Hamburg University of Applied Sciences
Faculty of Life Sciences

Assessment of the Viability of Wind Farm Projects in Northern Nigeria

Master thesis

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Renewable Energy Systems - Environmental and Process Engineering

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Abstract

This thesis focused on investigating the viability of commercial wind farm projects in northern Nigeria. Potential location for wind farms projects were identified based on reported wind resource availability in the region. In addition, a concise evaluation of the power sector in Nigeria was carried out detailing the regulatory framework guiding the electricity industry as well as opportunities for Renewables. At the end of the thesis, the planning, siting as well as energy yield calculations of a 103 MW wind farm were carried out using the Wind Atlas Analysis and Application Program (WAsP). In conclusion, an economic analysis to show the economic viability the of the wind farm was done.

All three sub-sectors (generation and distribution) of the Nigerian Electricity Supply Industry (NESI) except transmission have been privatized. Ownership as well as management of key assets have been transferred to the private sector. On the regulatory side, the Nigerian Electricity Regulation Commission (NERC) is the key agency in charge of the technical and economic regulation of the NESI and issues licenses to the different participants based on their activities.

There are numerous incentives by the FGN and well as other development organizations which RE generators can benefit from. Some of this are support mechanisms targeted at RE while others are for investors generally. Nonetheless, these policies are still largely uncoordinated and short of the market-oriented policies necessary to increase RE investment. Also, the three subsectors still have unique infrastructure and operational problems that can stall the successful deployment of RE. In pursuit of a solution, the Federal Government of Nigeria together with Siemens AG, have signed in 2019 and already kickstarted the Nigeria Electrification Roadmap.

The simulation using WAsP produced an AEP of 412 GWh and an average shading loss between turbines of about 2%. The P_{90} AEP is about 315.92 GWh and this amount to a capacity factor of 34%. The LOCE of the project was 0.069 USD/kWh and the cashflow analysis produced a positive NPV ($17,874,395.08) and a 15.13% return on equity was achieved. The IRR on equity is 13.85%, considering our discount rate is 6.5%, it shows that the project can be profitable.

Additionally, a sensitivity analysis was conducted with the selling price by varying to 0.065 $/kWh and 0.075 $/kWh. The result demonstrated clearly that the selling price of electricity is a very important factor in the economic health of the project and effort should be made to negotiate the best price possible.

Acknowledgement

I would also like to thank my family and friends who have showed me encouragement and support throughout this program. Especially to my Mother, my Wife and my Son, who have been patient with me and made numerous sacrifices all through.

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"ٱلْحَمْدُ لِلَّهِ رَبِّ ٱلْعَلَمِينَ"

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Acronyms and abbreviations

RE	Renewable Energy
AEP	Average Energy Production
ATC&C	Aggregate Technical, Commercial and Collection
CF	Cash Flow
CFM	Cash Flow Model
CRF	Capital Recovery Factor
CRT	Cost-reflective Tariff
DCCF	Discounted Cumulated Cash Flow
DCF	Discounted Cash Flow
DFI	Development Financial Institutions
DisCos	Distribution Companies
DSCR	Debt-Service Coverage Ratio
EASE	Energizing Access to Sustainable Energy
ECN	Energy Commission of Nigeria
EPSRA	Electricity Power Sector Reform Act
EWEA	European Wind Energy Association
FGN	Federal Government of Nigeria
FMENV	Federal Ministry of Environment
FMPWH	Federal Ministry of Power, Works and Housing
GDP	Gross Domestic Product
GE	General Electric
GenCos	Generation Companies
GHI	Global Horizontal Irradiation
GIZ	Deutsche Gesellschaft für Internationale Zusammenarbeit
GWC	Generalized Wind Climate
GWEC	Global Wind Energy Council
IEA	International Energy Agency
IPP	Independent Power Producers
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
JICA	Japanese International Cooperation Agency
LCOE	Levelized Cost of Energy
LRMC	Long Run Marginal Cost
MO	Market Operator
MYTO	Multi-Year Tariff Order
NBET	Nigeria Bulk Electricity Trading Plc
NDA	Niger Dams Authority

NDPHC	Niger Delta Power Holding Company
NEPA	National Electric Power Authority
NEPP	National Electric Power Policy
NERC	National Electricity Regulatory Commission
NESI	Nigerian Electricity Supply Industry
NGN	Naira
NIPP	National Integrated Power Projects
NPV	Net Present value
NREEEP	National Renewable Energy and Energy Efficiency Policy
O&M	Operations and Maintenance
PCC	Point of Common Coupling
PCOA	Put and Call Options Agreements
PHCN	Power Holding Company of Nigeria
PPA	Power Purchase Agreements
PSRP	Power Sector Recovery Program
PV	Photovoltaic
PVC	Present value of Cost
REA	Rural Electrification Agency
RETF	Rural Electrification Trust Fund
SME	Small and Medium Enterprise
SO	System Operator
SRT	Service Reflective Tariff
TCN	Transmission Company of Nigeria
TSP	Transmission System Planning
UNDP	United Nations Development Program
USD	US dollar
WAsP	Wind Atlas Analysis and Application Program
WT	Wind Turbine

1 Introduction

About 11% of the world's population are still without access to electricity. In the sub-Saharan Africa, the numbers are as high as 55%, with about 600 million people without access to reliable electricity supply [1]. In Nigeria alone, which has about 20% of the region's population, more than 45% (85 million) of the population are still without electricity supply [2]. The World Bank and United Nations now consider access to electricity a fundamental factor for economic development and poverty alleviation and the federal government in Nigeria plans to get the national electricity generation to 30,000 MW by 2030, of which 30% is to be from renewable energy (RE) sources [3].

One of the more mature sources of renewable energy which has grown into prominence around the world is wind energy. Wind is one of the fastest growing RE resources in the world thanks to its prices which continues to decrease due to improvements in the area of grid integration, procurement, technological improvements as well as economies of scale [4]. The global weighted average cost of onshore wind energy in 2018 was between 54 -56 USD/MWh which is approximately 13% decrease from 2017 [5]. This is competitive with conventional combined gas cycle power plants (44 – 68USD/MWh) and considerably cheaper than coal and nuclear power plants (66 – 182 USD/MWh) [6][7].

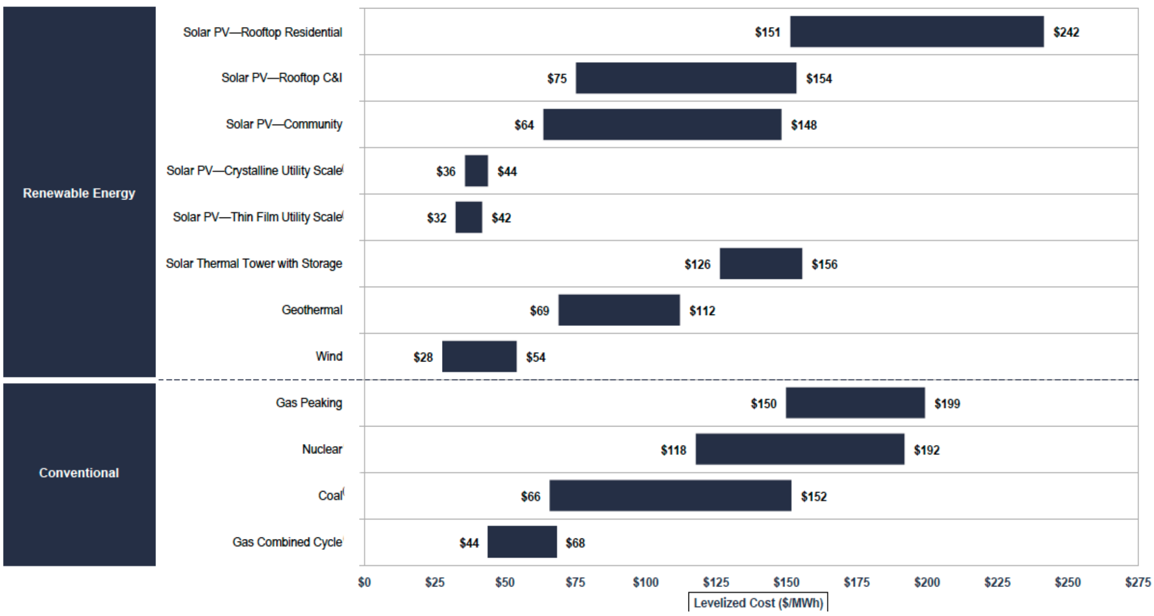


Figure 1-1: Levelized Cost of Energy Comparison [6]

The Global Wind Energy Council (GWEC) reports that global wind installation for 2019 was around 60 GW, a 10% growth from 2018 [4]. This brings the worldwide cumulative installation of wind to about 651 GW. The top 5 countries with new installations in 2019 are China, USA, UK, India and Spain. Although wind has grown in different parts of the world in recent years, only 5 countries (China, US, Germany, India and Spain) still account for about 72% of worldwide cumulative installations [4].

Africa is said to have the highest amount of RE resources in the world and wind energy is a part of this abundant supply. Unfortunately, the wind energy industry has not taken off in Africa as it has in other parts of the world. The total wind energy installation in the continent, as of 2018, is just a meagre 5.7 GW which is just 1% of total worldwide installation (see Figure 1-2) [8]. Although this is big improvement from the 1 GW installed as of 2010, there is still a long way to go. GWEC market intelligence estimates that this number will reach about 14 GW by the end of 2023 [8].

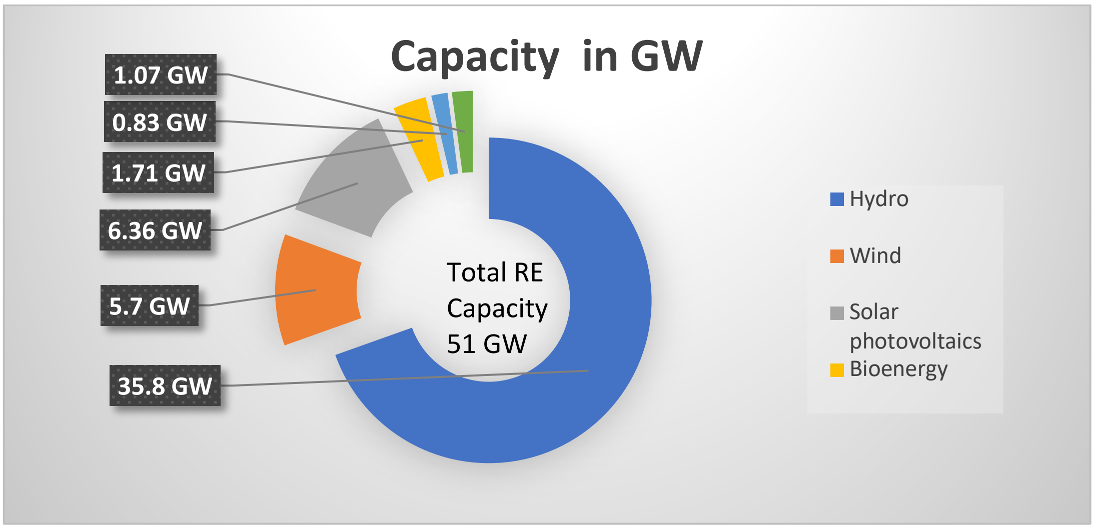


Figure 1-2: Renewable energy capacity in Africa (2019)[9]

Most of the commercial wind energy projects in Africa have largely been concentrated in the north (Egypt, Morocco and Tunisia), South Africa, and most recently in Kenya with the commissioning of its 310 MW Lake Turkana Wind Power Project in 2018 [10].

Although there are only a few small projects in Nigeria and no operational commercial scale wind farm, a number of researchers have attempted to estimate the wind resource in Nigeria. Ojosu and Salawu [11], Dalero and Musa [3], Akinsola and Ogunjobi [12] and many others have all studied wind data and wind availability in different parts of the country. While the scope and location of the research varies, they have all agreed to the presence of sufficient wind energy resource in different parts of Nigeria.

Ojosu & Salawu used data obtained from the meteorological agency of Nigeria to estimate wind characteristics and availability all over Nigeria. Their research showed that wind can be used for generating electricity in the rural areas and consequently help stem rural-urban migration. The research also indicated that the northern part of Nigeria allows a higher wind power generation due to the higher average wind speed.

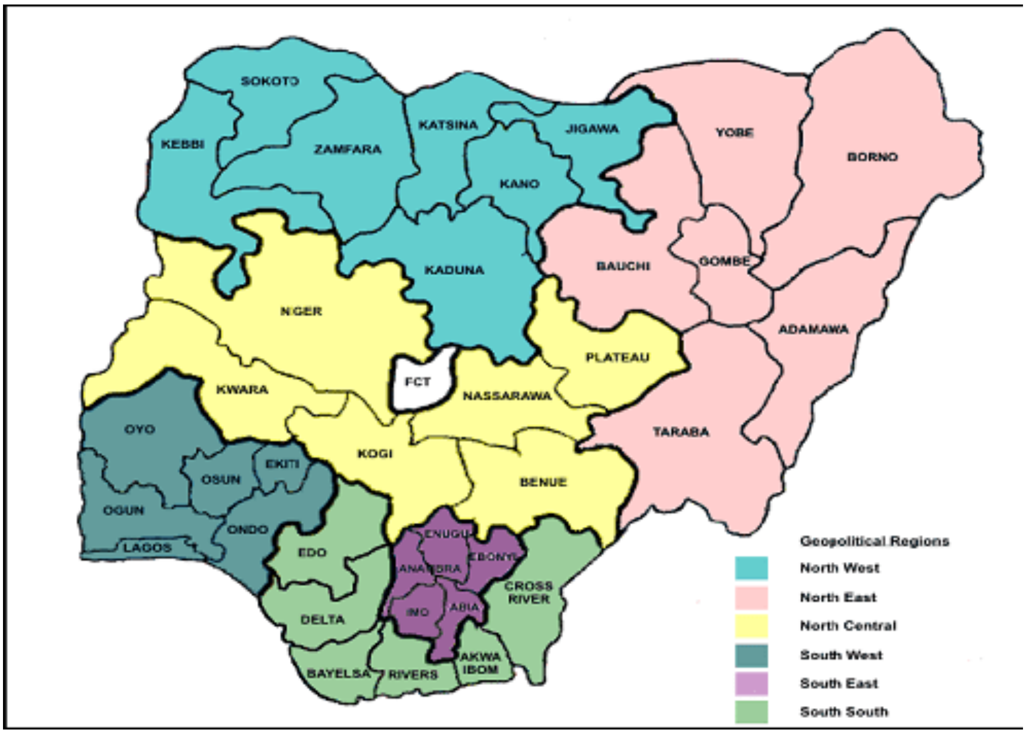


Figure 1-3 List and map of Geopolitical Zones & states in Nigeria [13]

In southern Nigeria, the wind energy potential for a small community in Bayelsa state was investigated using windspeed data and direction data between 1984 and 2013. The data was subjected to different statistical tests and compared with two parameter Weibull probability density. It was observed that the wind resource was only suitable for small scale wind power generation and the capacity factor was as low as 10% [12].

1.1 Motivation for the thesis

The goal of this thesis is to study existing works on wind resource in Nigeria with special focus on northern Nigeria. Furthermore, it will identify potential sites for commercial wind farm projects and assess the potential and feasibility of wind farm projects in the region. A concise evaluation of the power sector in Nigeria will also be carried out detailing the regulatory framework guiding the electricity industry as well as the grid system. At the end of the thesis, the wind resource assessment, siting and energy yield calculations of a potential 103 MW wind farm will be carried out using the Wind Atlas Analysis and Application Program (WAsP). This thesis will conclude with an economic analysis to investigate the viability of wind farms in northern Nigeria.

Since existing literature shows that locations in the northern part of the country have higher wind energy potential than the locations in the southern part, further research was done in 2017 to review existing literatures, narrow down and evaluate the wind resources in 6 locations in North-western Nigeria. It was shown that locations in Kano, Sokoto, and Katsina are suitable for large-scale wind power generation while places like Kaduna and Yelwa do not have as much wind potential [14]. The same was also observed on the global wind atlas.

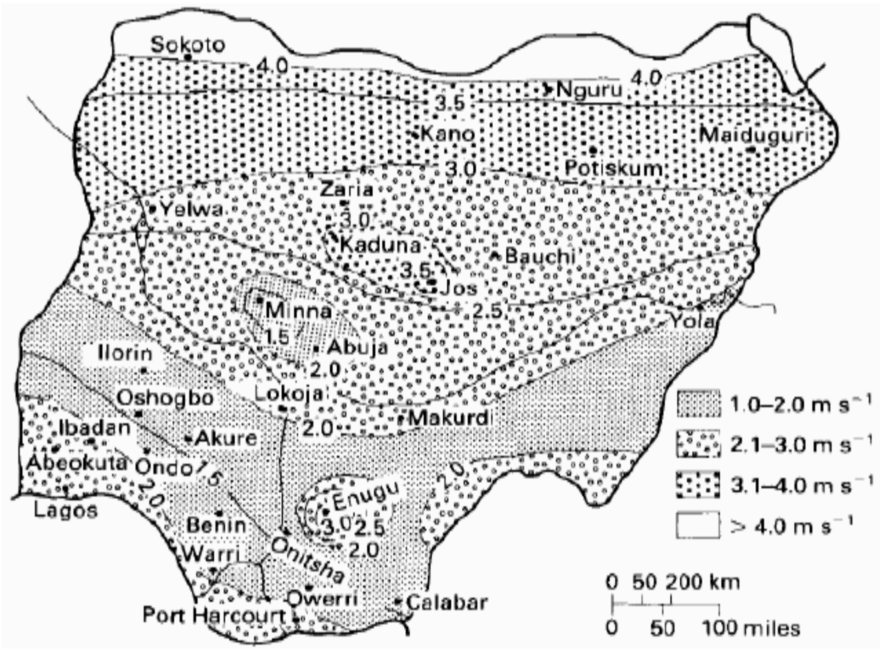


Figure 1-4: Annual Mean Wind Speeds Distribution at 10 m Height in Nigeria [14]

Nigeria, whose southern coast is on the Gulf of Guinea in the Atlantic Ocean, is also the largest oil and gas producer in Africa and the 11th largest in the world with over 80 years oil exploration experience [15]. This points to prospective offshore resources as well as competence in the area of on- and offshore exploration. Olaofe [16] looked into the wind speed distribution along the southern coast using a high-resolution satellite observation. The results revealed that higher wind speed and power density at the coastal region similar to over land in the northern part of Nigeria. It was demonstrated that while onshore wind power generation might not be economically viable in the southern part of Nigeria, offshore generation is viable.

Even though all these works and others have shown that the wind resource in Nigeria is at least medium, there is limited research dedicated to assessing the potential and commercial feasibility of wind farms in Nigeria. At the moment, there are only a few small projects in Nigeria and no completed commercial scale wind farm. The first attempt at a commercial scale wind farm was the Kastina state 10 MW wind farm. Terrawatt GmbH won the tender in 2010 and was billed to erect 37 wind turbines from the French manufacturer Vergnet. The turbines had a capacity of 275 kW each and was funded by the Japanese International Cooperation Agency (JICA) [17].

This Kastina wind farm project was originally scheduled to be completed within 30 months but a combination of insecurity, inadequate funding and vandalization has guaranteed that today, more than 10 years later, only 31 turbines have been installed and it's still not generating power commercially [18].

1.2 Methodology

The thesis will provide an understanding of the Nigerian electricity system and a brief history; the different eras, how it was setup and how it has developed, how has the demand and supply developed over the years and where the consumption centers are located. This is further strengthened by looking at Nigeria's future energy outlook as well as the role renewables will play in it.

To give an idea of the kind of market potential wind farm operators will be playing in, the following section dives into the regulatory and legal framework guiding the electricity market. Questions like who the major players and stakeholders are, how they are structured etc. will be carefully answered. Furthermore, the grid system and conditions of grid access will be appraised, specifically as it relates with the recently signed grid improvement contract with Siemens AG [19]. On the commercial side, an overview on potential offtakers of electricity in Nigeria, especially as it relates with Independent Power Producers (IPP) and Power Purchase Agreements (PPA), will be provided.

Wind resource i.e., estimation of mean wind climate is probably the most important factor to consider when planning a wind farm. As it is already shown that the northern part of Nigeria has more viable onshore wind resources, this thesis will further evaluate the different existing literatures on wind resources in the northern part of Nigeria to identify areas with best prospects.

For an accurate estimation of the observed wind climate and consequently Annual Energy Production (AEP), there should ideally be further onsite met mast measurements for one or several years at the wind farm site. But for the purpose of this thesis, a generalized wind climate data will be acquired from the global wind atlas. This will show the variation of wind speed, wind direction as well as power density at a given height above ground over a period of time at the proposed site. This wind data as well as location information from *Google Earth* will serve as basic input data for the simulation of the wind farm.

The modelling and simulation of the potential wind farm will be done using the Wind Atlas Analysis and Application Program (WAsP). WAsP is a very powerful tool used for wind data analysis, wind climate estimation, wind farm power production calculations and siting of wind turbines. It has over the years become the de facto industry standard for wind resource assessment and siting of wind turbines and wind farms. In addition, WAsP has now been employed in more than 110 countries around the world [20].

When completed, this thesis is intended to be one of the first works that looks at the topic of windfarms in Nigeria holistically from both a techno-economic and policy perspective. This would hopefully serve as both a call to action as well as a building block upon which other more detailed works would be carried out.

2 The energy system in Nigeria

Nigeria is the largest economy and the richest oil resource center of the African continent [21]. Also, it is Africa's largest oil producing country with about 37 billion barrels of proven reserves and 6 trillion cubic meters of natural gas reserves [22]. This is estimated to be about 2.2 % of total world reserve. The daily production of about 2 million barrels per day is also about 2.2% of the total world production [23]. With this in mind, it comes as no surprise that almost all of Nigeria's electricity consumption comes from non-renewable energy sources and the economy is also highly dependent on the oil industry. The fall in oil prices in the international market naturally almost always has a big impact on Nigeria's overall revenue and the economy.

Akuru and Okoro [24] opine the Nigerian energy sector is highly vulnerable to shocks due to its overdependence on fossil sources. The resilience of the Nigerian energy system is very weak, and critics say the combination of climate change, poor infrastructure and low oil prices will only further intensify its vulnerability and consequently depress the economy. All these energy challenges have compounded and side effects such as oil pollution and gas flaring have continued to damage agricultural land and marine ecology irreversibly [24].

2.1. Primary energy supply

The diagram in Figure 2-1 shows Nigeria's historical energy supply between 1990 and 2017.

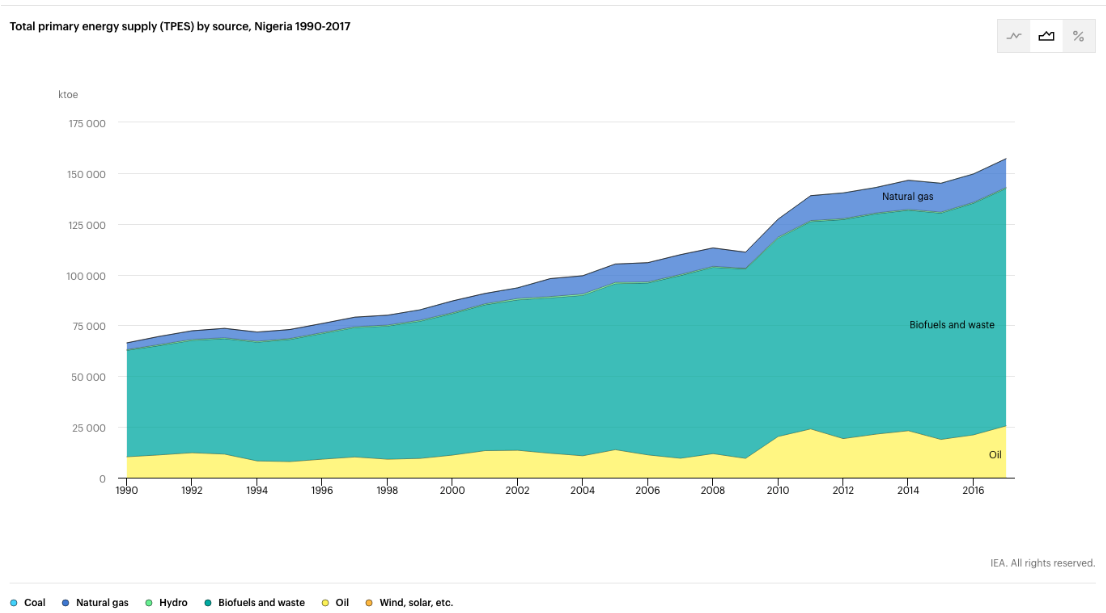


Figure 2-1: Total primary energy supply (TPES) by source, Nigeria 1990-2017 [25]

As shown in Figure 2-1, bioenergy (biofuel and waste) has remained the dominant player in the energy mix while oil and natural gas come a distant second and third respectively. Out of Nigeria's total supply of 157.137 Mtoe, bioenergy contributes about 116.926 Mtoe (74%) while Oil products contribute a paltry 25.541 Mtoe (16%) and Natural gas about 14.164 Mtoe (9%). Hydro accounts for about 0.475 Mtoe (0.3%) and coal as well as conventional renewables like wind, solar etc. account for the remaining tiny portion of 0.030 Mtoe (0.02%) as shown in Figure 2-2 [25]. Although Nigeria has abundant oil and gas reserves, oil and gas contribution has remained low over the years due to high cost for consumers and absence of standard domestic gas utilization infrastructure in the country [26].

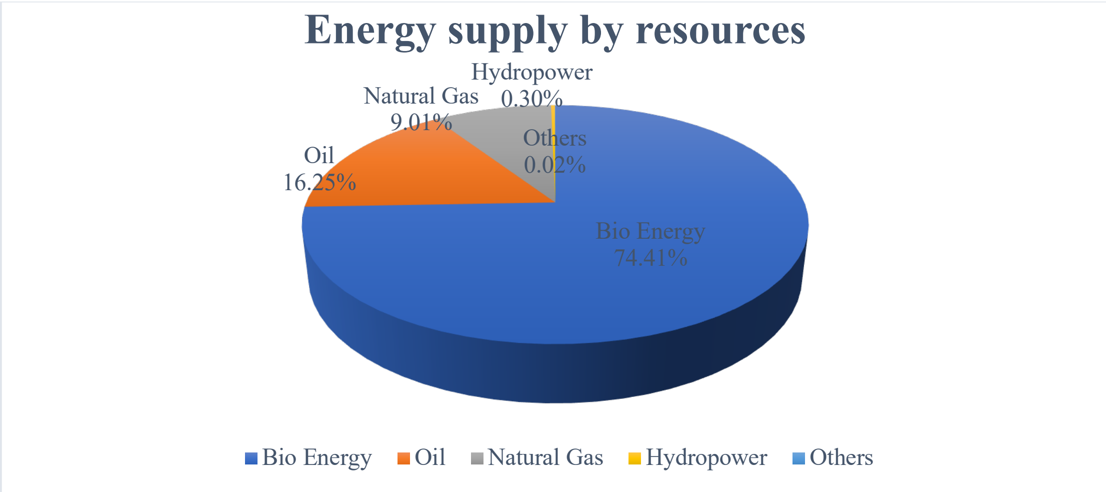


Figure 2-2 : Nigeria energy supply by resources in 2017

2.2. Energy consumption

The major energy consumption, 116 Mtoe (>70%), in Nigeria is from bioenergy [25]. About 90% of this consumption is residential in the form of cooking etc. which means almost all of residential consumption is catered for by bioenergy [26].

The remaining energy consumption comes from conventional sources with the vast majority being from oil and gas sources. The outlook (Figure 2.3) is to improve infrastructure and cut back on bioenergy consumption in form of household cooking etc. to just below 40 Mtoe by 2030. This is in addition to improving the utilization of oil and gas and renewables.

Electricity accounts for only about 2% of the total final energy consumption and therefore remains a marginal source of energy in Nigeria. More so, electricity represents 9% of the household's total energy consumption with most households having less than 6 hours of electricity supply daily [26].

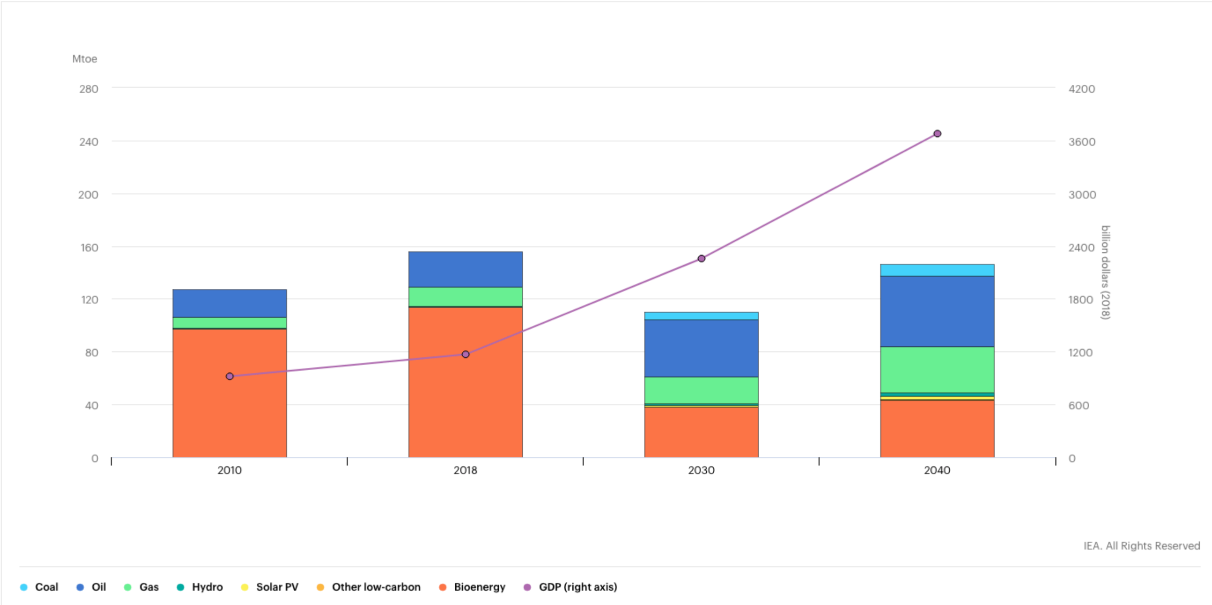


Figure 2-3:Nigeria primary energy demand and GDP in the Africa Case, 2010-2040 [25]

One of the major challenges and the reason the country is falling behind its peers economically is that the major energy consumption (almost 80%) is residential while industrial activities contribute less than 10 %. As illustrated in Figure 2-4, this is very poor as compared to Bangladesh (23%), Brazil (36%), Indonesia (23%) and South Africa (35%) [26]. Considering the percentage of the population that still reside in the rural areas, electricity generation to drive industrialization and rural electrification are both policy imperatives.

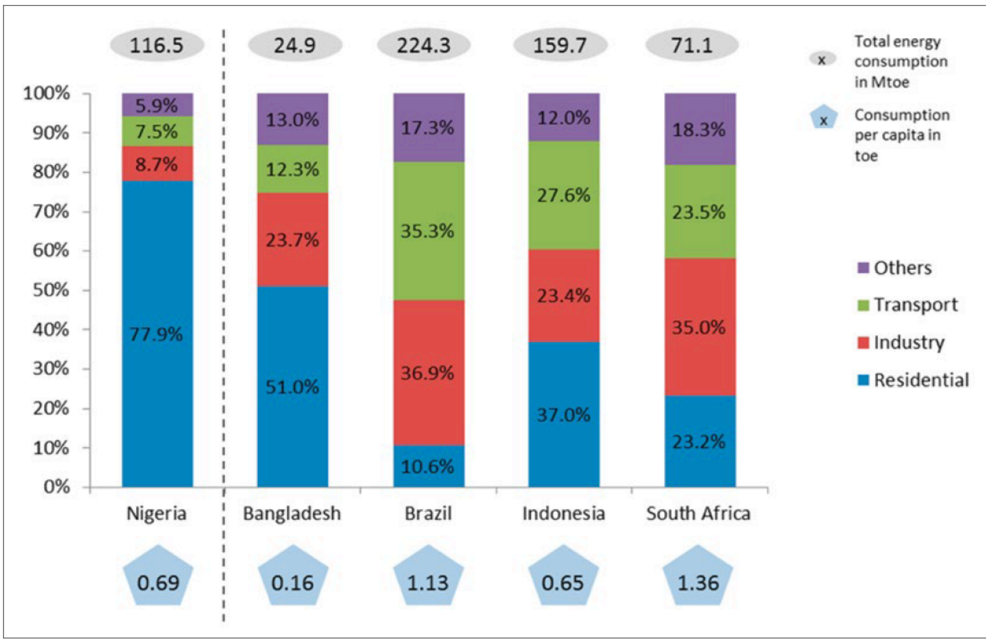


Figure 2-4:Energy consumption by sectors and consumption per capita for Nigeria and Peer Countries [26]

2.3. Renewable energy as a key part of Nigeria's energy future

Nigeria is certainly an energy poor country with about 45% of the population still without access to electricity [26]. Out of the 55% with access, most have less than 6 hours of electricity daily. In addition, the population and Gross Domestic Product (GDP) of Nigeria continues to grow at about 2.6% and 1.9% per annum respectively [25][26]. This means energy and specifically electricity demand (Figure 2-5 shows the projected peak demand till 2034) will continue to grow due to population and economic growth. For this reason, meeting the current and future energy demand is a major challenge that policymakers at all levels of government are grappling with. RE is one solution that continues to gain prominence.

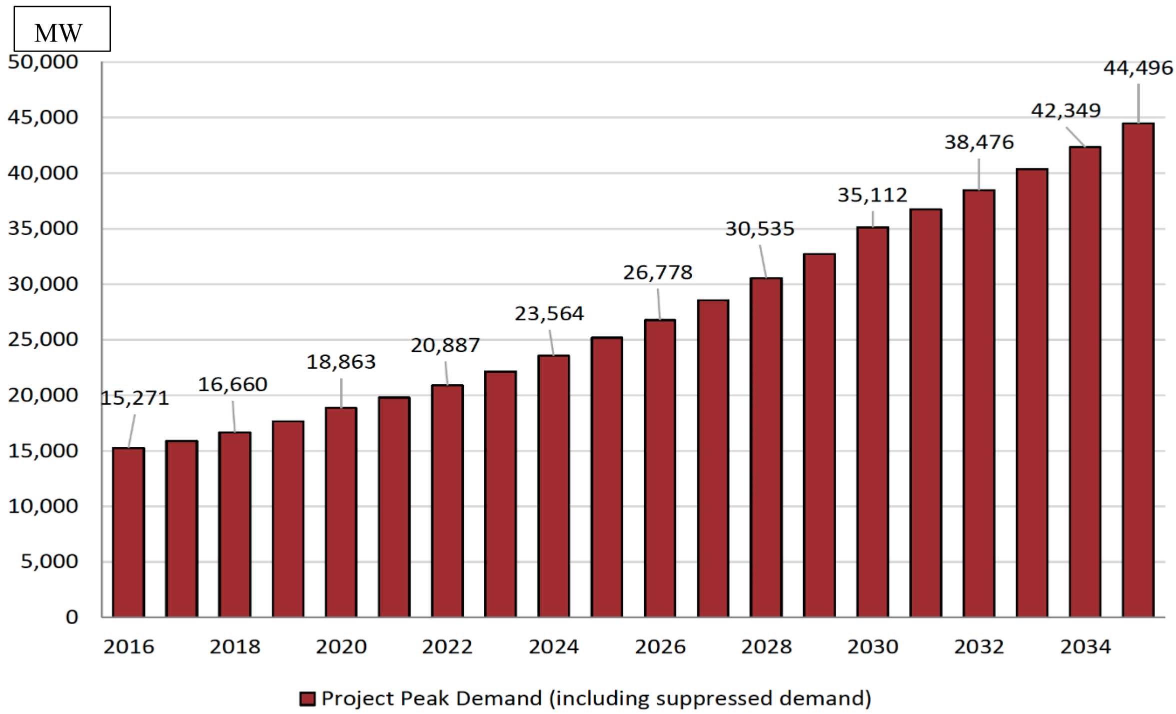


Figure 2-5:Projected grid electricity demand in Nigeria [28]

Investing in Renewables have multiple benefits and opportunities especially for a country like Nigeria. First, Nigeria has abundant renewable energy resources in form of solar, wind, tidal and geothermal. This means as a net importer of energy, Nigeria can reduce its import bills and in the long run also become a net exporter. Secondly, renewables are increasingly becoming very cost competitive. More recent data have revealed that renewable projects such as solar and wind farm projects now have levelized cost of energy (LCOE) below that of oil-based power plants. And in some cases, even below that of coal-based power plants [29].

Considering the benefits of investing in RE and the abundance of resources, it is however baffling there has not been a sustained and well-coordinated drive to invest and develop the renewable resources in Nigeria. Although the federal government signed into law the Electricity Power Sector Reform Act (EPSRA) to diversify Nigeria's energy mix and provide profitable and sustainable access to electricity to all Nigerians, this has not materialized into real progress.

2.3.1. Renewable Energy in Nigeria

Hydropower is the major on-grid RE source in Nigeria. While only roughly half of it is operational, there are 1,900 MW hydropower capacity installed in 3 large power plants (Kainji: 800 MW; Jebba: 540 MW; Shiroro: 600 MW) at the moment [30]. The Energy Commission of Nigeria (ECN) estimates Nigeria has large and small hydropower potential of about 11,250 MW and 3,500 MW respectively [26]. Although the large seasonal variation means the numbers are a little lower than estimated, there are plans to increase hydropower utilization to about 7,500 MW by 2035. As of February 2020, a 3,050 MW hydroelectric power plant was under construction in Kakara Village, Taraba State [31]. Table 2-1 shows some renewable sources and their estimated potential.

Table 2-1: Renewable energy potential and current utilization [9] [25]

Resource	**Potential**	**Current Utilization**
Large Hydropower	11,250 MW	1,940 MW (17.2%) exploited
Small Hydropower	3,500 MW	171 MW (4.8%) exploited
Solar	4.0 kWh/m^2/day–6.5 kWh/m^2/day	28 MW dispersed solar PV installations. (estimated)
Wind	2–4m/s @ 10m height mainland	3 MW (Electronic wind information system (WIS) available;)
Biomass (non-fossil organic matter)	Municipal waste	18.5 million tons produced in 2005 and now estimated at 0.5kg/capita/day
	Fuel wood	43.4 million tons/year fuel wood consumption
	Animal waste	245 million assorted animals in 2001
	Agricultural residues	91.4 million tons/yr. Produced
	Energy crops	28.2 million hectares of arable land; 8.5% cultivated

Sub-Saharan Africa is a region described by the International Renewable Energy Agency (IRENA) as having "exceptional solar resources" [32]. Nigeria, with approximately 3.5 – 7.5 kWh/m^2/day of solar radiation and an average of 6 hours of daily sunshine, is no exception [33]. The annual average global horizontal irradiation (GHI) values in the northern states ranges from 2,000 to 2,200 kWh/m^2 and a country wide average of about 1831.06 kWh/m^2 [34]. This is comparable to the best yield sites around the world like in southern Spain, northern Africa, and Australia [35].

Theoretically, if only 1% of the land area (approximately 920 km^2) of Nigeria is covered in photovoltaic (PV) technology, Nigeria has the potential to produce electricity up to 207,000 GWh per year. This is approximately 3 times the total electricity generated in Nigeria in 2019 [36]. Although there exist currently no on-grid solar farms, there have been increased focus by government and international agencies on off-grid/microgrid solutions and a robust and profitable ecosystem is being developed around that. In 2016, the federal government through the Nigeria Bulk Electricity Trading Plc (NBET) signed PPAs with 14 investors to build solar power plants mostly up north to generate about 1.1 GW of electricity into Nigeria's national grid [37].

Wind energy is probably the least utilized RE source in Nigeria. Although Northern Nigeria has been shown to have the most promising sites, other sites with usable potential are also located on the western shoreline [38]. There are two relatively large ongoing wind farm projects at the moment; namely the 10 MW in Kastina state and the 100 MW in Plateau State [26]. As regards the 100 MW wind-power farm outside Jos, the capital city of Plateau, the owner (JBS Wind Power Limited) has met all regulatory requirements to commence operation and an Independent Power Producer (IPP) license has been obtained from the National Electricity Regulatory Commission (NERC). Unfortunately, very little information is available publicly about the progress of project.

There exist other resources like geothermal, nuclear energy, tidal energy and ocean thermal gradient but they remain largely untapped and unqualified. A recent study for example concluded that geothermal analysis based on geothermal gradients indicated areas of higher-than-average gradient values and geothermal anomalies within sedimentary basins [26].

2.3.2. Renewable energy policies

Over the years, different policies affecting RE sources have continued to spring up. In 2003, a National Energy Policy was approved. This policy articulated Nigeria's goal to utilize its resources (conventional and renewable) to develop the electric power industry and make reliable electricity available to 75% of the population by 2020 [39]. Two years later, in 2005, a renewable energy master plan document was produced in conjunction with United Nations Development Program (UNDP) [40]. This document articulates a vision for achieving sustainable development as well as mapping out a plan for RE to help achieve this.

Another major milestone was the enactment of the Electric Power Sector Reform Act (EPSR). ESPR unbundled and privatized the electricity sector thereby allowing Independent Power Producers (IPP) to generate and sell to the national grid. The act also created the Rural Electrification Agency (REA). The REA has the statutory mandate of promoting and supporting rural electrification as well as the administration of a Rural Electrification Trust Fund (RETF) which provides autonomous funding for rural electrification projects [41] [42]. More recently, in 2012, the Nigerian Electricity Regulatory Commission (NERC) also signed an embedded generation permit which allows investors, communities, local governments etc. to generate and distribute electricity for their exclusive consumption. It also granted them the right to use the infrastructure of existing distribution companies for this purpose [43].

The Federal Government of Nigeria has also developed the National Renewable Energy and Energy Efficiency Policy (NREEEP). The NREEEP outlines various policies and programs for the deployment of RE technologies in the country. The NREEEP outlines short term, midterm and long-term targets. For the Short term (2015) it plans to reach 5 MW, 15 MW, and 117 MW of biomass, wind, and solar electricity respectively. For medium term (2020), it sets a target of 57 MW, 632 MW and 1,343 MW of biomass, wind, and solar electricity respectively. The long term (2030) targets 292 MW, 3,211 MW and 6,832 MW of biomass, wind, and solar electricity respectively [44].

The Vision 30:30:30 target sets to achieve a goal of 32,000 MW of available on grid generation capacity by 2030 with 30 percent coming from RE [45]. The aim is for Nigeria to have 9,100 MW of RE on the grid, including solar PV (5,000 MW), solar thermal (1,000 MW), wind (800 MW), biomass (1,100 MW), and small and medium-scale hydroelectric (1,200 MW) power generation. Indeed, Nigeria has the resources and potential to meet those targets but for the targets mentioned in the NREEEP to become a reality, these potentials need to be converted to renewable energy power plants. While the targets for 2015 and 2020 have obviously not materialized, Nigeria can still achieve the ambitious targets of the NREEEP by 2030.

Another program looking to promote RE is the Energizing Access to Sustainable Energy (EASE) program. This program aims to improve the enabling framework conditions for renewable energy and energy efficiency in Nigeria [46]. Its main focus is the use of RE by Small and Medium Enterprises (SMEs) and households. EASE sets out to address the massive deforestation and cutting of trees for fuel wood which is the main energy source for the majority of the population, by planting more trees. The program is in partnership with the World Bank and the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) [33].

While the above-described policies and regulations indicate progress in RE related policy making, they are largely uncoordinated and still short of the market-oriented policies that is necessary to increase RE as well as investor participation in the development of the RE resources in Nigeria. Incentives through effective policy making is pivotal to strengthen the prospect for investment and development of RE technologies in Nigeria.

3 The Nigeria power sector

While the first utility company was not created until 1929, electricity generation started in Nigeria as early as 1896 when two generating sets were installed to serve the then colony of Lagos. Subsequently, an Act of Parliament established the Electricity Corporation of Nigeria (ECN) in 1951 and in 1962, the Niger Dams Authority (NDA) was also established for the development of hydroelectric power. The two organizations were merged in 1972 to form the National Electric Power Authority (NEPA). Up till the turn of the 21st century, the state owned NEPA was in control of generation, transmission and distribution of electric power in Nigeria. However this control was characterized by unstable and unreliable power supply which was often due to problems such as inadequate maintenance of power infrastructure, high losses, power theft, non-cost efficient tariffs etc. [47].

In order to solve these problems, the Federal Government of Nigeria (FGN) started a journey towards the complete privatization of the sector in 2001. This began with the signing of the National Electric Power Policy into law. The objective of this policy was to transfer the ownership and management of the infrastructure and assets of the electricity sector to the private sector, consequently creating the structures necessary to form and sustain an electricity market in Nigeria. This gave birth to the new Nigerian Electricity Supply Industry (NESI) whose structure is as shown in Figure 3-1.

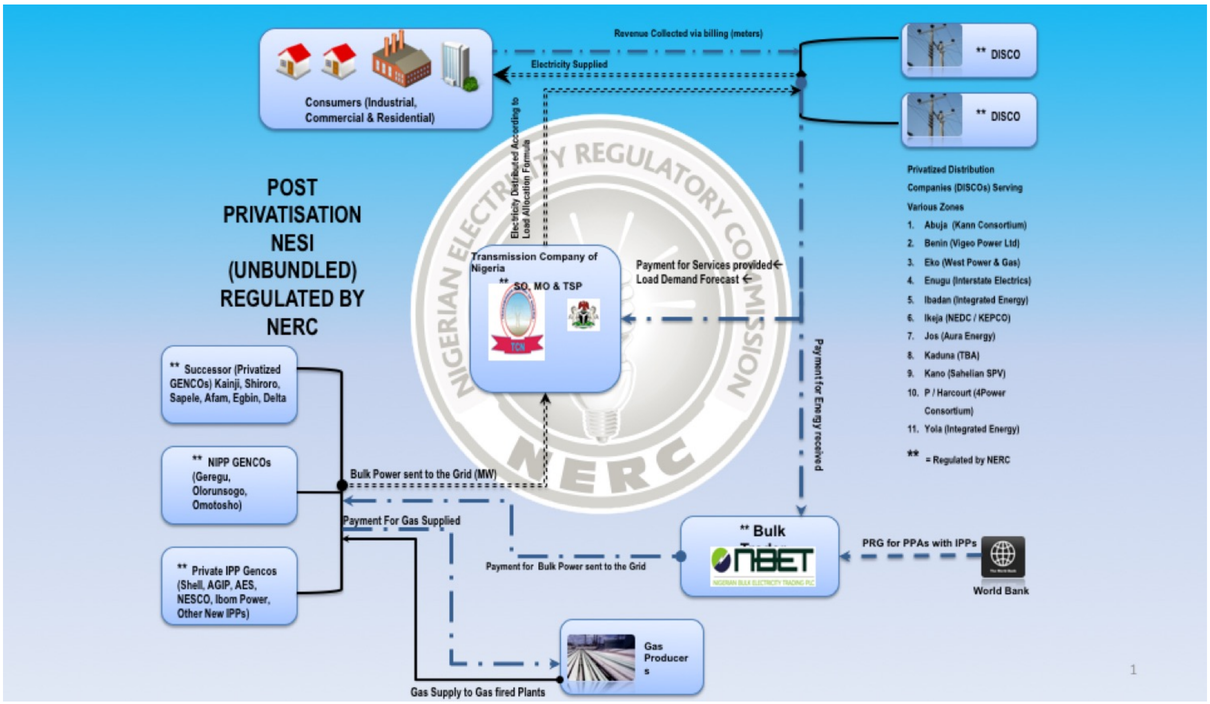


Figure 3-1: The Nigerian electricity supply industry overview [48]

3.1. Power sub-sectors

As a further step to restructuring the industry, the Electric Power Sector Reform (EPSR) Act was enacted in 2005 and with it the Nigerian Electricity Regulatory Commission (NERC) was established as an independent regulatory body for the electricity sector. A transitional corporation that comprises of the 18 successor companies (6 generation companies, 11 distribution companies and 1 transmission company) was formed known as Power Holding Company of Nigeria (PHCN). By 2013, the privatization of all generation companies (GenCos) as well as 10 distribution companies (DisCos) was completed while the FGN retained ownership of the transmission assets under the Transmission Company of Nigeria (TCN). The Nigerian Bulk Electricity Trading Plc (NBET) was also established as a credible off-taker of electric power from GenCos. The Nigeria power sector is now divided into 3 major subsectors as depicted in Figure 3-2.

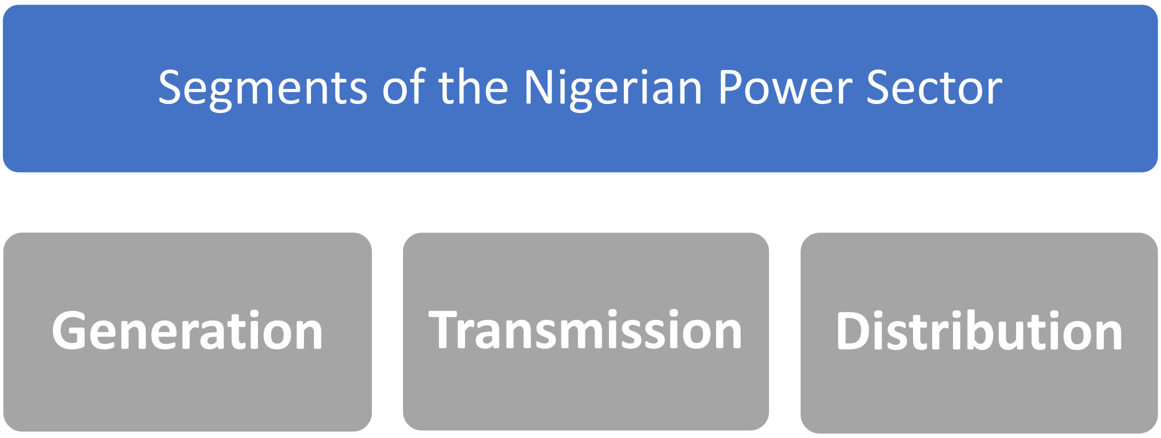


Figure 3-2 Nigerian power sub-sectors

3.1.1. Generation

Presently, there are about 28 grid-connected generating plants in the generation sub-sector with a total installed capacity of about 12,310 MW with only about 7,788 MW (60%) of the capacity available [45]. The vast majority (over 80%) is from thermal plants and the remaining are from hydropower plants [49] [30]. This further shows how dependent on gas the Nigeria electricity sector is. In reality, only about 3,000 MW to 5,300 MW is being generated daily with the peak generation as at October 2020 standing at 5,459 MW [50]. The Nigeria Task Force on Power regularly publishes the estimated peak demand and peak generation, whereby the former is with 12,800 MW regularly close to four times the latter [26]. After the successful unbundling of PHCN, the generating assets were divided into 6 generating companies and the FGN presently has fully divested its interests in all the 6 GenCos. Table 3-2 shows the GenCos created after the unbundling.

Table 3-1: Successor Generation Companies (GenCos) [29]

GenCo	Installed Capacity (MW)	Type	Privatization Status
Afam Power Plc	987.2	Gas	100% Sold
Sapele Power Plc	414	Gas	51% Sold
Egbin Power Plc	1,020	Gas	100% Sold
Ughelli Power Plc	942	Gas	100% Sold
Kainji/Jebba Power Plant	1330	Hydro	Long Term Concession
Shiroro Power Plc	600	Hydro	Long Term Concession

Contributing to the grid also are several Independent Power Producer (IPP) operated power plants which already operated before the privatization process. Between 2012 and 2013 the NERC issued about 70 further IPP licenses which are in several stages of development. This is an area where renewable energy plants, especially wind power plants have an opportunity. The NERC in 2012 in a bid to increase renewable integration also developed an embedded generation regulation. This regulation allows generation plants to be directly connected and evacuated through the distribution network [43].

The third major contributor to the on-grid generation are the National Integrated Power Projects (NIPP). The NIPP was conceived in 2004 as public sector funded initiative to fast-track the ramping up of generation capacity. There are about 10 NIPPs presently running with a combined capacity of about 5,455 MW and they are now owned and operated by the Niger Delta Power Holding Company (NDPHC) [51]. Table 3-3 shows the NIPPs and their installed capacity

Table 3-2: NIPPs in Nigeria [30]

GenCo	Installed Capacity (MW)
Alaoji	1131
Benin	508
Calabar	634
Egbema	381
Gbarain	254
Geregu	506
Ogorode	508
Olorunsogo	754
Omoku	265
Omotosho	513

3.1.2. Transmission

TCN is responsible for managing the electricity transmission network in Nigeria. TCN is the product of merging the transmission and system operations part of the now unbundled PHCN. This is the only part of the electricity system that is still owned completely by the FGN and its main responsibility is evacuating power generated by the GenCos and delivering it to the DisCos.

Presently, the wheeling capacity of the transmission system in Nigeria is about 7,500 MW and over 20,000km of transmission lines [52]. This capacity, although more than the operational generation capacity (5,300 MW), is still considerably lower than the installed generation capacity (12,310 MW). This could potentially be a problem if generation is ramped up as planned without substantially expanding transmission capacity. Figure 3-3 shows an overview of the transmission grid layout.

Figure 3-3: Nigeria Transmission Grid [53]

There was a massive reorganization and restructuring after the unbundling with the sole aim of improving reliability and expanding capacity. This led to TCN's operation to be divided into three main functions: Transmission System Planning (TSP), the System Operator (SO) and Market Operator (MO). TSP takes ownership of the transmission assets and is responsible for maintaining the physical infrastructure of the grid and its expansion to other areas. The main responsibility of the System Operator is to operate the transmission system and the connected installed generation in a safe and reliable manner [54]. This also means overall responsibility for the security and reliability of the grid system, economic dispatch of available generation resources and system stability. The MO on the other hand is responsible for the administration of the wholesale electricity market as well as promoting and sustaining efficiency and healthy competition. The key functional responsibilities are shown in Table 3-4.

Table 3-3: Overview of SO & MO responsibilities in NESI [52]

System Operator	Market Operator
Implementing and enforcing Grid Code, and draft/implementation of operating procedures as may be required for the proper functioning of the System Operator Controlled Grid	Implementing and administering the Nigerian Electricity Market Rules,
System Planning	Drafting and implementing the Market Procedures
Designing, installing, and maintaining Supervisory Control and Data Acquisition (SCADA) and Communication facilities for effective grid operations;	Administration of the Commercial Metering System by ensuring that each trading point has adequate metering systems in place;
Economic dispatch of generating units	Administration of the Market Settlement System;
Procuring & managing ancillary services;	Administration of the Payment System and commercial arrangement of the energy market, including Ancillary Services;
Enforcing the Grid Code and the operational procedures	Supervising Electricity Market Participants' compliance with and enforcing the Market Rules and the Grid Code.
Coordinating all planned outages for the maintenance of system equipment;	Periodic reporting on the implementation of the Market Rules;
Performing post fault analysis of all major grid disturbances.	Capacity building of market of Participants on the Market Rules and Procedures and Trading Arrangements

Due to a lack of redundancy in the transmission system, there remain serious reliability issues with transmission network losses amounting to about 7.4%. This is higher than the 2-6% benchmark for other similar economies like Ghana and South Africa [45]. TCN also recorded about 206 partial or complete system power grid collapses between 2010 and 2019 [55]. Although this dropped from 42 per year in 2010 to just 9 in 2019, it still reflects critical infrastructure and operational challenges in the transmission subsector.

As a way of tackling these problems, the FGN in 2019 signed an implementation agreement for the Nigeria Electrification Roadmap with Siemens AG. The Roadmap was structured in three phases with the first and second phase focusing largely on essential and quick-win measures [19]. The goal is to increase the system`s end-to-end operational capacity to 7,000 MW. The second phase specifically targets network bottleneck`s to enable complete utilization of existing generation and distribution capacities, bringing the systems operational capacity to 11,000 MW. Phase three is more futuristic; the aim is to, in the long-term, develop the system up to 25,000 MW through upgrades and expansions in all three subsectors. The FGN has approved the release of funding for the first part of Phase 1 in May 2020 to kick-off the pre-engineering and concession financing workstreams [56].

3.1.3. Distribution

The distribution grid operates mainly on 33 kV and 11 kV (medium voltage and low voltage level) and was unbundled into 11 private distribution companies (DisCos) which came into operation in 2010. It is important however to note that the Nigerian government still retains a 40 percent share in the DisCos [30]. The DisCos were allotted in different geographical areas, and these can be seen in the map in Figure 3-4.

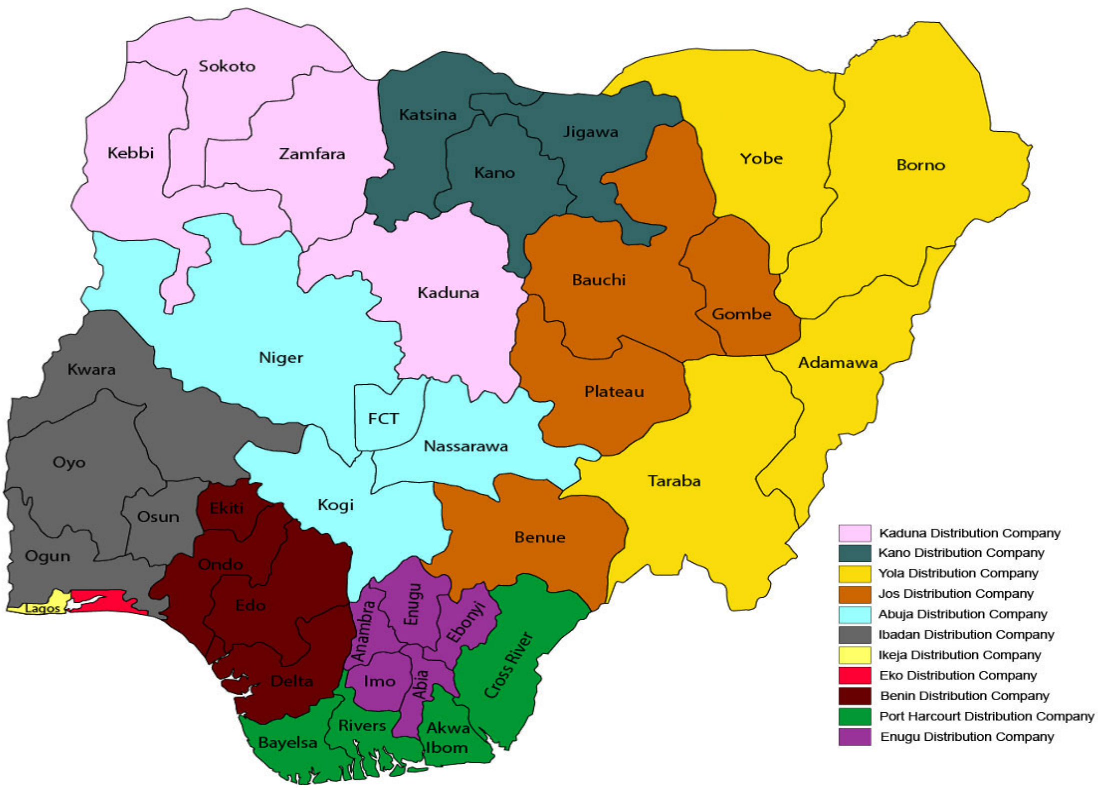


Figure 3-4: Map of the Electricity Distribution Companies (DisCos) Coverage in Nigeria [57]

Ikeja Electric (IE) Plc. is the biggest DisCo by load allocation, and it covers a large portion of Nigeria's main economic hub, mainland Lagos. IE serves about 700,000 customers and this sums up to nearly 15% of Nigeria's total load allocation. Other large DisCos are Ibadan DisCo, Abuja DisCo and Eko DisCo with 13%, 11.5% and 11% of total load allocation respectively [30]. Table 3-4 shows all DisCos and their percentage load allocation.

Table 3-4: DisCos and percentage load allocations [30]

S/N	DisCo	%Load allocation
1	Abuja Distribution Company	11.5%
2	Benin Distribution Company	9.0%
3	Eko Distribution Company	11.0%
4	Enugu Distribution Company	9.0%
5	Ibadan Distribution Company	13.0%
6	Ikeja Distribution Company	15.0%
7	Jos Distribution Company	5.5%
8	Kaduna Distribution Company	8.0%
9	Kano Distribution Company	8.0%
10	Port Harcourt Distribution Company	6.5%
11	Yola Distribution Company	3.5%

Although the DisCos have a joint distribution capacity of 24,457 MW, they only have an injection capacity of 13,571 MW [45]. The performance level amongst the different DisCos vary but the distribution network is still at a subpar level on the average. As the segment of the NESI which directly interfaces with consumers, the importance of efficient customer service delivery cannot be overemphasized. Some of the major problems as detailed in NERC's quarterly report [58]. They are mostly are due to weak and inadequate network coverage, overloaded transformers, substandard distribution lines and a very poor metering and billing system. As at the last quarter of 2019, only about 3.9 million (37.7%) of the about 10.3 million estimated electricity customers are metered. Benin DisCo (54%) and Abuja DisCo (53%) had the highest percentage of metered customers while most of the other DisCos were below 50%. Kano and Jos have the lowest metering percentage of around 19% (Figure 3-5).

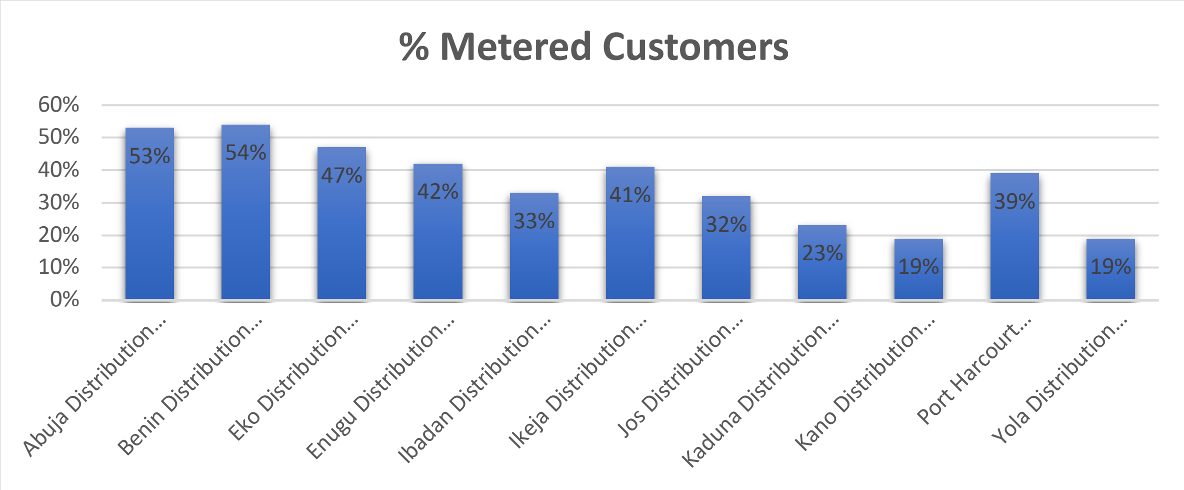


Figure 3-5: Percentage of metered customers as at Q4 2019 [58]

The problem of inadequate metering has meant that majority of the billing are estimates hence, most customers, citing inflated billing, refuse to pay. This has affected electricity sales revenue and has meant that the DisCos report a very high (43%) level of Aggregate Technical, Commercial and Collection (ATC&C) losses monthly [58]. This means DisCos are unable to fully pay for the electricity they receive, and the industry remains in a liquidity crisis. In an effort to remedy this problem, NERC issued an order repealing the Methodology for Estimated Billing Regulations 2012 in February 2020 as well as giving a target to close the metering gap by December 2021 [59]. It is unlikely that this target will be met considering the unexpected economic crisis due to COVID-19, but it is at least expected that serious progress will be made.

Another effort at remedying the distribution problem is the Presidential Power Initiative in cooperation with Siemens AG. Part of the proposal which was approved by the FGN has plans for a distribution system upgrade. Siemens is to work with the DisCos on improvements such as national metering infrastructure, upgrade of existing substations, grid automation, improvement of communication infrastructure as well as personnel training [19].

3.2. Legal and regulatory framework

The National Electric Power Policy (NEPP) signed into act in 2001 is the major framework guiding the reformation of the NESI [41]. It sets out to help meet the current and future electricity demand in Nigeria in an efficient and economically viable manner. The EPSR act then followed in 2005 and provides a legal framework for achieving the objectives of the NEPP. The EPSR Act states its goal as: "to create efficient market structures, within clear regulatory frameworks, that encourage more competitive markets for electricity generation and sales (marketing), which, at the same time, are able to attract private investors and ensure economically sound development of the system" [60]. In order to be able to achieve this goal, the EPSR established NERC as the independent regulator of the sector and clearly define its powers and functions which include:

1. Promote competition and private sector participation, when and where feasible.
2. Establish or approve appropriate operating codes and safety, security, reliability and quality standards.
3. Tariff regulation and fair pricing
4. License and regulate persons engaged in the generation, transmission, system operation, distribution and trading of electricity.
5. Approve amendments to the market rules and monitor the operation of the electricity market.

The NERC is led by seven commissioners with a commissioner each from the 6 geo- political zones in the country in addition to one commissioner designated as Chairman and Chief Executive Officer. The key agencies and institutions are as shown in Figure 3-6.

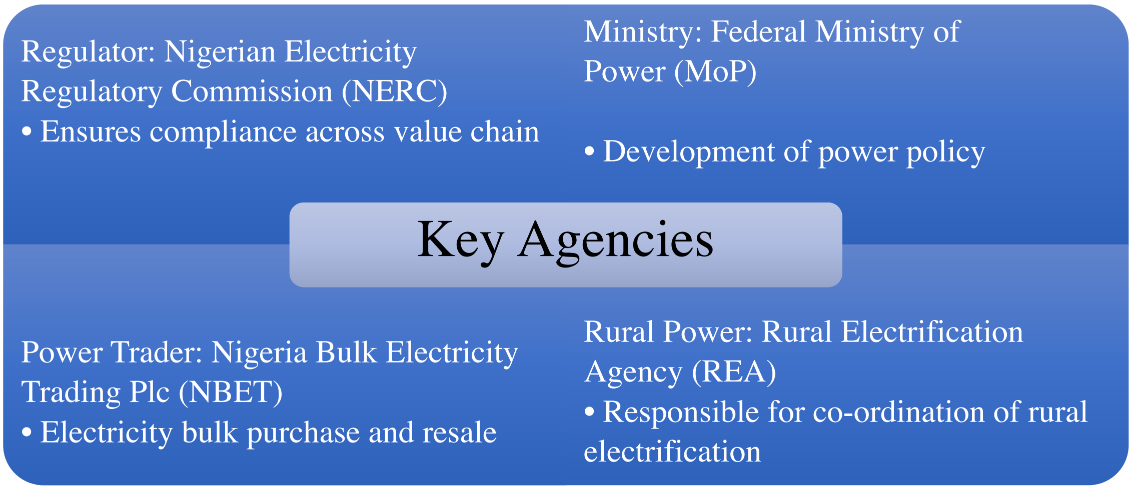


Figure 3-6: Key power sector agencies [61]

Other than NERC, there are other peripheral government institutions and agencies that also have some influence on the sector. The Federal Ministry of Power is the administrative arm of the government which focuses on the development as well as facilitating implementation of policies for the sector that promotes the development of electricity generation from all sources. The Rural Electrification Agency (REA) is an agency under this ministry and was launched in 2006 as part of the Electric Power Sector Reform Act [62]. The core function of this agency is the management of the rural electrification fund and to coordinate rural electrification projects which includes deployment of off grid renewable energy systems.

The Federal Ministry of Environment (FMENV) is another pivotal ministry. FMENV is responsible for conserving the country's natural resources for sustainable development as well as protecting the environment against pollution and degradation. The ministry also houses the Department of Climate Change responsible for climate change topics whose objective is to foster renewable energy and energy efficiency. The Environmental and Social Impact Assessment which is mandatory for all development projects (including Renewables) in Nigeria is overseen by the FMENV [26]

3.2.1. Licensing

The various players in the NESI are often referred to as market participants. For a market participant to operate in any sector of NESI, it is required to obtain the appropriate license from the Nigerian Electricity Regulatory Commission (NERC). Appendix I contains information on the license application requirements. There are five major types of licenses issued in the industry namely [63]:

1. Generation License: Needed for generation in excess of 1MW
2. Distribution License: Authorizes the recipient to construct, operate and maintain distribution systems and facilities.
3. Transmission License: Authorizes the recipient to carry on grid construction, operation, and maintenance of transmission system within Nigeria, or that connect Nigeria with a neighboring jurisdiction.
4. System Operator License: Authorizes the recipient to carry on system operation such as generation scheduling, congestion management, transmission scheduling etc.
5. Trading License: Authorizes the recipient to engage in the purchasing, selling, and trading of electricity and in some cases bulk purchase and resale.

3.2.2. Organizational structure

NERC oversees the technical and economic regulation of the NESI and issues licenses to the different participants based on their activities. One of the provisions in the EPSR Act is the licensing of a bulk trader for the bulk procurement of electric power and ancillary services through power purchase agreements. NBET was created for this purpose and it guarantees assurance to GenCos for the bulk procurement of the power produced as well as ensuring that a minimum capacity is provided to each of the DisCo.

The relationship in the industry is as shown in Figure 3-7. The GenCos generate electricity and this electricity is transmitted by TCN to the DisCos for delivery to the consumers. In the privatized power sector, NBET purchases power generated by the GenCos (including NIPPs and IPPs) at agreed prices stated in Power Purchase Agreements (PPA) and resells to the DisCos who are tasked with delivering the power to the end consumer.

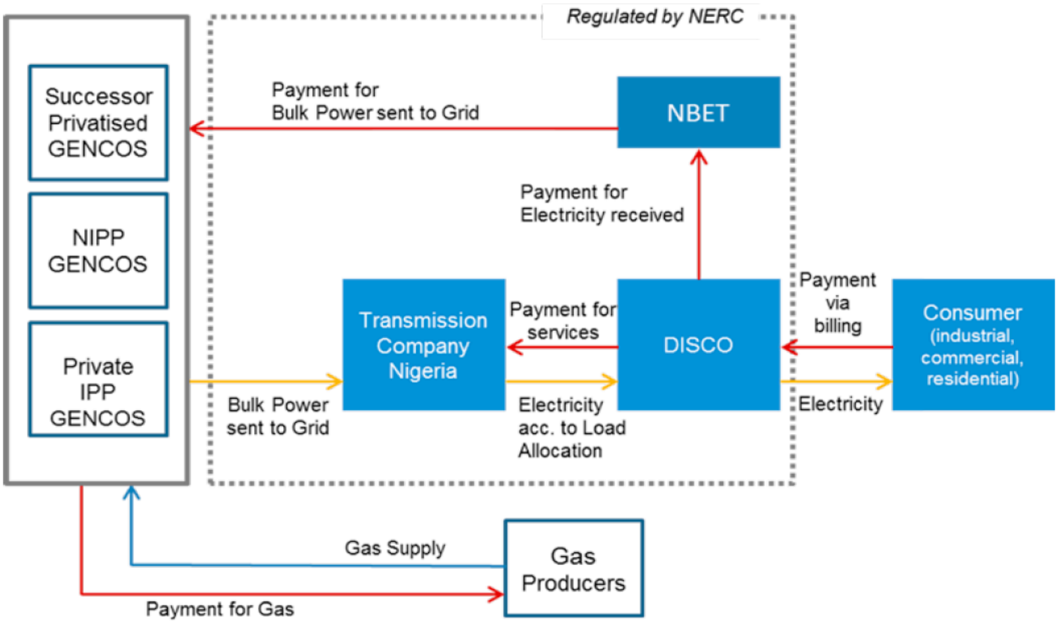


Figure 3-7: NESI structure post-privatization [26]

Payment for electricity also follows the same path from the consumers back to the GenCos. TCN goes into grid agreements with GenCos as well as transmission use agreements with DisCos. After distribution of electricity to consumers, payment is made to DisCos who in turn remit to the market operator for further distribution along the value chain. As most of the generation in the industry is still gas powered, GenCos enter into gas supply agreements with gas producers in order to guarantee prompt supply of gas and stay operational.

3.2.3. IPPs and markets for power purchase

Having now sold off most of its electricity assets, the Nigerian government is not expected to be the primary builder of power plants in the future and may not even build any at all [64]. The government instead views its role as creating a facilitative environment for Independent Power Producers (IPPs). NERC has over the years licensed several private Independent Power Producers (IPPs), a number of which are at various stages of project development [65]. The

Commission also enacted the Bulk Procurement Guidelines that will ensure the efficient and orderly procurement of large capacity generation in the NESI [66].

Both NBET and DisCos can procure generation capacity directly from IPPs generators as long as the NERC Regulation for the Procurement of Generation Capacity is adhered to. The regulation stipulates that the System Operator (SO) provides an annual load projection report detailing capacity needs as well as system constraints for a five years period. If this annual report indicates requirement for additional generation capacity, then a buyer can commence the process of procurement from IPPs. This procurement process includes an expression of interest as well as a bidding phase and only applies to power plants larger than 10 MW.

NERC also developed a regulation on embedded generation which allow power generating plants (including renewable energy) to directly connect to the distribution network and its electricity evacuated through it [43]. It gives RE plant owners the opportunity to generate and sell power without going through the transmission grid.

More recently in 2017, NERC introduced the eligible customer regulation, after the Minister of the Federal Ministry of Power, Works and Housing (FMPWH) had declared the eligible customer policy [67]. This regulation will allow eligible consumers to buy electricity directly from existing GenCos or new IPPs instead of the DisCos. This means IPPs can now go to the market and look for corporate offtakers for their electricity.

3.2.4. Renewable energy support mechanisms

There are numerous incentives both by the FGN and well as other development organizations which RE generators can benefit from. Some of these are support mechanisms targeted at RE directly while others are for investors generally. Some of the most notable by the FGN are as follows [63], [37]:

1. Guaranteed price & access to grid
2. Feed-In-Tariff for Solar, Wind, Biomass & Small Hydro
3. Power Purchase Agreement (PPA) based on plant life cycle of 20 years
4. Electricity distribution companies (DisCos) to procure minimum of 50 per cent of the total projected renewable sourced electricity

5. Nigerian Bulk Electricity Trading Company (NBET) to procure minimum of 50 per cent of the total projected renewable sourced electricity [66]

Also, as mitigation against the socio-political, geographical and financial risks RE projects are exposed to, put and call options agreements (PCOAs) are sometimes signed by the FGN [68]. Other international institutions like the World Bank and the African Development Bank also provide Partial Risk Guarantees and this goes a long way in reducing the cost of financing [69].

3.3. Tariff system

The biggest hurdle militating against the financial viability of the Nigerian electricity value chain is the insufficiency of cash flows that recover all costs and generate an appropriate return on investment [70]. NERC is the body responsible for the economic regulation in NESI. This includes setting tariffs that are both fair to the customers as well as allowing the players to finance their activities and obtain reasonable profit for efficient operations. The framework which NERC has adopted to do this is the Multi-Year Tariff Order (MYTO) system [71].

The MYTO lays out the methodology for determining the price of on-grid electricity in Nigeria for a period of 15 years (2008 to 2023) which is subject to a minor review biannually and major reviews every five years; this gives room to update tariffs based on new macroeconomic and sector-specific factors such as inflation, the US dollar (USD) to Naira (NGN) exchange rate, and generation capacity on the grid [45]. This framework was designed to set a wholesale and retail prices of electricity in NESI in a cost reflective manner, provide financial incentives for investment in the industry and allocate risks to the various industry stakeholders efficiently. The MYTO is also an incentive-based tariff model which rewards utilities' performance on loss reduction and improved standards [71].

Generation tariffs or wholesale tariff paid to the generators is set by NERC at a level sufficient for a new entrant to cover its life cycle costs which includes both short run fuel and operating costs as well as the long run return on capital used. This method used is referred to as The Long Run Marginal Cost (LRMC) method. The three basic building blocks are: allowed return on capital, allowed return of capital and efficient operating costs and overheads [71].

Retail tariff is the price paid by final electricity consumers and therefore reflects the cost incurred in the entire value chain of the electricity market. The retail tariff consists of four basic components namely: generation cost, transmission cost, distribution cost and other sector services and tax [45].

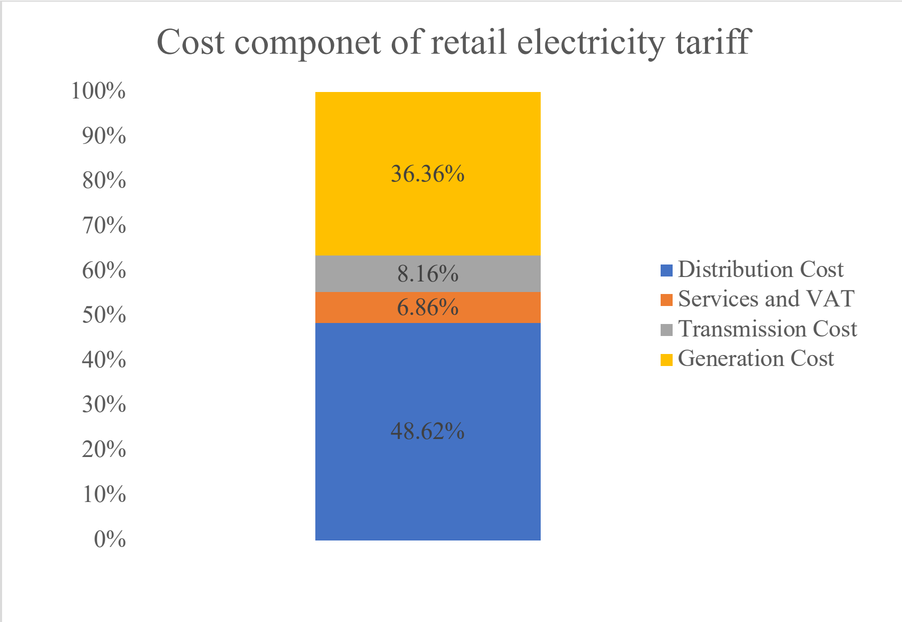


Figure 3-8: Cost component of retail electricity tariff [71]

As shown in Figure 3-8, the generation component represents about 36.36% of the total retail tariff. While the transmission component also known as grid charge constitutes about 8.16% of the retail tariff. This grid charge is made to the TCN for transmitting electricity from the GenCos to the DisCos through its transmission networks. The distribution component of the tariff is the largest (48.62%) and it is also known as distribution charge which covers the cost of electricity distribution by DisCos. This varies across the 11 DisCos depending on location as well as density of customers [45]. The services and tax component accounts for only 6.86% and is the smallest component of the electricity tariff. This component caters for the cost of running the institutions in NESI (NERC, NBET, SO, MO etc.) which operate and facilitate the NESI.

In 2015, the FGN approved feed-in tariff regulation for renewables in order to encourage more investments. The DisCos will now be obliged to source, at a fixed price, at least 50% of total production from priority renewable generators and the remaining 50% is to be sourced by the Nigerian Bulk Electricity Trading Company. The electricity generated by small renewable plants (between 1 MW and 30 MW) will automatically be integrated as renewable energy, but for larger renewable energy projects (more than 30 MW), the NERC will initiate a competitive bid process [72]. The new feed-in tariff regulation also stipulates the procedure for auctions for these larger projects.

Each variant of the MYTO has always retained a subsidy component. This is in order not to overburden the consumers with the real cost of electricity and with a view of attaining a cost-reflective tariff (CRT) overtime. This has caused a mismatch between retail electricity tariff and wholesale electricity tariff and is largely responsible for the insufficiency of cash flows and severe supply shortage [45]. To remedy this, there have been clamors to transition to a truly cost-reflective tariff where demand and supply interact to set the price of electricity.

A direct product of this is the Power Sector Recovery Program (PSRP) approved in January 2018 [73]. This policy advocates that tariffs in the NESI be appropriate and sustainable to ensure financial viability of the sector. In December 2019, NERC indicated a move to cost reflective tariff and in March 2020 issued a framework for transitioning from the present system to a more cost-reflective system. After a number of postponements due to COVID-19 and consultation with the different stakeholders, a new Service Reflective Tariff (SRT) came into effect in September 2020 [74].

The new SRT is a tariff structure whereby an upward increment in tariffs will only be possible when DisCos consult with customers, commit to increasing the number of hours of supply per day and quality of service [75]. Any tariff increase must result in substantially longer hours of power supply, good quality voltage profile, swifter response to faults clearing and provision of pre-paid meters. DisCos in the new tariff system have grouped customers into bands based on the duration and quality of electricity supply delivered to them. This will enable DisCos to conveniently charge customers tariffs proportional to the achieved service level parameters and go a long way to help reduce their collection losses and possibly the liquidity crisis in the NESI. Figure 3-9 is a publication by one of the DisCos, Ibadan Electricity Distribution Company (IBEDC), to that effect.

IBADAN ELECTRICITY DISTRIBUTION COMPANY PLC

NOTICE OF COMMENCEMENT OF SERVICE REFLECTIVE TARIFF

Dear esteemed customer,

The Management of Ibadan Electricity Distribution Company (IBEDC) Plc hereby informs its esteemed customers that as part of efforts to deliver excellent services, it will commence implementation of the Service Reflective Tariff (SRT) from the 1st of September 2020 as approved by the Nigerian Electricity Regulatory Commission(NERC).

The new tariff is commensurate and aligned with the quality and availability of power supply we have committed to each cluster of customers under the Service Reflective Tariff. Kindly find below the structure of the new tariff:

Tariff Class	Sept - Dec 2020 (₦)	Jan - June 2021 (₦)	July - Dec 2021 (₦)	Jan - Dec 2022 (₦)	Jan - Dec 2023 (₦)	Jan - Dec 2024 (₦)	Jan - Dec 2025 (₦)
Life-line (R1)	4.00	4.00	4.00	4.00	4.00	4.00	4.00
A – Non MD (min of 20hrs/day)	62.33	62.33	68.83	68.99	68.52	67.68	66.43
A - MDI (min of 20hrs/day)	61.33	61.33	67.79	67.64	66.46	66.24	65.41
A-MD2 (min of 20hrs/day)	59.70	59.70	61.54	61.39	60.33	60.31	60.10
B - Non MD (min of 16hrs/day)	58.39	58.39	65.71	65.56	65.46	63.60	63.37
B-MDI (min of 16hrs/day)	57.33	57.33	64.67	64.52	63.42	62.58	61.39
B-MD2 (min of 16hrs/day)	56.33	56. 33	58.42	58.27	57.28	57.24	56.70
C-Non MD (min of 12hrs/day)	53.97	53.97	62.58	60.41	62.40	60.54	59.22
C- MDI (min of 12hrs/day)	52.93	52.93	61.54	59.37	60.35	58.26	56.35
C-MD2 (min of 12hrs/day)	51.36	51.36	55.29	55.15	54.22	54.17	52.21
D-Non MD (min of 8hrs/day)	48.99	48.99	59.46	55.21	59.33	55.43	55.73
D-MDI (min of 8hrs/day)	47.93	47.93	58.42	54.17	57.28	54.40	52.34
D-MD2 (min of 8hrs/day)	46.67	46.67	52.17	52.02	51.15	51.11	48.88
E – Non MD (min of 4hrs/day)	30.39	30.39	31.64	31.64	31.07	31.06	31.08
E-MDI (min of 4hrs/day)	40.30	40.30	41.96	41.96	41.21	41.19	41.21
E-MD2 (min of 4hrs/day)	45.40	45.40	47.27	47.27	46.42	46.41	46.43

There shall be no tariff reviews for customers experiencing an average power supply availability of less than 12 -hours per day over a period of one month.

This review is critical to provide more efficient and reliable service to customers, upgrade aging infrastructure and be more responsive to the complaints of our customers. We therefore, appeal for the understanding and cooperation of our esteemed customers as we commence the implementation of the Service Reflective Tariff through prompt payment of electricity bills and vending, as we are resolutely committed to delivering better service.

Signed
Management

www.ibedc.com customercare@ibedc.com 0700 123 9999 ibedc.ng ibedc_ng

IBEDC
distributing power, changing lives...

Figure 3-9: Announcement of SRT by IBEDC [76]

4 Wind farm project

Following the detailed exposition on the electric power system in Nigeria, the major stakeholders as well as opportunities for renewable energy generation, this thesis assesses the planning of a 103 MW wind farm project in Nigeria. There is conclusive research that wind resources suitable for large and medium scale wind power generation can mainly be found in the northern part of Nigeria [11][14]. Figure 4-1 shows a map of the annual average wind speed at 10 m height around Nigeria.

From the six northern states evaluated in [14], Kano and Katsina have the highest wind potential with monthly wind power density (WPD) of 128.47 – 778.63 Wm^{-2} and 259.52 – 832.60 Wm^{-2}, respectively. In addition, Katsina state boasts of the only existing commercial scale wind power project in the country and our wind farm project will also be located in this state. The simulation of the wind farm will be done using the WAsP software.

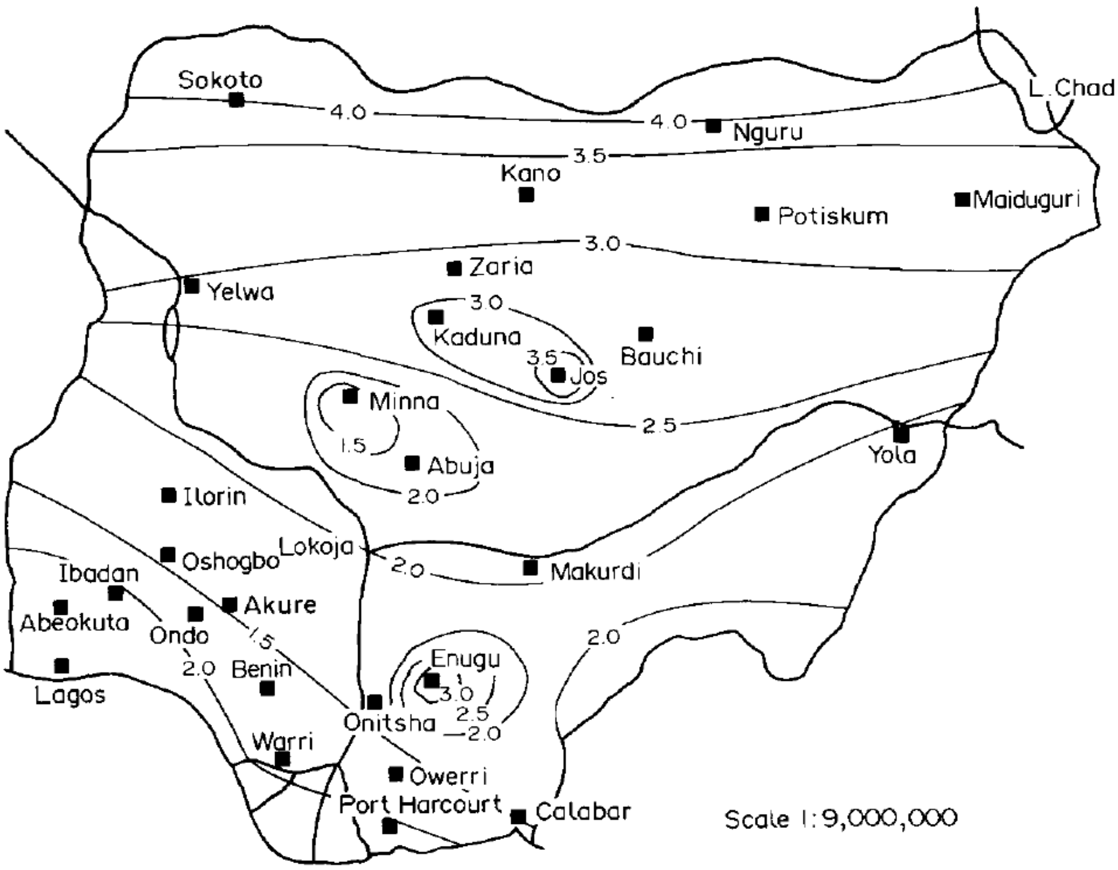


Figure 4-1: Annual average wind speeds (m/s) ; isovents at 10 m height [11]

The WAsP software uses a numerical calculation mode which is in effect an inversion of the European wind atlas analysis model (Figure 4-2) [77]. The software estimates the annual energy yield based on two fundamental assumptions: first, the generalized wind climate is nearly the same as the wind data used in predicting it. Second, the historic wind data is assumed to be adequately representative of the future wind data for the lifetime of the wind turbine [78]. It is very important to note that the reliability of our WAsP results is dependent on how correct these two assumptions are for our project.

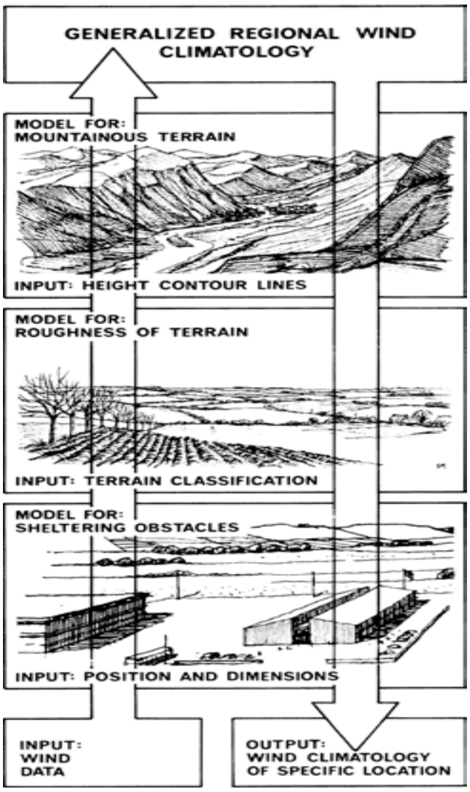


Figure 4-2: WAsP Wind Atlas Methodology [50]

In addition to WAsP, a number of other tools are used. Some of these tools are included in the WAsP application suite and others are freely available online. They include Google Earth, WAsP Climate Analyst, WAsP Map Editor and WAsP Turbine Editor.

4.1. Site selection

One of the more complex and challenging phases in wind farm development is the selection of a befitting site. The goal of this phase is to identify a wind farm site that ensures that net revenue is maximized as well as minimizing less desirable effects from noise, environment and excessive cost [79]. For these reasons, a number of parameters and exclusion factors are considered before siting a windfarm. Talinli and Aydin [80] listed about 17 considerations and grouped these considerations into four broad groups namely: technical, economic, environmental and sociopolitical.

On the other hand, Sanchez-Lozano et al. in [81] recognizing that not all sites are suitable for wind farm siting, first identified the restricted area. This is done based on status of the given territory according local and regional policies, natural heritage and biodiversity laws, conservation laws and other such legal restrictions. These restricted areas are then subtracted from the initial area and the remaining area is what is legally suitable for wind farms. In order to identify from the total available area that which is most suitable for wind farms, they further identified four groups of general criteria namely [81]:

1. Environmental criteria,
2. Orography criteria,
3. Location criteria and
4. Climatology criteria.

The environmental criteria include factors like agrological capacity, visual impact, wildlife impact etc. while the orography criteria address considerations such as slope and roughness profile of the site, area of land etc. For the location criteria, consideration is given to factors such as closeness to urban areas, main roads, electricity substations and power lines. The last criteria which is climatology considers the wind speed and wind direction data for the different possible sites. This method will be used for the purpose of this thesis.

As noted in [81], it is often advisable to combine spatial representation tools such as Geographic Information Systems (GIS) with Multicriteria Decision Making Methods (MCDM) when solving complex location problems required to for wind turbine siting. But for the purpose of this thesis, basic observation of Google Earth images, Global Wind Atlas, WAsP as well as published materials on land use in Nigeria will suffice.

4.1.1. Environment criteria

The proposed location of the wind farm is in Damari, Sabuwa local government area of Kastina state, and is largely a farming community. Idris et al. [82] found the area to be a mixture of farmland with shrubs and vegetation with some few settlements. Wind power has a clear advantage over other forms of energy development in that preexisting land uses e.g., farming and land grazing can be combined with power generation with very little problem. A careful look at the land use map (Figure 4.3) shows large suitable areas in Sabuwa specifically and in

Katsina as a whole. The center of the wind farm site is located at coordinates Lat. 11.406196°N, Long. 7.064643°E.

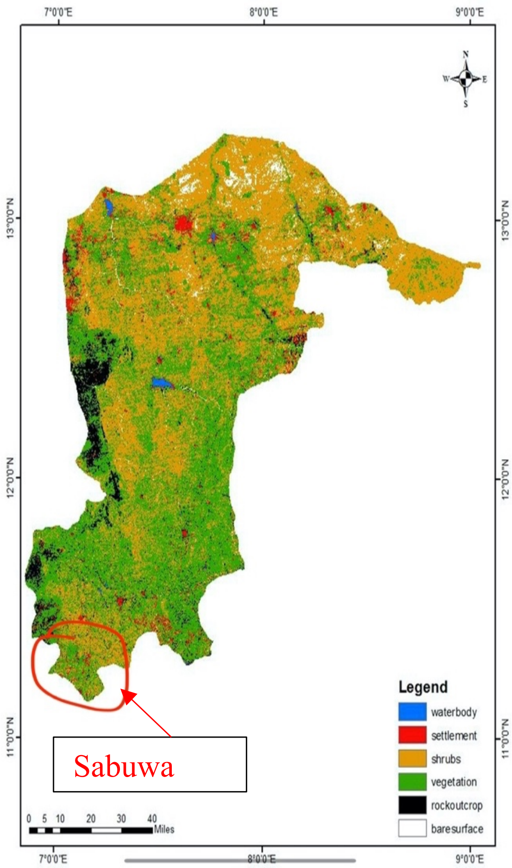


Figure 4-3: Land Use Classification - Kastina State [82]

4.1.2. Orography Criteria

The nature of the earth surface has a significant influence on the speed of wind over that surface. Since wind turbines are operated at a height above ground surface, the nature of the surface affects the wind speed at the wind turbine operating height. The orography criteria evaluate the nature of the site area such as the height, slope as well as roughness profile of the site.

In addition to windspeed, the nature of the site also affects the accessibility of cranes and trucks during construction and this can significantly affect building cost. Therefore, it is recommended that sites with slopes larger or equal to 30% be avoided for the purpose of wind farm projects [83].

With the help of the WAsP Map Editor, we generate vector maps which provide information on the topography and orography of the site in form of contour lines. These vector maps contain all the important information about the potential site and is for simulation in the main WAsP program. For our chosen site in Damari, the vector map in Figure 4-4 shows the orography and roughness lines drawn. Our site which is mostly a farming area with very few settlements and obstacles, falls in the roughness class 2.

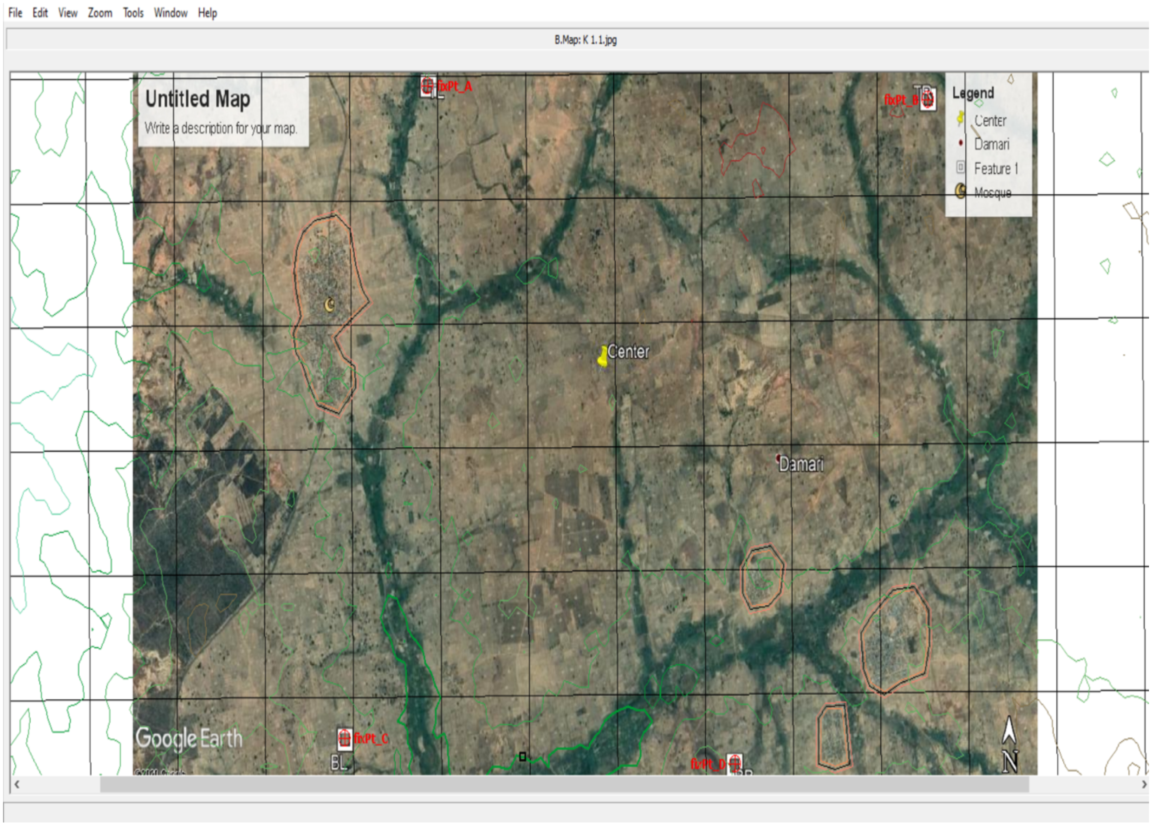


Figure 4-4: Vector map of site

4.1.3. Location criteria

The location criteria subsume mainly three important factors namely: proximity to access roads, proximity to the power grid and proximity to consumers. In order to reduce the cost of new access roads and to avoid soil sealing, wind farms are located as close as possible to the existing road network. In addition, these roads must have a minimum width of 4 m and a solid pavement [84].

Our wind farm site as showing in Figure 4-5 is located in close proximity to the main access road that leads into the township. While the exact width and conditions of these roads cannot be verified, it is nonetheless an advantage that an existing access road which could possibly be refurbished already exists.

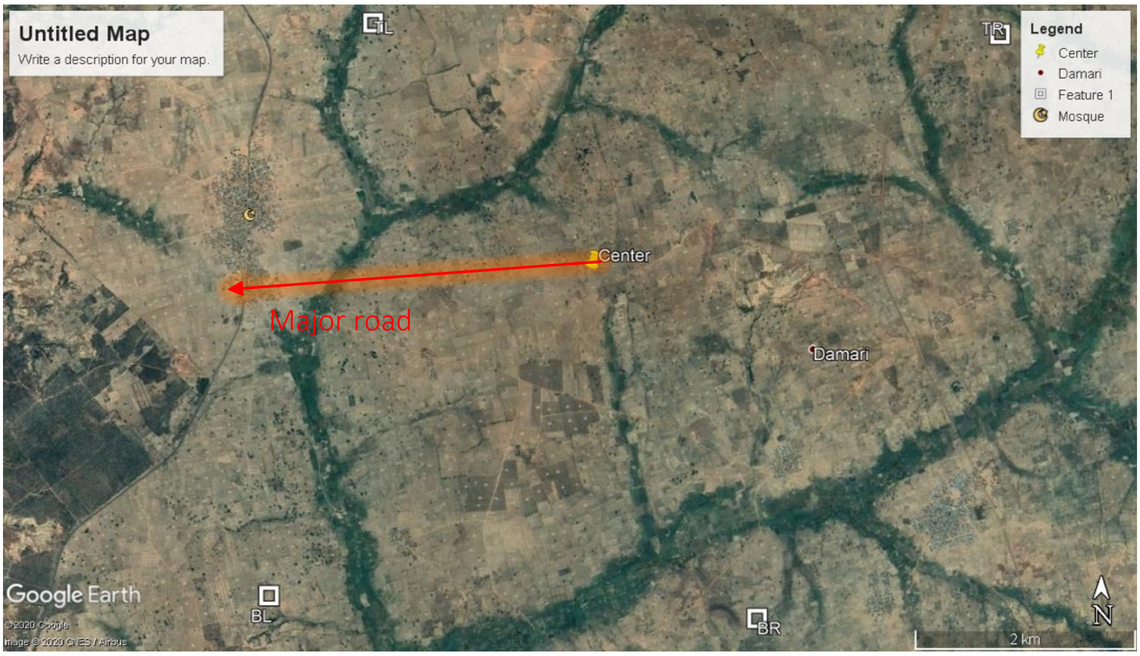


Figure 4-5:Wind Farm Proximity to Access Roads

In addition to the cost of new access roads, the costs associated with cabling and as well as electric losses over long distance transmission are also avoidable costs. These costs are greatly reduced by locating wind farm sites in close proximity to an existing electricity grid. The recommended maximum distance in reviewed literatures varies from 2 km to 20 km while the minimum is put at one rotor diameter between the blade tip and power line. Summarily, the maximum distance to the electricity grid appears to be highly dependent on the location of the study area [84].

For a large capacity wind farm (103MW) like ours, the point of connection to the grid needs to be a high voltage grid. The closest high voltage grid to Damari is the 330kV/132kV interconnection substation in Funtua which is approximately 30 km away (Figure 4-6). Additionally, this substation directly connects to substations in Kano state and Kaduna state which houses two of the biggest economies as well as the largest DisCos in the region. Together, all three states also house about 30 million people and this provides a consuming market for the generated electricity [85][86].

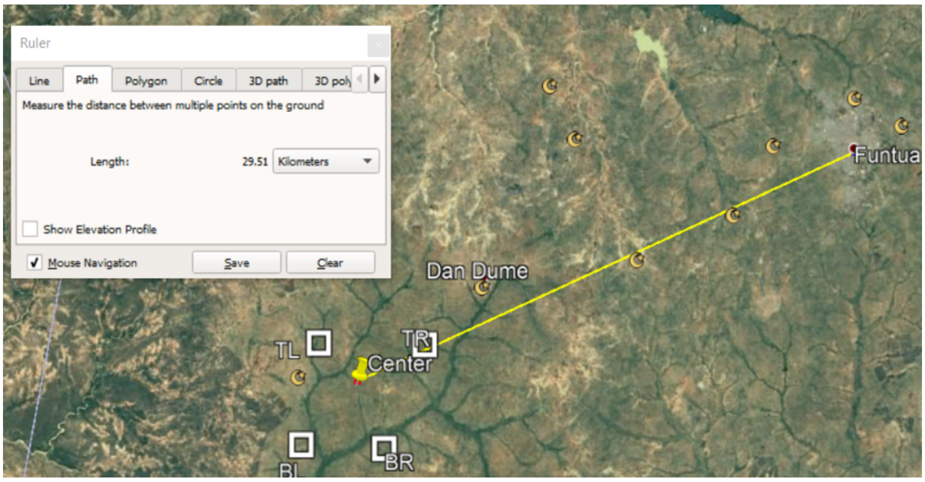


Figure 4-6: Proximity to Electricity Grid

4.1.4. Climatology criteria

The climatology i.e., the average wind speed, in a given area is a key determinant of the economic performance of a wind farm. For this reason, the climatology criteria is the most important criteria to consider before locating a wind farm [84][87]. An initial examination of the wind speed distribution in Katsina state was done using the Global Wind Atlas as shown in Figure 4-7. This showed that at a height of 100 m, a good number of locations have average wind speeds of above 7 m and are suitable for large scale wind power generation.

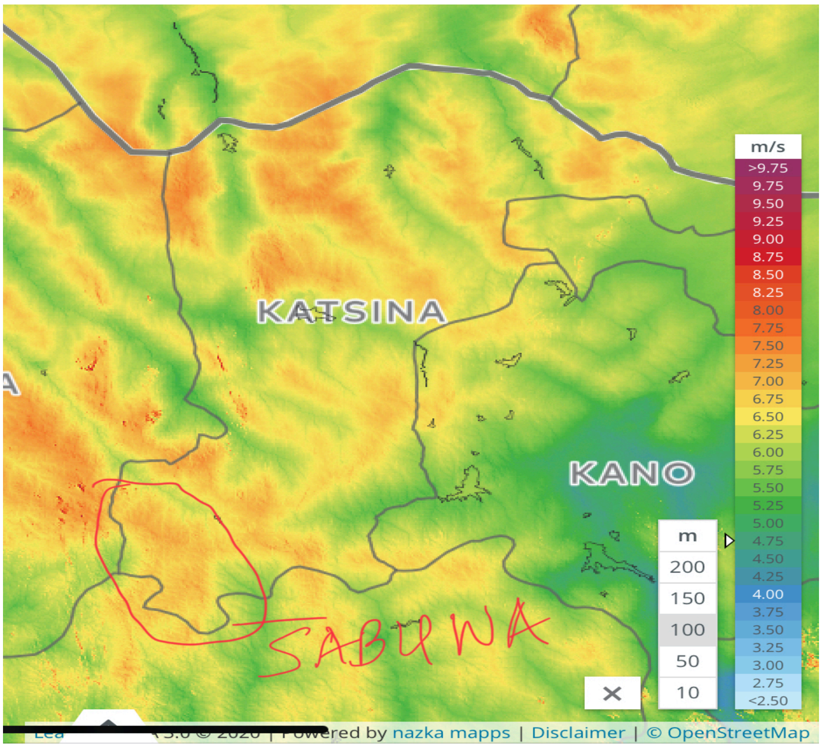


Figure 4-7: Global wind atlas for Kaduna state [88]

Sabuwa, the proposed location of the wind farm, is circled in red. It has an average wind speed of about 7 m/s. For the purpose of this thesis, we were unable to take wind speed measurements at the site and had to make extrapolations from the Global Wind Atlas. Before investing in any project, it is always better and more diligent to use wind data from measurements taken onsite. Nonetheless, wind data from Global Wind Atlas have been declared of high quality i.e. accurate, representative of the site conditions, and reliable after validation and are therefore suitable for our purpose [89].

A generalized wind climate (GWC) data which contains the terrain-independent (uniform surface roughness and atmospheric conditions as those of the measuring position) wind climate of the wind farm site is downloaded from the Global Wind Atlas to be used for the simulation in WAsP (Figure 4-8).

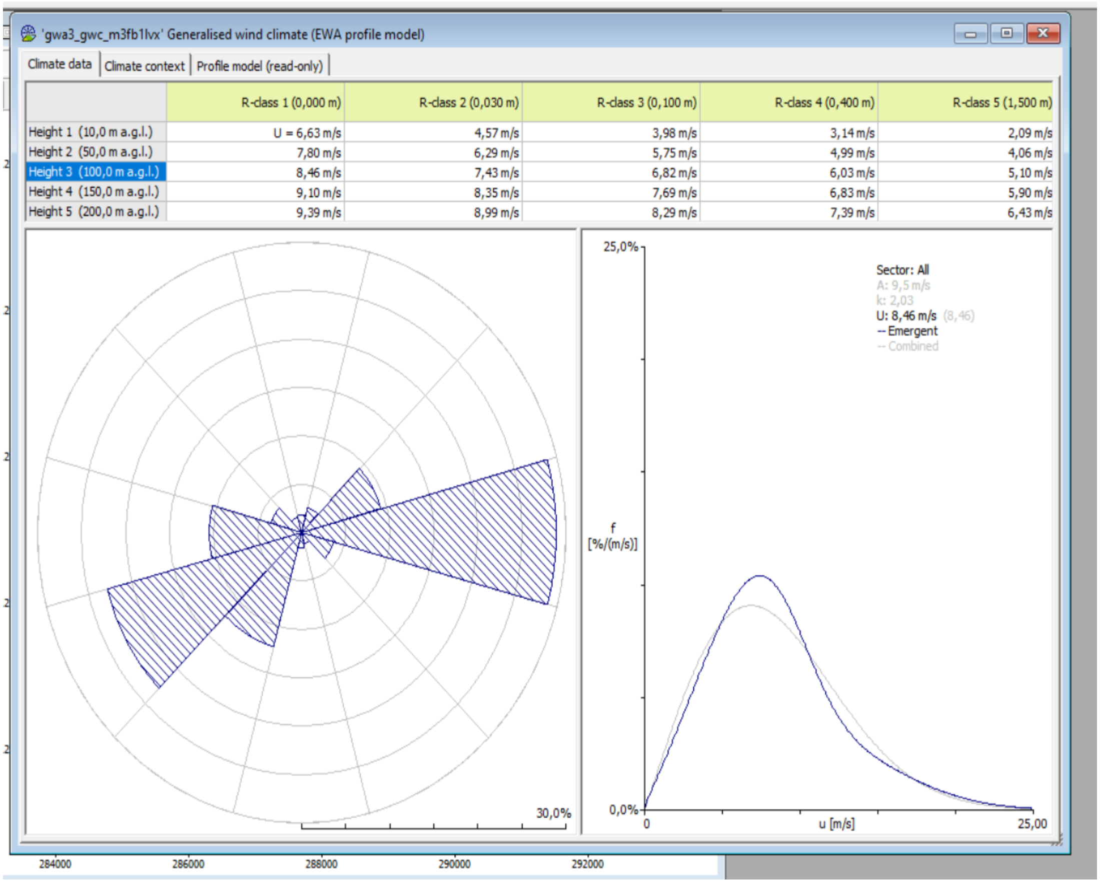
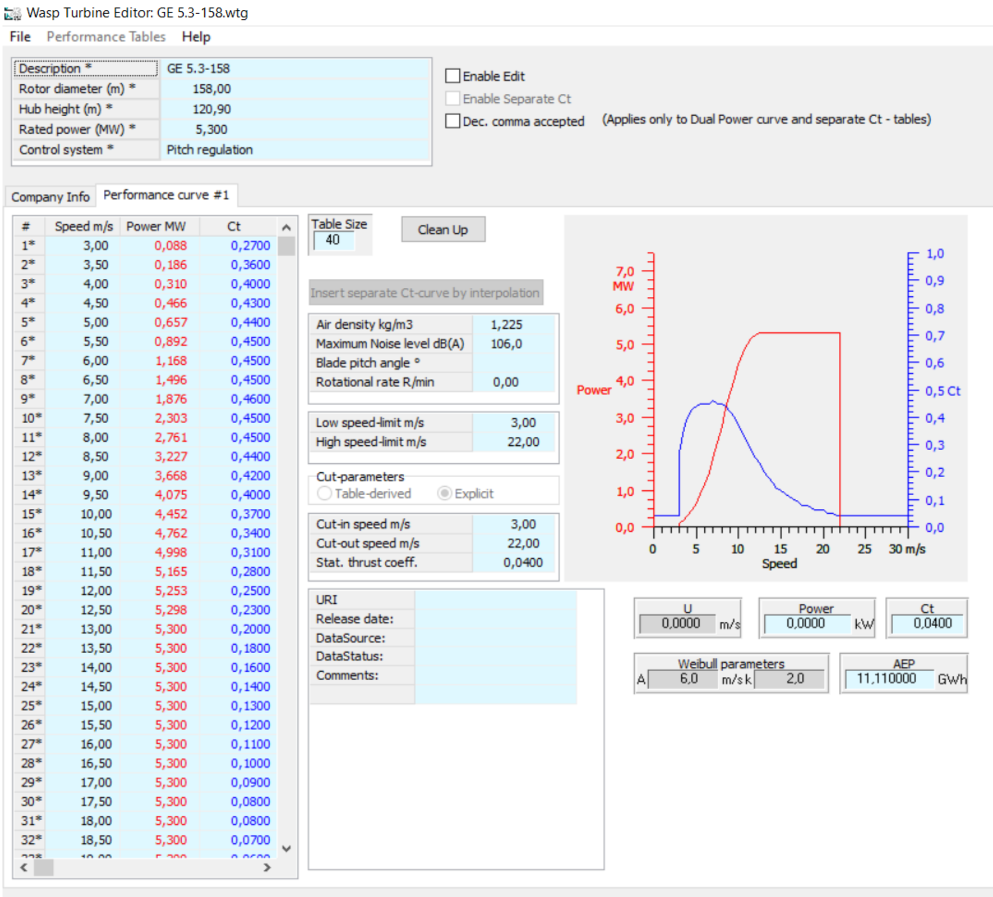


Figure 4-8: Generalized Wind Climate (GWC) Data

4.2. Turbine selection

The most important factors for energy production from a wind turbine (WT) are the swept area (size) of rotor and the wind speed. By definition, if the rotor diameter is doubled the available energy increases by a factor of four [87]. For our proposed wind farm in Sabuwa, the General Electric GE 5.3 MW-158 WT (Appendix B contains the description of its characteristics) has been chosen for the following reasons:

1. The GE 5.3 MW-158 due to its bigger size and larger rotor swept area (19,607 m^2) can catch more wind and consequently produces more power. Although such large WTs are more expensive, they can be more economical due to reduced costs of installation and operation. The cost of and amount of manpower involved in building and operating a small wind turbine is very similar to that of a bigger machine [90].
2. GE 5.3 MW-158 has been installed and greeted with positive reviews in more established markets like Europe, Brazil and Turkey [91].
3. GE as a company has a high footprint in the Energy and Power generation industry in Sub-Saharan Africa as a whole and Nigeria specifically. More recently, GE have supplied the turbines to projects like Lake Turkana Wind Power Project and the Kipeto Wind Power Project both in Kenya [92][93].
4. A very important consideration in the selection of the wind turbine is the power curve which shows how much power the rotor produces at different wind speeds and at what efficiency (coefficient of power Cp). The WAsP Turbine Editor is used to create wind turbine configurations, which include the hub height of the WT and the power curve (Figure 4-9). The wind turbine configurations will be integrated into the WAsP project and serve as a basis for the calculation of annual energy production and shading losses.



#	Speed m/s	Power MW	Ct
1*	3,00	0,088	0,2700
2*	3,50	0,186	0,3600
3*	4,00	0,310	0,4000
4*	4,50	0,466	0,4300
5*	5,00	0,657	0,4400
6*	5,50	0,892	0,4500
7*	6,00	1,168	0,4500
8*	6,50	1,496	0,4500
9*	7,00	1,876	0,4600
10*	7,50	2,303	0,4500
11*	8,00	2,761	0,4500
12*	8,50	3,227	0,4400
13*	9,00	3,668	0,4200
14*	9,50	4,075	0,4000
15*	10,00	4,452	0,3700
16*	10,50	4,762	0,3400
17*	11,00	4,998	0,3100
18*	11,50	5,165	0,2800
19*	12,00	5,253	0,2500
20*	12,50	5,298	0,2300
21*	13,00	5,300	0,2000
22*	13,50	5,300	0,1800
23*	14,00	5,300	0,1600
24*	14,50	5,300	0,1400
25*	15,00	5,300	0,1300
26*	15,50	5,300	0,1200
27*	16,00	5,300	0,1100
28*	16,50	5,300	0,1000
29*	17,00	5,300	0,0900
30*	17,50	5,300	0,0800
31*	18,00	5,300	0,0800
32*	18,50	5,300	0,0700

Figure 4-9: Wind turbine configuration using WAsP turbine editor

4.3. Turbine siting

The primary objective of optimal wind farm planning is to minimize the cost of energy and maximize the net energy production and the layout of a wind farm plays an important role in this [94]. Because wind farms are constructed in clusters, neighboring wind turbines will always cast a shade in the downwind direction. These shadows result in succeeding wind turbines experiencing reduced windspeed and thus reduced wind energy yield and this is known as the wake effect [87].

In order to reduce wake effect, careful attention is given to the prevailing wind direction and proper spacing between wind turbines in that direction. The recommended minimum spacing for turbines is about 3-5 rotor diameters within a row and 5-9 rotor diameters between rows (Figure 4-10) [95]. For the wind farm project in Sabuwa, the minimum distance between any of the turbines is about 5.3 times the rotor diameter (831.73 m). The report of the inter turbine distance can be found in Appendix C.

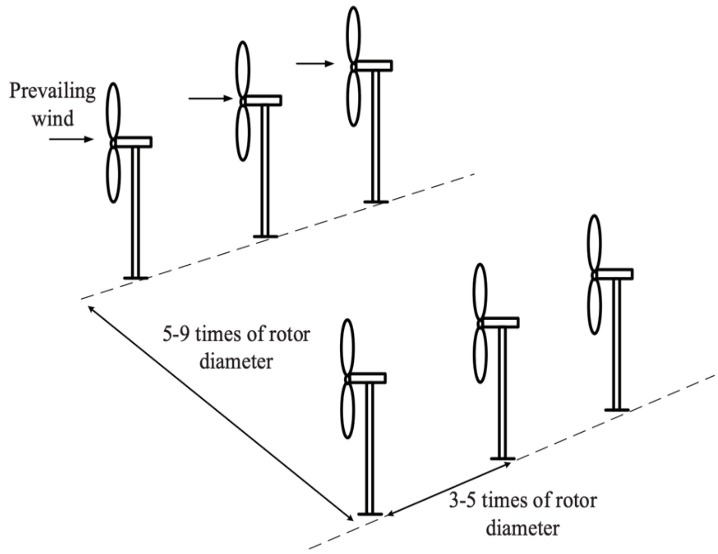


Figure 4-10: Wind farm with optimum spacing [95]

A mathematical calculation model for shading losses which supports the calculation of wind farms with different types of wind turbines was described in a publication of the European Wind Energy Association (EWEA) conference in 1986 [96]. This model is used for example in the software WAsP to simulate the annual energy yield of wind farms.

With the help of the resource grid (Figure 4-11) calculated by WAsP, an optimal arrangement of wind turbines in areas of high wind resource was ensured. The calculated resource grid shows a vector map of the wind farm site and this can be overlaid with different resources such as Average Energy Production, Mean Wind Speed, Power Density etc. Also, it can be filtered to display a vector map for specific resources and wind directions.

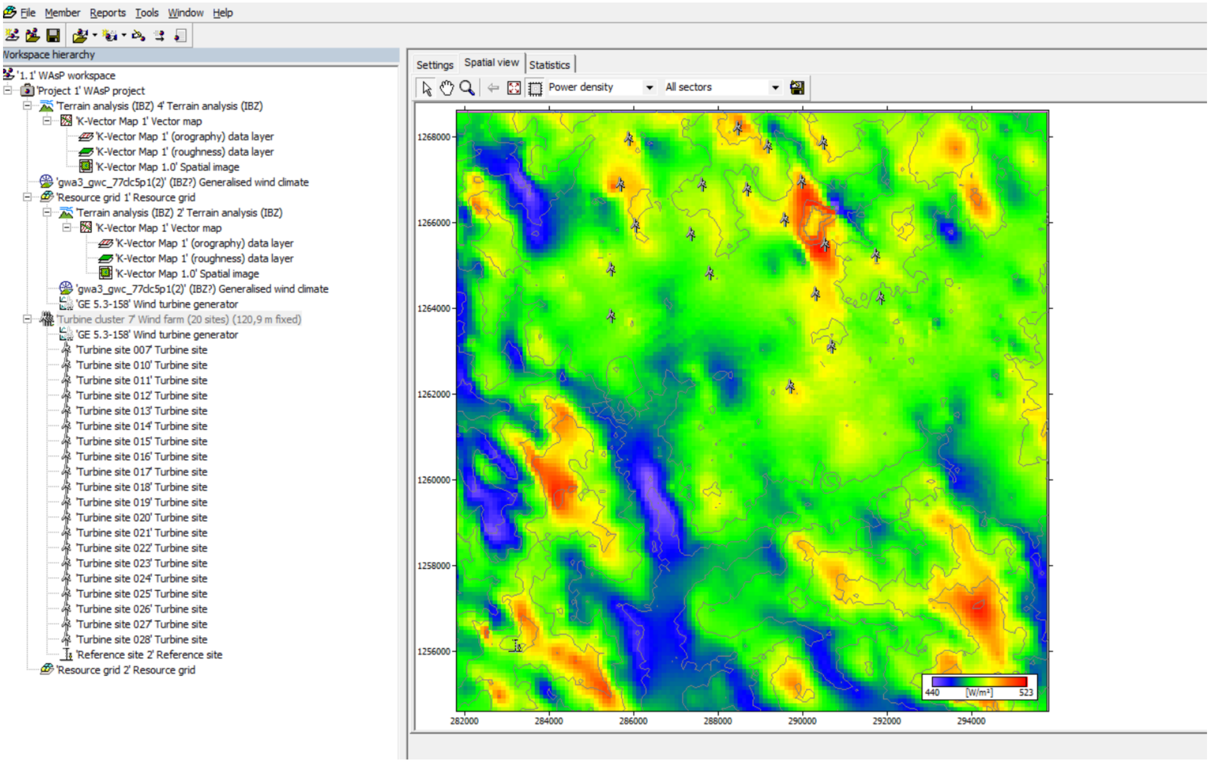


Figure 4-11: WAsP calculated resource grid with turbine arrangement

4.4. Estimated power production

The amount of power a wind turbine at a selected site will produce is the most significant input for the economic evaluation as well as the final decision to go through with the project or not [97]. The estimated power production also helps developers make a case for a project to investors and shareholders by showing the possible revenues for the project.

After the WAsP calculation, a report is generated detailing a site list containing information on each individual WT, such as Annual Energy Production (AEP) and wake losses. In addition, it provides a statistical overview of the results of the entire wind farm, such as Total gross AEP, Total net AEP or mean wind speed (m/s). A summary of the site's energy production is as shown in Table 4-1 and a fuller report can be found in Appendix D.

Table 4-1:Wind farm energy yield report

Parameter	Total	Average	Minimum	Maximum
Gross AEP (incl. wake losses) [GWh]	411.781	20.589	20.225	21.157
Gross AEP (excl. wake losses) [GWh]	418.881	20.944	20.704	21.404
Wake loss [%]	1.69	-	-	-

4.4.1. Energy yield and losses

The energy yield refers to the net amount of energy that is gained from harvesting an energy source. This is the amount of energy gained from harvesting this source minus the losses or energy wasted in producing this useful energy. As this energy yield is what will be fed into the electrical grid at the point of common coupling (PCC), there is a need to adjust for all the technical and operational losses that will occur between the turbine rotors and the PCC [78]. These losses are as summarized in Table 4-2 below:

Table 4-2:Additional technical losses which are not taken into account by WAsP [78]

Technical loss type	Typical	Typical	Range	Used	GWh/year
Availability	Turbine availability Balance of plant availability Grid availability	> 3% < 1% < 1%	2-10%	4%	16.47124
Electrical	Operational electrical losses Wind farm consumption	1-2%	2-3%	2%	8.23562
Turbine performance	Power curve adjustments High-wind hysteresis Control losses (SCADA)	1-2%	0-5%	2%	8.23562
Environmental	Blade degradation and fouling Degradation due to icing High and low temperature	1-2%	1-6%	2%	8.23562
Curtailments	Wind sector management Grid curtailment Noise, visual and environment	Design dependent	0-5%	2%	8.23562
				Total	49.41372

All these losses are evaluated for every site and subtracted from the AEP. This difference is our best estimate of the net AEP or the so-called P_{50} value. This means that the actual achieved AEP will exceed the calculated half the time over the period of one year [98].

Other than the operation and technical losses, there is a need to factor in the uncertainty associated with using a mathematical modelling tool like WAsP, its sensitivity to the various input data and parameters and how it affects the energy yield estimation. The aggregate uncertainty for the estimation of the yield of an onshore wind farm in Europe is often between

10 and 15% of AEP and for the purpose of this thesis we will assume 10%. Additionally, it is recommended to use P_{75} or P_{90} values of the AEP as this indicates a higher chance of exceedance (75% and 90% respectively) and are preferred by investors and lenders [78]. The P_{90} AEP was estimated using gaussian normal distribution and the values are as shown in Table 4-3.

Table 4-3: Energy Yield calculation

ID	Data	Value
[1]	Gross AEP P50 (incl. wake losses)	411.781GWh
[2]	Total losses	49.41 GWh
[3]	Net AEP P_{50} = *[1]-[2]*	362.37 GWh
[4]	Uncertainty	10%
[5]	Net AEP P_{90}	315.92 GWh
[6]	Capacity Factor	34.02%

To assess the performance of our wind farm, the capacity factor (C_p) is calculated. This estimates the power plant's actual generation compared to the maximum amount possible. It is divided by the rated peak power and can be evaluated using Equation 2. The calcuated C_p for our wind farm is about 34% which is about close to the global weighted-average capacity factor of 36% [99].

$$\frac{Total\ Net\ power\ generation\ per\ annum}{Total\ rated\ power\ generation\ per\ annum} \quad \text{[Equation 2]}$$

5 Wind farm economics

For the decarbonization of the energy sector to truly be successful, RE projects must not only be technically feasible but also economically viable. This in addition to sound policies will help further grow the sector as well as encourage investment from private investors and lending institutions [100]. Hence, before deciding on whether or not to invest in a wind project, an estimation of the economic profitability is required.

5.1. Wind farm cost break down structure

In a wind farm project, the cost of installation of the wind turbine itself represents the major capital expenses throughout the lifecycle of the project. This total cost can be divided into four broad categories and a breakdown of these costs is as shown in Figure 5-1. The cost of the wind turbine generator itself is the most significant of this and represents about 64-68% of the total installation cost [101]. Other cost categories are the grid connection, civil works (foundation) which cost around 9-11% and 16% respectively. The cost of planning and other miscellaneous are estimated to cost about 9% of total installation cost.

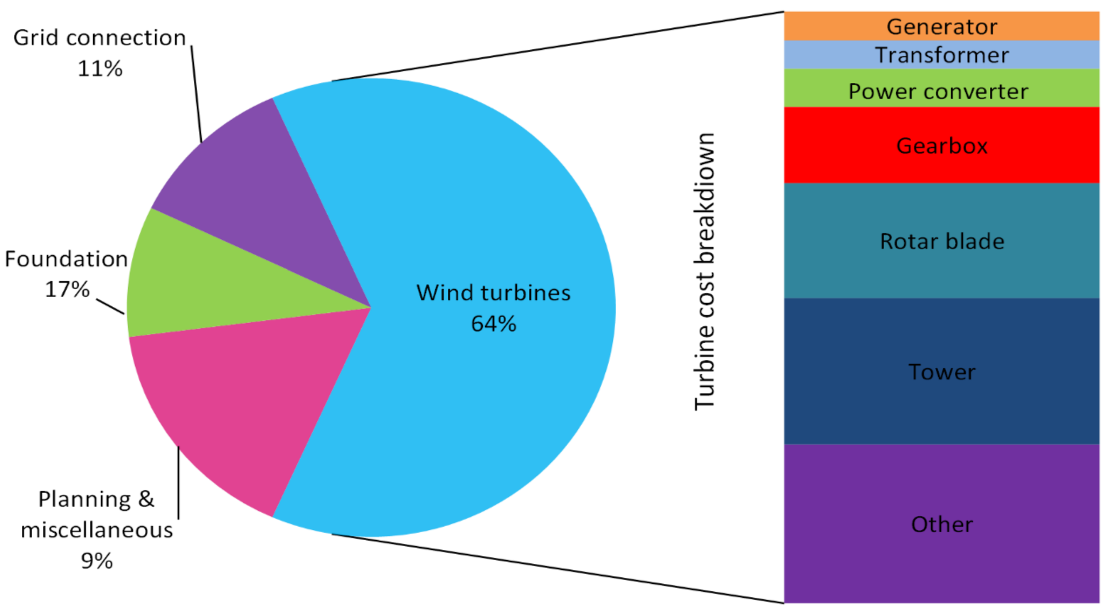


Figure 5-1: Typical Onshore wind farm installed cost breakdown [102]

In reality, the total installation cost per kilowatt varies in different regions and countries. It also depends on turbine and site-specific requirements e.g., turbine yield, limitations for transportation, local content policies, land-use limitations, labor costs etc. IRENA, in the 2019 renewable energy cost report, estimates the weighted average installation cost of onshore wind projects in Africa to be 1,952 USD/kW. In the same report, about 5% of all projects in the region had installation cost of 1,448 USD/kW or lower while another 5% had an installed cost of 2,189 USD/kW or higher [99]. For the purpose of this thesis, the total installed cost will be assumed to be 1,800 USD/kW.

5.2. Economic analysis

This economic analysis involves forecasting all the costs and revenue associated with a project, calculating different financial indicators to help evaluate the project and then analyzing these results from the perspective of the different holders of capital [103]. Indicators like LCOE, Payback Period, Internal Rate of Return, Net Present Value are some commonly used metrics for evaluating energy projects.

5.2.1. Factors influencing cost

The total lifecycle cost incurred for a wind farm project can be grouped into 3 cost groups namely: investment cost, operation and maintenance cost and financing cost [104].

1. Investment Costs, all cost incurred from the ideation of the project until commercial operation can be categorized under investment costs. They include costs such transportation, installation, civil works, legal, consultancy, bill of material (BOM) as well as project management [104]. The investment cost distribution varies from site to site and project to project.

2. Financing Costs, due to the capital-intensive nature of wind farm (upfront costs for purchase and installation of turbines) projects they are often financed by banks and other lending institutions. These institutions expect some returns on their money at maturity which is interest in the case of banks. The cumulative interest over the life of the project amount to a cost known as the cost of financing.

3. Operations and Maintenance (O&M) Costs, these are the costs incurred in keeping the wind farm operating optimally during its lifetime as well as repairing in case of faults. This includes the cost of monitoring and maintenance as well as insurance, lease, taxes, salaries etc. O&M costs increases with aging of the turbine and is estimated to range from about 1.5 to 3% of total installed cost [104]. For the purpose of this thesis, O&M cost is assumed to be 2.5%.

5.2.2. Present value of cost (PVC)

Putting into consideration that a dollar received today is worth more than a dollar received tomorrow, present value analysis is used to calculate the present worth of a transaction that will occur in the future and account for changing money valuations with time [105]. The Present Value of Cost (PVC) method is used in computing wind energy projects and other project costs as it considers the dynamic development of the economic factors. In addition, it takes into consideration the different occurring cost and incomes regardless of whether they are paid in the future or the present by discounting all payment flows to a common time [106].

For the case where the future or past cash flows are equal and occur over a specific number of periods, these costs are annualized using a Capital Recovery Factor (CRF) at a specified discounting rate. CRF converts a present amount into a stream of equal annual payments over a specified time (n) at a specific discount rate (i) [107].

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \qquad \text{[Equation 3]}$$

The annual discount rate is used to deflate the annual cash flows to account for the risk inherent in an investment and the cost of time and capital [108]. The discount rate for each project has to be determined on a case-by-case basis. This is so because each project has a unique risk profile, financing terms and ownership structure. For the purpose of this thesis and putting into considerations the numerous de-risking measures by the government and other Development Financial Institutions (DFIs), a discount rate of 6.5% will be used.

$$PVC = I_c + [O\&M_c] * \frac{1}{CRF} \qquad \text{[Equation 4]}$$

To calculate the present value of all our expenditures over the 20 years lifetime of the project, we use the inverse of the CRF. The present value cost of our wind turbine is then evaluated as the sum of the present value worth of all our costs which include our Investment cost (I_c) as well all our future costs ($O\&M_c$).

5.2.3. Levelized cost of electricity (LCOE)

The LCOE is a widely-used measure of energy technology cost presented by IRENA. The LCOE measure is defined as the present value of all costs divided by the present value of all energy produced over the energy project's lifetime [109]. It is in essence the average cost per kWh of the produced electricty by the wind farm. LCOE is given by:

$$\frac{Present\ value\ of\ all\ costs}{Present\ value\ of\ total\ energy\ production} \quad \text{[Equation 5]}$$

The net present value of energy is used as opposed to total for the same reason the net present value of cost is used. Our energy generated is going to be sold and produce future cash flows and these future cash flows need to be discounted to their present value.

As discussed in Chapter 3, there is no fixed feed-in-tariff for renewable energy projects of this size. Large projects of this nature go through a clearly defined procurement process, and if successful, a PPA at an agreed price for the lifetime of the project is signed. The last set of RE PPAs signed in Nigeria were solar IPPs in 2016 at the rate of 0.115 $/kWh. NBET, citing continued project cost decline, proposed a new rate of 0.075 $/kWh in 2018 and final closure was reached. 0.070 $/kWh will be assumed for our project and the project calculations are as shown in Table 5-1.

Table 5-1: Project calculations

ID	*Parameter*	*Unit cost*	*n*	*Unit*	*Case 1*
[1]	Annual Energy Power Output			KWh/a	315,928,044.50
[2]	Turbine Life Time			Years	20.00
[3]	Turbine Installation cost (GE 128G-5.3 MW)	$9,540,000.00	20	$	$190,800,000.00
[5]	Financing Bank [85%]*[3]			$	$162,180,000.00
[6]	Own Capital [15%]*[3]			$	$28,620,000.00
[7]	Cost of Operation & Maintenance=2.5%*[3]			$	$4,770,000.00
[8]	Discount Rate (r)			%	6.50%
[9]	Lending Interest Rate			%	5.00%
[10]	Selling Price of electricty/kWh			$	$0.070
[11]	Yearly Revenue from Electricty			$	$22,114,963.115
[12]	Capital Recovery Factor (CRF)				0.0908
[13]	Loan Terms			Years	20
[14]	Yearly Payment on Loan			$	$13,013,742.79
[15]	Yearly Expenditure (Financing + O&M)= [7]+[14]			$	$17,783,742.79
[16]	Present Value of Energy Produced =[2]/[12]			kWh	3,481,055,447.98
[17]	Present Value of Costs(PVC)			$	$243,358,279.57
[18]	LCOE = [17]/[16]			$/KWh	$0.0699

5.3. Financing

Financing is the process of providing funds for business activities, making purchases, or investing. In our case, investing in the wind farm. The decisions on how to do this and for which value must be considered to assess investment projects. While there are numerous ways to finance a project, for renewable energy projects the decision is usually between using corporate or project finance. Recently, especially in developing countries, the project finance method has found use in large and complex power plants projects and this will be used for our wind farm also [110].

Project finance entails creating a new entity separate from the sponsor (e.g., special purpose vehicle) and all lenders will depend on the cashflow of that entity/project alone. The structure for the project is divided into Owner (Equity Investors, Owner corporation) and Lender which are usually Banks and DFIs. For our wind farm, it is assumed that 15% of investment is by the owner with an 85% funding agreement from financing institutions.

Presently, debt financing, especially with commercial banks and long-term loan tenors are difficult to find and expensive (16.9%) in Nigeria [111]. An alternative financing source is the Bank of Industry (BOI) which finances industrial and manufacturing projects at lower interest rates (7%) for Nigerian companies [37]. Having said that, the easiest source of financing for renewable energy projects in developing countries are international investments, foreign credits as well as development finance from Development Finance Institutions (DFI). Overall, attracting financing and other private capital to large-scale renewable-energy projects depends on the conditions of the risk-sharing agreements, the mix of investors in the project consortium, and the relevant legal and institutional conditions [112] . For the purpose of this thesis, an interest rate of 5% per annum is assumed.

5.3.1. Cash flow analysis

To make sound investment judgment on a project, information regarding each year of the life of the investment taking into account relevant costs, taxes, and returns on investment is needed. But nobody knows the future, therefore, a good predictor of the future like a Cash Flow Model (CFM) is used. A cash flow model based in microsoft excel is used and the table can be found in Appendix E. The net cash flow (CF) for each financial year is evaluated as the diffrence of total revenue generated for that year and the total cost incurred as shown in Equation 6.

$$\sum Cash\ flow(CF)_n = \sum Benefits_n - \sum Costs_n \quad \text{[Equation 6]}$$

In order to account for the time value of money, the discounted cash flow (DCF) is calculated for each year using the 6.5% discounting rate. Furthermore, the annual cash flow from succesive years are added togther to get a discounted cumulated cash flow (DCCF) for every year throughout the life of the project. Through this cash flow anaylsis, other important indicators for measuring the viability of an investment such as the Internal Rate of Return (IRR), Debt-Service Coverage Ratio (DSCR) and Amortization can be estimated.

$$DCF_n = \frac{CF_n}{(1+i)^n} \quad \text{[Equation 7]}$$

It is important to note that the CFM requires making a number of assumptions e.g., future income, future expenditure and discount rate. These all could be altered by factors like market demand, the health of the economy etc. [113]. The dynamic view of the wind farm fiances are as shown in Figure 5-2.

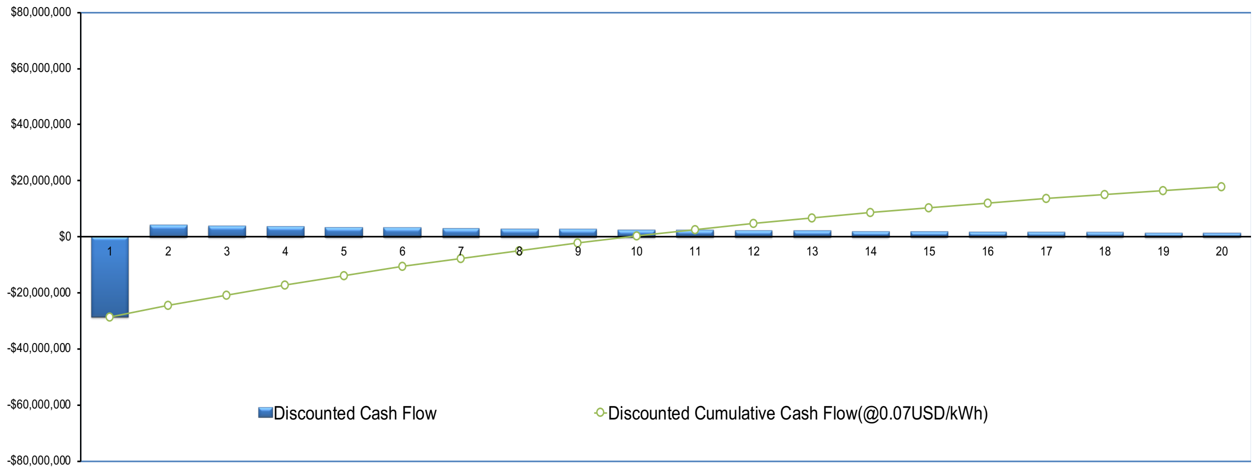


Figure 5-2: The Cash flow of the wind farm (106MW)

5.3.2. Internal rate of return (IRR)

The deployment of RE technologies requires large up-front investments which must be financed, therefore, the cost of capital makes up a significant part of the lifecycle costs of RE projects [108]. To achieve the minimum required return on capital, the future earnings of the project must be worth at least the invested capital when discounted to present value [104]. The internal rate of return (IRR) is the discount rate that makes the net present value (NPV) of all cash flows equal to zero; it is in essence, the maximum discount rate for which our project is economically viable [114].

Table 5-2 shows the input and output of the cash flow model. For our project, a positive NPV ($17,874,395.08) and a 15.13% return on equity were observed. The IRR on equity is 13.85%, considering our discount rate is 6.5%, it shows that our project can be profitable.

Table 5-2: Inputs and outputs of the cash flow model

ID	CALCULATION MODEL (an equal annual CF is assumed)	Value
	INPUT	
[1]	Price of electricty/kWh	$0.070
[2]	Equity	$28,620,000.00
[3]	Revenues p.a.	$22,114,963.12
[4]	Expenditures p.a.(O&M + Loan servicing)	$17,783,742.79
[5]	Cash flow (Rev - Expenditure)	$4,331,220.32
[6]	Discount rate	6.50%
	OUTPUT	
[7]	**Discounting factor (20a)**	**11.73**
[8]	**Net Present Value**	**$17,874,395.08**
[9]	**Return on Equity =[5]/[2]**	**15.13%**
[10]	**IRR (Equity)**	**13.85%**

5.3.3. Sensitivity analysis

Parameters such as wind speed, AEP, O&M cost, project lifetime cost of capital etc. that could affect the profitability of a wind farm are numerous and it is very important to include a sensitivity analysis in the investigation. Since a lot of these parameters are only known through predictions and assumptions, it is recommended to systematically alter some of these parameters and observe the effect on the project's key profitability indicators [115]. This provides a better overview of the project's risk profile and aids planning.

For our project, a sensitivity analysis was conducted with the selling price of electricity. The selling price of electricity was varied to 0.065 $/kWh and 0.075 $/kWh and the effect of these changes on key project profitability indicators is discussed in Chapter 6.

6. Discussion of results

The focus of this investigation as described in Chapter 1 can be summarized into three broad topics:

1. Investigating the energy system, its history as well as demand and supply trends,

2. The regulatory and legal framework of the electricity industry in Nigeria,

3. Wind farm planning and economic analysis.

For the energy system history as well as demand and supply, we relied mostly on previous research works, government archives as well publications by international agencies such as the United Nations (UN), the International Energy Agency (IEA) and the World Bank. The data on regulatory and legal framework was majorly sourced from policy documents of government agencies, news bulletins, published papers as well as publications by private sector players like KPMG and PwC. As for the wind farm planning, energy yield and economic analysis, wind data from free web-based application Global Wind Atlas was used. In addition, published scientific papers, textbooks as well as the notes of the author from the master program were consulted.

For the purpose of clarity and easy of reference, the results and findings form the thesis will be presented according to these three broad groups mentioned.

6.1. Energy system: History, demand and supply

It has been observed that the major source of energy, both supply and consumption, in Nigeria is biofuels. An estimated 90% of the consumption is for domestic cooking in the rural part of the county which is mostly cut off from the grid. This is largely due to the higher cost of alternatives, but this also means a large change in the country's vegetation and an increase in desertification.

Out of all energy consumption in Nigeria, electricity accounted for just about 2%. Additionally, only about 8.7% of the energy consumption was due to industrial activity which is a very low percentage when compared to peer countries with similar industrialization goals. Brazil (36.9%), Indonesia (23.4%), Bangladesh (23.7%) and South Africa (35%) are countries with similar population size and economic goals.

Although Nigeria was found to be rich in different renewable energy resources, safe for hydropower, the current level utilization of these resources is very minimal. The total installed hydropower capacity was found to be about 1,900 GW while the sum of other renewables amounts to just a paltry 200 MW. To further put the enormity of these resources into context, if just 1% of the land area is used to harvest PV energy it will yield about 207,000 GWh.

There is no doubt Nigeria has large energy poverty and the demand will only continue to grow with increase in population and economic activity. There are adequate renewable resources in the country to meet this demand, what needs to be improved is enabling environment and policies that encourage investors to develop these resources.

6.2. Legal and regulatory framework, opportunities for renewables

In order to improve the energy situation in the county, a number of bold policy steps have been taken over the years. In 2001, the FGN began the privatization of the electricity power sector and transferred ownership and management of key asses to the private sector. This also culminated in the creation, by an act of parliament, the Nigerian Electricity Regulation Commission (NERC). In addition to NERC, another pivotal player is the Nigerian Bulk Electricity Trading Plc (NBET) which was established as a credible off-taker of electric power from GenCos.

NERC, as the independent regulatory agency, is responsible for the technical and economic regulation of the sector. It is responsible for establishing appropriate operating codes and standards, tariff regulation as well as issuing licenses to operate in the sector. Since inception, NERC has used a Multi-Year Tariff Order (MYTO) system for determining the price of on grid electricity in Nigeria. This system updates tariffs based on new macroeconomic and sector-specific realities such as inflation, the US dollar (USD) to Naira (NGN) exchange rate, and generation capacity on the grid. In March 2020, NERC issued a framework for transitioning from the present system to a more cost-reflective system. In September 2020, new Service Reflective Tariff (SRT) came into effect. This new development will help counter some of the liquidity problems in the sector and encourage investors.

The power sector is divided into 3 subsectors: generation, transmission and distribution. The generation sector consists of 6 generation companies (GenCos) which have now been privatized. In addition to the GenCos, there are the NIPP projects which is run by government and then independent power producers. Together, they sum up the total installed capacity of

12,300 MW with an available capacity of 7,788 MW and a peak generation of 5,377 MW. It was also observed that the power sector is unhealthily coupled to international gas cost as about 80% of all this capacity is from thermal power plants while the rest is from hydropower plants. This is a motivation to diversify the energy mix and invest in renewables.

The transmission subsector is the only sector still fully owned and managed by the FGN through TCN. TCN presently has an installed wheeling capacity of about 7,500 MW which is still lower than the peak demand (12,800 MW). In the case where generation is rapidly ramped up this can be a problem for the system. Additionally, there has been persistent problems of reliability and partial or complete grid collapse. The reported transmission losses are about 7.4% which is higher than the industry benchmark of 2-6 % in similar contexts. Other than losses, the grid recorded about 206 grid collapses between 2010 and 2019. Although only 9 of those was in 2019, the situation indicates that the grid needs improvement to able to accommodate REs.

The distribution subsector which is the third pillar of the sector was also privatized in 2013. The subsector is now being fully run by 10 private distribution companies (DisCos) although the FGN still retains a 40% stake. Ikeja Electric covers the largest portion of the consumers (15%) which include central economic hub, Lagos. Although service of the DisCos has been observed to vary by location, the average performance is still below par. The major complaints are of weak grids, inadequate network coverage, overloaded transformers as well as poor billing system.

On the billing system, it was further observed that only about 3.9 million (37.7%) of all customers are metered. Benin DisCo has the highest metering rate of about 54% but some DisCos like Kano and Jos have just 19%. This metering gap has led to a lot of electricity unaccounted for and consequently a revenue crisis. Recognizing this problem, NERC, the regulator, has given all DisCos a target until December 2021 to close the metering gap. The breakout of the COVID-19 crisis will likely mean this target will not be met but it shows that the problem is recognized and there is motivation solve it.

All the three subsectors have unique infrastructure and operational problems that can stall the successful deployment of RE. However, the FGN together with Siemens AG, have signed in 2019 and already kickstarted the Nigeria Electrification Roadmap. The first phase, which is already underway, is dedicated to improving end to end operational capacity to about 7,000 MW. The second phase will specifically tackle bottle necks in the system to at least reach maximum utilization of existing capacities in all the three subsectors. The third and final phase is a long-term target of expanding all generation, transmission and distribution and get the overall system to a capacity of about 25,000 MW.

With the sale of all electricity generating assets, the FGN has shown political will to encourage private investors to enter the electricity industry, especially the generation subsector. On the side of policy, NERC has made a number of very important policy declarations over the years. Some of the most relevant for RE generation is the bulk procurement guidelines for procurement of large capacity generation from IPPs. The regulation on embedded generation allows generating plants directly connect to the distribution network. And more recently, the eligible customer regulation which allows eligible consumers to buy electricity directly from IPPs.

Some other RE generation incentivizing measures are guaranteed price and access to grid, power purchase agreements (PPA) based on plant life cycle of 20 years, requirement of DisCos and NBET to each procure a minimum of 50 per cent of the total projected renewable sourced electricity. Hence, with proper investor interests and engagement of policy makers, many more could potentially be achieved to increase the electrification rates.

6.1. Wind farm planning and economic analysis

Literature review showed that wind resource in northern part of Nigeria is more suitable for large scale commercial energy production. Based on considerations of environment, orography and location, a site in Sabuwa local area of Kastina state is selected. The site is observed to fall in roughness class 2 with no large obstacles and mostly farmlands. Based on wind climate data from Global Wind Atlas, the average wind velocity is assumed to be 8.46 m/s at the wind turbine hub height of 129 m. The direction of wind flow was from the east and southwest.

The simulation by WAsP produced an AEP of 412 GWh and an average shading loss between turbines of about 2%. The P_{90} AEP is about 315.92 GWh and this amount to a capacity factor of 34%. This is comparable with the global average of 36%. Although the actual performance of the turbine will depend on the wind turbine technology as well as maintenance regime, this result demonstrates an overall good energy production.

For the economic analysis, key project financial indicators such as LCOE, IRR_{equity}, NPV and return on equity were calculated. The LOCE of the project was 0.069 USD/kWh. This is not only competitive with global prices of comparable projects, but also at par with recent onshore projects in Africa. For the Nigerian context, the LCOE of gas-powered plants, the dominant source of electricity in Nigeria, is between 0.044–0.068 USD/kWh. An LCOE of 0.069 USD/kWh means this project is competitive.

The result of the sensitivity analysis is as shown in Figure 6-1 and the complete cash flow table can be found is in Appendix E. The reduction of our electricity selling price to 0.065 USD/kWh saw a rapid increase in the equity payback period (10 years to about 20 years) and a similarly rapid decrease in the IRR_{equity} (13.85% to 6.92%). The NPV also reduced and the return on equity was about 9.61% (see Table 6-1).

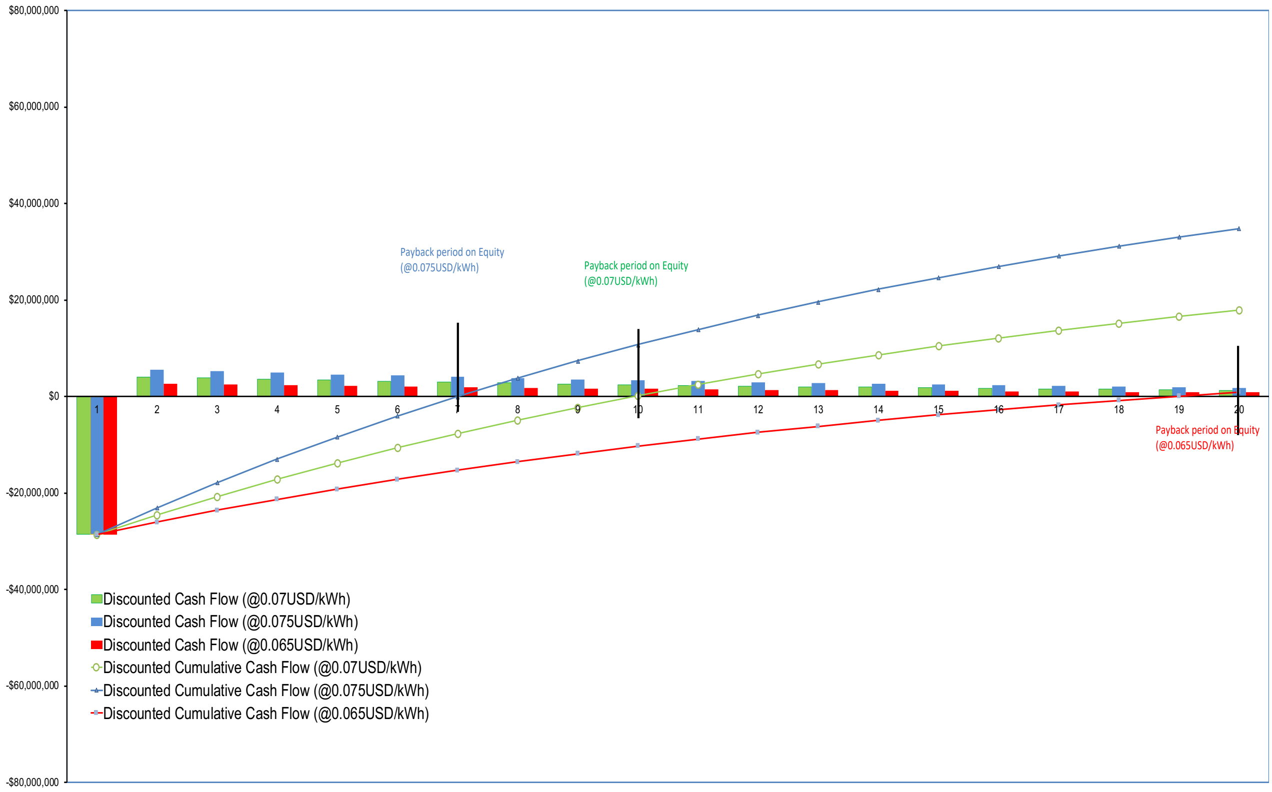


Figure 6-1: Sensitivity analysis (Discounting Rate)

Similarly, an increase of electricity selling price to 0.075 USD/kWh had a drastic effect on the project indicators. The IRR_{equity} increased to about 20.1% and the payback period on equity reduced to just 7 years. The resulting increase in cash flow also saw return on equity increase to about 20.65%. These results demonstrate clearly that the selling price of electricity is a very important factor in the economic health of the project and effort should be made to negotiate the best price possible. A more concise overview of the sensitivity analysis result is shown in Table 6-1.

Table 6-1: Inputs and outputs of the cash flow model (sensitivity analysis)

ID	Calculation Model (Equal annual cash flow is assumed)	Column1	Case 1	Case 2	Case 3
	INPUT	Price of electricty/kWh	*0.07 USD/kWh*	*0.075 USD/kWh*	*0.065 USD/kWh*
[1]	Equity		$28,620,000.00	$28,620,000.00	$28,620,000.00
[2]	Revenues p.a.		$22,114,963.12	$23,694,603.34	$20,535,322.89
[3]	Expenditures p.a. (O&M + Loan servicing)		$17,783,742.79	$17,783,742.79	$17,783,742.79
[4]	Cash flow		$4,331,220.32	$5,910,860.55	$2,751,580.10
	DISCOUNT RATE		6.50%	6.50%	6.50%
	OUTPUT				
[5]	**Discounting factor (20a)**		**11.73**	**11.73**	**11.73**
[6]	**Net Present Value**		**$17,874,395.08**	**$34,831,375.11**	**$917,415.04**
[7]	**Return on Equity =[4]/[1]**		**15.13%**	**20.65%**	**9.61%**
[8]	**IRR (Equity)**		**13.85%**	**20.01%**	**6.92%**

6.4. Future work

This thesis was not conceived to be a detailed planning of any particular wind farm, rather as an initiator to shed light on a hitherto ignored sector, the opportunities in the sector and framework within which prospective projects will be developed. As a way to demonstrate practical viability, this thesis opted to minimally plan, simulate and do an economic analysis of a 103 MW wind farm.

Due to this limitation of scope, an online data obtained from the global wind atlas was used for the simulation. While this is sufficient for general insights, further investigations using wind data measured on the actual wind farm site over a period of at least 12 months are required. This is needed for more accurate energy production estimation and project planning.

In addition to the sensitivity analysis conducted using the electricity selling price, it is recommended to conduct further sensitivity analysis on other key project variables. Metrics such as cost of turbine, O&M cost, debt-to-equity ratio, interest rate etc. are other project variables that could potentially affect the economic viability of a project. A good understanding and visibility of how these variables affect the project's economic health is key for making sound investment decisions.

It is hoped that this thesis will serve as both a call to action as well as a building block upon which other more detailed works would be carried out investigating commercial wind energy production in Nigeria.

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Appendix A: License application requirements

PART I – General requirements

Legal	Financial	Technical
Certificate of Registration, Certificate of Incorporation,	Tariff methodology and calculation	Details of experience in and knowledge of the electricity industry
Memorandum and Articles of Association, Deed of	Short term cash flow projection	Summary of skills and experience of the Directors and top management
Partnership, Deed of Trust (as applicable)	Medium term cash flow projection	
Certified Audited Financial Statements and Accounts for the last or latest three years (if applicable)	Funding arrangements	
Tax Clearance Certificate for the last or latest three years (if applicable)	Investment plans	
Environmental Impact Assessment Report and approval agreements (e.g., PPA, FSA etc.), if applicable.	Asset base	
Certificate of Occupancy for project site (if any)	Risk Management Strategy	
Evidence of consents or permits from other relevant authorities and agencies relating to the project	Management experience and depth	

PART II – Specific requirements
Technical data requirement

Site Information of Power Station	Power Station Information	Generating Unit Information
Furnish location map to scale showing roads, railway lines, transmission lines, rivers, and reservoirs if any.	Number of Generating Units	Generator Type
For Hydro, map should show proposed dam, reservoir area, water conductor system, fore bay, powerhouse etc.	Size of Generating Units (MW)	Rating (MVA)
For Hydro station, provide information on area of villages, forestland, agricultural land etc.	Fuel Type	Terminal Voltage (KV)
Fuel supply arrangement (contractual, gas and oil pipelines-where available)	Annual Generation	Rated Power Factor
Furnish information on means of Coal transport from mines or means of coal carriage if coal is to be brought from distance.	Running Regime	Unit efficiency
In case of other fuels, furnish details of sources of fuel and their transport.	Station load	Reactive Power capability (MVAr) in the range 0,95 leading and 0,85 lagging
Water Sources (furnish information on availability of water for operation of the Power Station).	Station Load Factor	Short Circuit Ratio
Environmental (State whether forests, wetlands, mining areas are affected).	Ancillary Services to be provided by station	Direct axis transient reactance (% on MVA rating)

On the site map show area required for the following: • Fuel delivery point, • fuel storage space, • water pipeline, • liquid waste disposal area, • ash disposal area (in case of coal plant)	Single line diagram of station including connection at Transmission Substation	Direct axis sub-transient reactance (% on MA rating)
	Commissioning Date	Auxiliary Power requirement
	State whether development will be carried out in phases and if so, furnish details	Generator Transformer/Station Transformer
	Information on waste handling and management	Turbine (Thermal Power Plant)

Technical data requirement for captive/off-grid generation

Requirement
Number of Generating Units per site
Size of Generating Units (MW and MVA)
Fuel Type
Terminal Voltage
Rated Power Factor
Reactive Power Capability
Noise Level (State distance from power plant)
Environmental Impact Assessment (for plants greater than 10MW). If EIA is not applicable, give detailed information on effluents and discharges and how they will be managed
State if generator will be connected directly or indirectly to Distribution or Transmission Network
Provide information on protective measures against infeed current (if applicable) • fuel storage space, • water pipeline, • liquid waste disposal area, • ash disposal area (in case of coal plant)

APPENDIX B: Wind turbine datasheet

GE Renewable Energy

Referenzertrag
GE 5.3-158

Auftraggeber:	GE Wind Energy GmbH
WEA-Typ:	GE 5.3-158
Hersteller:	GE Wind Energy GmbH
Nennleistung:	5300 kW
Rotorkreisfläche:	19.607 m²
Abschaltwind-geschwindigkeit:	22 m/s
Messbericht:	
Messinstitut:	
Messort:	
Berichtsdatum:	
Richtlinie:	Technische Richtlinie für Windkraftanlagen, Teil 5; Rev. 7
EEG-konform:	Nein (basis Theoretische Kennlinie, Rev. 02)
Korrekturen:	Nein

Leistungskurve		
v_{Wind} in m/s	P_{Wirk} in kW	cp
3.0	88	0.27
3.5	186	0.36
4.0	310	0.40
4.5	466	0.43
5.0	657	0.44
5.5	892	0.45
6.0	1168	0.45
6.5	1496	0.45
7.0	1876	0.46
7.5	2303	0.45
8.0	2761	0.45
8.5	3227	0.44
9.0	3668	0.42
9.5	4075	0.40
10.0	4452	0.37
10.5	4762	0.34
11.0	4998	0.31
11.5	5165	0.28
12.0	5253	0.25
12.5	5298	0.23
13.0	5300	0.20
13.5	5300	0.18
14.0	5300	0.16
14.5	5300	0.14
15.0	5300	0.13
15,0-cutout	5300	0,04-0,12

Berechneter Referenzertrag	
Nabenhöhe in m	Referenzertrag EEG 2017 in MWh
101	82,242
120,9	88,745
149	96,365
161	99,195

Anmerkungen bzgl. der Eignung für das EEG
(Zutreffendes ist angekreuzt)

☐	Die verwendete Leistungskurve wurde nach der Technischen Richtlinie für Windenergieanlagen (TR) Teil 2 oder MEASNET- Richtlinie oder nach einer anderen allgemein anerkannten Regel der Technik ermittelt unter Berücksichtigung der Ergänzungen der TR Teil 5. Die ausgewiesenen Referenzerträge sind uneingeschränkt für Anlagen gleichen Typs nutzbar.
☐	Die verwendete Leistungskurve wurde nach einem vergleichbaren Verfahren vor dem 01.01.2000 ermittelt. Die ausgewiesenen Referenzerträge sind nur zu verwenden, wenn mit der Errichtung von Anlagen des Typs nach dem 31.12.2001 im Geltungsbereich des EEG nicht mehr begonnen wurde.
☐	Die verwendete Leistungskurve wurde aus den Konstruktionsunterlagen des Anlagentyps ermittelt. Die ausgewiesenen Referenzerträge sind nur zu verwenden, wenn Anlagen des Typs nach dem 01.04.2000 im Geltungsbereich des EEG nicht mehr in Betrieb genommen worden sind.
☒	Die hier angegebenen Referenzenergieerträge erfüllen nicht alle Bedingungen des Erneuerbaren-Energien-Gesetzes. Die Berechnungen sind auf Basis der berechneten Leistungskennlinie durchgeführt worden und sind daher als Grundlage für die Ermittlung der Laufzeit der erhöhten Vergütung nicht geeignet.

GE Wind Energy GmbH
Holsterfeld 16
D-48499 Salzbergen

APPENDIX C: Distance data

[meters]	Turbine site 007	Turbine site 010	Turbine site 011	Turbine site 012	Turbine site 013	Turbine site 014	Turbine site 015	Turbine site 016	Turbine site 017	Turbine site 018	Turbine site 019	Turbine site 020	Turbine site 021	Turbine site 022	Turbine site 023	Turbine site 024	Turbine site 025	Turbine site 026	Turbine site 027	Turbine site 028
Turbine site 007	0	6.206,71	3.610,28	3.017,78	1.939,81	3.074,85	1.993,05	3.986,35	5.304,08	6.291,63	2.967,27	6.270,73	1.075,14	6.705,35	3.085,46	5.050,97	1.034,01	4.301,68	4.904,08	2.046,97
Turbine site 010	6.206,71	0	5.633,09	4.706,46	5.163,57	6.157,11	5.047,07	3.902,68	2.235,87	1.357,50	3.264,68	3.684,10	6.923,78	2.967,18	4.545,84	3.410,85	5.248,22	4.793,97	5.745,95	4.263,08
Turbine site 011	3.610,28	5.633,09	0	1.122,16	1.793,96	831,73	4.689,53	1.754,11	3.640,40	4.920,67	3.254,34	3.593,08	3.293,42	4.427,68	5.429,66	2.665,01	3.648,48	1.148,06	1.309,94	2.733,16
Turbine site 012	3.017,78	4.706,46	1.122,16	0	1.082,73	1.452,40	3.721,41	1.126,13	2.935,55	4.179,81	2.132,31	3.394,49	3.042,67	4.033,68	4.372,56	2.240,25	2.787,28	1.300,02	2.100,87	1.682,78
Turbine site 013	1.939,81	5.163,57	1.793,96	1.082,73	0	1.555,66	2.924,53	2.126,24	3.728,28	4.886,61	2.074,95	4.428,14	2.024,98	4.983,89	3.755,09	3.234,38	1.855,05	2.362,25	3.026,99	1.186,90
Turbine site 014	3.074,85	6.157,11	831,73	1.452,40	1.555,66	0	4.447,68	2.404,91	4.300,40	5.570,41	3.436,21	4.403,86	2.584,63	5.205,08	5.310,00	3.415,73	3.326,27	1.962,69	2.052,02	2.699,51
Turbine site 015	1.993,05	5.047,07	4.689,53	3.721,41	2.924,53	4.447,68	0	4.271,81	4.885,21	5.534,38	2.341,93	6.271,07	3.065,27	6.403,06	1.096,37	5.092,11	1.161,13	4.953,86	5.821,78	2.068,08
Turbine site 016	3.986,35	3.902,68	1.754,11	1.126,13	2.126,24	2.404,91	4.271,81	0	1.899,25	3.175,97	2.164,25	2.302,47	4.139,48	2.907,66	4.689,69	1.117,47	3.545,20	971,90	2.008,39	2.239,37
Turbine site 017	5.304,08	2.235,87	3.640,40	2.935,55	3.728,28	4.300,40	4.885,21	1.899,25	0	1.280,41	2.559,51	1.689,94	5.723,30	1.520,34	4.875,73	1.178,63	4.570,24	2.657,01	3.546,14	3.272,42
Turbine site 018	6.291,63	1.357,50	4.920,67	4.179,81	4.886,61	5.570,41	5.534,38	3.175,97	1.280,41	0	3.366,37	2.385,78	6.828,31	1.610,08	5.277,82	2.388,47	5.449,23	3.924,41	4.769,67	4.247,76
Turbine site 019	2.967,27	3.264,68	3.254,34	2.132,31	2.074,95	3.436,21	2.341,93	2.164,25	2.559,51	3.366,37	0	3.944,19	3.663,20	4.070,05	2.549,83	2.797,22	2.083,01	3.041,48	4.048,16	1.008,99
Turbine site 020	6.270,73	3.684,10	3.593,08	3.394,49	4.428,14	4.403,86	6.271,07	2.302,47	1.689,94	2.385,78	3.944,19	0	6.433,75	1.017,47	6.424,01	1.224,00	5.732,57	2.445,27	2.895,37	4.391,27
Turbine site 021	1.075,14	6.923,78	3.293,42	3.042,67	2.024,98	2.584,63	3.065,27	4.139,48	5.723,30	6.828,31	3.663,20	6.433,75	0	7.008,72	4.153,96	5.253,68	2.029,50	4.208,65	4.597,09	2.660,74
Turbine site 022	6.705,35	2.967,18	4.427,68	4.033,68	4.983,89	5.205,08	6.403,06	2.907,66	1.520,34	1.610,08	4.070,05	1.017,47	7.008,72	0	6.381,35	1.804,54	6.038,49	3.292,45	3.869,42	4.713,83
Turbine site 023	3.085,46	4.545,84	5.429,66	4.372,56	3.755,09	5.310,00	1.096,37	4.689,69	4.875,73	5.277,82	2.549,83	6.424,01	4.153,96	6.381,35	0	5.327,27	2.183,88	5.497,92	6.447,30	2.698,52
Turbine site 024	5.050,97	3.410,85	2.665,01	2.240,25	3.234,38	3.415,73	5.092,11	1.117,47	1.178,63	2.388,47	2.797,22	1.224,00	5.253,68	1.804,54	5.327,27	0	4.512,68	1.574,39	2.382,87	3.172,70
Turbine site 025	1.034,01	5.248,22	3.648,48	2.787,28	1.855,05	3.326,27	1.161,13	3.545,20	4.570,24	5.449,23	2.083,01	5.732,57	2.029,50	6.038,49	2.183,88	4.512,68	0	4.075,83	4.853,22	1.341,80
Turbine site 026	4.301,68	4.793,97	1.148,06	1.300,02	2.362,25	1.962,69	4.953,86	971,90	2.657,01	3.924,41	3.041,48	2.445,27	4.208,65	3.292,45	5.497,92	1.574,39	4.075,83	0	1.038,27	2.886,27
Turbine site 027	4.904,08	5.745,95	1.309,94	2.100,87	3.026,99	2.052,02	5.821,78	2.008,39	3.546,14	4.769,67	4.048,16	2.895,37	4.597,09	3.869,42	6.447,30	2.382,87	4.853,22	1.038,27	0	3.777,79
Turbine site 028	2.046,97	4.263,08	2.733,16	1.682,78	1.186,90	2.699,51	2.068,08	2.239,37	3.272,42	4.247,76	1.008,99	4.391,27	2.660,74	4.713,83	2.698,52	3.172,70	1.341,80	2.886,27	3.777,79	0

[rotor diameters]	to Turbine site 007	to Turbine site 010	to Turbine site 011	to Turbine site 012	to Turbine site 013	to Turbine site 014	to Turbine site 015	to Turbine site 016	to Turbine site 017	to Turbine site 018	to Turbine site 019	to Turbine site 020	to Turbine site 021	to Turbine site 022	to Turbine site 023	to Turbine site 024	to Turbine site 025	to Turbine site 026	to Turbine site 027	to Turbine site 028
from Turbine site 007 (158,0m)	0	39,3	22,8	19,1	12,3	19,5	12,6	25,2	33,6	39,8	18,8	39,7	6,8	42,4	19,5	32,0	6,5	27,2	31,0	13,0
from Turbine site 010 (158,0m)	39,3	0	35,7	29,8	32,7	39,0	31,9	24,7	14,2	8,6	20,7	23,3	43,8	18,8	28,8	21,6	33,2	30,3	36,4	27,0
from Turbine site 011 (158,0m)	22,8	35,7	0	7,1	11,4	5,3	29,7	11,1	23,0	31,1	20,6	22,7	20,8	28,0	34,4	16,9	23,1	7,3	8,3	17,3
from Turbine site 012 (158,0m)	19,1	29,8	7,1	0	6,9	9,2	23,6	7,1	18,6	26,5	13,5	21,5	19,3	25,5	27,7	14,2	17,6	8,2	13,3	10,7
from Turbine site 013 (158,0m)	12,3	32,7	11,4	6,9	0	9,8	18,5	13,5	23,6	30,9	13,1	28,0	12,8	31,5	23,8	20,5	11,7	15,0	19,2	7,5
from Turbine site 014 (158,0m)	19,5	39,0	5,3	9,2	9,8	0	28,1	15,2	27,2	35,3	21,7	27,9	16,4	32,9	33,6	21,6	21,1	12,4	13,0	17,1
from Turbine site 015 (158,0m)	12,6	31,9	29,7	23,6	18,5	28,1	0	27,0	30,9	35,0	14,8	39,7	19,4	40,5	6,9	32,2	7,3	31,4	36,8	13,1
from Turbine site 016 (158,0m)	25,2	24,7	11,1	7,1	13,5	15,2	27,0	0	12,0	20,1	13,7	14,6	26,2	18,4	29,7	7,1	22,4	6,2	12,7	14,2
from Turbine site 017 (158,0m)	33,6	14,2	23,0	18,6	23,6	27,2	30,9	12,0	0	8,1	16,2	10,7	36,2	9,6	30,9	7,5	28,9	16,8	22,4	20,7
from Turbine site 018 (158,0m)	39,8	8,6	31,1	26,5	30,9	35,3	35,0	20,1	8,1	0	21,3	15,1	43,2	10,2	33,4	15,1	34,5	24,8	30,2	26,9
from Turbine site 019 (158,0m)	18,8	20,7	20,6	13,5	13,1	21,7	14,8	13,7	16,2	21,3	0	25,0	23,2	25,8	16,1	17,7	13,2	19,2	25,6	6,4
from Turbine site 020 (158,0m)	39,7	23,3	22,7	21,5	28,0	27,9	39,7	14,6	10,7	15,1	25,0	0	40,7	6,4	40,7	7,7	36,3	15,5	18,3	27,8
from Turbine site 021 (158,0m)	6,8	43,8	20,8	19,3	12,8	16,4	19,4	26,2	36,2	43,2	23,2	40,7	0	44,4	26,3	33,3	12,8	26,6	29,1	16,8
from Turbine site 022 (158,0m)	42,4	18,8	28,0	25,5	31,5	32,9	40,5	18,4	9,6	10,2	25,8	6,4	44,4	0	40,4	11,4	38,2	20,8	24,5	29,8
from Turbine site 023 (158,0m)	19,5	28,8	34,4	27,7	23,8	33,6	6,9	29,7	30,9	33,4	16,1	40,7	26,3	40,4	0	33,7	13,8	34,8	40,8	17,1
from Turbine site 024 (158,0m)	32,0	21,6	16,9	14,2	20,5	21,6	32,2	7,1	7,5	15,1	17,7	7,7	33,3	11,4	33,7	0	28,6	10,0	15,1	20,1
from Turbine site 025 (158,0m)	6,5	33,2	23,1	17,6	11,7	21,1	7,3	22,4	28,9	34,5	13,2	36,3	12,8	38,2	13,8	28,6	0	25,8	30,7	8,5
from Turbine site 026 (158,0m)	27,2	30,3	7,3	8,2	15,0	12,4	31,4	6,2	16,8	24,8	19,2	15,5	26,6	20,8	34,8	10,0	25,8	0	6,6	18,3
from Turbine site 027 (158,0m)	31,0	36,4	8,3	13,3	19,2	13,0	36,8	12,7	22,4	30,2	25,6	18,3	29,1	24,5	40,8	15,1	30,7	6,6	0	23,9
from Turbine site 028 (158,0m)	13,0	27,0	17,3	10,7	7,5	17,1	13,1	14,2	20,7	26,9	6,4	27,8	16,8	29,8	17,1	20,1	8,5	18,3	23,9	0

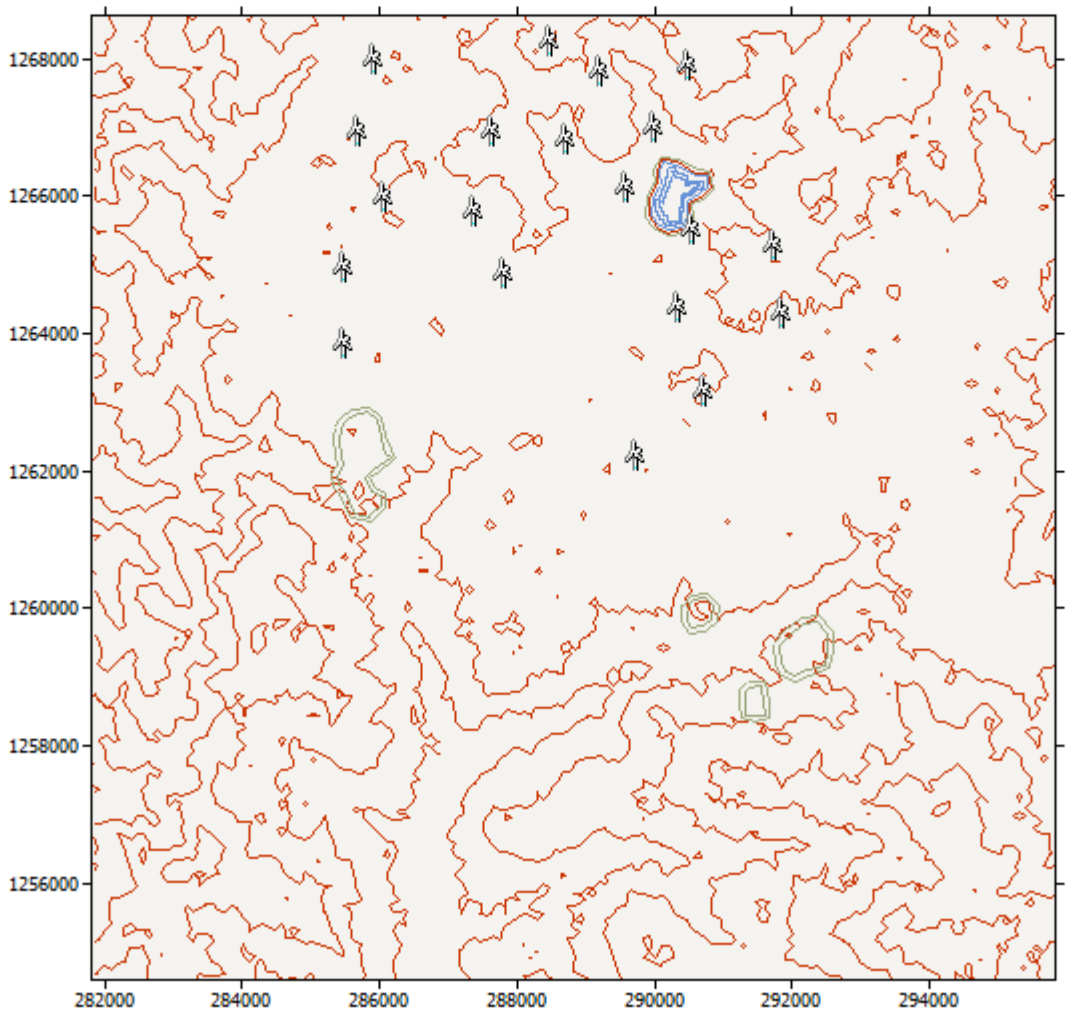
APPENDIX D: WINDFARM ENERGY YIELD REPORT

Produced on 18/10/2020 at 10:12:55 by licensed user: Thomas Stegmann using WAsP Version: 12.04.0042

Site information

Site count	20
Uniform hub height a.g.l	120,9 m

The Wind farm lies in a map called 'K-Vector Map 1'.



Summary results

Parameter	Total	Average	Minimum	Maximum
Net AEP [GWh]	411,781	20,589	20,225	21,157
Gross AEP [GWh]	418,881	20,944	20,704	21,404
Wake loss [%]	1,69	-	-	-

Site results

Site	Location [m]	Turbine	Elevation [m] a.s.l.	Height [m] a.g.l.	Air density [kg/m&sup3]	Net AEP [GWh]	Wake loss [%]
Turbine site 007	(285711,2, 1266765,0)	GE 5.3-158	694,3	120,9	1,071	20,796	1,08
Turbine site 010	(289738,3, 1262042,0)	GE 5.3-158	697,4	120,9	1,070	20,855	0,58
Turbine site 011	(289211,2, 1267650,0)	GE 5.3-158	705,0	120,9	1,070	20,312	3,10
Turbine site 012	(288726,3, 1266638,0)	GE 5.3-158	703,3	120,9	1,070	20,405	2,63
Turbine site 013	(287651,0, 1266765,0)	GE 5.3-158	702,2	120,9	1,070	20,225	2,87
Turbine site 014	(288494,3, 1268072,0)	GE 5.3-158	714,2	120,9	1,069	20,639	1,98
Turbine site 015	(285500,4, 1264783,0)	GE 5.3-158	693,7	120,9	1,071	20,532	1,43
Turbine site 016	(289611,8, 1265942,0)	GE 5.3-158	712,3	120,9	1,069	20,789	1,02

Turbine site 017	(290349,8, 1264192,0)	GE 5.3-158	700,8	120,9	1,070	20,677	1,19
Turbine site 018	(290729,3, 1262970,0)	GE 5.3-158	699,3	120,9	1,070	20,680	1,15
Turbine site 019	(287840,8, 1264698,0)	GE 5.3-158	697,9	120,9	1,070	20,475	1,35
Turbine site 020	(291762,4, 1265120,0)	GE 5.3-158	708,3	120,9	1,069	20,678	1,30
Turbine site 021	(285922,1, 1267819,0)	GE 5.3-158	686,2	120,9	1,072	20,798	0,90
Turbine site 022	(291867,8, 1264108,0)	GE 5.3-158	697,4	120,9	1,070	20,492	1,03
Turbine site 023	(285500,4, 1263686,0)	GE 5.3-158	684,4	120,9	1,072	20,523	0,93
Turbine site 024	(290560,6, 1265352,0)	GE 5.3-158	710,3	120,9	1,069	21,157	1,15
Turbine site 025	(286069,7, 1265795,0)	GE 5.3-158	699,2	120,9	1,070	20,359	2,83
Turbine site 026	(290012,4, 1266828,0)	GE 5.3-158	708,5	120,9	1,069	20,670	2,45
Turbine site 027	(290518,4, 1267735,0)	GE 5.3-158	709,8	120,9	1,069	20,400	2,88
Turbine site 028	(287398, 1265605)	GE 5.3-158	694,9	120,9	1,071	20,320	2,03

Site wind climates

Site	Location [m]	H [m]	A [m/s]	k	U [m/s]	E [W/m²]	RIX [%]	dRIX [%]

Turbine site 007	(285711,2, 1266765,0)	120,9	9,0	2,09	7,96	495	-	N/A
Turbine site 010	(289738,3, 1262042,0)	120,9	9,0	2,09	7,95	492	-	N/A
Turbine site 011	(289211,2, 1267650,0)	120,9	9,0	2,09	7,95	492	-	N/A
Turbine site 012	(288726,3, 1266638,0)	120,9	9,0	2,09	7,94	490	0,0	N/A
Turbine site 013	(287651,0, 1266765,0)	120,9	8,9	2,10	7,91	484	-	N/A
Turbine site 014	(288494,3, 1268072,0)	120,9	9,0	2,09	7,98	496	-	N/A
Turbine site 015	(285500,4, 1264783,0)	120,9	8,9	2,10	7,91	482	-	N/A
Turbine site 016	(289611,8, 1265942,0)	120,9	9,0	2,10	7,95	491	0,0	N/A
Turbine site 017	(290349,8, 1264192,0)	120,9	9,0	2,09	7,94	491	-	N/A
Turbine site 018	(290729,3, 1262970,0)	120,9	9,0	2,09	7,94	490	0,0	N/A
Turbine site 019	(287840,8, 1264698,0)	120,9	8,9	2,09	7,89	481	-	N/A
Turbine site 020	(291762,4, 1265120,0)	120,9	9,0	2,10	7,95	490	0,0	N/A
Turbine site 021	(285922,1, 1267819,0)	120,9	9,0	2,08	7,95	495	-	N/A

Turbine site 022	(291867,8, 1264108,0)	120,9	8,9	2,10	7,88	478	0,0	N/A
Turbine site 023	(285500,4, 1263686,0)	120,9	8,9	2,10	7,88	478	-	N/A
Turbine site 024	(290560,6, 1265352,0)	120,9	9,1	2,08	8,08	518	0,0	N/A
Turbine site 025	(286069,7, 1265795,0)	120,9	9,0	2,10	7,95	490	-	N/A
Turbine site 026	(290012,4, 1266828,0)	120,9	9,1	2,08	8,02	507	0,0	N/A
Turbine site 027	(290518,4, 1267735,0)	120,9	9,0	2,09	7,96	493	-	N/A
Turbine site 028	(287398, 1265605)	120,9	8,9	2,10	7,88	479	-	N/A

APPENDIX E: PROJECT CALCULATIONS AND CASHFLOW ANALYSIS

ID	*Parameter*	*Unit cost*	*n*	*Unit*	*Case 1*	*Case 2*	*Case 3*
[1]	Annual Energy Power Output			KWh/a	315,928,044.50	315,928,044.50	315,928,044.50
[2]	Turbine Life Time			Years	20.00	20.00	20.00
[3]	Turbine Installation cost (GE 128G-5.3 MW)		20	$	$190,800,000.00	$190,800,000.00	$190,800,000.00
[5]	Financing Bank [85%]*[3]	$9,540,000.00		$	$162,180,000.00	$162,180,000.00	$162,180,000.00
[6]	Own Capital [15%]*[3]			$	$28,620,000.00	$28,620,000.00	$28,620,000.00
[7]	Cost of Operation & Maintenance=2.0%*[3]			$	$4,770,000.00	$4,770,000.00	$4,770,000.00
[8]	Discount Rate (r)			%	6.50%	6.50%	6.50%
[9]	Lending Interest Rate				5.00%	5.00%	5.00%
[10]	Selling Price of electricty/kWh			$	$0.070	$0.075	$0.065
[11]	Yearly Revenue from Electricty			$	$22,114,963.115	$23,694,603.338	$20,535,322.893
[12]	Capital Recovery Factor (CRF)				0.0908	0.0908	0.0908
[13]	Loan Terms			Years	20	20	20
[14]	Yearly Payment on Loan			$	$13,013,742.79	$13,013,742.79	$13,013,742.79
[15]	Yearly Expenditure (Financing + O&M)= [7]+[14]			$	$17,783,742.79	$17,783,742.79	$17,783,742.79
[16]	Present Value of Energy Produced =[2]/[12]			kWh	3,481,055,447.98	3,481,055,447.98	3,481,055,447.98
[17]	Present Value of Costs(PVC)			$	$243,358,279.57	$243,358,279.57	$243,358,279.57
[18]	LCOE = [17]/[16]			$/KWh	$0.0699	$0.0699	$0.0699

	CALCULATION MODEL (for annually equal CF)																								
Case 1		Price of electricty/kWh	**$0.070**																						
	INPUT			**YEARS**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**TOTALS**
		EQUITY	**$28,620,000.00**	**Revenues**	$0	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$22,114,963	$420,184,299.19
		REVENUES p.a.	**$22,114,963.12**	**Expenses**	$28,620,000	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$366,511,113.02
		EXPENDITURES p.a.	**$17,783,742.79**	**CF**	-$28,620,000	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$4,331,220	$53,673,186.17
CASH FLOW			**$4,331,220.32**	**CCF**	-$28,620,000	-$24,288,780	-$19,957,559	-$15,626,339	-$11,295,119	-$6,963,898	-$2,632,678	$1,698,542	$6,029,763	$10,360,983	$14,692,203	$19,023,424	$23,354,644	$27,685,864	$32,017,085	$36,348,305	$40,679,525	$45,010,746	$49,341,966	$53,673,186	$250,531,861.66
				DCF	-$28,620,000	$4,066,874	$3,818,661	$3,585,597	$3,366,758	$3,161,275	$2,968,333	$2,787,167	$2,617,058	$2,457,332	$2,307,354	$2,166,529	$2,034,300	$1,910,141	$1,793,559	$1,684,093	$1,581,308	$1,484,797	$1,394,175	$1,309,085	
DISCOUNT RATE			**6.50%**	**DCCF**	**-$28,620,000**	**-$24,553,126**	**-$20,734,466**	**-$17,148,869**	**-$13,782,111**	**-$10,620,837**	**-$7,652,504**	**-$4,865,336**	**-$2,248,278**	**$209,054**	**$2,516,408**	**$4,682,937**	**$6,717,237**	**$8,627,378**	**$10,420,937**	**$12,105,030**	**$13,686,339**	**$15,171,135**	**$16,565,310**	**$17,874,395**	
				Discounting	100%	94%	88%	83%	78%	73%	69%	64%	60%	57%	53%	50%	47%	44%	41%	39%	37%	34%	32%	30%	1173%
	OUTPUT																								
	DISCOUNTING FACTOR (25a)		11.73																						
	NET PRESENT VALUE		**$17,874,395.08**																						
	RETURN ON EQUITY		**15.13%**																						
	IRR (EQUITY)		**13.85%**																						
Case 2		Price of electricty/kWh	**$0.075**																						
	INPUT																								TOTALS
		EQUITY	**$28,620,000.00**	**Revenues**	$0	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$23,694,603	$450,197,463.41
		REVENUES p.a.	**$23,694,603.34**	**Expenses**	$28,620,000	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$366,511,113.02
		EXPENDITURES p.a.	**$17,783,742.79**	**CF**	-$28,620,000	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$5,910,861	$83,686,350.39
CASH FLOW			**$5,910,860.55**	**CCF**	-$28,620,000	-$22,709,139	-$16,798,279	-$10,887,418	-$4,976,558	$934,303	$6,845,163	$12,756,024	$18,666,884	$24,577,745	$30,488,605	$36,399,466	$42,310,327	$48,221,187	$54,132,048	$60,042,908	$65,953,769	$71,864,629	$77,775,490	$83,686,350	$550,663,503.93
				DCF	-$28,620,000	$5,550,104	$5,211,365	$4,893,301	$4,594,648	$4,314,224	$4,050,914	$3,803,675	$3,571,526	$3,353,546	$3,148,869	$2,956,685	$2,776,230	$2,606,789	$2,447,689	$2,298,299	$2,158,028	$2,026,317	$1,902,645	$1,786,521	
DISCOUNT RATE			**6.50%**	**DCCF**	**-$28,620,000**	**-$23,069,896**	**-$17,858,531**	**-$12,965,231**	**-$8,370,582**	**-$4,056,358**	**-$5,444**	**$3,798,232**	**$7,369,758**	**$10,723,304**	**$13,872,173**	**$16,828,858**	**$19,605,088**	**$22,211,876**	**$24,659,565**	**$26,957,864**	**$29,115,892**	**$31,142,209**	**$33,044,854**	**$34,831,375**	
				Discounting	100%	94%	88%	83%	78%	73%	69%	64%	60%	57%	53%	50%	47%	44%	41%	39%	37%	34%	32%	30%	1173%
	OUTPUT (2)																								
	DISCOUNTING FACTOR (25a		11.73																						
	NET PRESENT VALUE		**$34,831,375.11**																						
	RETURN ON EQUITY		**20.65%**																						
	IRR (EQUITY)		**20.01%**																						
Case 3		Price of electricty/kWh	**$0.065**																						
	INPUT																								TOTALS
		EQUITY	**$28,620,000.00**	**Revenues**	$0	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$20,535,323	$390,171,134.96
		REVENUES p.a.	**$20,535,322.89**	**Expenses**	$28,620,000	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$17,783,743	$366,511,113.02
		EXPENDITURES p.a.	**$17,783,742.79**	**CF**	-$28,620,000	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$2,751,580	$23,660,021.94
CASH FLOW			**$2,751,580.10**	**CCF**	-$28,620,000	-$25,868,420	-$23,116,840	-$20,365,260	-$17,613,680	-$14,862,099	-$12,110,519	-$9,358,939	-$6,607,359	-$3,855,779	-$1,104,199	$1,647,381	$4,398,961	$7,150,541	$9,902,121	$12,653,702	$15,405,282	$18,156,862	$20,908,442	$23,660,022	-$49,599,780.62
				DCF	-$28,620,000	$2,583,643	$2,425,956	$2,277,893	$2,138,867	$2,008,326	$1,885,752	$1,770,659	$1,662,591	$1,561,118	$1,465,838	$1,376,374	$1,292,370	$1,213,493	$1,139,430	$1,069,887	$1,004,589	$943,276	$885,705	$831,648	
DISCOUNT RATE (2)			**6.50%**	**DCCF**	**-$28,620,000**	**-$26,036,357**	**-$23,610,401**	**-$21,332,507**	**-$19,193,641**	**-$17,185,315**	**-$15,299,563**	**-$13,528,905**	**-$11,866,314**	**-$10,305,196**	**-$8,839,358**	**-$7,462,984**	**-$6,170,614**	**-$4,957,121**	**-$3,817,691**	**-$2,747,803**	**-$1,743,214**	**-$799,938**	**$85,767**	**$917,415**	
				Discounting	100%	94%	88%	83%	78%	73%	69%	64%	60%	57%	53%	50%	47%	44%	41%	39%	37%	34%	32%	30%	1173%
	OUTPUT (2)																								
	DISCOUNTING FACTOR (20a		11.73																						
	NET PRESENT VALUE		**$917,415.04**																						
	RETURN ON EQUITY		**9.61%**																						
	IRR (EQUITY)		**6.92%**																						

Parameter	Value
Total Loan (85% of the Initial Investment)	$162,180,000.00
Loan Terms	20
Interest Rate	5.00%
Yearly Payment	$13,013,742.79
O&M Yearly cost	$4,770,000.00
Yearly Expenditure	$17,783,742.79