Cost of 2019.01.29.

Wednesday 30th of January 2019

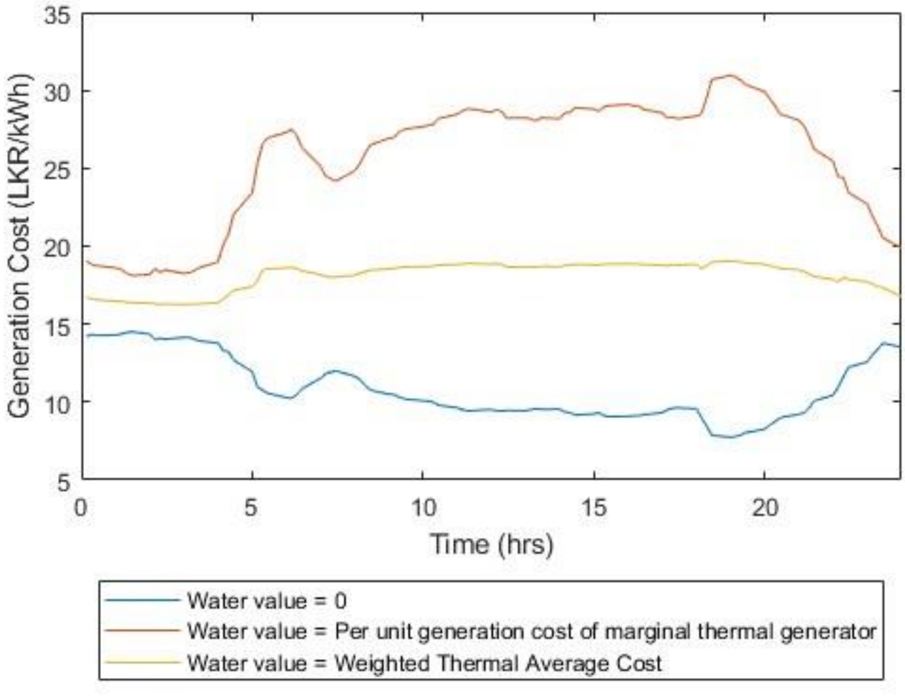


Figure L. 30: Generation Cost of 2019.01.30.

Thursday 31st of January 2019

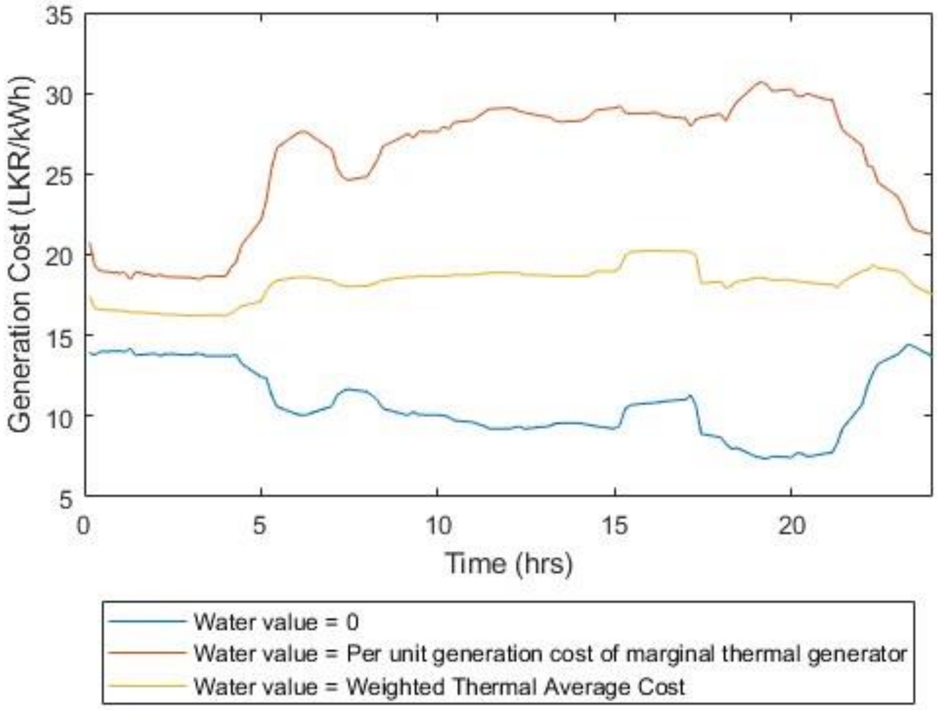


Figure L. 31: Generation Cost of 2019.01.31.

[Appendix M- Sri Lankan Calander 2019: displaying holidays]

Figure M. 1: Sri Lankan Calander of 2019