Norges miljø- og
biovitenskapelige
universitet

Master's Thesis 2021 30 ECTS
Faculty of Environmental Sciences and Natural Resource Management

Exploring future energy solutions in Ghana with FPV/PHS hybrid system through techno-economic analysis

Solveig Barstad Thoresen and Torgrim Skogheim
Renewable Energy

Acknowledgements

Writing a master's thesis often marks the end of a long educational chapter in life, and the transition to another. Even though we are excited for the new chapter, our experiences along the way both inside and outside the classroom will stay fond memories going forward. The master's thesis is one way to leave a watermark within the academic community, and we are very proud to join that privileged group of people. Our journey, that started with mutual interest in a topic, which later turned into a collaborative joint effort to write this thesis, would not have been possible without the support from many people along the way.

The motivation for specializing our knowledge within solar power is in many ways thanks to our supervisor Muyiwa Samuel Adaramola. Your knowledge and assistance within this field was of exceptional help. Your motivational way of teaching, combined with such calmness and humour have been invaluable along the way of completing this task and previous courses. We could not have asked for a better supervisor, so thank you very much. Secondly, we also owe great thanks to our other professors at NMBU who taught us relevant theory for both this task and professional use going forward.

Working with this thesis introduced us to the guys at Glint Solar. We thank you for showing interest in our work and contributing with your evaluator tool, allowing us to add something new and innovative to our thesis. We would also like thank our fellow students within the renewable energy program at NMBU with such enthusiasm and engagement, on and off campus. Our trip to Smøla will always be a highlight looking back, along with endless breaks in Disco at Sørhellinga.

And to our friends and families who always cheered and supported us every step of the way: Thank you everyone, you are the most important crews in our lives.

Ås, 28.05.2021

Abstract

Ghana accommodates abundant solar resources and has a goal of installing 425 MW of new utility scaled photovoltaics by 2030. Would conventional ground-based photovoltaics (PV) or the growing floating PV (FPV) technology provide a better solution for the solar installation? What about combining the FPV with a hybrid system including pumped hydro storage (PHS) to improve flexibility and stabilise reservoir levels?

These questions created the framework of what this thesis has examined through a techno-economic analysis with the use of hybrid energy optimization software and a newly developed site evaluator engine for FPV. To establish a comparison between ground-based PV, FPV and the hybrid option with FPV and PHS, two locations with existing hydropower plants in Ghana were selected. The Akosombo and Bui hydropower plants have a current installed capacity of 1,020 MW and 400 MW, respectively. To compare the solar PV potential of two locations, the planned installed effect of 425 MW was evenly split between the two hydropower plants.

The results showed that ground-based PV yielded around 275 GWh annually for each of the two locations with a levelized cost of energy (LCOE) of $0.098/kWh. This is slightly higher than average industry values ranging from $0.047-0.053/kWh, but well below the currently largest PV site in Ghana; Navrongo ($0.2411/kWh). Choosing FPV over ground-based PV increased the yield by 18% and 16% for Bui and Akosombo, respectively, at a marginally higher LCOE ($0.104/kWh and $0.106/kWh).

Coupling FPV with PHS yielded annual output of 262.43 GWh to the grid where the FPV efficiently charged the reservoirs in the dry months. LCOE came to $0.234/kWh, which is lower than most thermal plants in Ghana. Further comparison between the FPV/PHS hybrid solution and thermal plant showed a simple payback period of under 13 years before the cost of the hybrid system was lower than diesel-fuelled thermal system. Changes in both FPV capital cost and fuel prices had a strong correlation with preferred system solution. With fuel prices above $0.5/L, PV were part of any suggested solutions with PHS. The analysis discovered certain software limitations where further development in optimization software for hybrid PHS and possible site feasibility studies in Ghana could strengthen the theoretical foundation.

Sammendrag

Ghana har gode solressurser og ønsker å installere 425 MW med ny solcellekapasitet innen 2030. Hvilke alternativer kan gi de beste løsningene? Er landbaserte solceller (PV) bedre eller kan flytende solceller (FPV) gi et bedre resultat? Og kan et hybridsystem som inkluderer lagring med pumpekraft, forbedre fleksibiliteten og stabilisere vannstanden i dammene?

Dette skapte rammeverket for hva denne masteroppgaven har undersøkt i et tekno-økonomisk perspektiv med bruk av optimaliseringsprogramvare for hybride energisystemer og en ny evalueringsprogramvare for FPV. For å få en sammenligning mellom landbasert PV, FPV og hybridalternativet med FPV og pumpekraft (PHS), ble to steder med eksisterende vannkraftverk valgt. Vannkraftverkene Akosombo og Bui har henholdsvis 1.020 MW og 400 MW installert kapasitet. For å sammenlikne potensialet på det to lokasjonene ble den planlagte installerte effekten på 425 MW fordelt likt mellom de to vannkraftverkene.

Resultatene viste at landbasert PV produserte 275 GWh årlig for hvert av de to stedene med en LCOE på $0,098/kWh over levetiden. Dette er litt høyere enn industrigjennomsnittet $0,047-0,053/kWh, men godt under det største solcelleanlegget i Ghana i Navrongo ($0,2411/kWh). Å velge flytende solcelleanlegg økte produksjonen med 18% og 16% for henholdsvis Bui og Akosombo med en marginalt høyere LCOE ($0,104/ kWh og $0,106/kWh). Forskjellen mellom Bui og Akosombo kan tyde på at Bui får utnyttet solinnstrålingen bedre gjennom høyere grad av vannflatekjøling blant andre faktorer.

Sammenkoblingen av FPV og PHS ga en årlig produksjon på 262,43 GWh til nettet samtidig som panelene bidro til å stabilisere det øvre magasinet i den tørre perioden. LCOE ble $0.234/kWh, noe som er lavere enn de fleste varmekraftverk i Ghana. Videre sammenligning mellom FPV/PHS hybridløsningen og varmekraftverk viste en tilbakebetalingsperiode på under 13 år før kostnadene for hybridsystemet var lavere enn et dieseldrevet varmekraftverk. Endringer i enten kapitalkostnad for FPV eller drivstoffprisen syntes å ha en sterk sammenheng når det gjaldt foretrukket systemløsning. Med drivstoffpriser over $0,5/L var solenergi en del av alle foreslåtte systemløsninger med lagring. Analysen avslørte visse begrensninger innen programvaren, hvor videre utvikling innen optimaliseringsverktøy som inkluderer hybrid pumpekraft samt mulighetsstudier på de aktuelle stedene kan styrke den teoretiske analysen ytterligere.

Table of contents

List of tables

List of figures

List of acronyms

AC – Alternating current

Ah – Ampere hours

CAPEX – Capital expenditure

CC – Cycle charging

CO_2eq – Carbon dioxide equivalents

DC – Direct current

FPV – Floating photovoltaics

GW/GWh – Gigawatt/Gigawatt hour

HOMER – Hybrid Optimization Model for Electric Renewable

IRENA – International Renewable Energy Agency

kW/kWh – Kilowatt / Kilowatt hour

LCOE – Levelized cost of energy

LCOS – Levelized cost of storage

MW/MWh – Megawatt / Megawatt hour

NASA – National Aeronautics and Space Administration

NPC – Net Present Cost

PHS – Pumped Hydro Storage

PV – Photovoltaics

PVGIS – Photovoltaic Geographical Information System

STC – standard test conditions

VRE – Variable Renewable Energy

ROI – Return on Investment

$ – United States dollar

1 INTRODUCTION

With continuous growth in world population and increasing consumption of natural resources, humans are faced with the challenge of a changing climate due to increased emissions and depletion of these natural resources. As the world evolves, so does our consumption, and one of the areas where our consumption is ever growing is the demand for power and energy. Most recently, the demand has flourished in developing countries, with access to energy being considered essential for development by reducing poverty, improving health services, increasing productivity, boosting competitiveness, and ensuring economic growth (The World Bank 2018). However, with nuclear and renewable energy only accounting for approximately 37% of the total electricity supply (Ritchie 2021), fossils fuels dominate electricity generation, and is continuing to emit substantial amounts of carbon dioxide (CO_2) into the atmosphere. Therefore, providing a secure and sustainable electricity access to the world population has been a goal to ensure development and reduce emissions for decades.

The access to available electricity varies around the globe with sub-Saharan Africa being among the areas with the least access to electricity. According to Power Africa (Power Africa 2021), two out of three people lack electricity access in this region. Ghana, being one of the developing countries in this region, has experienced increasing electricity demand for some time due to economic growth, urbanization, and increased production (Gyamfi et al. 2014). Although, the current renewable energy fraction is very low, Ghana has an abundant potential of resources to diversify its power generation from non-fossil fuels resources (Effah & Boampong 2015).

1.1 Energy sector in Ghana

In Ghana, 83.24% of the population had access to electricity in 2019 making it among the highest in Sub-Saharan Africa (Ministry of Energy 2021). Out of this amount, only 50% of the population in rural areas had energy access, compared to 91% in urban areas. Even in the connected areas, however, the power distribution system falls short as it is regularly affected by inadequate supply infrastructure such as the high cost of fuel for electricity generation, high transmission and distribution losses and vulnerability to climate change (Eshun & Amoako-Tuffour 2016) (Gyamfi et al. 2018). As a result, the country has a high electricity supply security risk as part of the peak load is not met by available supply. Figure 1. 1 show a map of the transmission system in Ghana outlining the major transmission lines.

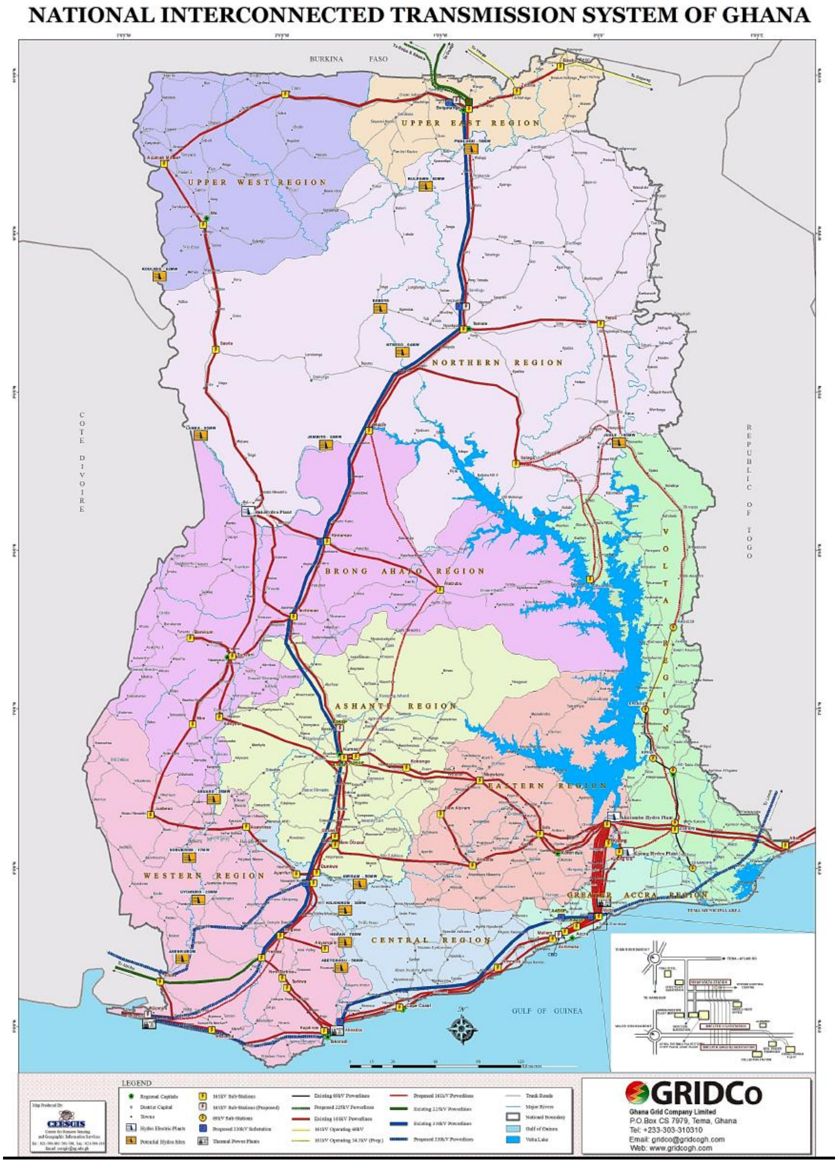


Figure 1. 1: National interconnected transmission system of Ghana (GRIDCo 2020).

As shown in Figure 1. 2, the present electricity generation in Ghana is dominated by thermal power (68.6%) and hydropower (30.6%) (Energy Commission Ghana 2020b). Even though there has been development of utility-scaled solar photovoltaics (PV) installations in Ghana, the total installed capacity of solar PV was 42.6 megawatt (MW) as of 2019, constituting a mere 0.8% of total installed power generating capacity. At the end of 2019, the total utility generation capacity equalled 4,990 MW, with another 181.6 MW of grid-tied embedded generation at sub-transmission level, making the total installed power capacity in Ghana 5,171.6 MW. However, dependable grid capacity was at 4,695 MW, with a peak load excluding exports that reached 2,612.5 MW. This left an excess capacity of 1,776.3 MW (Energy Commission Ghana 2020a).

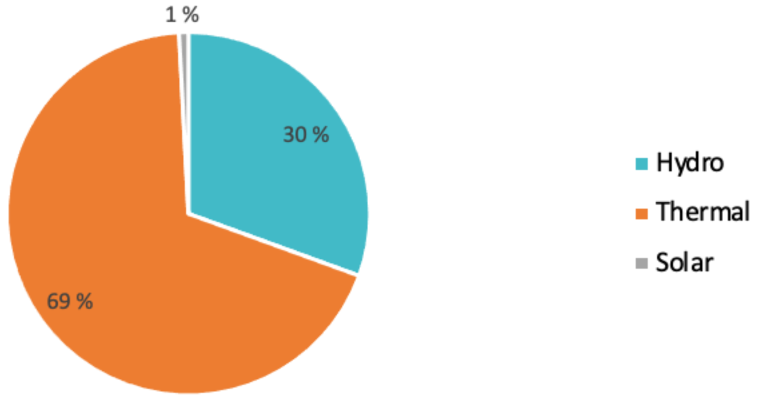


Figure 1. 2: Power generation by energy sources in 2019.

The Energy Commission (2020a) reported that a key objective going forward would be to ameliorate the overall power supply in the country. To achieve this objective, certain challenges in the electricity production facilities were examined. One of these challenges was the risk of hydropower reservoir elevation dropping below minimum operating level in the dry season, leaving the country dependent on costly oil and gas supply. Additionally, low reservoir levels posed a risk to the overall electricity supply in Ghana, as hydropower accounts for a considerable amount (30.6%) of the total electricity production.

Figure 1. 3 and Figure 1. 4 illustrate the observed variation in water levels at Ghana's two biggest hydropower reservoirs, Bui and Akosombo dam, in 2018 and 2019. They both record considerable fluctuations in the reservoir levels over a year, where the curves correlate with the country's climatic seasons. For the Bui reservoir (Figure 1. 3), the water elevation came very close to minimum operating level between June and August in both 2018 and 2019. Similarly, Figure 1. 4 illustrates the same occurrence for the Akosombo dam in 2018. However, due to the considerable size of Lake Volta, the variation in reservoir level is normally lower, as shown by the curve representing 2019 reservoir profile level in Figure 1. 4.

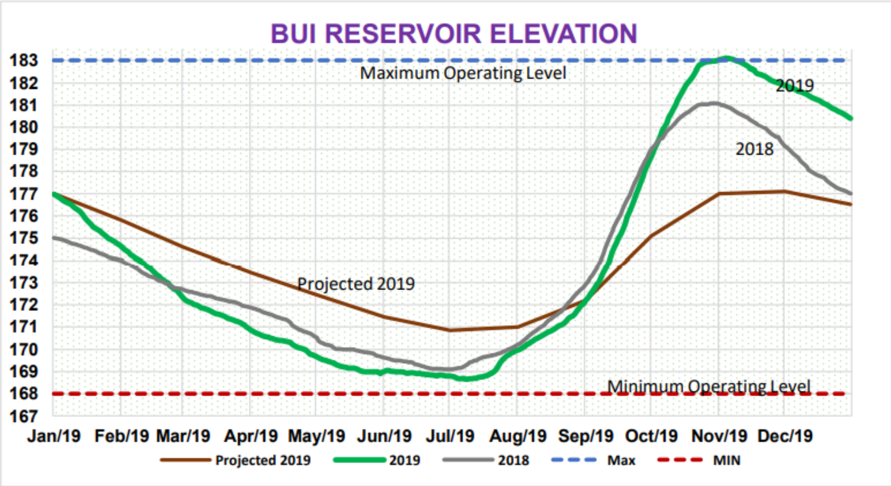


Figure 1. 3: Bui reservoir elevation 2018 & 2019 (Energy Commission Ghana 2020a).

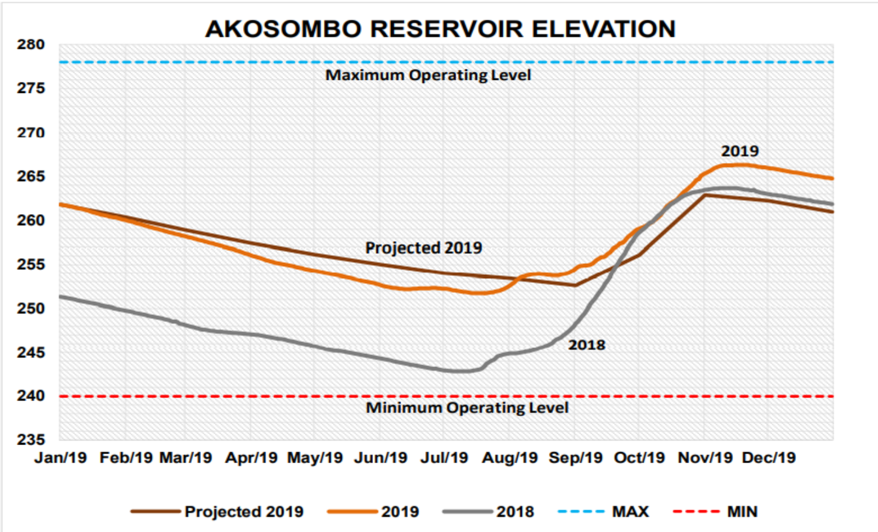


Figure 1. 4: Akosombo reservoir elevation 2018 & 2019 (Energy Commission Ghana 2020a).

The concern of low reservoir levels was noted by Gyamfi et al. (2014), where dependency on hydropower led to a power crisis in 1998, 2002 and 2007. The low reservoir levels were attributed to drought in those years, which was due to low rainfall patterns in the Volta basin region that serves the Akosombo dam and corresponding power plant. Furthermore, the significant variability in precipitation makes it difficult for producers to predict and schedule a balanced hydropower production in Ghana. Especially in periods where the difference between available reservoir capacity and peak demand have been marginal. Therefore, it would be crucial to secure availability from the hydropower plant capacities to provide reliable hydropower supply. The potential low reservoir levels during the dry season are still a challenge for power producers and system operators in the country.

In general, availability of the water resource in Ghana depends on the season. Ghana's climate is dominated by a tropical maritime air mass from the southwest bearing rain, followed by the dry, north-eastern continental air mass (Lacombe et al. 2012). These air masses meet at the Inter-Tropical Convergence Zone and causes a frontal low-pressure zone that migrates across West Africa. This is what forms the wet season with rainy days, which is later followed by a dry season without much precipitation. The wet season ranges from May to October within vicinity of coast region but ranges from May to August at the country level. The dry season is a term that describe an arid period of the climate in Ghana, where length and timing vary at different regions of the country.

The government of Ghana resolved parts of the issue concerning hydropower availability by rapidly building up fossil-fuel-based thermal power plants (see Figure 1. 5). Therefore, the installed thermal power capacity increased from 580 MW in 2000 (or 35.1% of contribution to cumulative capacity) to 3,549 MW in 2019 (Energy Commission Ghana 2020b p.15). This indicate that proportion of thermal plant to cumulative installed capacity increased from 35.1% in 2000 to 68.6% in 2019. In addition to aging infrastructure, inadequate fuel supply to power these thermal power plants is currently the greatest obstacle to secure a stable power supply in Ghana (Power Africa 2020). Hence, hydropower plants were forced to produce more than projected due to unavailability of the thermal capacities in 2019. As a result, this led to the reservoir levels dropping beneath their projected levels earlier in the year, but a greater than normal wet season helped regain the water levels quickly (Energy Commission Ghana 2020a).

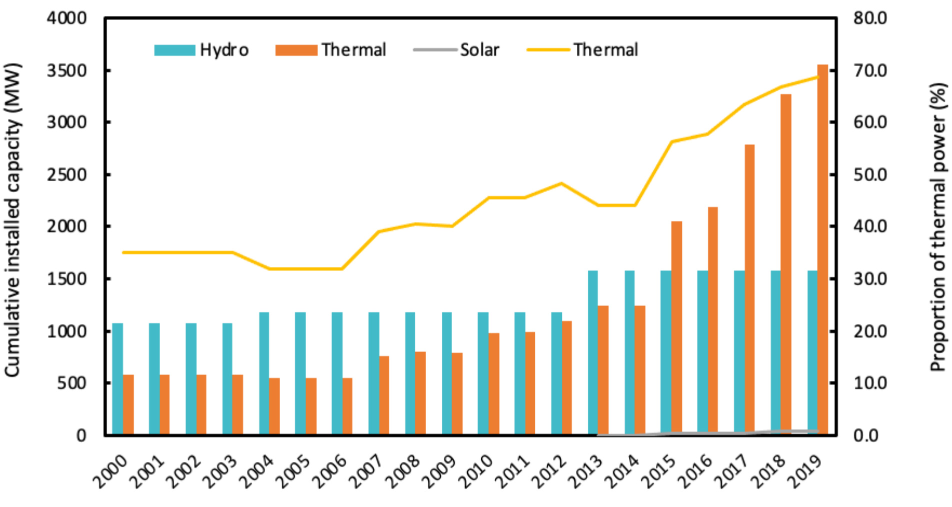


Figure 1. 5: Trend in power generation in Ghana (Energy Commission Ghana 2020b).

To overcome these obstacles, development in non-hydro renewable energy resources (such as solar energy and wind energy) and natural gas has been suggested as alternative solutions. Poor financial health in the energy sector, limited creditworthiness of utilities and short-term excess generation capacity are listed as the biggest challenges for this development by Power Africa (2020). The financial health in Ghana's energy sector is highlighted in the Energy Outlook report (Energy Commission Ghana 2020a) showing a total debt of $4.0 billion by 2019.

Despite those challenges, Ghana has implemented a masterplan for renewable energy with an anticipated annual increase in energy demand of around 10%, upward to 40,000 giga watt hours (GWh) by 2030 (Ahiatagu-Togobo et al. 2019 p. 7). This means that in addition to today's generating capacity, another 200 MW per year is required to keep up with future demand according to the Energy Commission. To ensure that the added generating capacity is sustainable and in line with the country's policy objective of increased renewable sources, it needs to be diversified across reliable renewable energy sources.

1.2 Renewable energy potential and policies in Ghana

1.2.1 Renewable energy potential

Ghana has huge potential and high availability of various renewable energy resources (IRENA 2018). According to the International Renewable Energy Agency (IRENA) (2018), the technical potential of solar PV, biomass and wind was estimated at 20,295 MW, 4,449 MW and 2,014 MW, respectively. Additionally, small-scale hydropower potential of 307 MW was identified through sites in Ghana as indicated in the West African Power Pool's Master Plan from 2011 (WAPP 2011).

1.2.2 Renewable energy policies

In 2015, Ghana released its National Renewable Energy Action Plans for the period 2015-2020, aiming to implement policies agreed on within the Economic Community of Western African States (ECOWAS) region. The government set a goal of increasing the renewable (excluding medium and large hydropower plants) share to 10% by 2020 from 0.2% in 2013 (Ministry of Power 2015). To reach that goal, the renewable energy action plan investigated the potential within several renewable energy sources, including wind, solar, biomass and hydro. The action plans targets were to increase grid-connected solar PV capacity from 2.5 MW in 2013 to 7 MW by 2020. Even though the installed capacity of grid-connected solar PV of 42.4 MW exceeded planned capacity, the proportion of non-hydro-based power was only 0.8% (mainly from solar PV) at the beginning of 2020. Furthermore, no utility connected wind power has been developed in the country as of yet.

When Ghana passed the Renewable Energy Act back in 2011, one of the objectives was to promote new renewable energy by implementing a feed-in tariff that was a guaranteed price of generated electricity for ten years. This aimed at reducing the financial risk for investors in renewable energy projects. The current feed-in tariffs from the Public Utilities Regulatory Commission (PURC) are shown in Figure 1. 6 (PURC 2016). PURC is currently doing a major tariff review this year, but at the time of writing, this was not yet completed (PURC 2021).

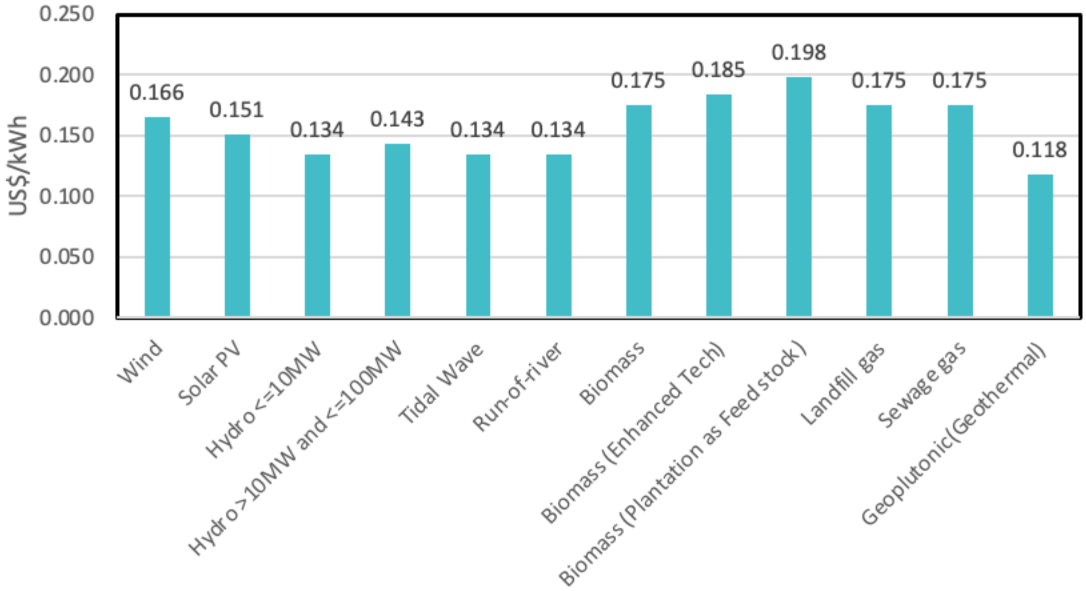


Figure 1. 6: Feed-in tariff rates for new renewable energy technology

In 2019, Ghana released its latest Renewable Energy Master Plan (REMP). The REMP aims to create a framework for increased investments in renewable energy resources, and increase the proportion of renewable energy in the national energy generation mix from 42.5 MW to 1,363.63 MW (with grid connected systems totalling 1,094.63 MW) by 2030. Among the anticipated 1,300 MW of added production, 425 MW is planned to originate from utility scaled solar PV, as shown in Table 1. 1. The table also lists the major generating capacity goals across the different renewable technologies.

Table 1. 1: Renewable energy development plan in Ghana 2019-2030.

RE technology	Reference 2015 (MW)	Cycle I (2019-2020) (MW)	Cycle II (2021-2025) (MW)	Cycle III (2026-2030) (MW)	Total added 2019-2030 (MW)
Solar utility scale	22.5	130	195	100	425
Distributed solar PV	2	18	80	100	198
Wind utility scale			275	50	325
Biomass utility scale			72		72
Waste-to-energy	0.1		30	20	50
Small/medium hydro		0.03	80	70	150.03
Wave power		5		45	50

Source: (Ahiataku-Togobo et al. 2019)

1.3 Thesis aim and research questions

Because of the African continent's high solar potential and hydropower's weakness to droughts, installing floating photovoltaics (FPV) on hydropower reservoirs was highlighted as an approach to help compensate dry periods with more FPV production. Sanchez et al. (2021) carried out an assessment of FPV potential in existing hydropower reservoirs in Africa. By covering less than 1% of the total water surface connected to hydropower plants, the installed power capacity could double, and electricity output grow by 58%. Furthermore, the study highlighted that for Ghana to match its hydropower capacity with FPV capacity, only 0.33% of the total reservoir surface area in the country would need to be covered by panels. This is mostly due to the massive size of Lake Volta, but nonetheless the power generation capacity from FPV could be installed without compromising too much surface area.

This thesis will aim to investigate the effects of installing the 425 MW of planned utility scaled solar PV referred to in Table 1. 1 as FPV on the upper reservoirs of the Bui and Akosombo hydropower plants. To explore the possible added benefits and/or challenges of choosing FPV instead of ground-based PV, the analysis will include two separate energy systems considering the PV and FPV production individually. Additionally, to also consider the challenges relating to adding a substantial amount of variable renewable energy (VRE) into an already struggling transmission system, the analysis will include a hybrid energy system where the option of pumped hydro storage (PHS) is added with the FPV. As a result, the goal will be to answer the following research questions:

i. How much electricity will a 425 MW FPV installation produce in comparison to a ground-based PV installation in Ghana and what will be the cost difference?
ii. How much production can 425 MW of FPV add to pumped hydropower production and flexibility, and what are the major benefits and challenges for this hybrid solution?
iii. Will a hybrid FPV/PHS solution ensure a more robust hydro production throughout the dry season, and if yes, will it be we worth the cost?

To address these questions, the thesis will conduct a techno-economic assessment of the proposed energy systems. Our goal is that this research can be of interest to both the government of Ghana when assessing their renewable energy strategy going forward, in addition to other governments, researchers and project developers.

2 THEORY AND LITERATURE REVIEW

2.1 Floating photovoltaics (FPV)

2.1.1 Background

In recent years, an aspiring market applying the PV technology in new areas has emerged with the FPV modules. As land resources are scarce and under high pressure from various development endeavours, moving power generation plants to water bodies proves as an advantageous option. This is a result of these areas having less conflicts of interest compared to an area of land.

Typically, FPVs are advantageous in freshwater bodies like wastewater and industrial basins, natural lakes, lagoons, and freshwater rivers (Kumar & Mallikarjun 2018). The modules can also be installed offshore, but this introduces a new set of issues related to mooring concerns caused by waves and high wind speeds. Partial shading of the FPVs caused by sea salt and higher depreciation rates of the modules are additional problems arising when the modules are installed at sea (Rosa-Clot M. & Tina G.M 2018 p.1-12). As the modules will be more exposed at sea, there are currently few offshore large scale FPV installations.

Since the first installation of a 29 kilowatt (kW) plant in Aichi Japan 2007 (Trapani & Santafe 2014), FPVs have emerged at various locations all over the world. In particular, the FPV market has seen a substantial growth in Eastern China, Southeast Asia, and India (Gorjian et al. 2020). At the time of writing this thesis, the world's two largest FPV plants located in China have an installed capacity of 150 MW each (Sanchez et al. 2021). However, larger projects are currently in the pipeline, where a 600 MW plant is currently being built in India which will be the largest FPV project once finalized (IANS 2021). The total installed world capacity of FPV as of August 2020 was equal to 2.6 gigawatt (GW), with China accounting for 73% of the capacity (Sanchez et al. 2021). In other words, the global FPV capacity is growing at an accelerating rate, with both the number of projects and generating capacities flourishing. According to PV Magazine (2020), the installed capacity of FPVs is expected to increase by an annual growth rate above 20% in the next five years.

FPVs have an enormous theoretical potential to meet our energy needs, and various academic articles have attempted to quantify this. A study conducted in 2014 (Tina et al.) found that 25% of the world electricity demand could be met by covering just 1% of the world's natural pools with FPVs. In 2018, the World Bank conducted a FPV market report that estimated a global potential of 400 GW made under conservative assumptions (World Bank Group 2018). In monetary terms, the report found that this corresponds with a market value greater than the Norwegian Pension Fund.

2.1.2 Advantages

FPVs introduce various advantages compared to land-based PVs. In particular, the cooling effect from water, reduced evaporation (Taboada et al. 2017) and enhanced water quality by reducing unwanted algae growth are some of the benefits highlighted (World Bank Group 2018).

Higher efficiency

One of the challenges with land-based PVs, is module overheating due to high ambient temperatures and solar irradiance (Akbarzadeh A. & Wadowski T. 1996). The PV power output is affected by the ambient temperature, wind speed and cell temperature of a module. When the ambient temperature rises, so does the cell temperature of the module, which accordingly decreases the power output from the module. Research has found that increasing the cell temperature of a monocrystalline and a polycrystalline silicon module by 1ºC, subsequently reduced the efficiency of the modules by 0.45% and 0.25% respectively (Kalogirou S.A.A. & Tripanagnostopoulos Y. 2006). Placing the PV panels on the water surface can solve this problem as it can reduce the operating temperature by approximately 3.5°C compared to a land-based installation (Liu L. et al. 2017). Multiple studies have attempted to measure the efficiency gains from FPVs compared conventional PVs at various sites and conditions with values ranging from 0.79% (Yaday et al. 2016) to 15.5% (Majid et al. 2014). However, the recent consensus amongst research suggests that the efficiency gain from the cooling effect of water in a FPV is approximately 12% (Ranjbaran et al. 2019).

Reduced evaporation

In addition to conserving land for agriculture and other economic activities, FPVs can lead to water conservation by reducing evaporation. With the increasing concern of water scarcity around the world, this benefit can be of particular significance in arid and semi-arid regions (Abid et al. 2018). If, for example, installed on water bodies intended for drinking water, reducing the evaporation effect could be of great importance.

When installed on hydro reservoirs, FPVs can increase the power output of the turbines as more water is saved for production. A study by Santafé et al. (2014) found that 25% of a reservoir capacity could be saved by completely covering the water surface with FPV modules. In a study by Mittal et al. (2017) in India, it was found that different penetration levels of FPVs covering 5%, 10%, 15% and 20% of the reservoir surface could conserve 64 million to 496 million litres annually. Moreover, another study from India (Mittal et al. 2017 b.) estimated that 191.174 million litres of water could be saved by installing 1 MW FPV. In China, research indicated that a 160 GW FPV installation covering 2,500 km^2 would save 2 x 10^{27} m^3 of water annually (Liu et al. 2017). As a result, the water savings by reducing the evaporation effect of water bodies depends both on the site location and its meteorological conditions, in addition to the level of FPV coverage.

Possible environmental benefits

In addition to reducing the evaporation effects, supplementary benefits can be achieved if FPVs are installed on agricultural or drinking water as it can lead to reduced algae growth and improved water quality (Cazzaniga et al. 2018). However, the ecological impact of FPVs is an area of research still in need of more attention. Some studies have however attempted to research the effects and in a study by Ziar et al. (2020), using ecological monitoring on various FPV installations did not disclose any noticeable effects on the water quality on a weekly basis, but the effects on the aquatic plant biomass and periods of low oxygen concentrations were significant. Haas et al. (2020) pointed out that the effects on the algae growth are highly dependent on the size of the FPV. Their results indicated that the FPV installation needed to be of moderate size to prevent algae blooms, and if the algae growth was to be avoided completely, very large installations were required. When comparing differences in environmental impacts between conventional ground-based PV and FPV, Da Silva & Branco (2018) found FPV to be more suitable because it minimizes certain problems associated with facilities of conventional PV. Low water consumption for cleaning and less use of chemicals for dust suppressants and herbicides was pointed out in favour of FPV over ground-based PV, in addition to already mentioned factors. However, as the full effects of the ecological impacts are yet undiscovered, a FPV literature review by Ranjbaran et al. (2019) concluded that more research is needed on the topic.

2.1.3 FPV and Africa

On the African continent, FPV could have immense potential, but there are currently few projects realized yet. One of the biggest projects to date was installed at the Bui dam in Ghana by the Bui Power Authority late last year (Takouleu 2020). A 5 MW FPV plant was finished in December 2020, which is included in the plan of adding a total of 250 MW of solar PV to support the hydropower plant. Once completed, this would be the first known utility scaled FPV system in Africa and shows that hybridization is on the agenda for Ghana. The Seychelles have also had plans for a 5.8 MW FPV plant since 2018, but it is currently on hold due to the COVID-19 pandemic (Bungane 2020). On a much smaller scale, Ciel et Terre delivered the first commercial scale FPV system to a farm in South Africa back in 2019. It had an installed capacity of 60 kW and was initiated to deliver energy, as well as reduce evaporation from the irrigation pond.

2.1.4 System cost

The capital expenditure (CAPEX) of FPV is slightly higher than ground-based PV system (World Bank Group 2018). According to the IFC (2020) FPV installations add an extra system cost of 20% to 25% compared to ground-based PV. The higher cost occurs with the PV system being located on water, as the float, mooring system and tougher electrical components introduces added costs. Parts of this added cost can also be linked to developing costs as the technology is less mature than ground-based PV. On the other side, a study by Sahu et al. (2016) argued that even though 25% of the total cost of a FPV is linked to the float, it can still be less expensive than the cost of acquiring and levelling suitable land areas for ground-based PV. Moreover, the operation and maintenance cost of the FPV could be lower than of a conventional PV as the water would naturally clean and cool down the system components (Ranjbaran et al. 2019). As a result, the CAPEX of a FPV system can be both more or less expensive than a ground-based PV system depending on the site location. Going forward, the cost of the float is expected to decrease in the future, making FPV even more competitive with ground-based PV owing to economies of scale.

According to the World Bank report (2018), FPV had a levelized cost of energy (LCOE) of approximately €53/MWh in 2018, compared to ground-based PV ranging from €35 to €40/MWh (IRENA, 2018). However, in comparison to the LCOEs of natural gas, coal and nuclear which ranges from $44 to $198/MWh (Lazard 2020), FPV is still a reasonable alternative.

2.2 Pumped Hydro Storage

2.2.1 Background

One of the most flexible forms of energy storage, in both scale and compatibility together with other power generators, is PHS. Taking full advantage of the potential energy within running water from an upper reservoir to a lower one, generating electricity through turbines in the powerhouse. A typical PHS plant is usually equipped with reversible turbines that function as generators when water is released down, and as pumps sending the water back up. An alternative solution is to have turbines and pumps operating with separate tunnels, serving their own purpose.

PHS has been around for over a century, but since the 1960's it grew into a large-scale system securing surplus power from big thermal generators to pump water to an upper reservoir during the night-time when demand was low (Rogner & Troja 2018). This was the basic form of operation mostly through the 60s, 70s and 80s. Nations in later years that had large hydropower resources began developing more PHS to enhance operation and utilize its balancing service. For instance, PHS in Norway was installed to secure seasonal balancing by pumping water to the reservoirs from periods of snow-melting, to generate electricity in the winter months. In recent decades, PHS has become a more viable way of integrating more VRE, with nations like China being in the forefront of installing new capacity. According to the International Hydropower Association (IHA), China has installed 15,000 MW capacity since 2010, adding to a total global capacity of 161,000 MW at the end of 2017 (Rogner & Troja 2018).

China also stays in front when it comes to incorporating some of the newest technological advantages in turbines to balance intermittent renewable energy. The turbines operate with either fixed or variable speed. Historically, fixed speed turbines have dominated since variable speed turbines were developed and improved in recent years (Yang & Yang 2019). The variable speed turbine provides more flexibility to handle intermittency in power fluctuations, making it more adaptable to a hybrid system with VRE as power source. However, these pump turbines have a 25% higher investment cost than fixed-speed turbines (Mongird et al. 2019 p.38).Accordingly, two variable speed generators are installed at Fengning 2 in China to secure fast and flexible ramping, stabilizing the system while integrating higher shares of VRE (Hopf 2020).

Like many energy systems, electricity generation through PHS causes significant energy losses through the conversion process. The total system loss is comprised of pumping efficiency, pipe head losses and turbine generator efficiency amongst other factors. The observed system efficiency for PHS varies from 75% to 85%, with some studies stating efficiencies as high as 87% (Ma et al. 2015). To justify the pumping of water in economic terms, a prerequisite is that the price of power at the time of the pumping must be at least 25% to 15% lower than what you expect to sell the electricity for. In other words, the price difference between pumping and turbine mode needs to be at least equal or greater to the efficiency loss of the total production cycle. As a result, a PHS facility is dependent on high fluctuations in either day to day or seasonal electricity grid prices to make the storage and generation profitable. An alternative method is to install affordable power generating systems in proximity to the PHS plant that will provide the pumps with electricity at a lower LCOE compared to the feed-in tariff.

2.2.2 Advantages

PHS is viewed as the most commercially important large-scale grid energy storage. In 2018, IHA reported that PHS accounted for 94% of installed global energy storage capacity (Rogner & Troja 2018). The same report also pointed out the role of PHS in enabling higher penetration of VRE sources through wider operating ranges giving additional flexibility.

Compared to other storage technologies, PHS is a mature mechanical technology with low response time and a long lifetime of operation. The charge time is longer than for example supercapacitors and batteries, but it provides a significantly longer discharge time and therefore long-term storage which could be used for energy arbitrage, peak shaving, time shifting or load levelling. The overall efficiency is lower than electrical and electromechanical storage technologies like superconductive magnetic energy storage and batteries, but higher than chemical storage like hydrogen (World Energy Council 2020). PHS also have significantly higher maximum power rating than other storage options (Aneke & Wang 2016).

The political landscape is willingly looking at PHS as the future for energy storage. In July 2020, the members of the European Parliament voted on European approach to energy storage and motioned a parliament resolution within EU states on the topic (Gamon 2019).

The report recognized that “a massive increase in energy storage is needed” to guarantee a secure energy supply when committing to become carbon neutral by 2050. Furthermore, the explanatory statement mentioned that energy storage was regarded as crucial to help reduce extreme electricity prices. Since PHS accounts for 97% of energy stored in the EU, exploring further potential in this field was highly relevant to the union members.

An analysis performed by RE100 Group at the Australian National University showed a global potential for 616,000 new PHS sites (RE100 Group ANU 2021). The analysis was performed using geographic information system (GIS) together with a set of constraints and criteria to investigate appropriate sites. However, the authors underlined that many of the identified sites may prove to be unsuitable, but less than one percent of the sites mentioned were needed to support a fully renewable electricity grid.

2.2.3 PHS and Africa

According to a report by the Energy Sector Management Assistance Program (ESMAP) from 2017, the installed capacity of PHS in Sub-Saharan Africa was equal to 1.6 GW of grid-tied energy storage, where 1,580 MW of the PHS was in South Africa (Eller & Gauntlett 2017). Another 1,330 MW is currently commissioned on the International Hydropower Association’s tracking tool for pumped storage (IHA 2021). Outside this region, the only African country having operating PHS was Morocco according to the same ESMAP-report. If future planned projects are realised the total capacity would be 4,550 MW by 2030, according to Hydro Review (Hydro Review 2018).

2.2.4 System cost

Mongird et al. (2019 p. 60) found that the capital cost of PHS vary significantly depending on the project, ranging from $1,500 to $5,100/kW with a mean value of $2,638. This included all components from the reservoirs, owner’s cost, engineering and construction, tunnels and powerhouse including excavations. Black & Veatch (2012p. 56) made a cost breakdown in a report to the National Renewable Energy Laboratory, where their total investment cost of $2,230/kW was allocated to the various elements as shown per Table 2. 1.

Table 2. 1: PHS cost breakdown.

Components	Cost ($) and proportion (%)
Powerhouse	835/kW; (37)

Upper reservoir	420/kW; (19)
Owner's cost	370/kW; (17)
Engineering, procurement & construction	390/kW; (17)
Tunnels	135/kW; (6)
Powerhouse excavations	80/kW; (4)

Source:(Black & Veatch 2012)

The same report expected the project life for PHS to be at least 50 years, which was also backed by May et al. (2018). Operation and maintenance costs amount to $15.9/kW for fixed, and $0.00025/kWh for variable costs annually (2018-prices) (Mongird et al. 2019 p. 9).

When looking at PHS in cost of energy storage terms it ranged as one of the cheaper options. Schmidt et al. (2019) projected PHS to have the lowest levelized cost of storage (LCOS) in 2015 ranging from $150 to $400/MWh. From a mean LCOS at 250$/MWh in 2015, there was an expected reduction to $190/MWh in 2030 and $150/MWh in 2050. LCOS is in this case determined by investment cost, O&M, charging, and end-of-life cost divided by electricity discharged during the investment period. Basically, the same formula as LCOE. Berrada & Loudiyi (2019) found the lower range of the LCOE-scale for PHS with €120/MWh ($146/MWh) and Lazard's LCOS version 2.0 (2016) place PHS in the range from $152 to $198/MWh. System lifetime is mentioned by both articles as one of the key features in reducing LCOE/LCOS.

2.3 FPV & PHS hybrid system

By combining the advantages of both FPV and hydropower, further power generation benefits can be achieved due to a hybrid synergy of the two energy systems (Silvério et al. 2018). Connecting the systems can help solve both the issues relating to the variability, randomness and intermittency of grid connected PV production (Liu et al. 2017). Additionally, the hybrid system can achieve further advantages by harmonizing the PV and hydro production (Liu L. et al. 2018). By installing a FPV on the hydropower reservoir, Kougias et al. (2016) found that the hybrid system was expected to deliver co-generation benefits for both power generation units. Moreover, Beluco and Souza (2012) argued that hydro and solar power are great compliments due to their features regarding flexibility and storage. The hybridisation allows for the full power generation of the variable PV power to be utilized during the day, while a greater amount of the hydropower can be stored for later use. A study by Cazzaniga et al. (2019) conducted at the Longyangxia PV/hydro plant in China on a sunny day illustrated this effect as shown in Figure 2. 1. Over a year, the Longyangxia hybrid system supplied 20% more energy without the need of any grid connection upgrades.

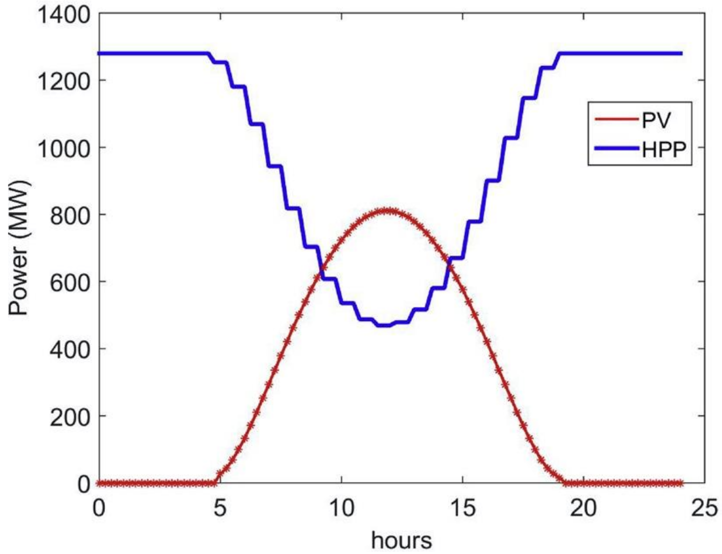


Figure 2. 1: Hydro and PV power on a sunny day at Longyangxia plant (Cazzaniga et al. (2019)).

Even further benefits can be achieved in an integrated FPV/PHS hybrid system as it enables the option to also charge the reservoir which can enhance grid stability, system reliability and power quality (Kocaman A.S. & Modi V. 2017). In a study by Patwal et al. (2018), it was found that combined PV and PHS system could increase both system efficiency and economic viability of a system. However, the economic viability would be highly sensitive to the grid power price as the objective of pumping the water, would be to minimize the operation cost occurring from the power exchange at the grid connection. A literature study on the optimal operation of a hybrid PHS system by Makhdoomi and Askarzadeh (2020), showed that simulating an optimum solution is challenging as it depends on the price and quantity of power bought from the grid. The optimal solution would therefore be dependent on minimizing the difference between water consumption and the predicted grid power price, while continuously maintaining the power supply reliability. At the time of writing this thesis, there is a shortage of FPV/PHS hybrid energy systems being realised.

2.4 Hybrid FPV and PHS market potential

IRENA looked at the innovate landscape for PHS in a brief from 2020 (IRENA 2020). From the report, it was made clear that coupling variable-speed PHS with VRE sources opens a potential for more flexibility and reduced curtailment. It can be argued that the hybrid system turns the VRE power plants, into a dispatchable power plant. To strengthen this potential further in the future, IRENA called for a regulatory framework that will give incentives for innovative operations of PHS. In addition, the organization listed ancillary service provision, energy arbitrage or capacity payments as examples of possible new revenue streams.

2.5 Summary

Despite the potential benefits of FPV, either as directly utility based or hybrid-hydro system based, and its positive impact on land use, there is lack of study on application of FPV in Ghana and its environment. Therefore, this thesis is aimed at exploring potential benefits of FPV, as independent power system and as energy source for pumped-hydropower system in Ghana.

Hopefully, this thesis can give valuable insights, in addition to uncover potential barriers, relating to both FPV projects and potentials of hybrid FPV/PHS solution in Ghana. In particular, that the results can be of relevance to appropriate stakeholders like the Government of Ghana, project developers, researchers and governments of other West African countries.

3 RESEARCH METHODOLOGY AND METHODS

In this section, the methods used to answer the research questions is presented (see Section 1.3 Thesis aim and research question). The thesis combines input data from official sources in Ghana and previous research papers on related topics, with the use of a commonly practiced software for hybrid energy optimization solutions. These methods also introduce a new element in the form of a newly Norwegian-developed software that analyse the energy potential from FPV sites worldwide.

3.1 Area of study

The FPV/PHS hybrid energy system was designed with the aim of meeting parts of the expected load increase in the upcoming years in Ghana by exploiting the existing infrastructure of Bui and Akosombo hydropower dams. The thesis is therefore limited to consider the two reservoir areas for the hybrid system analysis. The Bui dam was completed in 2013 and is currently operating with an installed capacity of 400 MW, allocated to three 133 MW turbines. The Akosombo dam was completed in 1965, after joint financing from the government of Ghana, the World Bank, the United States and the United Kingdom (Britannica 1998). Initial hydropower capacity was 912 MW, but the plant was refurbished in 2005, and currently operates with an installed capacity of 1,020 MW, allocated to six turbines. When constructing the Akosombo dam, it subsequently created Lake Volta, which became one of the largest artificial lakes in the world (Gyau-Boakye P. 2001). Figure 3. 1 shows the map of Ghana with the location of the two dams. The dam's surface area of 444 km^2 and 6,500 km^2 for Bui and Akosombo, respectively, were set as constraint for the FPV installations.

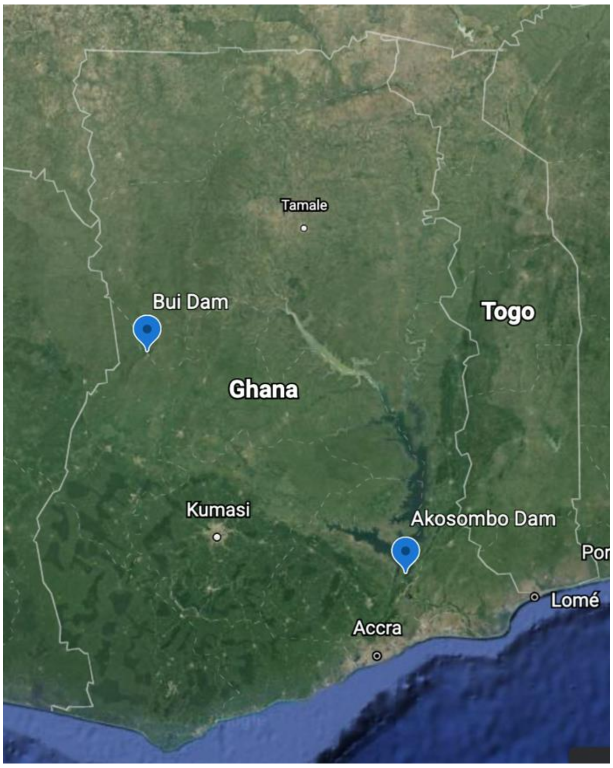


Figure 3. 1: Map of Ghana showing the location of Bui and Akosombo dam. Google Earth (2021) Available at: https://earth.google.com/web/

3.2 Analysis software

3.2.1 HOMER software

The FPV/PHS hybrid system and output from ground-based PV was modelled using the Hybrid Optimization Model for Electric Renewable (HOMER) developed by the US National Renewable Energy Laboratory (NREL). The HOMER software was developed in 1993, designed to estimate both the economic and technical optimization of multiple energy resources in hybrid combinations (Homer Energy 2021a). It has since become the most widely used simulation tool in scientific papers and analysis of both microgrid systems and distributed energy resources (Sinha S. & Chandel S.S. 2014).

HOMER investigates three main aspects of an optimized hybrid system: 1) the simulation, 2) the optimization, and 3) the sensitivity analysis (Lambert et al. 2006). Firstly, the simulation of the hybrid system is computed on an hourly basis over a year to establish its feasibility to meet the required load. Secondly, HOMER optimizes the dispatch from multiple energy sources and finds the design with the lowest system cost over its lifetime. Lastly, the sensitivity analysis estimates multiple optimization simulations to consider the system robustness to changes in uncertain input variables like fuel prices or interest rates. As shown in Figure 3. 2, as an energy system analysis tool, input to HOMER software include energy resources data, load demand, components' capacity and cost of the energy system, while the output include optimal sizing system and financial indicators.

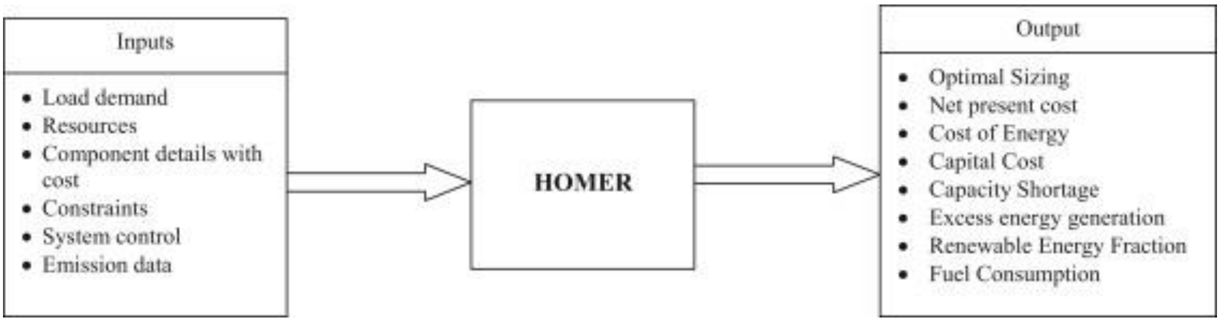


Figure 3. 2: Schematic presentation of HOMER (Sinha & Chandel 2014).

3.2.2 Glint Solar

To simulate a hybrid system considering the electrical output from FPVs, the Glint Solar software, which is specifically designed for FPV sites, was included in the analysis. This is due to HOMER not being able to provide the option to model FPVs in its current version (HOMER Pro 3.14.4). In fact, there is currently a limited availability of computation tools that enables project developers to efficiently compare FPV specific sites (Oliveira-Pinto S. & Stokkermans J. 2020).

Glint Solar is a Norwegian tech company started in 2020, with the idea of creating a Site Evaluator Engine (SEE) for FPV. The SEE uses satellite data in combination with machine learning to evaluate different water surfaces as project locations. What is unique about the software is that it includes parameters conventional PV estimation tools exclude in their analysis. Such parameters include site specific shading, historical water level fluctuations for hydropower dams and a FPV technology optimizer given the local climate conditions (Glint Solar 2020). The Glint Solar software utilize Photovoltaic Geographical Information System (PVGIS) for PV modelling where it has geographical coverage, which includes Africa in the PVGIS-SARAH dataset (PVGIS 2020). Together with a world map, users draw up a surface area for the intended installation and then the program gives estimates on annual production, area covered, a wind rose and average monthly temperature for air and above water surface.

Glint Solar was used to calculate the output from the suggested FPV installation at Bui and Akosombo, respectively. The estimated electrical output data was used in HOMER with their associated costs.

3.3 System Configuration

The hybrid system modelled in HOMER, as shown in Figure 3. 3, includes the FPV modules, and battery bank representing the pumped-hydro system (PHS) on the DC bus. A converter was installed to connect the direct current (DC) to the alternating current (AC) bus, where the diesel generator and the load was connected. The diesel generator was included in the system configuration to both serve as the base case and to enable HOMER to generate a valid solution if the renewable energy production capacities were unable to meet the load. However, all solutions considered for this analysis were based on a 100% renewable scenario.

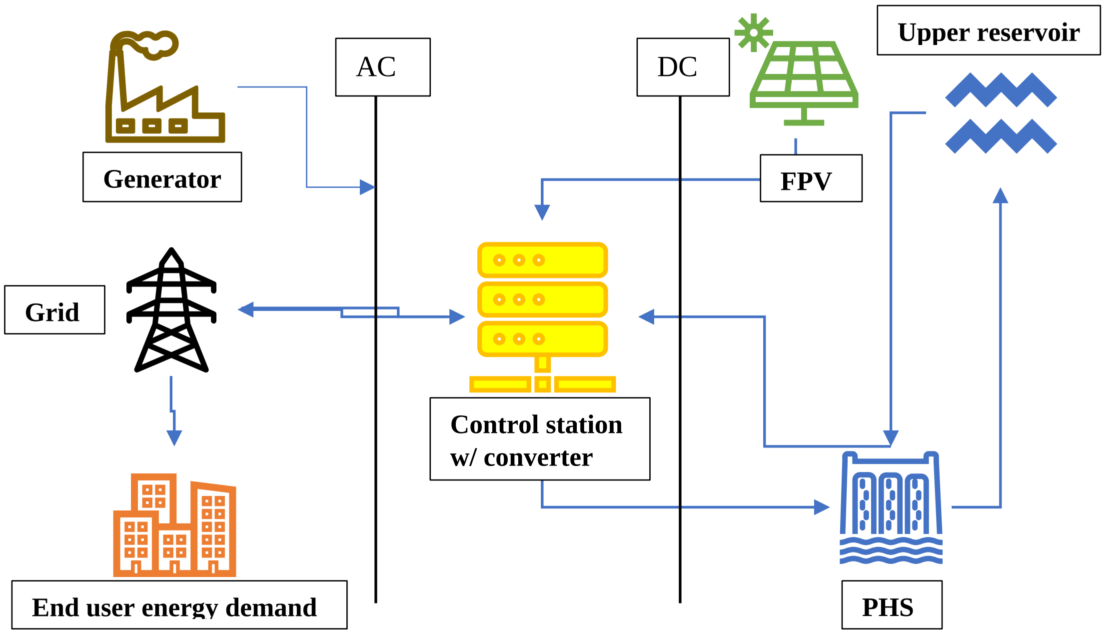


Figure 3. 3: Configuration of the hybrid FPV/PHS system.

3.4 Data collection

3.4.1 Load demand

Ghana´s daily load profile can be considered quite constant throughout the day, with a peak load appearing in the evening hours as shown in Figure 3. 4. The flat shape of the daily load profile can be explained by 42.89% of Ghana´s electricity being consumed by the industrial sector (Energy Commission Ghana 2020a). As a result, the industrial load profile, which has a similar shape, was selected for the analysis in HOMER.

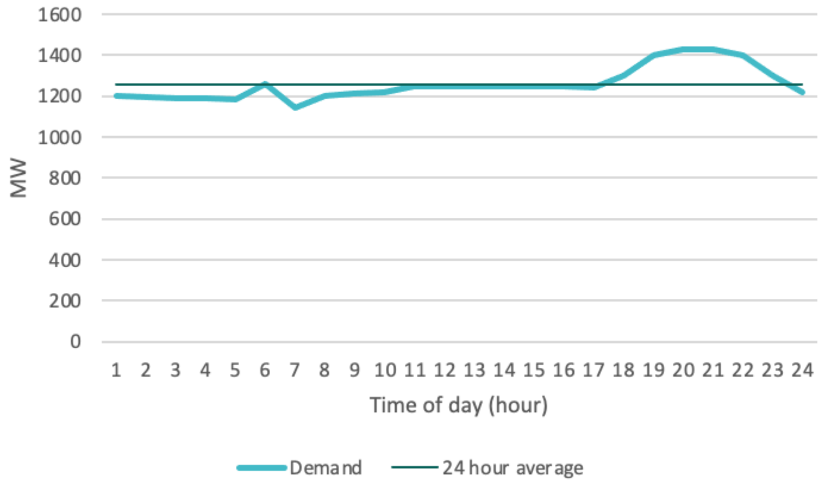


Figure 3. 4: Ghana daily load profile (GRIDCo 2010 in Amankwaa 2017).

Further load boundaries were set in accordance with the latest Ghana's Renewable Energy Master Plan, where Ghana set a goal of increasing the utility scaled PV capacity by 425 MW (see Table 1. 1) by 2030 (Ahiataku-Togobo 2019). For the system analysis, this planned PV capacity was split between the Bui and Akosombo hydropower plants equally. With an equal split of installed capacity between the two locations, it was also possible to observe site differences on annual yield from FPV compared to the ground-based solution. Accordingly, the load entered in HOMER was based on the estimated annual production from installing 212.5 MW of both ground-based PV and FPV at Bui and Akosombo, respectively. The analysis aimed to configure a system with renewable energy generation only, so electrical load was set to maximize system output within 100% renewable fraction. The scaled annual average (kWh/day) was adjusted to the point where the simulation would still produce a 100% renewable solution without the need for the diesel generator. Following this, certain adjustments were made in relation to how the load was distributed over a year to make the simulation charge the reservoir in the dry months for the FPV/PHS system. To do so, the load demand was split equally between six months and entered from May to October only, when reservoir levels are falling due to the dry season and solar radiation levels are low. This meant that the storage unit, in this case the virtual battery, was charged with pumped water in the months from November until end of April when solar radiation is at its peak, maximizing PV output. Moreover, as an additional purpose was to utilize the energy storage as a possible substitute for fossil fuelled thermal power, we treated the pumped storage hydro as an operating reserve not to be counted on for regular hydropower production. This compromise was also based on software limitations (see Section 5.2 Software limitations).

Table 3. 1: Electric load input in HOMER

Variable	Unit	Input
Load profile Nov-April	kW	1
Load profile May-Oct	kW	65,000
Scaled annual average	kWh/day	719,000
Scaled peak load	kW	59,427.32
Load type	AC or DC	AC
Random variability	-	-
Day-to-day	%	0
Timestep	%	0

HOMER Energy use scaled data for its simulations, meaning the analysed systems will satisfy a fixed load of 59,427.32 kW each hour from May 1st to October 31st. Total daily load served would then be 1,426,258 kWh/day for 184 days.

3.4.2 Dispatch strategy

HOMER is designed to optimize a solution for the dispatch strategy through the controller component. Each controller uses a unique strategy, whether it is cycle charging (CC) or load following (LF). Under CC, whenever a generator is needed it operates on full capacity and the surplus power charges the battery bank. With the LF strategy, the generator, when required, will only produce enough power to meet the demand. This option is considered more optimal in systems with a high degree of renewable energy that sometimes exceed the load, according to HOMER (2021c). In this system analysis, both LF and CC strategies were considered.

3.4.3 Hydro resource

Statistics from the Energy Commission in Ghana (2020b) were used to estimate the average monthly reservoir level for Bui and Akosombo. The historical data for Akosombo were observed in the period from 2000-2019 while the data for Bui were from 2014-2019. As shown in Figure 3. 5 and Figure 3. 6, the fluctuation in the reservoir levels is bigger for Bui than Akosombo. This might not be surprising given the fact that the reservoir size serving Akosombo dam is many times larger. In an average year, the reservoir level in Bui changed up to 30 feet from its low to highest point (see Figure 3. 5). For Akosombo, the same change was approximately 11 feet from low to high over a year (see Figure 3. 6).

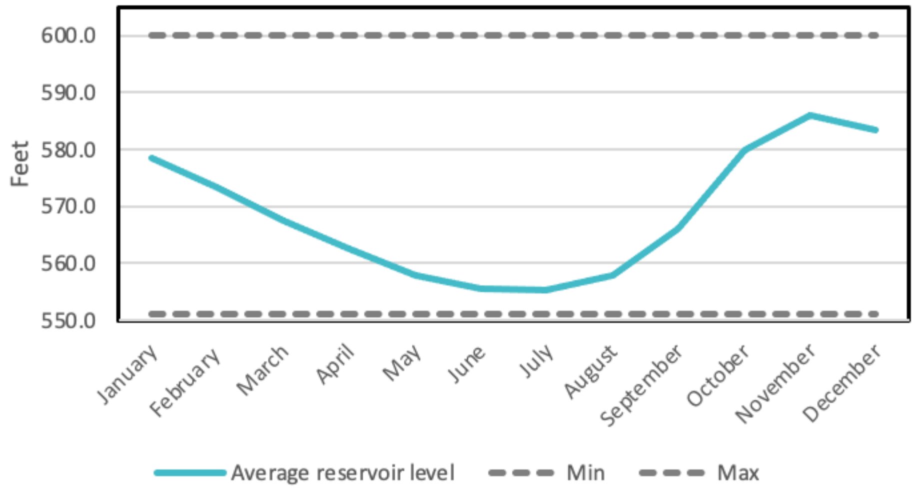


Figure 3. 5: Average reservoir level at Bui from 2014-2019 (Energy Commission Ghana 2020b).

The minimum and maximum reservoir levels at the Bui dam are 551 feet and 600 feet, respectively. Accordingly, the volume of the water stored between these two levels represent the reservoir potential energy. The average reservoir level over the period was 569 feet, with the maximum level of 600.4 feet observed in October 2019 and the minimum level of 551.7 observed in July 2014.

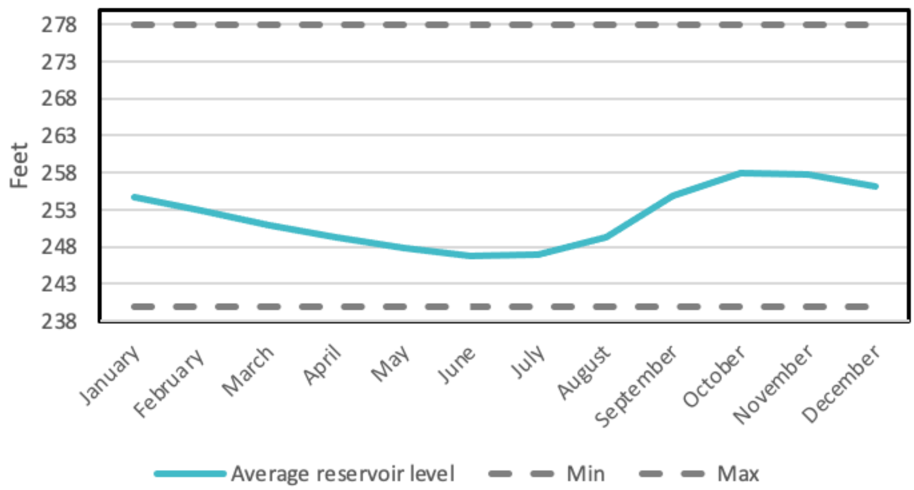


Figure 3. 6: Average reservoir level at Akosombo from 2000-2019 (Energy Commission Ghana 2020b).

The minimum and maximum reservoir levels at the Akosombo dam are 240 feet and 278 feet, respectively. The average reservoir level over the period was 252 feet, with a maximum level of 277 feet observed in October and November 2010. The lowest observed level of 235 feet was observed in July 2007, which is below the minimum operating level. In total, seventeen of the observations from the dataset had reservoir levels under the minimum level, where five consecutive months had levels below this in 2016. As a result, the observations indicate that Akosombo dam is more exposed to having reservoir levels below the minimum, and therefore being unable to operate the hydropower turbines.

The stream flow for the Bui and Akosombo dam are shown in Figure 3. 7 and Figure 3. 8, respectively. The data for the Bui dam show mean rainfall stream flow from 1982 – 2011 (Obahoundje et al. 2017). The discharge flow for Akosombo was determined by data series from the Global Runoff Data Centre site administered by the University of New Hampshire as shown in Figure 3. 8. Both figures illustrate the substantial variation in discharge following the climatic seasons in Ghana.

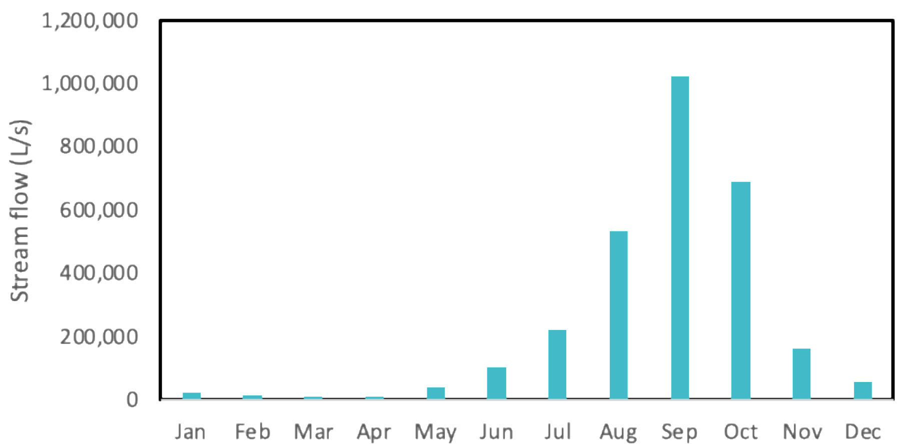


Figure 3. 7: Bui average discharge data (Obahoundje et al. 2017).

The discharge data for Bui showed that the lowest level occurs in March where the stream flow is 10.78 m^3/s, and the maximum level occurs in September with 1,022.27 m^3/s. On average over a year, the discharge was estimated at 241.82 m^3/s with annual total of 2,901.83 m^3/s.

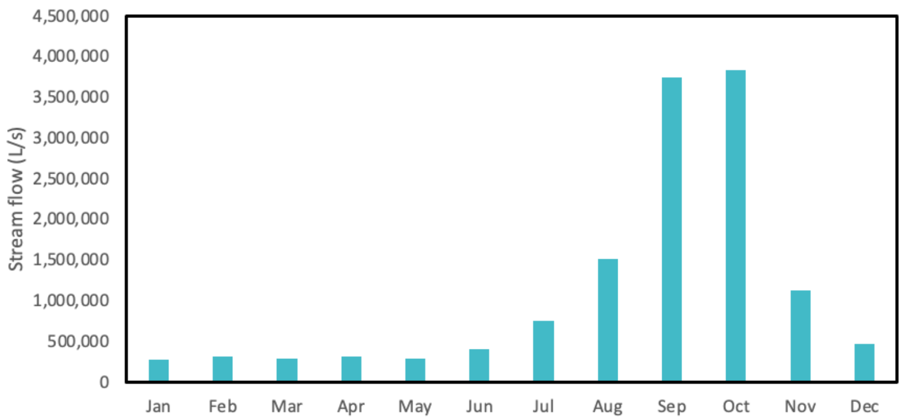


Figure 3. 8: Akosombo average discharge data (GRDC 1979).

The lowest average discharge at Akosombo occurs in January, where the flow is equal to 268 m^3/s and the maximum occurs in October with a flow of 3,832 m^3/s. From the dataset, the average stream flow over a year was 1,105 m^3/s, which is higher than the maximum average flow at Bui which was expected due to its relative size.

3.4.4 Solar resource

The ground-based PV application was estimated using solar radiation satellite data obtained from National Aeronautics and Space Administration (NASA) (2021). HOMER then calculated monthly average clearness index, which is the fraction of solar radiation that hits the ground surface to extra-terrestrial solar radiation, to estimate the average daily radiation on a horizontal surface. HOMER uses an algorithm developed by Graham and Hollands (1990) to produce synthetic hourly solar data on a horizontal surface at the site latitude by combining the averaged global solar radiation and clearness index. The monthly daily average global solar radiation at Bui and Akosombo are shown in Figure 3. 9 and Figure 3. 10 respectively.

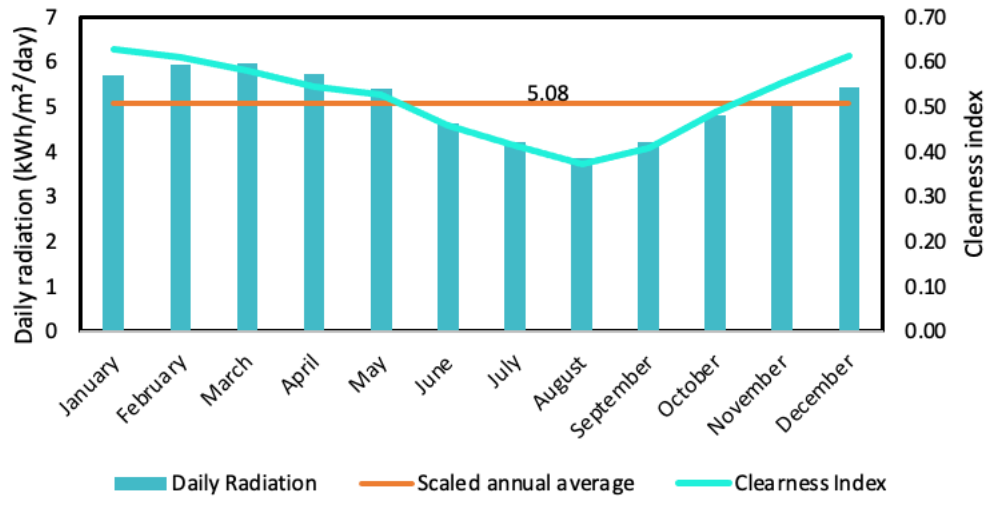


Figure 3. 9: Bui monthly averaged global solar radiation and clearness index (NASA 2021).

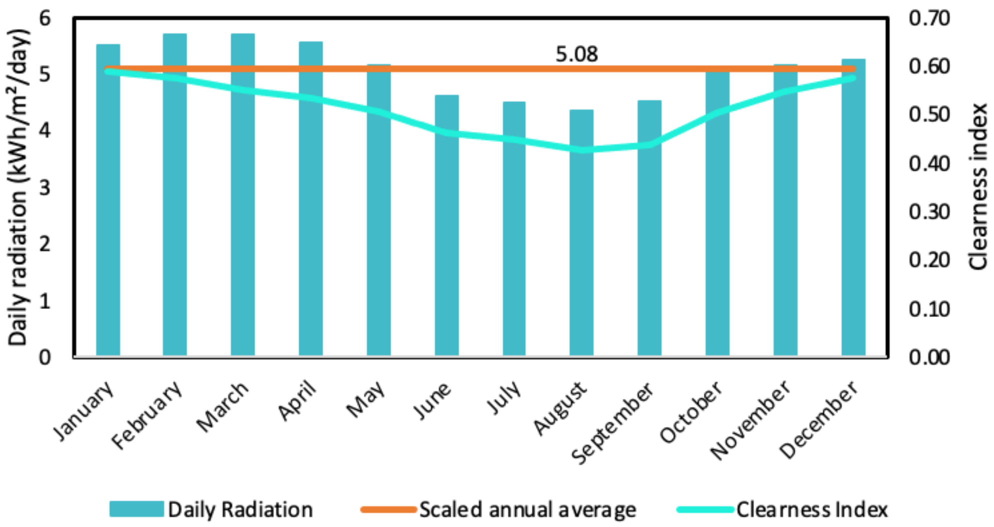


Figure 3. 10: Akosombo monthly averaged global solar radiation and clearness index (NASA 2021).

On average, the global solar radiation at Bui and Akosombo were similar, but their minimum and maximum values differ. At Bui, the minimum level was equal to 3.85 kWh/m^2/day in August and the maximum was 5.97 kWh/m^2/day in March. For Akosombo, the minimum value was 4.36 kWh/m^2/day in August and 5.7 kWh/m^2/day in both February and March. The relative difference between the average maximum and minimum observations was 2.12 kWh/m^2/day for Bui and 1.34 kWh/m^2/day for Akosombo. As a result, it is expected for the Akosombo arrays to have a more even production than the Bui location, but Bui is expected to better exploit the peak solar radiation in March. A similar relationship between the two locations in the clearness index was also observed. Bui had a slightly higher (0.01) clearness index compared to Akosombo’s 0.51. However, over the year, the relative variation was greater at Bui compared to Akosombo. The highest and lowest values for Bui was 0.63 and 0.37, respectively. At Akosombo the maximum clearness index was 0.59 and the minimum was 0.43.

To estimate production from the FPV technology, Glint Solar use satellite data from ECMWF ERA5 (PVGIS 2019) obtained through PVGIS developed by the European Commission Joint Research Centre (EU Science Hub 2019). PVGIS calculate solar radiation from satellite data based on methods from several scientific papers (Müller 2009) (Müller 2012) (Gracia Amillo et al. 2014). The NASA and ECMWF ERA5 datasets are considered to be much alike (see Appendix 1), where the global solar radiation and clearness index applied for the FPV installation is considered similar to the data presented in Figure 3. 9 and Figure 3. 10.

3.4.5 Temperature and wind resource

The Glint Solar software incorporates temperature and wind data to estimate the specific FPV production, as these factors influence the module power output. To incorporate the cooling effect of the water on the panels, the Glint SEE includes the air temperature (at 2 meters height) in addition to the water surface temperature. This data is obtained from the ERA5 dataset (ECMWF 2016) and Global Surface Water – Data Access (Pekel et al. 2016) before being adjusted for a typical meteorological year with proprietary modification of the Sandia method (Wilcox & Marion 2008). The temperature and wind data for Bui and Akosombo is presented in Figure 3. 11 and Figure 3. 12, respectively.

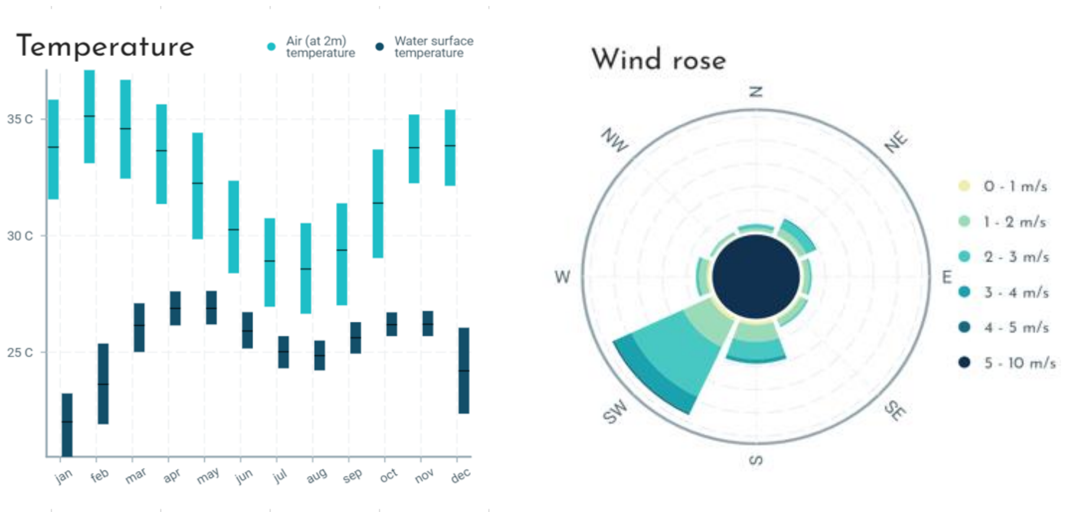


Figure 3. 11: Bui annual temperature data and wind rose (Glint Solar 2020).

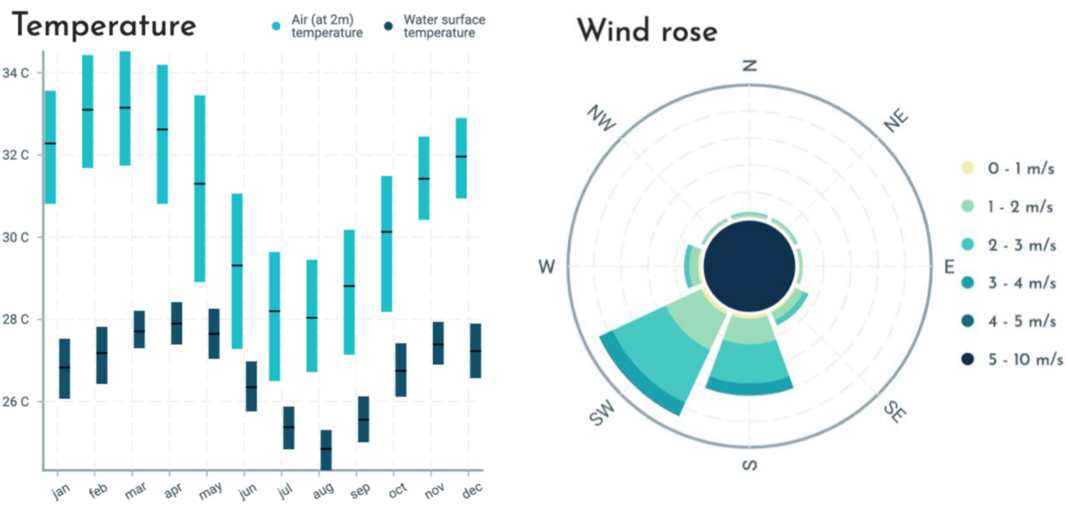


Figure 3. 12: Akosombo annual temperature data and wind rose (Glint Solar 2020).

Figure 3. 11 and Figure 3. 12 show that the water surface temperature is colder than the air temperature throughout the year at both Bui and Akosombo. The spread in the temperature difference is greater in the winter months, compared to the summer months. This happens as it takes longer for the water to warm up in the summertime, and during winter it takes longer to cool down, resulting in a more stable water temperature. This can be considered as an extra benefit with the summer months as it correlates with when the global solar radiation is at its best, benefitting the power output. As expected, due to their location proximity, the temperature over the year is quite similar at the two locations. The wind rose show the typical wind direction and wind speed at a location. Figure 3. 11 show that the predominant wind direction at Bui is southwest with wind speeds up to 4-5 m/s. Similarly, Akosombo has comparable south-west winds but compared to Bui, a larger share is also coming from the south. Overall, the two sites are quite similar with moderate wind speeds which is favourable for the mooring of the panels.

3.5 System analysis

3.5.1 PV array power output

The power output from the ground-based PV and FPV module is calculated using Equation 3.1, (Duffie & Beckman 2013):

$$P_{output} = Y_{PV} f_{PV} \left(\frac{G_T}{G_{T,STC}}\right)\left(1 + a_p\left(T_c - T_{C,STC}\right)\right) \tag{3.1}$$

Where the Y_{PV} is the rated power output of the PV panel in kW, f_{PV} is the derating factor of the PV given in a percentage, G_T is equal to the solar radiation hitting the PV array in kW/m^2, $G_{T,STC}$ is the solar radiation under standard test conditions (STC) in 1 kW/m^2, a_p is the temperature coefficient of power, T_c is the temperature of the PV cell and the $T_{c,STC}$ is the cell temperature of the PV under standard test conditions at 25°C.

The user application associated with Glint Solar is set up with a basic silicon-based PV panel type set at a fixed 5-degree tilt angle. To generate comparable results from the ground-based PV module and the FPV module, a similar PV array is used for the ground-based PV solution. Glint Solar provided specifications for the default panel type used in the software application (see Table 3. 2), which was used to create a similar flat panel type in HOMER. The solar arrays applied has a STC-rated capacity of 0.3 kW each. Since the PV array is not horizontal, but it tilted at an angle b equal to 5°, HOMER applies the Hay, Davies Klucher, Reindl (HDKR) model (Duffie & Beckman 2013) to determine the global solar radiation that hits the surface of the PV array.

Table 3. 2: PV array technical specifications.

	Unit	Input
Material		Monocrystalline Silicon
Rated capacity at STC	W	300
Temperature coefficient of power	(%/ºC)	-0.41
NOCT	(ºC)	45
Efficiency at STC	(%)	15.46
Tilt angle	(º)	5
Length	mm	1,956
Width	mm	992
Lifetime (80% power output warranty period)	years	25

Glint Solar applies a derate factor of 0.858 for the FPV arrays. To account for more realistic operating conditions for the ground-based PV, HOMER also include a derate factor, f_{PV}, to adjust output regarding losses from soiling on the panels, shading, wiring losses and aging, among other factors. The derate factor represents a percentage that will be deducted from the rated power of the PV panel (Homer Energy 2021d). Derate factors may vary depending on local conditions i.e., the amount of soiling from dust in one area. Marion et al. (2005), on behalf of NREL, found the typical overall derate factor to be 0.731 at nominal operating cell temperature after comparing 24 different PV systems. When looking at the observed performance from the Navrongo PV plant, the annual average performance ratio (PR) was 0.706, and accounted for losses from high ambient temperature, soiling due to dust and low winds, but also measured against final output after converting from DC to AC (Mensah et al. 2019). Other analysis use derate factors of 0.8 (Idoko et al. 2018) or even as high as 0.9 (Guaita-Pradas et al. 2015). Therefore, overall derate factor for the land-based PV system in HOMER was set at 0.75.

The investment cost of the ground-based PV array was set to $2.0/W based on the system cost of Navrongo PV project in Ghana completed in 2013 (ECREEE 2017). This cost was also backed up in a study by Pueyo et al. (2016) investigating the cost of renewable energy in Sub-Saharan Africa, in addition to the IRENA (2016) reported costs for African utility-scaled PV in Africa in 2015, which ranged from $1.35/W and $4.1/W. As a result, the total investment cost of the ground-based PV system entered in HOMER was $425,000,000 for Bui and Akosombo, respectively. As previously discussed, the CAPEX of FPV can prove to be both lower and higher than of ground-based PV. However, based on the assumption that the cost of ground-levelling work and the cost of acquiring the land would be reasonable, we assume the FPV CAPEX to be 25% higher compared to ground-based PV (Agostinelli G. 2020) giving a total capital cost of $531,250,000 for both systems. The operation and maintenance cost of the PV and FPV was set equal to 1% of the investment cost of the panels (Pueyo et al. 2016). Consequently, the O&M values entered in HOMER was $0.8 for the ground-based PV and $2.0 for the FPV. Both the ground-based PV and FPV modules were simulated disregarding any tracking systems.

3.5.2 Pumped hydro storage

The current version of HOMER Pro 3.14.4 does not provide the option to model large scale PHS. Consequently, Canales and Beluco (2014) description of the step-by-step process of how to model PHS in HOMER was applied in the analysis. The article outlined the need to create a new battery in HOMER, where the battery inputs are specified by calculating the potential energy of the reservoir. The PHS capacity was calculated by converting the hydropower reservoir potential energy into ampere hours (Ah). In this calculation, the PHS round trip efficiency was also incorporated to account for the system losses. Accordingly, the converter connecting the PHS production to the grid, had to be set at 100% efficiency as all losses in the producing component was already accounted for in the battery calculation.

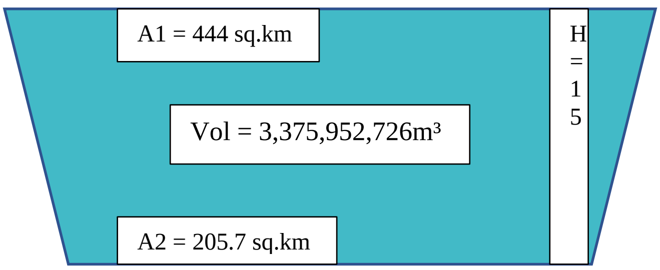
To calculate potential energy from the reservoirs, we assumed the lakes as inverted trapezoids, where the upper area is total surface size at maximum operating level, and the lower area is surface size at minimum operating level. Lakes have varying shapes and depths which made it challenging to set an exact angle of the shoreline slope. For theoretical purposes, the slope was assumed as a five percent decrease in surface area per meter depth.

This gives the following formula for calculating volume of reservoirs:

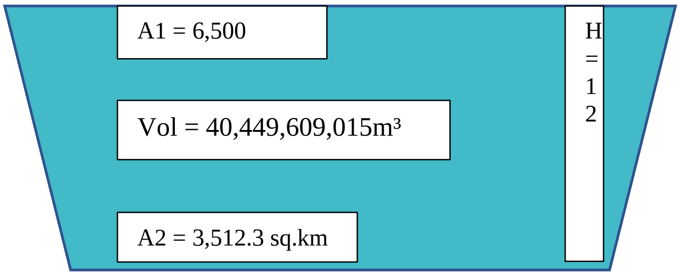
$$Trapezoid\ volume = \frac{H}{3} * \left(A1 + A2 + \left(\sqrt{A1 + A2}\right)\right) \tag{3.2}$$

Where H is equal to total height, A1 is upper surface area in km² and A2 is lower surface area. A2 would be equal to A1*0.95^H given five percent reduced surface per meter depth. Applying this formula calculated the following volume for the two dams:

$$Bui\ operating\ volume = \frac{15}{3} * \left((444) + (444 * 0{,}95^{15}) + \left(\sqrt{444 + 444 * 0{,}95^{15}}\right) * 10^{6}\right)$$
$$= 3{,}375{,}952{,}726\ m^{3}$$



$$Akosombo\ dam\ volume$$
$$= \frac{12}{3} * \left((6{,}500) + (6{,}500 * 0{,}95^{12}) + \left(\sqrt{6{,}500 + 6{,}500 * 0{,}95^{12}}\right) * 10^{6}\right)$$
$$= 40{,}449{,}609{,}015\ m^{3}$$



To convert these sizes to an equivalent amount of stored energy in kWh, we looked at the effective volume of the dam and the power produced during the hours it takes to empty it with a flow rate Q (m^3/s), and the round-trip efficiency for pumped hydro. To do so, we used the formula for volume and effect divided it by time and flow rate.

$$Energy\ stored\ (kWh), E_s = \frac{Vol*P(Q)}{Q*3{,}600}, where\ P(Q) = g*\eta*Q*H \tag{3.3}$$

Where P(Q)=$g*\eta*Q*H$. Here, g is the gravitational acceleration, $9.81m/s^2$, η is the round-trip efficiency, Q is the flow rate and H Is the hydraulic head. As a result, we can write the following:

$$E_s = \frac{9.81*\eta*H*Vol}{3{,}600}\ , where\ Vol\ is\ volume\ in\ m^3 \tag{3.4}$$

For the two reservoirs this gives:

$$Bui\ stored\ energy\ (kWh) = \frac{9.81*0{,}85*108*3{,}375{,}952{,}726}{3{,}600} = 993{,}542{,}887\ kWh$$

$$Akosombo\ stored\ energy\ (kWh) = \frac{9.81*0{,}85*68.8*40{,}449{,}609{,}015}{3{,}600} = 7{,}583{,}492{,}698\ kWh$$

According to Canales & Beluco (2014), the total stored energy for a battery with fixed voltage and a capacity independent of discharge current, can be defined as:

$$E_S = V*\left(\frac{C_B}{1{,}000}\right) \tag{3.5}$$

Where V is the voltage and C_B is Ah. To calculate stored energy in Ah for battery sizing this equation rewrites as:

$$C_B = \frac{E_S * 1,000}{V} \tag{3.6}$$

The nominal voltage for Akosombo's generator is given as 14,400 V. For Bui it was difficult to obtain this information, so generator voltage was assumed same as Akosombo.

Energy stored in Ah for the two reservoirs:

$$Bui\ C_B = \frac{993,542,887 * 1,000}{14,400} = 68,996,034\ Ah$$

$$Akosombo\ C_B = \frac{7,583,492,698 * 1,000}{14,400} = 526,631,437\ Ah$$

These values were set as the nominal capacities for the virtual battery created in HOMER. Table 3. 3 present the calculated inputs for the virtual batteries.

Table 3. 3: Summary of parameters for HOMER PHS battery inputs.

Function	Unit	Bui	Akosombo
Surface area	Sq.km	444	6,500
Operating zone	m	15	12
Operating volume	m^3	3,375,952,726	40,449,609,015
Energy in operating zone	kWh	993,542,887	7,583,492,698
Nominal capacity	Ah	68,996,034	526,631,437
Nominal voltage	V	14,400	14,400
Maximum charge current	A	12,500	35,417
Maximum discharge current	A	25,000	70,833
Efficiency roundtrip	%	100	100

The size of the pumping capacity was set equal to the capacity of the FPV, which was 212.5 MW for Bui and Akosombo. Variable-speed pump turbines were chosen to better handle the intermittent nature of the energy production from the FPV.

As most of the infrastructure to build a PHS-capacity was already in place at both project locations, parts of the capital cost components (see Section 2.2.4 System cost) did not apply. Given lesser need for certain components, but also adding to the cost of variable-speed pumps, a total of $1,800/kW was applied in the analysis and capital cost amounts to 382,500,000 for each powerplant. The operation and maintenance costs amounted to $15.9/kW for fixed costs and $0.00025/kWh for variable costs annually (Mongird et al. 2019 p. 9). With the proposed sizes and annual PHS output this totalled $3,655,179 per year for both Bui and Akosombo.

The cost inputs for HOMER have been summarized in Table 3. 4. Replacement costs are disregarded as project lifetime is less than the expected PHS lifetime of at least 50 years.

Table 3. 4: PHS cost inputs in HOMER.

Component	Bui	Akosombo
Capital cost ($)	382,500,000	382,500,000
O&M ($)	3,655,179	3,655,179
Lifetime (years)	25	25

3.5.3 Converter/inverter

The converter/inverter component was in place to ensure an efficient electrical flow between the DC and AC bus, uniting the hybrid system. As both the ground-based PV, FPV and PHS are located on the DC bus of the system, a power converter is needed to serve the AC load. For the hybrid system including the full capacity of the hydro turbines, the generators considered have an installed effect of 400 MW and 1,020 MW for Bui and Akosombo, respectively. Here, the size of the converter has been adapted to accommodate the installed capacity of both hydro power plants to make sure the production was able to meet grid load.

The lifetime of the generic converter used in HOMER is set to 15 years. The investment and replacement cost of the generator is set at $0/kW since the converter cost was already accounted for in the ground-based PV, FPV and PHS components of the hybrid system. The efficiency of the converter was set at 100%, as already mentioned and described in Canales & Beluco (2014). Similarly, the converter efficiency loss was accounted for in the ground-based PV and FPV derate factors.

3.5.4 Base case system

For comparison of the proposed new capacity of ground-based PV, FPV and the hybrid FPV/PHS option, it was necessary to create a base case. This allowed HOMER to analyse and compare how the different cash flows evolved, what payback period to expect and expected return on investment (ROI) in form of yearly cost savings relative to the initial investment (Homer Energy 2021b).

$$ROI = \frac{\sum_{i=0}^{R_{proj}} C_{i,ref} - C_i}{R_{proj}(C_{cap} - C_{cap,ref})} \quad (3.7)$$

Where R_{proj} is the projected lifetime in years, $C_{i,ref}$ is the annual cash flow for base system, C_i is the nominal annual cash flow for current system, C_{cap} is the capital cost of the current system and $C_{cap,ref}$ is the capital cost of the base system.

By creating a base case for comparison, the internal rate of return (IRR) can also be provided which shows the discount rate where the base case and the selected system have the same net present cost (NPC). HOMER calculate this by determining what discount rate makes the difference in the two cash flows equal to zero.

$$0 = NPC = \sum_{t=1}^{T} \frac{C_t}{(1+IRR)^t} - C_0 \quad (3.8)$$

Where C_t is net cash flow during period t, C_0 total initial investment cost and t is the number of time periods.

We assumed that any new renewable energy would replace fossil fuel-based generation, making this the base case. Thermal power generator capacity was selected as base case architecture, with automatic sizing to meet the load. Capital cost for combined gas cycle technology ranges from $700/kW to $1,250/kW, so $1,000/kW was selected (Lazard 2020). O&M were set at $0.009 per operating hour (reported as fixed $27.6/kW per year, so this was divided by 8,760 hours, plus variable O&M of $0,006/kWh) and a lifetime of 50,000 hours (EIA 2020). Ghana currently has two major LNG projects underway, but we concentrated the base system around oil/diesel as fuel source. This was due to crude oil being considered a strategic reserve in Ghana to handle fuel supply security and erratic fuel prices, which makes it a reasonable comparison to the storage option generated from renewable energy (Energy Commission Ghana 2020a). Average oil price in Ghana the last ten years have been $77.86/barrel (Bank of Ghana 2021b). This gave $0.65/l as fuel price input for HOMER. Table 3. 5 summarizes the main cost inputs for the generator in HOMER.

Table 3. 5: HOMER input for Generator component.

Variable	Value
Initial capital cost ($/kW)	1,000
Replacement cost ($/kW)	1,000
O&M cost ($/op. hour)	0.009
Fuel price ($/L)	0.65
Lifetime (hours)	50,000

3.6 Economic evaluation

The economic evaluation of the system is based on a total project lifetime of 25 years. Moreover, all costs associated with necessary site-preparation and relevant activities are assumed to be included in the investment cost of each system component. The economic criterion for the analysis was based on the NPC and cost of energy.

3.6.1 Discount rate

To account for the time value of money, HOMER applies the real discount rate in its calculations. The real discount rate excludes the inflation component, so all associated calculations in the analysis are given in real values. At the time of writing the thesis, the interest rate in Ghana was 14.50% and the inflation rate was 10.3% (Bank of Ghana 2021a). Using the following formula gives a real discount rate of 3.8%.

$$i = \frac{i' - f}{1 + f} \tag{3.9}$$

Where i is the real discount rate, i' is the nominal discount rate and f is the inflation rate.

3.6.2 Net present cost

The NPC, or life-cycle cost, represents the value of all the costs of the hybrid system components minus the project revenue over the project lifetime discounted to a present value. To calculate the total NPC, HOMER sums up all the discounted cash flows for each system component over the project lifetime (Rohani & Nour 2014):

$$C_{NPC} = \frac{C_{a,total}}{CRF(i,n)} \tag{3.10}$$

Where $C_{a,total}$ is the total cost of each system component, CRF is the capital recovery factor and can be expressed as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{3.11}$$

Where *i* is the real discount rate and *n* is time period in years.

3.6.3 Levelized cost of Energy

The LCOE is defined as the average cost of producing one unit of electricity (kWh) by the system. The formula for finding the LCOE divides the total annualized cost of the energy system by the total energy production:

$$LCOE = \frac{C_{ann,tot}}{E_{served}} \tag{3.12}$$

Where $C_{ann,tot}$ is the system total annualized cost of the system and E_{served} is the yearly amount of primary AC load served by the system.

3.7 Sensitivity analysis

The changes in the global solar radiation, interest rate and investment costs are identified as the input variables with the most significant impact on the system configuration and cost. With solar energy being a VRE source, varying global radiation levels is expected over the project lifetime. Moreover, changes in the inflation rate or lending rate in Ghana is also considered likely, which would impact the project profitability. It also exists a great risk of the system components like the PV arrays, the float and pump turbines to implicate added costs, as these components will most likely be produced overseas and transported to Ghana. Additionally, alternative cost from the base case that indirectly affect renewable energy projects, in this case the impact of fuel price, was considered. To account for both possible variations and errors in these inputs, a sensitivity analysis of these variables was conducted. The analysis was superimposed with LCOE-values as a comparison towards the industry in general. Table 3. 6 lists the parameters and values included in the sensitivity analysis.

Table 3. 6: Sensitivity analysis variables.

Variable	Original value	Upper value	Lower value
Global Solar Radiation Scaled annual avg. (kWh/m^2/day)	5.08	7	3
Discount rate (%)	3.8	8	2
FPV invest. Cost multiplier	1	2	0.6
PHS invest. Cost multiplier	1	2	0.6
Diesel cost ($/L)	0.65	1	0.3

4 RESULTS

This section presents the simulation results for the 25-year analysis period. The presented solutions are optimal results generated by HOMER that provides the lowest system cost while meeting the load. All optimal solutions gave a 100% renewable scenario and were met under the CC dispatch strategy. Table 4. 1 and Table 4. 2 summarize key results from the optimal system solutions by HOMER.

Table 4. 1: Bui simulation results.

	Unit	Ground-based PV	FPV	Hybrid FPV & PHS
Installed capacity (PV)	MW	212.5		
Annual output	GWh/year	275,06	324.92	262.43
Capacity factor	%	14.8	17.5	NA
Storage (energy in)	GWh/year	NA	NA	232.64
Storage (energy out)	GWh/year	NA	NA	170.97
Storage depletion	GWh/year	NA	NA	-61.67
LCOE	$/kWh	0.098	0.104	0.234
Total NPC	$	427,710,539	538,026,348	978,805,800

Table 4. 2: Akosombo simulation results.

	Unit	Ground-based PV	FPV	Hybrid FPV & PHS
Installed capacity (PV)	MW	212.5		
Annual output	GWh/year	275,25	319.37	262.43
Capacity factor	%	14.8	17.2	
Storage (energy in)	GWh/year	NA	NA	225.88
Storage (energy out)	GWh/year	NA	NA	168.95
Storage depletion	GWh/year	NA	NA	-56.93
LCOE	$/kWh	0.098	0.106	0.234
Total NPC	$	427,710,539	538,026,348	978,805,800

4.1 Ground-based PV

4.1.1 System output

The ground-based PV system energy output located near the Bui and Akosombo dam are presented in Figure 4. 1 and Figure 4. 2 respectively. Ground-based PV production near Bui dam produced 275.06 GWh annually, with specific yield of 1,294 kWh per kW installed. Mean output from the simulation was 753,601 kWh/day with a peak production of 163,636 kW. With 4,342 hours of operation, it had a capacity factor of 14.8%. Based on the cost parameters assumed for the system, the simulation returned an LCOE of $0.0975 and total NPC of $427,710,539.

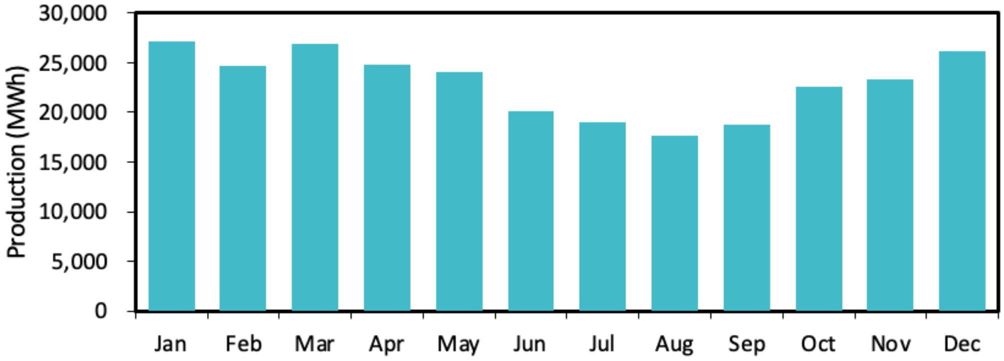


Figure 4. 1: Bui ground-based PV energy output.

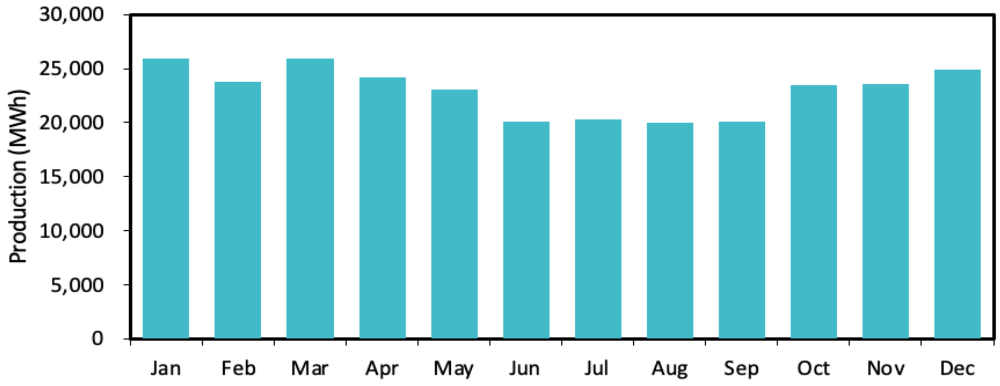


Figure 4. 2: Akosombo ground-based PV energy output.

The Akosombo ground-based PV system generated an annual electricity of 275.25 GWh which equals to a specific yield of 1,295 kWh per kW installed. This results in an annual difference of approximately 19 MWh of production and 1 kWh per kW installed more compared to Bui. The Akosombo PV module supplied on average 754,101 kWh/day and had a peak production of 164,947 kW. This equals a capacity factor of 14.8% with 4,380 hours of operation over a year. The simulation resulted in a LCOE of $0.0975/kWh and a total NPC of $427,710,539 for the Bui location.

Both Bui and Akosombo have similar production estimates, which was expected due to their location proximity. Even if global radiation at Bui was higher in certain months than Akosombo, the total output, specific yield and capacity factor is marginally higher at Akosombo. The difference in total expected output between the two sites was approximately 0.19 GWh. This could be a result of the fixed 5° tilt angle of the PV panels being more optimal at Akosombo with a latitude of 6° compared to Bui with a latitude of 8°. This hypothesis was tested by changing the panel tilt angle at both site locations to 8°, while keeping all other inputs constant. As expected, this resulted in Bui PV electrical output surpassing the Akosombo PV output, making the total expected generation greater at Bui. This indicate that the minor output difference from the two sites when using a fixed 5° panel tilt angle is favouring the Akosombo plant for ground-based PV.

4.1.2 System economics

Both LCOEs are on the other hand quite high compared to the IRENA (2018) numbers ranging from €35-40/MWh. By using current exchange rate between € and $, this corresponds to approximately $47-53/MWh. Meaning that the investment cost entered for the Ghana PV installations was nearly twice the amount of the cost reported by IRENA. However, the high investment cost applied in this case are specific costs for investments in Ghana (ECREEE 2017). The investment costs in Ghana are expected to be greater than other parts of the world, as it is highly context specific. In Ghana, scarcity of local resource availability and capability, previous experience, infrastructure, and technological progress, amongst other factors, is expected to result in higher investment costs compared to more developed areas.

Compared to the Navrongo solar PV project, which was the first utility scale PV plant in Ghana (2.5 MW installed capacity), both Bui and Akosombo’s specific yields are approximately 29 kWh lower per kW installed than the reported Navrongo specific yield at 1,520 kWh per kW installed (ECREEE 2017). One reason might be that solar radiation is higher further north were Navrongo is located. However, in terms of costs, the CAPEX of the Navrongo PV plant was $3,600/kW compared to the $2,000/kW applied for the Bui and Akosombo PV plants. Due to the considerable investment cost difference, the LCOEs for both Bui and Akosombo were lower than the Navrongo plant ($0.2411/kWh (Mensah et al. 2019)).

4.2 FPV

4.2.1 System energy output

Production results from the FPV installation at Bui dam is shown in Figure 4. 3.

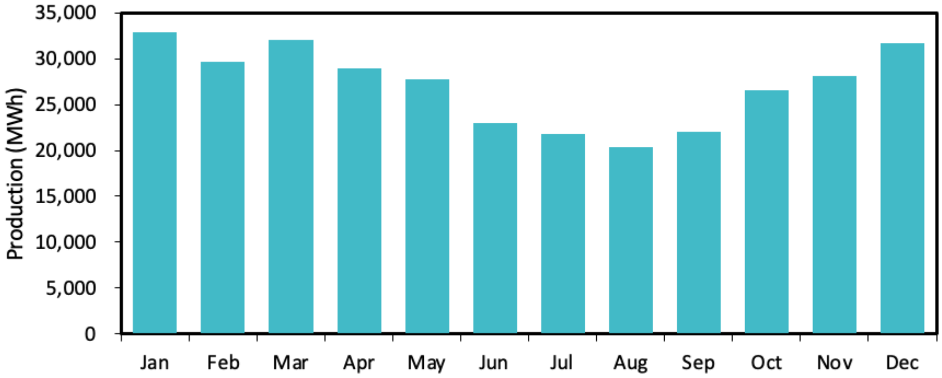


Figure 4. 3: Bui FPV production.

FPV generated 324.92 GWh electricity annually with a specific yield of 1,529 kWh/kW installed at Bui. Like the ground-based installation, it operates 4,342 hours a year, which resulted in a capacity factor of 17,5%. On average, the module supplied 890.2 MWh/day and had a peak output of 207.4 MW. The simulation returned an LCOE of $0.104/kWh and a total NPC of $538,026,348. The 212.5 MW installation was estimated to cover an area of 1.88km^2, as shown in Figure 4. 4.

Figure 4. 4: Map of the total area of the Bui FPV installation (Glint Solar 2020).

The FPV output of the installation at Akosombo dam is shown in Figure 4. 5.

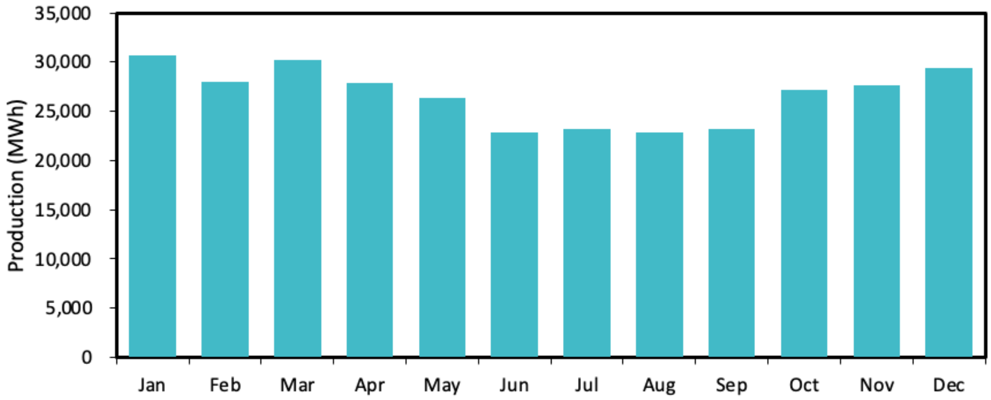


Figure 4. 5: Akosombo FPV production.

The FPV system at Akosombo was estimated to produce 319.37 GWh/year which equals a specific yield of 1,503 kWh/kW installed. The PV module supplied on average 874,978 MWh/day with peak power of 203.82 MW. Capacity factor was 17.2%, with 4,380 hours of operation over a year. Total system NPC was $538,026,348 and that resulted in a LCOE of 0.106 $/kWh. Figure 4. 6 shows the size of the FPV installation at the Akosombo dam which equalled 1,8811 km^2 for the 212.5 MW plant.

Figure 4. 6: Map of the total area of the Akosombo FPV installation (Glint Solar 2020).

The results showed that when comparing ground-based PV and the FPV solution, FPV produced an extra 49.9 GWh at Bui and 44.12 GWh at Akosombo per year. That is an increase equal to 18% and 16% for Bui and Akosombo, respectively, which is slightly higher than the 12% of added production from FPVs as argued by Ranjbaran et al. (2019). However, according to The World Bank (World Bank Group 2018), the increased energy yield from FPV could range from 10% to 15% in warmer climates. This could indicate that the electrical output difference between FPV and ground-based PV is higher in warmer climates, as the relative difference between the air temperature and water surface temperature will be greater compared to colder climates. With the relative percentage gain being larger at Bui than

Akosombo, it might suggest that FPV at Bui exploits the solar resource better when the panels are cooled down by the water surface. The greater output from FPV, relative to the ground-based PV, could also be explained by the FPV derate factor having less shading and dust issues, in addition to lower operating temperatures improving the power output. In total, over the 25-year project lifetime, the added generation from FPV compared to the ground-based PV equalled a total of 1,247 GWh for Bui and 1,103 GWh for Akosombo. The significant amount of added production from the FPV proves a considerable advantage from choosing this technology.

4.2.2 System economics

In terms of costs the FPV installation produced an LCOE of approximately $0.104/kWh for Bui and $0.106/kWh for Akosombo. This is approximately $0.006/kWh and $0.008/kWh higher compared to the ground-based PV scenario. Those results favour the ground-based system due to its relatively lower cost per kWh produced. However, our simulation assumed a 25% added cost for FPV, but the reality of the added cost might be less depending on the need for site levelling work as argued by Sahu et al. (2016). The added cost of FPV are a combination of higher investment cost in addition to higher operation and maintenance costs accumulating from the float, mooring, anchoring and plant design (World Bank Group 2018). As a result, the investment cost of the FPV will be addressed in the sensitivity analysis to try and see more of its effect on system solutions.

Compared to Ghana's current feed-in tariff $0.151/kWh (see Section 1.2.2 Renewable energy policies) for new renewable energy production, LCOE from FPV was lower. It could therefore be financially beneficial for producers and increase chances of investments in new projects.

4.3 FPV/PHS hybrid system

One of the questions this thesis aimed to answer was if a hybrid FPV/PHS solution could ensure a more robust hydropower generation throughout the dry season. The following section present the simulation results from incorporating PHS together with production from FPV.

4.3.1 System energy output

For both Bui and Akosombo, the FPV power output calculated (see Section 04.2.1 System energy output) is the amount of energy available for the FPV/PHS hybrid option. In this section, the FPV production is combined with the PHS option. Both optimal results presented gave a 100% renewable fraction within the defined load demand where FPV was able to supply the pump with sufficient power in the dry season without the help of fossil fuel generator.

In the optimal solution for Bui, 232.64 GWh of the total 324.92 GWh of FPV production is allocated to operate the pumps for the pumped-hydro system. This amount of energy is equal to 790.5 million m³ of water when adjusted for Bui's hydraulic head of 108 meters. This volume could be used to stabilize the reservoir elevation. Out of the amount of stored energy supplied to the pumps, 170.97 GWh was later released from the upper reservoir and generated through the turbines before feeding the grid together with FPV production. Annual storage depletion of approximately 61.67 GWh was a result of the losses accumulating from both pumping and turbine mode. The remaining amount of AC output to the grid that was provided by FPV when not directed to pumping, constituted a little over half the total output of 262.43 GWh, given the schemed load demand in the defined period. Figure 4. 7 shows how the schemed load for Bui was satisfied by the combination of FPV output and complementary use of PHS energy to deliver the 1,426,256 kWh/day for the 184-day period from May to October. FPV production dropped in those months due to lower radiation, so the reservoir state of charge also reduced as shown in Figure 4. 8 because more stored energy was needed to complete the demand. For Akosombo the combination was similar, but FPV production was a slightly higher in the summer and therefore less need for PHS supplement.

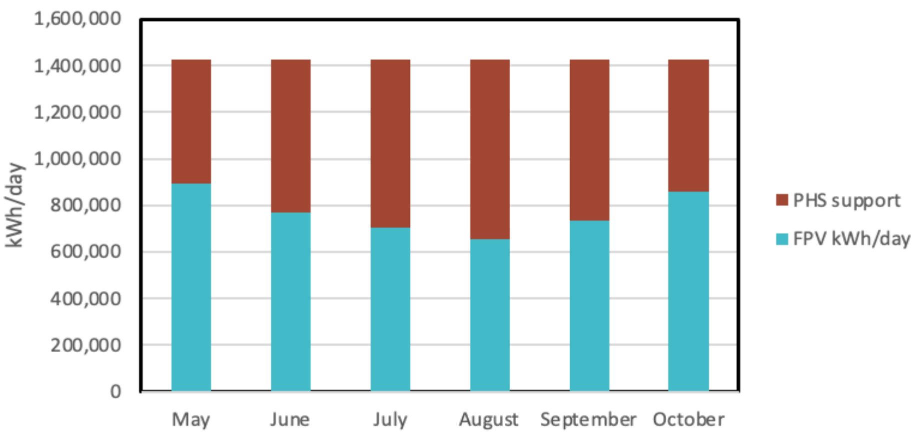


Figure 4. 7: Daily load served by FPV and PHS for Bui.

Figure 4. 8 show how storage increased during the dry months because of pumping, before being released in the months where the discharge levels normally pick up. As the initial state of charge was set equal to 0.00 for both Bui and Akosombo, the curve in Figure 4. 8 and Figure 4. 9 represents a % change in the available water between the minimum and maximum reservoir levels. For Bui's sake, the maximum charge level reached almost 12%, which can be considered a significant contribution to the elevation level of the reservoir.

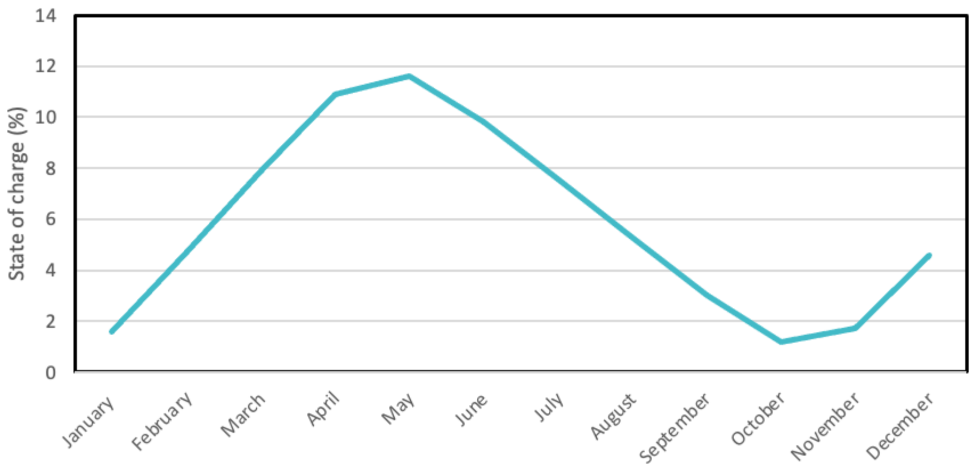


Figure 4. 8: Bui PHS state of charge.

Out of the 319.37 GWh of yearly FPV production at Akosombo, 225.89 GWh was supplied to the pump. In total, this amount equals 1,205 million m^3 of water provided to the reservoir annually, given Akosombo's hydraulic head of 68.8 meters. From this, 168.95 GWh per year was released from the reservoir and generated through the turbines to supply demand. That resulted in annual storage depletion of approximately 65.93 GWh. Figure 4. 9 shows the Akosombo reservoir state of charge from pumping mode. The maximum state of charge reached at Akosombo was 0.75%. Compared to Bui's 12% state of charge, this is relatively low. However, the wast size of the Akosombo dam would be a logic reason for this.

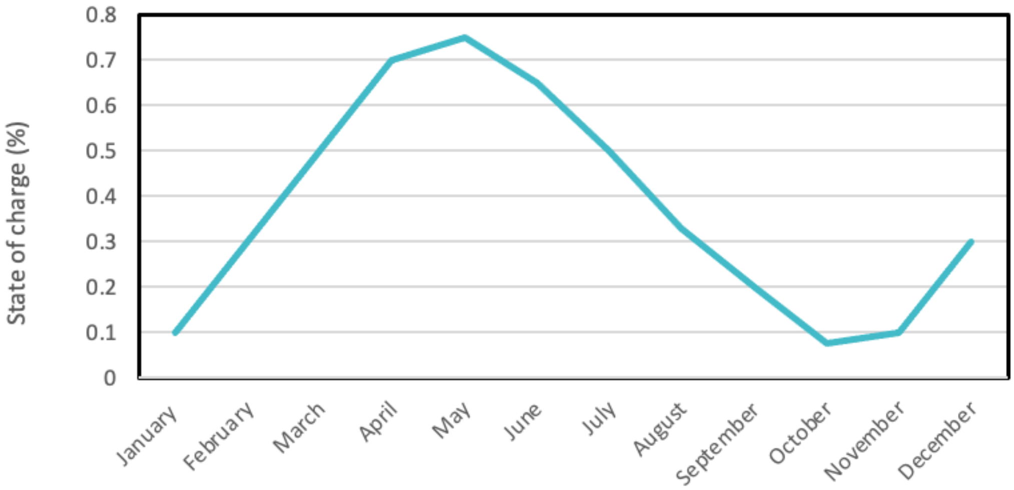


Figure 4. 9: Akosombo PHS state of charge.

The shape of Figure 4. 8 and Figure 4. 9 are much alike, however, the value of the greatest state of charge is reached at Bui owing to the smaller reservoir size. Comparing this shape to Figure 1. 3 and Figure 1. 4 which plotted the registered reservoir variations over a year at the two sites, showed how the curves are anti-correlative (or mirror-images). The energy from FPV serves the pump power for six months of the dry season, while it contributes as general electricity to supply load demand in the other six months. Subsequently, the solutions efficiently contributed to filling the reservoir and make water available during the dry season to add to the water level. More so for Bui, but also in some capacity for Akosombo.

4.3.2 System economics

Installing PHS capacity together with FPV resulted in LCOE of $0.234/kWh for both Bui and Akosombo. The similar LCOE is a result of the calculation being based on final energy output, which is the same at both sites since the load demand was equal. Compared to the PHS cost review (see Section 2.2.4 System cost) the proposed Bui and Akosombo systems end up in the mean area of the LCOE range. A significant implication to our calculated LCOE is that PHS usually have a longer lifetime than the 25 years used in this analysis. Consequently, the LCOE could be lower when the relatively large investment spreads over a longer system lifetime. Then the LCOE of Bui and Akosombo would probably end closer to the lower LCOE range ($0.152 – 0.198/kWh) when including total economic lifetime.

Compared to the option of having intermittent FPV only, these results show that for an extra cost of $0.13/kWh storage and flexibility becomes available. To assess if this added cost is worthwhile, the solution might depend on the demand for storage and flexibility. If the pumped water can be utilized for electricity production in periods where Ghana would normally have unsatisfying hydropower capacity i.e., the driest months where reservoir levels are low, the alternative cost could be more expensive. Sun et al. (2020) calculated the different LCOEs for some of the largest generating systems in Ghana, including both renewable and fossil generating units. The cost of energy from thermal power plants ranged from GH¢96.67 – 351.44/kWh or $0.17 – 0.61/kWh. Here, the initial investment costs were based on a IRENA-report (2018) with a weighted average cost of capital of 12% for thermal plants. The LCOE calculation was performed by a program set in Euros, with exchange rates from 2019. Since the Euro have appreciated against Ghanaian cedi the last two years, those LCOE numbers would probably be somewhat higher due to today's exchange rates that were used between cedi and $. From the article only two existing thermal power plants in Ghana had lower LCOE than the proposed system for Bui and Akosombo with FPV/PHS capacity. Sun et al. (2020) did not specify which types of fuels that were used in calculating LCOE for the thermal plants, but it did refer to Lazard's LCOE report (Lazard 2020) which consider natural gas. Gas is the primary fuel for combined cycle generators, and its price of $3.5 per Metric Million British thermal unit (MMBtu) is significantly lower than oil in terms of cost per kWh generated. However, oil and diesel are still a part of such power plants. Accordingly, implementing the PHS system could reduce the dependency on those sources, and subsequently lower overall cost of power if PHS capacity were realized.

Table 4. 3 show the comparison between FPV/PHS hybrid system and the base system consisting of generator capacity only. The simple payback shows number of years at which the cumulative cash flow of the difference between the proposed system and the base case switch from negative to positive (Homer Energy 2021b). If a similar amount of thermal capacity were to be replaced by the hybrid system, HOMER indicated that it would take 12.4 years to recover the difference in investment costs between those systems. Over the project lifetime, we found that ROI was 3.88% with net present worth of $218,000,000 in favour of the hybrid system. The project IRR of 6.03%, is the discount rate where both systems end up with the same NPC, meaning the present value of the difference of the two cash flows equal to zero.

Table 4. 3: Economic result of FPV/PHS hybrid system compared with base case system.

Variable	Unit	Value
Simple payback	years	12.4
ROI	%	3.88
IRR	%	6.03
Present worth	$	218,000,000
Annualized savings	$	66,900,000

Figure 4. 10 show the cumulative discounted cash flow between the two systems mentioned. Fossil based systems typically have low initial investment cost, but high annual operation costs. For the renewable system, the opposite is usually true, showing a large initial investment, before requiring very low annual operating costs. The figure plotting the two cash flows intersect around year 18, representing the year the total NPC from the base system surpass the FPV/PHS hybrid system. This could indicate that for timelines shorter than 18 years, a generator would be more cost effective. Comparing this against other hybrid systems was somewhat difficult as many are fitted to suit the available resources at given locations. One study from the Greek islands of Karpathos and Kasos looked at maximizing wind energy penetration and minimizing use of fossil-fuelled thermal plant, through the installation of PHS to secure power production for certain hours per day (Katsaprakakis et al. 2012). The project lifetime was 20 years, and economic indexes showed a simple payback of 5.46 years and a discounted payback of 7.55 years. Even with the differences in project size and type, it might indicate that the payback time for the proposed systems in Ghana trend toward a higher end of the time scale.

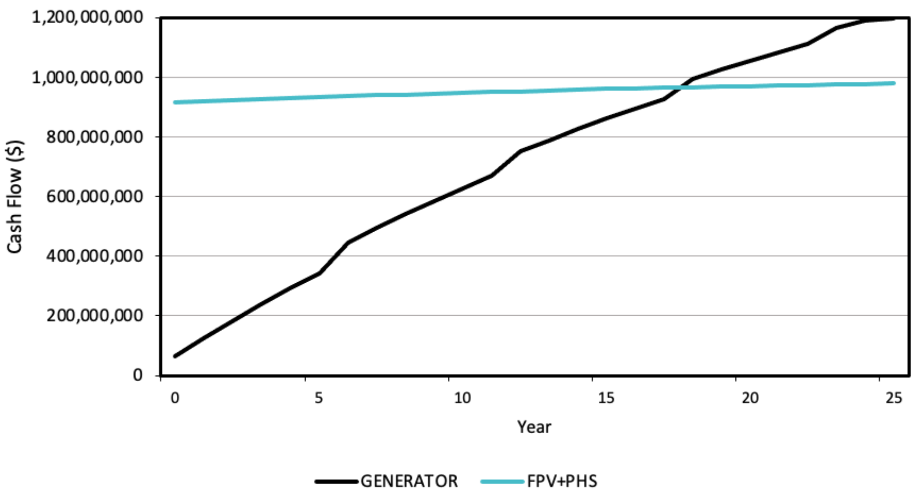


Figure 4. 10: Discounted cash flow development and payback time of generator and FPV/PHS hybrid system.

4.4 Sensitivity analysis

The sensitivity analysis addressed the effects of changing different input variables of the optimal system against the base case. The analysis was performed on the hybrid FPV/PHS solution only. With the hybrid systems of Bui and Akosombo being very similar, with equal load and costs, they were treated as one in the sensitivity analysis, as the differences from the results (see Section 4.3.1 System energy output) were also marginal.

Renewable energy projects are generally sensitive to changes in investment costs and interest rates, with these having the biggest effect on the NPC (IEA & NEA 2020). When comparing a 100% renewable scenario to a base case consisting of a thermal generator, the alternative cost effect was also analysed through changes in fuel price. Thermal power plants run on fossil fuels and generally have low investment costs, but high operation and maintenance costs deriving from the fuel consumption (IEA & NEA 2020). Compared to a renewable system, this is quite the opposite with the diesel fuel price being the major component affecting total NPC over the project lifetime.

The inputs investigated in the sensitivity analysis was limited to the global solar radiation, interest rate, diesel price and capital cost for FPV and PHS. These variables were considered in the analysis as they would have the greatest impact on the optimal solution.

4.4.1 Global solar radiation and PHS capital cost

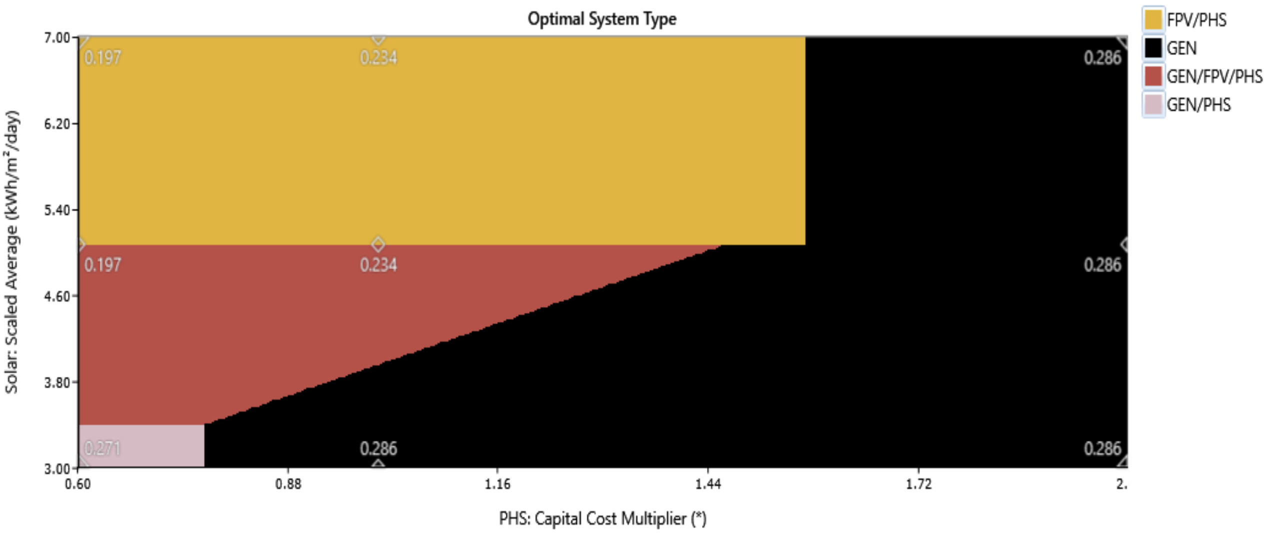


Figure 4. 11: Sensitivity analysis changing the scaled annual average and PHS capital cost.

Figure 4. 11 shows optimal system outcomes under different solar radiation levels and capital cost for the PHS-component when fuel price, discount rate and FPV capital costs are fixed. The solution provided four possible optimal systems, where PHS was included in three of them; generator-PHS, generator-FPV/PHS and FPV/PHS. For radiation levels below 3.4 kWh/m²/day, FPV was not included in the optimal system. Furthermore, it is worth noting that FPV was included in all solutions for solar radiation levels above 3.95 kWh/m²/day, when all other components remained unchanged. If PHS capital cost exceeded 1.57 multiplier, renewable solutions were no longer possible.

4.4.2 Diesel fuel price and discount rate

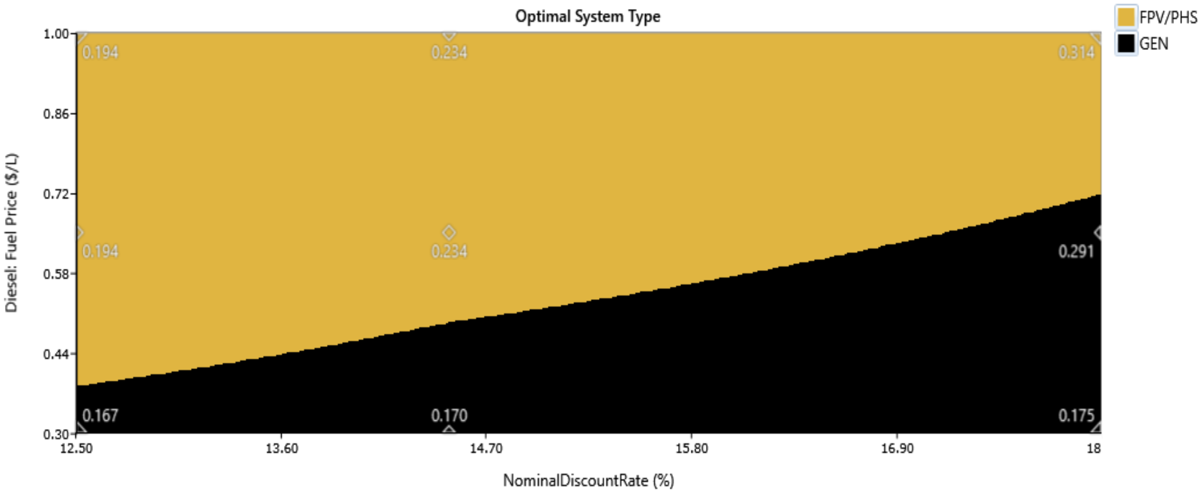


Figure 4. 12: Sensitivity analysis changing the diesel price and discount rate.

Figure 4. 12 show the optimal system type under different fuel prices and discount rates when all other variables were unchanged. The result showed two optimal systems, namely generator only or FPV/PHS hybrid system. What was worth noting was the two end points of the two solutions, showing that if the nominal discount rate dropped to 12.5% (2% real interest rate), fuel prices needed to be lower than $0.38/L before the generator base system was cheaper in total NPC. On the other hand, if nominal discount rate increased to 18% (8% real interest rate), the FPV/PHS hybrid system could still be preferred if fuel prices stayed above $0.72/L. If the discount rate remains unchanged to the original solution, the hybrid system was preferred when fuel prices are over $0.50/L.

4.4.3 Diesel fuel price and FPV capital cost

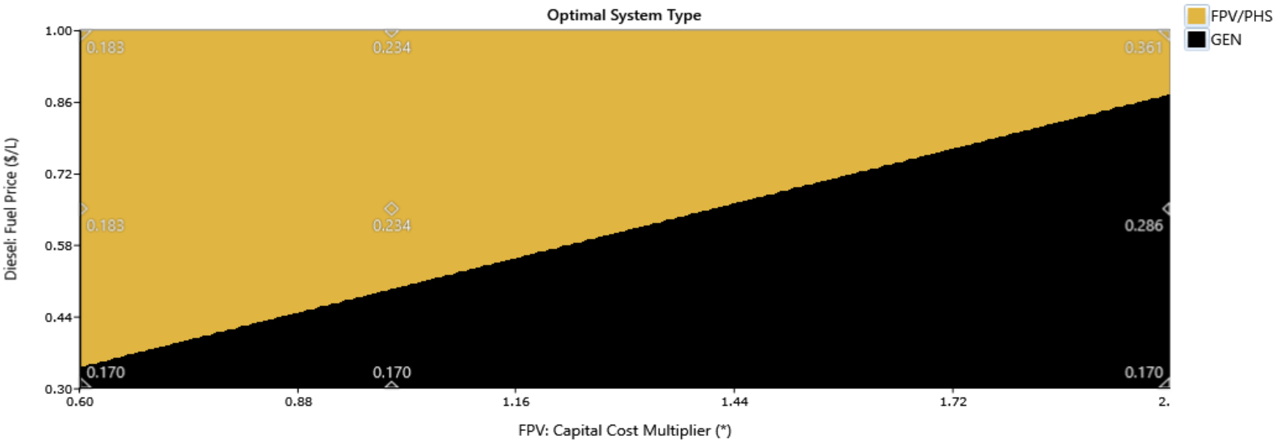


Figure 4. 13: Sensitivity analysis changing the fuel price and FPV capital cost.

Figure 4. 13 show the optimal system under varying fuel prices and capital cost for FPV, when the discount rate, PHS cost and solar radiation was fixed. Two main solutions appeared with a close linear relationship between the two variables considered. The value of the slope was approximately 0.04 for a 0.1 change in the capital cost multiplier. Hence, if the FPV capital cost increased by 20%, the fuel price could increase near to $0.08/L without HOMER changing preferred solution. The analysis showed that the FPV/PHS hybrid solution was financially best as long as the diesel price stay above $0.50/L, when all other variables are kept equal to the original solution. If FPV capital cost were doubled, the FPV/PHS system would only be preferred against a generator system if fuel prices were above $0.87/L.

4.4.4 Global solar radiation and diesel fuel price

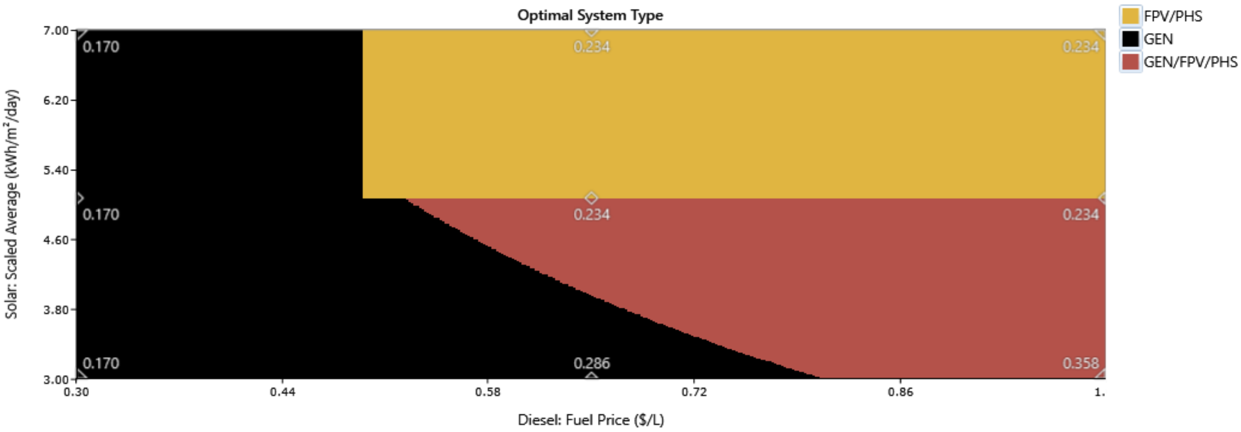


Figure 4. 14: Sensitivity analysis changing solar radiation and fuel price.

Figure 4. 14 show the optimal system with changing levels of different solar radiation and diesel fuel prices, keeping all other inputs constant. Three different system solutions were

proposed in the figure, consisting of generator only, generator with FPV/PHS and fully renewable FPV/PHS. Again, we saw that for fuel prices below $0.50/L, the base system with generator only was preferred regardless of solar radiation. This would be a result of fixating load demand to the maximum extent of what the hybrid FPV/PHS system of this specific size could cover within 100% renewable fraction. For solar radiation levels below 5.08 kWh/m²/day, the solution including generator and FPV/PHS was the preferred system in terms of total NPC. For fuel prices above $0.81/L, a system including the FPV/PHS option was included as part of the winning system, even with solar radiation down to 3 kWh/m²/day.

4.4.5 Summary

The sensitivity analysis showed that renewable energy sources were part of all solutions for cases with diesel prices above $0.50/L, given average solar radiation of 5.08 kWh/m^2/day at both Bui and Akosombo. Additionally, when solar radiation was above 3.8 kWh/m²/day, FPV was included in any preferrable system combination, given that other variables remained the same. These findings could be relevant to other locations where solar radiation might be less than the average levels of Bui and Akosombo. Moreover, there seemed to be a strong correlation between FPV capital cost and diesel fuel price. For fuel prices above $0.81/L, the designed FPV/PHS hybrid system became part of optimal solution, even if FPV capital cost were to double.

5 DISCUSSION

5.1 Analysis input data

The system analysis was based on data that were gathered from either historical observations or satellite inputs. Consequently, the system results have certain limitations when attempting to describe resources in real time. The data implemented in the analysis was applied in the absence of more accurate data, where the global solar radiation was based on satellite data from NASA and ERA 5. Here, a more reliable source would have been ground-based observations, but such measurements were not obtained. However, satellite data is considered to be more precise when applied at smaller, compared to larger latitudes benefitting the locations of Bui and Akosombo (Laliberté et al. 2016).

When calculating solar irradiation, HOMER use satellite data from NASA, while Glint Solar use the dataset ERA 5 obtained from PVGIS (see Section 3.4.4 Solar resource). This could potentially result in differences in terms of potential yield given variance in irradiation calculations. However, Suri et al. (2008) found that between six datasets providing solar radiation estimates, including PVGIS and NASA, the uncertainty expressed by standard deviation did not exceed seven percent for horizontal surface radiation. Even if these differences are quite small, we explored them in the dataset for our project locations in Ghana. We ran a test for predicted PV output from PVGIS and HOMER. The comparison used the same panel inputs as in our analysis, with equal system losses and tilt angles. The result found that PVGIS' calculation predicted 1.5% higher annual PV-production compared to HOMER (see Appendix 1). Given this slight variation in total output, we consider this difference to have minimal implications on the analysis' main findings.

With Ghana's latitude ranging between 5 and 10º'N, it caused local differences for optimal PV tilt angle depending on project location. Our results found this to implicate the production output estimate in some way. In particular, the electricity generation at Bui fell notably compared to Akosombo when applying the same fixed tilt angle for ground-based PV as the default setting in the Glint Solar application (5º). The reduction in total output was 1 GWh less a year compared to using optimal tilt angle based on the sun's trajectory at Bui's latitude (8.3º'N). In comparison, the reduction in output was minor at Akosombo with a latitude of 6.3 º'N. On the other side, using 5º tilt angle at both Bui and Akosombo for the FPV system solution resulted in total output at Bui increasing relatively more than Akosombo compared to the ground-based PV scenario. This may indicate the other factors like water surface temperature and wind speed play more in favour of Bui, since they are calculated specifically towards the output in Glint Solar's software. The 18% and 16% output gain for Bui and Akosombo, respectively, are larger than most experience data (Ranjbaran et al. 2019). Even though this has not been further examined in our analysis, there are undoubtably other factors impacting this result. One could be that the ground-based PV derate factor of 0.75 is based on experience from an actual site at a similar location in combination with previous research. In comparison, Glint Solar's evaluator engine apply a derate factor of 0.858 which is not specifically obtained from similar projects in Ghana.

5.2 Software limitations

The intention of using HOMER for the analysis was to provide comparable results with other works. However, our results showed that certain challenges must be overcome to efficiently analyse a hybrid system incorporating larger scaled PHS in the software. One essential implication of our analysis was that HOMER is not set up for PHS or hydropower that includes an existing reservoir. As described earlier in the thesis, some authors (such as (Canales & Beluco 2014) have described the process of modifying these components in HOMER to simulate energy systems including a reservoir and storage. Based on our findings, however, these modified components are unable to adequately operate and account for specific features of these generating units.

In essence, one implication is associated with HOMER's missing ability to include the hydrological dependent inflow of water to the modified battery serving as a reservoir. Accordingly, the hydro resource is greatly compromised, where our simulation results completely disregard the natural changes in reservoir levels over a year taking place due to the different climatic seasons. As a result, certain benefits of the hybrid system are not simulated, like the potential effect of FPV electrical output stabilizing reservoir levels in sun peak hours. In addition, our is analysis is not necessarily answering the research question adequately as the full size of the hydro turbines were not considered. Our calculation and modelling of the complete size of the Bui and Akosombo reservoirs in Ah (see Section 3.5.2 Pumped hydro storage) proved to be without much value as HOMER was unable to incorporate the full reservoir capacity in an optimal solution. Consequently, our hybrid system analysis disregarded the size of the reservoir capacity and initial reservoir state of charge was set equal to zero for both sites. This was to create a simulation of how FPV power output could be provided to pump the water. It is worth noting that in the latest version of HOMER, there is a small PHS capacity that can be used. Yet, for our analysis, a much larger component was ideally needed.

A different challenge related to HOMER was its missing ability to simulate a system where low tariff periods could be exploited to run the pump. This might have affected the analysis of economic viability of the PHS option with the FPV solely supplying the pumps.
Hybrid solutions coupling VRE with PHS can function as dispatchable power plants, making such systems comparable to the features of thermal power capacities. For the producer, it might also open new benefits by offering ancillary services, energy arbitrage and receiving more scheduled capacity payments at lower costs than most of the thermal plant alternatives. However, for our system in Ghana, such additional benefits might be unrealisable as the country operates with a set electricity tariff. For our analysis, the price of power purchased from the grid in pumping mode had to be at least 15% less than the price when selling electricity back to the grid. However, with a set tariff in Ghana, price fluctuations are not available for producers to make such a price arbitrage possible. From our findings, it did not significantly impact our results as we expect most producers would avoid using grid power in Ghana for pumping since it is not economically profitable. For similar systems in a different location however, considerable benefits from investing in a PHS solution could be neglected by only considering generation from the FPV or other generating units to fuel the pumps, if low-priced electricity is available.

A somewhat different software limitation identified in our analysis was related to the load setup in HOMER. To efficiently simulate a system that considered both the total ground-based PV and the FPV output, in addition to supplying the PHS with electrical output in the dry months, the electric load had to be altered accordingly. Therefore, the power generation for each system configuration had to be estimated before the load was adjusted, and not the other way around. To ensure that the optimal solution had the lowest possible system cost, the schemed load had to be optimized to the point where maximum generation from ground-based PV and FPV was demanded by the load. This is a result of the LCOE calculated in HOMER being based on delivered AC output to the grid only. Consequently, some of the FPV power allocated to PHS that was stored in the reservoir at the end of each year did not count towards calculating LCOE of the optimal system. Furthermore, this also limited our sensitivity analysis, as changing the scaled annual global solar radiation to levels above 5.08

kWh/m²/day did not result in lower LCOE as seen in Figure 4. 11 and Figure 4. 14. Because the FPV was already fitted to supply the load at solar radiation levels of 5.08 kWh/m²/day, meant that higher radiation only served as excess electricity not demanded by the grid.

5.3 Possible impacts on Ghana's energy sector

Returning to the energy challenges in Ghana discussed previously (see Section 1.1 Energy sector in Ghana), ameliorating the overall power supply and reducing certain challenges relating to stable power supply were highlighted as crucial goals for the authorities. The Energy Commission Outlook Report (2020a) highlighted hydrological risk as one out of two supply challenges. To ensure sustainable operation of the Bui hydropower plant, the report highlighted that the reservoir elevation could not drop below 168 meters above sea level (MASL). In 2019, the reservoir was recorded at 168.66 MASL on its lowest point, only 0.66 meters above minimum. From the results (see Section 4.3 FPV/PHS hybrid system), the pump would be able to provide the Bui reservoir with 790.5 million m^3 of water annually. This volume corresponds to an increase in the Bui reservoir level of 1.8 meters when assuming the full surface area of the Bui dam in the calculation. In reality, the increase could potentially be greater as it would be dependent on the surface are of the dam at minimum operating level. Consequently, our designed system solution with the FPV/PHS hybrid system could have successfully helped stabilize minimum operating level at Bui in 2019. For Akosombo however, the result (see Section 4.3.1 System energy output) estimated 1,205 million m^3 of water being supplied from the pumping. In terms of reservoir elevation levels, this equals an increase of 0.2 meters only for the Akosombo dam. That number could also be higher or lower in reality but given the massive size of the dam, the change in reservoir level would nevertheless be minor.

The second supply challenge highlighted by the Energy Commission in its outlook report for 2020 was reliability of gas supply from West Africa Gas Pipeline Authority and Ghana Gas Company, which is seen as a major risk. Disruptions in gas supply could render some thermal plants inoperable, and have consequences on the nation's power system, i.e., prolonged load shedding. Relying heavily on fossil fuels like gas and oil, also poses challenges in terms of the financial health of the power sector. As of 2019, the country had a debt of $4 billion, which could potentially grow to $12.5 billion by 2023 if no immediate action is taken (Energy Commission Ghana 2020a). Insufficient payments of the delivered gas were mentioned as a contributor to huge debt burdens. Limiting the reliability on gas and oil supply could therefore contribute towards the financial health of the country. For this to occur, renewable energy sources could help reduce the need for some fuel-based thermal capacity and as established in the analysis, be economically beneficial long term. When we investigated the comparison between oil-based thermal generation and the FPV/PHS hybrid system, we found that the discounted NPC of the renewable system matched today's oil-fuelled thermal power production costs within 18 years. This is well within the projected lifetime of investing in new renewable energy. With Ghana currently having excess capacity within its energy sector (where approximately 69% is fossil-based), it would not necessarily make financial sense to support investments that add more renewable generating capacity. However, the energy outlook presented in the introduction also project that annual electricity demand could increase up to 40,000 GWh by 2030. Accordingly, acting quickly and installing new renewable energy capacity could mean Ghana stays ahead of the growing demand curve.

5.4 Environmental impact

All three analysed scenarios introduce potentially harming environmental impacts. For ground-based PV, land usage is an important implication to consider. From our analysis, 212.5 MW of FPV would occupy roughly 1.88 km² according to Glint Solar's evaluator and that was assumed similar for ground-based PV as well. Occupying the same total area of a water body could not only prove to introduce less conflicts, but also provide positive environmental effects (see Section 2.1.2 Advantages). With a considerable amount of similar system components, both systems are assumed to have about the same environmental impacts from resources used in production of the panels and other components like inverters and wiring. There would, on the other hand, be differences in parts used for installation, like the floating system for the FPV versus the support system applied for ground-based PV. To establish which system having the biggest negative environmental impact, the result would depend on the system boundaries in addition to the choice of materials. A Life Cycle Assessment (LCA) could be used determine the outcome of these impacts in further research.

For PHS, many of the environmental implications could be argued as already accounted for since the two locations currently encompasses reservoirs and powerhouses. The negative environmental impacts from open-loop PHS operation are mostly related to changes in surface water quality, effects on aquatic ecology and geology, in addition to soiling changes (Saulsbury 2020). Pumping and generating operations can also increase sedimentation due to shoreline erosion from rapid fluctuations in the water level. Some of these impacts already exist due to current hydropower operations, which can be argued to limit the extent of further impacts by introducing the pumping operation. However, installing pumping turbines would potentially have undesirable flow rate effects at both project locations which could pose further implications on people living downstream of the dam.

On the other hand, there are also positive impacts of the proposed hybrid system, especially if it replaces the need for fossil fuel-based power generation. With the calculated total energy stored from the hybrid solution at both reservoirs, this could replace roughly 525,000 MWh of delivered energy from thermal power plants. Based on the assumption that these fossil fuel-based plants have some of the lowest emissions from natural gas (0.422t CO_2eq/MWh for combined cycle plants (Moomaw et al. 2011)) and state-of-the-art conversion efficiency at 60% (GE 2021), approximately 369,250 tons of CO_2eq could be saved annually just from fuel savings. The existing hydropower in comparison has estimated emissions of 0.004t CO_2eq/MWh which means 2,100 tons CO_2eq from producing the same amount of electricity (Moomaw et al. 2011). According to estimates from the Navrongo PV project, annual carbon savings of 1,400 tons of carbon dioxide equivalents (CO_2eq) for the 2.5 MW was estimated for the installation, which has later been confirmed by studies on the actual carbon savings from the national dispatch (ECREEE 2017). Transforming this to our 425 MW PV installation results in potential carbon savings of 238,000 tons of CO_2eq annually. Accordingly, we assume the potential annual carbon savings to be somewhere around these estimates depending on the fossil fuel-based generation it replaces in Ghana.

6 CONCLUSIONS

6.1 Conclusion to research questions

According to this analysis, installing FPV in Ghana will yield around 16% to 18% higher annual output compared to ground-based PV, equalling a total estimated production of 644 GWh yearly. Comparing the two different system locations, Bui achieves the greatest FPV output and would therefore be considered the optimal location for a hybrid system. The actual added output from FPV could be higher or lower and maybe closer to where the literature averages at around 12% gain compared to ground-based PV. The cooling effect from water and wind reducing cell operating temperature seem to be the main benefit for the efficiency gain. Over the project lifetime of 25 years, LCOE from FPV was \$0.006/kWh to 0.008/kWh higher compared to ground-based PV of \$0.098/kWh. This result assumes that FPV adds an additional 25% to the investment cost owing to the float and mooring system. In a climate like Ghana, these findings look promising for future deployment of FPV. The relatively low added cost for significantly extra electricity generation, in addition to lower environmental impacts, made it recommendable over ground-based PV.

Introducing the flexible PHS option allocated 233 GWh at Bui and 226 GWh of the FPV production to pumped storage for six months. Out of this amount of stored energy, 171 GWh from Bui and 187 GWh from Akosombo was discharged and supplied to the grid along with FPV, within the schemed load scenario for the other six months. Adding PHS approximately doubled total system cost, and LCOE of the FPV/PHS hybrid system got disadvantaged by how it was calculated in HOMER. It could possibly be lower given longer PHS lifetime in reality and a load scheme better fitted to include regular hydropower generation as well. Despite the challenges discussed in the previous section, we believe the FPV/PHS hybrid system to be a viable solution given the current need for flexibility in existing hydropower reservoirs. Even though PHS has a relatively high cost and higher system losses compared to the FPV only scenario, the added benefits from system flexibility can be of great significance for the power sector in Ghana. Moreover, the full pumping potential was not properly disclosed by our analysis, where additional benefits could also arise. Given the hybrid system’s remarkable exploitation of the existing infrastructure limiting the system’s environmental implications, we argue this to be a sustainable solution worth the added cost.

The hydrological challenge of reservoirs in Ghana dropping below minimum operating levels for hydropower prevent both Bui and Akosombo from optimal utilization over a calendar year. Introducing FPV/PHS hybrid system capacities has shown an efficient way to contribute towards water preservation throughout the dry season as shown in the analysis. However, with the substantial added cost associated with the PHS option, the added storage is currently difficult to justify on pure economic basis as the set electricity tariff limits the price arbitrage from complementing with grid power in addition to the FPV. Accordingly, a cost-benefit analysis could be useful to help evaluate the decision further. It is worth nothing that a major limitation of this analysis was linked to HOMER not able to model the full size of the reservoir with hydrological resources and regular hydropower production next to FPV. The proposed solution might have other additional benefits as the hybridisation would further stabilize reservoir levels. In 2020, Akosombo was projected to only operate four to five, out of the six turbines installed and Bui was set to use two out of three. Hence, there could be pumping capacity available if some of the units were to be replaced with variable speed reversible pump-turbines. This also add to the value of investing in PHS in the sense of maximizing use of power plant capacities.

6.2 Recommendations for future work

One of the initial objectives of this thesis was to simulate hybrid renewable energy systems including large scale energy storage, such as PHS. To serve this purpose, our finding is that optimization software such as HOMER Energy is currently not adequate, even with the possibility of modifying storage components to create a virtual battery. Because the virtual battery is not able to consider the natural changes in reservoir levels occurring from the hydrological discharge along with increased storage from pumping operation. Large scale hybrid systems including storage looks to become more common in the future, which will demand more viable simulation software to incorporate both renewable generation and storage. Therefore, we believe hybrid energy software developers should expand the storage option in relation to PHS and multiple renewable resource inputs.

Commercial FPV projects are still establishing itself as a reliable and cost-effective energy generation technology. Particularly in Africa, it is still considered a relatively new concept with few realized projects to date making investments riskier to investors. Once some of those projects start operating, like the Bui FPV project, experience data from that site could be of great significance. Moreover, potential environmental implications of FPV on the aquatic conditions is still a topic in urgent need of more research. Specifically for the sake of Ghana, we hope to see more research within the field of hybrid systems including renewable energy. Hopefully, this thesis could motivate a closer look into actual PHS and FPV feasibility around some of those large hydropower plants.

7 REFERENCES

Abid M. Abid Z. Sagin J. Murtaza R. Sarbassov D. and Shabbir M. (2018). Prospects of floating photovoltaic technology and its implementation in central and South asian countries. *International Journal of Environment and Science Technology*. doi: 10.1007/s13762-018-2080-5.

Agostinelli G. (2020). Floating Solar Photovoltaic on the Rise. I: IFC, I. F. C. (red.). *Emerging Energy Solutions*. International Finance Corporation.

Ahiataku-Togobo, W., Gifty Tettey, Seth A. Mahu, Senna Hammond, Dr Alfred Kwabena Ofosu Ahenkorah, Kwabena Otu-Danquah, Michael Opam, Dr Nii Darko Asante, Frederick Ken. Appiah, Paula Edze, Eric Kumi Antwi-Agyei, Oforiwa Asare, Dr Isaac Frimpong Mensa-Bonsu, Dr Francis Kemausuor. (2019). *Ghana Renewable Energy Masterplan*. Ministry of Energy. Energy Commission Ghana: Energy Commission Ghana.

Akbarzadeh A. & Wadowski T. (1996). Heat pipe-based cooling systems for photovoltaic cells under concentrated solar radiation. *Applied Thermal Engineering*, 16: 81-87. doi: 10.1016/1359-4311(95)00012-3.

Amankwaa, E. F. (2017). *Water and electricity access for home-based enterprises and poverty reduction in the greater Accra metropolitan area (GAMA)*: University of Ghana.

Aneke M. & Wang M. (2016). Energy storage technologies and real life applications - A state of the art review. *Applied Energy*, 179: 350-377.

Bank of Ghana. (2021a). *Bank of Ghana*. Tilgjengelig fra: https://www.bog.gov.gh/ (lest 19.04).

Bank of Ghana. (2021b). Commodity prices. I: *Bank of Ghana*, . Tilgjengelig fra: https://www.bog.gov.gh/economic-data/commodity-prices/.

Beluco A. Souza PKD. Krenzinger A. (2012). A method to evaluate the effect of complementarity in time between hydro and solar energy on the performance of hybrid hydro PV generating plants. *Renewable Energy*, 45: 24-30.

Berrada A. & Loudiyi K. (2019). Chapter 3 - Economic Evaluation and Risk Analysis of Gravity Energy Storage. *Gravity Energy Storage*: 51-74. doi: https://doi.org/10.1016/B978-0-12-816717-5.00003-7.

Black & Veatch. (2012). Cost and performance data for power generation technologies. I: National Renewable Energy Laboratory, N. (red.). *Cost report*.

Blakers A. Stocks M. Lu B. Cheng C. Nadolny A. (2021). *Global Pumped Hydro Atlas*. Australian National University: RE100. Tilgjengelig fra: http://re100.eng.anu.edu.au/global/ (lest 3.2).

Britannica, T. e. o. E. (1998). *Akosombo Dam*. Encyclopaedia Britannica (red.). https://www.britannica.com/topic/Akosombo-Dam.

Bungane, B. (2020). Seychelles delays planned floating solar plant due to COVID-19. Tilgjengelig fra: https://www.esi-africa.com/industry-sectors/renewable-energy/seychelles-delays-planned-floating-solar-plant-due-to-covid-19/.

Canales F.A & Beluco A. (2014). Modeling pumped hydro storage with the micropower optimization model (HOMER). *Journal of Renewable and Sustainable Energy*, 6 (4). doi: 10.1063/1.4893077.

Cazzaniga R. Cicu M. Rosa-Clot M. Rosa-Clot P. Tina G.M. and Ventura C. (2018). Floating photovoltaic plants: Performance analysis and design solutions. *Renewable and Sustainable Energy Reviews*, 81: 1730-1741. doi: 10.1016/j.rser.2017.05.269.

Cazzaniga R. Rosa-Clot M. Rosa-Clot P. Tina G.M. (2019). Integration of PV floating with hydroelectric plants. *Helyion*, 5 (6). doi: 10.1016/j.heliyon.2019.e01918.

Da Silva G.D.P & Branco D.A.C. (2018). Is floating photovoltaic better than conventional photovoltaic? Assessing environmental impacts. *Impact assessment and Project Appraisal*, 36 (5): 390-400. doi: https://doi.org/10.1080/14615517.2018.1477498.

Duffie J.A. & Beckman W.A. (2013). *Solar engineering of thermal processes*. Hoboken, New Jersey: John Wiley & Sons.

ECMWF, E. C. f. M.-r. W. F. (2016). *ERA5*. ECMWF (red.). European Centre for Medium-range Weather Forecast.

ECREEE. (2017). Case Study Navrongo Solar PV Project Ghana. I: Hille G. & Reiche K. (red.). *RE Flagship projects in the ECOWAS region*. ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE), Praia, Cabo Verde.

Effah B. & Boampong E. (2015). Biomass Energy: A Sustainable Source of Energy for Development in Ghana. Asian Bulletin of Energy Economics and Technology. *Asian Bulletin of Energy Economics and Technology*, 2 (1): 6-12.

EIA. (2020). Capital cost and performance characteristics for utility scale power generating technologies. I: U.S Energy Information Agency (red.). *Independent Statistics & Analysis*. U.S Department of Energy, Washington, DC.

Eller A. & Gauntlett D. (2017). Energy Storage Trends and Opportunities in Emerging Markets. I: IFC, E. (red.). esmap.org: Energy Sector Managment Assistance Program.

Energy Commission Ghana. (2020a). *2020 Energy (Supply and Demand) Outlook for Ghana*. Accra: Energy Commission Ghana.

Energy Commission Ghana. (2020b). *National Energy Statistics 2000 - 2019*. Ministry of Energy and Petroleum. http://www.energycom.gov.gh/files/2020%20ENERGY%20STATISTICS-revised.pdf: Energy Commission Ghana.

Eshun, M. E., Amoako-Tuffour, J. (2016). A review of the trends in Ghana's power sector. *Energy Sustainability and Society*, 6. doi: https://doi.org/10.1186/s13705-016-0075-y.

EU Science Hub. (2019). *The PVGIS project, a bit of background*. I: Joint Research Centre (red.). European Commission,: European Commission, EU Science Hub. Tilgjengelig fra: https://ec.europa.eu/jrc/en/PVGIS/about/who (lest 13.05).

Gamon, C. (2019). A comprehensive European approach to energy storage. European Parliament: Committee on Industry, Research and Energy.

GE, G. E. (2021). *9F Gas turbine*. Gas Power/Products. ge.com. Tilgjengelig fra: https://www.ge.com/gas-power/products/gas-turbines/9f (lest 14.05).

Glint Solar. (2020). *The Site Evaluator Engine*. glintsolar.co: Glint Solar. Tilgjengelig fra: glintsolar.co (lest 19.04).

Gorjian, S., Sharon, H., Ebadi, H., Kant, K., Scavo, F. B., & Tina, G. M. (2020). Recent technical advancements, economics and environmental impacts of floating photovoltaic energy conversion systems. *Journal of Cleaner Production*, 124286.

Gracia Amillo A. Huld T. and Müller R. (2014). A new database of global and direct solar radiation using the eastern meteosat satellite, models and validation. *Remote Sensing*, 6: 8165-8189.

Graham V.A & Hollands K.G.T. (1990). A method to generate synthetic hourly solar radiation globally. *Solar Energy*, 44 (6): 333-341. doi: 10.1016/0038-092X(90)90137-2.

GRDC. (1979). Volta Basin - Station: Senchi (Halcrow). Tilgjengelig fra: https://www.compositerunoff.sr.unh.edu/html/Polygons/P1531700.html.

GRIDCo. (2020). *National Interconnected Transmission System of Ghana*. http://smpweb.gridcogh.com/displayxx/.

Guaita-Pradas I. Marques I. and Soucase B.M. (2015). *Economical and financial study of photovoltaic energy production in Africa: Case of Morocco, Côte d'Ivoire and South Africa*. 2015 3rd International Renewable and Sustainable Energy Conference (IRSEC).

Gyamfi, S., F.A. Diawuo, E.N. Kumi, F. Sika, M. Modjinou. (2018). The energy efficiency situation in Ghana. *Renewable and Sustainable Energy Reviews*,, 82: 1415-1423. doi: https://doi.org/10.1016/j.rser.2017.05.007.

Gyamfi, S., Modjinou, M. & Djordjevic S. (2014). Improving electricity supply security in Ghana - The potential of renewable energy. *Renewable and Sustainable Energy Reviews*,, 43: 1035-1045. doi: https://doi.org/10.1016/j.rser.2014.11.102.

Gyau-Boakye P. (2001). Environmental impacts of the Akosombo dam and effects of climate change on the lake levels. *Environment, Developement and Sustainability*, 3: 17-29.

Haugwitz, F. (2020). Floating solar PV gains global momentum. *pv magazine*.

Homer Energy. (2021a). *About us*. Tilgjengelig fra: https://www.homerenergy.com/company/index.html (lest 26.04).

Homer Energy. (2021b). *Compare Economics*. homerenergy.com. Tilgjengelig fra: https://www.homerenergy.com/products/pro/docs/3.14/compare_economics.html (lest 04.05).

Homer Energy. (2021c). *Controller*. Tilgjengelig fra: https://www.homerenergy.com/products/pro/docs/3.13/controller.html (lest 26.04).

Homer Energy. (2021d). *PV derate factor*. homerenergy.com. Tilgjengelig fra: https://www.homerenergy.com/products/pro/docs/latest/pv_derating_factor.html (lest 30.04).

Hopf, D. (2020). *Balancing technology: Fengning 2, China*. Andritz. Tilgjengelig fra: www.andritz.com/hydro-en/hydronews/hn32/fengning2-china.

Hydro Review. (2018). *Africa Market Brief*. Tilgjengelig fra: https://www.hydroreview.com/business-finance/africa-market-brief/#gref (lest 27.04).

Haas, J., Khalighi, J., de la Fuente, A., Gerbersdorf, S. U., Nowak, W., & Chen, P. J. (2020). Floating photovoltaic plants: Ecological impacts versus hydropower operation flexibility. *Energy Conversion and Management*, 206, 112414. doi: 10.1016/j.enconman.2019.112414.

IANS. (2021). *India's biggest floating solar power plant coming up in Telangana*. I: The Economic Times (red.). Energyworld.com. Tilgjengelig fra: https://energy.economictimes.indiatimes.com/news/renewable/indias-biggest-floating-solar-power-plant-coming-up-in-telangana/81881262 (lest 27.04).

Idoko L. Anaya-Lara O. and McDonald A. (2018). Enhancing PV modules efficiency and power output using multi-concept cooling technique. *Energy Reports*, 4: 357-369.

IEA & NEA. (2020). Projected costs of generating electricity 2020. I: International Energy Agency & Nuclear Energy Agency (red.). Paris, France.

IHA. (2021). *Pumped Storage Tracking Tool*. International Hydropower Association (red.). https://professional.hydropower.org/page/map-pumped-storage-tracking-tool.

Ilas A. Ralon P. Rodriguez A. Taylor M. (2018). Renewable power generation costs 2017. I: IRENA (red.). *Technical Report*. International Renewable Energy Agency, Abu Dhabi.

IRENA. (2016). *Solar PV in Africa: Costs and Markets*.

IRENA. (2018). IRENA. *Planning and prospects for renewable power: West Africa*. International Renewable Energy Agency, Abu Dhabi.

IRENA. (2020). I: IRENA (red.). *Innovation landscape brief: Innovative operation of pumped hydro storage*. International Renewable Energy Agency, Abu Dhabi.

Kalogirou S.A.A. & Tripanagnostopoulos Y. (2006). Hybrid PV/T solar systems for domestic hot water and electricity production. *Energy conversion and Management*, 47: 3368-3382. doi: 10.1016/j.enconman.2006.01.012.

Katsaprakakis D. Christakis D. Pavlopoylos K. Stamataki S. Dimitrelou I. Stefanakis I. and Spanos P. (2012). Introduction of wind powered pumped storage system in the isolated insular power system of Karpathos-Kasos. *Applied Energy*, 97: 38-48. doi: https://doi.org/10.1016/j.apenergy.2011.11.069.

Kocaman A.S. & Modi V. (2017). Value of pumped hydro storage in a hybrid energy generation and allocation system. *Applied Energy*, 205: 1202-1215. doi: 10.1016/j.apenergy.2017.08.129.

Kougias I. Bódis K. Jäger-Waldau A. et al. (2016). The potential of water infrastructure to accommodate solar PV systems in Mediterranean islands. *Solar Energy*, 136: 174-182. doi: 10.1016/j.solener.2016.07.003.

Lacombe G. McCartney M. & Forkour G. (2012). Drying climate in Ghana over the period 1960-2005: evidence from the resampling-based Mann-Kendall test at local and regional levels. *Hydrological Sciences Journal*, 57: 1594-1609. doi: 10.1080/02626667.2012.728291.

Laliberté, J. e. a. (2016). Evaluation of satellite-based algorithms to estimate photosynthetically available radiation (PAR) reaching the ocean surface at high northern latitudes. *Remote Sensing of Environment*, 184: 199-211.

Lambert T. Gilman P. and Lilienthal P. (2006). Micropower System Modeling with Homer. I: Dr. Felix A. Farret & Dr. M. Godoy Simoes (red.) *Integration of alternative sources of energy*, s. 379-416. Hoboken, New Jersey: John Wiley & Sons Inc.

Lazard. (2016). Lazard's Levelized Cost of Storage - Version 2.0. https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf.

Lazard. (2020). Lazard's Levelized Cost of Energy Analysis - Version 14.0. https://www.lazard.com/media/451419/lazards-levelized-cost-of-energy-version-140.pdf: Lazard.

Liu L. Liu D. Sun Q. et al. (2017). Forecasting power output of photovoltaic system using a BP network method. *Energy Procedia*, 142: 780-786.

Liu L. Sun Q. Wang Y. Ronald W. Liu Y. (2018). Research on short-term optimization for integrated hydro-PV power system based on algorithm. *Energy Procedia*, 152: 1097-1102.

Liu L. Wang Q. Lin H. Li H. Sun Q. Wennersten R. (2017). Power generation efficiency and prospects of floating photovoltaic systems. *Energy Procedia*, 105: 1136-1142. doi: 10.1016/j.egypro.2017.03.483.

Ma T. Yang H. Lu L. & Peng J. (2015). Optimal design of an autonomous solar-wind-pumped hydro storage power supply system. *Applied Energy*, 160: 728-736. doi: https://doi.org/10.1016/j.apenergy.2014.11.026.

Majid Z.A.A. Ruslan M.H. Sopian K. Othman M.Y. Azmi M.S.M. (2014). Study on performance of 80 watt floating photovoltaic panel. *Journal of Mechanical Engineering Science*, 7: 1150-1156. doi: https://doi.org/10.15282/jmes.7.2014.14.0112.

Makhdoomi S. & Askarzadeh A. (2020). Daily performance optimization of a grid-connected hybrid system composed of photovoltaic and pumped hydro storage (PV/PHS). *Renewable Energy*, 159: 272-285. doi: 10.1016/j.renene.2020.06.020.

Manoj Kumar, N., Mallikarjun P.,. (2018). *FLOATOVOLTAICS: towards improved energy efficiency, land and water management*. Int. J. Civ. Eng. Technol.: IJCIET 9,1089e1096.

Marion B., A. J., Boyle K., Hayden H. Hammond B., Fletcher T. Canada B. Narang D. Shugar D. Wenger H. Kimber A. Mitchell L. Rich G. and Townsend T.,. (2005). *Performance parameters for grid-connected PV systems*. 31st IEEE Photovoltaics specialists conference and exhibition, Lake Buena Vista, Florida.

May G.J. Davidson A. & Monahov B. (2018). Lead batteries for utility energy storage: A review. *Journal of Energy Storage*, 15: 145-157. doi: 10.1016/j.est.2017.11.008.

Mensah L.D. Yamoah J.O. and Adaramola M.S. (2019). Performance evaluation of a utility-scaled grid-tied solar photovoltaic (PV) installation in Ghana. *Energy for Sustainable Developement*, 48: 82-87. doi: https://doi.org/10.1016/j.esd.2018.11.003.

Ministry of Energy. (2021). *Overview of the Ghana power sector*. Tilgjengelig fra: https://www.energymin.gov.gh/sector-overview (lest 6.5).

Ministry of Power. (2015). *National Renewable Energy Action Plans*. Ministry of Power. https://www.se4all-africa.org/fileadmin/uploads/se4all/Documents/Country_PANER/Ghana_National_Renewable_Energy_Action_Plans.pdf: Ministry of Power and ECOWAS Centre for Renewable Energy and Energy Efficiency (ECREEE).

Mittal D. Kumar Saxena B. Rao K.V.S. (2017). *Potential of floating photovoltaic system for energy generation and reduction of water evaporation at four different lakes in Rajasthan*. 2017 International Conference On Smart Technologies For Smart Nation (SmartTechCon), Bengaluru, India, s. 238-243: IEEE.

Mittal D. Saxena B.K. and Rao K.V.S. (2017). *Comparison of floating photovoltaic plant with solar photovoltaic plant for energy generation at Jodhpur in India*. 2017 International Conference on Technological Advancements in Power and Energy (TAP Energy), Kollam, India, s. 1-6: IEEE.

Mongird K. Viswanathan V. Balducci P. Alam J Fotedar V. Koritarov V. & Hadjerioua B. (2019). Energy storage technology and cost characterization report. I: HydroWires (red.). U.S. Department of Energy.

Moomaw, W., P. Burgherr, G. Heath, M. Lenzen, J. Nyboer, A. Verbruggen. (2011). Annex II: Methodology. In IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation. I: O. Edenhofer, R. P.-M., Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow, (red.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Müller, R. B., T.; Hammer, A.; Kemper, A. (2012). A new algorithm for the satellite-based retrieval of solar surface irradiance in spectral bands. *Remote Sensing*, 4: 622-647.

Müller, R. M., C.; Gratzki, A.; Behr, H.; Hollmann, R. . (2009). The CM-SAF operational scheme for the satellite based retrieval of solar surface irradiance—A LUT based eigenvector hybrid approach. *Remote Sensing of Environment*, 113: 1012-1024.

NASA. (2021). Atmospheric Science Data Center. I: *NASA*. Tilgjengelig fra: https://asdc.larc.nasa.gov/.

Obahoundje, S., E. A. Ofosu, K. Akpoti, A. T. Kabo-bah. (2017). Land use and land cover changes under climate uncertainty: Modelling the impacts on hydropower in Western Africa. *Hydrology*, 4 (1). doi: https://doi.org/10.3390/hydrology4010002.

Oliveira-Pinto S. & Stokkermans J. (2020). Assessment of the potential of different floating solar technologies - Overview and analysis of different case studies. *Energy conversion and Management*, 211. doi: https://doi.org/10.1016/j.enconman.2020.112747.

Patwal R.S. Narang N. (2018). Crisscross PSO algorithm for multi-objective generation scheduling of pumped storage hydrothermal system incorporating solar units. *Energy conversion and Management*, 169: 238-254. doi: 10.1016/j.enconman.2018.05.067.

Pekel J.F. Cottam A. Gorelick N. and Belward A.S. (2016). High-resolution mapping of global surface water and its long-term changes. *Nature*, 540: 418-422. doi: 10.1038/nature20584.

Power Africa. (2020). *Ghana*: US Aid,. Tilgjengelig fra: https://www.usaid.gov/powerafrica/ghana (lest 01.03).

Power Africa. (2021). *About us*: US Aid. Tilgjengelig fra: https://www.usaid.gov/powerafrica/aboutus (lest 01.03).

Power Utilities Regulatory Commission. (2016). *Publication of feed-in tariffs for electricity generated from renewable sources*. http://purc.com.gh/purc/sites/default/files/fit_2016.pdf.

Pueyo A., B. S., & Osiolo H.,. (2016). Cost and returns of renewable energy in Sub-Saharan Africa: A comparison of Kenya and Ghana. I: Studies, I. o. D. (red.). *Pro-Poor Electricity Provision*.

PURC. (2021). *PURC 2021 Major Tariff Review*. I: Power Utilities Regulatory Commission (red.). https://purc.com.gh/news-det/purc-2021-major-tariff-review: Public Utilities Regulatory Commission,.

PVGIS. (2019). *Data sources and calculation methods*. I: PVGIS (red.). European Commission: European Commission, EU Science Hub. Tilgjengelig fra: https://ec.europa.eu/jrc/en/PVGIS/docs/methods (lest 13/05).

PVGIS. (2020). *PVGIS users manual*. I: EU Science Hub (red.). European Commission: European Commission, EU Science Hub. Tilgjengelig fra: https://ec.europa.eu/jrc/en/PVGIS/docs/usermanual (lest 13.05).

Ranjbaran P. Yousefi H. Gharehpetian G. B. & Astaraei F. R. (2019). A review on floating photovoltaic (FPV) power generation. *Renewable and Sustainable Energy Reviews*, 110: 332-347. doi: 10.1016/j.rser.2019.05.015.

Redón Santafé M. Torregrosa Soler J.B. Sánchez Romero F.J. Ferrer Gisbert P.S. Ferrán Gozálvez J.J. and Ferrer Gisbert C.M. (2014). Theoretical and experimental analysis of a floating photovoltaic cover for water irrigation reservoirs. *Energy*, 67: 246-255. doi: 10.1016/j.energy.2014.01.083.

Ritchie, H. (2021). *Electricity mix*. Our World In Data. Tilgjengelig fra: https://ourworldindata.org/electricity-mix (lest 27.04).

Rogner M. & Troja N. (2018). The world's water battery: Pumped hydropower storage and the clean energy transition. I: IHA (red.). International Hydropower Association, London, UK.

Rohani G. & Nour M. (2014). Techno-economic analysis of stand-alone hybrid renewable power system for Ras Musherib in United Arab Emirates. *Energy*, 64: 828-841. doi: 10.1016/j.energy.2013.10.065.

Rosa-Clot M. & Tina G.M. (2018). *Submerged and Floating Photovoltaic Systems - Modelling, design and case studies*. London: Academic Press.

Sahu A. Yadav N. Sudhakar K. (2016). Floating photovoltaic power plant: a review *Renewable and Sustainable Energy Reviews*, 66: 815-824. doi: https://doi.org/10.1016/j.rser.2016.08.051.

Sanchez R.G. Kougias I. Moner-Girona M Fahl F. Jäger-Waldau A. (2021). Assessment of floating solar photovoltaics potential in existing hydropower reservoirs in Africa. *Renewable Energy*, 169: 687-699.

Saulsbury, B. (2020). A comparison of the environmental effects of open-loop and closed-loop pumped storage hydropower. I: Pacific Northwest National Laboratory (red.). *HydroWires*: U.S. Department of Energy Water Power Technologies Office.

Schmidt O. Melchior S. Hawkes A. and Staffell I. (2019). Projecting the future levelized cost of electricity storage technologies. *Joule*, 3 (1): 81-100. doi: https://doi.org/10.1016/j.joule.2018.12.008.

Silvério N. Barros R. Filho G. et al. (2018). Use of floating PV plants for coordinated operation with hydropower plants: case study of the hydroelectric plants of the São Francisco River basin. *Energy conversion and Management*, 171: 339-349.

Sinha S. & Chandel S.S. (2014). Review of software tools for hybrid renewable energy systems. *Renewable and Sustainable Energy Reviews*, 32: 192-205. doi: 10.1016/j.rser.2014.01.035.

Sun H. Khan A.R. Bashir A. Alemzero D.A. Abbas Q. and Abudu H. (2020). Energy insecurity, pollution mitigation, and renewable energy integration: Prospective of wind energy in Ghana. *Environmental Science and Pollution Research*, 27: 38259-38275. doi: https://doi.org/10.1007/s11356-020-09709-w.

Suri M. Remund J. Cebecauer T. Dumortier D. Wald L. Huld T. and Blanc P. (2008). *First Steps in the Cross-Comparison of Solar Resource Spatial Products in Europe*. 1st International Conference on Solar Heating, Cooling and Buildings, Lisbon, Portugal.

Taboada M.E.E., L. C., T.A.A. Graber, H.R.R. Galleguillos, L.F.F. Cabeza, R. Rojas. (2017). Solar water heating system and photovoltaic floating cover to reduce evaporation: experimental results and modeling. *Renewable Energy*, 105: 601-615.

Takouleu, J. M. (2020). Ghana: BPA connects a floating solar power plant in the basin of the Bui dam. Tilgjengelig fra: https://www.afrik21.africa/en/ghana-bpa-connects-a-floating-solar-power-plant-in-the-basin-of-the-bui-dam/.

The World Bank. (2018). Access to energy is at the heart of development. Tilgjengelig fra: https://www.worldbank.org/en/news/feature/2018/04/18/access-energy-sustainable-development-goal-7 (lest 06.05.2021).

Tina, G. M., Cazzaniga, R., Rosa-Clot, M., & Rosa-Clot, P. (2018). Geographic and technical floating photovoltaic potential. *Thermal Science*, 22: 831-841.

Trapani & Santafe, K. a. M. R. (2014). A review of floating photovoltaic installations: 2007-2013. *Progress in photovoltaics: Research and applications*, 23: 524-532. doi: https://doi.org/10.1002/pip.2466.

WAPP. (2011). WAPP. *Update of the ECOWAS Revised Master Plan for Generation and Transmission of Electrical Energy*. West Africa Power Pool, Cotonou, Benin.

Wilcox S. & Marion W. (2008). Users manual for TMY3 Data sets. I: NREL (red.). *Technical Report NREL/TP-581-43156*. National Renewable Energy Laboratory, Colorado, USA.

World Bank Group, E. a. S. (2018). *Where sun meets water - floating solar market report*. Washington D.C.

World Energy Council. (2020). Five steps to energy storage. *Innovation Insights Brief*. World Energy Council, London, UK: World Energy Council.

Yadav N. Gupta M. and Sudhakar K. (2016). Energy assessment of floating photovoltaic system. *Int. Conf. Electr. Power Energy Syst., IEEE*: 264-269. doi: 10.1109/ICEPES.2016.7915941.

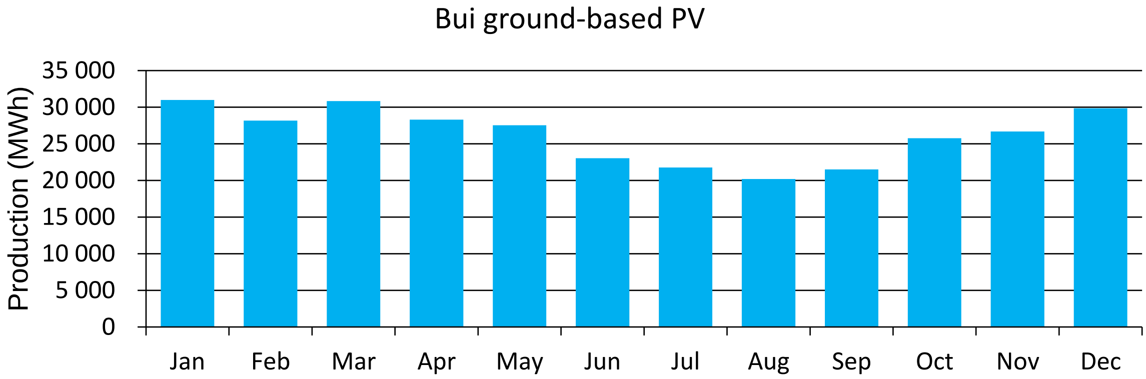
Yang W. Yang J. (2019). Advantage of variable-speed pumped storage plants for mitigating wind power variations: Integrated modelling and performance assessment. *Applied Energy*, 237: 720-732. doi: 10.1016/j.apenergy.2018.12.090.

Ziar H., B. P., Fen-Yu (Vicky) Lin, B. Roeffen, D. Heijkoop, T. Stark, S. Teurlincx, L. de Senerpont Domis, E. Garcia Goma, J. Garro Extebarria, I. Narvaez Alavez, D. van Tilborg, H. van Laar, R. Santbergen, O. Isabella. (2020). Innovative floating bifacial photovoltaic solutions for inland water areas. *Progress in photovoltaics: Research and applications*. doi: 10.1002/pip.3367.

Appendix

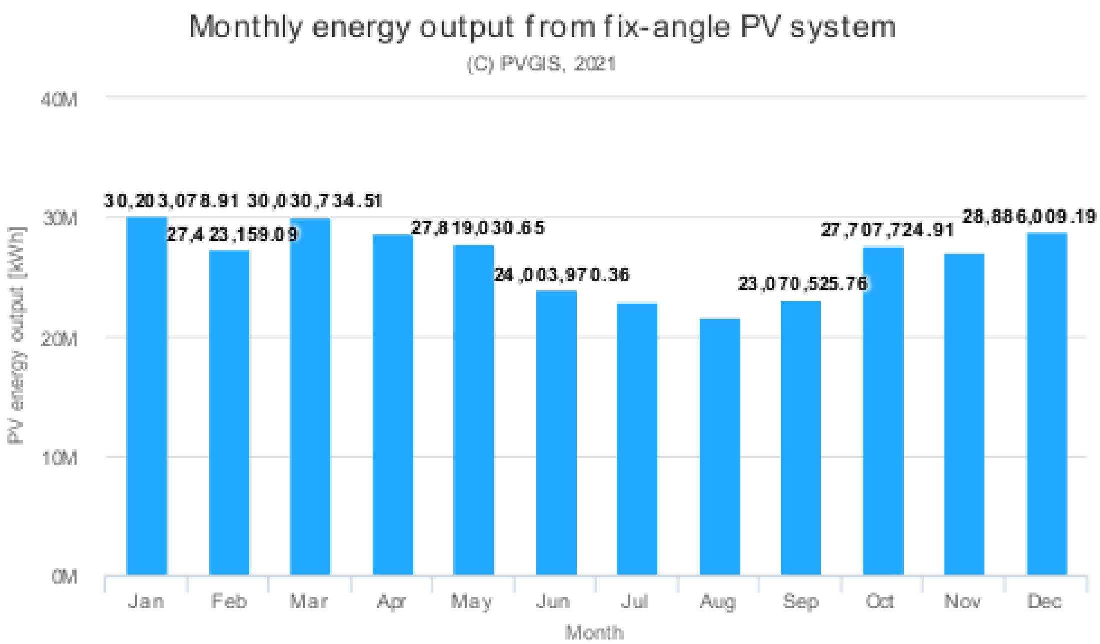
Appendix 1

PV yield from Homer with same panel type as Glint Solar and the same derate factor of 85.8% and 5-degree slope:



Annual output	GWh	314.67

PV yield from PVGIS with same losses/derate factor as Glint Solar and same slope of 5-degrees:



Annual output	GWh	319.43

Appendix 2

Yearly load data input in HOMER:

Yearly Load Data

Weekdays Weekends

Hour	January	February	March	April	May	June	July	August	September	October	November	December
0	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
1	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
2	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
3	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
4	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
5	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
6	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
7	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
8	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
9	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
10	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
11	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
12	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
13	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
14	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
15	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
16	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
17	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
18	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
19	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
20	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
21	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
22	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000
23	1.000	1.000	1.000	1.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	65,000.000	1.000	1.000

Norges miljø- og biovitenskapelige universitet
Noregs miljø- og biovitskapelege universitet
Norwegian University of Life Sciences

Postboks 5003
NO-1432 Ås
Norway