Master's thesis

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# A comparison of the energy market in Scandinavia and in Nigeria and the role of framework for Independent Hydropower Producers

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# ABSTRACT

Hydropower optimization could aid in minimizing resource input for electricity generation and overall system operations cost. This study used the EMPS modelling to analyze the performance of Nigeria's large hydropower systems (Kainji, Jebba, and Shiroro) and used obtained results as cues to investigate how the integration of independent hydropower systems would influence the efficiency of power production in the foreseeable future.

Two case scenarios were formulated. The first case involved optimizing hydropower generation and use of water resources for hydropower production. The first steps required gathering needed data for modelling from hydrological stations of the three hydropower stations. Following this, the three hydropower stations were grouped into two distinct areas (Kainji and Jebba in 'Area 1' and Shiroro being the only station in 'Area 2'). The data collected was entered as inputs into EMPS taking the area groupings into account, and EMPS was used to model the data, given historical inflow series in an optimization process. The model provided results for 21 weather scenarios, and the hydropower generation for each Area were validated using historical data. The obtained data provided satisfactory results for the Area under study.

The second case which involved modelling how the integration of more independent hydropower system could shape the efficiency of energy delivery in Nigeria was also worked out. 7 new hydropower systems were included in EMPS, and a higher power transmission capacity was modelled in the system. The results showed that the inclusion of new hydropower stations raised power production significantly and reduced the dependency of the Kainji, Jebba, and Shiroro hydropower stations.

In general, the use of EMPS to optimize the hydropower system, and model a scenario of newer hydropower station additions were satisfactory. Although, fine tuning is required to improve the obtained results.


**Keywords**: Hydropower; EMPS; Stochastic model; Nigeria's hydropower modelling

## PREFACE

This document represents a master's thesis written in relation to the subject "TVM4915 Hydropower Development, Master's Thesis" at NTNU. It mainly discusses the effect of Independent Hydropower Producers on Energy market using Scandinavia Hydropower framework with simulation results from the hydropower scheduling tool EMPS. The objective is to analyzes the performance of the three large hydropower plants in the Nigeria Power market. The main reason why I have chosen to carry out this project in my home country is that I know that the Norwegian hydropower framework is replicable in my country. The framework that is working for Scandinavia can also work in Nigeria if government policies permit. EMPS is recommended because it is the most suitable for the power situation in Nigeria. EMPS is a SINTEF developed software which has been used for many projects not only in Norway but across Europe.

An effort has been made in keeping a consequent IEEE citation style throughout the thesis. The IEEE style has been chosen over alternative methods because it is the recommended style for the students in Technological field. I would like to thank my supervisors Bruland Oddbjorn and Mari Haugen for their guidance. Mari's quick response to email for help is deeply appreciated. She did everything possible to ensure the model runs, also thanking Stefan for the knowledge and experiences shared with me. The use of this model is the best thing happening to me and I am not taking it for granted.

Special thanks to my wife, parents and siblings for the moral and emotional support. Also, my colleagues, student assistants and lecturers in Hydropower for allowing me to draw from the well of knowledge and also for the good memories made. I would also say big thanks to the Directors and staff of different parastatals in the Power sector for their time and attention at the time of data collection. Finally, I would recognize NORAD that made it possible for me to earn this degree. In closing, I would say Thank you, Jesus, for the strength and grace I enjoyed all through this program.

Trondheim, 05-10-2020.

Oluwatosin Aremu

## ABBREVIATIONS

| | |
|---|---|
| EMPS | Efi's Multi-Area Power Market Simulator |
| SINTEF | Norwegian: Stiftelsen for Industriell og teknisk Forskning (Foundation for Industrial and Technical Research. |
| GIZ | German Agency for International Cooperation |
| PWC | PriceWaterhouseCooper |
| TLF | Transmission Loss Factor |
| MYTO | Multi-Year Tariff Order |
| ODA | Official Development Assistance |
| TSO | Transmission System Operator |
| SO | System Operator |
| DSO | Distribution System Operator |
| ENS | Energy Not Supply |
| IPP | Independent Power Producer |
| PPA | Power Purchase Agreement |
| SHP | Small Hydro Power |
| NORWEP | Norwegian Energy Partners |
| NESCO | Nigeria Electricity Supply Company |
| PHCN | Power Holding Company of Nigeria |
| EPSR | Electricity Power Sector Reform |
| NERC | Nigerian Electricity Regulatory Commission |
| FMoP | Federal Ministry of Power |
| NBET | Nigeria Bulk Electricity Trading Plc |
| GENCOs | Generating Company of Nigeria |
| TCN | Transmission Company of Nigeria |
| DISCOs | Distribution Company of Nigeria |
| ECN | Energy Commission of Nigeria |
| REA | Rural Electrification Agency of Nigeria |
| NESI | Nigerian Electricity Supply Industry |
| NEMSA | Nigeria Electricity Management Services Agency |
| MW | MegaWatt |
| GW | GigaWatt |
| FMWR | Federal Ministry of Water Resources |
| NIWRMC | National Integrated Water Resources Management Commission |

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# CHAPTER ONE

## 1.0 INTRODUCTION

Nigeria is enriched with large rivers and natural falls. The major rivers that provide rich hydropower potential are the Niger and Benue rivers as well as Lake Chad basin. Per capita per year of renewable water resources available is estimated 1800m$^3$, this makes Nigeria one of the water rich countries in the world, but lack of investment and management to meet demand makes it an economically water scarce country in the world ranking [1].

Hydropower operations started as early as 1929 in Nigeria under the establishment of Nigeria Electricity Supply Company (NESCO) which led to construction of hydroelectric power station at Karu, Jos in Plateau state [2]. NESCO started operating this small hydropower as an independent Power Producer in 1993 which sells to state government as bulk. The development of large hydropower started in 1968 which has been the sole responsibility of the government until the establishment of Power Sector Reform Acts 2013 which led to unbundling of Power Holding Company of Nigeria (PHCN) into private Generation and Distribution Company leaving only Transmission for the government. As part of this reform process, two indigenous private company acquired 30 years concession for the three large functional Hydropower namely Kainji, Jebba, and Shiroro.

The total installed capacity of hydropower in Nigeria is 12,522 MW without off-grid generation of about 2,062 MW and the total exploitable potential capacity estimated as over 14,120 MW, giving about 50,800 GWh of electricity in a year. This large percent untapped could provide solution to power shortage in the country.

The Electric Power Sector Reform (EPSR) Act 2005 is known to be a shift in the National energy policy, as it determined the framework upon which private sectors could participate in the generation, transmission and distribution of electricity. Part of the reform policy is the establishment of Nigerian Electricity Regulatory Commission (NERC) which provides for the development of a competitive electricity market and serves as the basis for determination of tariffs, customer rights and obligations, and other related matters.

Energy market in Nigeria depends majorly on these players, Nigerian Electricity Regulatory Commission (NERC), Federal Ministry of Power (FMOP), Nigerian Bulk Electricity Trading Plc. (NBET), Generation Companies (GENCOs), Transmission Company of Nigeria (TCN), Distribution Companies (DISCOs). Other Government Agencies that contribute to market operations are Energy Commission of Nigeria (ECN), Rural Electrification Agency of Nigeria (REA), Nigerian Electricity Supply Industry (NESI) and Nigeria Electricity Management Services Agency (NEMSA).

Scandinavian countries are blessed with falling rivers that have been greatly explored as major source of energy. A country like Norway has hydropower system with reservoir capacity of about 84 TWh, which is approximately 50% of the total storage capacity in Europe [3] [4]. Hydropower has been fully explored in Norway to the stage of using pump storage and improving the maintenance and expansion of the existing system.

Due to advance knowledge and desire to contribute to SDG7, Norway is in best position to invest in developing country like Nigeria with hydro potential because they have what it takes to change the narratives of hydro-electricity in the country, they have the technology, financial resources, experiences and the expertise. This draw the aim for this project which is to check the how energy market would change if Independent hydropower producers takes over hydropower in Nigeria. Independent Hydropower Producers play important roles in the Scandinavia Power market.

## 1.1 Problem Statement

The Nigeria power system is characterized by huge gap between supply and demand; current power demand is estimated at 17,520MW including latent and suppressed demand, against 5,300MW peak generation [5]. As a result, about 90 million Nigerians have been reported to have no access to electricity according to (African Progress Report 2015). Out of this non-electrified population, 17 million people live in urban areas, while 73 million live in rural areas.

The poor performance of the sub-sector has generated debate that with the abundance and potentials of energy resources, there is no reason for Nigeria to import energy to achieve a sustainable generation capacity for optimum economic growth. Moreover, Nigeria had been able to trace the collapse of her industrial sector, and small and medium scale businesses and economic downturn to the inadequate and erratic state of the country's electricity market [6].

This work is targeted in solving poor management of Hydropower in Nigeria. The government policies towards hydropower development seems not favorable to the growth and survival of hydro-planting.

The availability of crude oil in abundance for power generation through gas also influence the government policies on hydropower because they concentrate more on gas neglecting the demerits attached to non-renewable energy, this practice is not the best for a country with shortage of power instead there should be provision for hydropower to enhance electricity production. Energy market in Nigeria is constantly changing but the electricity generation seems unaffected positively. Despite the effort the government is putting in place, situation gets deteriorating as there hasn’t been a corresponding result in per consumption.

## 1.2 Aim & Objective

The aim of this project is to access the effect of Independent Hydropower Producers on Energy market using Scandinavia Hydropower framework while the Objective are to:

- Use EMPS to analyze the performance of three large hydropower plants in the Nigeria Power market.
- Make findings, investigate and suggest how the future role of Independent hydropower producers could be shaped in Nigeria

# CHAPTER TWO

## 2.0 LITERATURE REVIEW

In order to attract investment into the sector, the Federal Government in 2005 enacted the Electricity Power Sector Reform (EPSR) Act which liberalized and commercialized and privatized the electricity sector.

Nigeria is well endowed with resources in both renewable and non-renewable energies which could sufficiently address existing power shortages and promote the Federal Government's drive to attain sufficiency in power supply in the year 2030 and beyond. As it stands, Nigeria's main energy carrier is biomass (81.25%), followed by natural gas (8.2%), petroleum products (5.3%), crude oil (4.8%), hydropower (0.4%), and others (< 1%) [5].

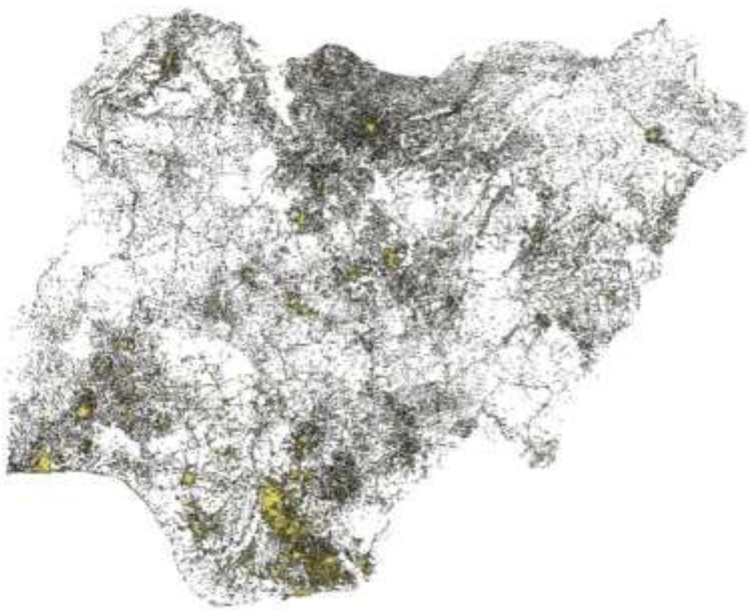


Figure 1: Geographical Distribution of Nigeria Population Clusters (Source: [5])

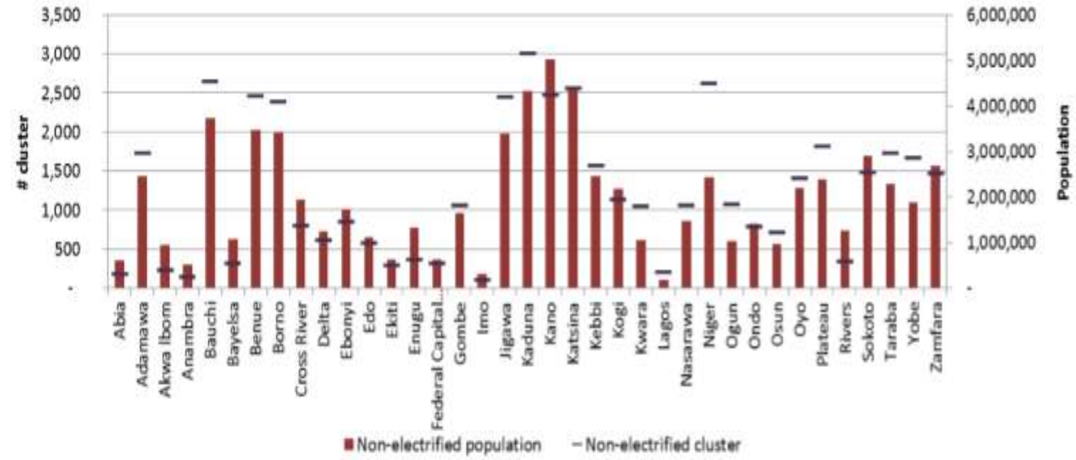



Figure 2: Statistics of Non-electrification Population Clusters per State. (Source: [5])

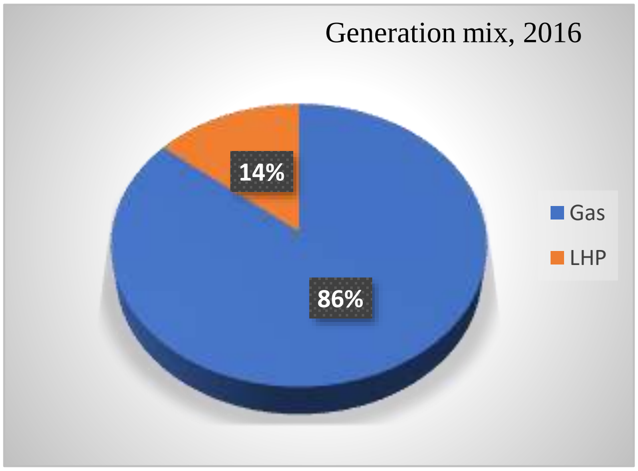
A recent study by GIZ/FMoP identified a total of 47,489 population clusters spread across the country. It was also established that out of the population of 193.4 million people [7], 174 million live within the clusters. Also, about 10 % of population is assumed to live in very small settlements or have no permanent settlement locations.

Of the identified clusters, a total of 45,456 clusters are considered to be non-electrified (95 %). Although this represents the vast majority of clusters, only 89 million people out of 193.4 million people (46 %) live in the electrified are

Energy Generation Mix in 2016 on average has capability of 5,700 MWh/H, 86% of this capability is from gas-fired thermal power stations. The remaining 14% is from the three large hydroelectric power stations.

In 2019, thermal share has been on the decline in the third quarter, it still dominates the electricity generation mix accounting for 67.02% of the electricity generated during the fourth quarter of 2019. This implies that approximately 6.70 KWh of every 10 KWh of electric energy generated in Nigeria in the fourth quarter of 2019 came from gas. However, there was a 7.61 percentage point increase in the share of electric energy generated from hydro in the fourth quarter, accounting for 32.98% of the total energy output. The Commission still notes with concern the security of supply implication of the continuous dominance of gas fired plants as acts of vandalism of gas pipelines could result in serious grid instability, as was experienced in the year 2016 [8].

The figure below shows the present capacity in 2016 [5] and Fourth quarter of 2019 [8].



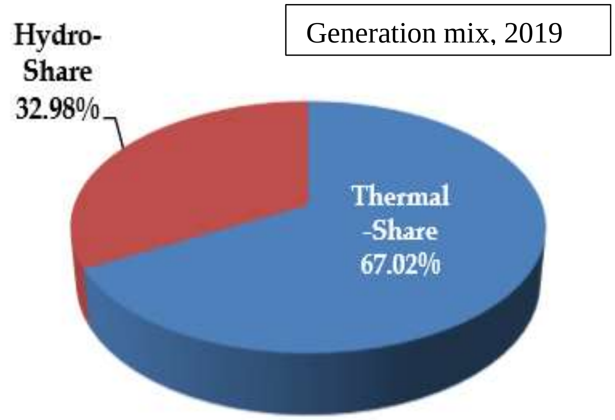




Figure 3: Generated Energy Mix (MW)

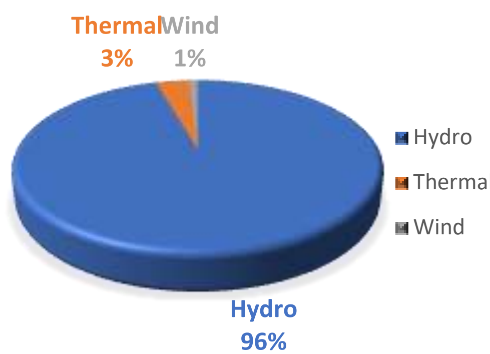



Figure 4: Norwegian Energy Mix

To make electricity supply less vulnerable to disruptions, more affordable, available and reliable, Federal Government of Nigeria has set targets for the country`s energy mix to exploit Nigeria potential for coal, solar, wind, biomass, large and small hydroelectric power generation.

The growth in energy mix would depend on the completion of various hydroelectric power projects funded by the Federal Government of Nigeria and those that are coming under the Private-Public – Partnership arrangement. The large proportion of the energy mix growth would come through other generation arising from already signed number of Power Purchase Agreements (PPAs) with Bulk Trader as well as those coming through new competitive procurement bid by electricity producers to meet expected target

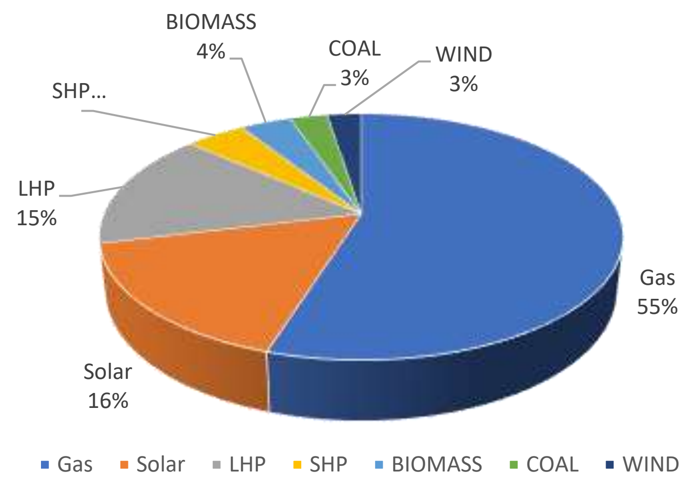



Figure 5: Target Energy Mix (MW) in Nigeria

## 2.1 Investment in Large and Medium Hydropower

According to Energy Commission of Nigeria (ECN) and Transmission Company of Nigeria (TCN), Hydropower investment in Nigeria has potential which comprises of Large, medium and small scheme hydropower across the length and breadth of the country.

Feasibility studies on Hydro power in Nigeria have shown the massive investment potential dormant within the nation’s rivers and estuaries site as itemized in the table below:

Table 1: Large and medium Hydropower potential sites in Nigeria

| S/N | Site | River | Technical Feasible Capacities (MW) | Average Annual Energy (GWH) |
|---|---|---|---|---|
| **LARGE** | | | | |
| 1. | Mambilla | Donga | 3,600 | 17,342 |
| 2. | Lokoja | Niger | 1,950 | 8,540 |
| 3. | Onitsha | Niger | 750 | 3,250 |
| 4. | Markudi | Benue | 600 | 4,750 |
| 5. | Ikom | Cross | 400 | 1,750 |
| 6. | Yola | Benue | 350 | 1,530 |
| 7. | Katsina-Ala | Katsina-Ala | 260 | 1,140 |
| 8. | Beli | Taraba | 240 | 1,050 |
| 9. | Donka | Niger | 225 | 984 |

| | | | | |
|---|---|---|---|---|
| 10. | Karamti | Taraba | 200 | 875 |
| 11. | Amper | Amper (Plateau) | 200 | 875 |
| 12. | Afikpo | Cross | 180 | 790 |
| 13. | Atan | Cross | 180 | 790 |
| 14. | Garin Dali | Taraba | 135 | 590 |
| 15. | Gembu | Donga | 130 | 570 |
| 16. | Manyo yin | Taraba | 65 | 284 |
| 17. | Kam | Taraba | 60 | 220 |
| 18. | Suntai | Donga | 55 | 240 |
| **MEDIUM** | | | | |
| 19. | Su | Taraba | 45 | 200 |
| 20. | SakinDanko | Suntai | 45 | 200 |
| 21. | Gudi | Mada | 40 | 180 |
| 22. | Kiri | Gongola | 40 | 150 |
| 23. | Richa I | Mosari | 35 | 150 |
| 24. | Kombo | Gongola | 35 | 150 |
| 25. | Gwaram | Jama'are | 30 | 130 |
| 26. | Ifon | Osse | 30 | 130 |

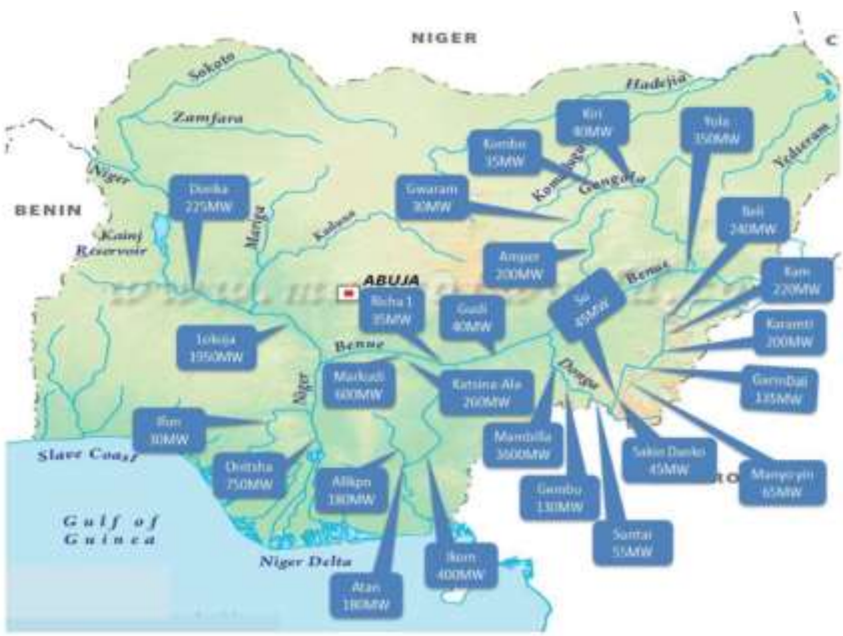



Figure 6: Map showing the Identified Large and Medium hydropower potential Sites

## 2.2 Investment in small hydropower

The fastest way to investing in small hydro in Nigeria lies with converting existing dams to hydro power stations. To this end, there are already over 25 small dams distributed across Nigeria capable of generating about 30MW if converted to hydro power plants. These plants have the capability of feeding into the embedded generation methodology, providing additional power to the distribution companies within their locations.

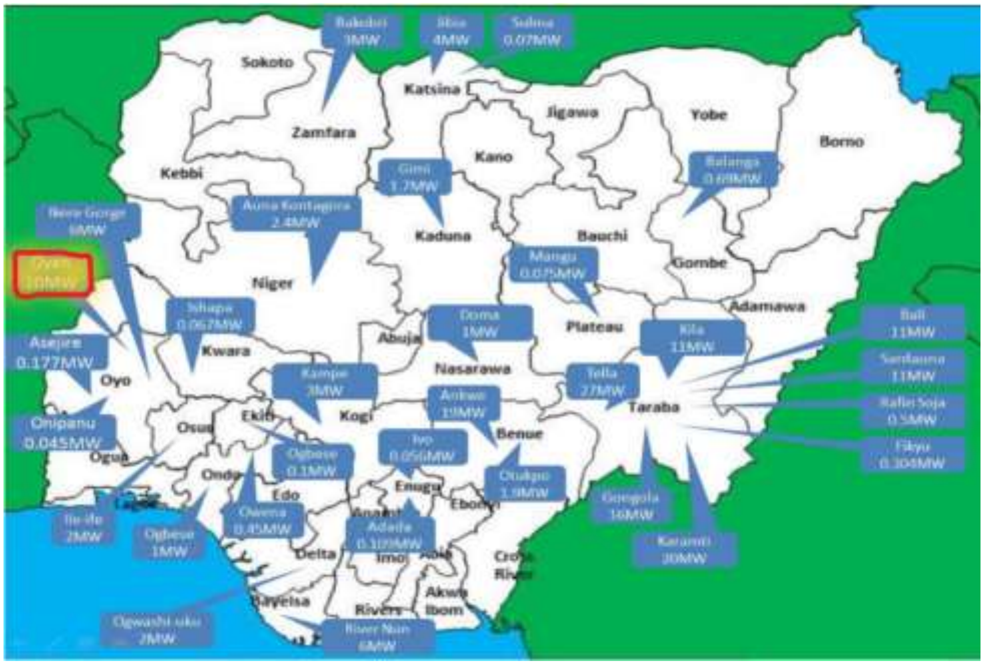



Figure 7: Map showing location of small hydropower potential site in Nigeria

Table 2: Showing small hydropower sites with their technical feasible capacities

| S/N | DAM | CAPACITY (MW) | STATE |
|---|---|---|---|
| 1. | Oyan | 10 | Oyo |
| 2. | Ikere-Gorge | 6 | Oyo |
| 3. | Bakobri | 3 | Zamfara |
| 4. | Kampe | 3 | Kogi |
| 5. | Owena | 0.45 | Ondo |
| 6. | Doma | 1 | Nassarawa |
| 7. | Jibia | 4 | Kastina |
| 8. | Gimi | 1.7 | Kaduna |
| 9. | Ile-Ife | 2 | Osun |
| 10. | Ogbese | 1 | Ondo |
| 11. | Ogwashi | 2 | Delta |
| 12. | AunaKontagora | 2.4 | Niger |

| | | | |
|---|---|---|---|
| 13. | Kila | 11 | Taraba |
| 14. | Karamti | 20 | Taraba |
| 15. | Bali | 11 | Taraba |
| 16. | Sardauna | 11 | Taraba |
| 17. | Tella | 27 | Taraba |
| 18. | Ankwe | 19 | Benue |
| 19. | Gongola | 16 | Taraba |
| 20. | Rafin Soja | 0.5 | Taraba |
| 21. | Sulma | 0.07 | Kastina |
| 22. | Balanga | 0.69 | Gombe |
| 23. | Ishapa | 0.067 | Kwara |
| 24. | Onipanu | 0.045 | Oyo |
| 25. | Mangu | 0.075 | Plateau |
| 26. | Ogbese | 0.1 | Ekiti |
| 27. | Adada | 0.109 | Enugu |
| 28. | Ivo | 0.056 | Enugu |
| 29. | River Nun | 6 | Bayelsa |
| 30. | Otukpo | 1.9 | Benue |
| 31. | Asejire | 0.177 | Oyo |
| 32. | Fikyu | 0.304 | Taraba |

## 2.3 Investment Guideline and Requirements for Hydropower Generation

After meeting up the general requirements, the following steps are required:

- All water ways belong to the Federal Government of Nigeria and Federal Ministry of Water Resources (FMWR) is the custodian.
- FMWR is vested with the responsibility of issuing Water Rights to investors for Hydropower generation, fisheries etc.
- Investors interested in Small and Medium Hydro power projects after completing their Feasibility Studies, are expected to apply for water usage rights from the National Integrated Water Resources Management Commission (NIWRMC);
- Investors interested in Large Hydro require Water Concession Agreement for water right [5].

## 2.4 Barriers to adequate power provision in Nigeria

It is essential to understand Nigeria's power value chain in order to fully appreciate the extent of the current challenges faced and the opportunities for investors to play their part in the growth of this sector. A summary of the losses across Nigeria's power value chain, along with the categories of players in each segment, is depicted in Figure 8.

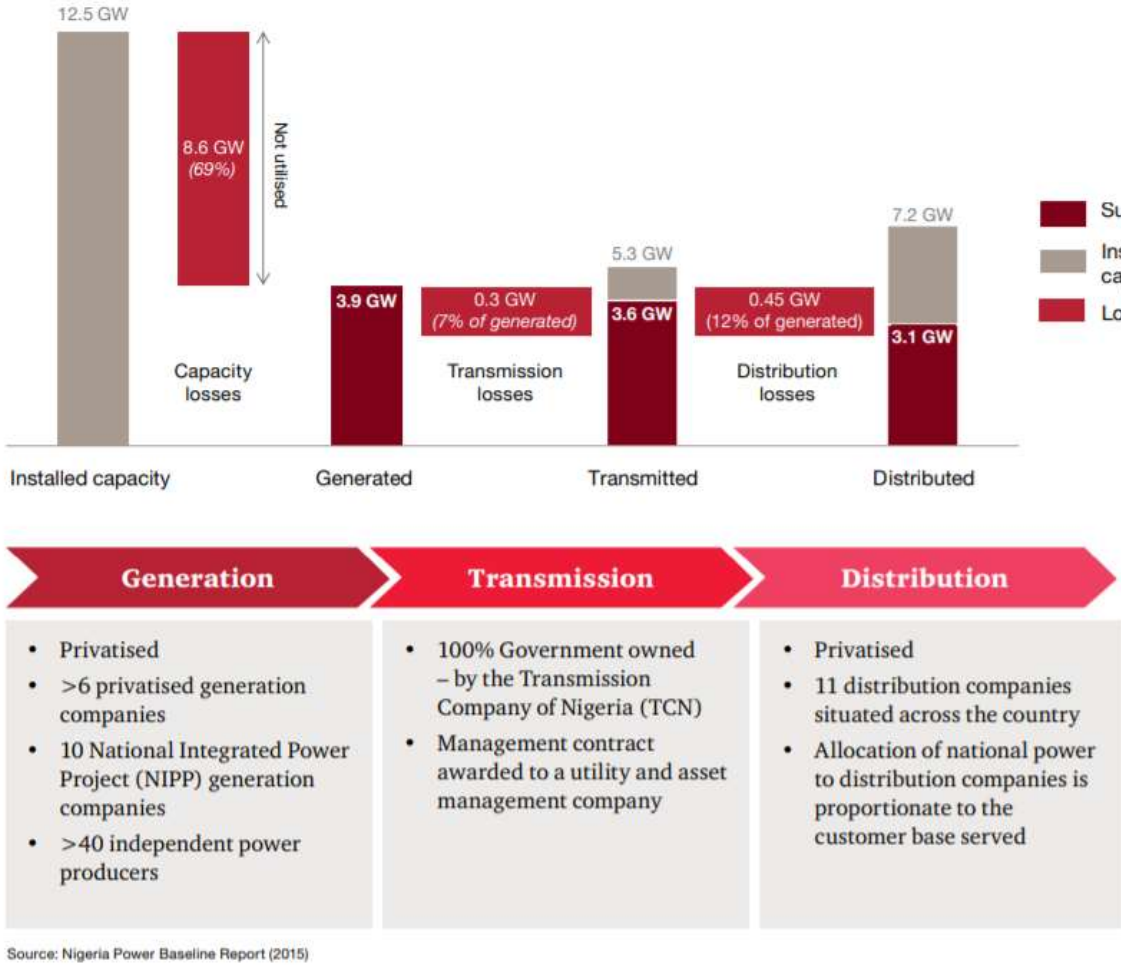



Figure 8: Installed capacity, supply and losses across the power value chain in Nigeria (GW), 2015 (Source: [5])

### 2.4.1 Value chain losses

In 2015, as depicted in Figure 7, installed generation capacity (defined as the total available power generation capacity, assuming the power plants are operating at 100% efficiency) was estimated at 12.5 GW. Of this capacity, only 3.9 GW was actually generated – a capacity utilization of only 31%. Exacerbating this loss, 7% of generated power (0.3 GW) was lost through the transmission process and a further 12% (of 3.9 GW) through distribution, resulting in a cumulative transmission and distribution loss of 19% of generated power. Overall, the net power available was 3.1 GW, which was only 25% of the installed generation capacity of 12.5 GW. These substantial losses across the value chain can be attributed to two key causes – technology limitations and outdated infrastructure.

In power generation, technology limitations can be significant, as power plants typically have a wide range of capacity utilization rates depending on the technology used, as well as the age and condition of the infrastructure. Nigeria's power generation capacity utilization is at the lower end of this range, which is unacceptable given the country's urgent need for power. On the other hand, other developing countries such as Brazil and India have relatively higher average utilization rates of approximately 50 % – 60 % as a result of significant efforts to attract investment in new technologies. Over the next decade, Nigeria must look towards improving capacity utilization (currently at 31 %) significantly by investing in new and efficient power generation technology, as well as revamping existing power plants.

Power transmission and distribution (T&D) losses in Nigeria further reduce generated power output by 19%. While this is lower than a few other developing markets where T&D losses are greater than 20%, the benchmarks set by countries such as South Africa, Malaysia, Peru and Ukraine are much better (see: Figure 10) These losses are heightened in rural areas, where infrastructure tends to be older, and maintenance is irregular. Transmission and distribution losses also result from issues such as limited funding and short-sighted policies which fail to encourage improvements in technology.

| Country | Total power capacity (GW) | Utilisation factor (% of installed capacity) | TD losses (% of power generated) |
|---|---|---|---|
| Nigeria | 12.5 | 31% | 19% |
| Brazil | 121.7 | 55% | 21% |
| Ecuador | 5.4 | 49% | 15% |
| Egypt | 27.0 | 63% | 16% |
| India | 254.7 | 55% | 22% |
| Malaysia | 28.5 | 53% | 14% |
| Mexico | 62.3 | 55% | 27% |
| New Zealand | 9.5 | 54% | 10% |
| Norway | 32.3 | 47% | 9% |
| Peru | 9.7 | 47% | 13% |
| South Africa | 44.2 | 66% | 10% |
| UK | 85.0 | 48% | 8% |
| Ukraine | 55.2 | 40% | 10% |
| Vietnam | 24.5 | 73% | 33% |

Source: Nigeria Power Baseline Report (2015), BMI Research, PwC Analysis

Figure 10: Value chain losses, 2015

### 2.4.2 Limited Transmission Coverage

The transmission sector is the only segment of the power value chain that is government owned. While it is managed and maintained by a private contractor, the government-owned Transmission Company of Nigeria (TCN) has the final word on decisions involving expansion of installed infrastructure. The existing transmission network comprises mostly 300kV circuits and substations. There are approximately 32 work centers spread across the country; although most are concentrated in the south. Furthermore, the transmission grid covers only 40% of the country – a limitation that is a significant growth barrier for the power sector in Nigeria. Going forward, Nigeria needs to attract new investments to increase geographic coverage in power transmission. (PwC)

The Transmission Loss Factor (TLF), as measured by the proportion of the difference between the total energy sent out by power stations and energy delivered to all DisCos and exported by TCN relative to the total energy sent out, decreased during the fourth quarter of 2019. As represented in Figure 5, the TLF declined by 0.86 percentage point from 8.26% recorded in September to 7.40% in December 2019. This decline implies an average TLF of 7.26% in 2019/Q4, which is significantly lower than the 8.05% industry Multi-Year tariff Order (MYTO) reference loss factor. The recorded TLF indicates an improvement in transmission network when compared with the 2019/Q3 average TLF of 8.12%. (NERC)


Figure 11: Transmission Loss Factor from Jan. 2019 – Dec. 2019

### 2.4.3 Supply Disruption

Supply disruptions due to violence are an additional challenge observed across the power value chain in Nigeria. Militant groups recognise the impact of disruptions on the economy – as evident through rampant violence targeted at oil and gas pipelines in the north and south of Nigeria, which in turn impacts power generation. While this situation has improved over the last year, investors remain cautious with exploration activities and expanding pipeline infrastructure (which has also been curbed due to the oil price drop). (PwC).

### 2.4.4 Theft and Corruption

Theft and corruption are other important concerns in the power sector – particularly for the distribution segment. Without sophisticated tracking systems to pinpoint illegal connections, electricity theft reduces profits for DISCOs and limits available electricity for paying customers.

This is exacerbated by rampant corruption in revenue collections, which are largely manual. We discuss potential solutions for this in the report. Overall, these challenges need to be adequately addressed in order to reap the positive effects of a well-functioning power sector – which is critical for the revival of the Nigerian economy. The focus needs to be on significantly improving availability and access to power over the next decade, by further accelerating the transformation journey started in 2005. Examples of successful transformational approaches (in power generation, distribution and transmission) adopted by other countries are provided in the 'The leap forward' section, and similar strategies can be adapted for Nigeria. However, we first need to evaluate what Nigeria should realistically target to achieve by 2025. This is outlined in the next section [9].

### 2.4.5 System Collapse

The industry witnessed a slight decline in the stability of the grid network during the fourth quarter of 2019 relative to the third quarter. Table 3 presents the number of system collapses experienced in 2019. Similar to the preceding quarter, the industry recorded one (1) incidence of total system collapse (i.e. total blackout nationwide) during the fourth quarter of 2019. However, there was one (1) incidence of partial system collapse (i.e., failure of a section of the grid) during the same period as compared to zero (0) partial system collapse recorded during the third quarter.

Table 3: System Collapse in 2019/Q1-Q4

| | 2019/Q1 | 2019/Q2 | 2019/Q3 | 2019/Q4 |
|---|---|---|---|---|
| Number of Partial Collapses | 0 | 0 | 0 | 1 |
| Number of Total Collapses | 5 | 3 | 1 | 1 |

To further improve the grid stability and prevent system collapse in subsequent quarters and beyond, the Commission in collaboration with the TCN shall intensify efforts to ensure further improvement in the grid performance. The Commission shall continue to intensify monitoring of strict compliance to the SO's directives to generators on free governor and frequency control mode in line with the provisions of the subsisting operating codes in the electricity industry. Furthermore, the Commission has reviewed the outcome of the competitive procurement of spinning reserves conducted by the TCN. This is to guarantee adequate spinning reserves for proper management of the grid by the System Operator.

### 2.4.6 Grid Frequency

Based on the provisions of the Grid Code, the system frequency, under normal circumstances, is expected to be between a lower limit of 49.75Hz and an upper limit of 50.25Hz. The Grid Code, however, provides for grid frequency to operate between 48.75Hz – 49.75Hz (lower bound stress) and 50.25Hz – 51.25Hz (upper bound stress) when the grid is stressed. The system frequency pattern from January to December 2019 represented in Figure 10 shows significant instability during the quarter under review. Specifically, during the fourth quarter of 2019, both the low and high system frequencies diverged considerably from the industry nominal standard (50Hz) by averages of -0.29Hz and 0.88Hz respectively per month. Similarly, both frequencies were outside their lower and upper limits during the quarter under review with the exception of the low frequency which was within the lower limit in October 2019.

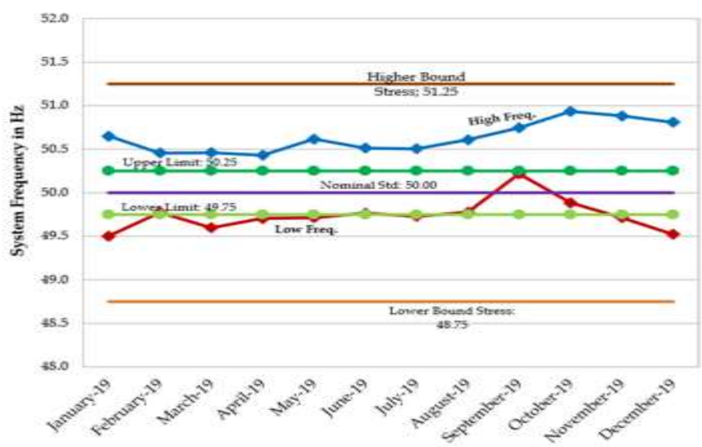



Figure 12: Average Daily System Frequency from Jan. – Dec. 2019

### 2.4.7 Voltage Fluctuation

Similar to the frequency pattern, the industry Grid Code allows for voltage fluctuation between a lower boundary of 313.50kV and an upper boundary of 346.50kV. The system voltage pattern from January to December 2019 is represented in Figure 13. Although there has been a continuous improvement in the actual high voltage level from April 2019 to date, both the high and low system voltages were outside the prescribed regulatory boundaries throughout the period.

As stated in the preceding quarterly reports, frequency fluctuation and other harmonic distortion will result in poor power quality that could damage sensitive industrial machinery and equipment that are connected at a high voltage level. To minimize the frequency and voltage fluctuations, the Commission shall continue to work with TCN and other relevant stakeholders to ensure that system voltage and frequencies operate within the prescribed regulatory limits in order to ensure safe and reliable electricity supply [8].

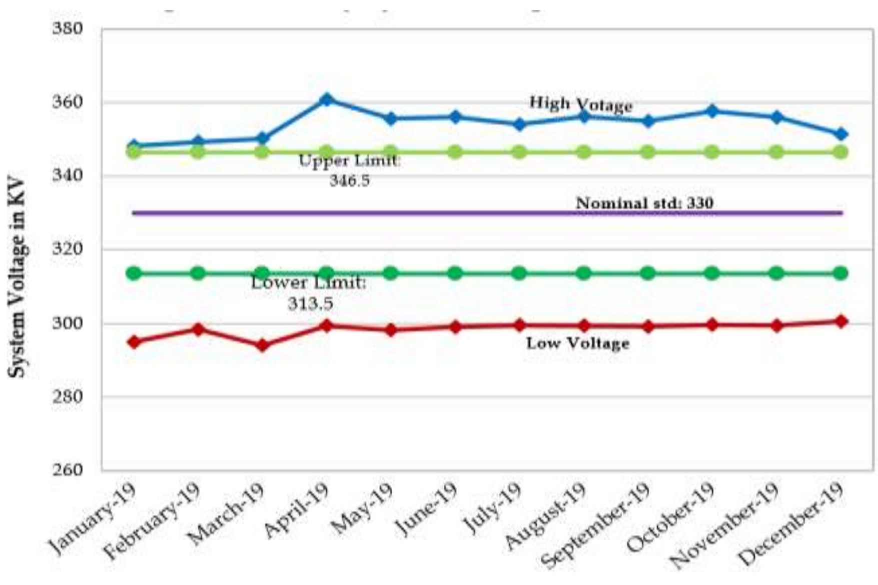



Figure 13: Monthly System Voltage from Jan. – Dec. 2019

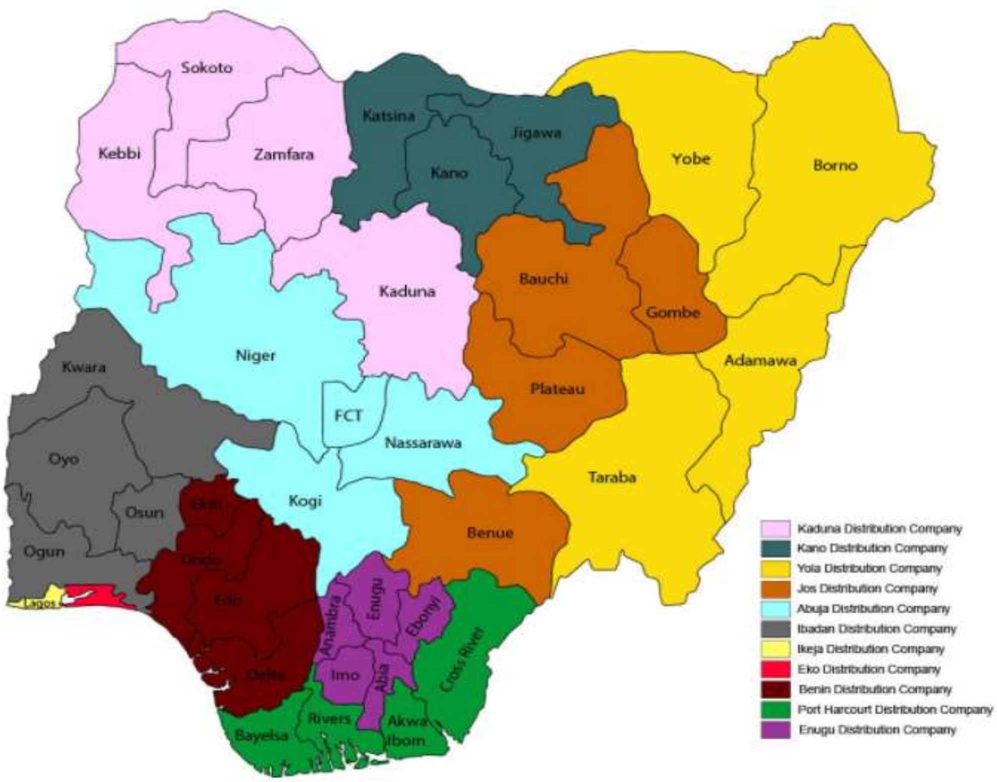



Figure 14: Geographical arrangement of the 11 Electricity Distribution companies

## 2.5 Scandinavian's Investment in Renewable energy in Developing countries

Scandinavian business communities related to investments in renewable energy has special focus on developing countries. The level of investment identified is considered as an indicator of the mechanisms' effectiveness and whether there is room for improvement.

There are reports stating the level of private and commercial activity in renewable energy in developing countries in Norway against Sweden and Denmark and provides an overview of the available policies and public instruments available to commercial actors to promote and support such investments.

To assess the relevance of such instruments, the report also briefly examines the barriers that investors and developers of renewable energy projects face when investing in renewable energy in developing countries; and whether existing instruments meet the investors' needs.

Against the backdrop of investment levels and available instruments, the report summarizes policy recommendations for the further efforts to support clean energy development through promotion of commercial investment, with a particular focus on the debate around a possible additional Norwegian investment guarantee instrument.

The report does not aim at assessing the overall results that have been achieved through the respective countries' energy sector development assistance other than with respect to investment activities.

The report is based on publicly available information, such as reports from various development agencies and financial institutions, as well as internal expertise and external interviews, information from companies' websites, news articles, other reports on the subject, (SE4ALL, u.d.) etc.

According to the UN, "the world needs to triple its investment in sustainable energy infrastructure per year, from around $400 billion now to $1.25 trillion by 2030". McKinsey has estimated that close to USD 500 million would be required to meet the needs for new electricity generating capacity in Sub- Saharan Africa until 2043. As it is increasingly recognized that Official Development Assistance (ODA) can only support a very limited part of this need, private investments are gaining importance to achieve the target. Private investors in sustainable energy services can also more efficiently bring new technologies to the market quickly from a diverse supplier base.

Against this backdrop, the Norwegian development assistance strategy has specifically aimed at contributing to achieving SDG 7, while recognizing the importance of access to energy for other SDGs. These contributions are ensured both through development assistance and financing, as well as through Norwegian companies' activities in developing countries' energy sectors.

## 2.6 Level of activity in commercial investments

In evaluating the level of activity in renewable energy in developing countries in Norway, Sweden and Denmark, the starting point is to get an overview of the different companies and organizations in this field in the respective countries. Although the overview is not exhaustive, it gives an indication as to how developed a "cluster" in this field is in each of the countries.

The cluster overview presents companies that in some way or the other have renewable energy activity in developing countries; developing projects, investing in projects, exports, consulting services etc. The players that have been included are those that have a track-record of some activity or strategic focus on developing countries, and where information has been available to verify that this is the case. There could for instance be other players that have some indirect activity in developing countries that are not included here (i.e. suppliers in up-stream value chain that contribute with parts that end up in products that are sold to developing countries).

### 2.6.1 Definitions of types of companies

The various types of actors that make up a cluster, are described below.

1. Developer & investors. The companies whose main activity (in this field) is to own projects and/or invest in project development.
    - On-grid: Companies that focus mainly on projects connected to the central grid.
    - Distributed: Companies that focus mainly on mini-grid, micro-grid and other off-grid systems and appliances, such as solar lamps and battery chargers.
2. Equipment/technology suppliers. The companies that do not necessarily provide capital to a project, but supplies equipment, products or technology of some kind that contributes to increasing capacity and access to renewable energy.
3. Financial institutions. Banks, funds, and other organizations/instruments whose main role is to fund projects and other players in the field, by providing capital through loans, equity and guarantees for instance.
4. Advisors. Companies or organizations, usually consultants, who provide services such as feasibility studies, market studies, projection of projects, etc.
5. Public agencies. Export Credit Agencies and other public organizations that extend credit or provide guarantees

### 2.6.2 Industry Mapping

The following overview shows actors in each of the Scandinavian countries with some activity in renewable energy in developing countries. Some companies are involved in two categories, such as suppliers that supply to both on-grid and off-grid markets, and companies that both develop projects and act as suppliers.

The mapping above is not exhaustive due to data availability. Both Norway and Sweden have significantly more companies that can be categorized as developers/investors, and suppliers, both in the on-grid and off-grid space, compared to Denmark. Norway especially seems to have more active on-grid developers/investors than the other two.

Many of the names listed under Sweden is received from Sweden Business as companies that have voiced interest in business in Africa. As far as we have been informed and our research shows, many have not yet realized business or investments in developing countries, or only at a very small scale, and would not be significant on an aggregated investments overview. Furthermore, the Swedish business community does not operate as a joint interest group through a common representation, as the Norwegian example with NORWEP and The Norwegian Solar Energy Cluster. Thus, it appears that Norway has the most active and mature business community in this field.

Several relevant consultancy and advisory firms are identified in all three countries. Denmark stands out when it comes to institutional investors, shown by the number of pension funds that have been involved in relevant investments.

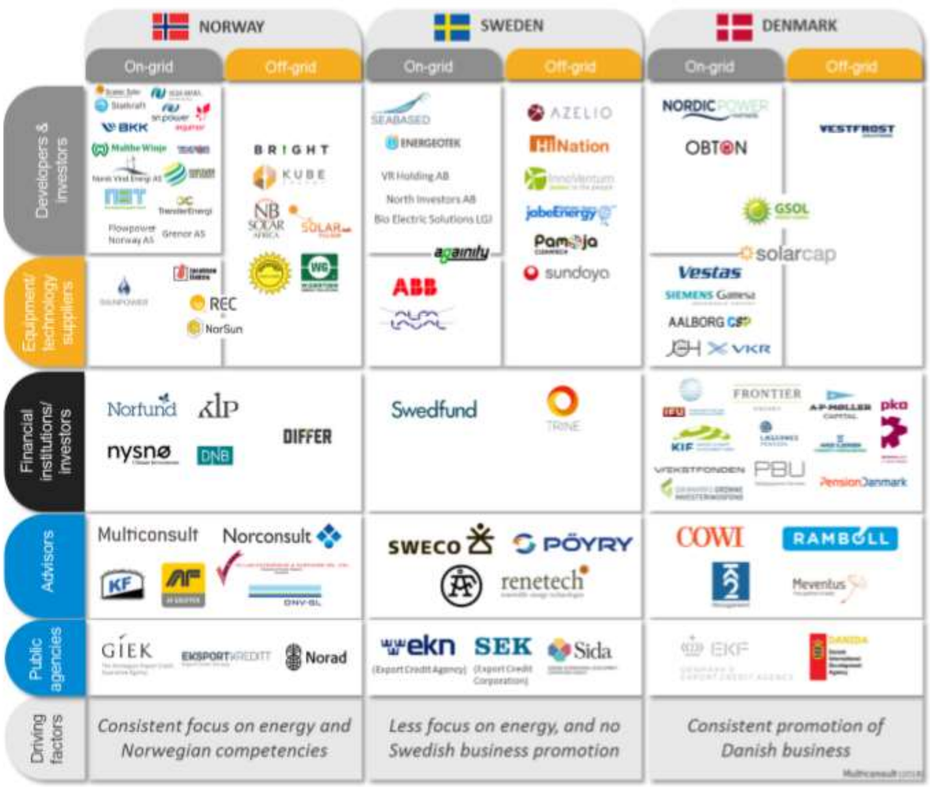



Figure 15: Mapping of active companies in the renewable energy sector in developing countries

## 2.7 Comparison of investment activities

In the following assessment of the level of investment activities related to renewable energy in developing countries, the focus is on developers/investors and financial institutions, as these contribute directly to promoting renewable energy with capital out of their domicile country.

To compare the activity levels across by Norway, Sweden and Denmark, we consider the following categories of activity separately:

- Investments of the countries' Development Finance Institutions
- Investments/projects of developers/investors and other financial investors

### 2.7.1 Investment level assessment methodology

The following central assumptions and limitations of scope should be noted.

- In general, only projects in developing countries outside Europe have been taken into consideration.
- Unless otherwise stated, only power generation facilities are taken into consideration. Auxiliary infrastructure such as power evacuation infrastructure or factories producing devices for renewable energy plants are not included.
- When it comes to off-grid energy, investments are primarily made by the energy users and are therefore counted as "trade" or "import" rather than "investments" and thus not reflected in investment statistics. This further implies that companies involved in off-grid activities contribute capital mainly as investments into the company, work capital etc. falls outside the scope of the investment analysis in this report.
- Where possible to isolate, only green-field and rehabilitation investments are taken into consideration. Investments in or loans to existing projects/companies are counted only where there are clear indications of that capital having catalyzed projects that in some way add additional capacity to existing generation.
- Where possible to isolate, investments in biofuel driven power plants are not included.
- Where otherwise not stated, investments in energy efficiency are not included.
- Where planned investments are found, these are also included in the analysis. Value is included in the year of commitment.
- Identification of projects, companies and investment and the research faces several challenges. The information given in the following should therefore not be considered an exhaustive overview, and direct comparison may not be possible. Despite these limitations, we believe that the findings give an accurate indication of relative activity and investment level.
- Although companies that export equipment/technology and export credit agencies have been included in the mapping of players, renewable energy exports and export finance is not included in the benchmark, as this does not qualify as investments. Furthermore, it has

not been possible to isolate the share or renewable energy of total exports and export finance for all the countries, thus benchmarking would not be possible.

- Institutional investors, such as pension funds, portfolio investors etc. are accounted for to the extent information has been available. This information does not specify type of investments, such as project size and type of technologies [10].

## 2.8 Network regulation

### 2.8.1 Unbundling

In Norway, there is only one TSO, the publicly owned company Statnett, which has been legally unbundled since 1992. In addition, the ownership of the TSO and the publicly owned electricity producer Statkraft has been divided between two different government ministries since 2002. Norway therefore complies with the requirements in the Electricity Directive 2003/54/EC for ownership unbundling. Today, DSOs with more than 100 000 connected customers in Norway are legally and functionally unbundled. In 2018, the seven DSOs in this category represented approximately 58 % percent of the total connected customers. In addition to the unbundling requirements, these companies are subject to participation in a compliance program according to the Electricity Directive and Norwegian regulation.

The participants of the program have to produce an annual report to NVE that enables NVE to monitor the DSOs fulfilment of the regulations regarding legal and functional unbundling. By the end of 2018, there were 113 Norwegian DSOs2 with less than 100 000 connected customers. These DSOs are therefore exempted from the regulations regarding legal unbundling. However, in the event of a merger or acquisition, NVE can require a DSO that also has activities in generation or supply to reorganise into separate legal entities. 39 of the DSOs with less than 100 000 customers are organised in a legal entity devoted entirely to managing the grid. All 120 DSOs (with more or less than 100 000 customers) are under regulation concerning neutral and non-discriminatory behaviour when it comes to the DSO's management of the information to customers, supplier switching, metering data and billing. These regulations are subject to supervision by NVE. Majority of the Norwegian DSOs are publicly owned.

This study is similar to what was done in Nigeria in 2013 but unbundling in Nigeria has not been fully executed because the Transmission still belongs to the Government 100%. In this case some irregularities are still in play within the power sector which makes reflective tariff impossible.

## 2.9 A Framework for Understanding the Enabling Environment for IPPs

The elements that contribute to sustainable IPP investments are discussed here. Host country governments have an immediate influence over some of the elements. These include policy, regulation, planning, and competitive procurement. Overall economic conditions and the legal framework are clearly relevant, as are policies that encourage private investment in general and in the power sector in particular. Stable macroeconomic policies, investment protection, respect for contracts, capital repatriation, tax incentives, and further IPP investment opportunities will attract more capital at lower cost.

Transparent, consistent, and fair regulatory oversight, with a commitment to cost-reflective tariffs, provides more price and revenue certainty, boosting the creditworthiness of off-takers and thus requiring less risk mitigation. Power planning and timely initiation of competitive tenders or auctions for new capacity are also important. The balance of issues is within the project purview. At the project level, debt and equity finance has to be appropriately structured and serviced through revenue guaranteed in a robust PPA and backed with the required credit enhancement and security arrangements, including guarantees, insurance, and other risk mitigation instruments [11].

## 2.10 Optimization of hydropower resources

Hydropower resource optimization refers to the most efficient way of making use of hydropower resources, given an expected demand to meet required energy production. Alternatively, if all constraints within the system are taken into account, the process could be referred to as hydropower scheduling [12]. Hydropower power system optimization is based in the levels of available resources (of which water is major) and the type of energy market being operated.

There are two major types of energy market – regulated and deregulated, and the types are differentiated by whether or not power is constant, and the level of flexibility plant managers have in terms of power production [12]. For instance, in a regulated market, the volume of power production and market prices are fixed, as such, optimization is based on minimizing the cost of power generation, while in a deregulated system, power production is based on current energy prices, and profit is maximized using price forecasts.

During hydropower optimization, several constraints could affect the process of optimization. For one, the volume of available data (plant data, reservoir data, reservoir constraints, plant constraints, inflows etc.) affects the optimization process, and the degree of uncertainty in optimization is dependent on the available data and the efficiency of the optimization process. The efficiency of optimization process is very important, as this could influence the planning and development of future scheduling. In essence, better optimization efficiency would yield better future planning and scheduling, while lower optimization efficiency would yield poor future planning and scheduling.

## 2.11 Optimization models

Hydropower optimization is implemented using mathematical models, although, to a great extent, it's based on the reliability of human judgment (calibration wise), choice of simulation or optimization, and the use of other decision support tooling [13]. The tools and models are based on either of linear, dynamic, mixed-inter or stochastic dynamic programming [12]. All act as decision support tools for efficient planning and operation of the system.

The tools are unique and more than often, many different tools may have to be used and calibrated to fit the reality of the hydropower system being optimized. Models are usually dynamic or stochastic and the selection of one tool over the other depends on the type of system being modelled, and the approach that would give the best possible obtainable result [12]. In deterministic models, the conditions at the start and end of the optimization process are known, while in stochastic models, predictions and decisions are based on stochastic events [12]. It is also noteworthy to point out the differences between optimized and simulation, as the former is used to automatically calculate solutions that best fit the operations of a power system, based on some assumptions, while the latter is used to predict and analyze the behaviour of a hydropower system, based on a given set of conditions [13]. In large hydropower systems modelling, more than one system have to be used, and this usually involves implementing optimization and simulations in the same solution [12].

There are a couple of modelling tools for optimization and simulation that have been developed and used in hydropower modelling, however, since the hydropower plants considered in this study are large hydropower plants, model tools would be limited to those with optimization and simulation capabilities. It is noteworthy to point out that there are currently no developed simulation and optimization tools in Nigerian, so focus would be on tools developed in other parts of the world, particularly Norwegian tools (due to accessibility and the cost implication associated with purchase of software). Norway is largely known for huge investments in hydropower and a lot of modelling tools have been developed in Norway over the past decade. Most of these tools have been developed by SINTEF, and an overview of some of these models is presented in Table 4.

Table 4: Optimization models developed by SINTEF

| Application | Term | Description | Problem | Method |
|---|---|---|---|---|
| EOPS | Long and Medium | Singe area hydro-thermal scheduling. Scheduling, use of reservoirs and expansion planning. | Stochastic | Optimization (SDP) and heuristic |
| EMPS | Long and Medium | Multi-area hydro-thermal market model. Price forecasting, planning, expansion, and power system analysis. | Stochastic | Optimization (SDP) and heuristic |
| Samlast and Samnett | Long | EMPS with physical power flow constraints. | Stochastic | Optimization (SDP) and heuristic |
| Seasonal model | Medium | Calculate individual water values, operation decisions, or input to short term model (SHOP). | Multi-deterministic | Optimization (LP) |
| ProdRisk | Long and Medium | Single area hydro-thermal scheduling. Scheduling, use of reservoir, expansion planning, and water values for short term model (SHOP). | Stochastic | Optimization (SDDP) |
| SHOP | Long and Medium | Single water course. Scheduling, power market trade. Also includes simulator for validation of the optimization. | Deterministic | Optimization (SLP, MIP) and heuristic |

Source: [14]

## 2.12 Hydropower scheduling hierarchy

Hydropower systems may consist or single or several reservoirs and plants. In system with several reservoirs, the optimization process becomes more complex and usually required higher computational time periods. In order the overcome this short fall, some modelling tools devised hydropower optimization and simulation into long, medium, and short term modelling, based on the computational power a user has access to.

Long term modelling involves hydropower system planning over a duration more than 1 year. IN long term models, a lot of simplifications have to be done to reduce the computational time, as such, results obtained from long term models cannot be used for short term planning [14]. Results from medium term planning on the other hand (which is usually within the confines of a year, acts as the link between long and short term hydropower planning, while short term planning refers to time periods ranging from a few days to two week. Results from short term planning cannot be used to determine the boundaries for long term planning.

Chosen planning length (short, medium, or long) usually depends on the total energy in the system and the capacity of the reservoirs. For systems with large reservoir volumes, planning is usually long term to optimize reservoir contents for better utilization. On the other hand, medium and short term planning are used for reservoirs with lower capacity, with the lowest capacity reservoirs (or no reservoir in some cases) planned on a short term basis.

## 2.13 Model selection

As previously stated, selecting a tool for hydropower modelling is based on the type of power system that will be modelled. Nigeria's hydropower system consists of large reservoirs suggesting that only models that allow for long term planning may suffice. Also, Nigeria's power system is composed majorly of hydropower and thermal power plants, suggesting that the choice of a modelling tool must take this into account. Only models that account for stochastic events are considered, because, the modeling in this context is based on the predictability of future uncertainties, given stochastic events. Finally, tools that considers multi-area rather than single areas are selected because of the semi-liberalized nature of the Nigerian power market, which liberalized more with time.

Of the listed hydropower modelling tools presented in Table 4, the EMPS (EFI's Multi-area Power market Simulator) would be the better tool to use given the earlier defined criteria. The model employs a strategy approach, which makes use of the optimization approach to solve for an optimal strategy, and the result from the strategy are calculated through simulation. More details on EMPS modelling and functionality is outlined in *Chapter 3* section of this study.

# CHAPTER THREE

## 3.0 METHODOLOGY

The method adopted for this study are Qualitative and Quantitative approach of research. Qualitative approach was done by sort of interview and gathering observations from the major players in the electricity sector in Nigeria and this approach addresses the second objective of this study while the Quantitative approach which is the technical approach was done with the use of EFI's Multi-Area Power Simulator (EMPS) and it tackles the first objective of this study. This approach is well discussed in the recommendation part of this study.

## 3.1 EMPS Model Concept

EMPS modelling is based on multiple area modelling [15] and is a decision support system that aims to minimize the cost of the hydropower system operations, given certain constraints [16] for optimal use of hydro resources and the uncertainty of future inflows. The model is resolved weekly [15], but can be divided into different load periods for more detailed simulation [12]. Each week can be divided into 168 sub-sections (hourly resolutions) where load and transmission capabilities can be provided. Major elements in required by EMPS for each area comprise hydro-power, thermal-power, and other generation sources e.g. wind or solar, as well as power consumption and transmission constraints with neighboring areas.

EMPS modelling constitute a *strategy* and a *simulation* phase. At the strategy phase, the marginal value of stored water (herein referred to as *water value*) is calculated per reservoir using stochastic dynamic programming. For the water values, modules in each area are aggregated to obtain a simplified model composed of an aggregate reservoir and an aggregate hydropower station [15], and interactions between areas are modelled using a heuristic approach [16]. The simulation part involves simulating the system based on strategy defined in the previous step [12], to define the water allocation according to individual reservoirs [17]. In the simulation part, total costs are minimized in a weekly basis for each climate scenario using a linear problem formulation (LP) [16].

For hydropower modelling, water values are first obtained using an aggregation principle, following which details of hydropower generation modules and electricity market are used for calculation. The strategy phase takes stochastic weather conditions (e.g. temperature, water inflows) into account. A graphical abstract of the model concept is presented in Figure 16.

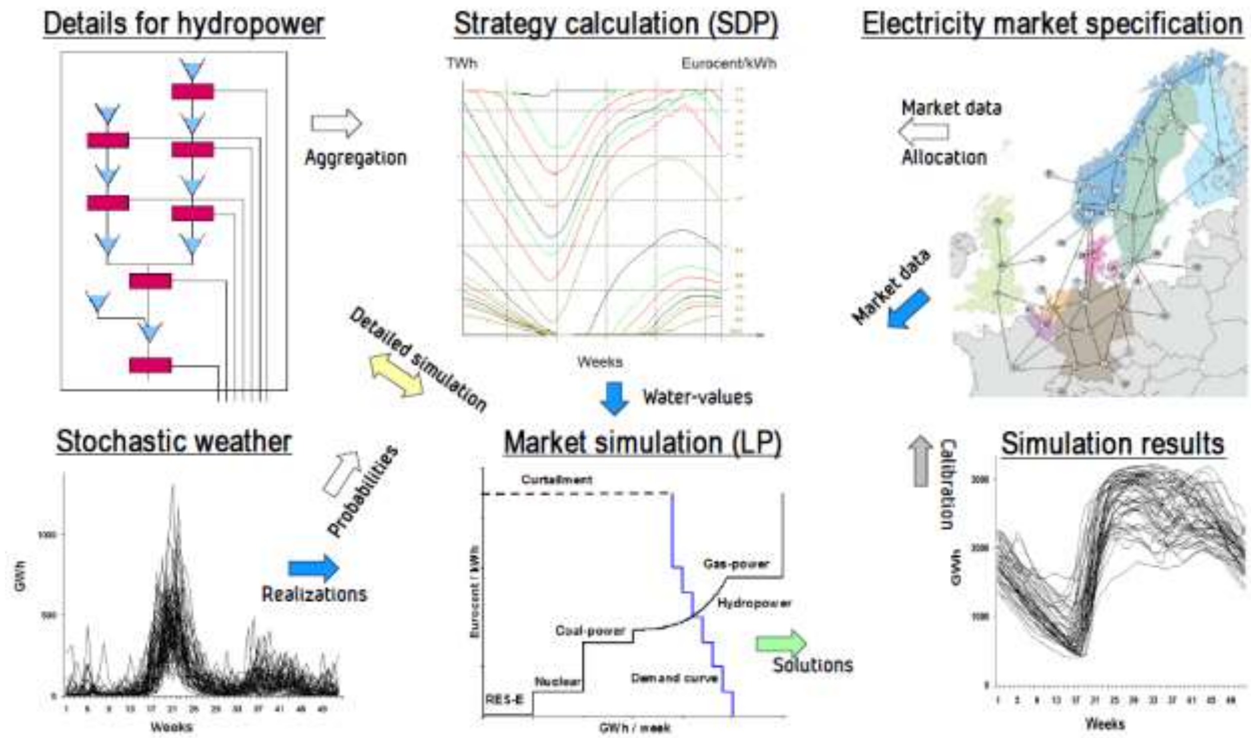



Figure 16: EMPS modelling concept. Source [16]

## 3.2 Modelling In EMPS

### 3.2.1 Hydropower System in EMPS

Hydropower systems are represented by modules that describe the reservoirs and station specifications in EMPS. Modules contain inflow series profile (regulated and unregulated inflows) and water course data (turbine discharge, bypass, and spillage). The coupling between modules can also be specified. Module details are based on data availability, and if some – not compulsory – details are not given, EMPS uses default values programmed in the model. Models with more details yield better results. A graphical abstract of an EMPS hydropower model is presented in Figure 17.

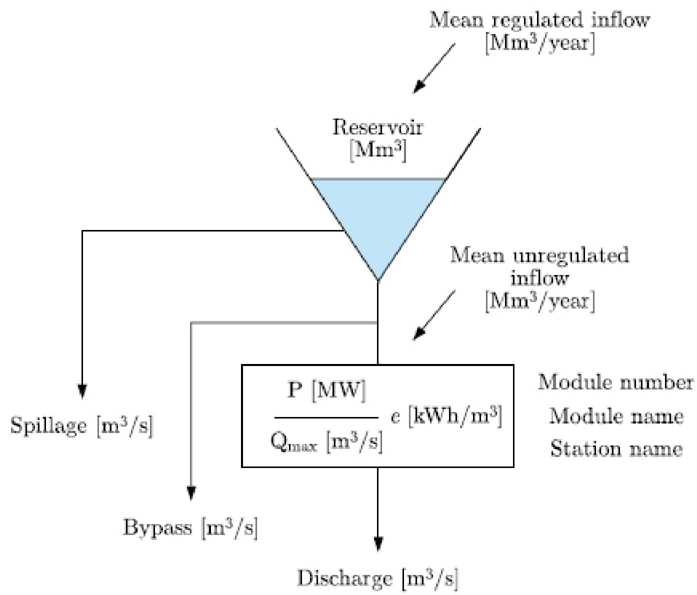



Figure 17: Overview of an EMPS hydropower module [15]

### 3.2.2 EMPS Model Elements

The EMPS model is able to function with very minimal inputs for the simplest hydropower module, however, some parameters – reservoir volume, annual inflow series, and discharge and capacity curve – are quintessential for running the model. The EMPS model grants a degree of freedom to users when modelling a hydropower system. As stated earlier, the EMPS model allows for regulated and unregulated modules, it also allows the specification of modules that are run-offs i.e., modules without a plant. The main elements of the hydropower module are – reservoir, power plant, inflows, topology, hydrological coupling, restrictions, and pump data (pump data is not defined in this study, because, the modelled hydropower stations don't support pumps).

**Reservoir**: For modules that contain a reservoir, this parameter is defined by the volume given in million cubic meter units ($Mm^3$) and must be specified for every module. In cases of run-off plants, the value can be set to zero. The reservoir can be described in more details an example which includes the reservoir height-volume curve, which is a piecewise linear curve shown in Figure 18 below. The curve can be used to correct production based on the reservoir height.

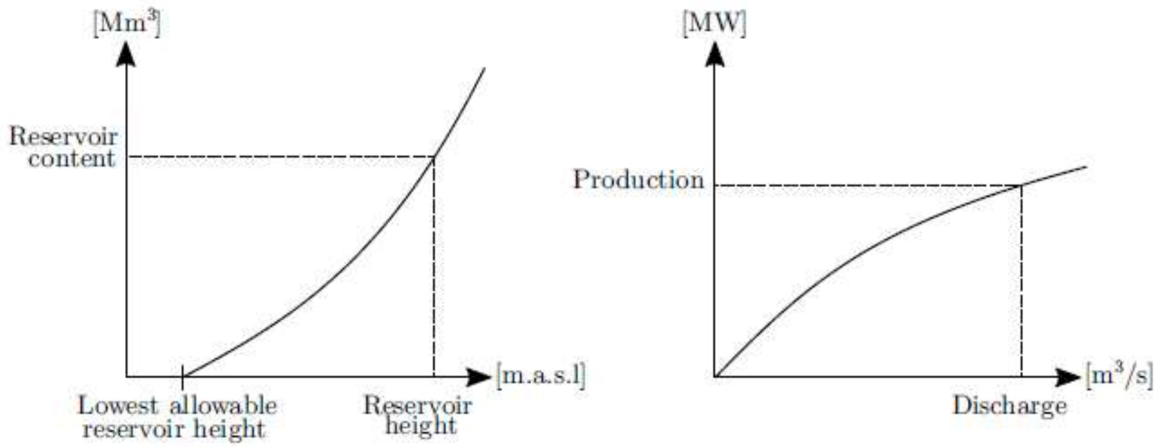



Figure 18: Reservoir and power-discharge curves example. Adapted from [15].

**Plant**: The plant is described by its energy conversion factor and power-discharge curve. The energy conversion factor of the plant is calculated as in equation 2 and it determines the volume of electricity (kWh) produced given a specific volume of water. Modules without a plant have their energy equivalent value set to zero.

$$e = \frac{1}{3.6 * 10^6} * p * g * h * \eta$$

Where:

$e = energy\ conversion\ factor\ \left[\frac{kWh}{m^3}\right]$

$p = water\ density\ \left[\frac{kg}{m^3}\right]$

$g = gravity\ acceleration\ \left[\frac{m}{s^2}\right]$

$h = plant\ head[m]$

$\eta = plant\ efficiency$

$3.6 * 10^6\ unit\ of\ correction\ to\ obtain\ kWh$

The plant-discharge given as a piecewise linear curve established the relationship between the power output and turbine discharge. The nominal power of the turbine is defined by the rated discharge. It is noteworthy to point out that the energy conversion factor (thereafter referred to as energy equivalent) is a static variable (i.e. fixed in EMPS), whereas, in reality, the variable is subjected to change based on factors such as changes in discharge and hydraulic head. Specifying the reservoir curve improves the efficiency of EMPS modelling.

**Inflows**: Modelling with EMPS requires specifying inflow data for each module. A regulated and unregulated inflow parameters can be fed into the EMPS model. A yearly and unregulated regulated inflow are given in numeric value in million cubic meter per year $\left[\frac{Mm^3}{year}\right]$. Of both parameters, the regulated inflow – which refers to reservoir stored inflow – is important and must be given for the model to run. The inflow series – usually a series of daily or weekly inflows throughout the year – must be provided to train the model on the behaviour of the inflows throughout the year. Inflows must correspond to the area where the reservoir is located.

**Topology**: The water course topology in EMPS is defined by stating the direction of inflows between modules. E.g. if inflows from module A goes into module B, one defines that the discharge data is linked by specifying the feeder and receiver module.

**Hydrological coupling**: EMPS allows different hydrological coupling specification, based on how the reservoirs are coupled to a plant. An example of the different hydrological coupling configuration is shown in Figure 19.

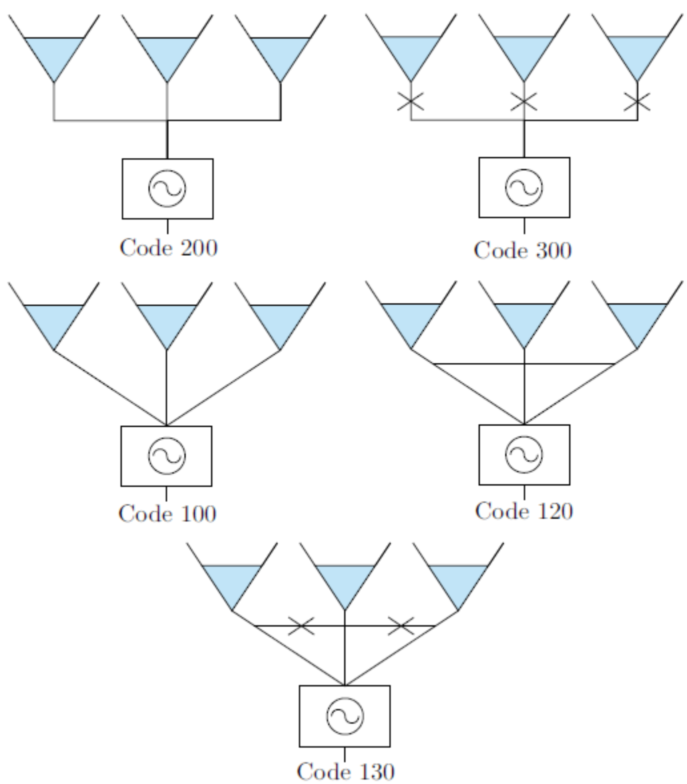



Figure 19: Different reservoir hydrological coupling configurations in EMPS. Adapted from [15].

**Constraints:** EMPS allows for the specification of certain constraints for each module. This is constraints are useful and aid in characterizing the behaviour of operations. Constraints that can be defined in EMPS are:

- Maximum and minimum reservoir level
- Maximum and minimum discharge
- Maximum and minimum bypass

The constraints are defined as data points in a curve, and modules can have all constraints defined. Although, they are deemed soft constraints as the modules can still be modelled if they are not specified, albeit, with penalties.

### 3.2.3 EMPS Inputs

Figure 20 presents the EMPS dialog window (with some dummy values) showing the parameter specification of for a hydropower module. The restrictions are specified as no 17 – 22 in the list and often improve the results of the model when inputted, however, they are optional when unavailable; although, getting exact curves for each module would be difficult as EMPS would result to the use of default values. Some other parameters can be optional depending on if the configuration of the module. For instance, modules with plants but no reservoirs would have "reservoir volume" set to zero. Also, modules without plants would have energy equivalent, average head and outlet level set to zero.

```
Module no.     301, Green Meadow                            Ownership  : 100.00
Type module:  Hydropower
-----------------------------------------------------------------------------
 no.  C o m m e n t s                      : no.  C o m m e n t s
-----------------------------------------------------------------------------
  1   Reservoir volume (Mm3)      195.0 :      Flagg =  0, Data is not uploaded
      Resid. res. vol. (Mm3)        0.0 :      Flag  >  0, Data is uploaded
  2   Energy con. fact (kWh/m3)  0.1390 :      Flagg = -1, Data not OK
  3   Max.  discharge  (m3/s)     30.00 :      Enter DF for detailed explanat.
  4   Average head(m)             61.00 :
  5   Outlet level    (m.a.s.l)  419.00 :
                                        :      Constraints        Type    Flag
  6   Discharge to module           302 : 17   Max. reservoir                0
  7   Spill to module               302 : 18   Min. reservoir                0
  8   Bypass to module              302 : 19   Max. discharge                0
  9   Code for hydraulic coupling     0 : 20   Min. discharge                0
 10   Coupling factor or number       0 : 21   Bypass                        0
 11   Max. balan. discharge (m3/s)    0 : 22   Max. bypass (m3/s)      10000.0

 12   Av. reg. inflow (Mm3/yr)    624.0 :      Functional relations       Flag
 13   Series name  reg. inflow
                                 9755-E  23   Discharge limitations         0
      Ref. period for inflow  1931-1960  24   Reservoir curve               1
 14   Av. unr. inflow (Mm3/yr)      0.0 : 25   Discharge strategy data       1
 15   Series name unr. inflow
                                 9755-E  26   Prod./discharge (PQ)          1
 16   Plant name  :                     : 27   Pump description              0
-----------------------------------------------------------------------------


Search no. and value * RETURN - Data OK * H - Help * ... :
```

Figure 20: EMPS dialog window showing input parameters for a hydropower module

## 3.3 EMPS Water Value Calculation

Water value calculation is an important step in EMPS modelling, as it defines the future value of water – in kWh – in the reservoirs [17]. The water value is controlled by some stochastic elements such as water inflows, power demand, and energy prices. Water value calculation minimizes system operation cost based on the value of water in the reservoir.

Calculation of water values improves operations as it helps determine when best to save water as opposed to when to discharge water to the turbines. It helps in the critical power planning process of choosing when to produce vs. when not to produce based on current electric power prices. Water value is calculated using an aggregation model, and must be simulated to determine the possible consequences of production based on the water value. Four factors which affect the water value are:

- Reservoir level and generation capacity
- Demand expectation
- Price expectation
- Inflow expectation

It is noteworthy to point out that these variables are stochastic in nature and affect the accuracy of the water value calculation.

### 3.3.1 Mathematical Derivation for Water Value Calculation

The planning period approach (Figure 21) shows how cost is minimized by determining power generation of the entire week from the start of the week. In Equation 1, the cost function *J* is given in terms of the reservoir levels *x* and time *t*.

$$J_t(x_t^{res}) = \min\{\sum_{T=t}^{T} L_T(x_T^{res}, x_T^{hyd}) + S(x_T^{res})\} \qquad (1)$$

Where

$J_t$: the cost function at time t

$x_T^{res}$: reservoir level at the beginning of week *t*

$L_t^k$: cost dependent on operation in week t, scenario k

$x_T^{hyd}$: hydropower production in week T

$S(x_T^{res})$: value of final reservoir at the end of week T

Equation 1 can be expanded by substituting the operation costs for generation cost and demand reduction cost (Equation 2).

$$J_t(x_t^{res}) = \min\{\sum_{T=t}^{T} \sum_{i=1}^{Isup} C\ x_T^{hyd}(x_{it}^{s}) + \sum_{i=1}^{Icon} D_{IT}(x^{red}{}_{iT} + S(x_T^{res})\} \qquad (2)$$

Where
$C_{iT}$ = cost of supplementary generation option $_i$ in week $_T$
$x_{it}^{s}$ = supplementary generation option $_i$ in week $_T$
$D_{iT}$ = cost of demand reduction option $_i$ in week $_T$
$x^{red}_{iT}$ = demand reduction option $_i$ in week $_T$
$I_{sup}$ = number of supplementary generations
$I_{red}$ = demand reduction contracts

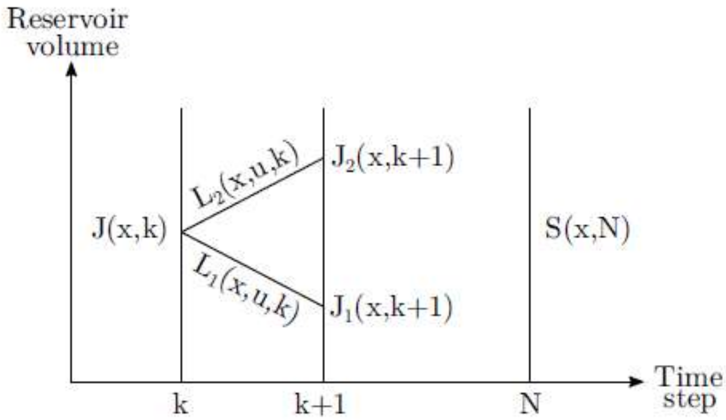



Figure 21: Planning period divided into weeks, different scenarios [17]

Each week will have a specific cost formulation that is based on the variable costs and the final reservoir water value. Major constraints in this optimization are energy balances (Equation 3) and reservoir balance (Equation 4). Maximum and minimum values for most variables are included in the formulation.

$$\sum_{i=1}^{Isup} x^{s}{}_{it} + x^{hyd}{}_{t} + \sum_{i=1}^{Itra} x^{imp}{}_{it} = \sum_{i=1}^{Icon} (x^{ini}{}_{it} - x^{red}{}_{it}) + \sum_{i=1}^{Itra} x^{erp}{}_{it} \qquad (3)$$

Where:
$x^{imp}{}_{it}$ = import option $_i$ in week $_T$
$x^{erp}{}_{it}$ = export option $_i$ in week $_T$
$x^{ini}{}_{it}$ = reference demand option $_i$ in week $_T$

$$X_{i+1}^{res} = x_t^{res} + y_t^{inf} - x_t^{hyd} - x_t^{spill} \qquad (4)$$

Where:
$y_t^{inf}$ = inflow in week $t$
$x_t^{spill}$ = spillage in week $t$

Following this, the optimization problem is reconstructed by calculating a Lagrangian and Karoush Kuhn-Tucker first order condition. Final results from optimization results shows optimal hydropower management is attained when the "purchase and sales marginal" "water value cost are equal and when there are non-binding reservoir and production constraints. The water value calculation is done per inflow scenario, yielding different results before a weighted average is obtained. For *n* scenarios, a corresponding *n* water value will be calculated with linked probabilities (see Figure 22 and Equation 5).

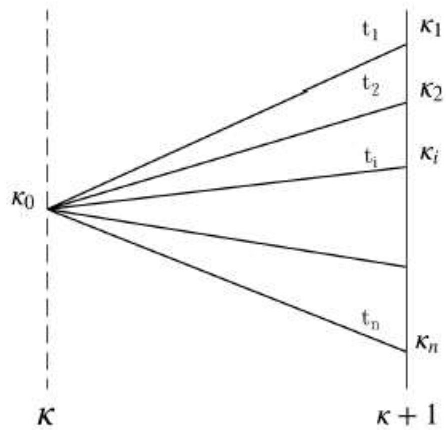



Figure 22: Illustration for principle of water value calculation [17]

$$K_0 = \sum_{I=1}^{n} p_i k_i \qquad (5)$$

$K_0$ = calculated water value
$P_i$ = probability of a certain inflow *i*
$K_i$ = water value with a certain inflow *i*

There can be different scenarios depending on whether the reservoir is empty of filled. During spillage, the water value set to zero (overflow). When the reservoir is empty, the water value is set as the last price (in kWh) purchased or curtailed, making the water value dependent on rationing.
EMPS calculates water value for each area following which the model is calibrated to account for differences in transmission capacities between the areas. This is done for optimal reservoir management and economic result.

### 3.3.2 Strategy Phase

The strategy phase is computed using stochastic dynamic programming (SDP). The expected value of stored water is calculated per area given the volume of the reservoir at a particular time. SDP requires some model simplifications to reduce computational time, and this is done by aggregating the modules within each area into a single reservoir and station, a concept called the *single reservoir model* (Figure 23).

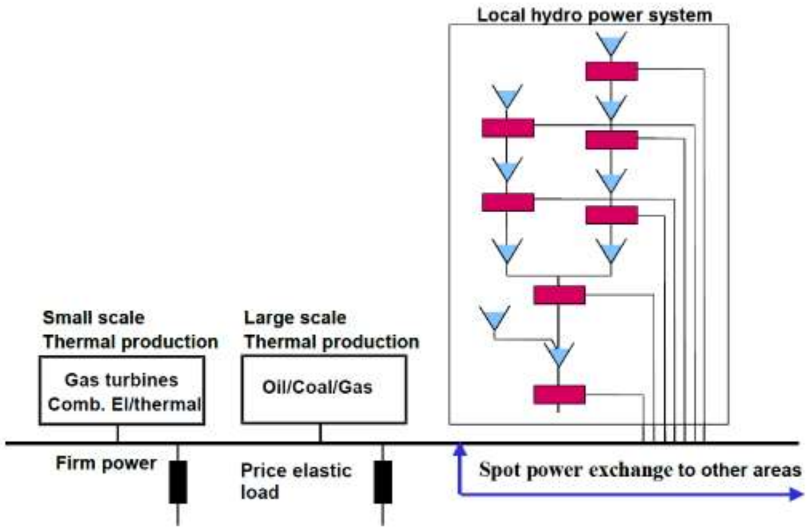



Figure 23: Aggregated system model in the strategy phase [12]

### 3.3.3 Calibration

As stated earlier, water value is calculated for each area, but said values are dependent on other areas connected to the same power market. As a result, the water values are corrected using a calibration procedure that takes into account the areas and exchange capacity between the other areas in the power market. Calibration functions to minimize the cost of the entire system.

### 3.3.4 Simulation Phase

Simulation is done to account for the variation in system operation under different inflow scenarios. Simulation is done using an area production optimization and a reservoir drawdown process.

#### 3.3.4.1 Area production optimization

This step involves calculating an optimal production plan for every system – given the specified constraints using a linear model. The problem is formulated as a cost minimization and is built on a basis of inelastic demand, but price dependent demand could also be included in the model formulation (Equation 6) [17]. The first, second, third, and fourth terms of the formulation corresponds to the thermal costs (including start-up costs), rationing costs, water value in the reservoirs, and transmission costs.

$$min \sum_{i=1}^{NA}\Big[\sum_{l=1}^{L}\Big\{\sum_{j=1}^{Nt(i)}(cth_{i,j,l} + SC_{i,j}\,.\,strt_{i,j,l}) + \sum_{j}^{Nrat} V_{j}\,.\,prat_{i,j,l}\Big\} + \sum_{m}^{Nm} W_{m,i}.\,xd_{m,i}\Big] + \sum_{l=1}^{L}\sum_{j=1}^{Ntr} ctr_{j,l} \qquad (6)$$

**Indices**

$i$= area number

$j$ = unit

$l$ = load period

$m$ = reservoir segment

$t$ = time (week number)

**Variables**

$cth_{i,j,l}$ = thermal cost in area $i$ in load period $l$ (USD)

$ctr_{j,l}$ = transmission cost of line $j$ in load period $l$ (USD)

$prat_{i,j,l}$ = demand rationing segment $j$ in area $i$ load period $l$ (GWh)

$strt_{i,j,l}$ = relative start-up cost in area $i$ in load period $l$ (USD)

$xd_{m,i}$ = reservoir segment $m$ for area $i$ at the end of week $t$ (GWh)

**Parameters**

L = number of load periods

$N_A$ = number of areas

$N_m$= number of discrete reservoir segments

$N_{rat}$= number of rationing levels

$N_{t(i)}$= number of thermal unit area $i$

$N_{tr}$= number of transmission lines

$SC_{i,j}$= start-up cost of unit $j$ in area $i$ (USD)

$W_{m,i}$= marginal end of week water value for reservoir level $m$ in area $i$

Defined constraints include the reservoir balance (Equation 7). Maximum and minimum reservoir limits are also defined as reservoir constraints, including size segment limits and the hydropower generation equations based on the plant discharge.

$$X_{i,t+1} + q_{i,t} + s_{i,t} = X_{i,t} + I_{l,i,t} \qquad (7)$$

Where:

$X_{i,\, t+1}$ = reservoir level in area $i$ at the end of week $t$ (GWh)

$q_{i,t}$= total discharge in area $i$ in week $t$ (GWh)

$s_{i,t}$ = hydro spillage in area $i$ in week $t$ (GWh)

$X_{i,t}$ = initial reservoir level for area $i$ at the beginning of week $t$ (GWh)

$I_{l,i,t}$ = regulated inflow to area $i$ in week $t$ (GWh)

Thermal units are modelled by specifying thermal power production and associated cost. Transmission lines cost are also included alongside its constraints (line segments and direction of flow). Rationing costs are included to assess the possible rationing costs from no generation, especially during the dry season and years. Finally, an intra-week dispatch a constraint is to account for the energy balance for each load period $l$ and each area $I$ (Equation 8). The energy balance constraint equalizes demand, generation types, imports addition, exports subtraction, and if present, rationing.

$$0 = phl_{i,l} + \sum_{j=1}^{Nt(i)} pt_{I,j,l} + \sum_{j=1}^{Nrat} prat_{I,j,l} + \sum_{j \in Mt1,i} (1-\alpha_{j,l}) \,.\, tr_{1,j,l} - \sum_{j \in Mt2,i} tr_{2,j,l} - D_{i,l} \qquad (8)$$

Where:
$\alpha_{j,l}$ = loss factor of line *j* in load period *l*
$D_{i,l}$ = inelastic demand in area *i* in load period *l*
$phl_{i,l}$ = hydro production in area *i* in load period *l* (GWh)
$pt_{i,j,l}$ = thermal production of unit *j* in area *i* in load period *l* (GWh)
$M_{t1,i}$= transmission lines importing to area *i*
$M_{t2,i}$ = transmission lines exporting to area *i*
$tr_{1,j,l}$= transmission line *j* in direction *k* in load period *l* (GWh), k = 1,2

### 3.3.4.2 Reservoir drawdown

This step involves splitting total optimal hydropower production across the different plants i.e., stored water are implicitly allocated to individual reservoir areas using heuristics. It shows how EMPS allocates hydropower from the aggregate model to individual plants and reservoirs. It is described as a reservoir allocation procedure which involves:

- Verifying physical constraints
- Modifying plant description in the aggregate model to comply with constraints
- Calculating discharge, production, and reservoir levels for all modules in each area.
- Calculating the aggregate reservoir volume at the end of the week for use in the following week.

The strategy used is dependent on the reservoir type (run-off or regulated). For instance, buffer reservoirs have marginal effects on weekly results due to the low degree of regulation, while regulated reservoirs must follow strategy rules as they may take several weeks, months, or years to be filled up. This is relevant in the drawdown model, which divides the year in two distinct seasons –filling and depletion seasons.

**Filling season**: This refers to the season when inflow values are greater than discharge values e.g. during the rainy season. Avoiding spillage becomes critical at this time. During the filing season, Equation 9 must be satisfied at every week (the equation shows that the individual weekly target levels and desired energy sum in the total system must be equalized).

$$\sum R_{target\ (i)} * e(i) = R_{esum} \qquad (9)$$

Where:
*i* = reservoir index
$R_{target}$ = weekly target for the reservoir
*e* = total energy equivalent
$R_{esum}$ = desired energy in the total system at the aggregated level

**Depletion season**: This is the season where discharge values are greater than inflow values. Occurs during the dry season, and it is expected that the rated plant capacity must be available as long as possible in order to avoid early deficits (where reservoirs are emptied too early into the season). The depletion strategy is done at an aggregated reservoir level.

The area production optimization and reservoir drawdown are resolved on a weekly basis i.e. for any week *n*, area production optimization is solved first, followed by the reservoir drawdown after which week *n* + 1 is resolved [17].

### 3.3.5 Interaction

The step-wise logical sequence of the simulation phase in show in Figure 24. The firsts step (A) involves the single area optimization where optimal solutions for the area is resolved weekly. Water is allocated to individual reservoirs in the drawdown model (B) and single area results are updated (C). Finally, validation mechanisms verify if minimal requirements have been met.

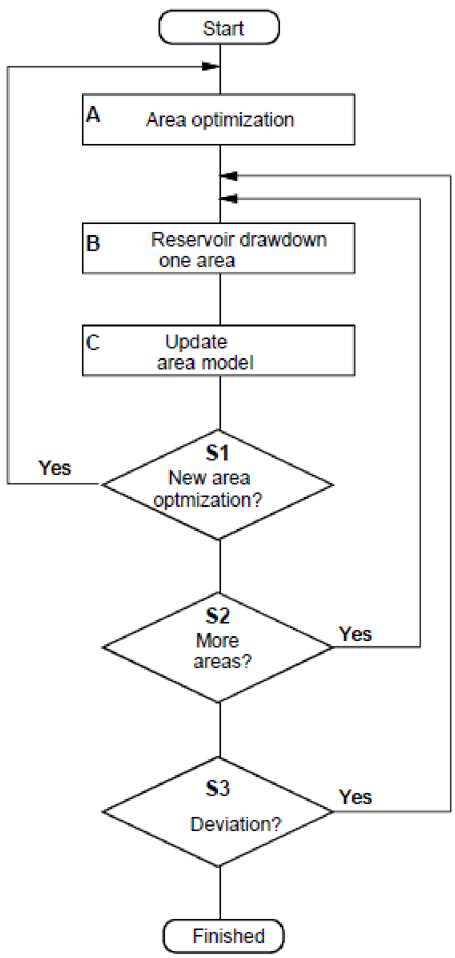



Figure 24: Weekly EMPS simulation process. (Source: [16])

## CHAPTER FOUR

### 4.0 Nigeria's Large Hydropower Plants

Quantifying hydropower production in Nigeria, requires having a database with installed capacity per area documented. The installed capacity of the major hydropower system in Nigeria as well as their hydrological specification is shown (Figure 25 and Table 4 respectively). The collected data was gathered from the sites where the power stations are located. Also, beyond pointing out the installed capacity per area, the available capacity of the hydropower plant is also shown (Figure 25), since Nigeria's hydropower plants do not operate at optimal efficiency.

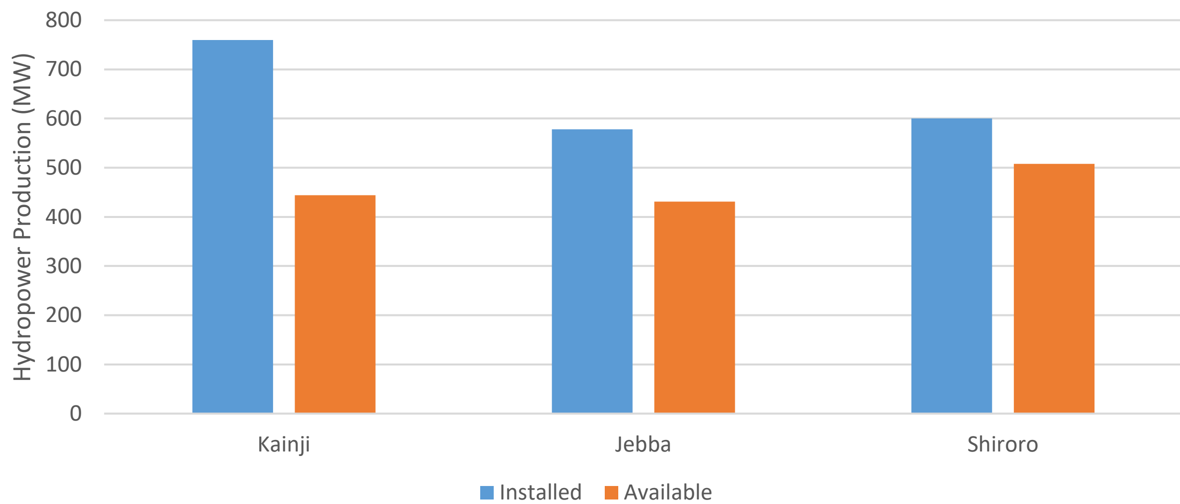



Figure 25: Installed and available capacity of Kainji, Jebba, and Shiroro hydropower plants

Table 5: Engineering specification of Kainji, Jebba, and Shiroro hydropower plants

| | Kainji | Jebba | Shiroro |
|---|---|---|---|
| Location | New Bussa | Jebba | Shiroro |
| Generated Energy | 440/338MW | 360/355MW | 450/360 |
| Number of Turbine | 8 | 6 | 4 |
| Turbine Type | Kaplan: 4 × 80MW<br>2 × 100MW<br>Propeller: 2 × 120MW | Fixed blade Propeller :<br>6 × 96.4MW | Francis: 4 × 150MW |
| Head | 37.20m | 27.75m | 97m |
| Dam height | 65.5m | 42m | 115m |
| Length of Dam | 550m | 670m | 700m |
| Dam Type | Concrete (Gravity) | Embarkment (Earth and Rockfill) | Rock-filled concrete- faced |
| Reservoir volume | 15000 million m³ | 3600 million m³ | 7000 million m³ |

## 4.1 Reservoir information of Nigeria's Large Hydro Power plants

Documentation of reservoir information is necessary for modelling of Nigeria's hydropower system. Reservoir information for Kainji, Jebba, and Shiroro hydropower are shown in Table 4.

### Kainji Hydro Power

The Kainji hydroelectric reservoir is located on latitude 9° 8' to 10° 7' and longitude 4° 5' to 4° 7' E, situated in New Bussa, Niger State, Nigeria [18].The area receives a mean yearly rainfall of 2200 mm and two types of rivers are identified in the area (the black and white rivers). The first river has a hydrological regimen that peaks at 2,000$m^3$/sec in February [18] while the second river has a hydrological regimen that peaks at 4,000 $m^3$/s in September to 6,000 $m^3$/sec in October.

### Jebba Hydro Power

Jebba hydroelectric reservoir is located on latitude 9º 35` and 9º 50`N and longitude 4º 30` and 5º 00` E. It located on Complex rocks such as porphyritic granite, mica, quartzite, etc. [19]. It has an estimated surface area of 303$km^2$ and a volume of 3.31 x 109 $m^3$. The maximum depth is 105m and a mean depth of 11m [20]. Discharge from the Kainji dam constitutes the major inflow into the Jebba dam since i.e., the plants are coupled serially based on inflow data. This implies that the higher the release from upper reservoir the faster the downstream reservoir fill up and excess will be discharged thereby leading to flooding. Literature sources [19] state that there are 2 seasonal hydrological regime pattern in Jebba. From May – October, rainfall in the produces flood that reaches the Jebba area at a peak of 4,000 $m^3$/s, while from September – October, flood levels reach 6,000 m3/s.

### Shiroro Hydro Power

Shiroro hydroelectric reservoir is located on 9º 58` 30‟N 6º 50` 04‟E in the shiroro Gorge on the Kaduna River approximately 60 km from Minna. The dam has crest length of 700m rising 125m above the original riverbed. The width of the dam at its toe is over 300m, whilst its crest accommodates a 7.5 wide service road. The reservoir was capable of 7billion cubic meters of water as at the time of constructed.

### Water course data for Kainji, Jebba, and Shiroro hydro power stations

Water course data (inflows, turbine discharge, and reservoir elevation) for the three hydropower stations were collected from the hydrological unit of the Kainji, Jebba, and Shiroro hydro power stations. Maximum, minimum and mean values, of the collected data (data for 21 years are reported i.e., 1990 – 2010) are shown in Figures 26 – 34.

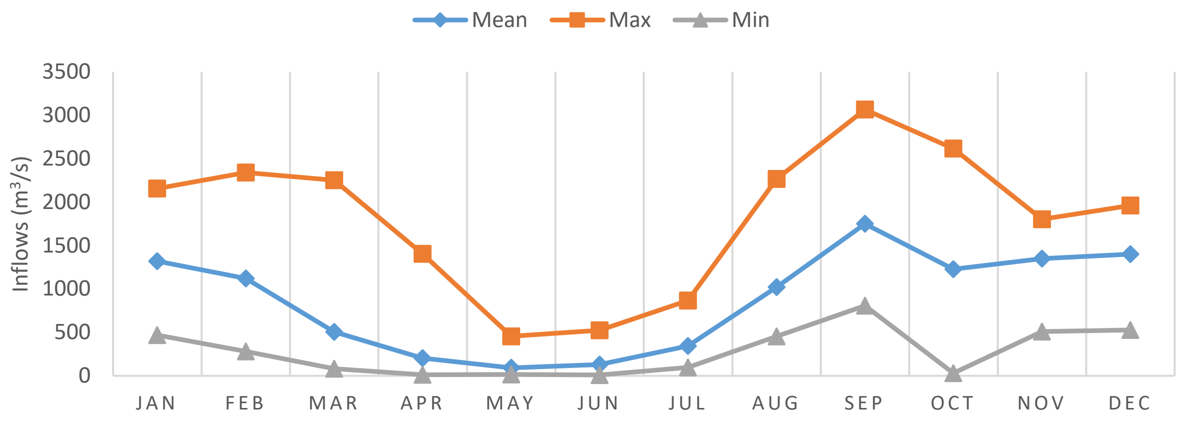



Figure 26: Inflows series (m$^3$/s) at the Kainji hydro-electric power dam. Data are average values for 21 years (1990-2010).

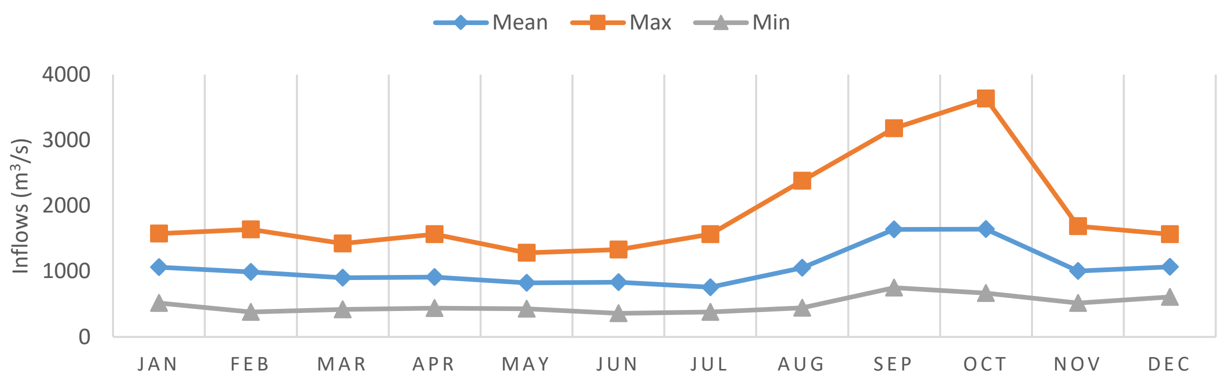



Figure 27: Inflows series (m$^3$/s) at the Jebba hydro-electric power dam. Data are average values for 21 years (1990-2010).

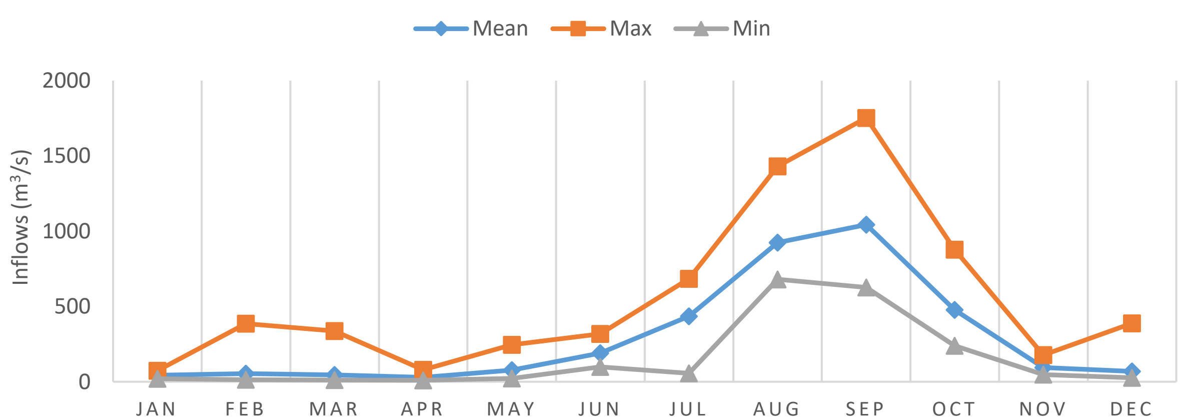



Figure 28: Inflows series (m$^3$/s) at the Shiroro hydro-electric power dam. Data are average values for 21 years (1990-2010).

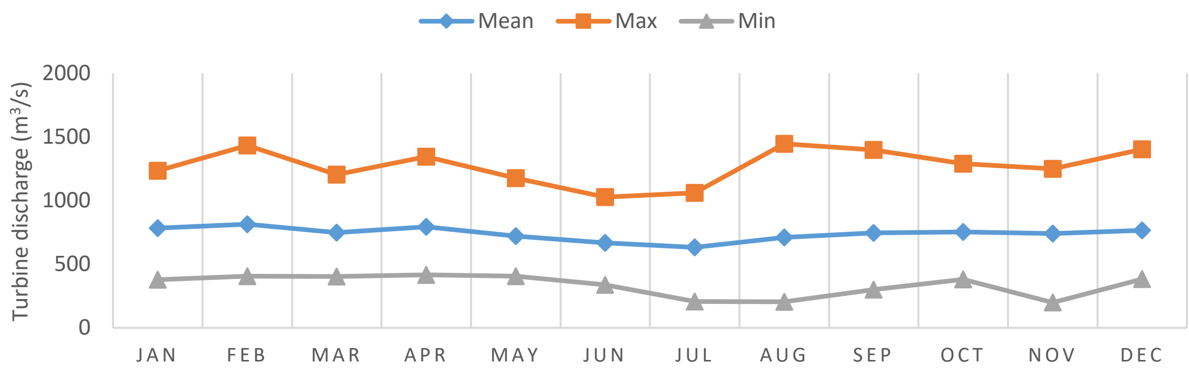



Figure 29: Turbine discharge data series (m3/s) at the Kainji hydro-electric power dam. Data are average values for 21 years (1990-2010).

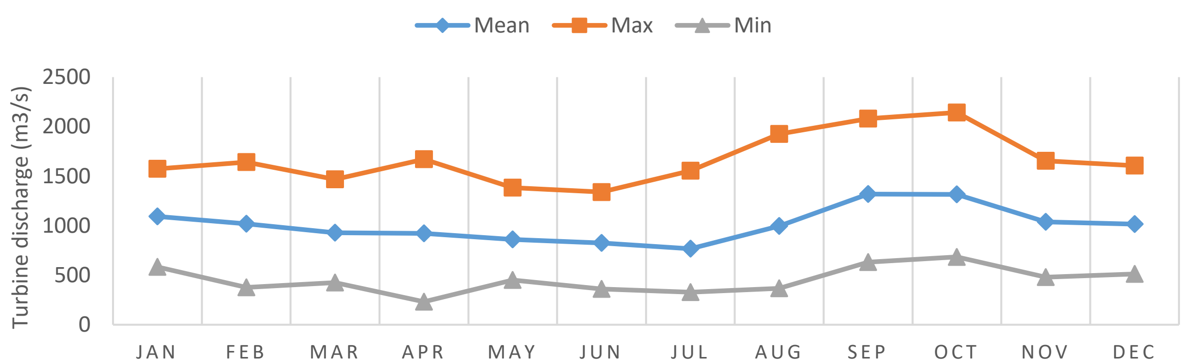



Figure 30: Turbine discharge data series (m3/s) at the Jebba hydro-electric power dam. Data are average values for 21 years (1990-2010).

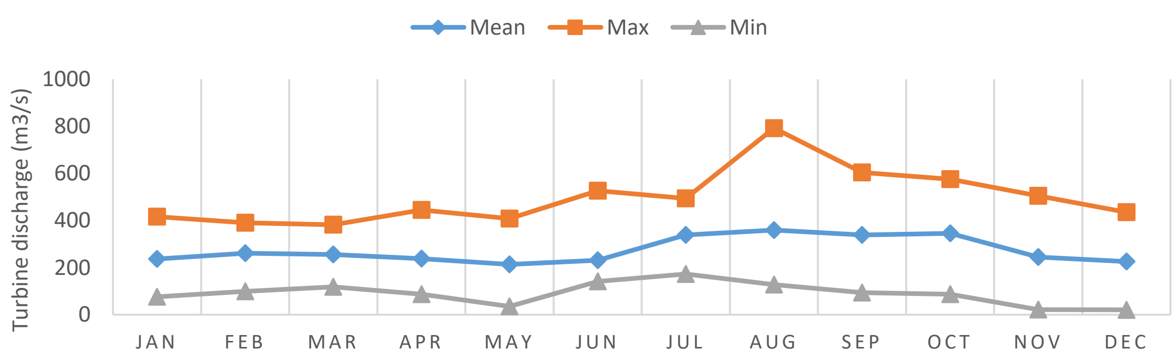



Figure 31: Turbine discharge data series (m3/s) at the Shiroro hydro-electric power dam. Data are average values for 21 years (1990-2010).

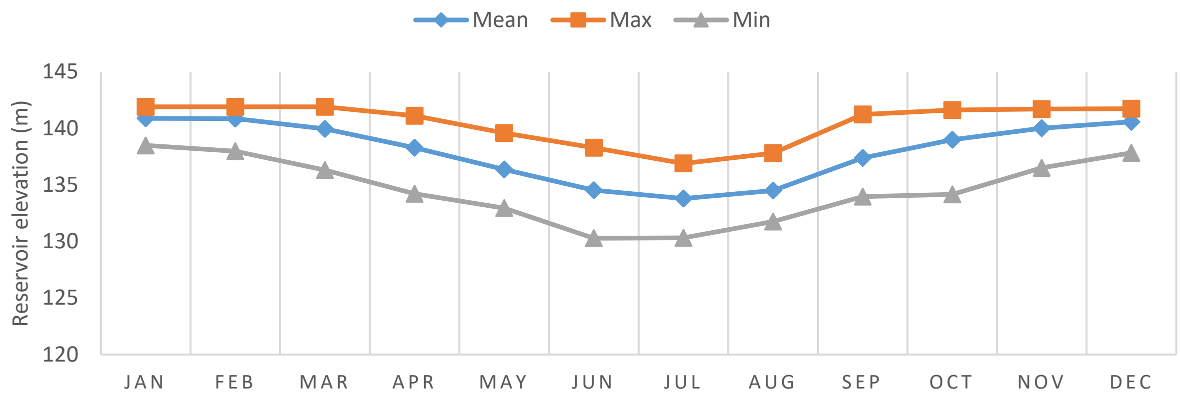



Figure 32: Reservoir elevation data series (m3/s) at the Kainji hydro-electric power dam. Data are average values for 21 years (1990-2010).

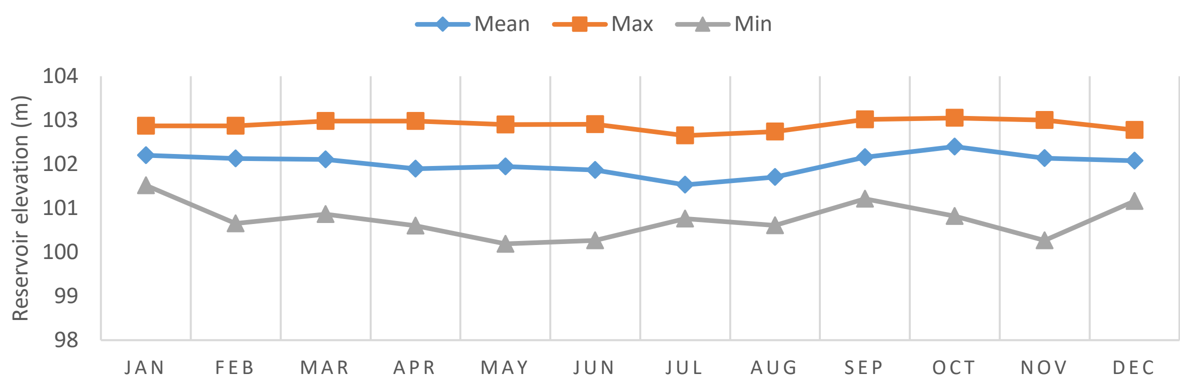



Figure 33: Reservoir elevation data series (m3/s) at the Jebba hydro-electric power dam. Data are average values for 21 years (1990-2010).

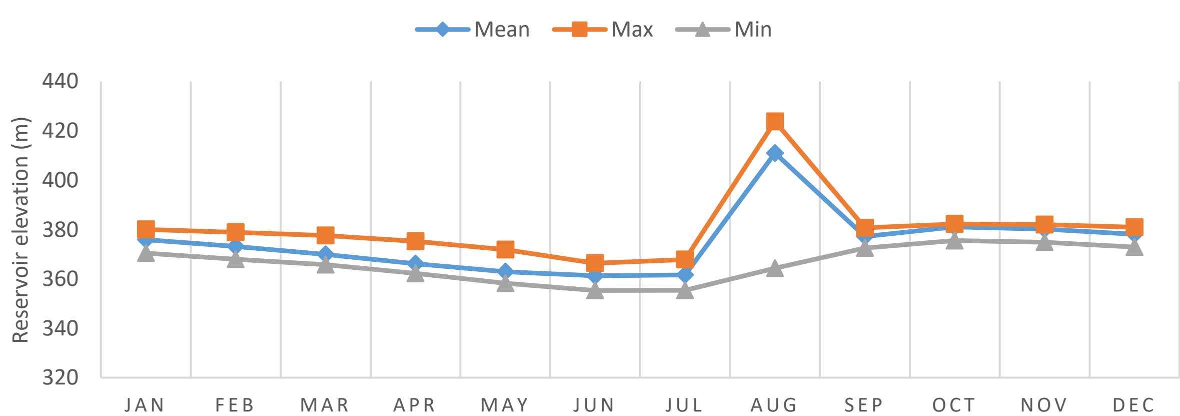



Figure 34: Reservoir elevation data series (m3/s) at the Shiroro hydro-electric power dam. Data are average values for 21 years (1990-2010).

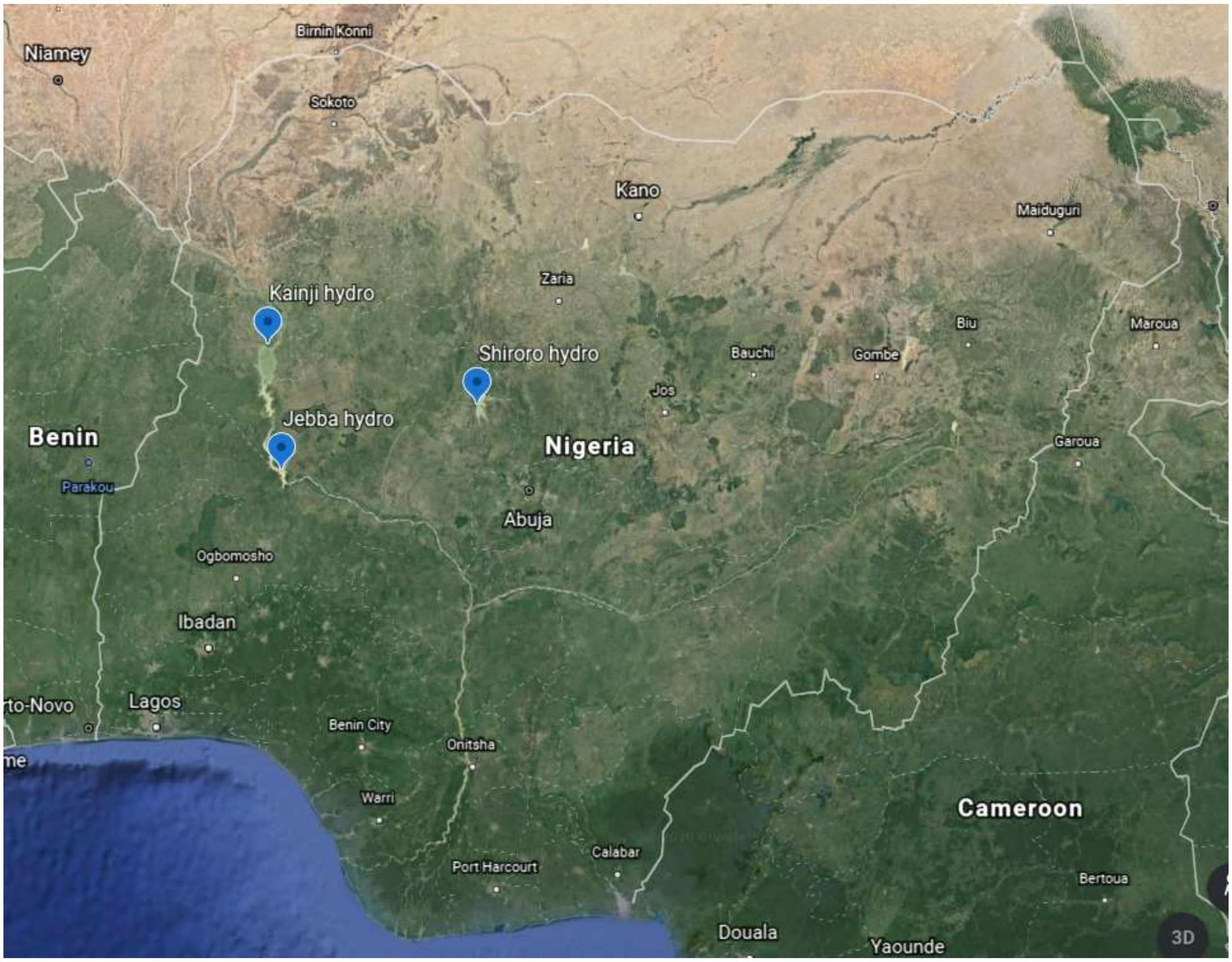



Figure 35: Map showing the location of the Kainji, Jebba, Shiroro hydropower in Nigeria (Source: [21])

## 4.2 Power Generation planning in Nigeria

As previously noted, Nigeria has a semi-liberalized power market. Its generation and distribution sectors have been conceded to the private sector – albeit, with strict regulations effected by the National Electricity Regulation Commission (NERC) – while the State manages the transmission sector of the industry. Power prices are regulated by NERC and are set at relative flat rates (based on supply type e.g. industry vs. residential). This places a barrier on the possibility of selling power at spot prices. Available power generation usually falls short of gross demand, although, limitations from poor transmission capacity contribute to the low power generation quota (i.e. gross power generated may not be transmitted, because, transmission lines are maxed out at 5 GW). There are currently no power import contracts from external sources, as such, grid failures results in rationing available power.

Power generation scheduling is usually done to optimize the utility of available power resources (i.e. satisfying power demand as much as possible while minimizing power production cost), given an expected demands. In Nigeria's case, the deficit in production, transmission, and distribution results in high economic cost, rationing costs, and $CO_2$ production (as PMS and AGO fueled generators form the majority of alternative power sources). Also, despite Nigeria's lower power generation and transmission capacities, Nigeria still sell export power contracts estimated at 2378 GWh/year to neighboring nations (Benin, Togo, Chad, and Niger).

Power generation falls in the drier seasons, which is caused by the depletion of hydropower resources (high temperature leading to evaporation loss, excessive heat results in increased power demand for cooling units, lower precipitation affects inflows, etc.) and peaks in the wet season (caused by high hydropower energy production, leading to a general rise in power generation). As a result, rationing is usually high in the drier season and low in the wet season.

## 4.3 Hydro power simulation in EMPS

### 4.3.1 Defining hydro power areas for EMPS

Modelling using EMPS requires specifying areas consisting of different hydropower modules. Usually, a geographical region on a national scale is modelled as an area with different hydropower modules. The interconnectedness of the different modules are defined as input parameters, implying that a water course can be deduced by studying the interconnectedness of the different modules. However, in this study, the Kainji, Jebba, and Shiroro hydro power systems are not regionally distinct.

Since EMPS modelling has an area assumption, an adaptation was made to meet this assumption. The Kainji and Jebba hydropower station are located on the same water course (inflows from river Niger, with Kainji located at the upstream of Jebba hydropower station), and were grouped as modules under an area labelled "Area 1", while Shiroro was the only module located in "Area 2". As such, based on this adaptation, the modules correspond to the EMPS assumption that the hydropower plants are located within a specific area.

Also, EMPS requires each module to be defined as regulated or unregulated hydropower (i.e. modules with a reservoir are regulated plants, while those without a plant are unregulated). In this study, all modules were modelled as regulated hydropower since they existed as single unit (i.e. power plants are coupled to individual reservoirs).

### 4.3.2 Defining EMPS inputs

As stated earlier, EMPS requires some inputs related to plant (water course and power production potential), firm obligations and market data to function. This following sub-sections outlines the different input data entered into the EMPS program.

### 4.3.3 Load Profile

In this study, load factors were specified, based on the differences in the volume of power for the day and the week. Load profile for business days are grouped, because, they are characterized by routine activities assumed to be relatively stable. Non-business days – weekends – were also grouped. In total, there were 7 load profiles, 4 for the weekdays and 3 for the weekend (See Table 5).

Table 6: Load hours profile for al days of the week. Hours with the same load profile have the same shading

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mon | | | | | | | | | | | | | | | | | | | | | | | | |
| Tue | | | | | | | | | | | | | | | | | | | | | | | | |
| Wed | | | **1** | | | | **2** | | | | | | **3** | | | | | | | | **4** | | | |
| Thu | | | | | | | | | | | | | | | | | | | | | | | | |
| Fri | | | | | | | | | | | | | | | | | | | | | | | | |
| Sat | | | **5** | | | | | | | | | | **6** | | | | | | | | **7** | | | |
| Sun | | | | | | | | | | | | | | | | | | | | | | | | |

### 4.3.4 Plant Data

Plant data was sourced from the hydrological station of Kainji, Jebba, and Shiroro dam areas. Not all required datasets were available, as such, some extrapolations had to be made. Data entered into the EMPS program, and fitted constraints are presented in Appendix I. It is noteworthy to point out that for some scenarios, certain input values were scaled differently to meet scenario assumptions.

### 4.3.5 Market Data

As explained earlier, the Nigerian power market is semi-liberalized, as such, there is no defined power price market. Prices are set at relative flat rates, based on the type of contractual obligation and power production type. Thus, price only varies if it is sold for industry or general power consumption (see Table 6). Fixed price per consumption profile makes a price forecast implausible.

Table 7: Power consumption price profile

| | Consumption | |
|---|---|---|
| Average Price | General (₦/KWh) | Industry (₦/KWh) |
| 28.58 | 19.69 | 37.46 |

### 4.3.6 Contractual obligation

Firm power demand (based on proportional allocation to hydropower) was grouped per area based on 2019 estimates. Total firm power demand was pegged at 7222.34 GWh/year split into 2299.989, 2693.74, and 2228.611 GWh/year for Kainji, Jebba, and Shiroro dam respectively. Monthly firm power production (GWh) and relative firm power demand values are presented in Figure 35 and Table 7 respectively.

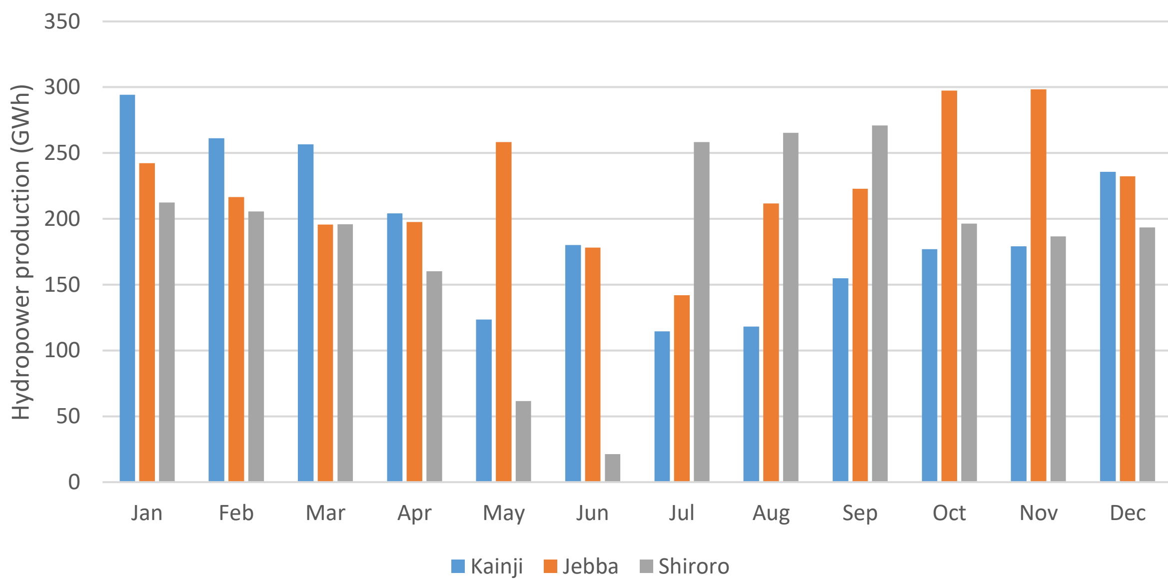



Figure 36: Monthly firm power production for Kainji, Jebba, and Shiroro hydropower plants. Values presented are 2019 estimates.

Table 8: Relative monthly firm power demand values

| Months | Kainji | Jebba | Shiroro |
|---|---|---|---|
| Jan | 1.53 | 1.08 | 1.14 |
| Feb | 1.36 | 0.96 | 1.11 |
| Mar | 1.34 | 0.87 | 1.05 |
| Apr | 1.07 | 0.88 | 0.86 |
| May | 0.65 | 1.15 | 0.33 |
| Jun | 0.94 | 0.79 | 0.12 |
| Jul | 0.60 | 0.63 | 1.39 |
| Aug | 0.62 | 0.94 | 1.43 |
| Sep | 0.81 | 0.99 | 1.46 |
| Oct | 0.92 | 1.32 | 1.06 |
| Nov | 0.93 | 1.33 | 1.01 |
| Dec | 1.23 | 1.04 | 1.04 |

### 4.3.7 Import

As stated earlier, since there is no particular spot market in Nigeria, additional power in case of deficit power production are offset by power produced from neighbor areas. Although, the neighbor areas are part of the total system, in EMPS, power offset from neighbor areas are considered 'imports'. Import power price are set by the area where power is imported from. The volume of 'imports' varies based on the current power production level, given the firm power demand.

### 4.3.8 Export

Excessive power production gives rise to power exports, especially in periods when power demands are low. As previously mentioned, Nigeria exports power to some of its neighboring countries. Although such exports aren't necessarily based on power surplus – as they are calculated as part of the total power demand, however, this study would consider such as power 'exports'. Of total power production, Nigeria exports 2378 GWh/year to neighboring countries. While the obligation to the export is tied to the whole system, in this study, a fraction of the export sale would be considered. Export power volume and price would be determined based on model calibration.

### 4.3.9 Rationing costs

Rationing in Nigeria is done to prioritize certain areas and sectors whose functioning may be quintessential or are of high value. Rationing also occurs in a bid to increase marginal revenue, as higher power rationing implies a higher load profile, and a consequential higher cost (price/KWh). Industries are usually placed on higher power rationing profile, with the opportunity cost being the higher price volume paid per KWh purchased.

### 4.3.10 Additional power

Power generation from hydropower is highly variable – due to differences in hydrological reference at the time of the year – and additional power have to be sourced from non-hydropower sources in order to balance power needs. Thermal power is the major non-hydroelectric power source, although, power generated from thermal power plants are much more expensive than power generated from hydropower, owing to the relative cost of gas purchase and high running cost. Power prices from thermal plants is presented in Table 8.

Table 9: Power consumption price profile

| | Consumption | |
|---|---|---|
| Average Price | General (₦/KWh) | Industry (₦/KWh) |
| 38.40 | 27.41 | 49.39 |

## 4.4 Case Analysis

### 4.4.1 CASE I

The first objective of this study seek to, "Use EMPS to analyze the performance of three large hydropower plants in the Nigeria Power market." This objective would be addressed in this section by means of a test simulation with EMPS.

#### 4.4.1.1 Model overview: Test simulation (case I)

A test simulation was conducted to see how EMPS handles total power production during dry and wet years. To conduct this simulation, the following assumptions were made:

- The hydropower from area 1 has power generation capacity of 609 MW (360 MW from Kainji and 249 MW from Jebba) and area 2 has a power generation capacity of 443 MW based on TCN 2017 report [22].
- The areas aren't connected, as such, there is not export or import of power between areas. This was done to estimate the volume of a 'power without market' scenario.
- The areas operated under similar electricity pricing regimes (cost of production and supply), using TCN (2017) annual report [22] electricity pricing templates.
- Additional power are supplied other power sources at a capacity of 200 MW supplied by thermal production plants.
- Total firm power demand was 5221.931 GWh split across the two areas (based on TCN 2017 annual report).
- Firm power production is curtailed at a cost of ₦ 80/KWh (based on TCN 2017 annual report [22]).
- Excessive power produced in an area can be sold off as interruptible power supply

The assumptions are summarized in Table 9 below

Table 10: Assumptions for test simulations

| | Area 1 | Area 2 |
|---|---|---|
| **Hydropower generation (MW)** | 609 | 443 |
| | | |
| **Firm power demand** | 3993.32 | 1228.611 |
| General Demand (70 %) | 2495.119 | 560.03 |
| Industry Supply (30 %) | 1498.20 | 668.58 |
| **Pricing template** | | |
| General demand (₦/KWh) | 19.69 | 19.69 |
| Industry (₦/KWh) | 37.46 | 37.46 |
| Curtailment (₦/KWh) | 80 | 80 |
| | | |
| **Additional power supply (MW)** | 200 | 200 |
| **Additional power supply prices (₦/KWh)** | 11 | 11 |
| | | |
| **Excess power exports (MW)** | 100 | 100 |

#### 4.4.1.2 Model results: Test simulation

**Overview**

The assumptions for the test simulation was tested on two reliabilities (dry and wet years using 0 and 100 % percentiles respectively). A summary of the obtained results are presented in Table 10. The result shows only variations in the volume of power produced in the dry and wet years, although, the deviations seem fairly marginal. Model results showed optimal use of hydro generated electrical power in ‘Area 1’, and an optimal use of thermal generated power in ‘Area 2’. Simulation for both areas resulted in significant power surplus i.e. power production without available demand. Although, this is very much expected considering that lower transmission capabilities reduce the volume of generated power that can be consumed, it is therefore logical to assume the model outputs are close to real scenarios. Further explanation for some of the other important outputs (inflows, reservoir levels, and volume of hydropower produced) are explained in the following section on an Area basis. Also, the share percentage of electricity production (hydro vs. thermal), volume of power produced by each hydropower module, and simulated reservoir levels are shown in Figures 36, 37, and 38.

Table 11: Results obtained from test simulation

| | Area 1 | | Area 2 | |
|---|---|---|---|---|
| Power production variables (GWh) | Dry | Wet | Dry | Wet |
| Inflow | 2000.7 | 2350.8 | 1165.3 | 1657.7 |
| Hydropower production | 3124.8 | 3127.9 | 1103.3 | 1273.4 |
| Firm power demand | 3993.3 | 3993.3 | 2228.6 | 2228.6 |
| Curtailed | 112.7 | 96.4 | 213.2 | 179.8 |
| **Additional power** | | | | |
| Interruptible purchase | 854 | 865.2 | 1168.9 | 1168.9 |
| Interruptible sale | 90.4 | 94.5 | 0 | 0 |
| **Exchange** | | | | |
| Import power exchange | 7 | 8.9 | 4.2 | 8.7 |
| Export power exchange | 0.2 | 7.7 | 8.8 | 5.2 |
| Transmission exchange Loss | 0.5 | 1.3 | 1 | 1.1 |
| Net exchange | 6.9 | 1.2 | -4.6 | 3.5 |
| Power surplus | 0.8 | 1.3 | 311.7 | 389.9 |

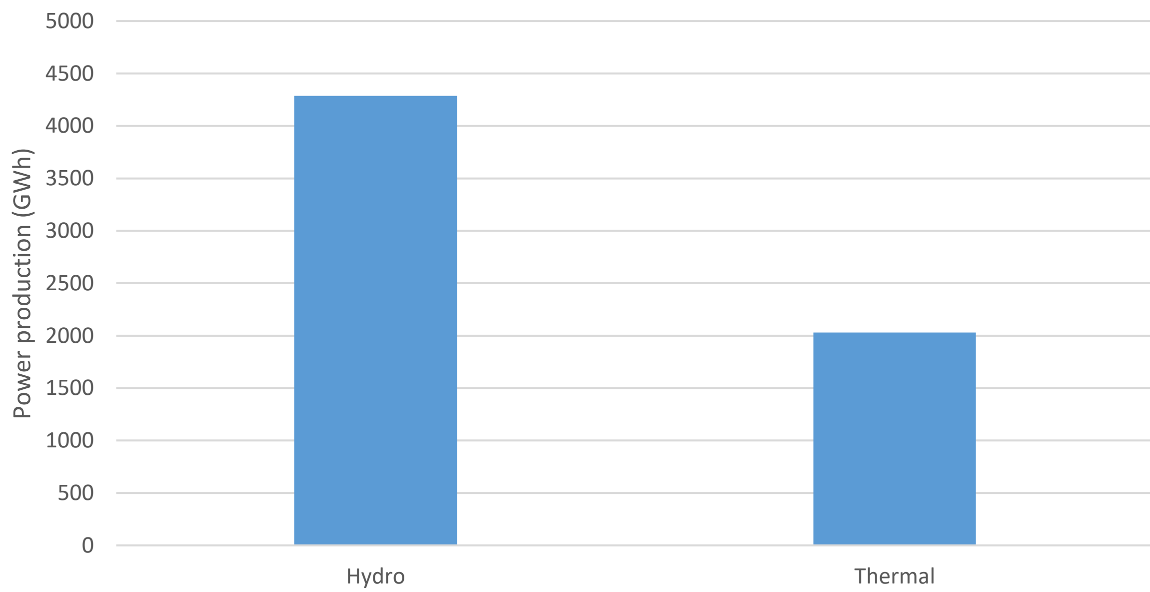



Figure 37: EMPS simulated annual power generation (GWh) for thermal and hydro power production.

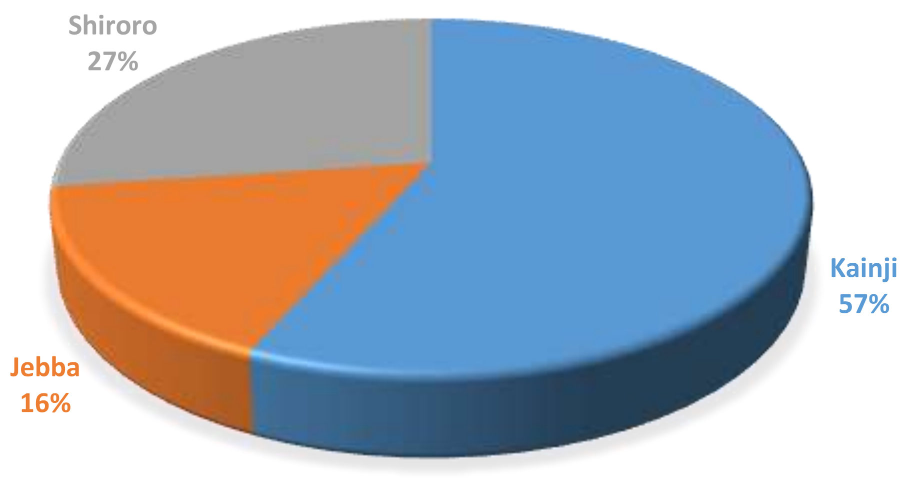



Figure 38: EMPS simulated hydropower electricity share generation (%)

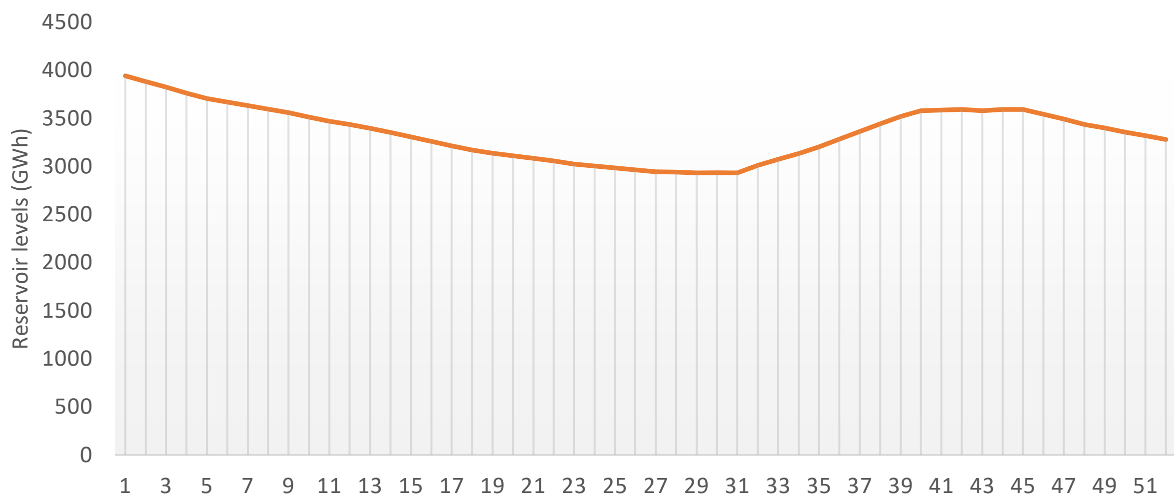



Figure 39: EMPS simulated annual reservoir levels (GWh) for all three hydropower stations.

### 4.4.1.3 Results: Area 1

**Energy Inflows**

Figure 39 presents energy inflows series for the first year of simulation (2020). The presented percentiles shows that there is perhaps, less variability in weather scenarios as the trend in variations for the reliabilities follow the same trend. The series shows a rise in energy inflows in May which peaks in August and declines steadily thereafter. It is expected that this variation would reflect in hydropower generation. The behaviour of the series also suggests that the utilizing the water in the reservoirs as much as possible before the rise that starts in May would prepare the reservoir for more water capacity storage.

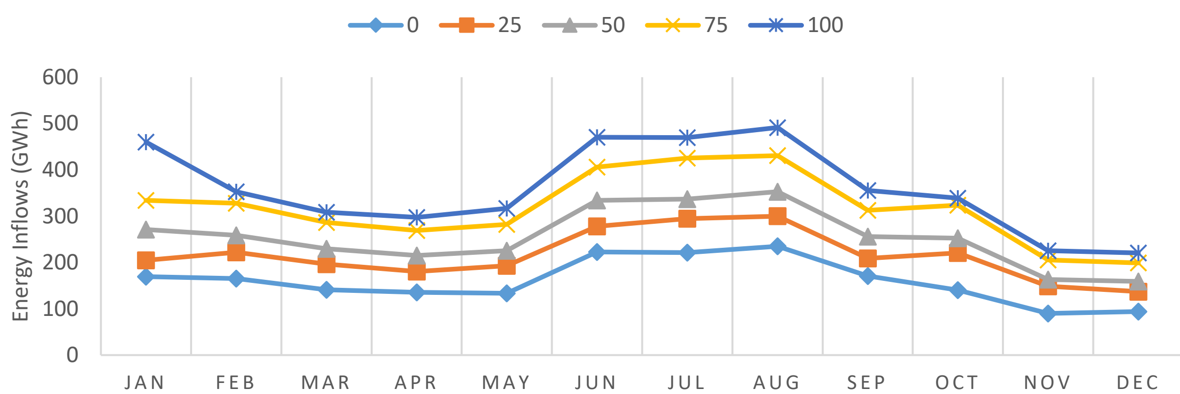



Figure 40: EMPS simulated annual energy inflows scenario for 'Area 1' at different level of reliabilities

**Hydropower Production**

Figure 40 presents the EMPS simulated results for hydropower production in 'Area 1'. As expected, the trend in hydropower production mirrors the trend of the energy inflows. Although, the volume of hydropower production seems less affected by weather scenarios as all level of reliabilities follow the same trend. The trend suggests that given the differences in energy inflows, expected hydropower production is met at the different level of reliabilities. Thus, hydropower curtailment may still result in expected output. This result would have severe implications for water rationing in a spot market scenario.

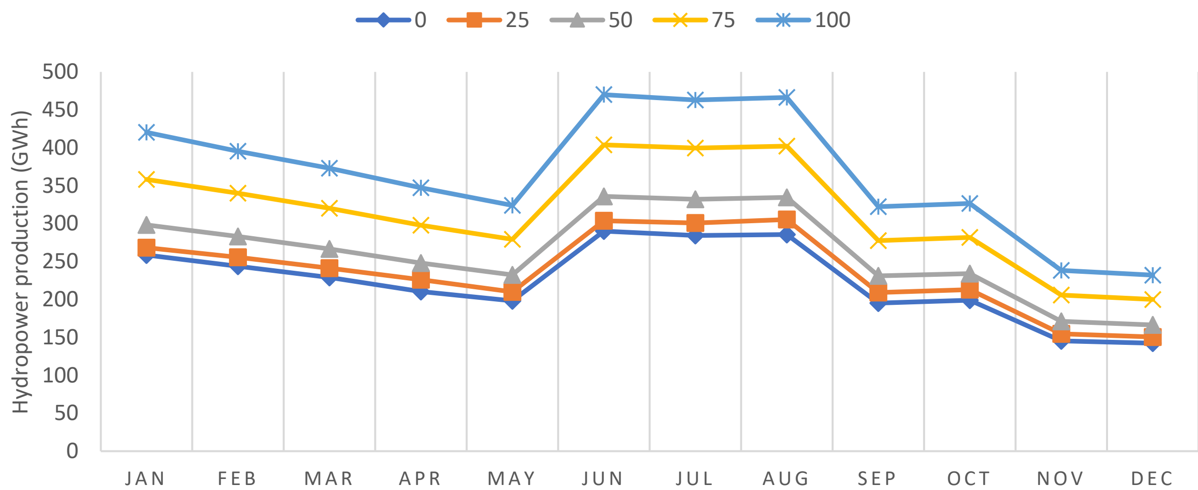



Figure 41: EMPS simulated hydropower production for ‘Area 1’ at different level of reliabilities

**Reservoir content**

The trend in reservoir content (results from EMPS simulation) is shown in Figure 41. Data trend shows that the content of the reservoir is very high at the beginning of the year, which declines in a linear fashion for the rest of the year. Just like the data from hydropower production, the levels of reliabilities follow similar trend. The trend suggest a low energy inflows to discharge ratio, highlighting the likelihood that reservoir usage is not optimized and could likely leads to an empty reservoir scenario.

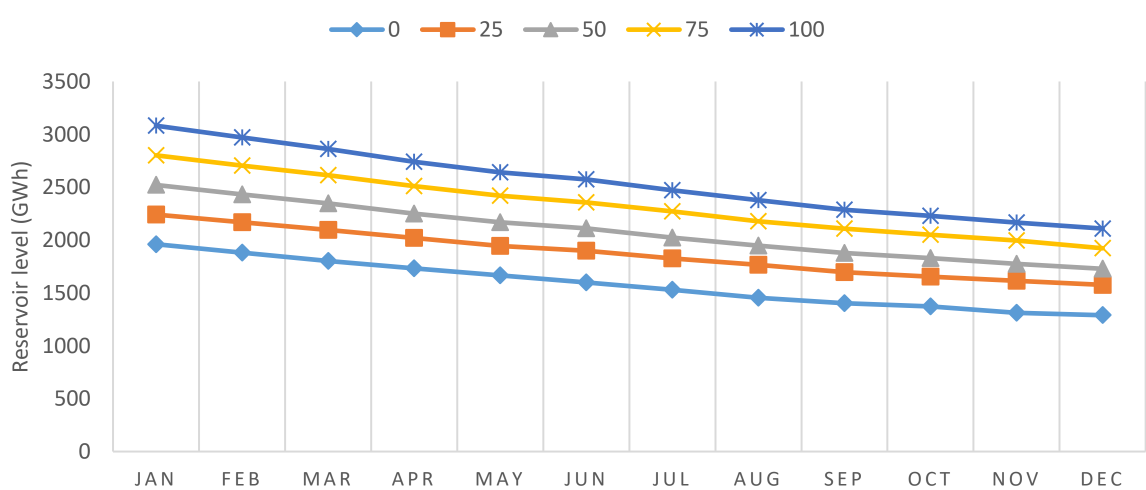



Figure 42: EMPS simulated reservoir level for ‘Area 1’ at different level of reliabilities

#### 4.4.1.4 Results: Area 2

**Energy Inflows**

Energy inflows for ‘Area 2’ is presented in Figure 42. The data trend starts off with negative trend values, suggesting that the energy inflows in ‘Area 2’ is significantly affected by dry season weather conditions, perhaps halting energy inflows into the reservoir at the start of the year. Inflows rise in June, and peak at August, following which there is a steady decline in the volume of energy inflows. The differences in the level of reliabilities is seen during the peak inflow period – which coincidentally corresponds with the wet season, suggesting that the volume of energy inflows is significantly affected by weather scenarios, and that reservoir filling would likely be affected.

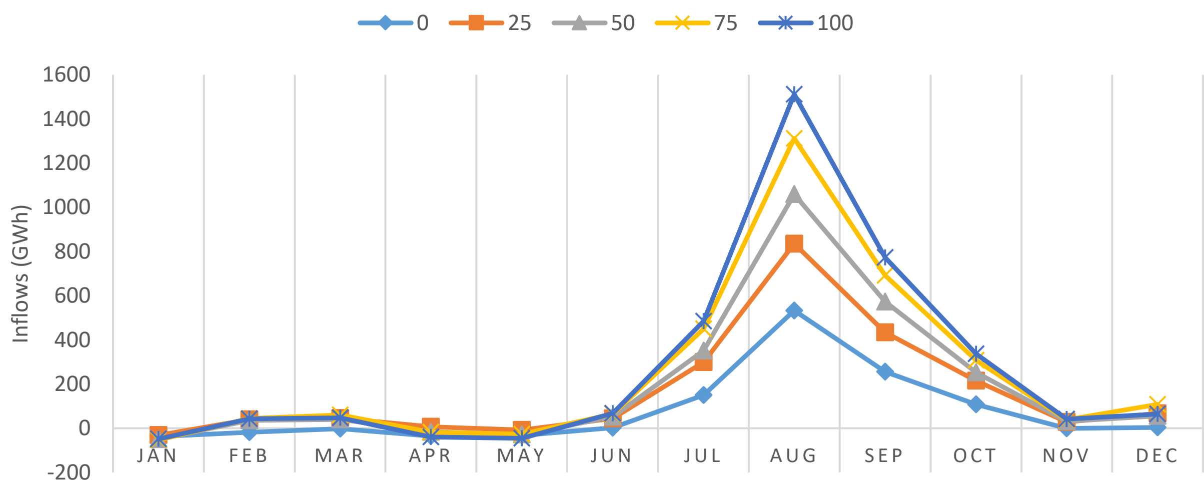



Figure 43: EMPS simulated inflows scenario for ‘Area 2’ at different level of reliabilities

**Hydropower production**

The simulated volume hydropower production is presented in Figure 43. The data series does not mirror trend observed for the energy inflows. The data starts off with a downward linear trend running from January till May, suggesting reservoir depletion may have led to a decline in the volume of power produced in the first quarter of the year. The volume of hydropower production rises at the end of May with two peak periods (August and October). Just as with the energy inflows, increase in hydropower production occurs during the wet season months, and declines as the dry season commences at the end of October.

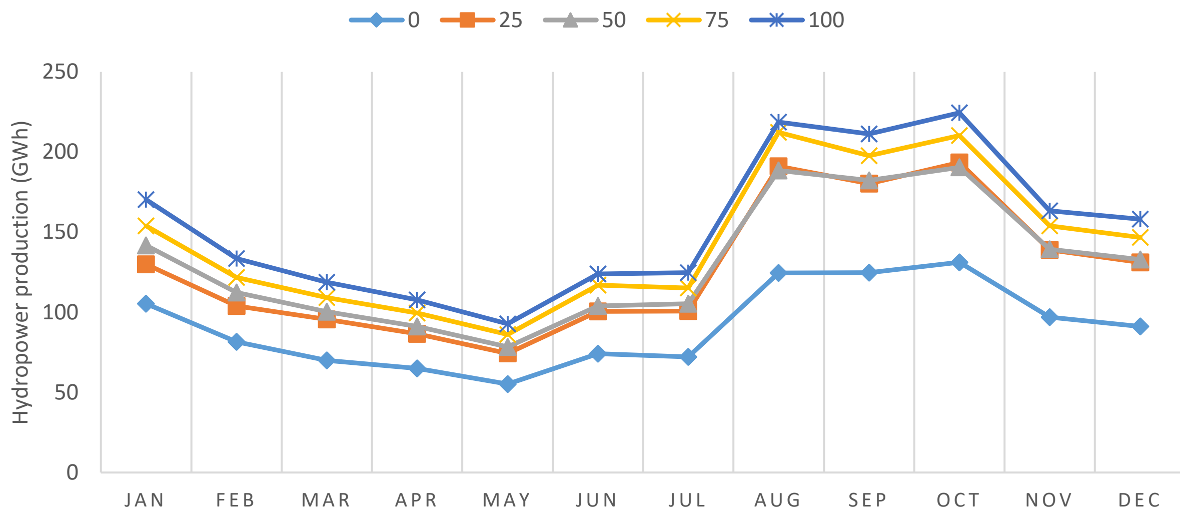



Figure 44: EMPS simulated hydropower production for ‘Area 2’ at different level of reliabilities

**Reservoir content**

The simulated reservoir levels from EMPS modelling is presented in in Figure 44. The contents of the reservoir mirrors the volume of hydropower produced, albeit, with slight changes. The data series also starts in a declining trend starting from January, with the lowest point observed in July, followed by a rise which peaks in October and declines – marginally – thereafter. The data also shows that the content of the reservoir is affected by the season of the year. The period of filling represents the wet season, and the start of depletion after filling – which starts in November – represents the dry season.

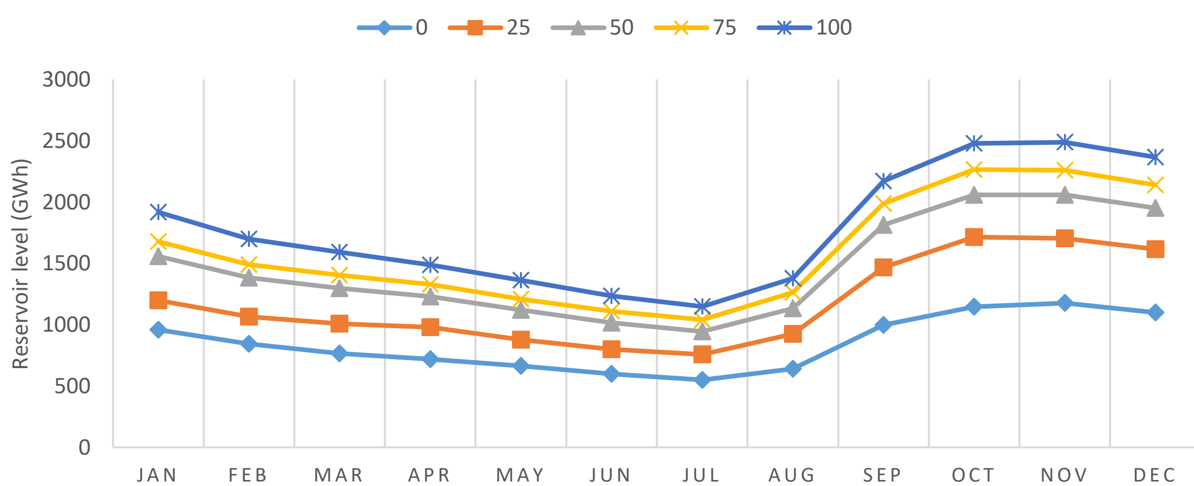



Figure 45: EMPS simulated reservoir level scenario for ‘Area 2’ at different level of reliabilities

### 4.4.1.5 Model Validation

This validation of the model for the simulated areas is presented in this section. Model validation is conducted by comparing simulated trends with real scenario statistics. The volume of simulated hydropower production in 2019 is compared with the simulated results. Only the 0 % and 100 % reliabilities are considered during validation.

**Area 1**

Figure 4.11 presents validation for results gotten from 'Area 1' which houses the Kainji and Jebba hydropower modules. The model shows significant deviations between the actual data and the modelled data. Save for the month of July where modelled data showed higher hydropower production than actual data, EMPS assigned lower hydropower production in the other months. It is possible to see that the trend in real power production for the first 6 months was followed by the EMPS, but trend afterwards were at variance. The results indicate that the model has a tendency to allocate lower hydropower production in a bid to optimize the volume of power produced while reducing wastage. Also, the model tends to scale down the volume of power produced in the dry months and upscale the volume of power produced in the wet months. Overall, the model curtails power based on seasonal differences than real scenarios which produces higher power volumes in the drier months – perhaps due to higher power prices during said periods.

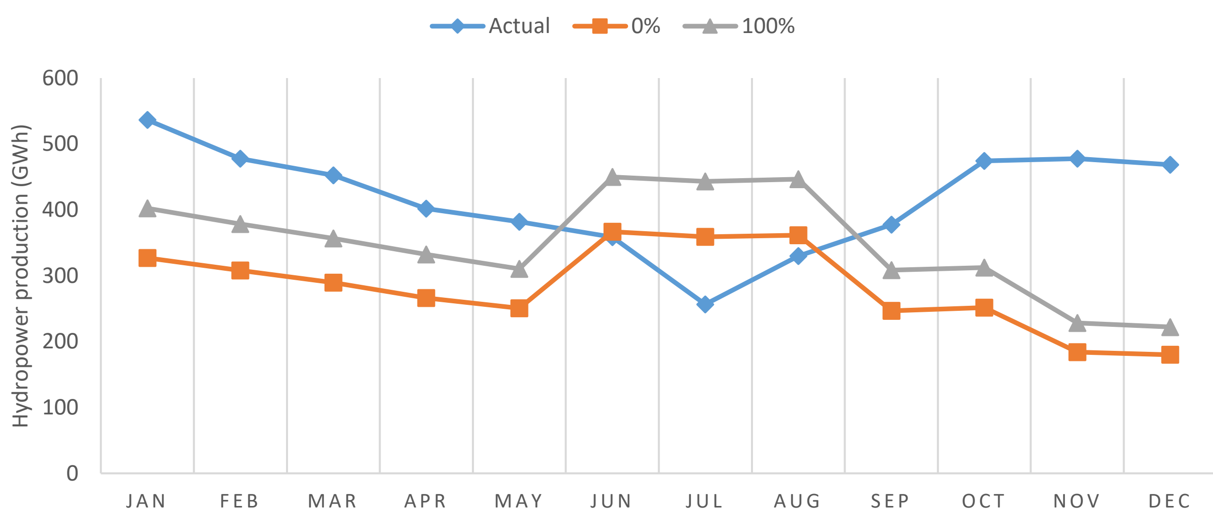



Figure 46: Combined hydropower production for Kainji and Jebba hydropower (Area 1 modules). Values are 2019 estimates drawn from TCN reports compared with model results from the EMPS at 0 and 100 % reliabilities.

**Area 2**

The hydropower production validation of simulated results for 'Area 2' is shown in Figure 46. The model closely follows the pattern of the real data, albeit, with lower volume of power allocation per month and a deviation in the month of July where the modelled power production is higher than real power production. The hypothesis that EMPS optimizes hydropower production also applies here, although, it cannot be asserted if optimization would profit as that is beyond the scope of this study. Overall, the model seems very conservative in terms of hydropower production.

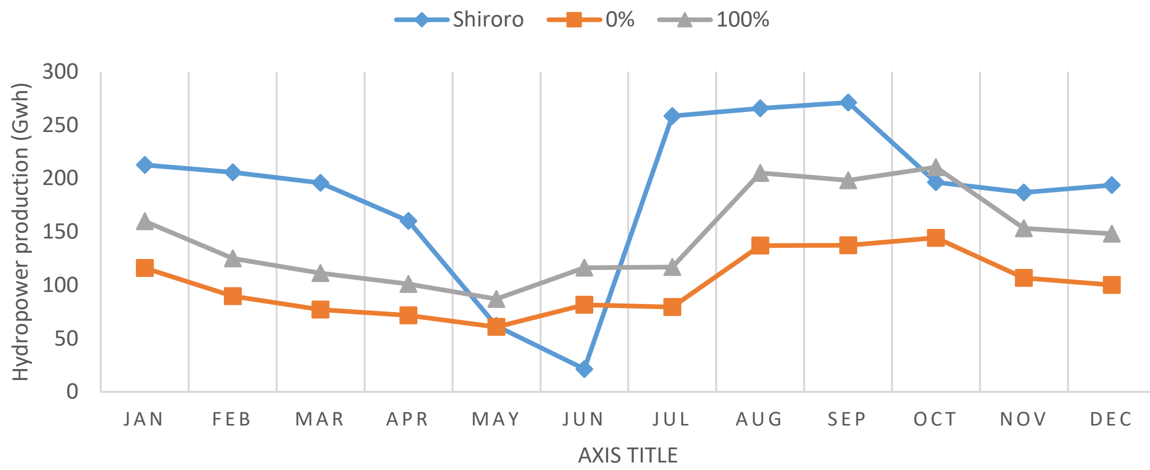



Figure 47: Combined hydropower production for Kainji and Jebba hydropower (Area 2 modules). Values are 2019 estimates drawn from TCN reports compared with model results from the EMPS at 0 and 100 % reliabilities.

### 4.4.2 CASE II

The second objective of this study seeks to, "Make findings, investigate and suggest how the future role of Independent hydropower producers could be shaped in Nigeria." This objective would be addressed in this section.

**Overview**

Future scenarios in Nigeria would likely see an improvement in its power potential, even as some projects are currently 'in progress' to address Nigeria's current and future energy needs. However, the strategy for expansion must be properly modeled to determine how to best optimize Nigeria's power expansion scheme. In the foreseeable future, Nigeria is expected to make a couple of changes to its current policy framework that limits the vertical and horizontal scaling of its power market. Some of the expected changes to Nigeria's policy framework based on KPMG's recommendation [23] are:

1. Increase investment inflows into the Nigerian power industry by making the sector more attractive for firms and individuals to enter and compete in through:
    a. Conduct a robust auditing of the power sector to determine critical investment and where possible adjustments have to be made.
    b. Increase capital allocation to TCN, including upgrading and expanding the current grid capacity transmission lines network for improved power transmission.
    c. Privatize TCN

2. Review the current policy framework and plug leaks that limits the 'gas-to-power' value chain through:
    a. Implementing a control mechanism that improved gas supplies to thermal plants.
    b. Enforce penalties for payment defaulters

3. Power generation expansion through renewable energy sources while reducing $CO_2$ emissions as old thermal plants are phased out through:
    a. The completion of ongoing independent solar power and hydropower projects
    b. Heavy investments in grid infrastructure
    c. Deregulate the system by allowing the integration of mini-grids to supply power at spot prices and to undeserved areas.

4. Invest in research to study consumer's energy demands, capacity, and consumption through a data driven process that would ultimately curb excessive losses in the power system.

It is noteworthy to point out that changes to Nigeria's policy framework expands beyond this, however, for context purpose, this section would exploit the following clauses in the proposed policy framework adjustment:

**Increase capital allocation to TCN, including upgrading and expanding the current grid capacity transmission lines network for improved power transmission**: This implies that power generation would not be hindered by limited transmission power capacity and won't have to be curtailed. For instance, 'Gurara I' is a completed hydropower plant but hasn't generated any electricity, because, there are no power transmission capabilities.

**Privatize TCN**: Privatizing the power transmission sub-sector is expected to yield significant benefits, one of which includes: edging closer to a fully liberal power market, increased transmission capacity, and better maintenance under for-profit schemes.

**The completion of ongoing independent solar power and hydropower projects**: Expected to increase the share percentage of non-fuel based resources, thereby cutting $CO_2$ emissions and reducing the share cost of power production (renewable energy sources are expensive on the short term, but cheap on the long term).

**Deregulate the system by allowing the integration of mini-grids to supply power at spot prices and to undeserved areas**: This would allow the introduction of new players into the power market and more efficient distribution of electricity at a mega, mini, and micro scale.

#### 4.4.2.1 New hydropower scenario: test simulation

In the following sections, the introduction of the currently ongoing hydropower would be considered and how they would affect production of the existing system, as well as possible power scenarios with an optimized grid system.

The scenario would be modelled in EMPS using the assumptions outlined below:

- The new hydropower plants (see Table 4.7) are added to the existing unit, although, they are modelled as power imported from other sources.
- The areas are connected, as such, export or import of power between areas is allowed. ‘Power without market’ scenario would also be analyzed.
- Effective transmission between Areas is allowed at a maximum capacity of 1 GW between areas, and an efficiency loss of 1 %.
- The areas operate under similar electricity pricing regimes (cost of production and supply)
- Additional power are supplied by other power sources are at a reduced capacity of 50 MW.
- An increase in power consumption is expected with the addition of the new hydro power modules.
- Power consumption from auxiliary gas powered personal generators are expected to be added to total grid power consumption, bring total grid electricity to be twice the initial volume i.e. 5221.931 GWh × 2 = 10443.862 split across the two areas based on previous percentiles.
- Power production are curtailed at a cost of ₦ 60/KWh to reduce excessive power supply.
- Excessive power produced in an area can be sold off as interruptible power supply

The assumptions are summarized in Table 4.8 below

**Table 4.7: Completed and ongoing construction of new hydro power plants in Nigeria**

| Name | Status | Capacity (MW) | Location |
|---|---|---|---|
| Mambilla | Under construction | 3,050 | Taraba State |
| Zungeru | Under construction | 700 | Niger State |
| Gurara I | Constructed but no generation | 30 | Niger State |
| Gurara II | Under construction | 360 | Kaduna State |
| Zamfara | Under construction | 100 | Zamfara State |
| Kano | Under construction | 100 | Kano State |
| Kiri | Under construction | 35 | Adamawa State |

**Table 4.8: Assumptions for test simulations (case II)**

| | Area 1 | Area 2 |
|---|---|---|
| **Hydropower generation (MW)** | 609 | 443 |
| **New Hydropower additions (MW)** | | |
| Mambilla | 3,050 | |
| Zungeru | | 700 |
| Gurara I | | 30 |
| Gurara II | | 360 |
| Zamfara | | 100 |
| Kano | | 100 |
| Kiri | | 35 |
| **Total power supply** | 3659 | 1768 |
| **Firm power demand** | 7986.64 | 2457.22 |
| General Demand (70 %) | 5590.65 | 1720.06 |
| Industry Supply (30 %) | 2395.99 | 737.17 |
| **Pricing template** | | |
| General demand (₦/KWh) | 19.69 | 19.69 |
| Industry (₦/KWh) | 37.46 | 37.46 |
| Curtailment (₦/KWh) | 60 | 60 |
| **Additional power supply (MW)** | 50 | 50 |
| **Additional power supply prices (₦/KWh)** | 11 | 11 |
| **Excess power exports (MW)** | 500 | 500 |

### 4.4.2.2 Model results: Case II

**Overview**

The assumptions for the simulation – case II – was also tested on two reliabilities (dry and wet years using 0 and 100 % percentiles respectively). A summary of the obtained results are presented in Table 4.9. The differences between the energy inflow series mirrors results obtained in Case I, suggesting that there are no extreme wet or dry years. The model suggests that a more efficient power production and transmission profile would lead to an overproduction of power. Even with power demand scaled twice the value in case I (although the volume of firm power demand is expected to be way higher than utilized , the addition of significant hydropower resources, coupled with an efficient transmission line between areas resulted in the overproduction of hydropower resources, suggesting highly likely 'power without market scenarios'. The over production of power did not allow for curtailment of firm power demands. Also, there were significant power volume exchange between areas (high import of power volume – > 4000 GWh – from Area 1 to Area 2), implying that power stations can choose to purchase power from other producers if production at that time does not optimize the content of their reservoirs. Although, in this scenario, this resulted in excessive power production of > 7000 GWh in Area 2. Overall, the data suggests that full liberalization of the power market and the introduction of independent power producers would allow for better optimization and delivery of power as opposed to the currently implemented system. Also, it is expected that emission losses would be significantly reduced, given an expected reduced power production from thermal plants and auxiliary sources.

**Table 4.9: Results obtained from test simulation**

| | Area 1 | | Area 2 | |
|---|---|---|---|---|
| Power production variables (GWh) | Dry | Wet | Dry | Wet |
| Inflow | 2172.6 | 2513.8 | 1199.6 | 1705.7 |
| Hydropower production | 3340.0 | 3334.2 | 1305.6 | 1485.7 |
| Firm power demand | 7986.6 | 7986.6 | 2457.2 | 2457.2 |
| Curtailed | 160.3 | 160.3 | 0.0 | 0.0 |
| **Additional power** | | | | |
| Interruptible purchase | 436.8 | 436.8 | 12744.1 | 12744.1 |
| Interruptible sale | 0 | 0 | 0.0 | 0.0 |
| **Exchange** | | | | |
| Import power exchange | 0.0 | 0.0 | 4378.8 | 4369.7 |
| Export power exchange | 2274.1 | 2274.1 | 0.0 | 0.0 |
| Transmission exchange Loss | 181.7 | 181.7 | 324.0 | 323.4 |
| Net exchange | -2274.1 | -2274.1 | 4378.8 | 4369.7 |
| Power surplus | 240.6 | 240.6 | 7213.6 | 7402.9 |

**4.4.2.3 Cross Analysis**

**Volume of Hydropower production**

Figure 4.13 presents simulated results comparing the volume of power produced in cases I and II. As can be seen, hydropower production was higher in case I than in case II, possibly due to the difference in available power vs. demanded power. In essence, the ratio of demand/supply is higher in case I than it is in case II. As such, in case II, there is less pressure on the power plants to produce such that better power scheduling can be done. Although, the presence of independent power producers also implies competition for the available demand.

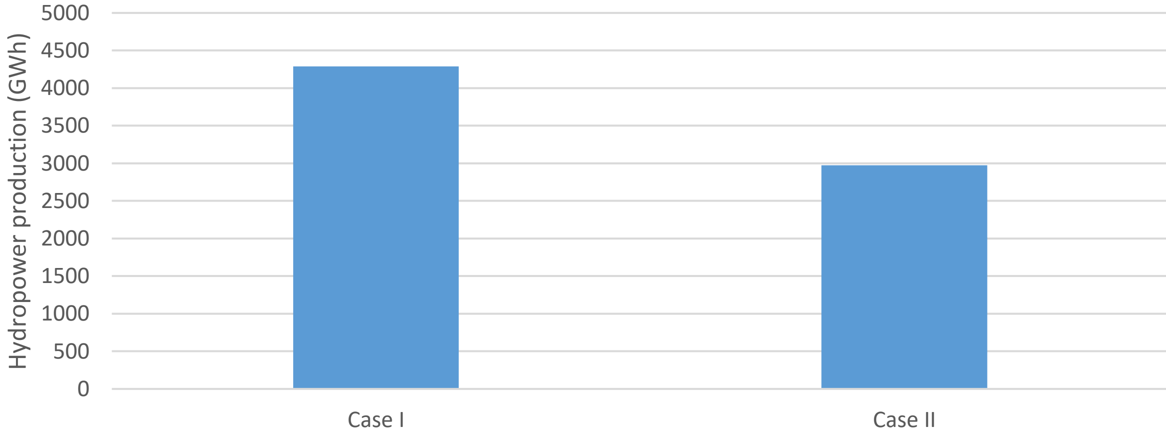



Figure 4.13: Comparison of simulated hydropower production between cases I and II

**Reservoir level**

Looking at the result of the simulated reservoir levels for cases I and II (Figure 4.14), it can be seen that reservoir content from case II is much higher than in case I. The results shows that the model in case II aims to optimize power production in all plants. The difference in reservoir content between the cases is 663.85 GWh. Also, production from the new plants would naturally reduce the pressure and demand from plants resulting in a higher conservation of reservoir content for better planning and scheduling.

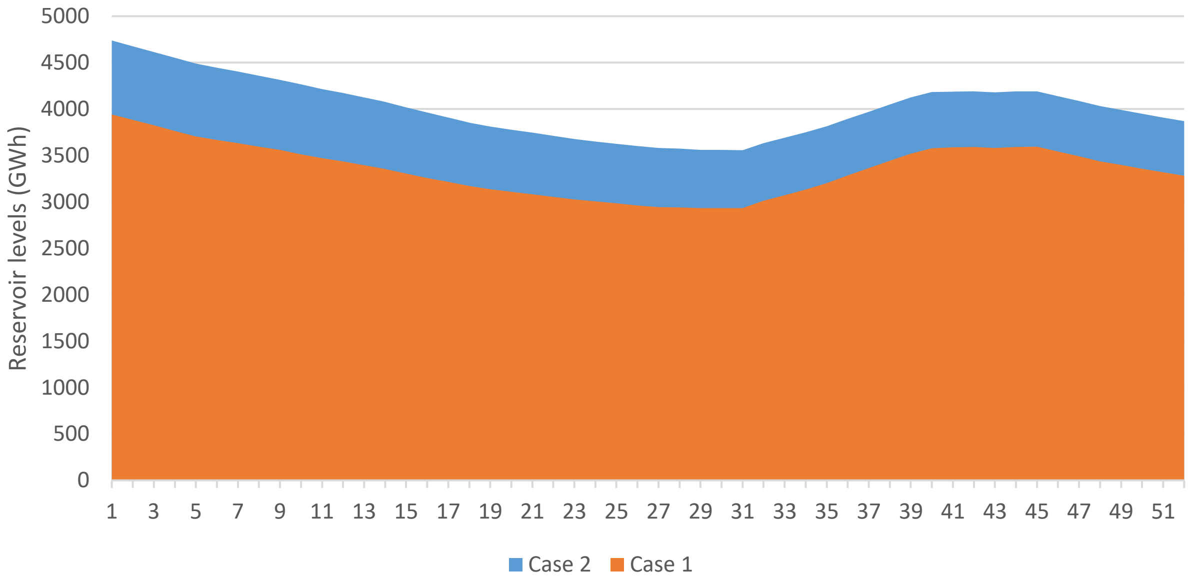



Figure 4.14: Comparison of simulated reservoir levels for all Areas between cases I and II.

### 4.4.2.4 Power generation and supply in case II

The introduction of new hydropower plants and corresponding improvement of transmission lines would eventually liberalizes the market as more independent power producers flood into the market, allowing for better optimization of hydropower resources.

While a rise in the number of independent power producers may imply an increase in competition, it must also be noted that a corresponding increase in the volume of firm power demand is expected, as a higher grid integrity implies that individuals, firms, and government can rely more on grid supply than auxiliary power sources. Also an increase in power generation, is expected to increase the number of manufacturing companies, which will ultimately result in higher power demands (TCN Report, 2015). It is also noteworthy to point out that increasing the per capita electricity volume above maximum demand, also increases the volume of electricity power exports to neighboring countries. On the overall, the addition of more independent hydropower serves greater benefit to Nigeria's power sector, with reduced $CO_2$ emissions being one of the added advantages.

## 4.5 Discussion

### 4.5.1 Case I

Modelling of Nigeria's hydropower system was successfully implemented using EMPS. The model functioned with minimal inputs some of which were gathered from publicly available information (e.g. engineering specifications of the hydropower plants) and from the hydropower stations (e.g. inflows, annual reservoir volume, etc.). The results from the model reveals certain optimization that needs to be done in power planning and scheduling in Nigeria, although, the model still needs further calibration for optimal functioning in real scenario basis to get better results. Although, there are a couple of reasons that may affect the quality of the modelled results.

First, the model was constructed on a scenario basis which may deviate from real scenarios. Second, hydropower modules were assigned to fictitious areas in order to meet the area assumption of EMPS. Third, some plant constraints were not accessible and had to be sources from published data, of which some are estimates and not spot values. Fourth, modules did not meet EMPS' energy equivalent assumption as input values were sourced directly from the power stations. Fifth, the inflow series had to be homogenized for all plants (reduction in the number of inflow years) and inflow data were only available until 2010; although the available data period – 21 years – was very realistic. Some data were not generally available (e.g. discharge limitation) and certain extrapolations had to be made. The results of the model is also limited by the lack of a reference historical weather profile. The model uses default values for the Norwegian weather scenario, which deviates significantly from weather scenario in Nigeria.

In view of the following limitations, the performance of the model was fairly optimal and represents and optimized hydropower planning for the modules taken into consideration.

A detailed description of EMPS modelling was highlighted in this study, however, there are still certain sections in EMPS – like the power market modelling – that remain highly untapped. Although, the nature of the Nigerian power market places this limitation. Also data was modelled without pump data – majorly because there are no pump description for Nigeria's hydropower plants, as such, details on how pump affects power production could not be determined.

Another major weakness was sourcing the inflow data used in this study. Data had to be physically sourced for as there are currently no online database where hydrological information of Nigeria's hydropower plants are stored. Also data on electricity pricing, changes in contractual obligation are not made available online.

The conducted test simulation which optimized hydropower production in the wet and dry years for the areas was satisfactory. The model worked as expected as the results showed lower annual production in a power curtailment scenario in order to better conserve hydropower resources for year round production.

Finally, it is important to know that power producers in Nigeria are still limited by semi-liberal power market laws and are sometimes forced to produce than what can be transmitted, leading to 'power without market scenarios'. In EMPS, the model accounted for the volume of power without market demand and well as the volume available for exports, showing the model can be used for power production scheduling and planning in markets that are semi-liberal like Nigeria’s.

### 4.5.2 Case II

Case II required a lot of made assumption to estimate a plausible liberalized power market scenario with new hydropower generation modules and increased transmission capacity lines.

The first assumption was that all new modules all operated at maximum capacity, which was rarely the case in real scenarios. Inflows and constraints were not defined for the new modules because they didn’t exist. Rather, each module was assumed was registered as an ‘import power plant’, implying that the existing hydropower modules would import power form the new modules when power production level is low. Firm power demand was assumed as twice the power demand in case I, without necessarily account for changes in relative demand given available power production and transmission capacities. Firm power curtailment was also allowed to give rise to a spot market scenario.

On the overall, despite the assumptions made, the model performed as expected by rationing the volume of available power based on the forces of market demand and supply. The results shows that EMPS can be used to model future market scenarios with good results.

## 5.0 CONCLUSIONS

**Case I**

The main conclusions of this case are summarized below:

- Inflow series are vital inputs for the EMPS model, especially to create the different stochastic weather scenarios.
- The results of the model mirrored historical trends to a certain degree, however, the model optimized water rationing for future.
- Further fine tuning is required to adjust and improve the model results. In general, this model requires constant maintenance.
- The integrity of input data affects model results, as such, adjustments in the EMPS settings is required to obtain better results.

**Case II**

The main conclusions of this case are summarized below:

- New power plants were implemented in EMPS and this raised the total hydropower production, but reduced relative share of hydropower produced for each plant.
- Modelling optimized reservoir contents better than in the previous case, suggesting the addition of the new modules balanced firm demand better.

**Overall**

- EMPS modelling aided the optimization of Nigeria's large scale hydro power plants, detailing better utilization of hydrological resources for power production.
- Power supply situation would be significantly improved with the addition of new hydropower modules.

## 5.2 RECOMMENDED FUTURE WORK

- Fine tuning the EMPS model for Nigeria's scenario would aid in the generation of better results.
- The assumptions done in the study were proven to be a good starting point, however they must be overcome to obtain more accurate results.
- Recommended future studies detailing the impact of new hydropower on CO2 production warrants investigation.

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## APPENDIX I

```
Module no.    1001, Kainji                                    Ownership  : 100.00
Type module:  Hydropower
-------------------------------------------------------------------------------
 no.  C o m m e n t s                      : no.  C o m m e n t s
-------------------------------------------------------------------------------
  1   Reservoir volume (Mm3)    15000.0 :      Flagg =  0, Data is not uploaded
      Resid. res. vol. (Mm3)        0.0 :      Flag  >  0, Data is uploaded
  2   Energy con. fact (kWh/m3)  0.2800 :      Flagg = -1, Data not OK
  3   Max.  discharge  (m3/s)    813.77 :      Enter DF for detailed explanat.
  4   Average head(m)             41.00 :
  5   Outlet level     (m.a.s.l)  99.83 :
                                        :      Constraints        Type    Flag
  6   Discharge to module          1002 : 17   Max. reservoir     (Local)    1
  7   Spill to module              1002 : 18   Min. reservoir     (Local)    1
  8   Bypass to module             1002 : 19   Max. discharge     (Curve)    1
  9   Code for hydraulic coupling     0 : 20   Min. discharge     (Curve)    1
 10   Coupling factor or number       0 : 21   Bypass                        0
 11   Max. balan. discharge (m3/s)    0 : 22   Max. bypass (m3/s)      10000.0

 12   Av. reg. inflow (Mm3/yr)    871.9 :      Functional relations       Flag
 13   Series name  reg. inflow
                                  104-A  23   Discharge limitations         1
      Ref. period for inflow  1990-2010   24   Reservoir curve               1
 14   Av. unr. inflow (Mm3/yr)      0.0 : 25   Discharge strategy data       1
 15   Series name unr. inflow
                                  104-A  26   Prod./discharge (PQ)          1
 16   Plant name  :                     : 27   Pump description              0
-------------------------------------------------------------------------------
```

Plant input data for Kainji module grouped under the area ‘Kainji’.

```
Module no.    1002, Jebba                                   Ownership  : 100.00
Type module:  Hydropower
-----------------------------------------------------------------------------
 no.  C o m m e n t s                : no.  C o m m e n t s
-----------------------------------------------------------------------------
  1   Reservoir volume (Mm3)     4000.0 :      Flagg =  0, Data is not uploaded
      Resid. res. vol. (Mm3)        0.0 :      Flag  >  0, Data is uploaded
  2   Energy con. fact (kWh/m3)  0.1480 :      Flagg = -1, Data not OK
  3   Max.  discharge  (m3/s)   1119.23 :      Enter DF for detailed explanat.
  4   Average head(m)             27.10 :
  5   Outlet level    (m.a.s.l)   74.88 :
                                        :      Constraints        Type    Flag
  6   Discharge to module             0 : 17   Max. reservoir     (Local)    1
  7   Spill to module                 0 : 18   Min. reservoir     (Local)    1
  8   Bypass to module                0 : 19   Max. discharge     (Curve)    1
  9   Code for hydraulic coupling     0 : 20   Min. discharge     (Curve)    1
 10   Coupling factor or number       0 : 21   Bypass                        0
 11   Max. balan. discharge (m3/s)    0 : 22   Max. bypass (m3/s)          0.0

 12   Av. reg. inflow (Mm3/yr)   1637.0 :      Functional relations       Flag
 13   Series name  reg. inflow
                                 1002-A  23    Discharge limitations         1
      Ref. period for inflow  1990-2010  24    Reservoir curve               1
 14   Av. unr. inflow (Mm3/yr)      0.0 : 25   Discharge strategy data       1
 15   Series name unr. inflow
                                 1002-A  26    Prod./discharge (PQ)          1
 16   Plant name  :                     : 27   Pump description              0
-----------------------------------------------------------------------------
```

Plant input data for Jebba module grouped under the area ‘Kainji’.

```
Module no.     103, Shiroro                                 Ownership  : 100.00
Type module:  Hydropower
----------------------------------------------------------------------------
 no.  C o m m e n t s                      : no.  C o m m e n t s
----------------------------------------------------------------------------
  1   Reservoir volume (Mm3)     7000.0 :      Flagg =  0, Data is not uploaded
      Resid. res. vol. (Mm3)        0.0 :      Flag  >  0, Data is uploaded
  2   Energy con. fact (kWh/m3)  0.2493 :      Flagg = -1, Data not OK
  3   Max.  discharge  (m3/s)    604.00 :      Enter DF for detailed explanat.
  4   Average head(m)             97.00 :
  5   Outlet level    (m.a.s.l)  285.00 :
                                        :      Constraints        Type    Flag
  6   Discharge to module             0 : 17   Max. reservoir     (Local)    1
  7   Spill to module                 0 : 18   Min. reservoir     (Local)    1
  8   Bypass to module                0 : 19   Max. discharge     (Curve)    1
  9   Code for hydraulic coupling     0 : 20   Min. discharge     (Curve)    1
 10   Coupling factor or number       0 : 21   Bypass                        0
 11   Max. balan. discharge (m3/s)    0 : 22   Max. bypass (m3/s)          0.0

 12   Av. reg. inflow (Mm3/yr)    289.9 :      Functional relations       Flag
 13   Series name  reg. inflow
                                  103-A  23   Discharge limitations         1
      Ref. period for inflow  1990-2010   24   Reservoir curve               1
 14   Av. unr. inflow (Mm3/yr)      1.0 : 25   Discharge strategy data       1
 15   Series name unr. inflow
                                 1231-A  26   Prod./discharge (PQ)          1
 16   Plant name  :                     : 27   Pump description              0
----------------------------------------------------------------------------
```

Plant input data for Shiroro module grouped under the area ‘Shiroro.

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