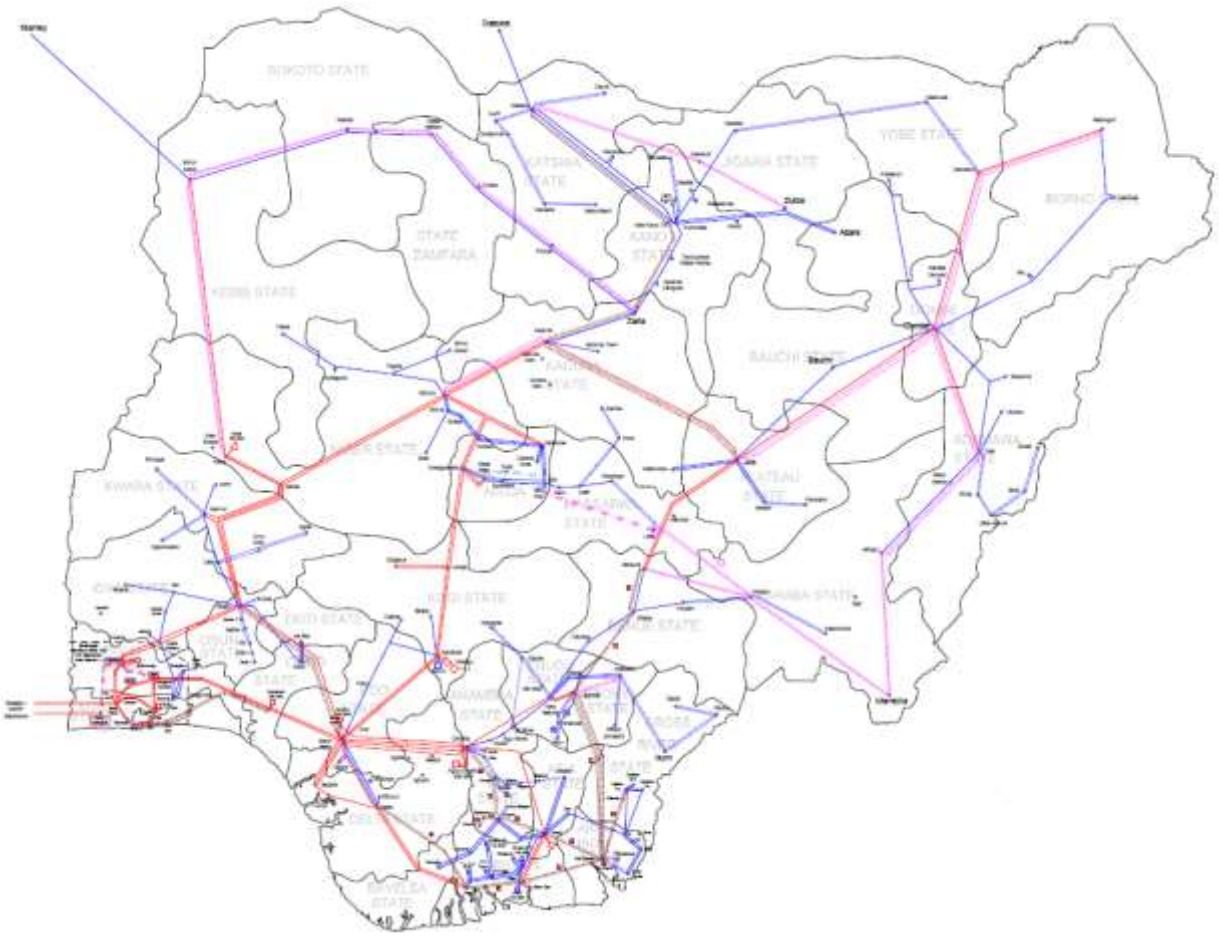
Nigeria Electricity and Gas Improvement Project
December 2017

Transmission Expansion Plan

Development of Power System Master Plan for the Transmission Company of Nigeria



Final Report

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Rev No.	Rev-date	Contents/amendments	prepared/revised	Checked/released
0	20.12.2017	Final Report	S. Grunwald	L. Oprea
1				
2				

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List of Abbreviations

Abbreviations	Declaration
AC	Alternating Current
ACCC	AC Contingency Calculations
DC	Direct Current
Dr.	German equivalent to Ph.D.
e.g.	Latin: for example
EIRR	Economic Internal Rate of Return
et. al.	Latin: and others
FIRR	Financial Internal Rate of Return
FMA	Financial Management Assessment
FNPV	Financial Net Present Value
GDP	Gross Domestic Product
GTMax	Generation and Transmission Maximization Tool
GWh	Gigawatt Hours
HPP	Hydro Power Plant
HV	High Voltage
i.e.	Latin: it/that is
ISO	International Organization for Standardization
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
KoM	Kick off Meeting
kWh	kilowatt-hours
LCEP	Least Cost Expansion Plan
LEC	Levelized Electricity Cost
LNG	Liquefied Natural Gas
LV	Low Voltage
MW	megawatt
MWh	megawatt-hours

Abbreviations	Declaration
MYTO	Multi-Year Tariff Order
NERC	Nigerian Electricity Regulatory Commission
NLCC	National Load Control Centre
No.	number
NPV	Net Present Value
OHL	Overhead Transmission Line
O/V	Over-Voltages
p.	page
PWC	Price Waterhouse Cooper
SCADA	Supervisory Control and Data Acquisition
S/S	Substation
ToR	Terms of References
US$	The national currency of the United States of America
U/V	Under-Voltages
WACC	Weighted Average Cost of Capital
WB	World Bank

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Transmission Expansion Plan

Development of Power System Master Plan for the Transmission Company of Nigeria (TCN)

Final Report

1. Executive Summary

1.1 General

The Power System Master Plan for the transmission network development is one of the key instruments needed by Transmission Company of Nigeria, which should support the large expansion program. This report presents the results of the studies carried out by the Consultant for the development of a Power System Master Plan for the Transmission Company of Nigeria covering the period 2020 to 2037. The studies have addressed a wide range of topics, including demand forecast, the projection of existing generation capacities availability, future generation candidates to be considered in the transmission and generation optimization studies, power system analysis (load flow, fault analysis and dynamics simulations), least cost generation and transmission analysis, cost estimations, financial analysis and environmental impact scoping. An overview of the main topics is indicated in the followings.

1.2 Power Sector Assessment

The electric power system of Nigeria has for many years been suffering from lack of generation capacity which requires permanent load shedding. Furthermore, frequent transmission and distribution system disturbances contribute to the unreliability of the power system.

Main reasons for shortage of generation are outages of generation units and the unavailability of gas for power generation. The gas supply is very often interrupted because of sabotage of pipeline network.

The main concern for the future expansion of generation, however, is the availability of gas for additional generation capacity and the expansion of the gas pipeline network. Currently, most of the power plants are installed in the Southern part of Nigeria close to the oil and gas fields. For a reliable and an optimum expansion of the transmission system, it will be necessary to install new power plants also in other areas of Nigeria.

There are some plans for new hydro power plants. Photovoltaic and wind power plants are also under consideration.

However, to provide sufficient base load power in future, large coal fired power plants may have to be included in the generation expansion program.

1.3 Electrical Transmission System

The power system model has been implemented in PSS/E to include the TCN, NIPP and certain JICA projects expected to be completed by 2020, forming the basis for the preparation of the transmission expansion plan for the planning horizon of the Master Plan. The PSS/E case has been further modified to include the decisions made, following extensive exchange of comments between TCN and the Consultant, as well as the updated information on the available generation capacities and on-going generation projects. All of these under the assumption that all ongoing transmission and generation projects scheduled to be completed by 2020, will be completed.

In terms of generation and load balance in the eight TCN planning regions, in 4 or 5 regions there is a significant generation deficit. With the exception of Benin and Port Harcourt regions, in all other regions in Nigeria the demand exceeds the available generation. In Shiroro region, the situation will be reversed once new HPP plants (e.g. Zungeru) will be commissioned.

The reason for this imbalance is due to the generation being mainly concentrated in South (thermal stations in Port Harcourt, Enugu, Benin and Lagos) and Central West (hydro stations of Jebba, Kainji and Shiroro in Shiroro region). Central, North and North East in particular are characterized by the total absence of generating stations, while the load demand is mainly in South and South West.

To supply the load in the areas with little or no generation such as North East, long 330 kV transmission lines are built (radial system). As a result, voltage regulation problems can be encountered and the excessive reactive power flowing through these lines necessitates large reactive power compensation equipment (reactors) at the corresponding substations (Kano, Gombe, Maiduguri).

Additional 330 kV lines running in parallel are expected to aggravate the overvoltage issues, necessitating additional compensation equipment at Yola, Jalingo and other substations.

1.4 Demand Forecast

The starting point of the demand forecast (year 2016) was established based on a bottom-up approach. TCN has carried out an extensive data collection to identify the load at the main 33 kV and 11 kV feeders and to identify and include also suppressed demand in the forecast.

Afterwards a thoroughly review of the load forecasts of Tractebel Engineering, TCN and JICA, and the underlying assumptions made on the interaction between energy and the economy has been done. This forecast was checked, updates made and an own forecast developed. The load demand forecast was made for 20 years and includes three credible scenarios (high, medium and low demand growth scenarios), taking into account a optimistic, most likely and conservative view on potential capital investment reflected by the GDP growth rate.

The estimation of the future electricity demand takes into account:

- consumers which are already connected to the grid and supplied with electricity

- consumers supplied off-grid
- consumers which are not yet supplied with electricity
- the demand of the present consumers which cannot be served.

In line with the foregoing demand forecasts and following roughly the retail tariff structure, the Consultant has determined five consumer groups that are most adequate to perform the demand forecast:

- Residential
- Commercial
- Industrial
- LNG
- Exports

In addition, network losses, suppressed demand (outages and disconnected demand), off-grid demand and load shedding have been estimated and added to the future demand.

Economic growth rates, historical demand data, population and demographic forecasts and other variables (such as growth in various energy-intensive sectors) have been considered. Based on the data collected for the electricity sector, key indicators relevant for future power demand development were calculated, such as electricity demand elasticity, energy intensity, price elasticity etc. An overview of key drivers used for each sector is presented in the Table 1-1 below:

Table 1-1: Key drivers used for demand forecast per customer group

Sector	Population	Number of customers	GDP	Electricity Tariff
Residential	x	x	x	x
Commercial			x	x
Industrial			x	
LNG			x	
Exports	Constant as rather based on agreements than economic development			

The analysis of available documents has revealed that information on the historical development of electricity consumption is not fully consistent and shows (minor) deviations in the different studies. Furthermore, collection of data on a regional or distribution area level was envisaged but has proven to be difficult.

Figure 1-1 shows the results of the demand forecast for the whole of Nigeria for the three scenario cases.

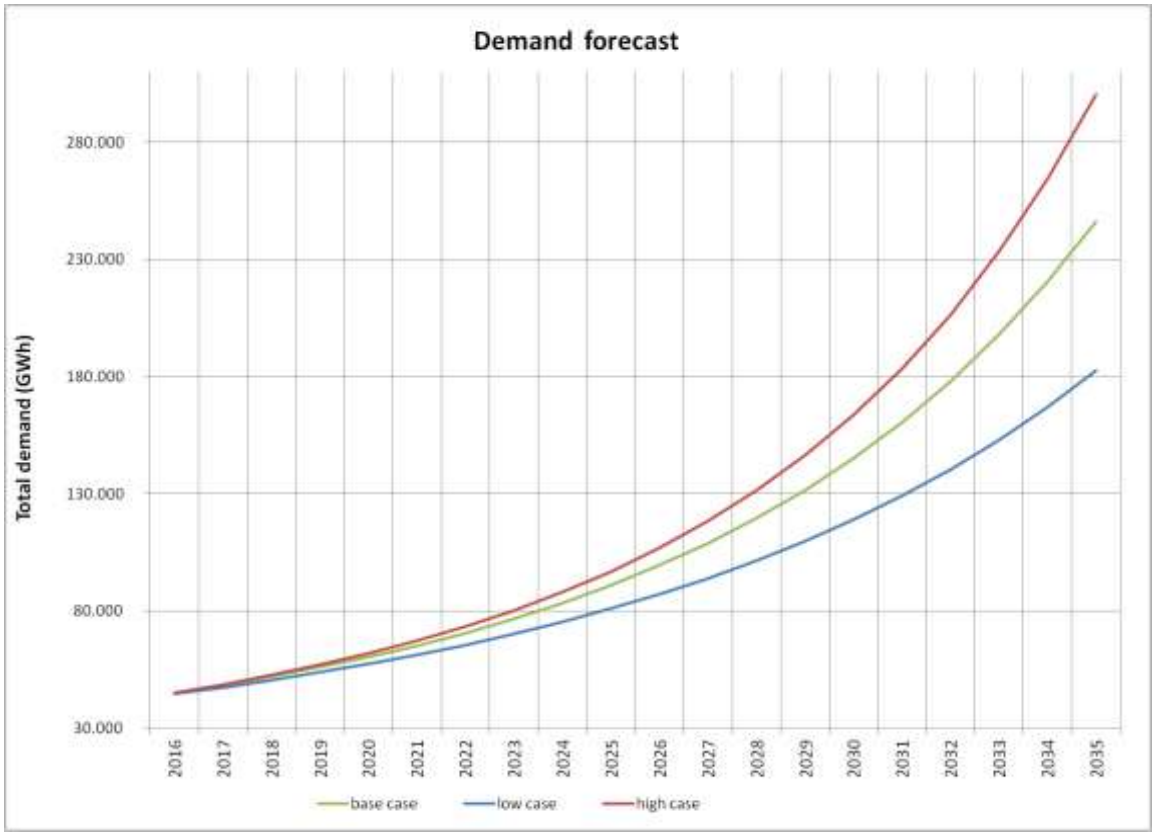


Figure 1-1: National demand forecast of Nigeria

From its level in 2015 total demand is expected to increase by a factor of 5.8 to 246,147 GWh in 2035 in the base case. This means an average annual growth rate of 9.2% in the base case during the observation period. Residential demand is being the main driving force during the whole study period.

The developed demand forecast was compared to three other studies, namely:

- JICA demand forecast, 2015 (as indicated in their Progress Report)
- TCN demand forecast, 2012
- Tractebel demand forecast, 2009 (based on the global method)

The comparison of energy demand forecast is shown in **Figure 1-2**.

The present forecast expects a similar development as the Tractebel report. While the current actual demand is estimated to be somewhat higher than indicated by Tractebel, it is almost at the same level or slightly below until 2031. The last two years could not be compared as Tractebel's study period is only until 2033. Compared the JICA projection, the estimated growth rate within this report is somewhat lower due to the different assumptions about off-grid demand development. TCN's own forecast dating 2012 is in total higher than the three other forecasts.

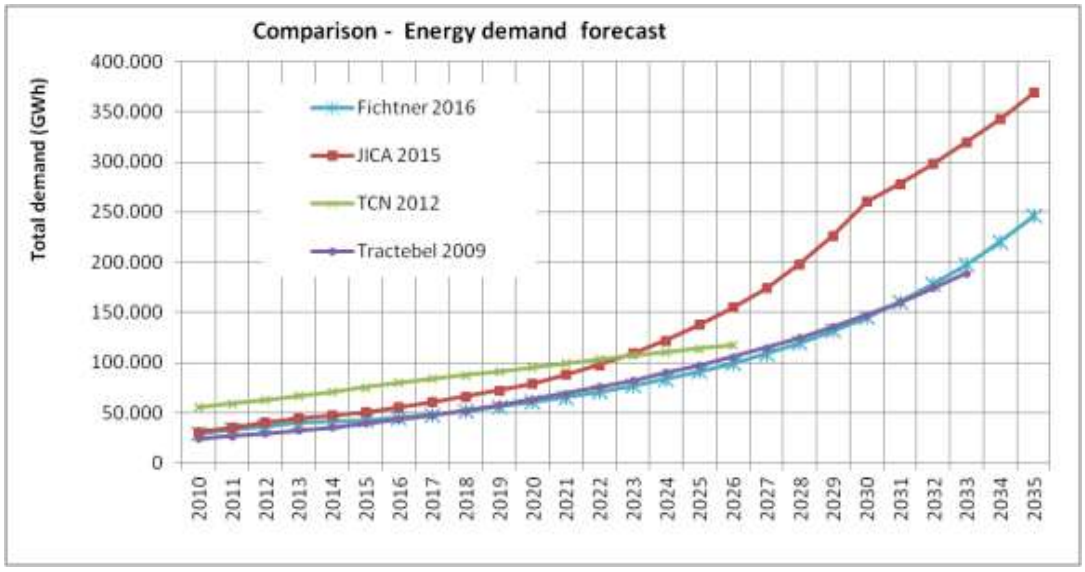


Figure 1-2: Comparison of demand forecasts

A major advantage of the demand forecast herein consists in the circumstance that compared with other forecasts a validated set of figures of suppressed demand has now been included in the forecast per DisCo. It is shown in **Table 1-2** below.

Table 1-2: Validated 2016 suppressed demand per DisCo

VALIDATED SUMMARY OF SUPPRESS LOAD DEMAND DATA BY DISCO'S IN 2016					
NAME OF DISCO	DISCO LOAD DEMAND FROM 2016 FIELD MEASURENT CAMPAIGN (SUM OF 11kV FEEDER AND 33kV FEEDER POINT LOADS) (MW)	HISTORIC 33kV PEAK LOAD COLLECTED IN 2016 FROM DISCO (MW)	DISCO ESTIMATE ON-GRID SUPPRESSED LOAD (MW)	DISCO ESTIMATED OFF GRID SUPPRESSED (POTENTIAL) LOAD (MW)	TCN COMMENT
AEDC	762.2	577.0	270.3	381.3	Validated without modification by AEDC
BEDC	1,223.3	776.7	163.1	220.6	Reviewed bY BEDC
EKEDC	1,350.4	856.6	493.8	350.9	Reviewed by EKEDC
EEDC	1,026.5	802.5	379.6	287.4	Validated by EEDC
IBEDC	1,285.9	1,119.2	183.7	279.7	Validated by IBEDC
IKEDC	1,215.6	977.2	302.8	364.5	Validated by IKEDC
JEDC	399.2	416.3	43.7	143.0	Validated by JEDC
KAEDCO	602.1	632.1	93.3	341.5	Validated by KAEDCO
KEDCO	708.1	513.8	186.8	224.4	Validated by KEDCO
PHEDC	948.5	884.9	130.1	229.5	Validated by PHEDC
YOLA	279.7	304.6	34.9	364.5	Validated without correction by YOLA
TOTAL ESTIMATED TCN DEMAND	**9,801.5**	**7,860.9**	**2,282.1**	**3,187.3**	

1.5 Existing Generation and generation Expansion

Data have been collected regarding to the existing power generation assets and the availability of installed units. All received information about existing power plants of different generation companies has been consolidated in one common table. In addition to the existing facilities, this table includes listed candidates for expansion of generation capacity by

installation of new units or plants. Some candidates have more advanced implementation status, other candidates are still requesting for permits by NERC and other authorities. However, it is not certain that all these candidates will finally be permitted to be implemented in projects.

Based on provided information, the already installed gross power generation capacity is about 13,300 MW, of which some 11,800 MW are noted as net available capacity.

Considering latest information by generation companies, about 9,500 MW (80%) of this capacity should have been available at the end of the year 2015. However, only 5,900 MW net capacity has been available as statistics of the National Control Center (NCC) show.

Reasons for unavailability are: planned outages for maintenance or forced outages due to technical deficiencies of assets, as well as unplanned unavailability due to shortage of fuel supply or sabotage of gas pipelines. A further analysis of meanwhile provided information shows that about 20% of installed generation capacity is based on plants which are 25 years old or even older. Some of these plants have an efficiency of less than 30%. It is obvious that most of the old thermal power plants are - or will be - causing more frequent forced outages or long term planned maintenance outages in near future. For this reason, they should be replaced by new facilities with higher efficiency. Some of the generation companies already started this modernization process during the past 15 years and this process is ongoing as announced projects and plants under construction show.

Together with TCN it was agreed on consideration of all currently existing power plant units being available latest in the year 2020 even in case that they are unavailable at the moment for serious technical reasons. The Transmission Expansion Plan shows a program for step by step modernization of these plants in parallel to implementation of new units at existing sites, as well as complete new power plants. It further shows technical data of all existing and of new generation facilities and the respective implementation time table. Newly proposed power plants are considering a diversification of primary energy sources in form from solar / wind / hydro technology, as well as modern gas and coal fired thermal plants. Installation of new assets will follow the assumed increasing power demand, as well as the need for replacement of existing power generation assets.

1.6 Power System Analysis

The methodology of the power system analysis performed in PSS/E is summarized as follows:

a) Definition of the Security Reference Level
The goal of the study is to propose the necessary updates and reinforcements to the TCN power system in order to achieve the secure operation of the system for the years 2020 to 2037. The analysis was first carried out on the present system model, taking into account the recently completed and ongoing TCN and NIPP projects that are scheduled to be completed by 2020. It has also been assumed that certain projects in the Lagos area undertaken by JICA will be completed by 2020.

b) Execution of the analyses on the 2020 model
The initial analysis is related to the static security assessment. Using the outcome of this analysis, a first reinforcement list and recommendations for new lines and transformers

is provided. Subsequently a dynamic security analysis was carried out based on the results of the static analysis and considering the reinforcements required, as detailed in section 7.

c) *Execution of the analysis on the 2025, 2030 and 2037 model*
Considering the recommendations and reinforcements to be implemented in the 2020 network model, the same analyses are carried out on the 2025, 2030 and 2035/2037 scenarios. New reinforcements and recommendations for these years are provided accordingly. From 2030 onwards, the options of introducing a "supergrid" (at 330, 500 or 750 kV level) were analyzed and appropriate recommendations were made.

Four milestone study years have been selected to cover the planning horizon of the Master Plan: 2020, 2025, 2030 and 2035/7.

The load demand in each of the DisCo areas in Nigeria is shown is summarized in **Table 1-3.**

In the 2020 network configuration the assumed total demand is 9895 MW, to closely match the validated DisCos load demand, as presented by the 11 DisCos in the workshop of January 2017 in Abuja. Thereafter, the load demand to be served depends on two factors: (a) the rate of increase of forecasted demand as presented in section 5 and, more importantly, (b) the limits of generation expansion plan, as presented in section 6.
The maximum load demand that can be realistically supplied will have, therefore, to follow the development of the generation planning schedule and it will be limited by the associated financial and time constraints.
The total demand that can be served includes the export requirements to neighboring countries.

Table 1-3: Load demand per DisCo

DISCO	DisCo	2020	Increase 2020-2025	2025	Increase 2025-2030	2030	Increase 2030-2035	2035
IKEDC	1-Ikeja	1250	16.08%	1451	39.57%	2025	13.66%	2302
IBEDC	2-Ibadan	1225	45.31%	1780	50.28%	2675	23.94%	3315
AEDC	3-Abuja	745	35.70%	1011	66.92%	1688	49.86%	2529
BEDC	4-Benin	1273	37.47%	1750	39.98%	2450	16.54%	2855
KAEDCO	5-Kaduna	590	78.31%	1052	93.96%	2040	21.82%	2486
JEDC	6-Jos	442	48.64%	657	86.06%	1222	10.40%	1350
EEDC	7-Enugu	1090	22.29%	1333	25.22%	1669	11.36%	1859
PHEDC	8-Port Harcourt	946	55.39%	1470	43.42%	2108	17.70%	2481
EKEDC	9-Eko	1320	25.08%	1651	35.51%	2237	13.38%	2537
KEDCO	10-Kano	705	34.04%	945	59.22%	1505	31.23%	1975
YOLA	11-Yola	309	99.03%	615	83.14%	1126	51.78%	1710
Total MW		**9895**	38.61%	**13715**	51.26%	**20746**	22.42%	**25397**
Export MW		387		1540		1831		2000
Total load MW		**10282**		**15255**		**22577**		**27397**

The increase of load that can be supplied by the planned generation in the period 2020-2035 is shown in **Figure 1-3**

Figure 1-3: Increase of served Nigerian load 2020-2035

The development of the generation system and associated demand can thus be referred to as the **10GW** in 2020, **15GW** in 2025, **23GW** in 2030 and **28GW** in 2035.

In 2020, the total generation required to meet the load in Nigeria is 10700 MW and since the generation from new power plants that are envisaged to be in operation by 2020 is limited, the existing generating units, which are currently out of service for various reasons, must be made available if 10GW of load is to be served.

In 2020 four scenarios were studied in detail, as shown in **Table 1-4**, to capture the extreme combinations of generation and load:

Table 1-4: 2020 study cases

Case		Description	Generation	Load (MW)	
Dry Season Peak	DP	Dry Night Peak Load	Dry-Reduced HPP generation No PV generation Increased requirement from GTs	Peak load (night)	9870 + export
Wet Season Peak	WP	Wet Night Peak Load	Wet-Normal HPP generation No PV generation Increased requirement from GTs	Peak load (night)	9870 + export
Dry Season Off-Peak	DOP	Dry Day Off-Peak Load	Dry-Reduced HPP generation PV generation Increased requirement from GTs	Off-Peak load (day)	8300 + export
Wet season Off-Peak	WOP	Wet Day Off-Peak Load	Wet-Normal HPP generation PV generation Increased requirement from GTs	Off-Peak load (day)	8300 + export

In 2025 the two most critical scenarios were studied: Dry Season Peak and Dry Season Off-Peak.

Following the power system analysis, a transmission expansion plan was developed, as detailed in section 12, with its associated cost estimations detailed in section 9.
In summary, the transmission expansion plan shall be as follows:

1.6.1 Expansion plan for 2020

Transmission Lines

The first priority is to resolve the overloads occurring under *normal (N-0)* operation of the four 132 kV lines: Alagbon-Ijora, Omoku-Rumusoi and Ibom IPP-Ikot Abasi.

As a next priority 23 overloaded 132 kV lines (circuits) under N-1 contingencies must be reinforced. This entails either re-conductoring to higher rating conductors or, in case of SC, conversion to DC by installing a 2nd parallel circuit.

Finally, in addition to the projects proposed and undertaken by JICA, the following new transmission lines are required to be implemented by 2020:

Part of 330 kV North East Ring:
Damaturu-Maiduguri, Gombe-Damaturu, Gombe-Yola, Yola-Jalingo and Jos-Gombe.

Part of 330 kV North West Ring:
Kainji-Birnin Kebbi

In addition:
330 kV: Akangba-Alagbon, Ugwuaji-Abakaliki
132 kV: Ayede-Ibadan North, New Agbara-Agbara, Ogijo-Redeem (JICA), Birnin Kebbi-Dosso

It should be noted that the lines recommended for the North East ring are required in order to comply with the N-1 static security criterion, as well as to improve the voltage stability of the area. It is recognized however that in terms of implementation it will be challenging to complete all by 2020.
However, if not possible to implement by 2020 they should be implemented as soon as possible thereafter within the period 2020-2025 and therefore the investment plan, detailed in section 9, has been based on this assumption.

Transformers

The upgrading of 14 x 330/132 kV 3-W and A/T transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-21**.

The upgrading of 25 x 132/33 kV and 132/11 kV transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-22.**

The upgrading of the following types of transformers overloaded above their 85% rating MVA under normal (base case) operation shall be upgraded, as listed in **Table 7-23**:

a) 10 x 330/132 kV 3-w and A/T,
b) 25 x 132/33 kV and 132/11 kV transformers

Reactive Power Compensation

SVC requirements
No SVC at Gombe is necessary by 2020.

Reactors
In *Dry Season Peak* case only four of the existing reactors are required to be in operation at Gombe and Yola and it is assumed they are in good working order.

In *Dry Season Off-Peak* case new reactor required at Maiduguri of 75MVar, in addition to existing reactors at Gombe, Kano and Yola.

Capacitors
New capacitors required at 132 kV at Omuaran (50MVar), Ondo (24MVar) and Irrua (24MVar), in addition to existing ones.

Power factor correction at DisCos level
With reference to the Grid Code requirements (ref. article 15.6 on *Demand power factor corrections and 16.7 on provision of voltage control* stating that *The Off-takers shall maintain a Power Factor not less than 0.95 at the Connection Point*), since the resulting power factor of loads connected at 33 kV level and below is less than the 0.95 required, all DisCos shall be required to undertake a program of having capacitors installed at distribution level to ensure the power factor at all 33 kV S/S is not less than 0.9 by 2020 and 0.95 by 2025, in line with the Grid Code requirements.

(Note: the loads in the 2025 model however have been based on a conservative power factor of 0.9 and only the 2030 loads have pf of 0.95)

Fault level remedial measures

The fault analysis has shown that the most critical 330 kV substations are BENIN, OMOTOSHO, SAPELE, ALAOJI and AFAM IV, with fault levels ranging from 34.9 kA to 25.7 kA for a 3ph busbar fault.

The most relatively critical 132 kV substation is IKEJA WEST, with fault level of 29.6 kA.

The TCN standard switchgear ratings of 31.5 kA are therefore inadequate particularly when new power plants are to be commissioned in the following years.

In order to solve the violations detected in the substations of TCN network, the following solutions could be adopted:

(a) Install breakers with a higher breaking capacity, (b) Study different topological configurations of the elements connected to the different bus sections and (c) Install Current Limiting Reactors (CLR) aimed at reducing the short circuit currents contributions from adjacent bus sections.

1.6.2 Expansion plan for 2025

Transmission lines

In addition to the projects undertaken by TCN and NIPP, the following 330 kV and 132 kV lines are included in the 2025 model. These lines are also in addition to those that have been included in the 2020 expansion plan.

Part of the 330 kV North West ring
Birnin Kebbi- Sokoto, Sokoto-Talata Mafara, Talata Mafara-Gusau, Gusau-Funtua, Funtua-Zaria

Part of the 330 kV North East ring
If cannot be implemented by 2020, implement as soon as possible thereafter:
Damaturu-Maiduguri, Gombe-Damaturu, Gombe-Yola, Yola-Jalingo (via Mayo Belwa)

330 kV lines for Mambila evacuation
Mambila-Jalingo, Mambila-Wukari, Wukari-Makurdi, Wukari-Lafia

In addition:
330 kV: Olorunsogo-Arigbajo (additional DC), Katsina-Daura, Daura-Kazaure, Shiroro-Kaduna (new DC and/or upgrade existing to Quad)

The 132 kV lines which are overloaded under normal operation (base case) requiring reinforcements, in addition to those reported for the 2020 case, are the following:

Ogijo-Sagamu, Dadinkowa-Kwaya Kusar, PHCT Main-PHCT Town.

It should be noted that the overloads of these lines have been reported in the 2020 case, but under N-1 conditions.
Furthermore, since a number of undervoltages were encountered in the Dry Season Peak case, and also in order to meet the N-1 security criterion, the following additions or conversions to a DC are required at 132 kV level:

Shiroro-Tegina, Tegina-Kontagora, Kontagora-Yelwa, Yelwa-Yauri, Ganmo-Ilorin, Obajana-Egbe, Omotosho-Ondo, Benin-Irrua, Irrua-Ukpilla, Ukpilla-Okene, Sagamu-Ijebu Ode, Dakata-Gagarawa, Gagarawa-Hadejia, Dakata-Kumbotso, Birnin Kebbi-Dosso.

Transformers
The following upgrades are required, in addition to those reported for the 2020 case:

The upgrading of 20 x 330/132 kV 3-W and A/T transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-36.**

The upgrading of 51 x 132/33 kV and 132/11 kV transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-37**. 25 of these transformers have already been reported as overload above their 85% rating in 2020.

Reactive power compensation

SVC requirements
There is no requirement for an SVC in 2025. More detailed and dedicated studies will be necessary at a later stage to determine any need for such equipment in the period beyond 2025.

In 2025, in addition to the reactors and capacitors listed in tables **Table 7-38**, **Table 7-39, Table 7-40** and **Table 7-41**, reactive power compensation (150 MVar capacitors) will be required at Birnin Kebbi due to export requirements to WAPP.

With regards to Gombe, should additional reactive power compensation be required at lightly loaded conditions, instead of SVC a more cost effective option would be to relocate from other S/S to Gombe approximately 100-150 MVAR of reactors that, as it has been shown in this analysis, are not needed there anymore.

As it is shown in the static security analysis for 2025, a more appropriate candidate for an SVC could be the Lagos / Ikeja/Eko region, where there is a reactive power deficit of approximately 400-500 MVar. It should be noted however that this deficit is expected to be greatly reduced when the DisCos implement the reactive power control program at distribution level, as proposed and in line with the Grid Code requirements, as well as when transmission lines and transformers are upgraded, as it has been shown in previous chapters of this report.

Reactors
In *Dry Season Peak* case no new reactors are required.
In *Dry Season Off-Peak* case new reactors are required at Maiduguri (75MVar).

Capacitors
In *Dry Season Peak* case one additional capacitor at Uyo (50MVar) is required in addition to the new ones required for 2020.

In *Dry Season Off-Peak* case also, no new capacitors are required in addition to those required for 2020.

Fault level remedial measures
As in the 2020 case, the most critical 330 kV substations are BENIN, OMOTOSHO, AZURA, EGBIN and BENIN NORTH, with fault levels ranging from 54.3 kA to 42 kA for a 3ph busbar fault.

The most relatively critical 132 kV substation is IKEJA WEST, with fault level of 39.3 kA. The recommended remedial measures are the same as those described for the 2020 case.

1.6.3 Expansion plan and “supergrid” options for 2030 and 2035

The load flow simulations have shown that without major upgrade of the transmission system, there will be widespread undervoltages and overloads throughout the system and at all voltage levels. Consequently, the system losses will be high.

It is therefore considered necessary and appropriate at this stage to introduce a new "super-grid", i.e. a backbone for bulk transmission at either 330, 500 or 750 kV.

A number of configurations have been examined and compared in terms of their efficacy in voltage support, system losses and relieve of line loadings of existing and planned 330 kV system.

The optimum configuration of a 330, 500 or 750 kV EHV grid is shown in **Figure 1-4**, encompassing the following substations:

Ikot Ekpene, Benin, New Agbara, Osogbo, Gwagwalada, Makurdi, Ajaokuta, Funtua and Kainji.

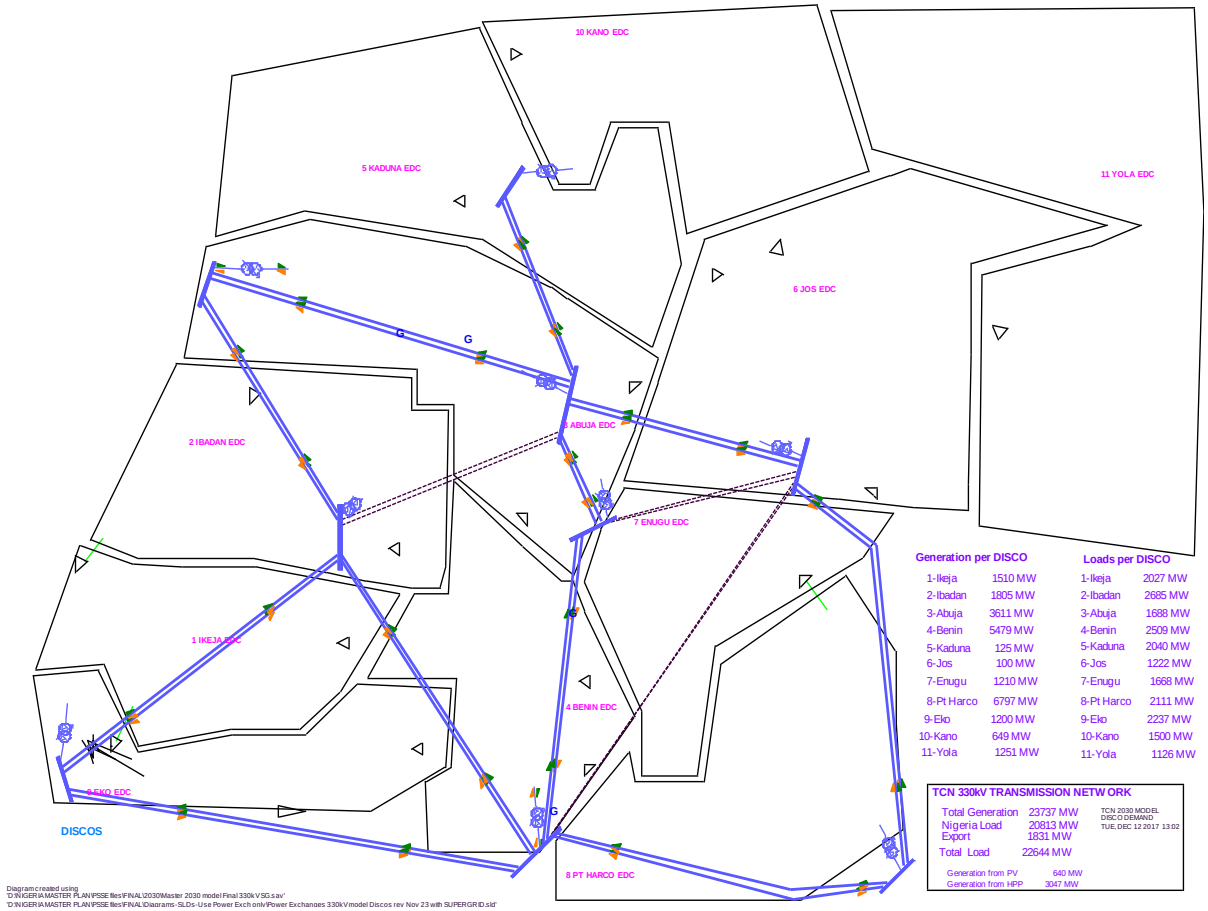


Figure 1-4: Configuration of 330, 500 or 750 kV grid in 2030

With regards to the conductor type necessary for each supergrid option, the following arrangements are recommended:

- At 330 kV a Double Circuit is proposed with 4-bundle (Quad) Bison conductors for each circuit. Capacity 2x1550 MVA
- At 500 kV a Single Circuit is proposed with 4-bundle (Quad) Bison conductors. Capacity 2350 MVA

- At 750 kV a Single Circuit is proposed with 5-bundle Bison conductors, which is typical at this voltage level due to corona phenomenon. Capacity 4400 MVA.

The cost comparison indicates that the investment cost in million US$ is: (a) For 330 kV is 1381, for 500 kV is 1256 and for 750 kV is1589.

The comparison indicates that the 500 kV supergrid will require the lower investment cost. However, the cost difference to 330 kV is relatively small.

Based on the technical considerations both the 330 and 500 kV options are adequate.

Furthermore, taking into considerations that:

a)	Capacity of 330 kV supergrid lines:	3100 MVA
b)	Capacity of 500 kV supergrid lines:	2350 MVA
c)	Difference in losses between 330 and 500 kV supergrids:	Marginal
d)	Impact on O/U voltages and overloads:	330 kV advantageous
e)	Higher static N-1 security of the 330 kV supergrid due to double circuit lines involved	

It appears that the 330 kV supergrid system is technically the preferred option and its 10% higher investment cost could be justified.

More detailed studies are required to confirm the conclusions of this study in this respect. It is therefore recommended to have these detailed studies carried out in due course, before a final decision can be made on the selection of voltage level (330 kV or 500 kV) for a future super grid.

There is no justification to adopt and/or consider further any higher (750 kV) option for the EHV grid, particularly when the implications of the high cost differences are taken into account, as detailed in section 9. The higher transmission capacity (4400 MVA) is not required at this stage and the marginal differences in losses cannot offset the high investment cost required in the planning horizon of this Master Plan.

Furthermore, the network calculations (Chapter 7) have indicated that a transmission capacity of the 330 kV and 500 kV supergrid system is sufficient.

1.6.4 Dynamic simulations

The dynamic model of the TCN system was developed based on data received for the representation in PSS/E of generators, governors and exciters of conventional power plants.

Furthermore, Wind and PV dynamic models were introduced by one set of the following PSS/E models:

- Renewable Energy Generator/Converter Model,
- Generic Electrical Control Model for large scale PV and Wind generation,
- Generic Renewable Plant Control Model.

Table 1-5 shows the cases simulated for 2020 and 2025, as a typical representation of extreme scenarios.

Table 1-5: Dynamic study cases

Case	Scenario	Fault at bus	Trip line / disturbance
F1	2020 Dry Season Peak	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo
F2		Benin 330 kV	Trip 330 kV line from Benin to Omotosho
F3		Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi
F4		Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji
F5		Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro
F6		Afam 330 kV	Trip largest generating unit Afam VI
F7	2020 Dry Season Off-Peak	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro
F8	2025 Dry Season Peak	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo
F9		Benin 330 kV	Trip 330 kV line from Benin to Omotosho
F10		Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi
F11		Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji
F12		Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro

The results of the dynamic simulations have shown that the system remains stable and all generating machines, including the PV and wind generation, remain synchronized for all cases studied.

1.7 Least-Cost Generation and Transmission Analysis

With the aid of the software GTMax (Generation and Transmission Maximization Model) the Consultant has studied the most economic generation and transmission expansion program for Nigeria for the period 2020 - 2037.

Conclusions from GTMax Results for 2020

Studying the results of the GTMax calculations for 2020 in both: dry and wet season, the following conclusions can be made:

- In order to supply the potential demand of 10 GW, a generation set-up as per Annex 6.1 for year2020 is necessary. Each location is considered to be run at least by 70% of the installed power at all times,
- Due to the low availability of hydro power projects in Nigeria compared to thermal power generation, the peaking is done also by thermal power plants,
- The main generation facilities are located in the DisCos: Abuja, Benin, Ikeja and Port Harcourt,
- Only the DisCos Abuja, Benin, Ikeja and Port Harcourt are self sufficient concerning the balance of generation and load,
- DisCos without generation facilities are: Kano, Yola and Eko. Jos has only small amount of wind generation,

- Solar power does not contribute for the evening peaking, but for the daily peaking does,
- The power flows between the DisCos in Nigeria for the peaking hours in dry season in 2020 are from the south to the north, from the east to the west.
- The power flows between the DisCos in Nigeria for the off-peak hours in dry season in 2020 remain the same: from the south to the north, from the east to the west.

It can be concluded that the installed transmission infrastructure can carry the required power flows and no additional transmission links between the DisCos are necessary up to 2020.

Investigations for 2025 Network Configuration

The Consultant performed two sets of calculation for 2025:

- new thermal generation only in South of Nigeria - Option 1
- new thermal generation in South and in North of Nigeria - Option 2

A) Conclusions from GTMax Results for 2025 - Option1
Studying the results of the GTMax calculations for year 2025 for Option 1 in both: dry and wet season, the following conclusions can be made:

- In order to supply the potential demand of 13 GW a generation set-up as per **Annex 6.1** for year 2025 is necessary. Each location of the existing, committed and presently under construction sites is considered to be run at least by 70% of the installed power at all times,
- The main generation facilities are located in DisCos: Abuja, Benin, Ikeja and Port Harcourt,
- Installing of generation facilities in Ibadan DisCo has advantages for the overall system (lowering losses, improving voltage profile)
- Only the DisCos Abuja, Benin, Ikeja and Port Harcourt are self sufficient concerning the balance of generation and load,
- DisCos without conventional generation facilities are: Kano, Yola, Eko and Jos. Jos has only small amount of wind generation, and Kano and Yola have PV installations.
- Solar power does not contribute for the evening peaking, but for the daily peaking does,
- The power flows between the DisCos in Nigeria for the peaking hours in dry season in 2020 are from the south to the north, from the east to the west.
- The power flows between the DisCos in Nigeria for the off-peak hours in dry season in 2020 remain the same: from the south to the north, from the east to the west.

B) Conclusions from GTMax Results for 2025 - Option2
Studying the results of the GTMax calculations for year 2025 for Option 2 in both: dry and wet season, the following conclusions can be made:

- The main generation facilities are located in DisCos: Abuja, Benin, Ikeja and Pt Harcourt, Kano and Kaduna
- Installing generation facilities for base load power on the north lowers the necessity of installation of thermal power plants in the south east (Pt Harcourt) and lowers the overall losses and transmission power flows within the DisCos
- Installing of generation facilities in Ibadan DisCo has advantages for the overall system (generation closer to the big demand centre Lagos)
- Only the DisCos: Kano, Abuja, Benin, Ikeja and Pt Harcourt are self sufficient concerning the balance of generation and load,
- DisCos without conventional generation facilities are: Yola, Eko and Jos. Jos has only small amount of wind generation, and Yola has PV installations.
- Solar power does not contribute for the evening peaking, only for the daily peaking,
- The power flows between the DisCos in Nigeria for the peaking hours in dry and wet season in 2020 are party from the south to the north (Pt Harcourt to Enugu), but also from the north to the southwest (Kano to Kaduna, Kaduna to Abuja, Abuja to Ibadan, Abuja to Benin). The power flows from the east to the west in the southern part of the country remain the same (Pt Harcourt to Benin, Benin to Ibadan).

It can be concluded that the installed transmission infrastructure can carry the required power flows and no additional transmission links between the DisCos are necessary up to 2025 for **Option 1** as well as for **Option 2**.

1.8 Summary Environmental Assessment

On example of 4 lines the possible environmental and social impacts have been identified (see Map 1-1). These are located in different regions and fit to all lines eventually planned in Nigeria.

Map 1-1: Overview selected transmission lines

Degradation is a major problem in Nigeria and the processes of desertification and deforestation are of special concern. Especially the fact that almost all primary forest is lost and only very little and degraded forest is left makes the cutting of trees inconceivable. Existing forest patches have therefore to be contoured. Depending on the type of forests, they can eventually be spanned.

All protected areas have to be strictly avoided. This includes the one existing National Park (Gashatka Gumti, crossed by line 2) and also the forest reserves concerned (including the two of them being proposed for the formation of new National Parks, close to line 1 and 4). Second issue for Nigeria is the regionally very high population density.

Physical relocation has to be avoided whenever possible. In the more populated areas, this might not always be feasible and resettlements might become necessary. However, the number of affected people has to be kept to a minimum. Wherever fruit trees must be cut or agriculturally used fields have to be used for the masts, compensation has to be paid.

So, there are two major requirements: spare the national resources and avoid physical relocation of people. Therefore, deviations and numerous costly angle towers might become necessary.

1.9 Cost estimation

1.9.1 General

Cost estimation was prepared based on the results of the load flow calculations to provide sufficient transmission capacity as well as sufficient 330/132 kV and 132/33 kV transformer capacities. Furthermore, also necessary reactive power compensation equipment (capacitor banks and shunt reactors) have been identified to maintain voltage levels within permissible range.

In addition to the network expansion measures identified by the Consultant, TCN provided in October 2017 additional information on their investment program until 2025 which includes rehabilitation measures of existing substations and transmission lines, construction of new substations and transmission lines to connect additional areas within Nigeria to the national grid and to strengthen existing substations (additional 330/132 kV and 132/33 kV transformers).

1.9.2 Transmission network investments until 2020

A summary of the investment required until 2020 is presented in **Table 1-6**.

Table 1-6: Summary of all additional investments in transmission lines and substations until 2020 to establish a 10 GW transmission network

Transmission System Expansions	Reference to Chapter 7	Transmission Lines	Substations	Total
		Million US$	Million US$	Million US$
Additional Transmission Lines to Relieve Existing Lines by 2020 (N-0)	Table 7-19	12.0	19.2	**31.2**
Additional Transmission Lines to Relieve Existing Lines by 2020 (N-1)	Table 7-20	162.8	140.8	**303.6**
Additional 330/132 kV Transformers	Table 7-21	0.0	35.0	**35.0**
Additional 132/33 and 132/11 kV Transformers to relieve existing transformers loaded above 100%	Table 7-22	0.0	78.2	**78.2**
Additional 132/33 and 132/11 kV Transformers to relieve existing transformers loaded above 85%	Table 7-23	0	131.7	**131.7**
New Reactors and Capacitors	Table 7-24 to 7-27	0	18.9	**18.9**
New Transmission Lines by 2020	Table 7-28	147.5	53.6	**201.1**
Total Additional Investment Cost by 2020				**799.6**

1.9.3 Transmission network investments between 2021 and 2025

A summary of the investment required between 2021 and 2025 is presented in **Table 1-7**.

Table 1-7: Summary of all additional investments in transmission lines and substations until 2025 to establish a 13 GW transmission network

Transmission System Expansions	Reference to Chapter 7	Transmission Lines	Substations	Total
		Million US$	Million US$	Million US$
Project 1: 330 kV North West Ring		355.5	165.8	**521.3**
Project 2: 330 kV North East Ring		499.5	152	**651.5**
Project 3: 330 kV Mambilla Network Connections		254.25	37.3	**291.6**
Additional Transmission Lines to Provide N-1 Reliability by 2025	Table 7-34	216.45	67.2	**283.7**
Additional Transmission Lines to Relieve Existing Lines by 2025	Table 7-35	16.4	25.6	**42.0**
Additional 330/132 kV Transformers by 2025	Table 7-36	0.0	78.1	**78.1**
Additional 132/33 and 132/11 kV Transformers	Table 7-37	0.0	68.2	**68.2**
New Reactive Power Compensation in Lagos Region				**50.0**
Costs for converting 330 kV DC lines to quad conductors	Table 7-42			**90.0**
Total Additional Investment Cost by 2025				**2076.3**

1.9.4 Transmission network investments after 2025

Regarding transmission network investments after 2025, only the investments in the highest transmission voltage level has been investigated, i.e. 330 kV and higher. The estimation of network investments in the 132 kV system and 132/33 kV substations is not possible at this stage because it requires detailed investigations and is considered to be part of medium term planning and not long term planning.

According to the Consultancy Contract, options for the introduction of a higher transmission voltage have to be studied. The Consultant has checked three options: continuation of network expansion with 330 kV and introduction of 500 kV or 750 kV as a new voltage level.

With regards to the 3 voltage level options for introducing a "Supergrid" beyond 2030, the cost comparison is summarized in **Table 1-8.**

Table 1-8: Summary of cost comparison between 330, 500 and 750 kV

Voltage level	Transmission Lines (million US$)	Substations (million US$)	Total (million US$)
330 kV	1161	220	1381
500 kV	722	533	1256
750 kV	903	686	1589

The investigations indicated lower investment costs for network expansions with a new 500 kV voltage level compared with the exiting 330 kV voltage level. However, the difference is relatively small. Prior to a decision on the introduction of a new voltage level the actual load and generation development has to be taken into account.

The introduction of a 750 kV voltage level is considerably costly and technically is not required.

1.9.5 TCN's Transmission Investment Plan up to 2025

TCN has allocated their network rehabilitation and expansion program for the time period up to 2025 in accordance with the expected financing by development banks. Details regarding the individual packages are presented in **Annexes 4.2.-1 to 6**.

Development Bank	Reference to Annex	Total million US$
AFD (French Development Agency - Agence Française de Développement)	4.2.d1	170
JICA (Japan International Cooperation Agency)	4.2.d2	200
AFDB (African Development Bank)	4.2.d3	200
World Bank	4.2.d4	486
Islamic Development Bank (IDB)	4.2.d5	210
AFD (French Development Agency - Agence Française de Développement)	4.2.d6	272
Total Additional Investment Cost by 2025		**1,538**

1.10 Financial Analysis

For the purpose of a financial analysis Fichtner has identified of the following three "Projects":

Project 1: 330 kV North West Ring
Project 2: 330 kV North East Ring
Project 3: 330 kV Lines for connection of Mambila HPP

The "Projects" have been defined under consideration that the benefits depend on the completion of a project rather than on completion of individual lines. However, the actual implementation sequence may be different.

All costs and benefits in the financial assessment are expressed in market prices and in US Dollar. The costs include project investment costs and O&M costs of 1% of the project investment costs. The total project costs include cost of new transmission lines and substations as well as physical and price contingencies and estimates of engineering, consulting and environment costs. **Table 1-9** presents the total financing cost of the project investment (excluding price contingencies) of the three projects.

Table 1-9: Cost estimates

Cost Estimates			Project 1	Project 2	Project 3
1. Transmission line		US$ million	355.60	499.50	254.30
2. Substations		US$ million	165.80	152.00	37.30
Total estimated equipment		**US$ million**	**521.40**	**651.50**	**291.60**
3. Engineering - foreign	5%	US$ million	26.07	32.58	14.58
4. Owners Engineer	3%	US$ million	15.64	19.55	8.75
5. Other Consulting Services, ESIA	1%	US$ million	5.21	6.52	2.92
6. Environmental Safeguard	1%	US$ million	5.21	6.52	2.92
7. Land acquisition, Resettlement	1%	US$ million	5.21	6.52	2.92
Total CAPEX		**US$ million**	**578.75**	**723.17**	**323.68**
Physical Contingencies	5%	US$ million	28.94	36.16	16.18
Project investment cost		**US$ million**	**607.69**	**759.32**	**339.86**

In a first step, the Consultant has calculated the financial levelized electricity costs (LECs) that provide an indicator for the level of the cost-recovering transmission charges required to render the project financially viable.

The LECs are calculated as the net present value of project costs divided by the net present value of energy transmitted. **Table 1-10** shows the LECs of the three projects.

Table 1-10: Levelized electricity cost

Results LEC		Project 1	Project 2	Project 3
LECs at				
WACC 1.15%	US$/kWh	0.0033	0.0094	0.0035
WACC 2%	US$/kWh	0.0039	0.0111	0.0040
WACC 4%	US$/kWh	0.0055	0.0163	0.0054

The financial LECs of the projects 1 and 3 are below the current average transmission tariff in Nigeria, which is estimated at US$ 0.0085 per kWh. At the current tariff, the projects have a FIRR of 6.79% and 7.31% respectively showing that these projects are financially feasible.

The next step is to set up the financial costs of the projects as cash flows over the entire lifetime of the projects and compare to the project revenues. The basic technique for comparing costs and benefits occurring in different periods is to discount costs and benefits and to express them in a common value at one point in time. The discount rate applied in the financial analysis for calculating net present values is equal to the weighted average cost of capital (WACC). A discount rate equal to the WACC of 1.15% is applied. The results of the base case assessment are summarized in **Table 1-11**

Table 1-11: Financial indicators

Results Base Case			Project 1	Project 2	Project 3
Project investment cost		US$ million	607.69	759.32	339.86
NPV at					
WACC	1.15%	US$ million	1,174	-91	610
WACC	2.00%	US$ million	848	-208	459
WACC	4.00%	US$ million	348	-374	65
FIRR			6.79%	0.63%	7.31%
Benefit/Cost Ratio			2.55	0.90	2.43
Payback Period		years	19.8	38.1	15.7

The consultant has also carried out a sensitivity analysis to show the robustness of the projects versus changes in major parameters which may have an adverse impact on the viability of the projects. Parameter changes include project investment costs, O&M cost, transmission charges, volume of energy transmitted and WACC.

In TCN's latest investment plan up to 2025 (see Section 1.9.5) it is planned to connect additional areas to the national grid. This will have positive effects on the economic viability of the projects.

2. Introduction

2.1 Project Title

Transmission Expansion Plan
Development of Power System Master Plan
For the Transmission Company of Nigeria

2.2 Authorization

The

Transmission Company of Nigeria (TCN)
7 Hombori
Wuse II
Abuja
Nigeria

Appointed

FICHTNER GmbH Co. KG
Sarweystrasse 3
70191 Stuttgart
Germany

to perform consultancy services for the **Transmission Expansion Plan.**

2.3 Project Dates

Contract date:	30 September 2015
Effectiveness:	04 February 2016
Scheduled completion date	31 December 2017*

2.4 Acknowledgement

Fichtner would like to thank the staff of TCN for their cooperation in furnishing data and information, and providing general support during local investigations.

3. Power Sector Assessment

3.1 General

The analysis of the development of the electrical power sector in Nigeria is based on information included in TCN's Annual Technical Reports. The Consultant has received these reports for the years 2006 to 2015 from TCN. Furthermore, information received from the National Control Center (NCC) at Osogbo has been analyzed.

3.2 Geographical Structure of the Transmission Company of Nigeria (TCN)

TCN has created eight Transmission Planning Regions for better planning.
The actual regions under field and maintenance services sector are shown in **Figure 3-1**.

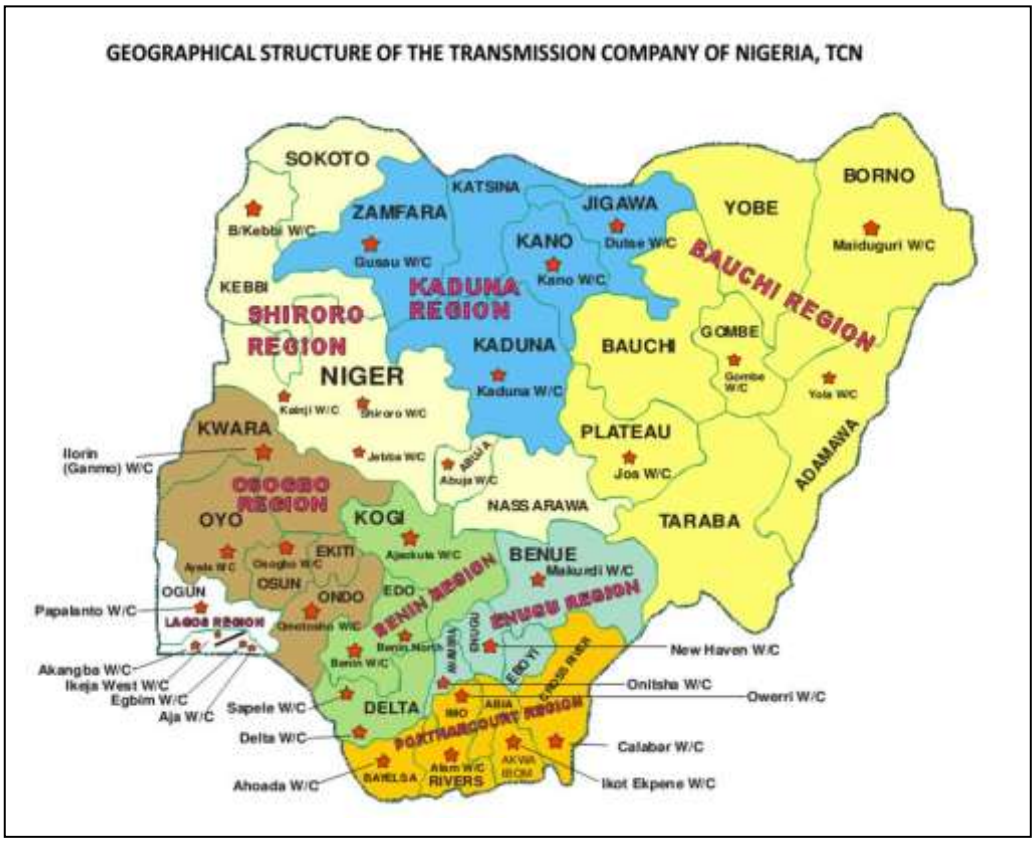


Figure 3-1 Geographical Structure of TCN

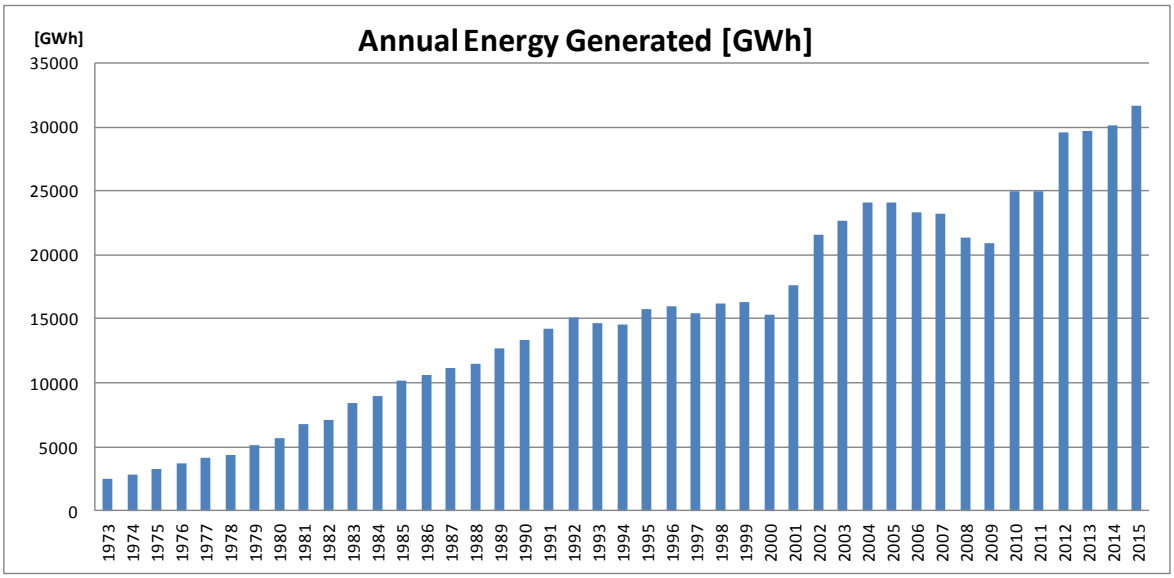
3.3 Development of Peak Output and Energy Generated

Records on Annual Energy Generated and Simultaneous National Peak demand of electricity show a permanent growth with two periods of stagnation /decline.

Figure 3-2 and **Figure 3-3** indicate that periods of stagnation / decline of energy generation and peak demand were offset rapidly in the following years.

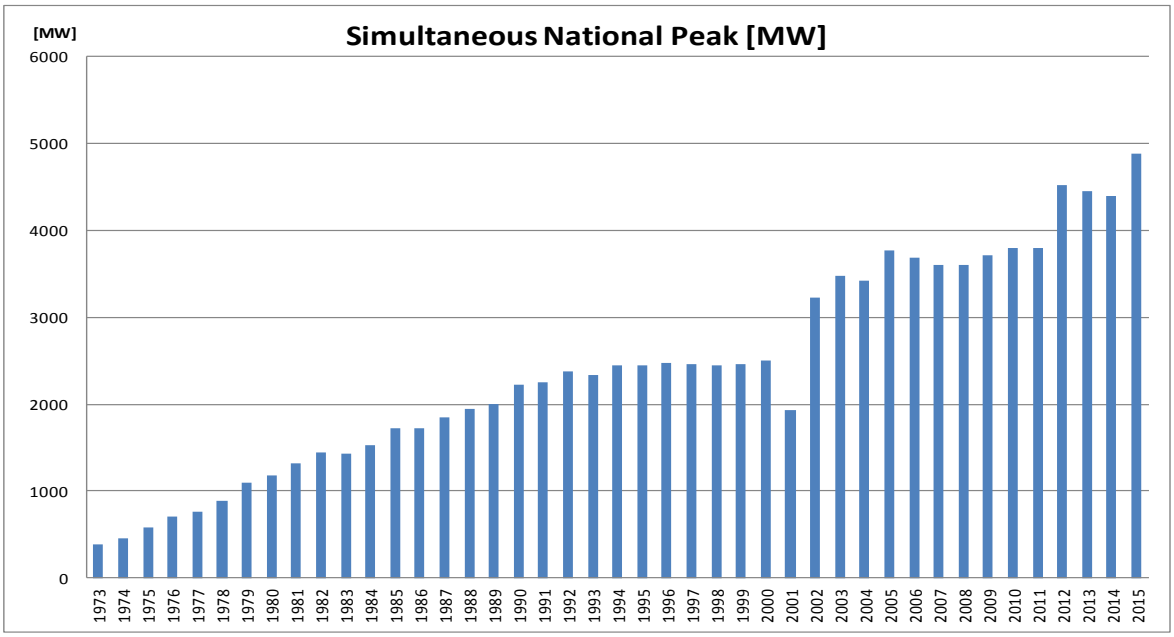
Between 1973 and 2015 peak generation was increased from 385 MW to 4,884 MW, i.e. with an average growth rate of about 6.3%. During the same period the annual energy generated increased from 2493 GWh to 31,616 GWh, i.e. with an average growth rate of about 6.4%.

In 2015 peak generation reached 4883.9 MW and on 2nd February 2016 peak output reached 5074.7 MW.



Source: TCN Annual Report 2015

Figure 3-2 Annual Energy Generated



Source: TCN Annual Report 2015

Figure 3-3 Simultaneous National Peak

3.4 Power Demand versus Generation

Peak output of power stations depends on the availability of generation units, water inflow for hydro power plants and gas supply for thermal power plants and not on the actual demand. Demand is always much higher than the available generation capacity.

In 2015 the NCC Osogbo daily operational report on 08.12.2015 shows a Peak Demand Forecast (connected + suppressed load) of 14,630 MW. The peak generation was about 4,885 MW. That means, only 33% of the estimated demand could be supplied.

NCC's operational reports show that many generation units are not in operation because of unavailability of gas. On December 8, 2015 for example, about 1,500 MW of generation capacity were not in operation for this reason. In some cases, gas supply has been interrupted because of sabotage of the gas pipeline system.

3.5 Daily Load Curve

The peak power demand of the electrical power system of Nigeria is during evening time, between 20:00 hours and 23:00 hours as shown in **Figure 3-4**. Minimum power demand is in the early morning between 03:00 hours and 05:00 hours.

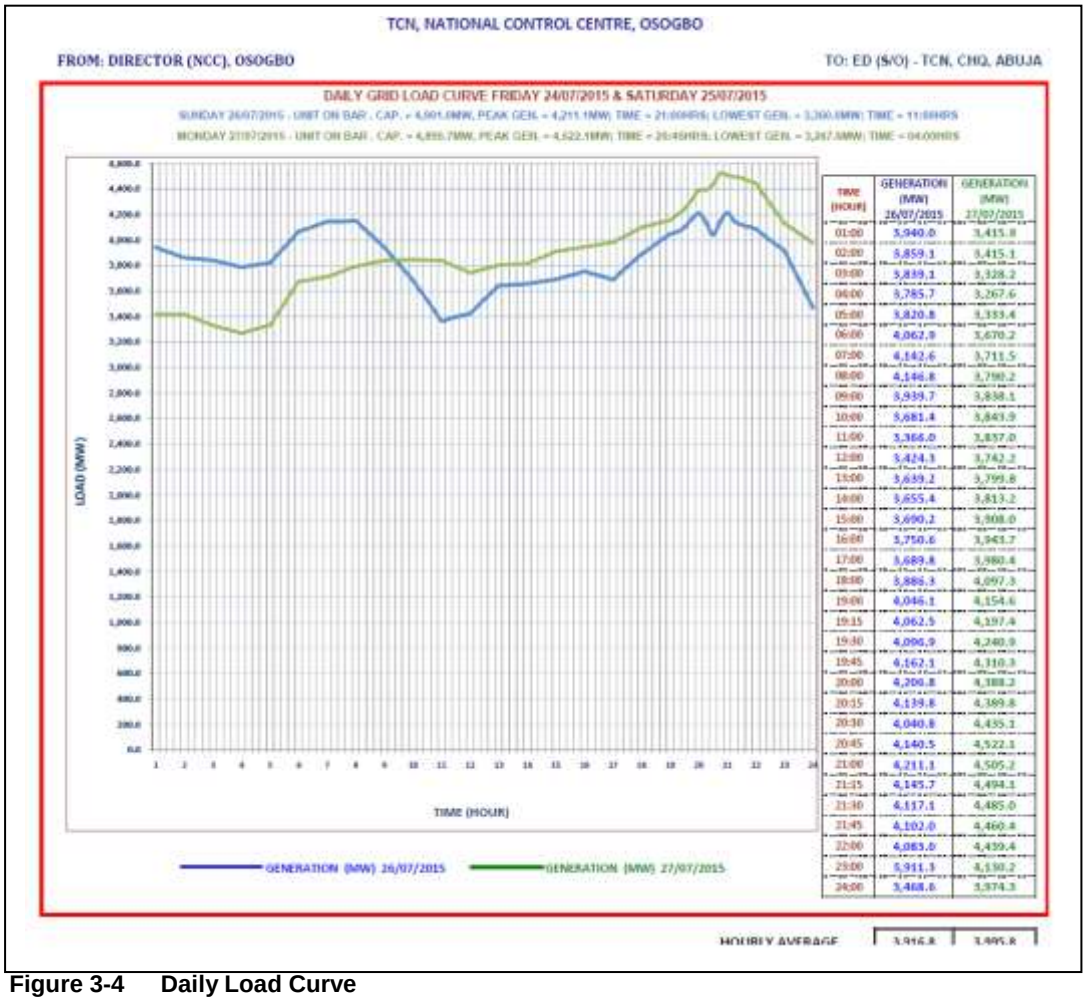


Figure 3-4 Daily Load Curve

3.6 Electricity Distribution

Electricity supply to Nigerian consumers is in the hand of 11 privatized distribution companies. The area of each distribution company is shown in **Figure 3-5.**

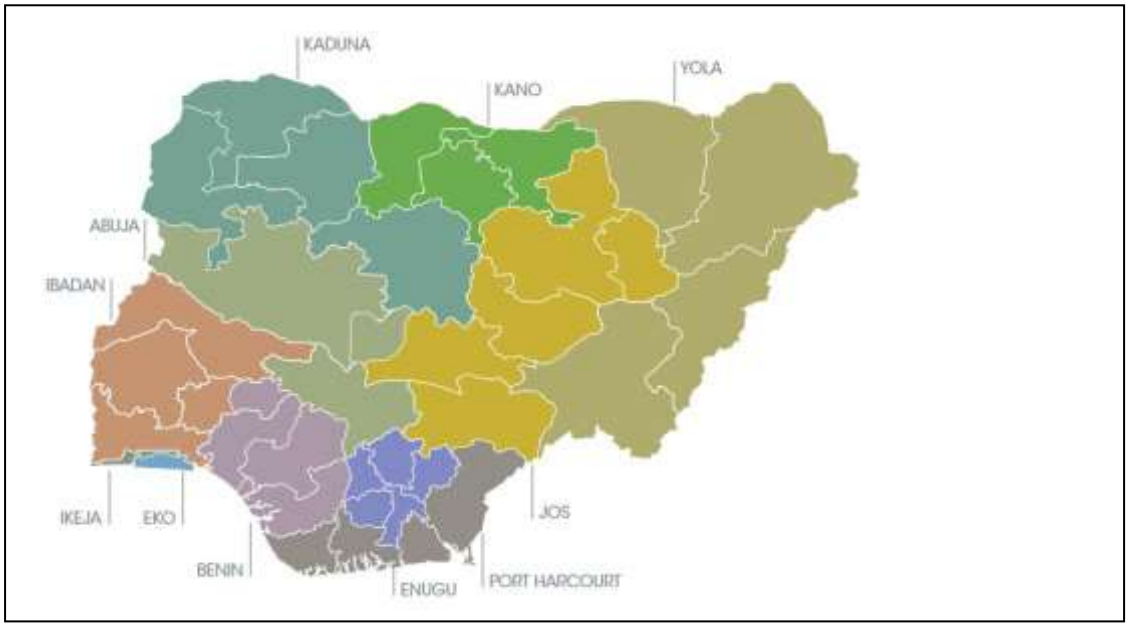
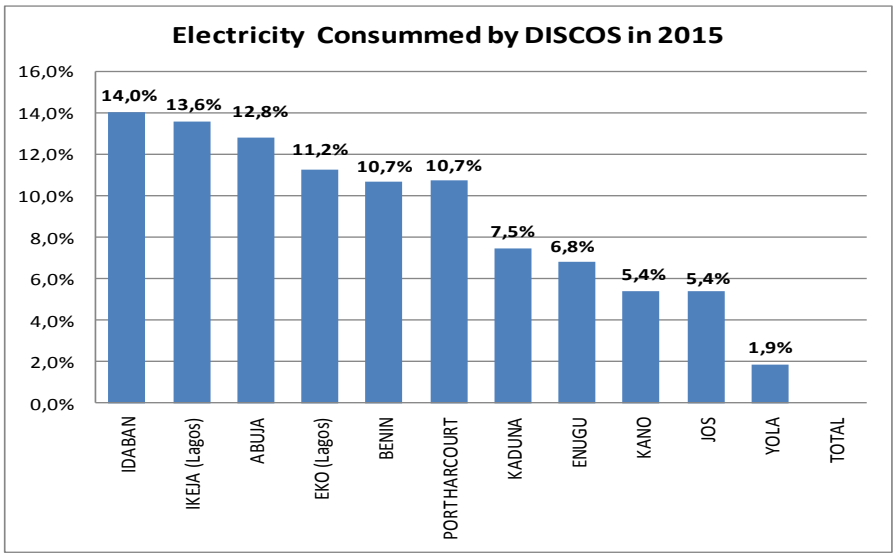


Figure 3-5 Areas of Distribution Companies in Nigeria

The electricity consumption of the southern DisCos is much higher than for the DisCos located in the North because the population in the southern DisCos is much higher and also most of the industries are located in the South, i.e. 73% of the electricity is consumed by the DisCos Ibadan, Ikeja, Eko, Benin, Abuja and Port Harcourt whereas Kaduna, Enugu, Kano, Jos and Yola consume 27% only, see **Figure 3-6.**

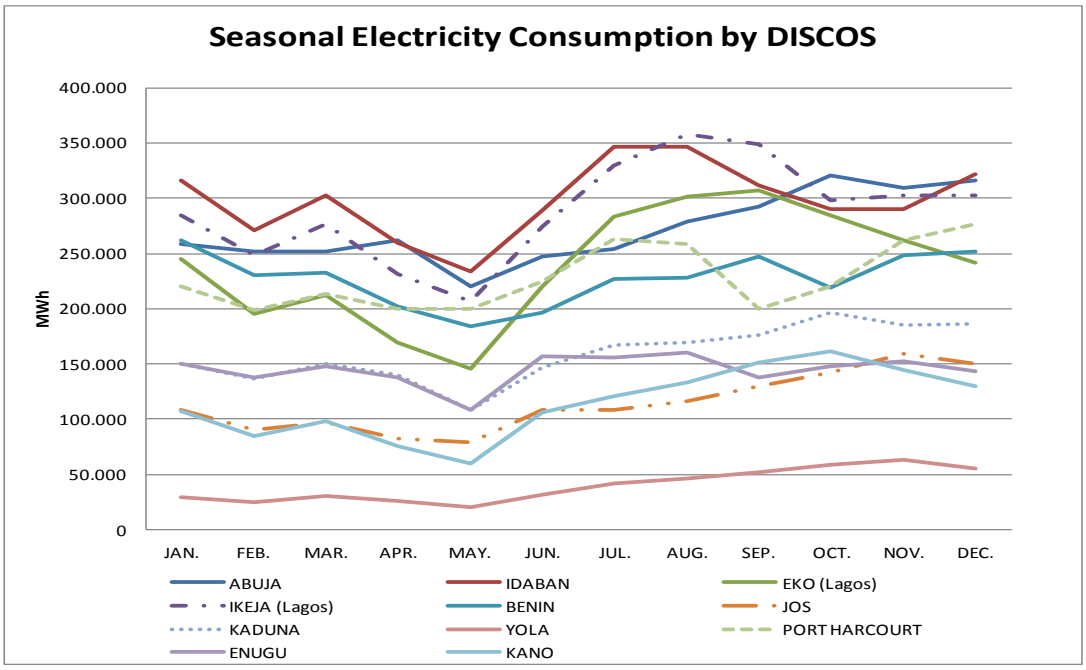


Source: TCN Annual Report 2015

Figure 3-6 Electricity Consumption of DisCos in 2015

The seasonal electricity supply to DisCos in 2015 is shown in **Figure 3-7.**

The graphs are strongly influenced by the availability of generation capacity in 2015 and depend less on climatic conditions.



Source: TCN Annual Report 2015

Figure 3-7 Seasonal Electricity Consumption by DisCos in 2015

4. Electrical Transmission System

4.1 Power System Data

4.1.1 General

Data on the power system is required for power system studies which include load flow, short circuit calculations and static and transient stability analysis.

4.1.2 Existing Power System

After the kick-off meeting in 4 December 2015 FICHTNER started with data collection from TCN and other organizations, e.g. statistical bureau. TCN provided data on the existing high voltage power system which are required for system analysis. Furthermore, additional data have been considered which were collected by FICHTNER in July 2015 from TCN for the WAPP interconnection study.

The latest map (received from TCN in December 2016) with the existing Nigerian 330 kV and 132 kV transmission network is shown in **Annex 4.1a**. The latest version of the single line diagram of the existing network (received from TCN in July 2016) is shown in **Annex 4.1b**.

4.1.2.1 Existing Transmission Assets

During the data collection phase in December 2015 the Consultant also received an EXCEL-file with two lists of on-going projects: one list with TCN on-going projects and another with NIPP on-going projects see **Annexes 4.2a and 4.2b**.

A map of Nigeria with the existing 330 kV and 132 kV transmission lines and ongoing transmission line projects is shown in **Annex 4.2c**. This annex shows also planned transmission expansions necessary for a grid of 10,000 MW transmission capacity.

It was agreed with TCN that as a basis for preparation of the Transmission Expansion Plan, it will be assumed that all on-going projects will be completed latest by 2020. Based on this network configuration, Fichtner has carried out the power system studies to identify further transmission system expansions between 2020 and 2035. It is recognized that it will be challenging to implement transmission projects identified in Fichtner's Transmission Expansion Plan before 2020 because it takes a minimum of three years from now to implement projects (one year for preparation of tender documents and selection of implementation contractor and two years for project implementation).

During data collection in February / March 2016 and the subsequent months, Fichtner carried out a comparison of the single line diagram of the file *BASE_10_31_83_nipp MODEL.sld* provided by TCN and the lists of on-going projects mentioned above and the PSS/E file was modified accordingly.

The technical data of transmission system components are shown in the following Annexes:

- **Annex 4.3:** Transmission lines
- **Annex 4.4:** Transformers
- **Annex 4.5:** Generators

4.1.3 Existing Power System Modelling

4.1.3.1 PSS/E files

A review of the all the existing PSS/E files in TCN was undertaken during the Kick-off Meeting. In discussions with the responsible TCN staff, the following issues were agreed:

The following PSS/E files were provided by TCN representing the existing system for steady state analysis:

Starting Model_TTC_BASE CASE 5.5GW_13012015_ MODEL.sav
Starting Model_TTC_BASECASE_5.5GW_ SVC_03012015_ MODEL.sld

The Consultant has processed further these files, made corrections and added the on-going projects by TCN and NIPP to create a base case for 2020. All fictitious capacitors, included in various files depicting the existing system, were removed. Only two capacitors at Kumbotso (Kano) remained in the files of the existing system.

In this respect, any violations reported in the study of the existing system should only be resolved by either operational measures and/or additional reactive power compensation equipment to be installed in future. Loads that cannot be served, either due to lack of generation or circuit overloads, should be shed, whenever possible and as per current practice by TCN.

4.1.3.2 Shunt Reactors and Fixed Capacitors

The present status of Reactors and Capacitors installed in the TCN network is summarized in **Table 4-1** and **Table 4-2.**

Table 4-1: Shunt Reactors

S/N	Substation	Voltage [kV]	MX [MVar]	Switchable
1	KANO	330	-75.00	Y
2	GOMBE	330	-50.00	Y
3	GOMBE	330	-50.00	Y
4	YOLA	330	-75.00	Y
5	KADUNA	330	-75.00	Y
6	JOS	330	-75.00	Y
7	JEBBA T.S.	330	-75.00	Y
8	JEBBA T.S.	330	-75.00	Y
9	OSHOGBO	330	-75.00	N
10	BENIN	330	-75.00	Y
11	BENIN	330	-75.00	Y
12	ALAOJI	330	-75.00	Y
13	IKEJA WEST	330	-75.00	Y
14	IKEJA WEST	330	-75.00	Y

S/N	Substation	Voltage [kV]	MX [MVar]	Switchable
15	KATAMPE	330	-75.00	Y
16	MAKURDI	330	-75.00	Y
17	ONITSHA	330	-75.00	Y
18	OKEARO	330	-75.00	Y
19	GOMBE	33	-30.00	Y
20	GOMBE	33	-30.00	Y
21	YOLA	33	-30.00	Y
22	YOLA	33	-30.00	Y

Table 4-2: Fixed capacitors

S/N	Substation	Voltage [kV]	Capacitor [MVar]	Status	Planned Action
1	Kumbotso	330	50	In operation	
2	Kumbotso	330	50	In operation	
3	Akangba A	132	72	Installed but not commissioned yet	To be commissioned
4	Akangba B	33	24	Installed but not commissioned yet	To be commissioned
5	Akoka	33	24	Installed but not commissioned yet	To be commissioned
6	Alausa	33	24	Installed but not commissioned yet	To be commissioned
7	Alimosho	33	24	Installed but not commissioned yet	To be commissioned
8	Ejigbo	33	24	Installed but not commissioned yet	To be commissioned
9	Ijora	33	24	Installed but not commissioned yet	To be commissioned
10	Isolo	33	24	Installed but not commissioned yet	To be commissioned
11	Ogba	33	24	Installed but not commissioned yet	To be commissioned
12	Otta	33	24	Installed but not commissioned yet	To be commissioned
13	Yandev	33	20	Installed but not commissioned yet	To be commissioned
14	Ikorodu	33	20	Faulty, mainly due to CB fault	Can be repaired
15	Ikorodu	33	20	Faulty, mainly due to CB fault	Can be repaired
16	Abeokuta	33	20	Faulty, mainly due to CB fault	Can be repaired
17	Abeokuta	33	20	Faulty, mainly due to CB fault	Can be repaired
18	Iseyin	33	20	Faulty, mainly due to CB fault	Can be repaired
19	Ayede	33	20	Faulty, mainly due to CB fault	Can be repaired
20	Ayede	33	20	Faulty, mainly due to CB fault	Can be repaired
21	Agbara	33	20	Commissioned, can be switched on	
22	Ijebu-ode	33	20	Commissioned, can be switched on	
23	Sagamu	33	20	Commissioned, can be switched on	
24	Irrua	33	20	Faulty, mainly due to CB fault	Can be repaired
25	Ilorin	33	20	Faulty, mainly due to CB fault	Can be repaired
26	Akure	33	20	Faulty, mainly due to CB fault	Can be repaired
27	Awka	33	20	Faulty, mainly due to CB fault	Can be repaired
28	Uyo	33	20	Faulty, mainly due to CB fault	Can be repaired
29	Effurun	33	20	Faulty, mainly due to CB fault	Can be repaired
30	Amukpe	33	20	Faulty, mainly due to CB fault	Can be repaired
31	Akwanga	33	20	Faulty, mainly due to CB fault	Can be repaired
32	Akwanga	33	20	Faulty, mainly due to CB fault	Can be repaired
33	Minna	33	20	Faulty, mainly due to CB fault	Can be repaired
34	Minna	33	20	Faulty, mainly due to CB fault	Can be repaired
35	Kontagora	33	20	Faulty, mainly due to CB fault	Can be repaired
36	Kontagora	33	20	Faulty, mainly due to CB fault	Can be repaired
37	Zaria	33	20	Faulty, mainly due to CB fault	Can be repaired
38	Zaria	33	20	Faulty, mainly due to CB fault	Can be repaired
39	Kaduna Town	33	20	Faulty, mainly due to CB fault	Can be repaired

S/N	Substation	Voltage [kV]	Capacitor [MVar]	Status	Planned Action
40	Kaduna Town	33	20	Faulty, mainly due to CB fault	Can be repaired
41	Dakata	33	20	Faulty, mainly due to CB fault	Can be repaired
42	Dakata	33	20	Faulty, mainly due to CB fault	Can be repaired
43	Apir	33	20	Faulty, mainly due to CB fault	Can be repaired
44	Kumbotso	33	20	Installed but not commissioned yet	To be commissioned
45	Okene	33	20	Installed but not commissioned yet	To be commissioned
46	Dan-Agundi	33	20	Installed but not commissioned yet	To be commissioned
47	Katsina	33	20	Installed but not commissioned yet	To be commissioned
48	Ife	33	20	Installed but not commissioned yet	To be commissioned
49	Ayede	33	20	Installed but not commissioned yet	To be commissioned
50	Ijebu-Ode	33	20	Installed but not commissioned yet	To be commissioned
51	Sagamu	33	20	Installed but not commissioned yet	To be commissioned
52	Iseyin	33	20	Installed but not commissioned yet	To be commissioned
53	Ilorin	33	20	Installed but not commissioned yet	To be commissioned
54	Akure	33	20	Installed but not commissioned yet	To be commissioned
55	Apo	33	20	Installed but not commissioned yet	To be commissioned
56	Apo	33	20	Installed but not commissioned yet	To be commissioned

4.1.4 Planned Network Extensions

TCN has prepared a summary of future transmission expansion projects, based on the report *"Appraisal of Transmission Projects - March 2014"* prepared by TCN / Manitoba Hydro International.

Fichtner has agreed to review these projects, verify their applicability and include in the modeling and study only those which are still considered applicable.

4.1.5 Approach to create PSS/E cases for future extensions

The files listed in Section 4.1.3.1 were the basis to build upon for the creation of new cases and scenarios for the planning horizon of the Master Plan.

The introduction of additional capacitors, as necessary, takes into consideration the status of the existing ones, as shown in **Table 4-2,** under the assumption that all faulty capacitors that can be repaired will, if necessary, be repaired and the others will be commissioned as planned.

The PSSE files of the existing system were updated to include the following transmission projects:

(a) Those listed in **Annexes 4.2a and 4.2b,** as detailed in **section 4.1.2.1**
(b) Those considered applicable from **section 4.1.4**.

4.2 PSS/E case for 2020

A new 2020 case has been prepared, whereby the following changes were made:

4.2.1 Reactive power compensations

All the fictitious capacitors and reactors have been deleted. **Table 4-3** and **Table 4-4** show the reactors and capacitors that the 2020 case contains:

Table 4-3: Shunt reactors in 2020

Reactors	Bus Number	Bus Name	kV	Id	B-Shunt [MVar]
	53001	KANO	330	1	-75
added	53005	KANO_NEW	330	1	-75
added	63005	MAIDUGURI	330	2	-75
	73001	ONITSHA	330	1	-75
	63000	GOMBE	330	1	-50
	63000	GOMBE	330	2	-50
	13003	IKEJA W	330	1	-75
	13003	IKEJA W	330	2	-75
	13026	OKE_ARO	330	1	-75
	23001	OSOGBO	330	1	-75
	33001	KATAMPE	330	1	-75
	33003	JEBBA T.S	330	2	-75
	33003	JEBBA T.S.	330	3	-75
	43002	BENIN	330	2	-75
	53000	KADUNA	330	1	-75
	63001	JOS	330	1	-75
	63002	YOLA	330	1	-75
	73003	MAKURDI	330	1	-75
	83002	ALAOJI	330	1	-75
	73001	ONITSHA	330	2	-69
	65001	YOLA T1	33	1	-30
	65014	GOMBE	33	1	-30

Table 4-4: Fixed capacitors in 2020

Capacitors	Bus Number	Bus Name	kV	Id	B-Shunt [MVar]
	15002	AGBARA	33	1	20
	25004	AYEDE	33	1	20
	25011	ILORIN	33	1	20
	25012	ISEYIN	33	1	20
	25018	AKURE	33	1	20
	25035	SAGAMU	33	1	20
	25038	IJEBU ODE	33	1	20
	35001	APO	33	2	20
	45003	OKENE	33	1	20
	55001	DAN AGUNDI	33	2	20
	55010	KATSINA	33	1	20
	75017	YANDEV	33	1	20
	15006	AKANGBA	33	1	24
	15007	AKOKA	33	1	24
	15009	ALAUSA	33	1	24
	15014	EJIGBO	33	1	24

Capacitors	Bus Number	Bus Name	kV	Id	B-Shunt [MVar]
	15015	IJORA	33	1	24
	15018	OGBA	33	1	24
	15028	ISOLO	33	1	24
	15079	OTTA	33	1	24
added	**32025**	**YAURI**	132	**3**	**20**
	12004	AKANGBA	132	1	72
added	**52011**	**GUSAU**	132	**1**	**75**
	75004	AWKA	33	1	10
	75012	OJI RIVER	33	1	10
	62021	MAIDUGURI	132	1	10.8
	65041	MAID T2	33	2	10.8
	65042	MAID T1	33	1	10.8
	15011	ABEOKUTA OLD	33	2	20
	15022	IKORODU	33	2	20
	15027	ILUPEJU	33	1	20
	15030	OJO	33	1	20
	35000	AKWANGA	33	1	20
	35009	KONTAGORA	33	1	20
	35012	MINNA	33	1	20
	35048	MINNA	33	2	20
	42014	EFFURUN	132	2	20
	42015	AMUKPE	132	1	20
	52022	HADEJIA	132	1	20
	55011	ZARIA	33	1	20
	55051	DAKATA	33	1	20
	55057	KUMB	33	1	20
	55069	KD TWN T2	33	1	20
	55072	KD TWN T3	33	1	20
	72009	AWKA	33	1	20
	75002	APIR	33	1	20
	75048	APIR	33	1	20
	15010	ALIMOSHO	33	1	24
	15080	OLD ABEOK	33	3	24
	35036	GWAGWALADA	33	1	50
	53001	KANO	330	2	50
	53001	KANO	330	3	50
	12032	OGBA	132	1	72

In addition, an SVC at Gombe 330 kV substation has been provisionally added to the model to study further its applicability and determine whether it is necessary to be installed in order to maintain voltage stability in the system in the period 2020-2035.

4.2.2 Inclusion of TCN, NIPP, JICA and AFD projects

The TCN and NIPP projects that are expected to be implemented by 2020 have been included in the new 2020 PSS/E case. These projects are listed in **Annex 4.2a** and **Annex 4.2b** and the PSS/E case has also been modified to include the decisions made, following the exchange of comments between TCN and the Consultant.

Annex 4.6a and **Annex 4.6b** show the 330 kV network configurations in the Lagos Region including the projects that will be implemented under JICA financing.

For a better understanding of the 330 kV and 132 kV network configuration a simplified single line diagram has been prepared for the network configuration of 2020 including all ongoing TCN, NIPP and JICA Projects, see **Annex 4.7.**

Furthermore, the following ongoing projects financed by AFD (Agence Française de Développment) for Abuja area have been considered:

New transmission lines:

- 142km of new 330 kV double circuit line from Lafia 330 kV Substation (new) to New Apo 330/132/33 kV Substation.
- 7km of new 132 kV double circuit line from new Apo 330/132/33 kV substation to Old Apo 132/33 kV substation
- 35km of new 132 kV double circuit line from New Apo 330/132/33 kV substation to the new Kuje132/33 kV substation
- 29km of new 132 kV double circuit line from the proposed Kuje 132/33 kV Substation to West Main (Lugbe) 330/132/33V substation.

New substations:

- 330/132/33 kV substation at New Apo
- 132 kV line bay extension at Old Apo 132 kV SS
- 330/132/33 kV substation at WestMain (Lugbe)
- 132/33 kV substation at Kuje to be equipped with 3No. 60MVA (ref AFD1 projects in following Table 4-5)
- 132/33 kV Substation at Wumba / Lokogoma
- 132/33 kV GIS substation at Gwarimpa

4.2.3 Additional Transmission System Expansions and Rehabilitation Measures Proposed by TCN

TCN requested FICHTNER to include in the Final Report additional transmission system expansions and rehabilitation/reinforcement measures which have been identified by TCN. With e-mail dated October 5, 2017, FICHTNER has received six EXCEL lists with proposed projects, see **Annex 4.2.3-1 to 6**. Some of these projects had already been submitted earlier by TCN and considered by FICHTNER. The annexes show also the costs of the individual measures as estimated by TCN.
TCN is planning to implement the measures using finance from development banks as follows:

Projects	Development Bank	Total Cost
Annex 4.2.3-1	AFD (French Development Agency - Agence Française de Développement)	170 million US$
Annex 4.2.3-2	JICA (Japan International Cooperation Agency)	200 million US$
Annex 4.2.3-3	AFDB (African Development Bank)	200 million US$
Annex 4.2.3-4	World Bank	486 million US$

Annex 4.2.3-5	Islamic Development Bank (IDB)	210 million US$
Annex 4.2.3-6	AFD (French Development Agency - (Agence Francaise de Development)	272 million US$
Total		**1538 million US$**

It is planned to implement all network expansions and rehabilitation/reinforcement measures as soon as possible. However, a lot of preparatory work (e.g. feasibility studies, tender documents etc.) for most of the measures needs to be done. At this stage only implementation of system expansions according to **Annex 4.2d1** (AFD-Project) is going-on and commissioning until 2020 may be achievable.

For projects financed by other banks (**Annexes 4.3d2 to 6**) it can be assumed that implementation between 2020 and 2025 is feasible. Usually about 2 to 3 years are required for feasibility studies, environmental impact studies, route survey, preparation of technical specifications and tender documents, bidding, tender evaluation and contracting and arrangement financing agreements. In addition, 2 to 3 years can be assumed for construction and commissioning of the projects.

The main 330 kV and 132 kV transmission line projects of the six excel sheets advised by TCN in October 5, 2017, are summarized in **Table 4-5** together with the expected year of operation. The projects entailing 330 kV lines are highlighted in blue fonts.

Table 4-5: Main TCN 330 kV and 132 kV transmission line projects

Area	Region	Location	Description	kV	in operation by
PROPOSED ABUJA TRANSMISSION RING PROJECT (AFD1)					
North Central	Abuja	New Apo	Construction of about 172km of new 330 kV double circuit line from Lafia 330 kV Substation (new) to the proposed New Apo 330/132/33 kV Substation.	330	2020
North Central	Abuja	Old Apo	Construction of about 7km of new 132 kV double circuit line from new Apo 330/132/33 kV substation to Old Apo 132/33 kV substation:	132	2020
North Central	Abuja	Kuje	Construction of 35km of new 132 kV double circuit line from New Apo 330/132/33 kV substation to the proposed Kuje 132/33 kV substation.	132	2020
North Central	Abuja	West Main Lugbe	Construction of 29km of new 132 kV double circuit line from the proposed Kuje 132/33 kV Substation to West Main (Lugbe) 330/132/33V substation.	132	2020
LAGOS/OGUN TRANSMISSION PROJECTS (JICA)					
South West	Lagos	New Abeokuta	Arigbajo – New Abeokuta 132 kV D/C Transmission Line (37.8km)	132	2022
South West	Lagos	Arigbajo	Olorunsogo – Arigbajo 330 kV D/C Transmission Line (12.9km)	330	2022
South West	Lagos	Ikeja West	Arigbajo – Ikeja West / Osogbo 330 kV D/C Turn in-out (5.9km)	330	2022
South West	Lagos	Arigbajo	Ogijo- Arigbajo D/C Transmission Line (43.7km)	330	2022
South West	Lagos	Sagamu	132 kV Quad Line (2.3km) from Ogijo – Existing Ikorodu /Sagamu 132 kV 2x D/C Transmission Line	132	2022
South West	Lagos	Redeem	132 kV D/C Transmission Line (10.3km) from Ogijo – Redeem.	132	2022
South West	Lagos	Ikeja West	MFM – Existing Benin (Omotosho)/Ikeja West 330 kV 2 x D/C Transmission Line (4.2km)	330	2022

Area	Region	Location	Description	kV	in operation by
South West	Lagos	New Agbara	Arigbajo – New Agbara 330 kV D/C Transmission Line (30.6km)	330	2022
South West	Lagos	Agbara	New Agbara – Agbara 132 kV D/C Transmission Line (20.8km)	132	2022
South West	Lagos	Badagry	New Agbara – Badagry 132 kV D/C Transmission Line (34.2km)	132	2022
PROPOSAL FOR NORTH EAST TRANSMISSION INFRASTRUCTURE PROJECT TO BE FINANCED BY AFDB					
North East	Bauchi	Maiduguri - Manguno - Marte - Dikwa - Bama	Construction of a New 321km, 132 kV Double Circuit Line Between Maiduguri - Manguno - Marte - Dikwa -Bama	132	after 2020
North East	Bauchi	Maiduguri - Bama - Goza - Gulak	Construction of a New 165km, 132 kV Double Circuit Line from Maiduguri - Bama - Goza - Gulak	132	after 2020
North East	Bauchi	Mayo Belwa - Jada - Ganye	Construction of a New 78km, 132 kV Double Circuit Line from Mayo Belwa - Jada - Ganye.	132	after 2020
North East	Bauchi	Biu - BuniYadi - Damaturu	Construction of a New 134km, 132 kV Double Circuit Line from Biu - BuniYadi - Damaturu	132	after 2020
North East	Bauchi	Dambua - Chibok - Uba - Mubi	Construction of a New 130km, 132 kV Double Circuit Line from Dambua - Chibok - Uba - Mubi	132	after 2020
North East	Bauchi	Mayo Belwa - Jada - Ganye	Construction of a New 78km, 132 kV Double Circuit Line from Mayo Belwa - Jada - Ganye.	132	after 2020
North East	Bauchi	Biu - BuniYadi - Damaturu	Construction of a New 134km, 132 kV Double Circuit Line from Biu - BuniYadi - Damaturu	132	after 2020
North East	Bauchi	Dambua - Chibok - Uba - Mubi	Construction of a New 130km, 132 kV Double Circuit Line from Dambua - Chibok - Uba - Mubi	132	after 2020
PROPOSED NETAP PACKAGE AS AT 03RD APRIL, 2017 - $486 MILLION					
South West	Osogbo	Osogbo- Offa - Ganmo - Ilorin	Reconductoring of 150km, 132 kV Line Between Osogbo-Offa/Omuaran to Ganmo and Ilorin TS	132	2020
South West	Osogbo	Ayede - Sagamu	Reconstruction and Conversion of SC to Double Circuit of Ayede -Ajebo-Ishara-Sagamu 132 kV Line (54km) and Creation of Additional Bays 132 kV Line Bays at Ayede , Ajebo, Ishara and Sagamu.	132	2020
South West	Osogbo	Osogbo- Ife / Ilesha	Reconstruction and Conversion to Double Circuit of Osogbo-Ife/Ilesha 132 kV Line (39.21 km) and Osogbo-Ilesha 132 kV Line **Tie-Off** (22.1km) and Creation of Additional 132 kV Line Bays at Osogbo and Ilesha.	132	2020
South East	Port Harcourt	Afam - PH Main	Reconstruction of Existing Double 132 kV Line Circuit to 4 x 132 kV Line Circuit Using the Same Right of Way from Afam to Port Harcourt Main (37.8km), and Creating Additional 3 x 132 kV Line Bays	132	2020
South East	Port Harcourt	PH Main - PH Town	Reconductoring of 132 kV Double Circuit of Port Harcourt Main to Port Harcourt Town 132 kV Line (6km)	132	2020
North West	Kaduna	Kumbotso - Hadejia	Reconductoring of Kumbotso- Hadejia 132 kV Line (165km)	132	2020
North West	Kaduna	Kumbotso - Kankia	Reconductoring of Kumbotso- Kankia 132 kV Line (100km)	132	2020
South East	Enugu	Onitsha - Oji River	Reconductoring of Onitsha- Orji 132 kV Line (87km) with Turn In- Turn Out Tower at Nibo (Agu Awka) in Awka 132 kV Substation.	132	2020
South East	Enugu	Alaoji to Aba Town	Reconductoring of Alaoji - Aba Town Double Circuit 132 kV line (8km) Including Rehabilitation of Two Nos. Towers along the Line.	132	2020
South South	Benin	Irrua - Benin	Reconductoring of Irrua - Benin 132 kV line (81km)	132	2020
South South	Benin	Irrua - Okpilla	Reconductoring of Irrua- Okpila 132 kV line (43km).	132	2020
South South	Benin	Okpila - Okene	Reconductoring of Okpilla - Okene 132 kV line (65km)	132	2020
South South	Benin	Ajaokuta-Okene	Reconductoring of Ajaokuta- Okene 132 kV line (60km)	132	2020
North East	Bauchi	Gombe-Biu-Damboa-Maiduguri	Reconductoring of the Entire Route Length from Gombe -Dadin Kowa- Biu -Damboa - Maiduguri 132 kV line of 356km Route Length	132	2020

Area	Region	Location	Description	kV	in operation by
NIGERIA TRANSMISSION EXPANSION (IDB)					
North West	Kaduna	Construction of Quad 330 kV on Kaduna-Kano 330 kV Single DC Transmission Line	Construction of Double Circuit 330 kV Quad Conductor Kaduna-Kano Transmission line.	330	after 2020
North West	Kaduna	Zaria	Turn-in Turn-out and Installation of 2x150MVA 330/132/33 kV Transformer, 6x330 kV bay extension, 2x60MVA 132/33 kV Transformer, associated 132 kV line bays and 6 number 33 kV feeder bays at Zaria	330	after 2020
North West	Kaduna	Millennium City Kaduna	Turn-in Turn-Out and Installation of 2x150MVA 330/132/33 kV Transformer, 2 x330 kV bay extension, and 2x60MVA 132/33 kV Transformer and 2x3number associated outgoing 33 kV feeders.	330	after 2020
North West	Kaduna	Rigasa town, Kaduna	Turn-in Turn-out and Installation of 2x60MVA 132/33 kV Transformer and 5 number outgoing 33 kV feeders	132	after 2020
North West	Kaduna	Jaji, Kaduna	Turn-in Turn-out and Installation of 2x60MVA 132/33 kV Transformer and 6 number outgoing 33 kV feeders	132	after 2020
South South	Benin	Reconstruction of Delta to Benin 330 kV Transmission Line	Reconstruction of one of Delta-Benin 330 kV Transmission Line Double Circuit to Quad Conductor 330 Double Circuit Line	330	after 2020
South South	Port Harcourt	Reconstruction of Alaoji to Onitsha 330 kV Transmission Line	Double Circuit Alaoji-Ihiala-Onitsha to Quad conductor 330 kV transmission line	330	after 2020
South South	Ahoda, Gilili and Sapele	Environmental Impact Assessment and Resettlement Action Plan and Payment of Compensation	Double Circuit(DC) 132 kV Ahoda-Gilli-Gilli DC Transmission Line and 2x60MVA 132/33 kV Transformer at Gilli Gilli plus associated 6 number outgoing 33 kV feeders and DC 132 kV Sapele - Odilli DC Transmission Line and 2x60MVA 132/33 kV Transformer at Gilli Gilli plus associated 6 number outgoing 33 kV feeders	132	after 2020
North East	`Bauchi	Environmental Impact Assessment and Resettlement Action Plan and Payment of Compensation	132 line and associated substations: Maiduguri-Manguno-Marte-Dikwa-Bama,Maiduguri-Bama-Gwoza; Hadejia-Nguru-Gashua-Damaturu; Biu-Miringa-Buni Yadi-Damaturu; Dambua-Chibok-Askira-Uba-Mubi; Mayo Belwa-Jada-Ganye	132	after 2020
NORTHERN CORRIDOR TRANSMISSION PROJECT 2 (AFD2)					
North West	Shiroro	Kainji - Birnin Kebbi 330 kV Double Circuit (DC) Line (310km)	330 kV DC Transmission Line Kainji-Birnin Kebbi (following the existing ROW of the SC 330 kV line) and 4x 330 kV bay extension at B/ Kebbi and 2 x 330 kV bay extension at Kainji	330	after 2020
North West	Shiroro	Birnin Kebbi-Sokoto 330 kV Double Circuit (DC) Line (130km)	(1) Birnin Kebbi-Sokoto 330 kV DC Transmission Line on the existing 132 kV Birnin-Kebbi Sokoto ROW and reconductoring the existing 132 kV Single circuit Birnin-Kebbi Line to double its capacity	330	after 2020
North West	Kaduna	Katsina-Daura-Gwiwa-Minjibir-Kura (234KM)	Construction of length of 330 kV DC Twin line between Katsina-Daura-Gwiwa-Jogana- Kura	330	after 2020
North Central	Shiroro	Lambata (Mina-Suleja Rd)	Turn in Turn out Mina - Suleja 132 kV DC and Construction of 1 x 60MVA 132/33 kV Complete substation	132	after 2020
North West	Shiroro	Fakun Sarki-Argungu	Turn in Turn Out on Birnin Kebbi-Sokoto 132 kV Line and Construction of 2 x 60MVA 132/33 kV Complete substation	132	after 2020
North West	Shiroro	Yelwa- Yawuri	Construction of 1 x 60MVA 132/33 kV Complete substation and High Voltage Switchgears and Associated Equipment.	132	after 2020
North Central	Shiroro	Birnin Gwari	Construction of 1 x 60MVA 132/33 kV Complete substation and High Voltage Switchgears and Associated Equipment.	132	after 2020

Area	Region	Location	Description	kV	in operation by
North West	Kaduna	Daura-Katsina State	Installation of 2x150MVA 330/132/33 kV Double Circuit Substation and with associated 132 kV bay extension and Installation of 2x60MVA 132/33 kV transformers, 6number outgoing 33 kV feeder bays	330	after 2020
North West	Kaduna	Jogana-Kano	Installation of 2x150MVA 330/132/33 kV Double Circuit Substation and with associated 132 kV bay extension and Installation of 2x60MVA 132/33 kV transformers, 6number outgoing 33 kV feeder bays	330	after 2020
North West	Shiroro	330 kV Sokoto Transmission Substation	Installation of 2x150MVA 330/132/33 kV Transformers at Sokoto New 330 Double Circuit Substation and with associated 132 kV bay extension and Installation of 2x60MVA 132/33 kV transformers, 6number outgoing 33 kV feeder bays	330	after 2020
North Central	Shiroro	Shiroro –Kaduna (Mando) 330 kV Lines 1 & 2 SC Transmission Lines (96km)	Reconstruction and upgrading of 2 Single Circuit 330 kV Transmission Lines 1 & 2 from Shiroro PS to Mando (Kaduna) to a 2 Double Circuit, Quad conductor Shiroro-Mando (Kaduna) Transmission lines 1 and 2. The line bay extension at Mando and Shiroro	330	after 2020
North East	Bauchi	Bauchi 330 kV Transmission Substation (2km)	Turn in-out of the existing 330 kV SC Jos-Gombe line at Bauchi, and installation of 2x150MVA 330/132/33 kV Transformers with associated 132 kV bay extension and 2x60MVA 132/33 kV transformers, 6number outgoing 33 kV feeder bays	330	after 2020

In section 7 (Power System Analysis) it has been shown that some of these projects are critical for the operation of the system in 2020 and if the load of 10GW is to be served adequately these projects will have to be expedited with the aim to be completed by 2020 or as soon as possible after 2020.

4.2.3.1 Transmission System Expansions Financed by AFD

A financing agreement is in place for improvement of the transmission system in the Greater Abuja area.

The transmission system expansions included in the ADF-financed project will strengthen the 330/132 kV system for power supply of the capital Abuja. A new 132 kV double circuit transmission line (172 km) between New Apo 330/132/33 kV Substation and the planned Lafia 330 kV Substation will establish a 3rd infeed to the Abuja 132 kV ring allowing power supply from the power plants in the Delta Area and the planned Mambila Hydro Power Plant.

These network expansions are planned to be commissioned in 2020, see section 4.2.2.

A detailed list of the transmission system expansions with their cost as estimated by TCN is shown in **Annex 4.2d1.** The planned transmission lines and substations are shown in **Annex 7.1** on a map of Nigeria.

4.2.3.2 Transmission System Expansions to be financed by JICA

For improvement of the transmission system operation and reliability of the transmission network in the Lagos region, it is planned to install new transmission lines and substations under JICA financing. A feasibility study is presently under preparation by JICA.

The planned 330 kV substations Ogijo and Arigbajo will reconfigure the transmission system from single to double circuit configuration improving rehabilitation during line maintenance and line outages. The 330 kV double circuit line to Arigbajo - New Agbara and New Agbara substation will allow power export to Benin bay-passing the heavily loaded Ikeja Substation. The new 132/33 kV substations Redeem, MFM and Badagry will provide additional in-feed capacity into the distribution system.

These network expansions are planned to be commissioned in 2020, see section 4.2.2.

Annex 4.6b shows the present network configuration in the Lagos area and the future configuration after commissioning of new lines and substations.

A detailed list of the transmission system expansions with their cost as estimated by TCN is shown in **Annex 4.2d2.**

Furthermore, the planned transmission lines and substations are shown in **Annex 7.1** on a map of Nigeria.

4.2.3.3 Transmission System Expansions to be financed by AFDB

The transmission system in the north-east of Nigeria is not much developed. Many cities in the north-east are not yet connected to the transmission system and rely on local generation only.

To improve the electricity supply from the national grid, TCN is planning to install various 132 kV transmission lines and new 132/33 kV substations as follows:

<u>New Transmission Lines</u>

- 321km, 132 kV Double Circuit Line Between Maiduguri - Manguno - Marte - Dikwa -Bama
- 165km, 132 kV Double Circuit Line from Maiduguri - Bama - Goza - Gulak
- 78km, 132 kV Double Circuit Line from Mayo Belwa - Jada - Ganye
- 134km, 132 kV Double Circuit Line from Biu - BuniYadi - Damaturu
- 130km, 132 kV Double Circuit Line from Damboa - Chibok - Uba - Mubi

<u>132/33 kV Substations</u>

- New 132/33 Manguno Substation, 2 x 60 MVA,
- Extension of Old Maiduguri 132 kV switchgear by 2 bays,
- New 132/33 Marte Substation, 2 x 60 MVA,
- New 132/33 Dikwa Substation, 1 x 60 MVA,
- New 132/33 Bama Substation, 2 x 60 MVA,

- Extension of New Maiduguri 132 kV switchgear by 2 bays,
- New 132/33 Gwoza Substation, 1 x 60 MVA,
- Extension of Gulak 132 kV switchgear by 2 bays,
- New 132/33 Jada Substation, 2 x 60 MVA,
- New 132/33 Ganye Substation, 2 x 60 MVA,
- New 132/33 Uba Substation, 2 x 60 MVA,
- New 132/33 Chibok Substation, 1 x 60 MVA,
- New 132/33 Biu Substation, 1 x 60 MVA,
- New 132/33 Bunyadi Substation, 1 x 60 MVA,
- Extension of Damaturu 132 kV switchgear by 4 bays,
- New 132/33 Kwaya Kusar Substation, 1 x 60 MVA,
- Extension of Gulak 132 kV switchgear by 2 bays,

The planned transmission lines and substations are shown in **Annex 7.1** on a map of Nigeria.

A detailed list of the transmission system expansions with their cost as estimated by TCN is shown in **Annex 4.2d3.**

4.2.3.4 Transmission System Rehabilitations and Reinforcements/Upgrading to be financed by World Bank

Under the *Nigeria - Electricity Transmission Project (NETAP)* it is proposed to carry out a large number of rehabilitations / reinforcements of existing substations and transmission lines, financed by World Bank.

The reinforcement and upgrading of substations includes the installation of additional 330/132 kV and 132/33 kV transformers and replacement of existing transformers by units with a higher rated capacity and installation of associated switchgear equipment and control and protection equipment. The rehabilitation measures include replacement of high voltage switchgear equipment and associated equipment as well as control and protection equipment.

The rehabilitation/reinforcement of transmission lines includes mostly reconductoring of lines.

A detailed list of System Rehabilitations and Reinforcements/Upgrading with their cost as estimated by TCN is shown in **Annex 4.2d4.** The annex shows that the location of the substations and transmission lines are in all TCN planning regions of Nigeria.

4.2.3.5 Transmission System Expansions to be financed by IDB

With financing provided by Islamic Development Bank (IDB), it is planned to build in the North West planning region of Nigeria a 330 kV double circuit line between Kaduna and Kano, two 330/132 kV substations and two 132/33 kV substations.

In the South South planning region the reconstruction of two 330 kV transmission lines is planned. The 330 kV lines Delta-Benin and Alaoji-Ihiala-Onitsha shall be replaced by double circuit lines with quad conductors.

Furthermore, environmental impact assessment for various transmission lines is included in the scope.

A detailed list of transmission system expansion measures included in the scope of financing is shown in **Annex 4.2.d5** with their cost as estimated by TCN**.**

4.2.3.6 Transmission System Expansions to be financed by AFD

Under a 2nd financing agreement with AFD it is planned to build new transmission lines and substations and to rehabilitate transmission lines and substations in various in the northern planning areas of TCN, in order to improve power transmission in the northern transmission corridor. The scope includes also various rehabilitation measures for substations and transmission lines.

A detailed list of Transmission system expansion measures included in the scope of financing is shown in **Annex 4.2.d6** with their cost as estimated by TCN.

5. Demand Forecast

5.1 Description of approach and methodology

5.1.1 Starting point

The overall objective of the least cost expansion plan (LCEP) is to establish the long term generation and transmission plan that meets the forecast national electricity demand at the lowest economic cost while at the same time meeting the specified reliability standard. Within this overall objective, the determination of the national electricity load forecast plays a core role.

According to the Terms of Reference, the Consultant had to carry out the following sub-tasks:

- Review the existing load profile.
- Determine realistic load profile and demand forecast for planning purposes.
- Define three credible scenarios, to be based on different levels of national economic activity during the study period. Define additional scenarios if deemed appropriate.

Tractebel Engineering produced a Load Study Report in January 2009. The report provides data on load demand for the short (5 year) and long (20 year) terms disaggregated by major customer groups (domestic, industrial, commercial, agricultural and government), and incorporating bottom-up (location specific) and top-down domestic and export (macroeconomic) drivers of demand growth. The Consultant and TCN-Planning Department have jointly reviewed the load demand report. Certain data and an already prepared methodology from the Tractebel and JICA reports have been utilized in preparing a revised version of the load demand forecast. The revised load demand forecast considers economic growth rates, historical demand data, population and demographic forecasts and other variables (macroeconomic parameters etc.).

The 20 years load demand forecast includes three credible scenarios (high, medium and low demand growth scenarios), the low-demand scenario takes into account conservative views on potential capital investment reflected by a lower GDP growth rate. Loads have been aggregated at the system level (including losses in transmission and distribution systems) in order to establish the gross electricity demand that has to be met by existing and future power sources, and the transmission system expansion decision to be made.

The Consultant has understood that Tractebel in its load forecast has applied three different methods to perform the load forecast:

- Global approach
- Semi-global approach
- Analytical approach

The global approach **(Figure 5-1**) uses correlation of historic trends for energy and load as well as macroeconomic indicators to predict demand. Within this method, the unsuppressed demand was estimated at 5100 MW in 2007. The semi-global approach did not

show robust results due to lack of statistical data. The third method, the analytical approach uses regional indicators (on distribution unit base) of demand and population development.

The results of their observation are briefly described in the figures below:

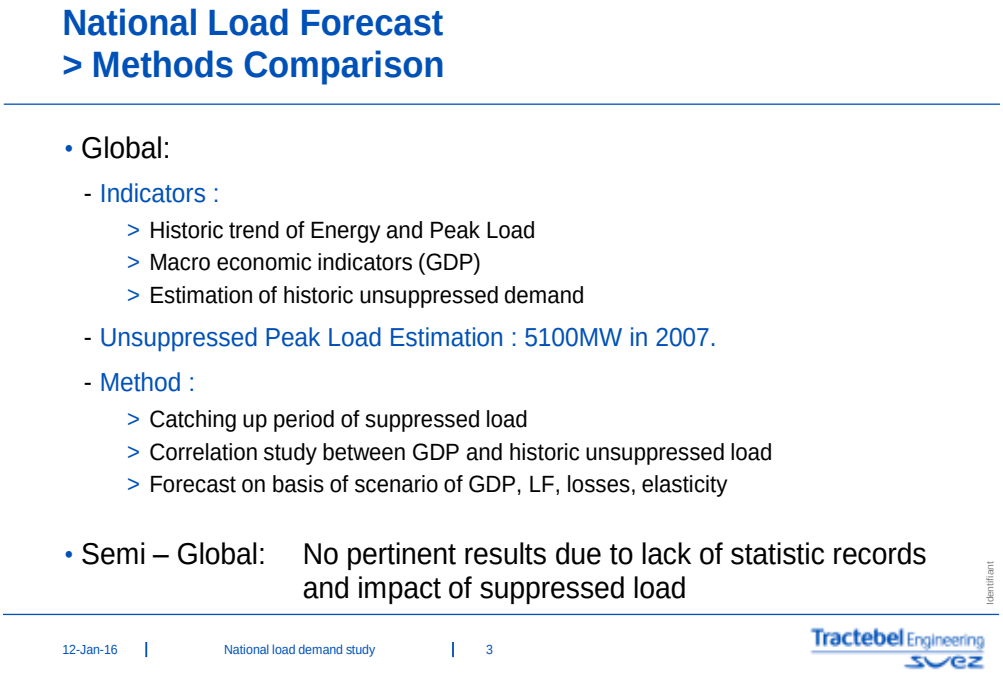


Figure 5-1 Tractebel global demand forecast method

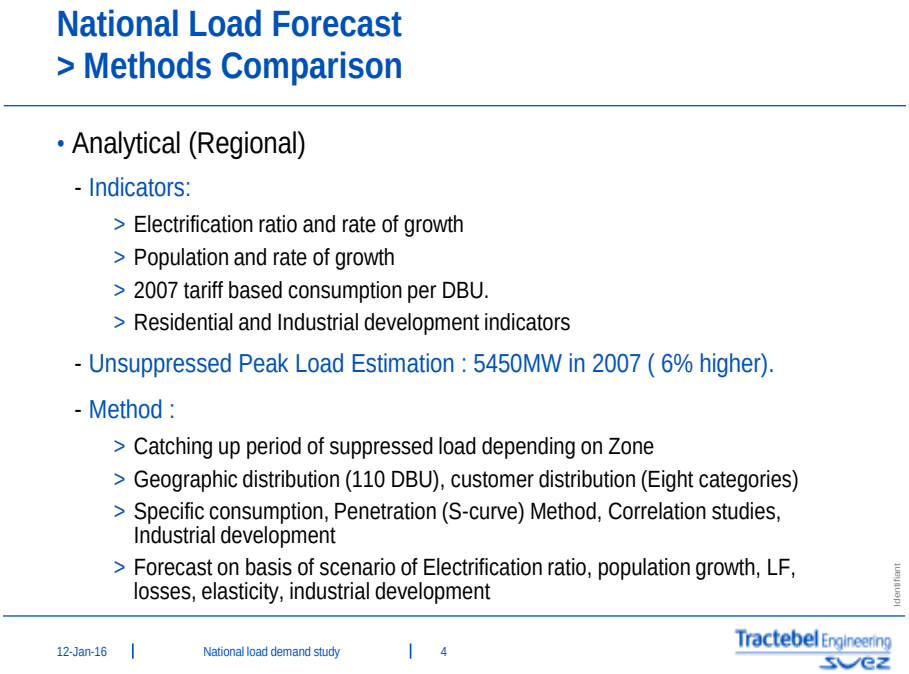


Figure 5-2: Tractebel analytical demand forecast method

National Load Forecast > Methods Comparison

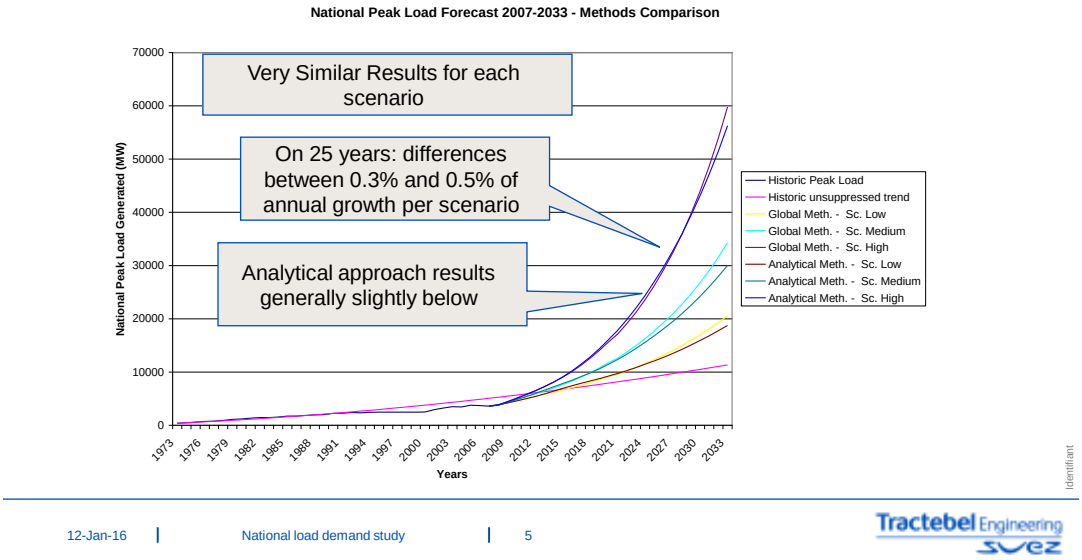


Figure 5-3 National Load Forecast

The Consultant has focused mainly on method 1, the global approach, due to constraints in the data availability. In addition, also specific consumption of the customer categories as prescribed by the semi-global approach was considered.

5.1.2 Data background

To provide a basis for the transmission expansion plan and ultimately a master plan project for the power sector, it is essential that basic data on the historical and present electricity demand as well as demand development in the future are clearly defined. So as a foundation for the demand and load forecast, the available demand data are evaluated.

The Consultant has started collecting data during the first site visit in Nigeria in December 2015.

The following meetings took place during which relevant documents have been received and further on reviewed by the consultant:

Meetings held in Abuja:

- Transmission Company of Nigeria (System Planning Department, Accounting Department)
- Energy Commission of Nigeria
- Nigerian Electricity Regulatory Commission

Documents received:

- Energy Commission of Nigeria: “Report on Nigeria Energy Calculator 2050”

- Energy Commission of Nigeria: “National Energy Master Plan”
- Energy Commission of Nigeria: “Renewable Energy Master Plan”
- TCN: “Unaudited Management Report and Financial Statements for January 1st 2014 to 31st October 2014”
- TCN: Load curves, Load flow peak, Load flow off peak, Power station mix, Power station short falls
- NERC: “Multi Year Tariff Orders “(2012, 2015, for generation, transmission and distribution)
- NERC: “Notice of approved methodology for the determination of connection charges by distribution licensees”
- NERC: “Grid Code of Nigeria”
- NERC: “Nigerian electricity supply and installation standards regulations 2015
- NERC: “Draft feed-in tariff regulations for renewable energy sourced electricity in Nigeria”
- NERC: “List of licensees in the Nigerian electricity supply industry connected to the national grid”
- NERC: “market rules for transitional and medium term stages of the Nigerian Electricity Power Sector”(2009)
- NERC: “The distribution code for the Nigeria electricity distribution system”
- NERC: “Methodology for Estimated Billing (2012)
- NERC: “Metering Code of Nigeria”
- NERC: “Regulations for independent electricity distribution networks (2012)
- JICA: The Project for Master Plan Study on National Power System Development in the Federal Republic of Nigeria (Progress Report December 2015)
- TCN: Final Freezed Suppressed Data.xlsm

In order to avoid double efforts to collect data from TCN, Fichtner has used in its revised demand forecast all data of the above mentioned JICA Progress Report, the source of which is clearly indicated to be TCN or Ministry of Power of Nigeria – after performing a plausibility check.

Furthermore, the Consultant has reviewed several documents on gas supply issues in Nigeria and on the WAPP project in which it was involved in the past being relevant for the preparation of the demand forecast as outlined in the terms of reference.

The analysis of available documents has shown that information on the historical development of electricity consumption is not fully consistent. There are (minor) deviations in the consumption data in the different studies, TCN annual reports and MYTO models. The deviations are larger in the case of network losses and generation. In order to be consistent, the Consultant has chosen to use the MYTO model data as the main source but checked for overall consistency with other data sources.

Collection of data on a regional or distribution area level was envisaged but has proven to be difficult. However, a new basis for the demand forecast could be established considering information on suppressed demand.

5.1.3 Approach

After data collection, it has been compiled, in order to receive the required information,

such as:

- determination and classification of future growth areas
- aggregated load centers and population clusters
- shortcomings in existing power supplies and network limitations
- scenarios of future load growth

The Consultant has prepared a model, which allows the systematic assessment of data and forecasting. The model integrates different types of data, such as demographic data, e.g. population growth, and economic data, e.g. GDP growth rates and sector structures.

In the model, data is compiled to produce defined outputs, whereas the future demand for electricity is the most important one. The estimation of the future electricity demand takes into account consumers which are already connected to the central or isolated grids and supplied with electricity, consumers which are not yet supplied with electricity and also the suppressed demand, meaning the demand of the present consumers which cannot be served.

Based on the data collected for the electricity sector, Fichtner has calculated key indicators relevant for future power demand development, such as electricity demand elasticity, energy intensity, price elasticity etc.

Growth in real gross domestic product (GDP), growth in various energy-intensive sectors (such as LNG), sectional preferences and hence possible sectional shifts as well as socio-economic and infrastructure development in the investigated rural areas are key factors for future development of electricity demand.

The Consultant started the development of the load forecast by thoroughly reviewing the load forecasts of Tractebel, TCN and JICA, and the underlying assumptions made on the interaction between energy and the economy. Fichtner checked these forecasts, made updates, and developed an own forecast and agreed this forecast with TCN.

From the previous forecasts it is also obvious that the target data on macroeconomic, sectoral and socio-economic developments, as planned, are thus a most important prerequisite for a revised load forecast. Energy demand and load forecast in any case must be consistent with macroeconomic, sectoral and socioeconomic projections. Therefore, the Consultant obtained target data from the government, ministries and other concerned authorities on overall economic development, sectoral development, rural development, including specific development programs. Target data on individual projects and on investment plans in various subsectors have been also researched.

Fichtner has evaluated the target data obtained and development plans made in the light of the background of the existing framework of future economic development. A detailed presentation of the approach is given in the following sections.

Analyzing the electricity demand, it has been investigated to what extent there is a suppressed demand. Forced outages and the availability of electricity supply are evaluated, on which basis the suppressed demand is quantified based on the information received by TCN in December 2016. By this amount, the present consumption had to be increased to obtain the actual electricity demand.

In order to consider the uncertainty range of the prognosis, different load forecast scenarios have been developed such as low scenario, most probable scenario and high scenario. These are the basis for sensitivity analysis.

The data processed in the model is also structured into different geographical areas, facilitating the identification of future projects. The geographic areas follow the structure of the distribution companies which is in line with available data.

5.1.3.1 Regional and sectoral structure

The demand has been separately investigated by each sector relevant in Nigeria. In line with the foregoing demand forecasts and following roughly the retail tariff structure, the Consultant has determined five consumer groups that are most adequate to perform the demand forecast:

- residential
- commercial
- industrial
- LNG
- exports

This distinction results from different demand patterns and attributes. At the same time, it allows building on the available information by not deviating too much from usually used consumer structures in Nigeria. Any disaggregation beyond these five categories is perceived as unreasonable, in order not to blur the interpretability of the results.

Furthermore, regional distinctions have been made based on distribution area and business unit affiliation.

5.1.3.2 Explanatory variables and parameters

The presented assessment generally uses a bottom-up approach to forecast demand based on a simplified econometric approach that uses the links between explanatory and target parameters, as is the case in econometric analysis. However, the actual values of the explanatory parameters are not only based on (regression) calculations, but also on estimates and assessments that are put together from experience in other countries with a similar economic environment and the Consultant's experience. Especially in case of inconsistent or unreasonable results, Fichtner based its analysis on judgment and experience rather than on regression analysis. Such a link of explanatory and target parameters is worked out for the above consumer groups.

More particularly, the steps used to derive demand for each consumer group within a bottom-up approach are:

- Step 1: Identify determinants of demand / explanatory variables
- Step 2: Identify relationship between each determinant and demand
- Step 3: Project development of determinants
- Step 4: Project development of demand, based on relationship with determinant.

These steps are discussed below.

Step 1: Identify determinants of demand
The approach uses two main determinants or explanatory variables. These are, firstly, income development, i.e. growth of economic activity or GDP, and, secondly, the electricity price development. Furthermore, the residential/domestic demand is driven by overall population growth, the number of connected customers and their specific consumption.

In addition, technological trends as well as governmental policy can impact the future demand, but are difficult to predict.

Step 2: Identify relationship between determinants and demand
The link between the determinants GDP growth and tariff development is established through the (estimated) income elasticity of demand and the (estimated) price elasticity of electricity demand (in real terms). Through this approach, the future annual growth of electricity demand is, in general obtained by multiplying the expected future annual growth rate of a sector by its income elasticity of demand for that specific year and adjusting it for a possible downward reaction that results from an increase in tariffs. The impact of the latter depends on price elasticity.

Experience shows that elasticities for the different customer groups tend to be similar across countries. Typical values are:

For residential customers:

- income elasticity 0.8 – 1.2
- price elasticity -0.2

For commercial customers:

- income elasticity 1.2
- price elasticity -0.15

These values are used as a cross-check for the elasticities established within the regression analysis. As mentioned above, priority is given to reasonable and consistent results.

Residential sector
Since so far only a limited share of population is connected to the electricity system in Nigeria, the development of customer numbers or the electrification ratio will play a significant role for the future household demand. Thus, the general approach is complemented in this sec-tor by adding the additional demand that will result from the expansion of the power sys-tem – while considering their estimated specific consumption.

The household specific consumption is a function of income and tariff and expressed by the following formula:

$$SC_{t+1} = SC_t * \left(\frac{GDP_{t+1}}{GDP_t}\right)^{EL_{GDP}} * \left(\frac{Tariff_{t+1}}{Tariff_t}\right)^{EL_{Tariff}}$$

where

SC_{t+1}	specific consumption
EL_{GDP}	Income elasticity
EL_{Tariff}	Price elasticity

The projection of total residential demand is then the product of specific consumption and number of customers – the latter being based on assumptions about the growth rate of new connections.

Commercial sector

In this sector, it is not the development of real income that drives electricity demand, but rather the development of economic output or value added specific for each sector. This increased value added will come either from the existing commercial establishments or new ones. Furthermore, the specific consumption of commercial customers is not uniform as in the residential sector. It is therefore not necessary to include an element of growth that results from new customers or to calculate specific consumption. Thus, the projection is based on the total demand.

Annual growth of expected electricity consumption in the commercial sector can be expressed by the following equation:

$$C_{t+1} = C_t * \left(1 + \left(\frac{GDP_{t+1}}{GDP_t}\right)^{EL_{GDP}}\right) * \left(1 + \left(\frac{Tariff_{t+1}}{Tariff_t}\right)^{EL_{Tariff}}\right)$$

where

C_{t+1}	Consumption
EL_{GDP}	Income elasticity
EL_{Tariff}	Price elasticity
t	Year
GDP	Gross Domestic Product

Industrial sector

The relationship between determinants and demand of the industrial sector follows a similar logic as in the commercial sector. By treating these two customer groups separately, the differences in the sector specific growth of value added can be considered. Furthermore, it is assumed, that the tariff is not relevant for industrial customers because cost of electricity has a small share in total costs.

The above formula is thus amended to include only income elasticity:

$$C_{t+1} = C_t * \left(1 + \left(\frac{GDP_{t+1}}{GDP_t}\right)^{EL_{GDP}}\right)$$

LNG sector

The LNG sector is assessed separately from the industrial sector due to its specific role in the Nigerian economy and its vulnerability to international price fluctuations. The demand of the LNG sector is projected in the same way as the industrial demand though based on sector specific determinants.

Export
Exports are not linked to the determinants used for the four consumer groups but rather based on agreements. In the case of Nigeria, exports are also not linked to the amount of surplus generation. Common sources for projecting electricity exports are memorandums of understanding with neighbouring countries or regional expansion plans. The Consultants analysis is based on projections used by TCN.

Steps 3 and 4: Development of determinants and demand
Step three and four of the approach (projection of the development of determinants and consequently of demand, based on relationship with determinants) will be explained in more detail in the following sections.

5.1.3.3 Further methodological considerations

Uncertainty
In line with the requirements of the TOR, an analysis period of 20 years, i.e. from 2016 to 2035 has been chosen, with 2014 as the base year (while 2015 relies partially on historic and partially on forecasted data). It is generally acknowledged, that every forecasting exercise, no matter what its subject, is fraught with uncertainties. These uncertainties increase with the length of the period of the forecast. Consequently, the forecast carried out by the Consultant should be construed such that it is considered adequate regarding its accuracy for the initial period, which might comprise some five to ten years at the most, with an increasing trend towards uncertainties in subsequent years.

Scenarios
As uncertainties from unpredictable developments increase over time and there are as well uncertainties stemming either from inadequate or missing current data, the Consultant has developed three demand forecast scenarios: Base, Low, and High – based on different levels of national economic activity. This is also a commonly applied approach. The Base Scenario reflects the most likely development. The High and Low Scenarios reflect developments that could realistically materialize, in favourable and non-favourable environments, for key parameters, such as the growth rate of GDP. The actual demand is expected to be within the range given by the High and Low Scenarios. This is usually described as the “Cone of Uncertainty” and likewise applies for any demand forecast.

Losses
The results obtained taking the approach and applying the formulas described above relate to net consumption of electricity at the level of the various customer groups. It is therefore necessary to add the transmission and distribution losses to the net figures of demand. Here it will also be necessary to forecast the development of network loss levels – building on loss reduction incentives posed by NERC as well as considering a realisable level.

Load factor
Based on the results of the demand forecast it will then be necessary to calculate the future development of the load for the power system by means of the load factor. Also in this regard the Consultant has estimated possible variations of the value of the load factor over time, which would have an impact on future load levels.

The demand and load forecast developed in the way just described will not assume any specific measures for Demand Side Management (DSM) or energy efficiency improvement.

5.2 Assumptions and Key Parameters

In this section, assumptions used by within the demand forecast and the values attributed to the various key parameters are discussed.

5.2.1 Gross domestic product

Nigeria is Sub-Saharan Africa's largest economy and with 182 million inhabitants (2015) also the most populous country. It was ranked as the 20th largest economy in the world (as of 2015) and is an emerging market according to the World Bank. The economy is heavily dependent on the export of oil products and exhibits an average GDP growth rate of 6.3% annually over the last ten years. The main driver is the services sector, which contributes about half of the GDP, followed by the oil and gas industry with almost a quarter. The agricultural sector accounts for about 20% of the GDP.

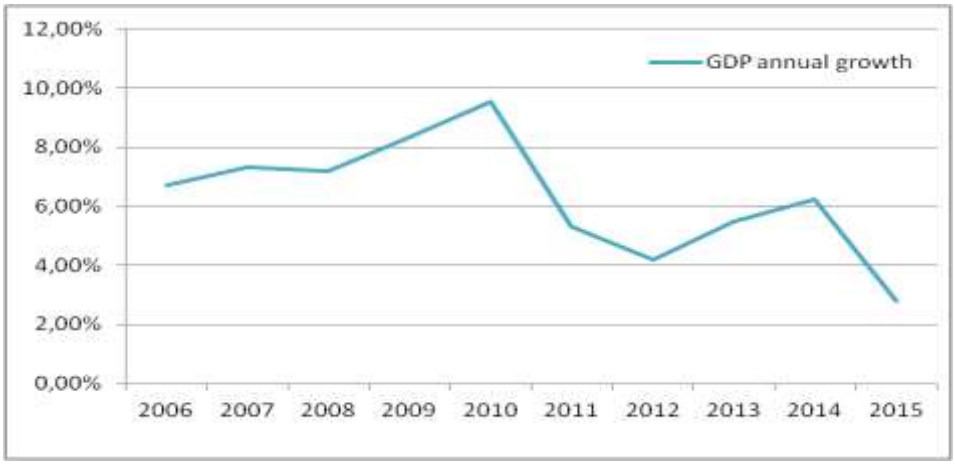


Figure 5-4: Historic GDP development

As shown in the **Figure 5-4**, Nigeria's GDP growth has been constantly above 4% except for 2015, where growth was hampered by low oil prices. But the development of GDP growth rate has been also volatile over the last few years. This makes it difficult to accurately forecast future GDP development – also because it requires a prediction of oil prices which affect Nigeria's economic growth. For example, a too optimistic forecast by several institutions can be observed for 2016 that is not fulfilled by the actual Q1 numbers. This shows the challenge of a forecast.

Given the overall outlook for Nigeria and its status as an emerging economy, annual growth rates between 5% and 7% are predicted by international institutions such as AfDB, IMF, in studies such as "The World in 2050" as well as by the National Bureau of Statistics in Nigeria. In its "Vision 20: 2020" of the Nigerian Government 13% p.a. are mentioned, but this number might be too optimistic given the current macroeconomic challenges, particularly exchange-rate volatility and falling global oil prices that impact public-sector spending as the IMF states. For the demand forecast, Fichtner has used the projec-

tions of the IMF World Economic Database (April 2016) until 2021 and made own assumptions afterwards. These are based on the assumption of a slow recovery but an annual growth of 5-7% until 2035.

In order to deduce more specific statements and forecasts, sectoral GDP data was used in the demand analysis: While the household income was reflected through the total GDP, we have used the GDP of commerce and services for the commercial demand development. The industrial sector GDP comprises of the growth of industry and construction and the LNG sector has been assigned with the crude petroleum and natural gas GDP.

The change in real sectoral GDP was projected based on own assumptions which were derived from the Price Water Cooper (PWC) report "World in 2050", the Regional Economic Outlook and short term projections. The figure below shows the historic as well as forecasted GDP growth rate for the defined sectors. While 2015 was a difficult year for the LNG sector and the industry, the economic development trend is predicted to be positive for all sectors in the future.

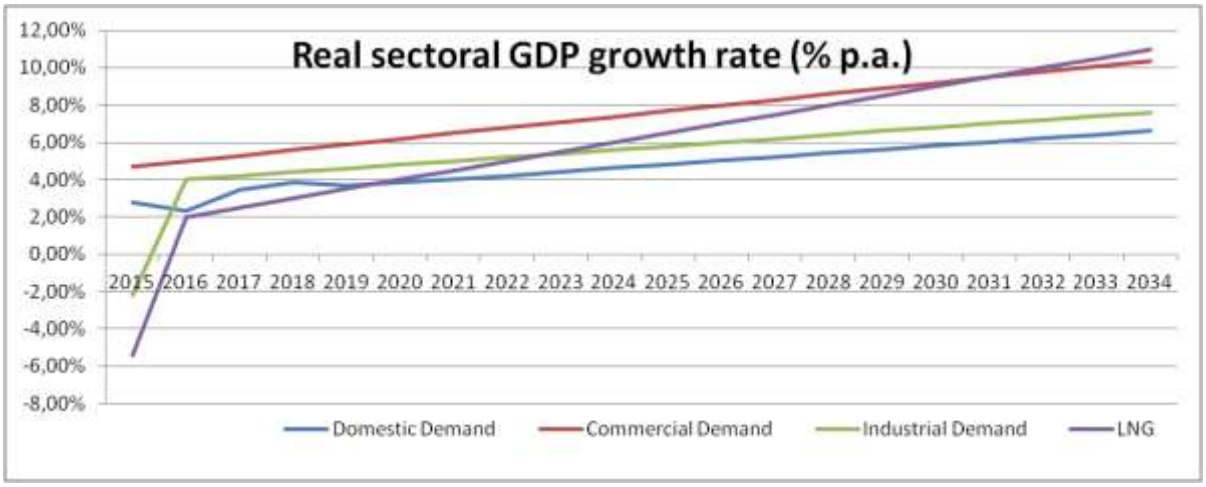


Figure 5-5: Sectoral GDP growth rate (real, % p.a.)

5.2.2 Tariff development

As stated before, price elasticity is only an issue for residential and commercial consumers while the industrial and LNG consumption are not significantly affected by changes in their electricity tariffs. Thus, only the tariff development for residential and commercial consumers will be presented in this section.

The tariff levels used for the demand forecast are derived from the MYTO Models and the tariff publications of NERC. As the current tariff structure entails several sub-groups of residential and commercial customers, an average tariff for each sector had to be calculated. Supplied quantities and average unit revenues in N/kWh are given for each sub-group for the period 2012 until 2016, allowing to derive weighted average tariffs for the aggregated consumer groups used in the demand forecast. In order to calculated elasticities, assumptions were made for tariffs in the years 2010 and 2011, presuming no major changes in real term.

Over the period 2012 to 2016, the average tariffs per unit (N/kWh) for both groups have been constantly rising, though given the inflation of over 8% (12.2% in 2012 even), the

real tariffs have declined by 3% on average for residential customers and 4% for commercial. **Table 5-1**, **Table 5-2** and **Table 5-3** show the tariff development (average tariff, residential and commercial tariff) over the period 2010 to 2019 according to the MYTO 2015 model.

Table 5-1 Average electricity tariff (2010-2019)

Average tariff	<--- Actual						Projection --->			
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Average tariff	15.5	17.7	19.9	19.4	21.2	32.5	31.0	30.6	30.7	32.0
Inflation	0.0%	10.8%	12.2%	8.5%	8.1%	8.8%	8.1%	7.5%	7.5%	7.5%
Real average tariff	17.4	17.7	17.7	16.0	16.1	22.7	20.0	18.4	17.1	16.6
Increase in real tariff	**0%**	**2%**	**0%**	**-10%**	**1%**	**41%**	**-12%**	**-8%**	**-7%**	**-3%**

Table 5-2: Average residential electricity tariff (2010-2019)

Residential tariff	<--- Actual						Projection --->			
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Average residential tariff	9.5	11.1	12.5	13.2	13.9	14.6	15.3	15.1	15.2	15.8
Inflation	0.0%	10.8%	12.2%	8.5%	8.1%	8.8%	8.1%	7.5%	7.5%	7.5%
Real residential tariff	10.7	11.1	11.1	10.8	10.5	10.2	9.9	9.1	8.5	8.2
Increase in real residential tariff	**0%**	**4%**	**0%**	**-3%**	**-3%**	**-3%**	**-3%**	**-8%**	**-7%**	**-3%**

Table 5-3: Average commercial electricity tariff (2010-2019)

Commercial tariff	<--- Actual						Projection --->			
Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Average commercial tariff	16.5	18.6	20.8	21.3	22.2	23.2	24.3	23.9	24.0	25.0
Inflation	0.0%	10.8%	12.2%	8.5%	8.1%	8.8%	8.1%	7.5%	7.5%	7.5%
Real commercial tariff	18.5	18.6	18.6	17.5	16.9	16.2	15.7	14.4	13.4	13.0
Increase in real residential tariff	**0%**	**0%**	**0%**	**-6%**	**-4%**	**-4%**	**-3%**	**-8%**	**-7%**	**-3%**

It is to be noted that the overall tariff level in Nigeria was not cost recovering until 2015. According to the MYTO model, this changed in 2015 where the average tariff overall customer groups has been raised substantially. It seems that the tariff increase was imposed on other customer groups, not residential and commercial as their real tariffs remained to decline. Given the fact that major investments in the power system are needed in the future to expand the network but also enhance generation, we tend to assume that a higher tariff will be needed to reflect the associated costs. At a point, this higher tariff needs to be also reflected in residential and commercial tariffs. On the other hand, the calculations of NERC until 2019 do not provide any indication of rising tariffs in the short-term.

We have thus assumed declining tariffs for residential and commercial customers as shown in the MYTO model until 2019 and a moderate increase thereafter. As electricity tariff increases are a politically sensitive issue, it will require considerable time to raise them smoothly which has been reflected by an average tariff increase of 1% annually from 2020 on – under the assumption that cost-reflective tariff levels have been achieved in 2015 already.

5.2.3 Elasticities of demand

5.2.3.1 Income elasticity

Usually, the income elasticity of demand is derived from past figures and their development. The Consultant has thus analyzed the development of the specific sales and sectoral GDP for all four consumer groups over a period of 2006-2010 according to data availability. The income elasticity has been calculated according to the following formula for each of the customer groups:

$$EL_{GDP} = \frac{growth\ rate\ sales}{growth\ rate\ GDP}$$

Residential sector
For the residential sector it is often argued that in low income countries with a comparatively low level of electricity demand, income elasticity can considerably exceed parity, i.e. a value of 1, and reach values as high as 1.3 to 1.5 and sometimes even more. It must be noted, though, that such elasticity figures relate to the entire residential sector and thus include additional demand from new connections as well.

For a more exact estimation, we have performed a regression analysis between the GDP (according to the National Bureau of Statistics in Nigeria) and the electricity sales to the residential sector (in line with JICA Progress Report) for the period 2006-2014. It can be observed, that there is a strong volatility of annual income elasticity (from -3.6 to +2.53). Thus, the average elasticity depends on the reference period chosen: If the last five (seven) years are considered, than an average income elasticity of 1.7 (1.26) is observed for residential customers[1]. Again, this figure relates to the entire residential consumption and does not distinguish between new connections and existing customers.

The approach applied in this study makes a distinction between the future demand of connected customers (expressed through the specific demand per capita) and demand added due to new customers (expressed as new connections), as described above. Thus income elasticity used in the model should apply only to customers that are already connected to the grid. Here increasing income often means that households can afford new electricity consuming appliances, but high income groups might reach some level of demand saturation. This means that income elasticity of demand might lie slightly above parity, but ultimately not much. Considering the regression analysis as well as typical values for residential customers, a value of 1.1 for the residential sector seems reasonable.

Commercial sector
In the commercial and industrial sector, the income elasticity of demand depends on the type of future industrial and commercial establishments. If heavy, energy-intensive industry is implemented, income elasticity can considerably exceed unity. If growth in services, commercial establishments, and light industry is the driving force in future, income elasticity will be below unity. Thus, in theory, the income elasticity of the commercial sector

[1] While data was available up to 2006, the first two years are excluded from regression analysis due to a significant drop in customer sales in 2006 which seems to be exceptional.

should be lower than for the industrial sector.

Similar to the residential sector, a regression analysis between the sectoral GDP and the commercial electricity sales has been performed to derive the income elasticity for the commercial sector. The commercial sector GDP comprises of the GDPs of commerce and services according to the National Bureau of Statistics in Nigeria. We have used the 2008 - 2014 average for our income elasticity assumptions resulting in a value of 0.88 which is considered to be realistic given the commercial structure in Nigeria. As no specific consumption is calculated for the commercial sector, this figure includes the projected total demand of new and existing customers. Thus, no downward adjustment is necessary for the income elasticity.

Industrial sector
The income elasticity for the industrial sector has been calculated based on the sector GDP as well as sales to this customer group as indicated in the JICA Progress Report. For the GDP input, the industry and construction GDPs were subsumed and compared to the sales to industrial customers. Similar to the commercial sector, the industrial demand is projected based on total demand not on specific consumption. Our calculations indicate an income elasticity of 1.1 to 2.5 depending on the chosen reference period (2010-2014 and 2008-2014). Considering usual figures in comparable countries, an amount of 1.3 has been used by the Consultant.

LNG sector
For the LNG sector, the GDP for crude petroleum and natural gas was used for regression analysis as well as sales to LNG customers. The 2008-2014 average indicates an income elasticity of 1.6.

5.2.3.2 Price elasticity

The price elasticity indicates the sensitivity of demand to changes in the price of electricity, i.e. the tariffs. It can be expressed with the formula:

$$EL_{Tariff} = \frac{growth\ rate\ sales}{growth\ rate\ of\ tariff}$$

Therefore, historic sales and real tariff figures have been analyzed for the 5-year period 2010 to 2014 for each customer group. This period has been chosen due to data availability although in general longer observation periods are advisable to eliminate short-term fluctuations and shocks. This was also the case for the analysis at hand as the regression analysis did not show robust results.

Experience from other countries with a similar economic background and framework indicates that the price elasticity for electricity is usually very low due to limited alternatives or scope for electricity savings. One can generally assume that the price elasticity of demand is somewhere in the order of magnitude of -0.1 to -0.3. This range has been applied for foregoing analysis and demand forecast. However, a distinction has been made for the customer sectors to account for their specifics.

Residential sector
In the residential sector, we would expect an attitude towards price increase that lies within

the range mentioned above. We therefore reckon with a price elasticity of demand of -0.2. This level takes into account the ability of the residential sector to react to tariff increases as well as the anticipation of not substantial tariff increases in the future for this customer group that may cause significant impact on consumption. It is also a commonly observed number for the residential price elasticity.

Commercial sector
The commercial consumers usually have an interest, driven by economic and profitability considerations, to react to increasing electricity tariffs. On the other hand, similarly to the residential sector, alternatives may be limited. We therefore assume that the commercial sector is at the lower limit of the range mentioned and we use a value of -0.15 for this group of consumers.

Industrial and LNG sector
Tariff fluctuations are usually not relevant for the industrial and LNG sector as electricity costs have a small share in total costs. Furthermore, these customers mostly have some means available to implement energy efficiency measures that can cut consumption in case of tariff increases. Thus, price elasticity has not been considered for these two customer groups.

5.2.4 Residential demand

The projection of total residential demand is somewhat specific as it requires predicting the specific consumption, as well as the number of customers which both need to be reasonably assumed. Thus, it will be discussed more in detail in the assumptions section, while the demand of other customer groups will be developed according to the methodology explained in section 5.1.3.2.

5.2.4.1 Number of residential customers

For the projection of on-grid residential demand in the future, the development of the customer numbers is an important input. Forecast of customer numbers can be derived from the anticipated connection rate and the expected population development. Usually, official connection rates are set by the Government, e.g. within energy sector master plans. These political targets are often set deliberately high and require a reality check. More reliable and realistic data can be obtained from the utilities – for this analysis the customer projections from the MYTO 2014 model have been used. The model shows customer numbers as well as new connections from 2011 to 2019. It can be observed that connections have been growing 9.2% to 10.0% annually in the past. Thus, a growth rate of around 9.2% has been envisaged for the next years based on the MYTO model assumptions. From 2020 on, we have assumed a slightly lower connection rate growth under the precondition that easily accessible areas will be connected first and connecting more remote areas requires more time and investment.

5.2.4.2 Electrification of households

According to the IMF World Energy Outlook 2015 the electrification rate in 2013 was 45%, while the World Bank Database indicates that 55.6% of the population had access to

electricity in 2015. For the calculation of the electrification rate of households (not population), the Consultant has assumed an average household size of 6 persons per household (based on the General Household Survey Panel of the NBS in Nigeria). With a population of 182 million and 7.3 million connected customers (MYTO 2015), an electrification rate of households of 24% was calculated for the year 2015. Assuming the above indicated annual connection growth rate, 87% of households will be supplied with electricity by the end of the projection period (2035).

Figure 5-6 below shows the growth rates of electricity connections and of total population (according to UN numbers) as well as the electrification rate of households. The connection growth rate is constantly above the population rate thus indicating an improvement of the electrification rate which is also envisaged by the Government.

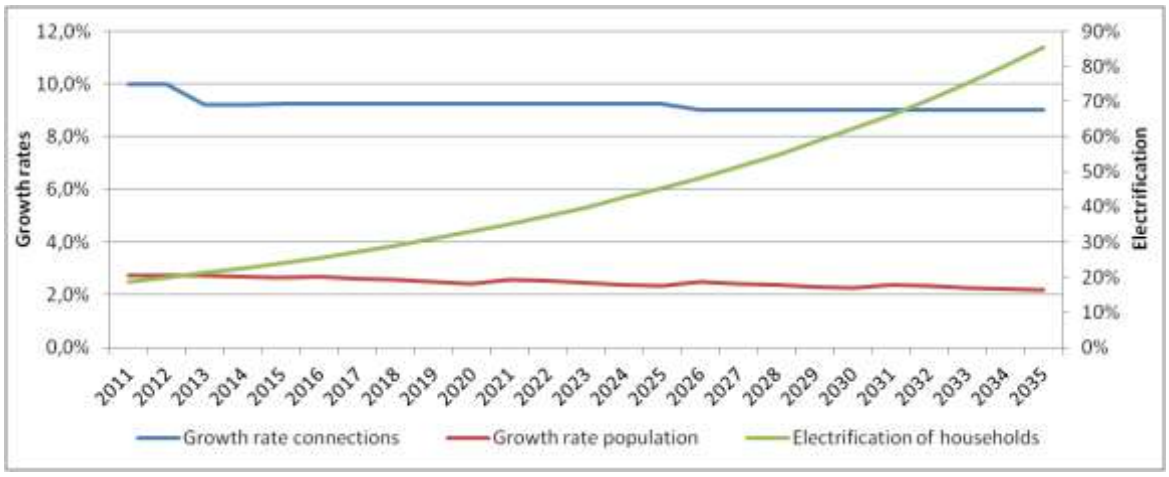


Figure 5-6: Growth of total population, new electricity connections and electrification of households

5.2.4.3 Specific consumption

Besides the number of customers, the specific consumption (kWh/connection per year) of residential customers also impacts the development of the future demand for this customer group. As explained in section 5.1.3.2, the determinants of the specific consumption are the household income (expressed by the GDP) and electricity tariffs.

In addition, the number of customers can also be factored into the equation since the specific consumption per customer tends to decline with increasing electrification rate. This considers the fact that electricity consumption rates for new connections may differ in relation to the rates for consumers who have been connected for a fairly long time, as newly connected consumers do not yet possess as many electronic appliances. Thus, we have included an additional elasticity with regards to new connection in the amount of -0.4.

5.2.4.4 Un-served energy

The existing demand consists not only of the demand connected and supplied via the grid, but also of the demand that is not served by the grid – either because it is not connected or because the demand could not be supplied although the customer is connected. This demand is discussed in the following subsections.

It should be noted, that the Consultant was supposed to model unserved energy with data on the actual amount of suppressed demand and load shedding. These data have been provided by TCN after completion of data collection on suppressed demand.

5.2.4.5 Suppressed demand

Defining the term "suppressed demand" is of importance for a correct understanding of the assumptions made for the demand forecast. Suppressed demand refers to an existing demand that is not served due to two reasons:

- Outages (connected demand which cannot be supplied due to system failure)
- Disconnection (demand that is not connected to the grid and not supplied off-grid)

Sometimes suppressed demand is broadly defined and includes also shed load.

Estimating the level of suppressed demand without reliable data is a difficult undertaking and somewhat hypothetical exercise. There are several methods to estimate suppressed demand, which may lead to different results by over- or under-estimating the actual suppressed demand.

Outages
For the purpose of this model, we have defined outages as unplanned part-time non-supply of customers that are already connected to the electricity system due to technical failure, overload of the system or external reasons, such as cable theft. The prevailing situation in Nigeria is characterized by overloaded lines and transformers, poor quality of supply and insufficient reliability of supply – all aspects contributing to frequent outages.

For the projection of future outages, we have assumed that outages will slowly decrease to the value of 3% in 2035 (i.e. an annual decrease of 2.5%). This will balance the opposed effect of additional connections on the network: On the one hand new connections will make the network more meshed, thus more stable, but connecting more remote areas will lead to an increased proneness to outages.

Disconnected demand
Suppressed demand, in a country with a low rate of households connected to the utility's electricity system, means in the main unserved energy for those that are not connected. It could be also defined as the potential load that would exist in case the customer would be connected (e.g. in non-electrified areas). This issue is reflected in the demand forecast by increasing connections of customers and is therefore not dealt with under "suppressed demand".

The load that could be connected and supplied but where the customer has instead decided to use its own separate generation is included in off-grid demand.

The Consultant has finally received validated figures from TCN on suppressed demand of the single DisCos which are shown in **Table 5-4** below.

Table 5-4: Validated summary of suppressed load demand data by DisCos in 2016

VALIDATED SUMMARY OF SUPPRESS LOAD DEMAND DATA BY DISCO'S IN 2016					
NAME OF DISCO	DISCO LOAD DEMAND FROM 2016 FIELD MEASURENT CAMPAIGN (SUM OF 11kV FEEDER AND 33kV FEEDER POINT LOADS) (MW)	HISTORIC 33kV PEAK LOAD COLLECTED IN 2016 FROM DISCO (MW)	DISCO ESTIMATE ON-GRID SUPPRESSED LOAD (MW)	DISCO ESTIMATED OFF GRID SUPPRESSED (POTENTIAL) LOAD (MW)	TCN COMMENT
AEDC	762.2	577.0	270.3	381.3	Validated without modification by AEDC
BEDC	1,223.3	776.7	163.1	220.6	Reviewed bY BEDC
EKEDC	1,350.4	856.6	493.8	350.9	Reviewed by EKEDC
EEDC	1,026.5	802.5	379.6	287.4	Validated by EEDC
IBEDC	1,285.9	1,119.2	183.7	279.7	Validated by IBEDC
IKEDC	1,215.6	977.2	302.8	364.5	Validated by IKEDC
JEDC	399.2	416.3	43.7	143.0	Validated by JEDC
KAEDCO	602.1	632.1	93.3	341.5	Validated by KAEDCO
KEDCO	708.1	513.8	186.8	224.4	Validated by KEDCO
PHEDC	948.5	884.9	130.1	229.5	Validated by PHEDC
YOLA	279.7	304.6	34.9	364.5	Validated without correction by YOLA
TOTAL ESTIMATED TCN DEMAND	**9,801.5**	**7,860.9**	**2,282.1**	**3,187.3**	

5.2.4.6 Load shedding

The term load shedding as used within this analysis refers to the controlled option to reduce load in order to protect the electricity power system from a blackout. It is thus distinguished from suppressed demand as it concerns connected customers in an amount that is controlled by the utilities.

Load shedding could be estimated based on information about the duration, the amount or impact of shed load (i.e. percentage) as well as the location. We have assumed load shedding to be in the amount of 10% of the energy delivered to customers. The Consultant has assumed that the amount of controlled load shedding will be stable in the future.

5.2.4.7 Off-grid demand

For the projection of off-grid demand we have reviewed the analysis of JICA from their Progress Report (Dec 2015) that refers to the National Renewable Energy Master Plan 2014 and the National Renewable Energy and Energy Efficiency Policy 2015. JICA has assumed that some share of installed solar and small hydro power will be used for off-grid supply. The current share of off-grid power demand is low compared to total computed demand, but is anticipated to grow over the next years. The projection of JICA regarding the total power demand and annual growth in off-grid power demand is presented in the figure below:

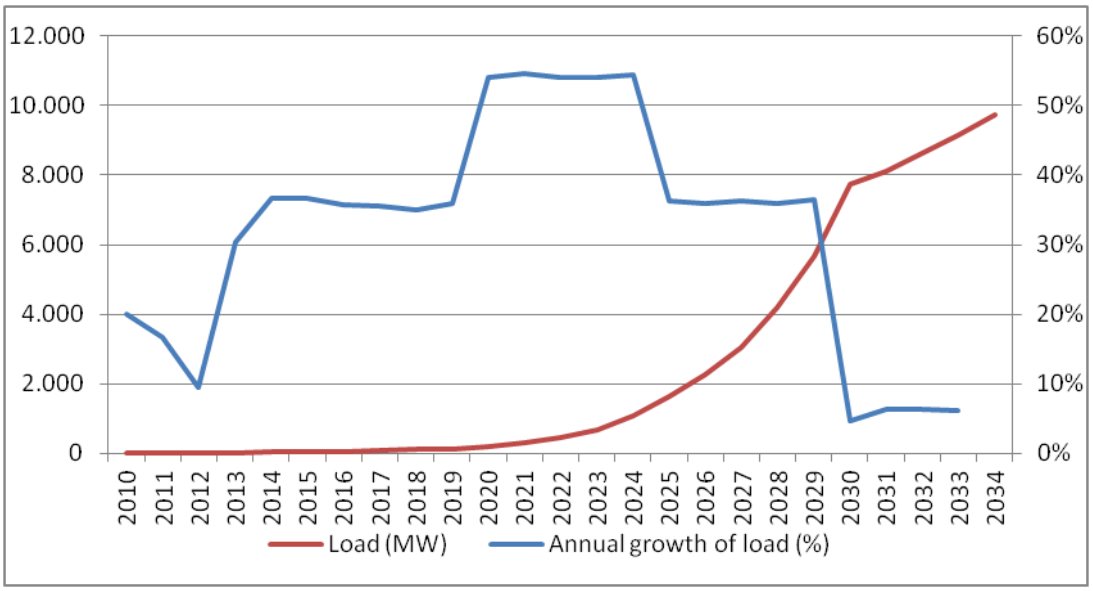


Figure 5-7: Projection of off-grid demand in JICA Progress Report (Dec 2015)

This projection seems optimistic as it would require an ambitiously fast development of large capacities of renewable energy plants. The Consultant has thus considered a more realistic growth rate for off-grid demand, assuming that new customers will be connected to off-grid systems at the same pace as customers being connected to the grid. This would mean that supply of customers will be equally undertaken by the grid and off-grid accounting for the grid development as well as remote character of some future customers. Furthermore, this approach would consider that power generated from renewables will not only be used to supply off-grid customers, but also serve as feed-in to the grid.

That said, the growth rate of off-grid connections is estimated to be 9% annually with the information from JICA used as a starting point in 2015. The Consultant has applied the same specific consumption for off-grid as on-grid customers to derive the demand. While some customers especially in rural areas tend to have a lower specific consumption, off-grid supply may also include large diesel generators or higher income customers that choose their own supply due to unreliability of the grid system. For estimating the off-grid consumption per customer group, we have assumed an allocation to groups according to their respective share in total sales over the last years.

5.2.5 Losses

Different approaches can be used for the projection of losses:

- Trend extrapolation of developments observed from historic losses
- Loss reduction programs indicated by the utility, the regulator or prescribed by covenants of donors

As a starting point for the estimation of the future development of losses of the transmission and distribution network are historic figures for the period 2010 to 2014, which are shown in **Table 5-5** below.

Table 5-5: Development of network losses

Network losses						<--- Actual
Year		**2010**	**2011**	**2012**	**2013**	**2014**
Total sent out from generation	**GWh**	**26,219**	**29,583**	**32,026**	**35,294**	**36,058**
Transmission losses	%	8.1%	8.1%	8.1%	8.1%	8.1%
Transmission losses	GWh	1,912	2,158	2,358	2,530	2,672
Distribution losses	%	11.0%	11.0%	10.0%	12.8%	9.3%
Distribution losses	GWh	2,463	2,779	2,731	3,870	2,870
Total sales	**GWh**	**21,843**	**24,646**	**26,937**	**28,894**	**30,516**
Total losses (as % of generation)	**%**	**16.7%**	**16.7%**	**15.9%**	**18.1%**	**15.4%**

The amount of losses in the transmission and distribution network has been estimated differently by the various sources of information that were available for this analysis. We have relied on the MYTO Model 2014 as an official source for the percentages from which we have calculated the amount of losses in GWh terms. It needs to be noted, that the losses in the table above are significantly higher than estimated in the JICA Demand Forecast. Nonetheless, the former seems more reasonable in a country like Nigeria.

For the projection of future losses, our assumptions are based on information from MYTO Model 2014 and the loss reduction program of NERC. These prescribe the following loss reduction targets:

- 14.0 % in 2016
- 13.0 % in 2017
- 12.5 % in 2018

These targets are ambitious, but seem realistic given the loss reduction trend observed over the last years.

After that period, an annual loss reduction of 0.5 percentage points was assumed so that in 2035 total losses would amount to 11.5%. While this figure is still notable, it needs to be considered, that initial loss reductions are easier but the pace of improving loss indicators slows down when achieving a certain level.

5.2.6 Exports

Export should be included in the demand forecast only if firm export is agreed between governments or utilities. As stated in the JICA Progress Report and MYTO Model 2012, Nigeria has been exporting an increasing amount of electricity to Niger and Benin despite the power deficit in the country. While exports amounted to 967 GWh in 2010, the figure has increased to 2,217 GWh in 2014. Our assumption for the amount of future exports is based on the MYTO Model 2015, where an export of 2,378 GWh per year was assumed for the upcoming years until 2019. In absence of any other indication (e.g. Memoranda of Understanding), we have kept this figure for the whole duration of the forecast.

5.2.7 Step loads

The term “step loads” refers to new industrial developments, e.g. mining or large construction projects that will increase the demand in a region significantly and suddenly. Such projects could be included directly in the forecast to improve the quality of forecast if information is available. The Consultant has analyzed the potential for connection of such major spot loads to the grid. As no approved projects were found with an electricity demand large enough to be included as spot loads, this figure equals zero in the model.

5.2.8 Load factor

The load factor is needed to derive the load forecast from the demand forecast. It is defined as the ratio of average load over a designated period to the peak load occurring in that period. Our load factor assumptions are based on the figures shown in the JICA Progress Report which were derived from the MYTO Model.

Historic values for the load factor according to the JICA Report show an increase from 73% in 2010 to 76% in 2014 indicating high levels of suppressed demand. From 2015 the load factor decreases by 0.5 percentage points until it reaches 70% in 2020. This value was assumed also for the rest of the forecasting period.

5.2.9 Summary of assumptions

Base Case Assumptions

Table 5-6 shows a summary of the assumptions of the base case.

Table 5-6 Summary of assumptions

Assumptions							
Parameter	**Unit**	**2014**	**2015**	**2020**	**2025**	**2030**	**2035**
GDP growth rate (% p.a.)							
Residential	%	6.2	2.8	3.9	4.8	5.8	6.8
Commercial	%	6.7	4.7	6.2	7.7	9.2	10.7
Industrial	%	7.0	-2.2	4.8	5.8	6.8	7.8
LNG	%	-1.3	-5.5	4.0	6.5	9.0	11.5
Income elasticities							
Residential		1.02					
Commercial		0.88					
Industrial		1.3					
LNG		1.6					
Change in real tariffs (% p.a.)							
Residential	**%**	-3.0	-3.0	1.0	1.0	1.0	1.0
Commercial		-4.0	-4.0	1.0	1.0	1.0	1.0
Price elasticity							
Residential		-0.2					
Commercial		-0.15					

Assumptions							
Number of residential customers							
Residential	No.	6,692,601	7,310,327	11,373,767	17,701,560	27,236,044	41,906,030
Suppressed demand							
Outages	GWh	1,526	1,569	2,266	3,414	5,451	9,246
Disconnected demand	GWh	Considered in number of customers					
Load shedding							
Load shedding	GWh	3,052	3,219	4,648	7,003	11,181	18,967
Off-grid demand							
Off-grid demand	GWh	267	291	456	725	1,217	2,142
Losses network							
Network losses	%	15.4	14.0	12.5	12.4	12.2	12.1

Basic assumptions in the scenario cases

In addition to the base case scenario, a low and a high scenario are developed to account for possible deviations in the forecast. The variable, for which we assume modifications in the high and low scenarios, is related to the overall economic development expressed by the GDP. In the high scenario, we assume a favourable economic development and consequent higher consumption by customers, which is expressed by a 40% higher growth rate of GDP. In the low scenario, we calculate with a little less pronounced deviation namely a 30% lower growth rate of GDP.

5.3 Forecast National Demand

5.3.1 Scenarios

Figure 5-8 and **Figure 5-9** show the results of the demand and load forecast for the whole of Nigeria. Both figures depict the three scenario cases, first for the demand (**Figure 5-8**) and then for the peak load (**Figure 5-9**). Underlying data are shown in **Annex 5.1**.

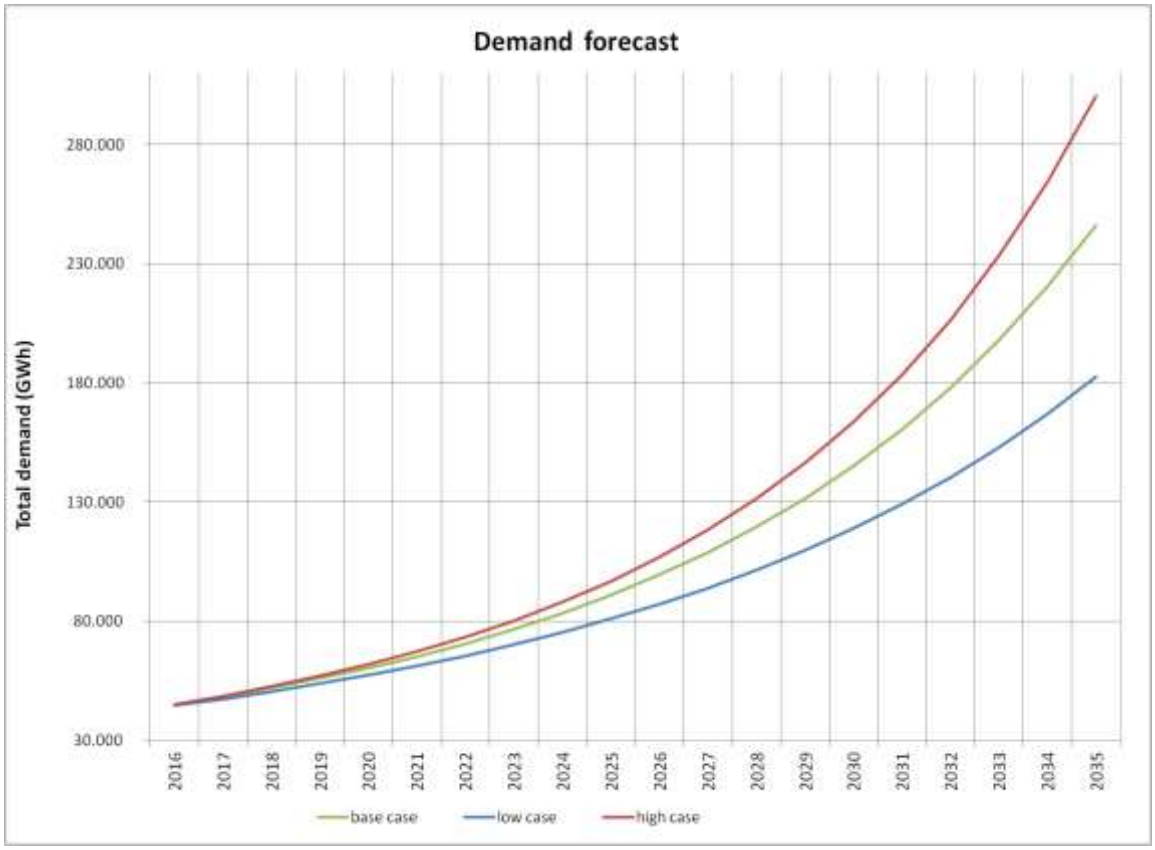


Figure 5-8: National demand forecast of Nigeria

Demand forecast

From its present level in 2015 total demand is expected to increase by a factor of 5.8 to 246,147 GWh in 2035 in the base case. This means an average annual growth rate of 9.2% in the base case during the observation period. The growth rate in the beginning is lower as population is expected to increase constantly and the average household consumption is expected to rise over time. Residential demand is the driving force in energy demand in Nigeria, showing the highest total growth.

In the case of the low scenario, total demand in 2035 is expected to reach 182,621GWh, which means an increase by a factor of 4.3. Net demand is thus only 74% of the base case demand in the last year of the forecasting horizon. It can be seen, that the GDP assumption has only a limited impact on the overall forecast with other factors such as residential specific consumption or development of suppressed demand and load shedding play also an important role. The average growth rate of this scenario is estimated to be 7.6%.

In the high scenario, total net demand would be 300,276 GWh in 2035 which would implicate an increase by factor 7.1 and an average growth rate of 10.3%. This represents 122% of the base case demand.

The base case average growth rate of the demand is realistic, because recent developments in energy demand increase cannot be simply extrapolated, especially in the light of a faster growing economy in the future. The future energy demand growth rates of all three scenarios defined by Fichtner are well-founded.

Load forecast
The load forecast shows a similar pattern to the demand development, as a uniform load factor was used to derive the load forecast from projected demand.

Peak load in Nigeria increases by a factor of 6 from its currently estimated level of 6,648 MW in 2015 to 40,141 MW in 2035 in the base case. This would translate into an average annual growth rate of 9.4%

Peak load in the low scenario develops with an average growth rate of 7.8% reaching 29,782 MW in the last year of observation.

In the high scenario, peak load would increase by a factor of 7.4 and reach 48,969 MW in 2035. This corresponds to an average growth rate of 10.5%.

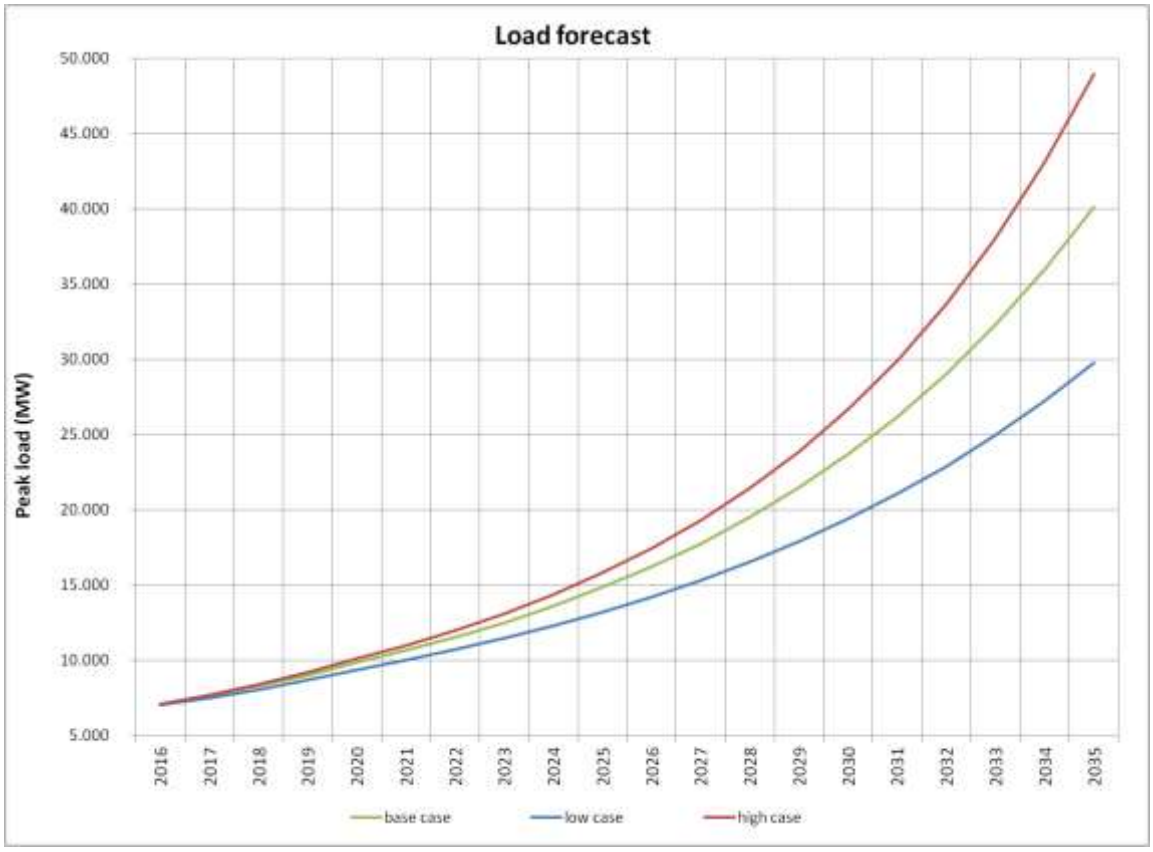


Figure 5-9: National peak load forecast for Nigeria

5.3.2 Contribution to national demand forecast

Figure 5-10 and **Figure 5-11** show the national demand forecast disaggregated by the contribution of customer categories and other sources of demand. **Figure 5-10** shows the contribution of each demand source as GWh, while **Figure 5-11** shows the percentage share in total demand. It can be observed, that the residential demand is currently the main contributor to total demand. Household consumption is estimated even to enhance its role slightly.

Other categories' share is almost constant or shows a slight decrease over the observation period. This refers for example to losses which are supposed to decrease relatively due to

loss reduction programmes. Also the share of exports is decreasing as their amount is held constant due to absence of other indications.

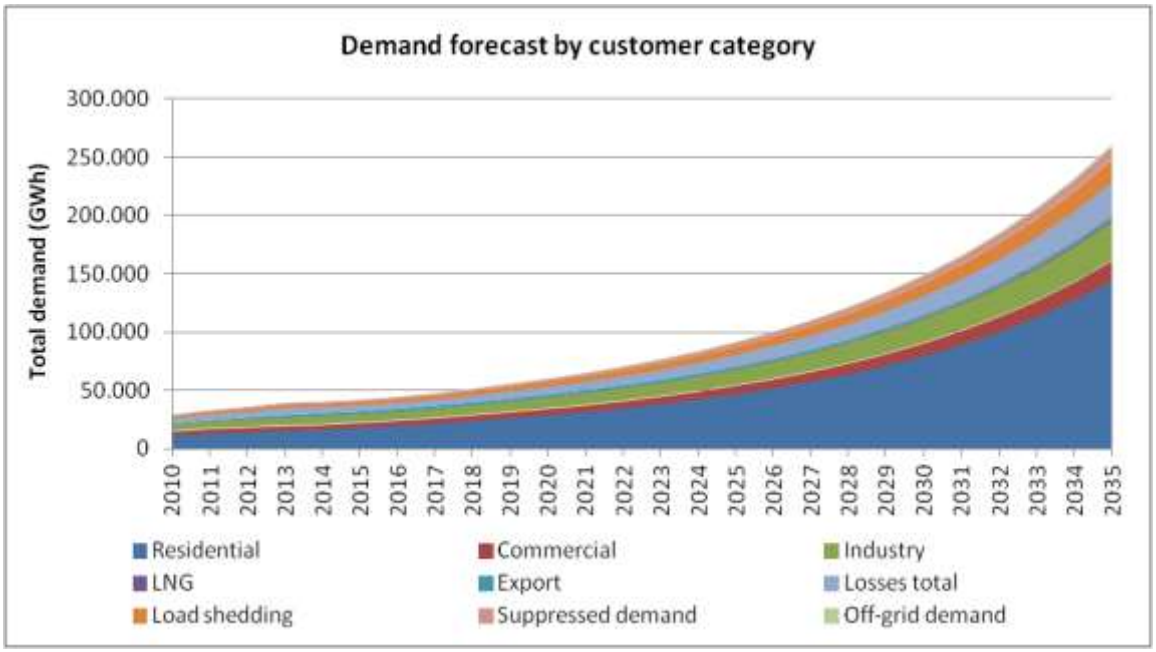


Figure 5-10: Demand forecast by customer category (total)

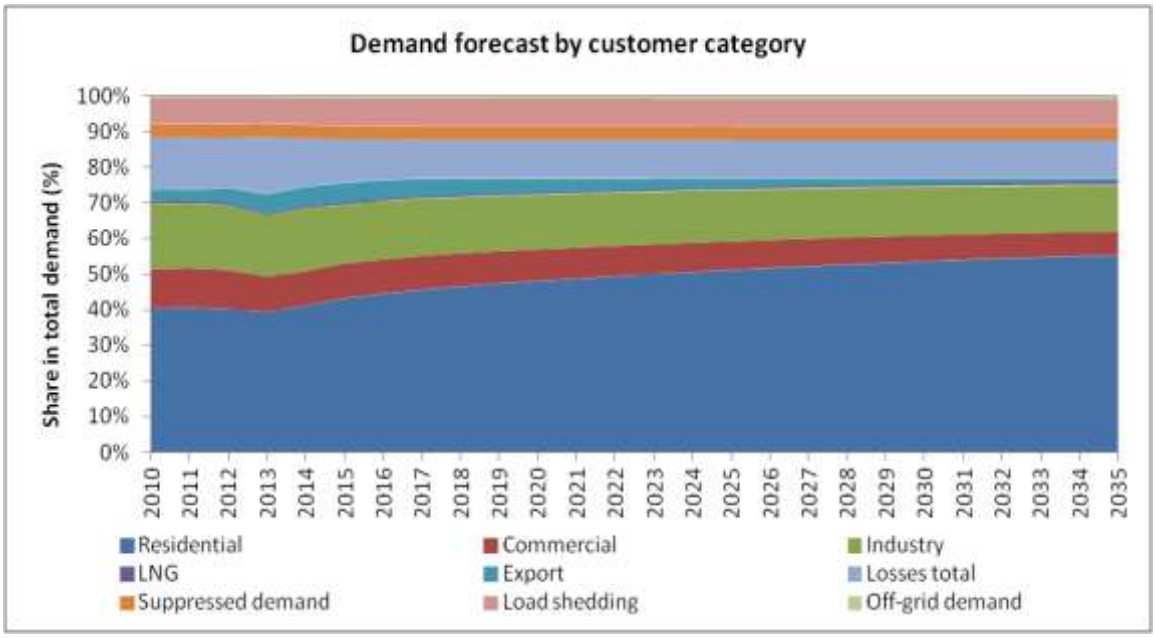


Figure 5-11: Demand forecast by customer category (%)

5.3.3 Comparison with other forecasts

The Consultant has compared the results obtained within this study with other demand forecasts. A comparison between studies may not be fully straightforward due to methodological differences and different assumptions leading to different results. Nevertheless, it is a useful plausibility check to ensure that the projections are somewhat in line with other assessments.

The Fichtner demand forecast was compared to three other studies, namely:

- JICA demand forecast, 2015 (as indicated in their Progress Report)
- TCN demand forecast, 2012
- Tractebel demand forecast, 2009 (based on the global method)

From **Figure 5-12** and **Figure 5-13** it can be seen that the deviations between the studies are less pronounced during the first few years, but increase significantly from 2020 onwards. This is in line with the fact that the quality of projections is reduced over time due to uncertainties and that underlying assumptions may cause higher deviations over time.

The Fichtner forecast expects a similar development as the Tractebel report. While the current actual demand is estimated to be somewhat higher than indicated by Tractebel, it is almost at the same level or slightly below until 2031. The last two years could not be compared as Tractebel's study period is only until 2033.

Compared the JICA projection, the estimated growth rate of Fichtner is somewhat lower. This is partially due to the different assumptions about off-grid demand development. As explained in section 5.2.4.7, the Consultant sees the off-grid demand too optimistic, thus setting it lower in his study.

TCN's own forecast dating 2012 is in total higher than the three other forecasts, but projects a flat curve with a lower growth rate than the other studies. It could be assumed that this deviation is due to a different estimation of current demand which leads to higher figures.

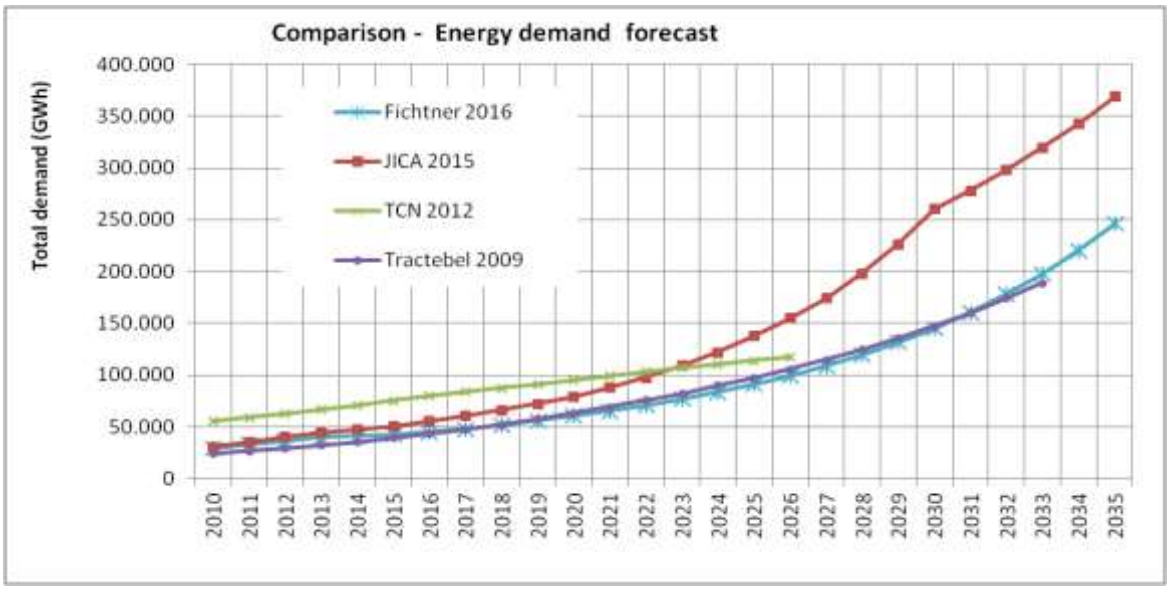


Figure 5-12: Comparison of demand forecasts

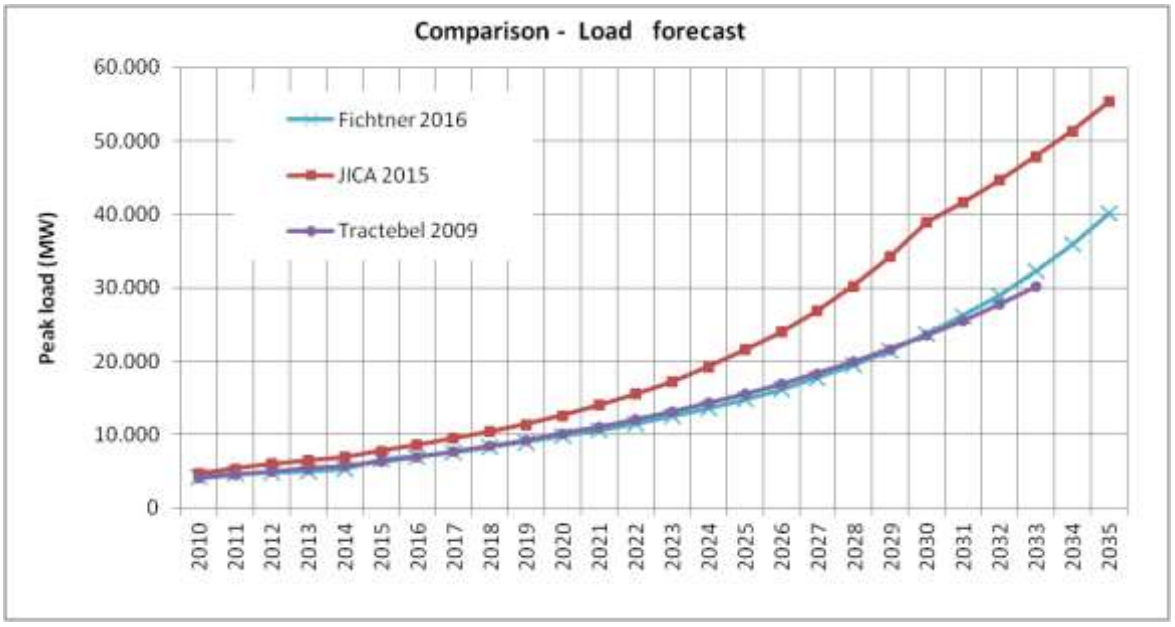


Figure 5-13: Comparison of load forecasts

5.4 Regional and DisCo Demand

The approach of the load forecast is disaggregated by regions, which are defined as distribution areas. The best way of performing a regional forecast would be using regionally specific data which give an accurate picture of the current demand in all its categories. Thus regional surveys where developed in order to compile this data and use it in the forecast.

The Consultant has chosen to allocate the national demand to distribution areas in order to predict their future demand. As an allocation factor, the current demand of each customer group at distribution level was chosen, wherefrom shares of each distribution company have been calculated. Numbers have been derived from the MYTO Model as the most reliable source available.

5.4.1 Regional allocation of customer groups

Figure 5-14 figure shows the allocation of residential, commercial and industrial demand per region. The highest share of residential demand is in the Benin (18.8%), Ikeja (13.8%) and Enugu (13.7%) region. Commercial customers are mainly in Ibadan (21.3%), Eko (17.2%) and Ikeja (16.6%), while the industry is mainly in Ikeja (20.5%), Ibadan (19.5%) and Eko (12.3%).

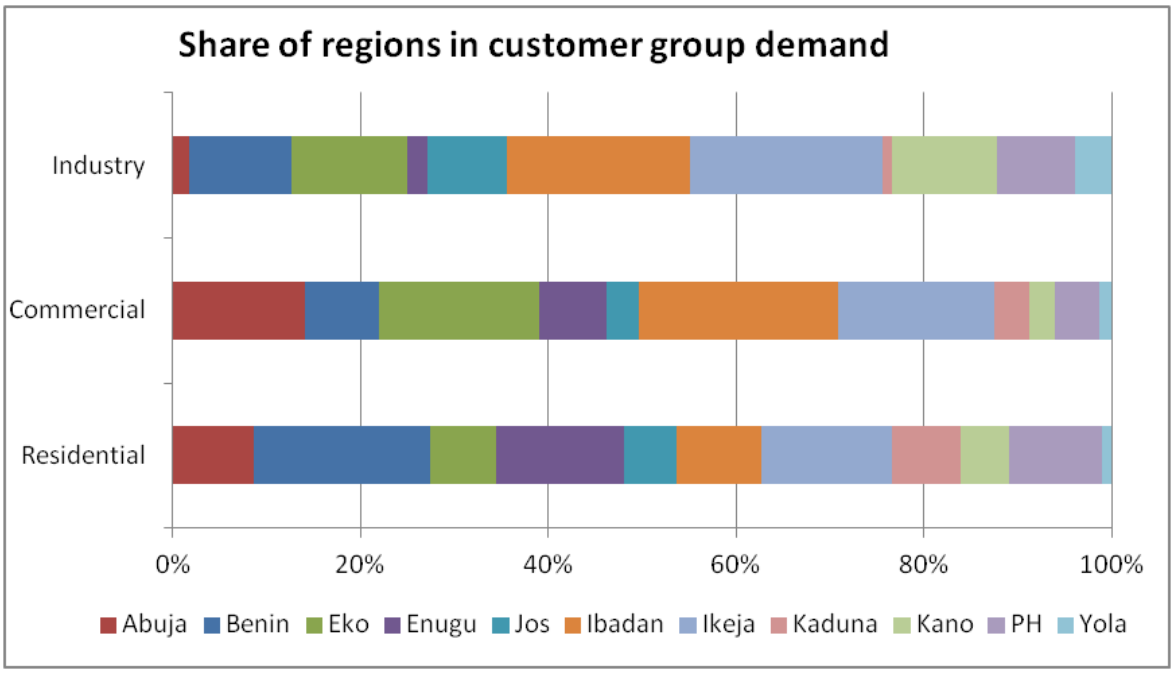


Figure 5-14: Share of regions in demand per customer group

With the residential demand being the driving force for future demand in Nigeria, regions with a high share of residential customers exhibit the highest growth rates of their demand.

Figure 5-15 gives an overview of the distribution of the three main customer groups in each distribution region. Residential customers are most dominant in Kaduna, Enugu, Benin and Port Harcourt. Yola, Kano and Jos are more industrial regions.

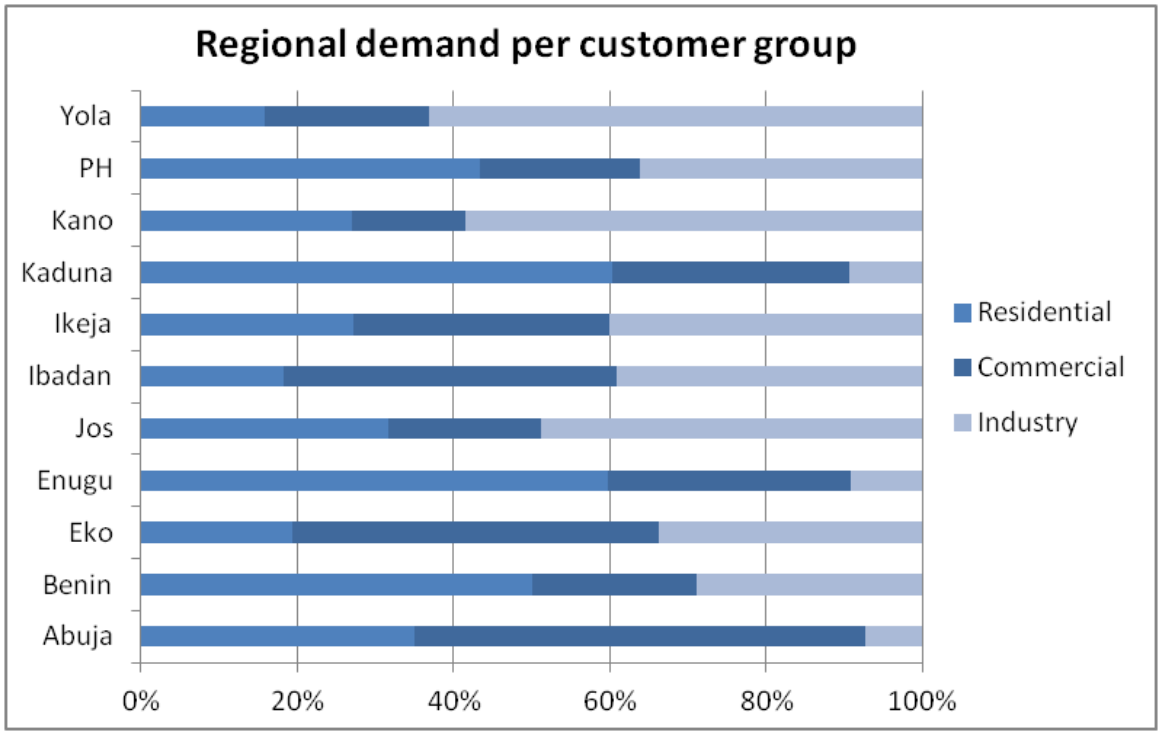


Figure 5-15: Share of customer groups in regional demand

5.4.2 Regional demand projection per DisCo

The demand projection per DisCo is shown in **Figure 5-16** and **Table 5-7**. Overall, the demand per DisCo rises according to the forecast provided by JICA with some minor adjustment made by Fichtner.

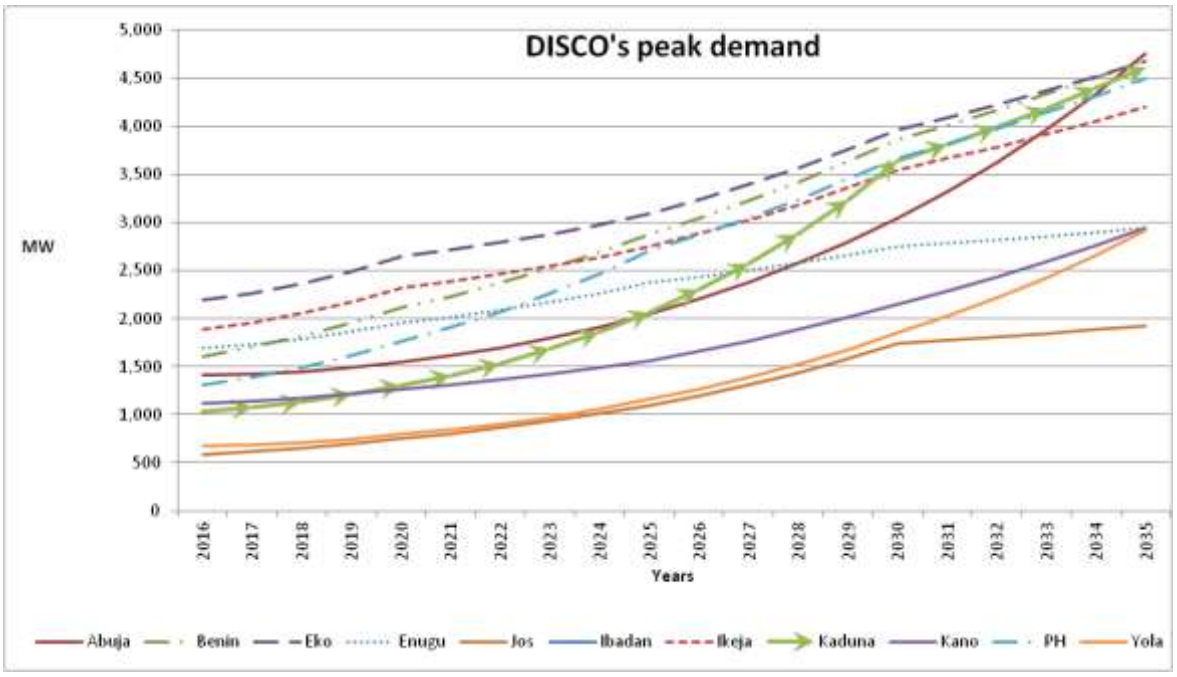


Figure 5-16: Peak demand projection per DisCo

Table 5-7: Peak demand projection per DisCo

Updated Regional Load Demand Forecast including Suppressed Demand (MW)																				
Year		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Abuja	AEDC	1,414	1,425	1,450	1,490	1,543	1,612	1,697	1,797	1,914	2,050	2,204	2,379	2,576	2,797	3,044	3,318	3,623	3,961	4,336	4,750
Benin	BEDC	1,607	1,703	1,818	1,953	2,109	2,232	2,370	2,523	2,692	2,877	3,045	3,227	3,423	3,634	3,861	4,011	4,168	4,333	4,506	4,687
Eko	EKEDC	2,195	2,267	2,366	2,493	2,649	2,713	2,789	2,878	2,978	3,091	3,235	3,394	3,568	3,757	3,962	4,090	4,225	4,368	4,519	4,677
Enugu	EEDC	1,694	1,733	1,789	1,864	1,957	2,017	2,087	2,170	2,264	2,370	2,432	2,502	2,577	2,658	2,746	2,780	2,816	2,855	2,896	2,939
Idaban	IBEDC	1,749	1,870	2,017	2,193	2,401	2,565	2,751	2,959	3,192	3,450	3,694	3,960	4,251	4,567	4,912	5,165	5,435	5,720	6,023	6,343
Ikeja	IKEDC	1,883	1,957	2,054	2,176	2,323	2,387	2,461	2,546	2,641	2,746	2,880	3,026	3,185	3,358	3,545	3,662	3,786	3,916	4,054	4,198
Jos	JEDC	586	616	653	698	753	805	865	933	1,010	1,097	1,198	1,312	1,439	1,580	1,738	1,773	1,809	1,846	1,885	1,925
Kaduna	KAEDCO	1,037	1,077	1,133	1,207	1,299	1,405	1,532	1,682	1,857	2,060	2,295	2,565	2,875	3,228	3,632	3,806	3,990	4,185	4,392	4,610
Kano	KEDCO	1,119	1,142	1,174	1,217	1,269	1,312	1,363	1,421	1,487	1,561	1,657	1,764	1,882	2,012	2,154	2,289	2,435	2,592	2,762	2,945
Port Harcourt	PHEDC	1,308	1,392	1,494	1,616	1,761	1,905	2,070	2,257	2,469	2,709	2,872	3,049	3,240	3,447	3,669	3,819	3,976	4,141	4,315	4,497
Yola	YOLA	679	689	711	747	799	845	903	974	1,060	1,161	1,265	1,384	1,519	1,674	1,850	2,022	2,213	2,426	2,662	2,924
Total		**15,271**	**15,870**	**16,660**	**17,653**	**18,863**	**19,798**	**20,887**	**22,140**	**23,564**	**25,172**	**26,778**	**28,561**	**30,535**	**32,713**	**35,112**	**36,734**	**38,476**	**40,345**	**42,349**	**44,496**

Details underlying the results in **Table 5-7** are depicted in **Annex 5.2**.

6. Generation Capacity and Future Generation Candidates

Since the kick-off meeting in December 2015, TCN and other organizations step by step provided updated information about the given situation with regard to the existing power generation facilities in Nigeria. In January 2017, Fichtner and TCN agreed on a reliable data basis comprising

- existing power generation assets and its operational availability
- power generation assets under construction
- power generation projects committed for realization
- committed solar power plant candidates based on PV technology
- power plant candidates announced by IPPs / industrial power producers
- gas fired power plants
- coal fired power plants
- existing dams with hydroelectric power potential
- wind power plants
- nuclear power plants
- power plant candidates proposed by Fichtner.

All meanwhile available data about existing power plants as well as of plants under construction and plant candidates are compiled in **Annex 6.1**: TRANSMISSION EXPANSION PLAN - GENERATION ASSETS.

The provided data are very comprehensive. Besides other information, they include

- names of generation companies
- names of power plants and number of installed generation units
- location of plants and closest substation including voltage level of the grid
- type of the power plant and its generation units
- makes of the turbines (partly)
- year of commissioning / intended year of demolition / end of service life time
- installed (rated gross) capacity and net available capacity in peak for each generation unit
- transformer details
- reasons for unavailability and in some cases estimated costs for repair / reconstruction
- Operating hours.

6.1 Existing Power Generation Assets

6.1.1 General

A first analysis of data received from the National Control Center (NCC) at Osogbo about installed and available power generation capacity as well as peak and off peak power generation indicated that more than 50% of the generation capacity is not available, either for

technical reasons / planned maintenance or due to unavailability of gas or other unplanned outage reasons.

Based on updated and latest information provided by TCN and by generation companies, the installed gross capacity of existing power plants is now about 12,500 MW, of which

- About 1967 MW ~ 15.7 % are Hydroelectric Power Plants (HYDRO)
- About 8685 MW ~ 69.5 % are gas-fired Gas Turbine Power Plants
  - 6749 MW (77.7%) in Open Cycle Gas Turbine Plants (GT OC)
  - 1936 MW (22.3%) in Combined Cycle Gas Turbine Plants (GT CC)
- About 1848 MW ~ 14.8 % are conventional Steam Power Plants (STEAM)

Main characteristics of these existing generation assets with operational status for the day of the 27th November 2016 are compiled in **Table 6-1.**

6.1.2 Age Structure of Generation Plants

The age structure of gas turbine units (independent from real operating time over the entire lifetime of each generation unit) shows that many generation units already reached - or are facing - the end of the operational lifetime. It is obvious that most of the older gas fired generation units are causing more frequent planned maintenance outages and/ or long term outages for repair. For this reason, they should be replaced in near future or latest at the end of the normal service life time by modern thermal plants with high efficiency. The listing shows a replacement need of up to 3000 MW within the next 5 - 10 years. Another 2700 MW gas turbine capacity will reach end of operational lifetime within the next 15 to 20 years. Some of the generation companies already started this necessary modernization process during the past 15 years and it is ongoing as announced projects under construction show.

In case of gas turbines, the end of its operational lifetime is reached latest after more than 200,000 hours of operation or 30 years after commercial operation date (COD).

- Gas Turbines:
  - about 528 MW capacity installed in 1982 (end of lifetime since 2012)
  - about 624 MW capacity installed in 1990 (approaching end of lifetime)
  - about 2755 MW capacity installed between 2000 and 2007 (approaching 2nd major overhaul)
  - about 4755 MW capacity installed between 2008 and 2017 are rather new

Egbin Power Plant is the only conventional steam plant using natural gas as primary energy source. The power plant has an installed generation capacity of 6 x 220 MW (in total 1320 MW). The power plant has been built between 1985 and 1987. Under consideration that the normal economic live cycle of this type of power plant is usually not more than 40 years, the power plant needs to be replaced within the coming 8 to 10 years.

Another reason for a replacement of Egbin Power Plant is its low efficiency of about 30% only compared with an efficiency of more than 50% for modern combined cycle power plants.
In case of hydro-electric plants, the operability is highly dependent on the frequency and intensity of maintenance works. But it shall be noted that all of them are more than 27 years old.

Table 6-1 Existing Power Generation Plants and Status of Availability on 27/11/2016 (Source NCC OSOGBO)

NCC No.	NAME OF STATION	PRIMARY ENERGY RESSOURCE	POWER PLANT TYPE	COMMERCIAL OPERATION DATE	NO. OF UNITS	UNIT CAPACITY [MW]	PLANT CAPACITY [MW]	AVAILABLE CAPACITY [MW]	INFEED TO GRID [MW]	OUTAGE DUE TO GAS CON-STRAINTS [MW]	OUTAGE DUE TO REPAIR / MAINTE-NANCE [MW]
1	KAINJI - G7-10	HYDRO	HYDRO	1978	4	80	320	160	160		160
1	KAINJI - G5-6	HYDRO	HYDRO	1968	2	120	240				240
1	KAINJI - G11-12	HYDRO	HYDRO	1976	2	100	200	100	100		100
2	JEBBA	HYDRO	HYDRO	1983-88	6	101	607	506	475		95
3	SHIRORO	HYDRO	HYDRO	1990	4	150	600	450	450		150
4	EGBIN	GAS	STEAM	1985-1987	6	220	1320	880	380	440	150
5	SAPELE	GAS	STEAM	1990	6	88	528	88	63		150
6	DELTA II - GT3-8	GAS	GT OC	2002	6	24	143	95	60	24	48
6	DELTA III - GT9-14	GAS	GT OC	2005	6	24	143	119	80	24	24
6	DELTA IV - GT15-20	GAS	GT OC	1990	6	99	594	297	160	99	297
7	AFAM IV - GT13-18	GAS	GT OC	1982	6	88	528				528
7	AFAM V - GT19-20	GAS	GT OC	2002	2	138	276				276
8	GEREGU FGN 1	GAS	GT OC	2007	3	138	414	414	145	276	
9	OMOTOSHO I	GAS	GT OC	2007	8	42	335	335	108	209	
10	OLORUNSOGO I	GAS	GT OC	2007	8	42	335	293	140	84	42
11	GEREGU NIPP 1	GAS	GT OC	2013	3	148	444	444	145	290	
12	SAPELE OGORODE 1	GAS	GT OC	2011	4	113	454	113	110		340
13	ALAOJI - NIPP	GAS	GT OC	2013-14	4	120	480	240	115	120	240
14	OLORUNSOGO II	GAS	GT CC	2011	4	126	504	504		504	
14	OLORUNSOGO II	STEAM	GT CC	2012	2	127	254	127		127	127
15	OMOTOSHO II	GAS	GT OC	2012	4	126	505	505	112	379	
16	CALABAR / ODUKPANI	GAS	GT OC	2015	5	113	565	113	116		452
17	IHOVBOR (EYAEN)	GAS	GT OC	2013-14	4	113	452	339	107	226	113
18	OKPAI IPP	GAS	GT CC	2005	2	150	300	300	284		
18	OKPAI IPP	STEAM	GT CC	2005	1	150	150	150	142		
19	AFAM VI - ST1	STEAM	GT CC	2005	1	230	230	230		230	
19	AFAM VI - GT11-13	GAS	GT CC	2009	3	166	498	498	302	166	
20	IBOM 1	GAS	GT OC	2009	1	42	42				42
20	IBOM 1	GAS	GT OC	2016	1	40	40	40		40	
20	IBOM 1	GAS	GT OC	2010	1	114	114	114		114	
22	EBUTE BARGE	GAS	GT OC	2002	9	31	279				
23	OMOKU IPP	GAS	GT OC	2006	6	25	150	75	51		75
24	TRANS-AMADI IPP	GAS	GT OC	2010	4	25	100	75		75	25
25	RIVERS IPP	GAS	GT OC	2012	1	191	191	191		160	
26	GBARAIN - GT2 NIPP	GAS	GT OC	2016	1	113	113	113		112	
28	PARAS ENERGY	GAS	GT OC		6	9	52	45	45	9	
	TOTAL						**12,500**	**7,954**	**3,850**	**3,708**	**3,674**

6.1.3 Availability of existing Generation Capacities

As **Table 6-1** gives information about availability as well as about unplanned / planned outages for maintenance or other reasons of these plants, it is obvious that on the day of 27th November

- about 7953 MW ~ 63.6% of the total installed capacity is in the status of being theoretically available.
- about 3850 MW ~ 30.8% of the total installed capacity - or 48.4% of the available capacity - could be used for power evacuation only About 3674 MW ~ 29.4% of the total installed capacity was out for maintenance / repair (long term as well as short term).
- about 3708 MW ~ 29.7% of the total installed capacity were not available due to gas constraints / vandalism in fuel supply structures About 1267 MW ~ 10.1% of the total installed capacity were out or had reduced infeed capacity for other reasons

The above shows the urgent need for improvement of existing assets with regard to

- vandalism and limited availability of gas
- quality of maintenance / availability of spare parts
- age structure of plants (availability of old plants is lower due to more frequent outages caused by material stress or missing spare parts)
- fuel price (much too low) and fuel availability (much too low)

The low fuel price results in the preferred installation of cheaper GTOC units, but

- GTOC have about 40% lower efficiency than GTCC
- GTCC have about 50% higher power output with the same amount of fuel

Table 6-2 shows the installed (gross) and available (net) capacity of existing generation plants as well as peak / off-peak infeed capacity and generated / evacuated energy of these plants as recorded by NCC for the day 28th November 2016. This is understood as typical screenshot of the power generation situation in Nigeria in 2016.

Table 6-2 as well confirms the given situation as shown and explained in **Table 6-1** with regard to installed, available and real used generation capacity. The net evacuated energy of each plant is used for calculation of the daily average capacity used of the plant, this being about 28.4% of total installed capacity only.

Table 6-2 Breakdown of installed gross and net available capacity versus real peak & off-peak generation capacity

			CAPACITY		GENERATION		ENERGY		NET ENERGY	
			INSTALLED	AVAILABLE	PEAK		OFF-PEAK	GENERATED	EVACUATED	
			gross	net	28/11/2016	28/11/2016	28/11/2016	28/11/2016	28/11/2016	28/11/2016
	STATION	TURBINE	[MW]	[MW]	[MW]	[MW]	[MWh/d]	[MWh/h]	[MWh/d]	[MWh/h]
1	KAINJI	HYDRO	760	600	313	312	7501	313	7484	312
2	JEBBA	HYDRO	607	475	473	383	9494	396	9481	395
3	SHIRORO	HYDRO	600	600	450	365	10534	439	10506	438
4	EGBIN	STEAM	1320	1100	337	329	7793	325	7279	303
5	SAPELE	STEAM	528	0	63	64	1352	56	1304	54
6	DELTA	GAS	879	832	320	320	7490	312	7341	306
7	AFAM IV-V	GAS	804	0	0	0	0	0	0	0
8	GEREGU GAS	GAS	414	414	145	61	2807	117	2787	116
9	OMOTOSHO GAS	GAS	335	335	109	106	2455	102	2434	101
10	OLORUNSOGO GAS	GAS	335	335	138	131	3111	130	3081	128
11	GEREGU NIPP	GAS	444	444	145	104	2970	124	2955	123
12	SAPELE NIPP	GAS	454	454	110	105	2611	109	2598	108
13	ALAOJI NIPP	GAS	480	240	115	61	2321	97	2310	96
14	OLORUNSOGO NIPP	GAS	758	631	0	0	0	0	0	0
15	OMOTOSHO NIPP	GAS	505	505	112	93	2378	99	2369	99
16	ODUKPANI NIPP	GAS	565	120	116	116	2665	111	2638	110
17	IHOVBOR NIPP	GAS	452	226	107	108	2550	106	2528	105
18	OKPAI	GAS	450	450	427	420	10089	420	9882	412
19	AFAM VI	GAS	728	727	302	301	7251	302	7159	298
20	IBOM POWER	GAS	196	0	0	0	0	0	0	0
22	AES EBUTE BARGE	GAS	279	0	0	0	0	0	0	0
23	OMOKU	GAS	150	75	51	52	1191	50	1153	48
24	TRANS AMADI	GAS	100	75	0	0	0	0	0	0
25	RIVERS IPP	(GAS)	191	160	0	0	0	0	0	0
26	GBARAIN	GAS	113	113	0	0	0	0	0	0
28	PARAS ENERGY	GAS	52	52	43	43	991	41	986	41
	TOTAL		**12500**	**8964**	**3877**	**3473**	**86560**	**3607**	**85289**	**3554**

6.1.4 Energy Balance of gas fired Power Plants

A further indication of the given situation in the Nigerian power business is shown in **Table 6-3** by the energy balance for gas fired power plants in the year 2015 as example.

Table 6-3 Energy Balance of Gas fired Power Plants in 2015

	Quantity of Gas Consumed		Energy Sent Out	Net Energy Efficiency	Net Heat Rate	Average operation
	[SCF]	[GJ]	[MWhe]	[kWhe/kWhth]	[MJ/kWhe]	[h/year]
EGBIN	53,965,156,491	59,612,264	5,192,951	0.31	11.479	3934
DELTA	35,372,927,009	39,074,477	2,761,016	0.25	14.152	3140
SAPELE	7,632,762,897	8,431,483	550,937	0.24	15.304	1043
SAPELE NIPP	8,448,997,178	9,333,131	919,606	0.35	10.149	2026
AFAM VI (GTCC)	23,935,446,666	26,440,138	2,991,284	0.41	8.839	4109
OMOTOSHO GAS	16,588,767,738	18,324,676	1,448,663	0.28	12.649	4325
OMOTOSHO NIPP	15,160,500,000	16,746,949	1,089,840	0.23	15.366	2156
GEREGU GAS	11,748,628,000	12,978,047	1,165,646	0.32	11.134	2816
GEREGU NIPP	1,246,166,000	13,546,557	1,165,646	0.31	11.622	2625
IBOM	6,223,319,000	6,874,549	510,565	0.27	13.465	2606
OKPAI (GTCC)	19,868,522,319	21,947,636	2,604,661	0.43	8.426	5788
IHOVBOR NIPP	12,461,912,480	13,765,972	1,106,267	0.29	12.444	2447
OLORUNSOGO GAS	31,984,785,036	35,331,788	1,522,245	0.16	23.210	4544
OLORUNSOGO NIPP (GTCC)	13,414,042,652	14,817,736	1,113,488	0.27	13.307	1469

The above table shows that none of the plants is operating in continuous base load over the year. The average utilization factor is about 0.35.

Under ideal operating conditions - without overhaul or other planned / unplanned outages - a utilization factor (load factor) of up to 0.95 is possible for modern open / combined cycle gas turbine plants.

An annual load factor of about 0.85 is assumed to be achievable as average over the whole lifetime under consideration of frequent and regular maintenance stops according to manufacturers' recommendations and under consideration of unrestricted fuel availability (no vandalism or other reason for shortages of gas supply).

Under ideal operating conditions (ISO), modern Open Cycle Gas Turbine Plants have an electrical efficiency of up to 35 - 39%. As this is highly dependent on the local ambient air temperature, about 33 - 36% should be considered for given climate conditions in Nigeria.

Modern Combined Cycle Gas Turbine Plants can achieve energy efficiencies of up to 60% (ISO conditions), which result in efficiencies of 50 - 55% under climate conditions in Nigeria.

The Sapele NIPP plant (GTOC) has high energy efficiency although operating only 2000 hours in 2015 only. It can be seen that it was mainly used in base load during this period.

The low energy efficiency of the Olorunsogo NIPP plant (GTCC) is resulting from short operating periods at part load only.

As the two combined cycle plants in Afam VI and Okpai show energy efficiencies of 41 - 43% for 2015, these plants were used in part load operation only.

The two conventional steam power plants of Egbin and Sapele have energy efficiencies of 24 to 31% only, although 39 to 41% should be achievable for this kind of technology.

As unavailability of existing generation capacity in a range of up to 70%, this is a critical issue for the Nigerian energy sector, priority of improvement activities shall be set in a reduction of unavailability due to vandalism, maintenance, overhaul and repair down to a future rate of 20 to 30%. By this, additional usable generation capacity in a range of up to 4900 MW can be achieved without installation of new capacities.

The age structure and poor utilization factor of existing generation units as well as the continuously increasing power demand result in the need for

- installation of further generation capacity
- improvement of fuel supply reliability and capacity in parallel to further diversification with regard to utilization of primary energy resources
- improvement of maintenance / repair processes at existing facilities

6.1.5 History of power Generation in Hydro-electric Plants

Monthly Energy Generated (GWh) and Monthly Maximum Power Output (MW) data were collected from Kainji, Jebba and Shiroro Hydropower Stations respectively. The data covered year 2010 to 2014. The analysis of these data is presented below.

6.1.5.1 Kainji Hydro-electric Plant

A summary of monthly energy generated at Kainji hydro-electric plant between 2010 and 2014 is presented in below **Table 6-4**.

Table 6-4 Generation History of Kainji Hydro-electric Plant

	Units	2010	2011	2012	2013	2014
January	GWh	294.193	237.821	194.858	105.417	0
February	GWh	261.319	198.463	195.371	95.154	30.583
March	GWh	256.710	183.061	167.527	104.020	89.890
April	GWh	204.302	199.059	135.004	99.742	77.638
May	GWh	123.655	128.825	91.707	78.525	103.564
June	GWh	180.218	117.905	56.794	38.425	64.070
July	GWh	114.599	66.233	66.364	38.653	45.162
August	GWh	118.285	5.866	58.046	81.214	83.615
September	GWh	154.760	142.392	120.880	98.492	32.859
October	GWh	176.972	127.492	117.639	98.492	84.705
November	GWh	179.127	112.362	58.874	73.930	71.764
December	GWh	236.851	196.780	129.291	46.184	50.065
Total	**GWh**	**2300.991**	**1716.260**	**1392.360**	**958.248**	**733.916**

The table shows the continuous decrease of generated and evacuated power from 2010 to 2014. This is resulting from a continuous decrease of available / operating generating capacity in this time period, as the **Table 6-5** shows:

Table 6-5 Generation History of Kainji Hydro-electric Plant (Maximum Monthly Power Output)

	Units	2010	2011	2012	2013	2014
January	MW	532.30	477.40	454.80	258.70	0.00
February	MW	532.40	480.00	462.80	220.00	74.10
March	MW	464.00	445.60	377.50	220.00	165.70
April	MW	437.10	443.00	344.70	216.00	154.30
May	MW	315.60	291.30	281.90	180.00	241.90
June	MW	452.30	382.30	205.30	100.00	159.30
July	MW	288.40	363.90	212.30	100.00	127.10
August	MW	332.80	267.10	172.50	186.80	223.90
September	MW	384.00	334.70	309.30	213.30	98.00
October	MW	370.00	351.60	339.30	126.50	185.80
November	MW	370.00	321.30	142.90	119.30	152.00
December	MW	471.70	427.30	241.30	104.70	96.800
Average	**MW**	**412.55**	**382.13**	**295.38**	**170.44**	**139.91**

There is a need to check reasons for the continuously decreasing peak capacity. This may result from the varying amount of river water. But this may not be the only reason. In case of technical reasons, availability of existing generation units shall be improved by better quality of maintenance. The low load factor is resulting from operation in base load and peak load, whereas other plants are running in base load.

6.1.5.2 Jebba Hydro-electric Plant

A summary of monthly energy generated at Jebba hydro-electric plant between 2010 and 2014 is presented in below **Table 6-6**.

Table 6-6 Generation History of Jebba Hydro-electric Plant

	Units	2010	2011	2012	2013	2014
January	GWh	242.25	252.03	185.13	213.10	275.53
February	GWh	216.48	217.04	177.50	204.86	213.87
March	GWh	195.76	238.57	163.07	250.11	222.43
April	GWh	197.67	276.70	139.77	238.16	181.77
May	GWh	258.33	229.15	114.90	249.18	194.82
June	GWh	178.20	202.42	117.06	220.83	191.69
July	GWh	141.93	132.93	157.65	209.72	209.72
August	GWh	211.77	136.56	244.46	98.11	129.05
September	GWh	222.95	220.19	274.38	220.49	220.49
October	GWh	297.42	290.40	275.27	264.76	264.76
November	GWh	298.53	200.42	284.12	248.18	212.11
December	GWh	232.45	170.92	265.02	239.99	216.78
Total	**GWh**	**2693.74**	**2567.34**	**2398.33**	**2657.48**	**2532.99**

The table shows the impact of reduced generation in 2012 which may result from reduced availability of water in this year. **Table 6-7** confirms the continuous technical availability

of generation units. Jebba HPP is used as base load plant and has a higher load factor for this reason.

Table 6-7 Generation History of Jebba Hydro-electric Plant (Maximum Monthly Power Output)

	Units	2010	2011	2012	2013	2014
January	MW	463.40	419.80	468.10	395.20	446.70
February	MW	405.40	424.20	430.50	375.50	368.90
March	MW	420.90	366.90	382.50	381.70	423.30
April	MW	471.70	453.10	372.30	379.20	366.70
May	MW	438.50	428.20	289.20	385.60	475.00
June	MW	386.80	379.20	382.30	382.20	393.10
July	MW	403.30	387.50	385.60	376.30	382.30
August	MW	428.70	407.40	378.00	385.60	435.20
September	MW	401.70	465.90	482.00	386.80	459.20
October	MW	481.70	475.80	474.70	367.80	447.90
November	MW	481.90	479.90	470.80	382.60	402.00
December	MW	398.00	477.80	457.10	378.20	383.600
Average	**MW**	**431.83**	**430.48**	**414.43**	**381.39**	**415.33**

6.1.5.3 Shiroro Hydro-electric Plant

A summary of monthly energy generated at Shiroro hydro-electric plant between 2010 and 2014 is presented in below **Table 6-8.**

Table 6-8 Generation History of Shiroro Hydro-electric Plant

	Units	2010	2011	2012	2013	2014
January	GWh	212.457	195.144	190.370	200.979	211.079
February	GWh	205.529	140.107	170.702	156.644	186.574
March	GWh	195.863	290.268	127.226	196.472	114.596
April	GWh	160.178	250.555	33.134	197.070	63.738
May	GWh	61.683	157.038	32.727	117.140	116.495
June	GWh	213.894	92.014	221.036	89.193	107.506
July	GWh	258.360	159.399	245.309	217.242	169.170
August	GWh	265.433	208.096	378.427	282.996	225.282
September	GWh	271.054	225.210	398.592	288.302	277.757
October	GWh	196.372	261.519	383.863	294.045	216.659
November	GWh	186.732	193.951	236.836	227.274	183.740
December	GWh	193.561	200.692	246.408	217.648	205.409
Total	**GWh**	**2421.120**	**2373.990**	**2664.630**	**2485.010**	**2078.010**

The table shows the impact of reduced generation in 2010 and 2014 which may result from reduced availability of water in this year. **Table 6-9** confirms the continuous technical availability of generation units:

Table 6-9 Generation History of Shiroro Hydro-electric Plant (Maximum Monthly Power Output)

	Units	2010	2011	2012	2013	2014
January	MW	450.0	295.2	304.8	558.6	330.0
February	MW	444.8	295.0	295.0	485.0	450.0
March	MW	375.0	450.0	498.4	594.0	435.0
April	MW	321.4	435.0	595.0	540.0	535.7
May	MW	445.2	348.4	396.8	550.0	450.0
June	MW	435.0	315.0	580.0	445.0	450.0
July	MW	450.0	338.7	532.3	375.0	430.6
August	MW	450.0	445.2	571.0	435.5	425.8
September	MW	445.0	450.0	595.0	445.0	440.2
October	MW	266.1	445.2	595.2	450.0	372.6
November	MW	300.0	445.8	440.0	356.9	450.0
December	MW	300.0	450.0	566.1	311.5	503.2
Average	**MW**	**390.2**	**392.8**	**497.5**	**462.2**	**439.4**

6.1.6 Estimation of Net Energy Infeed to Grid

Estimation of the annual net energy infeed to the grid by existing generation assets is based on

- current level of annual net generation (infeed to grid) of each plant / unit
- assumptions about future availability of existing assets, which are currently under repair or in maintenance
- assumption of unrestricted availability of fuel (no shortage due to vandalism or size of transmission / distribution pipelines)
- load factors / utilization factors according to modern standards are achievable due to improved maintenance / repair management / implementation

For Kainji, Jebba and Shiroro HPPs average annual energy production has been calculated on the basis of information included in TCN's annual reports, as shown in **Table 6-10**. Because of outage of generation units at Kainji HPP in recent years the generation figures of the years 2007 to 2010 only have been considered for calculation of the average generation.

Table 6-10: Generation History of Kainji, Jebba and Shiroro HPPs

		Annual Energy Generation [GWh]										
	Installed Capacity [MW]	2007	2008	2009	2010	2011	2012	2013	2014	2015	Average Annual	Plant Factor *
Kainji	760	2786	2701	2511	2300	1716	1392	958	733	1504	**2575	0.39
Jebba	606	2726	2776	2679	2694	2567	2398	2657	2533	2199	2581	0.49
Shiroro	600	2243	1960	2278	2421	2374	2664	2485	2078	1833	2260	0.43

* Utilization Factor ** Only 2007 to 2010 figures considered

Annex 6.2 gives an overview of the development of future annual total energy infeed into the grid as well as infeed by each plant.

6.2 Power Plants under Construction

Table 6-11 shows the generation assets currently under construction and which will be ready for operation within the next 4 years.

Table 6-11 Power Plants under Construction in 2017

NAME OF STATION	PRIMARY ENERGY RESSOURCE	POWER PLANT TYPE	COMMERCIAL OPERATION DATE	NO. OF UNITS	UNIT CAPACITY (MW)	PLANT CAPACITY (MW)
ALAOJI 2+ NIPP	STEAM	GTCC	2021	1	285	285
GBARAIN / UBIE 1	GAS	GTOC	2017	1	113	113
SAPELE ROT	GAS	GTOC	2018	2	150	300
EGBEMA 1 NIPP	GAS	GTOC	2018	3	113	339
KADUNA IPP	GAS	GTOC	2018	1	215	215
OMOKU NIPP	GAS	GTOC	2018	2	113	226
GURARA	HYDRO	HYDRO	2017	2	15	30
TOTAL						**1508**

Another 39 MW Hydroelectric Power Unit is expected to be ready for operation by 2018. This plant will be located in DADIN KOWA.

Again, most of the new generation units (79%) will be open cycle gas turbines. Alaoji 2+ forms the completion of the Alaoji plant to a combined cycle power plant. The small sized Gurara plant is the only hydro-electric plant under construction.

6.3 Future Generation Projects

Several projects initiated by different generation companies are coming up. Besides NIPP, many other companies (IPPs as well as industry) are announcing their interest in building, owning and operation of newly designed or refurbished power plants.

The below listed power plant candidates have been agreed with TCN as being the most reliable projects to be considered for the time period until 2037. As most of the candidate plants are based on gas turbine technology, it is assumed that sufficient gas amount will be available for

- Existing gas fired power plants => increase of utilization factor
- New gas fired gas turbine based power plants (GTOC as well as GTCC)

A second basic requirement is given by financing limitations. For this reason, the annual increase of new generation capacity for gas-fired and hydro-electric power plants is limited to 1000 - 1500 MW per year.

Besides costs for construction of generation units, the complete supply chain requires funds for

- Expansion of the gas supply system (transmission and distribution)
- Expansion of transmission and distribution systems for power evacuation

6.3.1 Process of Project Development and Licensing

A generation developer has to carry out various studies and has to reach various agreements before being able to start with construction process:

- evacuation Studies
- EIA Studies
- grid connection agreement
- transmission project agreement
- cooperation agreement
- ancillary services agreement
- NERC License
- PPA agreement.

As a precondition, all new IPPs need a license from the Nigerian Electricity Regulatory Commission (NERC). The homepage of NERC shows a large number of licensees. However, it is not certain that all these licensees will finally be permitted to implement their intended generation projects.

6.3.2 Basic Considerations with regard to Selected Technology and Location of new Generation Facilities

First priority should be the utilization of existing power plants for refurbishment of existing assets, replacement of existing assets after expiry of lifetime and expansion of generation capacity at these locations. As most of the existing power plants using gas turbine technology are of open cycle design, the possibilities for conversion to combined cycle plants should be checked and implemented. This is an already ongoing process, which has to be continued in view of optimization of fuel utilization, increase of plant availability and reduction of expenditures for repair.

In a second step, new generation plants shall be implemented at new locations, considering the following technologies:

1. Gas fired Combined Cycle Power Plants
2. Coal fired Conventional Power Plants
3. Hydro-electric Power Plants, as only 26% of potential is developed
4. Photovoltaic Power Plants

It has to be noted that the duration of the whole implementation process between first idea and start of operation is highly depended on the selected technology. In case of thermal power plants duration of 4 to 7 years has to be considered. In case of hydro-electric power plants, the duration is between 5 to 10 years.

New locations highly depend on the given infrastructure with regard to

- size of the proposed site is sufficient for possible future expansion of generation capacity
- Check of site conditions (soil, street connections, existing burdens on the ecosystem and on population, etc.)

- location and voltage level of possible grid connection substation and distance to the proposed site
- location of gas transmission substations and capacity of the transmission pipeline
- expansion of the existing gas pipeline transmission system including interconnection to gas transmission systems of countries in the North
- re-activation of existing coal mines for purposes of power generation including
  - check of large sized rivers for suitability of coal transport and as resource for utilization as cooling water
  - check of large sized roads and railway systems for suitability of coal transport
- check of potential of natural resources for suitability of utilization for hydro-electric power generation
- check of potential of natural resources for solar power generation

6.3.3 Gas Turbine based Power Plants

6.3.3.1 Conversion of open cycle to combined cycle power plants

Open cycle gas turbine (GTOC) power plants use fuel for heating of compressed air, which is utilized in a turbine for power generation. The hot exhaust gases are emitted to the environment without further use of the containing energy in form of heat and thrust.

The purpose of combined cycle (GTCC) power plants is to utilize this –wasted - energy from the hot gas turbine exhausts for steam generation in a downstream heat recovery steam generator (HRSG). This steam can then be further used for power generation in a steam turbine process by expanding the steam.

By that, the total electrical generation capacity of a GTCC power plant is made up from

- the power output of gas turbines
  and of
- the steam turbine without the need of further fuel.

6.3.3.2 Development of Gas Turbine Technology

Table 6-12 shows the development of gas turbine technology in the time period between 2001 and 2017 on the basis of some typical GT models. The effect of conversion of open cycle gas turbines to combined cycle gas turbines is demonstration for some of them in **Table 6-13**. All data are shown for ISO Conditions at 15°C and sea level.

The development towards larger gas turbine sizes and improved unit efficiencies results in the limitation of possibilities for extension of gas turbine lifetime after design life expiry.

Table 6-12 Development of gas turbine technology between 2001 and 2017

GT model	Capacity OC	Improvement	Efficiency OC	Improvement
GE Frame 6B.03	44 MW	+ 11.0%	33.5%	+ 5.0%
GE Frame 6F.03	82 MW	+ 17.0%	36.0%	+ 5.5%
GE Frame 9E.04	145 MW	+ 17.5%	37.0%	+ 9.4%
GE Frame 9F.04	281 MW	+ 15.6%	38.6%	+ 6.0%
GE/Alstom GT13E2	203 MW	+ 23.0%	38.0%	+ 6.4%
Siemens SGT-800	50 MW	+ 17.4%	38.3%	+ 3.5%
Siemens SGT5-2000E	187 MW	+ 19.1%	36.2%	+ 5.2%
Siemens SGT5-4000F	307 MW	+ 15.4%	40.0%	+ 3.6%

Table 6-13 Improvement potential of conversion from OC to CC

Plant Configuration 2 + 2 + 1 *)	Capacity CC	Efficiency CC	Improvement OC to CC	Improvement OC to CC
GE Frame 9E.04	433.8 MW	54.9%	+ 150.0 MW	+ 48.3%
GE Frame 9F.04	872.3 MW	59.8%	+ 315.8 MW	+ 54.9%
GE/Alstom GT13E2	588.9 MW	55.2%	+ 193.4 MW	+ 45.2%
Siemens SGT5-2000E	551.0 MW	53.3%	+ 177.0 MW	+ 47.2%
Siemens SGT5-4000F	950.0 MW	59.7%	+ 320.0 MW	+ 49.2%

*) 2 gas turbines + 2 heat recovery steam generators + 1 steam turbine

The new gas turbine generation based on H-Class technology can achieve efficiencies of > 60% @ ISO Conditions for combined cycle configurations.

6.3.3.3 Development of the Gas Transmission System

The majority of existing gas fired power plants is located in the south of Nigeria, having a well developed gas transmission and distribution system. Although the system itself is highly affected by vandalism and although the supply capacity in several lines is limited due to the size of the pipelines and due to a cap in the supply quantity, most of the new plants under construction as well as most of the project candidates are located in this region.

In order to overcome this critical component in the Nigerian power business, which is indirectly resulting in a concentration of electrical transmission capacity in this region as well, the Government of Nigeria initiated the development of an expansion plan for electrical and gas transmission systems. As a part of this expansion plan, new gas transmission pipelines shall be foreseen for gas supply to the central and northern regions of Nigeria.

Figure 6-1 shows the proposed and ongoing expansion plan for the gas transmission system towards the centre of Nigeria including the size of the pipelines. In addition, it is intended to connect the system to countries north of Nigeria. The schematic already shows some of the locations for proposed new gas fired power plants.

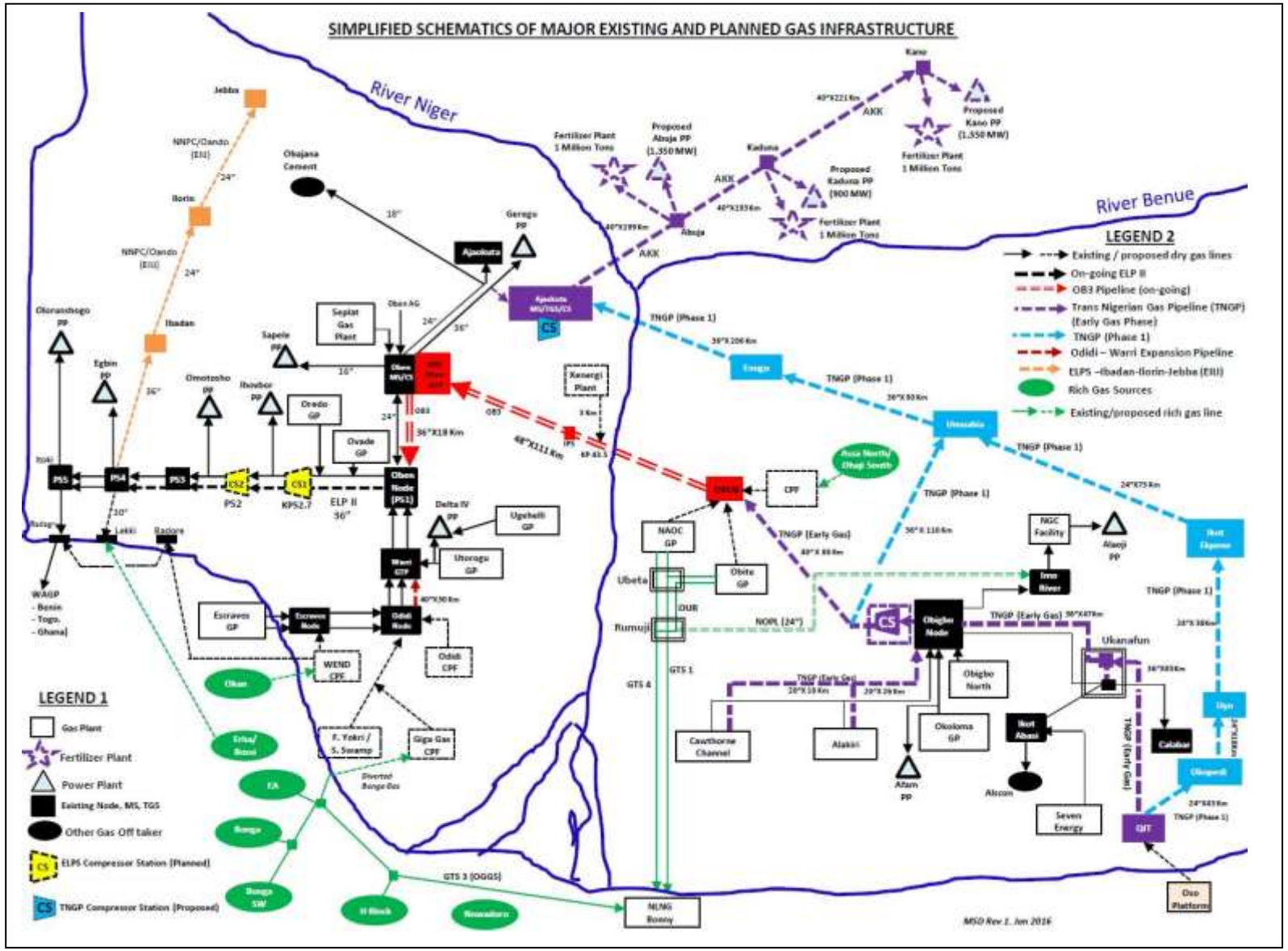


Figure 6-1: Schematic with existing and proposed Gas Transmission Pipelines *(Source: TCN)*

6.3.4 Coal Fired Power Plants

Nigeria still holds large coal reserves, estimated to be at least 2 billion metric tons. Coal mines are located in Enugu State, Kogi State, Delta State, Anambra State, Benue State and Gombe State. In 2010, the Nigerian government placed a high priority on utilizing coal resources to increase Nigeria's electricity generating capacity. Nigeria's goal is to revitalize the coal mining industry and expand power generation by attracting companies to develop these large coal resources and construct coal-fired generating plants that will connect to the country's electrical distribution grid.

The design lifetime of coal fired power plants is about 30 years, but life time can easily be extended up to 40 years of operation.

The working availability (energy availability) of a modern large sized hard coal fired power plant can be up to 86%, means 7533 full load operating hours of the plant. Due to proper maintenance and operation regime, the real availability is expected to be even higher. Manufacturers guarantee an average time availability of 90% and give 6% annual average planned outages for maintenance works in case of proper execution according to manufacturers recommendations. For coal fired power plant candidates, a utilization factor = annual load factor of about 0.85 is assumed in the energy balance, see **Annex 6.2**.

The development of coal fired power plant technology can easily be demonstrated by the diagram of **Figure 6-2**, showing the increase of net plant efficiency over the timeline with increasing live steam parameters.

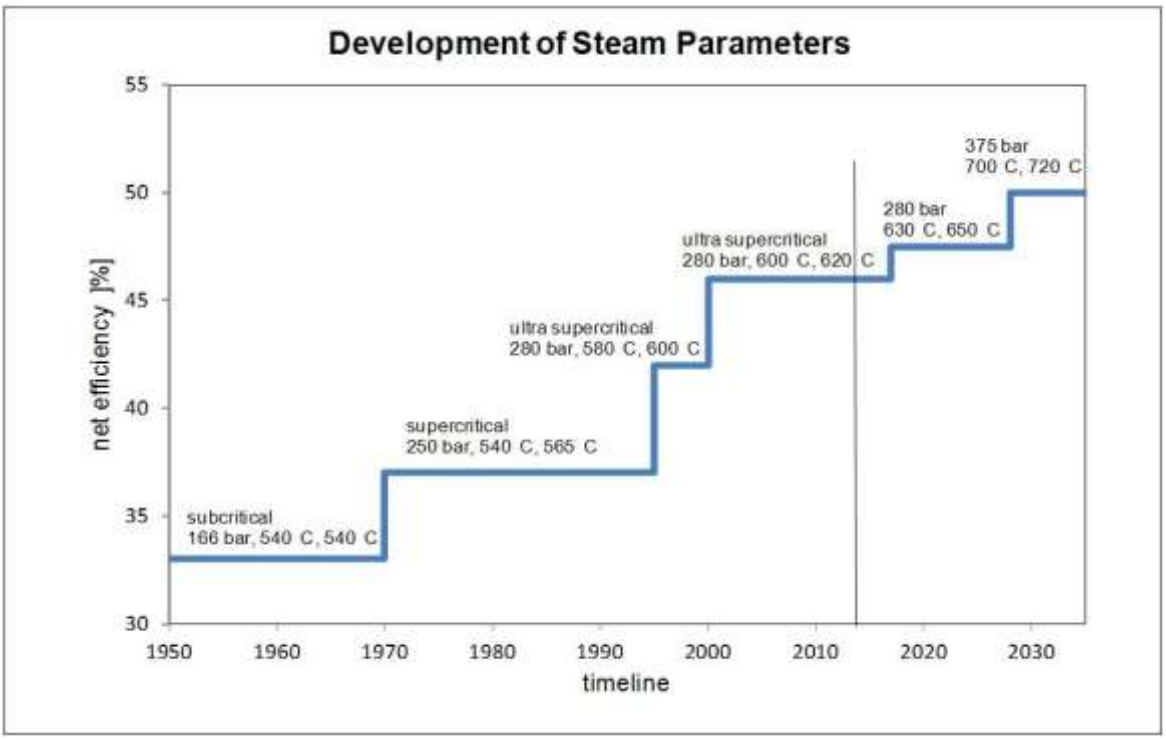


Figure 6-2: Development of coal fired Power Plant Technology

At climate conditions given in Nigeria, the net power plant efficiencies can be achieved for typical 660 MW plant size, see **Table 6-14**.

Table 6-14 Typical Performance Parameters of recent Coal fired Power Plants

	Unit	SC *)	USC *)	SC *)	USC *)
Capacity rating, gross	MWe	660.0	660.0	660.0	660.0
Capacity rating, net	MW_e	629.6	631.3	605.0	606.6
Main fuel	-	bituminous hard coal		local lignite	
El. efficiency, gross	-	43.3%	45.5%	41.9	44.1%
El. efficiency, net	-	41.3%	43.5%	38.5	40.5%
Total required area of plant site	ha	8.7	8.4	10.5	10.0

*) SC = supercritical; USC = ultra-supercritical

With increasing and more expensive steel materials, the boiler sizes increased as well.

Table 6-15 and **Table 6-16** show references of most recent hard coal and lignite fired power plants for some of the international market players (manufacturers of steam generators and steam turbines). Dependent from the location of the plant, either USC or SC steam parameters are selected.

Table 6-15 References for recent hard coal fired Power Plants

MANUFACTURER	PLANT NAME / LOCATION	YEAR	CAPACITY	SC / USC
Shanghai Electric	China, Quang Ninh	2006	4 x 300 MW	SC
	India, Rosa TPP	2008	4 x 300 MW	SC
	India, Tilaiya	2015	12 x 660 MW	SC
	India, Sasan	2012	6 x 660 MW	SC
	China, Guangdong	2013	2 x 600 MW	SC
GE / Alstom	Germany, Karlsruhe 8	2014	1 x 912 MW	USC
	Turkey, CNEIC	2016	2 x 660 MW	USC
	India, Mouda II	2016	2 x 660 MW	SC
	Malaysia, Tanjung Bin 4	2016	1 x 660 MW	USC
	India, Barh II	2015	2 x 660 MW	SC
	Netherlands, Eemshaven	2015	4 x 820 MW	USC
MHPSE	Germany, Wilhelmshaven	2008	1 x 790 MW	USC
	South Africa, Kusile	2008	6 x 800 MW	SC
	Poland, Kozienice	2012	1 x 1075 MW	USC

Table 6-16 References for recent lignite fired Power Plants

MANUFACTURER	PLANT NAME / LOCATION	YEAR	CAPACITY	SC / USC
GE (Alstom)	Sostanj, Slovenia	2015	1 x 600 MW	USC
	Ledvice, Czech Rep.	2016	1 x 660 MW	USC
	Neurath, Germany	2012	2 x 1100 MW	USC
	Belchatow, Poland	2011	1 x 858 MW	SC
MHPSE	Turow, Poland	2014	1 x 496 MW	USC
	Ptolemais, Greece	2013	1 x 660 MW	USC
	Boxberg, Germany	2005	1 x 670 MW	USC
	Neurath, Germany	2003	2 x 1100 MW	USC

6.3.5 Generation Expansion Plan

6.3.5.1 General

In 2016 a detailed data collection and analysis was carried out by TCN and the Consultant regarding the future generation development.

As mentioned in Section 6.3.1 "*Process of Project Development and Licensing"*, a generation developer will have to carry out various studies and will have to reach various agreements before being able to start with the construction process. Based on the available information on state of preparatory works, a scenario of future generation development has been identified.
At a workshop in January 2017 agreement was reached on a generation development plan for consideration in the network calculations and Transmission Expansion Plan.

In the course of 2017 TCN carried out a review of the generation development plan and submitted a revised plan end of August 2017 for consideration in the Final Report. This is shown in **Annex 6.1.**

6.3.5.2 Power Plants to be commissioned until 2020

Table 6-17shows the new power plants which will be commissioned until 2020. The gas fired power plants are under construction. Regarding the PV power plants, it is expected that their construction will start soon.

Table 6-17 Power Plants to be commissioned until 2020

NAME OF STATION	PRIMARY ENERGY RESSOURCE	COMMERCIAL OPERATION DATE	NO. OF UNITS	GROSS UNIT CAPACITY (MW)	GROSS PLANT CAPACITY (MW)
GBARAIN / UBIE I	GAS	2017	1	113	113
GURARA	HYDRO	2017	2	15	30
EGBEMA I - NIPP	GAS	2018	1	113	113
OMOKU - NIPP	GAS	2018	1	113	113
MABON - DADIN KOWA	HYDRO	2018	1	39	39
AZURA	GAS	2018	3	150	450
AFAM III	GAS	2018	8	30	240
NOVA SOLAR	PV	2018			100
NOVA SCOTIA POWER	PV	2018			80
EGBEMA I - NIPP	GAS	2019	1	113	113
EGBEMA I - NIPP	GAS	2019	1	113	113
KADUNA IPP	GAS	2019	1	215	215
OMOKU - NIPP	GAS	2019	1	113	113
KASHIMBILLA	HYDRO	2019		40	40
ZUNGERU	HYDRO	2019	4	700	700
PAN AFRICA SOLAR	PV	2019			75
LR AARON SOLAR POWER PLANT	PV	2019			100
QUAINT ENERGY SOLUTIONS	PV	2019			50
NIGERIA SOLAR CAPITAL PARTNERS	PV	2020			100
MOTIR DUSABLE	PV	2020			100
MIDDLE BAND SOLAR	PV	2020			100
AFRINERGIA SOLAR	PV	2020			50
KVK POWER NIGERIA LTD	PV	2020			55
ANJEED KAFACHAN SOLAR IPP	PV	2020			100
CT COSMOS	PV	2020			70
ORIENTAL	PV	2020			50
EN Consulting & Projects - Kaduna	PV	2020			100
OKPAI IPP II - AGIP(*NNPC POWER BUSINESS PLAN*)	GAS	2020	2	150	300
OKPAI IPP II - AGIP(*NNPC POWER BUSINESS PLAN*)	STEAM	2020	1	150	150
IBOM II	GAS	2020	4	138	552
Generation Capacity Additions until 2020					**4,524**

6.3.5.3 Power Plants Committed for Implementation after 2020

Besides the above projects with generation plants / generation units under construction, further projects are in a status of being committed for implementation. Most feasible projects are listed in **Table 6-18** for the time period 2021 to 2025, in

Table 6-19 for the time period 2026 to 2030 and in **Table 6-20** for the time period 2031 to 2037. Details are shown in Annexes 6.1 and 6.2.

Table 6-18 Power Plants to be commissioned between 2020 and 2025

NAME OF STATION	PRIMARY ENERGY RESSOURCE	COMMERCIAL OPERATION DATE	NO. OF UNITS	GROSS UNIT CAPACITY (MW)	GROSS PLANT CAPACITY (MW)
ASCO	GAS	2021	2	55	110
ELEME	GAS	2021	1	75	75
QUA IBOE POWER PLANT	GAS	2021	4	130	520
Cummins Power Gen. LTD.	GAS	2021	1	150	150
ONDO IPP - King Line	GAS	2021	1	200	200
TURBINE DRIVE	GAS	2021	3	167	501
EGBIN 2+	GAS	2021	4	300	1200
EGBIN 2+	STEAM	2021	2	350	700
SAPELE POWER PLC	GAS	2021	30	20	600
ZUMA (Egbema)	GAS	2021		374	374
PARAS	GAS	2022	2	150	300
OMA POWER GENERATION COMPANY LTD	GAS	2022			500
CENTURY IPP	GAS	2022	4	124	496
BRESSON Nigeria Ltd	GAS	2022	2	45	90
SAPELE POWER PLC	GAS	2022	1	100	100
ETHIOPE	GAS	2022	2	172	344
ONDO IPP - King Line	GAS	2022	1	150	150
ONDO IPP - King Line	GAS	2022	2	100	200
ETHIOPE	STEAM	2023	1	156	156
PROTON	GAS	2023	1	150	150
ZUMA *(Itobe)*	COAL	2023	4	300	1200
DELTA III 2+	GAS	2023	1	143	143
DELTA IV 2+	GAS	2023	4	148.5	594
LAFARAGE PHASE I	GAS	2023	1	50	50
CALEB INLAND	GAS+STEAM	2023	2	250	500
JBS Wind Power Plant	WT	2024	1	100	100
MAMBILLA	HYDRO	2024	10	305	3050
ALSCON *(Phase 1)*	GAS	2024	1	100	100
YELLOW STONE	GAS	2024	2	180	360
ETHIOPE	GAS	2024	2	172	344
ETHIOPE	STEAM	2024	1	156	156
ALAOJI 2+ NIPP	STEAM	2025	1	285	285
IKOT ABASI	GAS	2025	2	125	250
LAFARAGE PHASE II	GAS	2025	2	110	220
CALEB INLAND	GAS+STEAM	2025	2	250	500
KAZURE (KANO DISCO) *)	PV	2025			1000
Generation Capacity Additions between 2021 - 2025					**15,768**

Table 6-19 Power Plants to be commissioned between 2026 and 2030

NAME OF STATION	PRIMARY ENERGY RESSOURCE	COMMERCIAL OPERATION DATE	NO. OF UNITS	GROSS UNIT CAPACITY (MW)	GROSS PLANT CAPACITY (MW)
ALSCON *(Phase 2)*	GAS	2026	2	130	260
ESSAR	GAS	2026	6	110	660
GEREGU NIPP 2	STEAM	2027	1	285	285
OMOTOSHO II 2+	STEAM	2027	2	127	254
CALEB INLAND	GAS+STEAM	2027	2	250	500
SAPELE 2 - NIPP	GAS	2028	3	151	453
OATS	GAS	2028	7	100	700
GEREGU FGN1-2	GAS	2029	3	138	414
CALABAR / ODUKPANI - NIPP	STEAM	2029	2	127	254
GBARAIN / UBIE 2	STEAM	2029	1	115	115
GEREGU NIPP 2	GAS	2030	3	148	444
CALABAR / ODUKPANI - NIPP	GAS	2030	4	141	564
EGBEMA II	STEAM	2030	1	127	127
IHOVBOR (EYAEN) 2 - NIPP	STEAM	2030	2	127	254
GBARAIN / UBIE 2	GAS	2030	8	113	904
CHEVRON AGURA(*NNPC POWER BUSINESS PLAN*)	GAS	2030			780
SUPERTEK	GAS	2030	5	100	500
MBH	GAS	2030	2	150	300
WESTCOM	GAS	2030	2	250	500
HUDSON POWER	GAS	2030	1	150	150
BRESSON AS NIGERIA	GAS	2030	3	150	450
AZIKEL IPP	GAS	2030	1	76	76
AZIKEL IPP	GAS	2030	1	250	250
AZIKEL IPP	GAS	2030	1	163	163
Generation Capacity Additions between 2026 - 2030					**9,357**

Table 6-20 Power Plants to be commissioned between 2031 and 2037

NAME OF STATION	PRIMARY ENERGY RESSOURCE	COMMERCIAL OPERATION DATE	NO. OF UNITS	GROSS UNIT CAPACITY (MW)	GROSS PLANT CAPACITY (MW)
TOTALFINAELF (OBITE)(*NNPC POWER BUSINESS PLAN*)	GAS	2031			420

6.3.5.4 Summary of Generation Expansion Plan

TCN and Fichtner agreed to consider all sites of existing power plants in the preparation of the Transmission Expansion Plan. For existing generation units which have reached the end of their economic life cycle and for generation units which cannot be repaired due to lack of spare part availability or due to the extent of damages, it will be assumed that new generation units will be installed at the same location.

Figure 6-3 and **Table 6-21** show the expected development of generation capacity between 2017 and 2037. **Annex 6.1** and **Annex 6.2** show details of the generation development program.

Firm Generation Capacity

The firm generation capacity is usually about 20 to 30% lower than the installed capacity because of maintenance and repair requirements. Furthermore, generation capacity based on renewable energy resources has a lower utilization factor that thermal generation using gas, coal or nuclear power:

- PV plants will not be available at peak load hours which are usually in the evening. The utilization factor is about 0.22 (corresponding to 2000h/year full load operation).
- The planned Mambila HPP (3050 MW installed capacity) has a low utilization factor of about 0.19 (corresponding to 2640h/year full load operation, 5000 GWh/year energy output). The maximum output is only available in the rainy season for about 2 to 3 months. Its reservoir will be relatively small and behaves like a run-off-river power plant.
- Also output of the three exiting HPPs - Kainji, Jebba and Shiroro is much lower during dry season (sometimes less than 50% of installed capacity). Also other planned HPPs will have a similar performance.

Risks regarding future generation development

There are some uncertainties whether the implementation of the generation expansion program is possible because of the huge investment requirements.

The availability of gas is the most uncertain factor in the generation development. As indicated in **Table 6-1** in 2016 a generation capacity of 3,700 MW was not available because of gas constraints. A large quantity of the present gas production is exported. To make more gas available for electricity generation huge investments in gas exploration, gas treatment facilities and gas supply systems (pipelines etc.) will be required.

Also the planned measure for rehabilitation and replacement of existing generation capacity after the end of the economic life cycle will require huge investments.

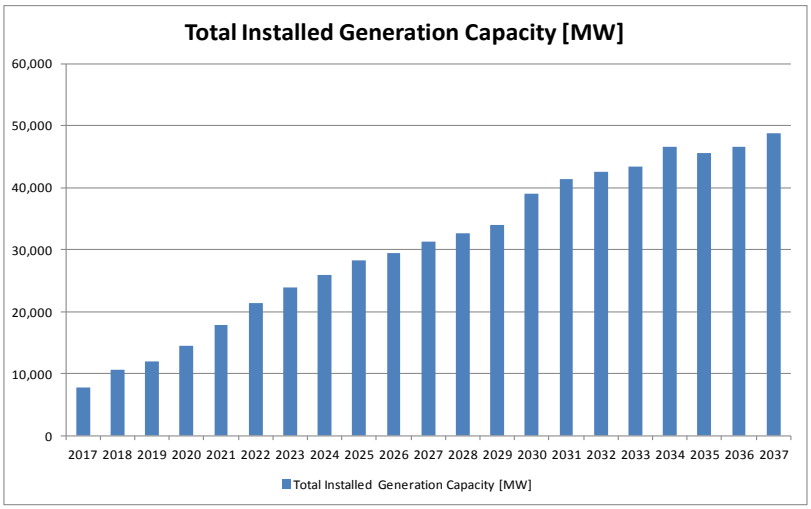


Figure 6-3: Development of Installed Generation Capacity

Table 6-21 Development of Installed Generation Capacity

Year	Installed Capacity [MW]	Year	Installed Capacity [MW]
2017	7,814	2027	31,328
2018	10,697	2028	32,586
2019	12,071	2029	34,074
2020	14,444	2030	38,991
2021	17,957	2031	41,420
2022	21,472	2032	42,635
2023	23,895	2033	43,442
2024	26,014	2034	46,556
2025	28,209	2035	45,586
2026	29,454	2036	46,613
		2037	48,813

7. Power System Analysis

7.1 Static security analysis, year 2020

7.1.1 Network configuration

The network configuration for the year 2020 is shown in the single line diagrams of **Annex 7.2** and **Annex 7.3**. The SLDs include all the ongoing and committed TCN, NIPP and JICA new projects, as discussed between TCN and the Consultant, under the assumption that they will all be completed by 2020.

The new transmission expansion projects that have been identified on the basis of the load flow studies carried out are shown on the map of **Annex 7.1** and **Annex 7.1a**.

The input data used and the assumptions made with regards to the load demand, generation capacities and expansion, transmission lines and reactive power compensation equipment are detailed in the following sections.

7.1.2 Available generation

On the basis of the installed generation, as detailed in Annex 6.1, the maximum generation that can be made available to supply the peak demand is calculated as shown in the following **Table 7-1** and **Figure 7-1** by making a number of rather optimistic assumptions in terms of planned and unplanned outages and implementation of the proposed candidate power plant projects.

The maximum load demand that can be realistically supplied will have, therefore, to follow the development of the generation planning schedule and it will be limited by the associated financial and time constraints. The generation expansion assumed for this study, for an average of over 2GW per year in the period 2020-2035, is considered rather optimistic and it is the Consultant's opinion that any assumption for a higher development rate would be unrealistic.

Table 7-1: Installed and available generation for 2020, 2025, 2030 and 2035

	2020	2025	2030	2035
Installed generation (GW)	14.4	28.2	39.0	45.6
Proposed candidates (GW)	0.7	7.9	16.1	20.9
Less PV (not available during peak load), in GW	-1.08	-1.31	-2.11	-2.11
Less a % of proposed candidates (in % and GW)	0%	25%	20%	20%
	0.0	-2.0	-3.2	-4.2
Les a min % on planned and unplanned outages (in % and GW)	20%	30%	26%	25%
	-2.7	-7.5	-8.8	-9.8
Available generation (max/rated) in GW	10.7	17.4	24.9	29.5
Available generation (running) during peak demand (GW)	**10.2**	**16.6**	**23.7**	**28.3**
Available generation (max), as % of the total (installed+planned+proposed).	74%	62%	64%	65%

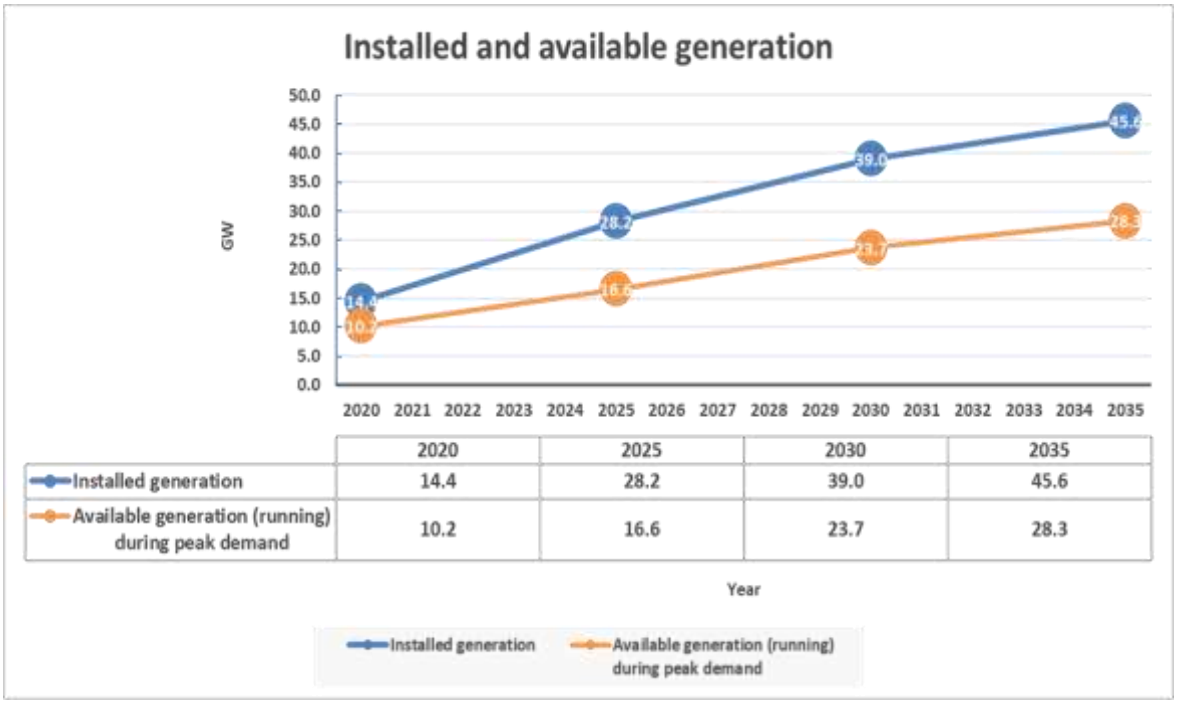


Figure 7-1 Installed and available generation for 2020, 2025, 2030 and 2035

7.1.3 Load demand

In the 2020 network configuration the assumed total demand is 9873 MW, to closely match the validated DisCos load demand, as presented by the 11 DisCos in the workshop of January 2017 in Abuja.

The load in each of the DisCo areas in Nigeria is shown in **Figure 7-2** and summarized in **Table 7-2**.

The total demand includes the export requirements to neighboring countries as follows:

To Benin (Sakete, 330 kV): 260 MW
To Niger (Niamey, 132 kV): 87 MW
To Niger (Gazoua, 132 kV): 40 MW

The export requirements modeled for 2020, 2025, 2030 and 2035 have been based on information provided by TCN and on the results of the earlier WAPP studies and reports.

In the 2020 load model representation in PSS/E a pessimistic power factor of around 0.85 has been assumed, despite the new Grid Code requirements calling for pf of 0.95, as it is believed that most users at distribution level are not in full compliance yet with this requirement. It is noted that the Grid Code requirements (ref. article 15.6 on *Demand power factor corrections and 16.7 on provision of voltage control*) states that *The Off-takers shall maintain a Power Factor not less than 0.95 at the Connection Point*.

Therefore, the loads in the 2020 models are based on pf of 0.85, in the 2025 model are based on a still conservative pf of 0.9 and only the 2030 loads have pf of 0.95.

Table 7-2: Load demand per DisCo

DISCO	Load (MW)
1-Ikeja	1250
2-Ibadan	1225
3-Abuja	745
4-Benin	1273
5-Kaduna	590
6-Jos	442
7-Enugu	1090
8-Port Harcourt	946
9-Eko	1320
10-Kano	705
11-Yola	309
Total for Nigeria	**9895**
Export	387
Total load	**10282**

The modeled loads of individual substations within each DisCo are detailed in the **Annex 7.9.**

As shown in **Figure 7-2** of the 2020 network configuration, the total generation required to meet the load in Nigeria is 10773 MW and the total losses are 494 MW.

The existing, ongoing and planned power plants to be in operation by 2020 and the corresponding Pmax (maximum generating capacity/rating) of each unit, as modeled in PSS/E, are summarized in **Table 7-3**.

7.1.4 Generation capacity

The ratings of the conventional generating units in Nigeria for year 2020 are shown in **Table 7-3**.

Table 7-3: Ratings of power generating units (Pmax)

Name of Station	Company	Primary energy resource	Commercial Operation Date	No of units	Gross Unit capacity (MW)	Gross Plant capacity (MW)	Total 2020
Existing generation capacity							
AFAM IV - GT13-18	AFAM POWER PLC.	GAS	1982	6	75	450	150
AFAM V - GT19-20	AFAM POWER PLC.	GAS	2002	2	138	276	276
AFAM VI - GT11-13	SHELL ROT	GAS	2009	3	166	498	450
AFAM VI - ST1	SHELL ROT	STEAM	2010	1	230	230	200
ALAOJI - NIPP	NIPP	GAS	2013	4	120	480	480
CALABAR / ODUKPANI NIPP	NIPP	GAS	2015	5	113	565	338
DELTA II - GT3-8	TRANSCORP POWER LTD	GAS	2002	6	24	143	123
DELTA III - GT9-14	TRANSCORP POWER LTD	GAS	2005	6	24	143	128
DELTA IV - GT15-20	TRANSCORP POWER LTD	GAS	1990	6	99	594	630
EBUTE BARGE (CYREX) AES	AES / CYREX ENERGY LTD	GAS	2002	9	31	279	0
EGBIN	EGBIN POWER PLC	STEAM	1985	6	220	1320	1,320

Name of Station	Company	Primary energy resource	Commercial Operation Date	No of units	Gross Unit capacity (MW)	Gross Plant capacity (MW)	Total 2020
GBARAIN - GT2 NIPP	NIPP	GAS	2016	1	113	113	113
GEREGU FGN 1	GEREGU GENERATION COMPANY LTD	GAS	2007	3	138	414	414
GEREGU NIPP 1	NIPP	GAS	2013	3	148	444	220
IBOM 1	IBOM POWER	GAS	2009	1	42	42	0
IBOM 1	IBOM POWER	GAS	2010	1	114	114	114
IBOM 1	IBOM POWER	GAS	2016	1	40	40	0
IHOVBOR (EYAEN) NIPP	NIPP	GAS	2013	4	113	452	339
JEBBA	POWER HOLDING CO OF NIGERIA	HYDRO	1983	6	101.15	606.9	607
KAINJI - G11-12	POWER HOLDING CO OF NIGERIA	HYDRO	1976	2	100	200	200
KAINJI - G5-6	POWER HOLDING CO OF NIGERIA	HYDRO	1968	2	120	240	240
KAINJI - G7-10	POWER HOLDING CO OF NIGERIA	HYDRO	1978	4	80	320	160
OKPAI IPP	NIGERIAN AGIP OIL CO	GAS	2005	2	165	330	300
OKPAI IPP	NIGERIAN AGIP OIL CO	STEAM	2005	1	140	140	140
OLORUNSOGO I	PACIFIC ENERGY	GAS	2007	8	42	335	335
OLORUNSOGO II NIPP	NIPP	GAS	2011	4	120	480	240
OLORUNSOGO II NIPP	NIPP	STEAM	2012	2	120	240	120
OMOKU IPP	FIRST INDEPENDENT POWER	GAS	2006	6	25	150	150
OMOTOSHO I	OMOTOSHO ELECTRIC ENERGY COMPANY	GAS	2007	8	42	335	304
OMOTOSHO II NIPP	NIPP	GAS	2012	4	120	480	240
PARAS ENERGY	PARAS ENERGY & NATURALS RES. DEV. LTD	GAS	2016	9	9	79	170
RIVERS IPP	FIRST INDEPENDENT POWER	GAS	2012	1	191	191	191
SAPELE	SAPELE POWER PLC	STEAM	1978	6	88	528	400
SAPELE OGORODE 1 NIPP	NIPP	GAS	2011	4	113	454	454
SHIRORO	SHIRORO HYDRO ELECTRIC	HYDRO	1990	4	150	600	600
TRANS-AMADI IPP	FIRST INDEPENDENT POWER	GAS	2010	4	25	100	100
						Subtotal 1-Existing generation capacity	10098
Additional generation capacity until 2020							
AFAM III		GAS	2018	8	30	240	240
AFRINERGIA SOLAR	AFRINIGER SOLAR	PV	2020			50	50
ANJEED KAFACHAN SOLAR IPP	ANJEED KAFACHAN SOLAR IPP	PV	2020			100	100
AZURA		GAS	2018	3	150	450	450
CT COSMOS	CT COSMOS	PV	2020			70	70
EGBEMA I - NIPP	NIPP	GAS	2018	1	113	113	113
EGBEMA I - NIPP	NIPP	GAS	2019	1	113	113	113
EGBEMA I - NIPP	NIPP	GAS	2019	1	113	113	113
EN Consulting & Projects - Kaduna		PV	2020			100	50
GBARAIN / UBIE I	NIPP	GAS	2017	1	113	113	113
GURARA	SALINI NIGERIA LTD	HYDRO	2017	2	15	30	30
IBOM II		GAS	2020	4	138	552	276
KADUNA IPP	KADUNA IPP	GAS	2019	1	215	215	215
KASHIMBILLA		HYDRO	2019		40	40	40

Name of Station	Company	Primary energy resource	Commercial Operation Date	No of units	Gross Unit capacity (MW)	Gross Plant capacity (MW)	Total 2020
KVK POWER NIGERIA LTD	KVK POWER NIGERIA LTD	PV	2020			55	55
LR AARON SOLAR POWER PLANT	LR AARON SOLAR	PV	2019			100	100
MABON - DADIN KOWA	MABIN LTD.	HYDRO	2018	1	39	39	39
MIDDLE BAND SOLAR	MIDDLE BAND SOLAR	PV	2020			100	100
MOTIR DUSABLE	MOTIR DUSABLE LTD	PV	2020			100	100
NIGERIA SOLAR CAPITAL PARTNERS	NIGERIA SOLAR CAPITAL PARTNERS	PV	2020			100	100
NOVA SCOTIA POWER	Nova Scotia Power Development Ltd	PV	2018			80	80
NOVA SOLAR	NOVA SOLAR POWER LTD	PV	2018			100	100
OKPAI IPP II - AGIP (*NNPC POWER BUSINESS PLAN*)	NIGERIAN AGIP OIL CO	GAS	2020	2	150	300	300
OKPAI IPP II - AGIP (*NNPC POWER BUSINESS PLAN*)	NIGERIAN AGIP OIL CO	STEAM	2020	1	150	150	150
OMOKU - NIPP	NIPP	GAS	2018	1	113	113	113
OMOKU - NIPP	NIPP	GAS	2019	1	113	113	113
ORIENTAL		PV	2020			50	50
PAN AFRICA SOLAR	PAN AFRICA SOLAR LTD	PV	2019			75	75
QUAINT ENERGY SOLUTIONS	QUAINT ENERGY SOLUTIONS	PV	2019			50	50
ZUNGERU		HYDRO	2019	4	700	700	700
Subtotal 2-Additional generation capacity until 2020							**4,198**
Total by 2020							**14,296**

The PV plants shown in **Table 7-4**, are planned to be installed mainly in the north part of Nigeria and most likely are expected to be in operation by 2020.

Table 7-4: PV plants in operation by 2020

PN Plant	Location	Installed Capacity [MW]
Pan Africa Solar	Kankia	75
Nova Solar	Katsina	100
LR Aaron Power	Abuja/Gwagwalada	100
Nova Scotia	Dutse/Jigawa	80
KVK Power	Sokoto	55
Quaint Power/Energy	Kaduna	50
Anjeed Kafanchan	Kafanchan	100
Nigeria Solar Capital Partners	Gombe/Bauchi	100
Motir Dusable	Oji	100
Afrinergia Solar	Karu-Keffi	50
CT Cosmos	Jos/Makeri/Pankshin	70
Oriental	Dutse	50
EN Consulting-Kaduna	Kaduna-Zaria	50
Middle Band Solar	Lokoja	100

7.1.5 330 kV transmission system

Figure 7-2 below shows the 330 kV transmission system in 2020, under the assumption that all the ongoing and committed TCN, NIPP and certain JICA new projects will be completed by 2020.

The diagram shows the running generation and load in each DisCo area and the power flows between DisCos.

Dotted lines denote possible future projects beyond 2020.

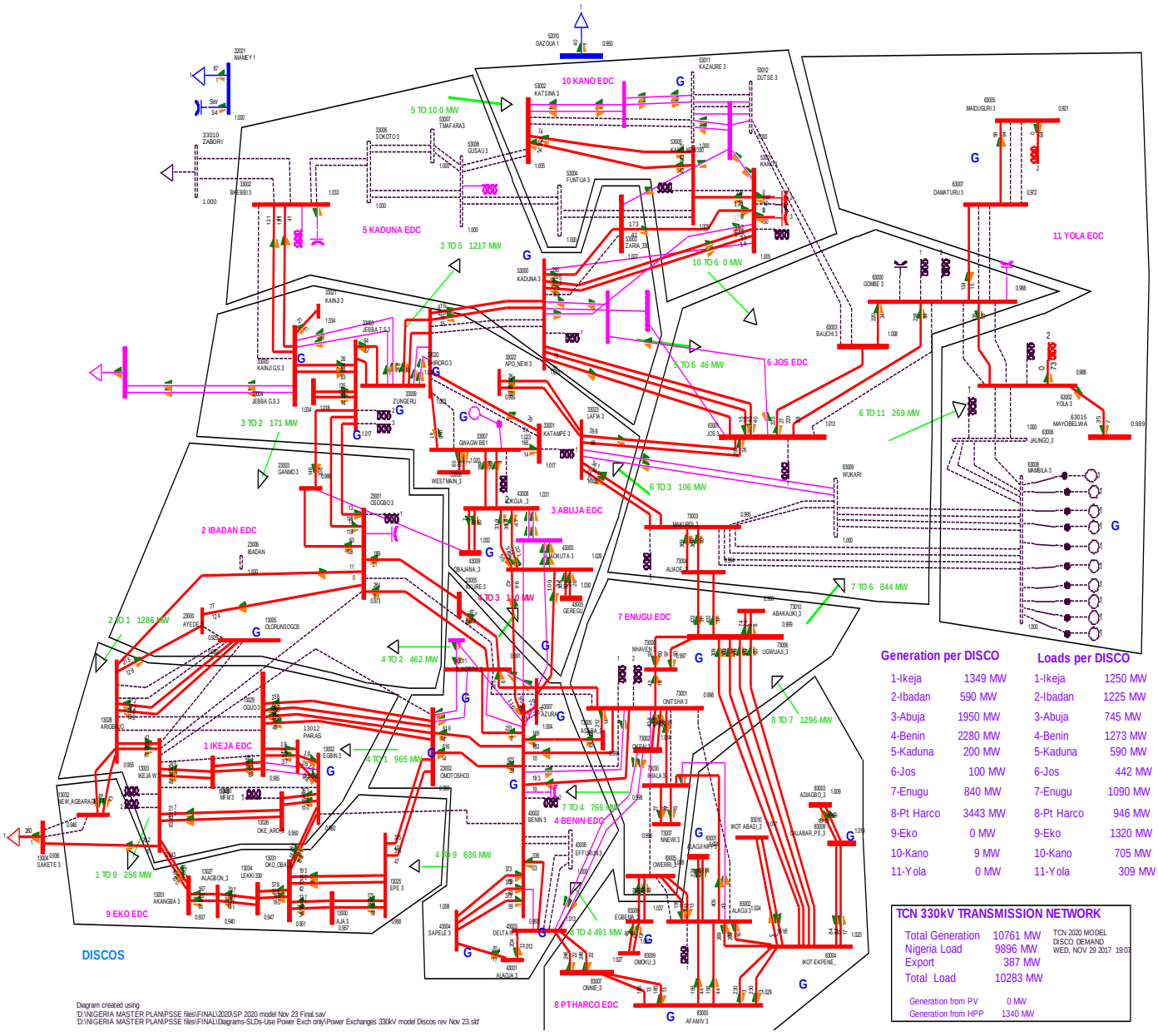


Figure 7-2 330 kV transmission system 2020

7.1.6 Study cases 2020

Four scenarios have been studied for 2020, to capture the extreme combinations of generation and load:

Table 7-5: 2020 study cases

Case		Description	Generation	Load [MW]	
Dry Season Peak	DP	Dry Night Peak Load	Dry-Reduced HPP generation No PV generation Increased requirement from GTs	Peak load (night)	9890 + export
Wet Season Peak	WP	Wet Night Peak Load	Wet-Normal HPP generation No PV generation Increased requirement from GTs	Peak load (night)	9890 + export
Dry Season Off-Peak	DOP	Dry Day Off-Peak Load	Dry-Reduced HPP generation PV generation Increased requirement from GTs	Off-Peak load (day)	8300 + export
Wet Season Off-Peak	WOP	Wet Day Off-Peak Load	Wet-Normal HPP generation PV generation Increased requirement from GTs	Off-Peak load (day)	8300 + export

The results of each of the above cases studied are shown diagrammatically in the SLDs of **Annex 7.4**.

7.1.7 Grid Code static security criteria

7.1.7.1 Voltage criteria

The Grid Code of 2014, v2, states that the System Operator shall endeavour to control the different busbar voltages to be within the Voltage Control ranges specified in **Table 7-6:**

Table 7-6: Voltage criteria

Voltage level	Normal operation		Contingency operation	
	Min Volt [kV] (pu)	Max Volt [kV] (pu)	Min Volt (pu)	Max Vol (pu)
330 kV	280.5 (0.85)	346.5 (1.05)	0.80	1.10
132 kV	112.2 (0.85)	145.2 (1.10)	0.80	1.15
66 kV	62.04 (0.94)	69.96 (1.06)	0.89	1.11
33 kV	31.02 (0.94)	34.98 (1.06)	0.89	1.11
11 kV	10.45 (0.95)	11.55 (1.05)	0.90	1.10

Under System Stress or following system faults, voltages can be expected to deviate outside the above limits by a further +/-5% (excluding transient and sub-transient disturbances).

7.1.7.2 Thermal criteria

The maximum allowed thermal overloading for all branches at 330 kV and 132 kV level is 100% of the nominal rating (Rate A) under normal (N) system conditions and 110% of the nominal rating under contingency (N-1) system conditions.

7.2 2020 base case load flow results

The load flow results are shown in **Annex 7.3** and **Annex 7.4.**

In the base case (N-0) load flow calculations the following observations are made:

7.2.1 Power flows between DisCos and regions

The diagram of **Figure 7-2** and the SLD in **Annex 7-1** show by the green arrows the power flows between the 11 DisCos areas in Nigeria for a general peak load and generation case. The *DisCos* are:

1-Ikeja	5-Kaduna	9-Eko
2-Ibadan	6-Jos	10-Kano
3-Abuja	7-Enugu	11-Yola
4-Benin	8-Port Harcourt	

The Nigeria planning *Regions* are:

1-Lagos	5-Kaduna
2-Osogbo	6-Bauchi
3-Shiroro	7-Enugu
4-Benin	8-Port Harcourt

In addition to the above regions, a new region (Abuja) has recently been created by TCN.

The generation (installed and running) and the load in each DisCo are summarized in **Table 7-7**. The running generation is approximately 74% of the total installed capacity.

Table 7-7: Running generation and load in different areas (DisCos)

Region	Running Generation [MW]	Load [MW]	Generation deficit/surplus [MW]	Remarks
1-Ikeja	1349	1250	**99**	*Generation surplus*
2-Ibadan	590	1225	**-635**	Generation deficit
3-Abuja	1950	745	**1205**	*Generation surplus*
4-Benin	2280	1273	**1007**	*Generation surplus*
5-Kaduna	200	590	**-390**	Generation deficit
6-Jos	100	442	**-342**	Generation deficit
7-Enugu	840	1090	**-250**	Generation deficit

Region	Running Generation [MW]	Load [MW]	Generation deficit/surplus [MW]	Remarks
8-Port Harcourt	3443	946	**2497**	*Generation surplus*
9-Eko	0	1320	**-1320**	Generation deficit
10-Kano	9	705	**-696**	Generation deficit
11-Yola	0	309	**-309**	Generation deficit
Total for Nigeria		**9895**		
Export		387		
Totals	**10761**	**10282**	**479(losses)**	

This is shown graphically in **Figure 7-3**

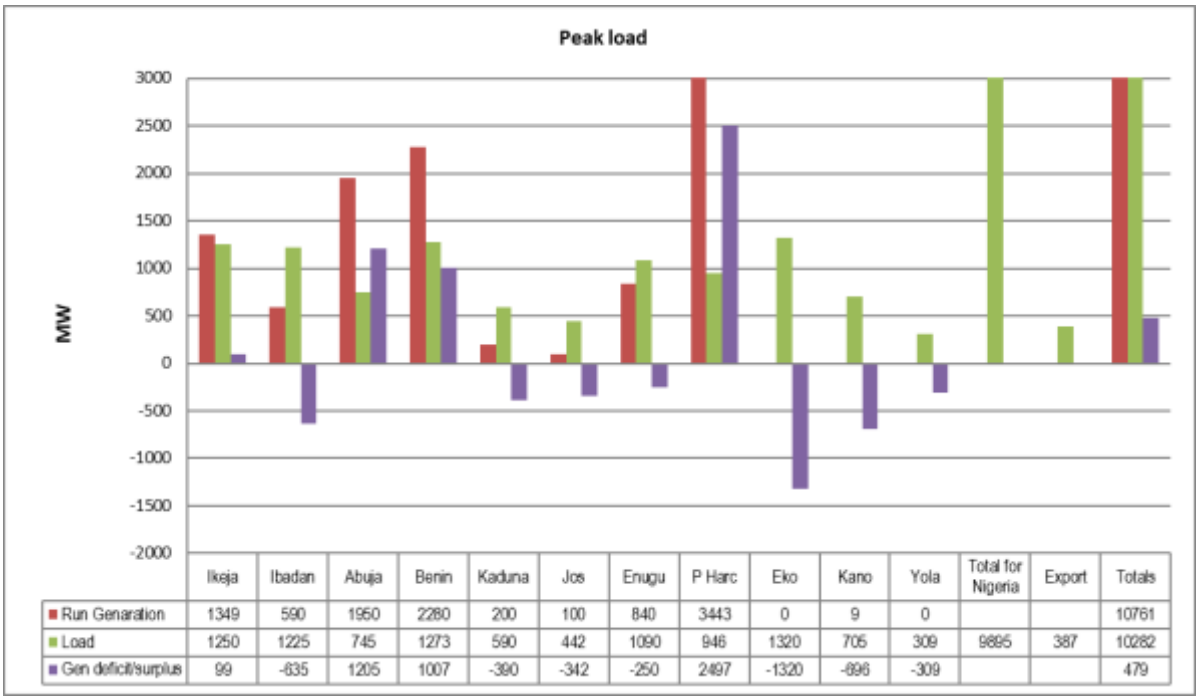


Figure 7-3 Generation and Load per DisCo

The general voltage profile is shown in **Figure 7-4**, with blue and red indicating relatively low voltages and high voltages respectively. Lagos, Osogbo and Kaduna are clearly areas with low voltages encountered due to high demand, insufficient local generation, voltage drop in radial feeders and overloaded 132 kV lines and 132/33 kV transformers, even in some areas with high generation.

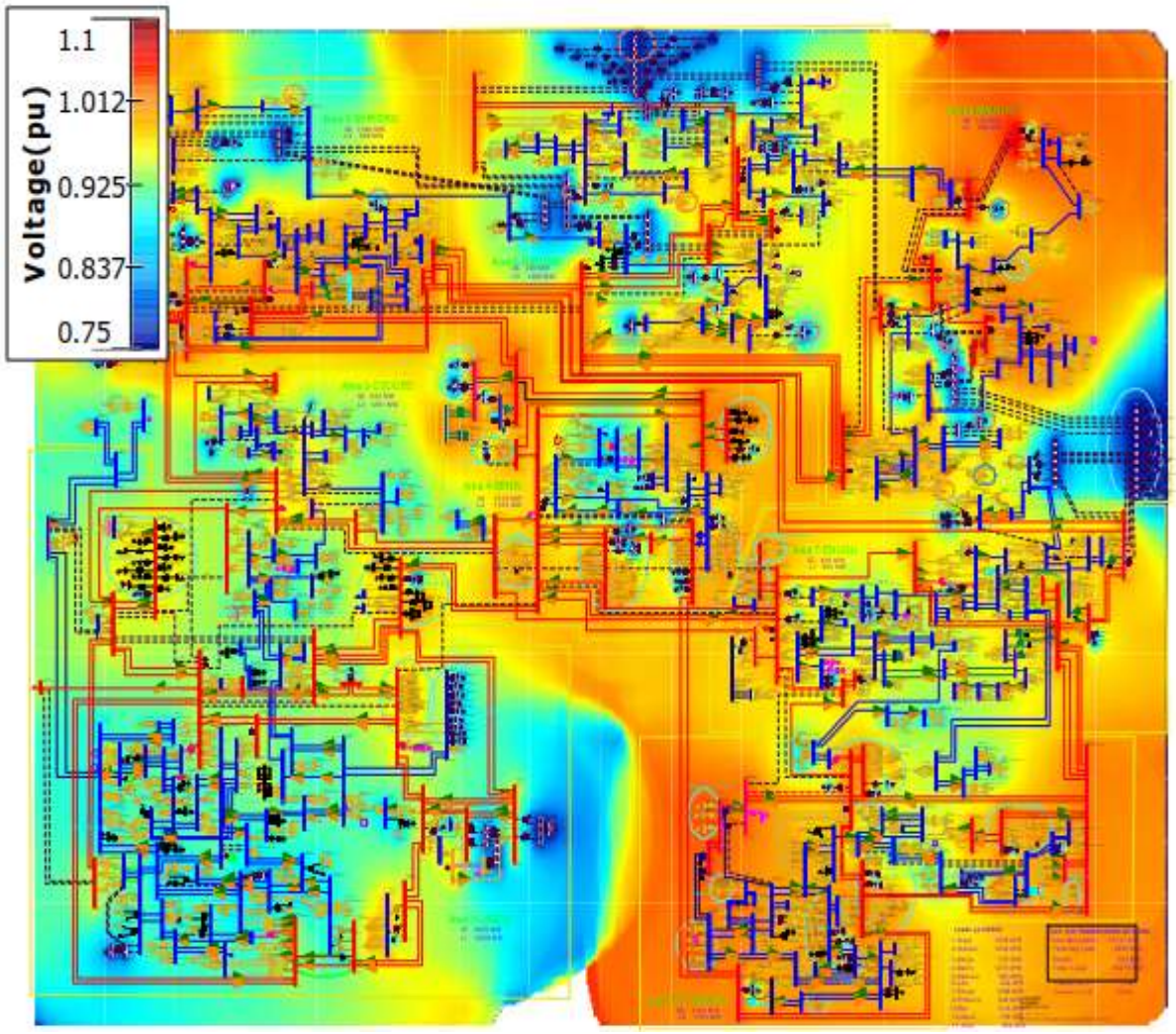


Figure 7-4 Voltage profile of 330, 132 and 33 kV system

It can be seen that:

- The generation is mainly concentrated in South (thermal stations in Port Harcourt, Enugu, Benin and Lagos) and Central West (hydro stations of Jebba, Kainji and Shiroro in Shiroro region). Central, North and North East in particular are characterized by the total absence of generating stations.
- The load demand is mainly in South and South West.
- The **Table 7-7** shows that with the exception of Benin, Abuja and Port Harcourt areas, where there is significant surplus of generation, in all other regions in Nigeria the demand exceeds the available generation.
- To supply the load in the areas with little or no generation such as North East, long 330 kV transmission lines are built (radial system). As a result, voltage regulation problems are encountered and the excessive reactive power flowing through these lines necessitates large reactive power compensation equipment (reactors) at the corresponding substations (Kano, Gombe, Maiduguri).

- Any addition of more 330 kV lines running in parallel, as planned, may require additional compensation equipment, as at Yola and Jalingo and possibly elsewhere to limit the over-voltages due to line charging currents.
- The general profile of power flows in the TCN system is shown graphically in **Figure 7-5**

Each of the 4 study cases is analyzed in details in the following sections.

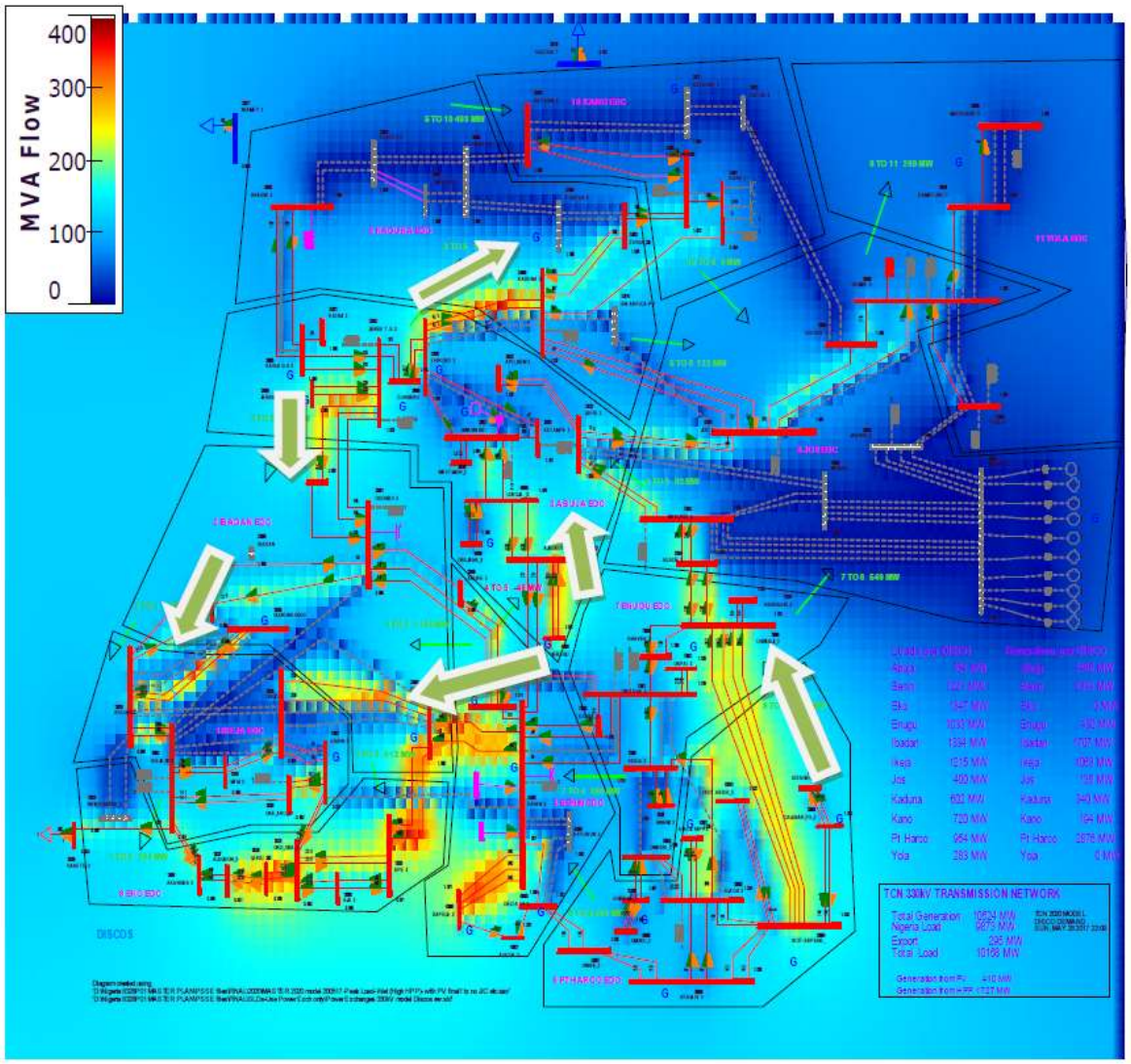
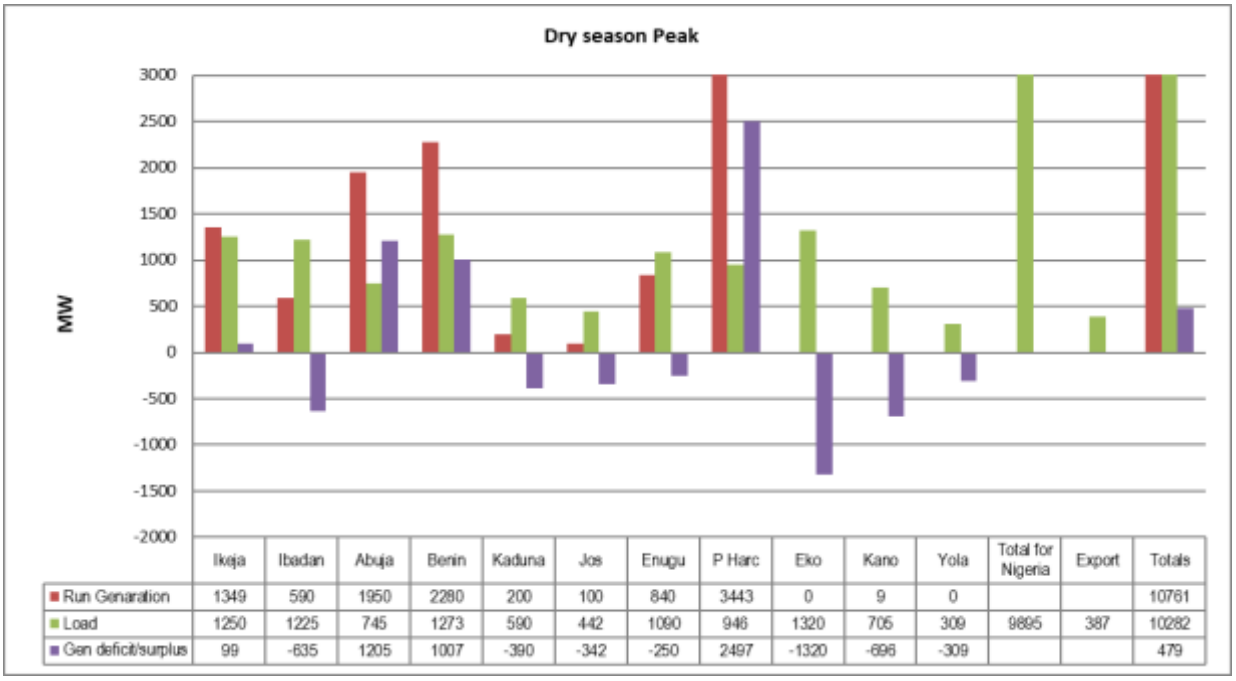


Figure 7-5 Power flows in the TCN system

7.2.2 Dry Season Peak case

Assuming:
(a) Generation from PVs = 0 and
(b) Reduced generation from HPP plants of 1340 MW,

The running generation and load for each DisCo is shown in **Figure 7-6**.



	Ikeja	Ibadan	Abuja	Benin	Kaduna	Jos	Enugu	P Harc	Eko	Kano	Yola	Total for Nigeria	Export	Totals
Run Generation	1349	590	1950	2280	200	100	840	3443	0	9	0			10761
Load	1250	1225	745	1273	590	442	1090	946	1320	705	309	9895	387	10282
Gen deficit/surplus	99	-635	1205	1007	-390	-342	-250	2497	-1320	-696	-309			479

Bus Name	PGen (MW)		Bus Name	PGen (MW)		Bus Name	PGen (MW)
AARON PV 15.000	0		GER NIPPGT2310.500	110		OLORUNSO GT610.500	35
AFAM VI GT1111.500	150		GEREGU GT11 10.500	130		OLORUNSO GT710.500	35
AFAM VI GT1211.500	150		GEREGU GT12 10.500	130		OLORUNSO GT810.500	35
AFAM VI GT1311.500	150		GEREGU GT13 10.500	130		OMOKU1 GT1 15.000	50
AFAM VI ST1011.500	200		IBOM GT1 11.500	32		OMOKU1 GT2 15.000	50
AFAM2 GT5-6 11.500	48		IBOM GT2 11.500	32		OMOKU2 GT1 15.000	113
AFAM2GT 7-8 11.500	48		IBOM GT3 11.500	32		OMOKU2 GT2 15.000	113
AFAM3 GT9-1011.500	50		IBOM II 11.500	260		OMOTNIPP GT110.500	115
AFAM3GT11-1211.500	50		IHOVBOR_GTB115.000	110		OMOTNIPP GT210.500	115
AFAM4GT13-1411.500	130		IHOVBOR_GTB215.000	110		OMOTNIPP GT310.500	0
AFAMV GT 19 11.500	125		IHOVBOR_GTB315.000	110		OMOTNIPP GT410.500	0
AFAMV GT 20 11.500	125		IHOVBOR_GTB415.000	0		OMOTOSO GT1 10.500	70
ALAOJI_GTB1 15.000	112.5		JBS WIND 15.000	70		OMOTOSO GT3 10.500	70
ALAOJI_GTB2 15.000	112.5		JEBBA 2G1 16.000	90		OMOTOSO GT7 10.500	62
ALAOJI_GTB3 15.000	112.5		JEBBA 2G2 16.000	90		PAN AFRIC PV15.000	0
ALAOJI_GTB4 15.000	112.5		JEBBA 2G6 16.000	90		PARASGT1-9 11.000	63
ANJEED PV 15.000	0		KAINJ 1G11 16.000	90		QUAINT PV 15.000	0
AZURA GT 15.000	140		KAINJ 1G12 16.000	90		RIVERS _GT1 10.500	170
BRESSON GTS 11.000	0		KAINJ 1G7-8 16.000	160		SAP_NIPP_GT115.800	112
CALABAR_GTB115.000	100		KASHIMB HPP 15.000	0		SAP_NIPP_GT215.800	112
CALABAR_GTB215.000	100		KT WF 33 33.000	9		SAP_NIPP_GT315.800	112
CALABAR_GTB315.000	100		KVKPOWER PV 15.000	0		SAP_NIPP_GT415.800	112
CALABAR_GTB415.000	0		LAFARAGE 1 11.000	0		SAPELE ST1 15.800	80
DELT3 GT9-1111.500	45		NOVA SCOT PV132.00	0		SAPELE ST2 15.800	80

Bus Name	PGen (MW)		Bus Name	PGen (MW)		Bus Name	PGen (MW)
DELT3GT12-1411.500	30		NOVA SOLA PV15.000	0		SAPELE ST3 15.800	80
DELTA GT 15 11.500	95		OKPAI GT11 11.500	150		SAPELE ST4 15.800	80
DELTA GT16 11.500	95		OKPAI GT12 11.500	150		SAPELE ST5 15.800	80
DELTA GT17 11.500	95		OKPAI ST18 11.500	140		SAPELE ST6 15.800	80
DELTA2 GT3-511.500	45		OKPAI_IPPII 11.500	400		SHIROR 411G116.000	140
DELTA2 GT6-811.500	45		OLOR NIPPST110.500	115		SHIROR 411G216.000	140
DKOWA G1 11.000	30		OLOR NIPPST210.500	0		ZUNGE_G1 16.000	150
EGBEMA_GTB1 15.000	100		OLORNIPPGT1110.500	0		ZUNGE_G2 16.000	150
EGBEMA_GTB2 15.000	100		OLORNIPPGT1210.500	0		ZUNGE_G4 16.000	150
EGBEMA_GTB3 15.000	100		OLORNIPPGT2110.500	115		EGBIN ST 1 16.000	242
GBARAIN_GTB115.000	112.5		OLORNIPPGT2210.500	115		EGBIN ST 2 16.000	242
GBARAIN_GTB215.000	112.5		OLORUNSO GT110.500	35		EGBIN ST 3 16.000	242
GEN_AMADI 15.000	90		OLORUNSO GT210.500	35		EGBIN ST 4 16.000	242
GEN_KADUNA 15.000	200		OLORUNSO GT310.500	35		EGBIN ST 5 16.000	242
GER NIPPGT2110.500	110		OLORUNSO GT510.500	35		EGBIN ST 6 16.000	242

Figure 7-6 Dry Season Peak generation and load per DisCo

The power flows are shown in **Figure 7-7**

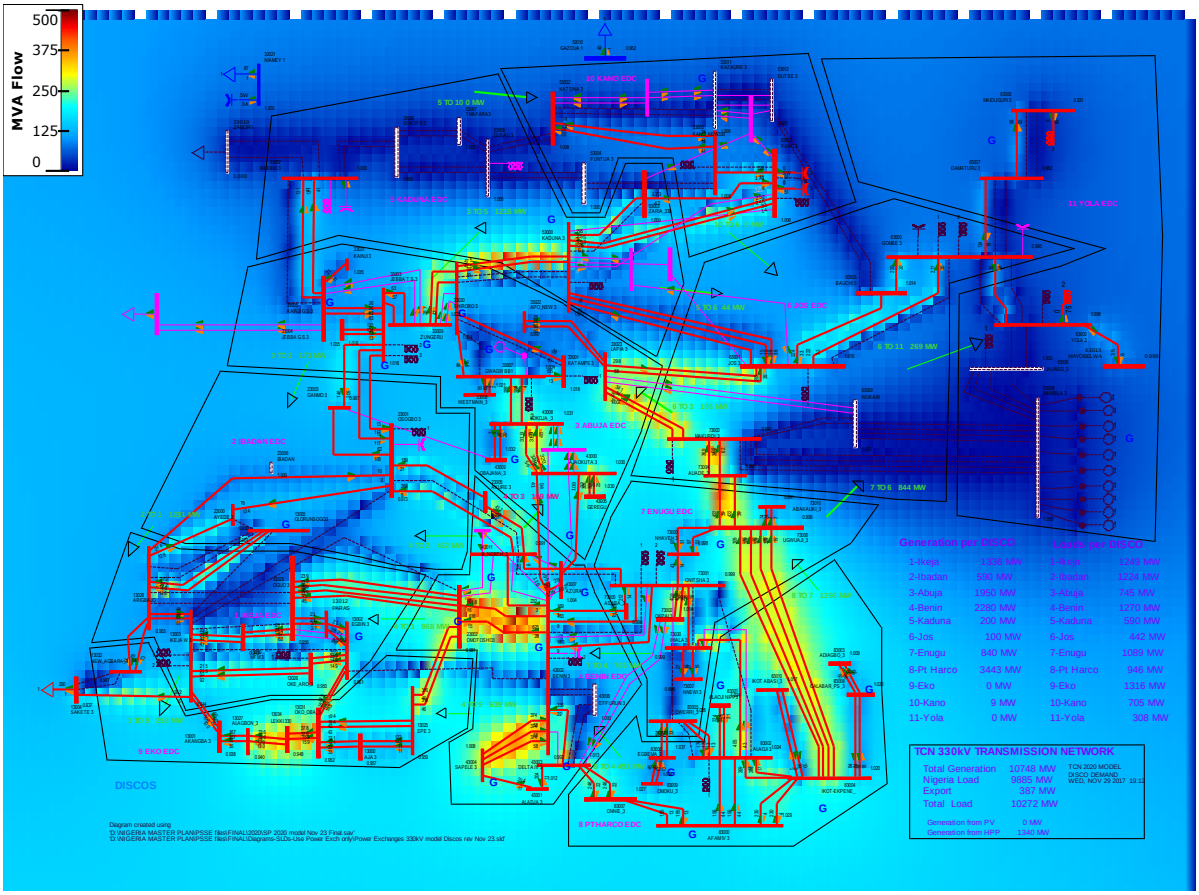


Figure 7-7 2020 Dry Season Peak power flows in 330 kV system

7.2.2.1 Voltage violations

No voltages are encountered outside the 0.85-1.05 pu range in the 330 kV, 132 kV and 33 kV system.

7.2.2.2 Overloads of lines and transformers

The base case (N-0) overloaded 132 kV lines as well as the 330/132 kV and 132/33 kV transformers are listed in **Table 7-8**, **Table 7-9** and **Table 7-10.**

Table 7-8: 2020 Dry Season Peak - Overloaded Lines (base case)

From Bus no	Bus name	To Bus no	Bus name	CKT	Contingency label	Rating	Flow [MVA]	Loading [%]
12017	ALAGBON 1 132.00	12024	IIJORA 1 132.00	1	BASE CASE	125.7	180	143
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	1	BASE CASE	125.7	133	106
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	2	BASE CASE	125.7	133	106
82024	IBOM IPP 1 132.00	82031	IKOT_ABASI 132.00	1	BASE CASE	125.7	161	128

Table 7-9: 2020 Dry Season Peak - Overloaded 330/132 kV transformers (base case)

Bus#	Name	Base kV	Area	Bus#	Name	Base kV	CKT	Loading [MVA]	Rating [MVA]	Loading [%]
330/132 kV 3-W and A/T										
13000	AJA 3	330	1	3WNDTR	AJA T2A	WND 1	3	153.3	150	102.2
23003	GANMO 3	330	2	3WNDTR	GANMO TR2A	WND 1	1	171.7	150	114.4
33002	BKEBBI 3	330	3	3WNDTR	B_KEBBI T1	WND 1	1	185.5	150	123.7
43002	BENIN 3	330	4	3WNDTR	BENIN TR1	WND 1	1	218.4	150	145.6
43002	BENIN 3	330	4	3WNDTR	BENIN TR2	WND 1	1	218.4	150	145.6
43002	BENIN 3	330	4	3WNDTR	BENIN TR3	WND 1	1	218.4	150	145.6
43011	B.NORTH_3	330	4	3WNDTR	BENIN 9T1	WND 2	1	129.7	67.5	192.1
12000	AJA 132	132	1	3WNDTR	AJA T4	WND 1	1	55.3	45	122.8
12001	AKANGBA 1	132	1	3WNDTR	AKANGBA5T4A	WND 2	1	127	112.5	112.9
12001	AKANGBA 1	132	1	3WNDTR	AKANGBA5T4B	WND 2	1	127	112.5	112.9
12005	IKJW T1BT2B	132	1	3WNDTR	IKW T2B	WND 2	3	126.8	120	105.6
22000	AYEDE 1	132	2	3WNDTR	AYEDE TR1	WND 2	1	120.3	112.5	106.9
22000	AYEDE 1	132	2	3WNDTR	AYEDE TR2	WND 2	1	120.7	112.5	107.2
22000	AYEDE 1	132	2	3WNDTR	AYEDE TR3	WND 2	1	120.7	112.5	107.2

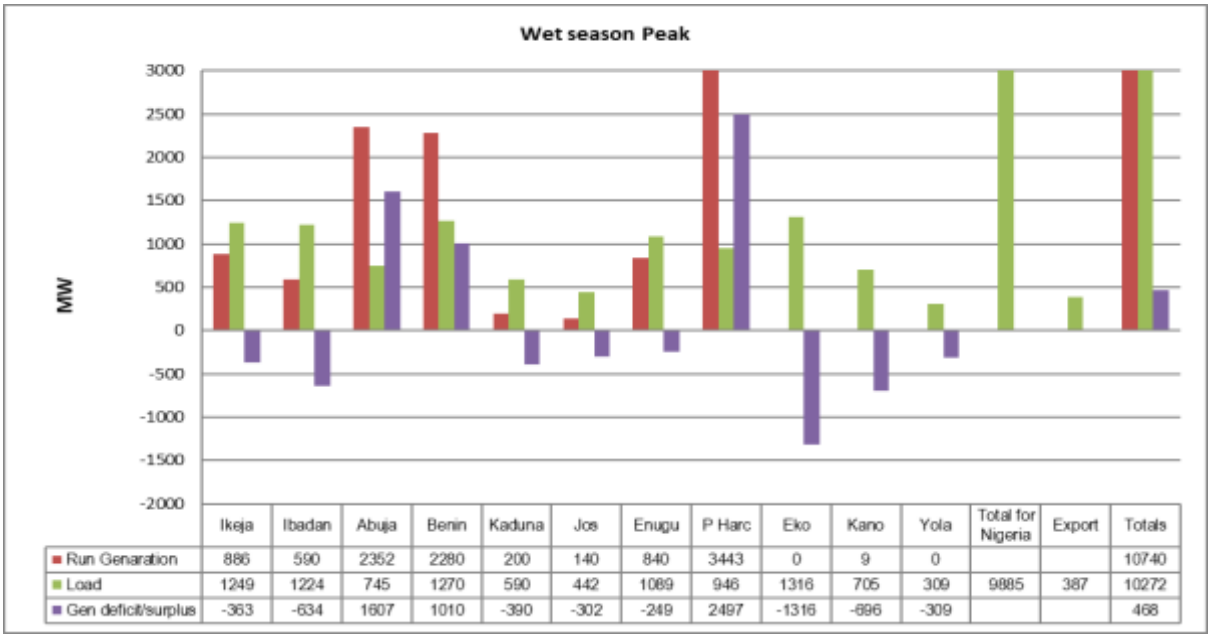
Table 7-10: 2020 Dry Season Peak - Overloaded 2-winding transformers (base case)

Bus#	Name	Base kV	Area	Bus#	Name	Base kV	CKT	Loading [MVA]	Rating [MVA]	Loading [%]
132/33 and 132/11 kV 2-W transformers										
82000	AFAM 1-2-3	132	8	86000	AFAM 11	11	1	66.3	64	103.7
82005	EKET 1	132	8	85002	EKET T1B	33	1	53	45	117.7
62001	JOS 1	132	6	65005	JOS T4 60MVA	33	2	71.8	60	119.7
52016	FUNTUA 1	132	5	56005	FUNTUA T2	11	2	8	7.5	106.1
52016	FUNTUA 1	132	5	56000	FUNTUA 11	11	1	9.6	7.5	127.7
52001	KANO 1	132	5	55058	KUMB T3 MOB	33	3	41.9	30	139.8
52016	FUNTUA 1	132	5	55003	FUNTUA 33	33	1	31.7	30	105.8
42004	BENIN 1	132	4	45031	BENIN T24 33	33	1	115.8	60	193
42004	BENIN 1	132	4	45030	BENIN T23 33	33	1	112.9	60	188.2
42004	BENIN 1	132	4	45029	BENIN T22 33	33	1	120.1	60	200.2
42005	B_N0RTH 1	132	4	45015	B_NORTH_33	33	1	102.3	60	170.4
42002	UGHELLI 1	132	4	45001	UGHELLI 33	33	1	73.1	60	121.9
42004	BENIN 1	132	4	45000	BENIN 33	33	1	60.1	60	100.1
42004	BENIN 1	132	4	45000	BENIN 33	33	9	60.1	60	100.1
32017	SULEJA 1	132	3	36016	SULEJA 11	11	1	15.8	7.5	211.2
22022	GANM0 T1 BB	132	2	25032	GANMO T1	33	1	63.6	60	106.1
22005	AKURE 1	132	2	25028	AKURE T2A	33	2	33.6	30	111.9
22015	OMUARAN 1	132	2	25016	OMUARAN 33	33	1	36.9	30	122.9
22013	OFFA 1	132	2	25015	OFFA 33	33	1	35.3	30	117.7
12023	EJIGBO 1	132	1	15128	EJIGBO 33	33	1	31.2	30	104
12023	EJIGBO 1	132	1	15128	EJIGBO 33	33	2	31.2	30	104
12044	AJA 132 BBII	132	1	15112	AJA 2 33	33	2	61.6	60	102.6
12055	ODOGUNYAN 1	132	1	15063	ODOGUNYA 33	33	1	62.3	60	103.8
12055	ODOGUNYAN 1	132	1	15063	ODOGUNYA 33	33	2	62.3	60	103.8
12029	OJO 1	132	1	15047	OJO T3_T4	33	5	69	60	115
12029	OJO 1	132	1	15030	OJO 33	33	1	37.5	30	125.1
12027	ISOLO 1	132	1	15028	ISOLO 33	33	1	60.1	60	100.1
12000	AJA 132	132	1	15003	AJA 33	33	1	84	60	140.1

7.2.3 Wet Season Peak Case

Assuming:
(a) Generation from PVs = 0 and
(b) Normal generation from HPP plants of 2282 MW,

The running generation and load for each DisCo is shown in **Figure 7-8**.



	Ikeja	Ibadan	Abuja	Benin	Kaduna	Jos	Enugu	P Harc	Eko	Kano	Yola	Total for Nigeria	Export	Totals
Run Genaration	886	590	2352	2280	200	140	840	3443	0	9	0			10740
Load	1249	1224	745	1270	590	442	1089	946	1316	705	309	9885	387	10272
Gen deficit/surplus	-363	-634	1607	1010	-390	-302	-249	2497	-1316	-696	-309			468

Figure 7-8 Wet Season Peak generation and load per DisCo

The power flows are shown in **Figure 7-9**

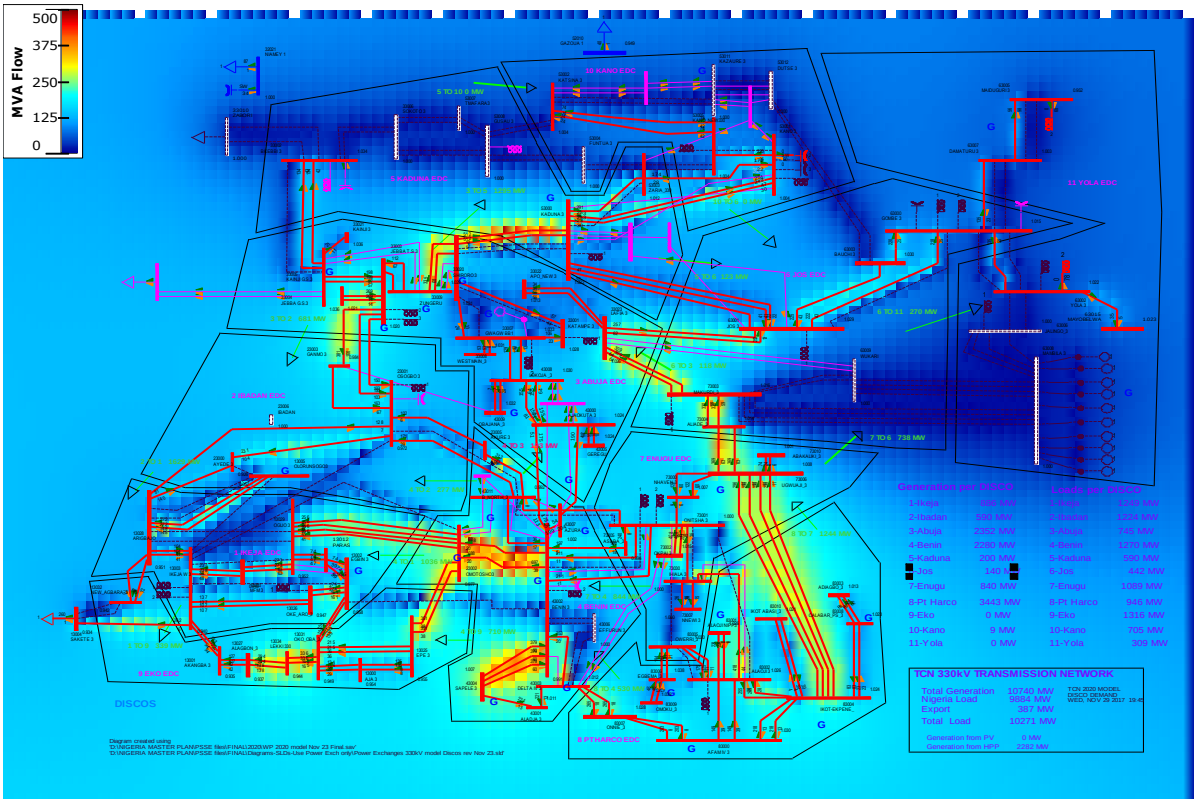


Figure 7-9 2020 Wet Season Peak power flows in 330 kV system

7.2.3.1 Voltage violations

No voltages are outside the 0.85-1.05pu range in the 330, 132 and 33 kV system.

7.2.3.2 Overloads of lines and transformers

The base case (N-0) overloaded 132 kV lines are listed in **Table 7-11.**

Table 7-11: 2020 Wet Season Peak - Overloaded Lines (base case)

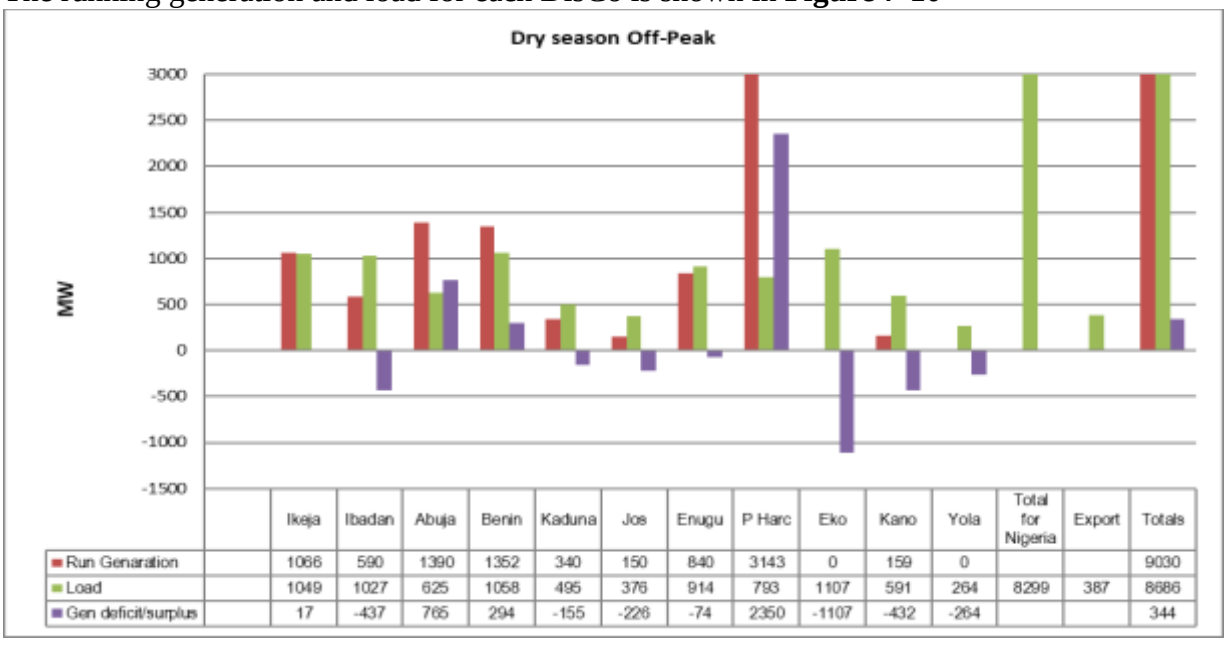
From Bus no	Bus name	To Bus no	Bus name	CKT	Contingency label	Rating	Flow [MVA]	Loading [%]
12017	ALAGBON 1 132.00	12024	IIJORA 1 132.00	1	BASE CASE	125.7	178	142
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	1	BASE CASE	125.7	133	106
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	2	BASE CASE	125.7	133	106
82024	IBOM IPP 1 132.00	82031	IKOT_ABASI 132.00	1	BASE CASE	125.7	162	129

The overloaded lines are the same as in the dry season peak case. The same applies for the overloaded transformers, although the overloads in some cases are less.

7.2.4 Dry Season Off- Peak Case

Assuming:
(a) Generation from PVs = 410MW and
(b) Reduced generation from HPP plants of 1200 MW,

The running generation and load for each DisCo is shown in **Figure 7-10**



	Ikeja	Ibadan	Abuja	Benin	Kaduna	Jos	Enugu	P Harc	Eko	Kano	Yola	Total for Nigeria	Export	Totals
Run Generation	1066	590	1390	1352	340	150	840	3143	0	159	0			9030
Load	1049	1027	625	1058	495	376	914	793	1107	591	264	8299	387	8686
Gen deficit/surplus	17	-437	765	294	-155	-226	-74	2350	-1107	-432	-264			344

Figure 7-10 Dry Season Off-Peak Generation and Load per DisCo

7.2.4.1 Voltage violations

No voltages are outside the 0.85-1.05pu range in the 330, 132 and 33 kV systems.

7.2.4.2 Overloads of lines and transformers

The base case (N-0) overloaded 132 kV lines are listed in **Table 7-12.**

Table 7-12: 2020 Dry Season Off-Peak - Overloaded Lines (base case)

From Bus no	Bus name	To Bus no	Bus name	CKT	Contingency label	Rating	Flow [MVA]	Loading [%]
12017	ALAGBON 1 132.00	12024	IIJORA 1 132.00	1	BASE CASE	125.7	144	115
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	1	BASE CASE	125.7	127.1	101
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	2	BASE CASE	125.7	127.1	101
82024	IBOM IPP 1 132.00	82031	IKOT_ABASI 132.00	1	BASE CASE	125.7	172.7	137

The overloaded lines are the same as in the dry season peak case, although the overloads are less. The overloaded transformers are also less.

7.2.5 Wet Season Off-Peak case

Assuming:
(a) Generation from PVs = 410 MW and
(b) Normal generation from HPP plants of 2282 MW,

The running generation and load for each DisCo is shown in **Figure 7-11**.

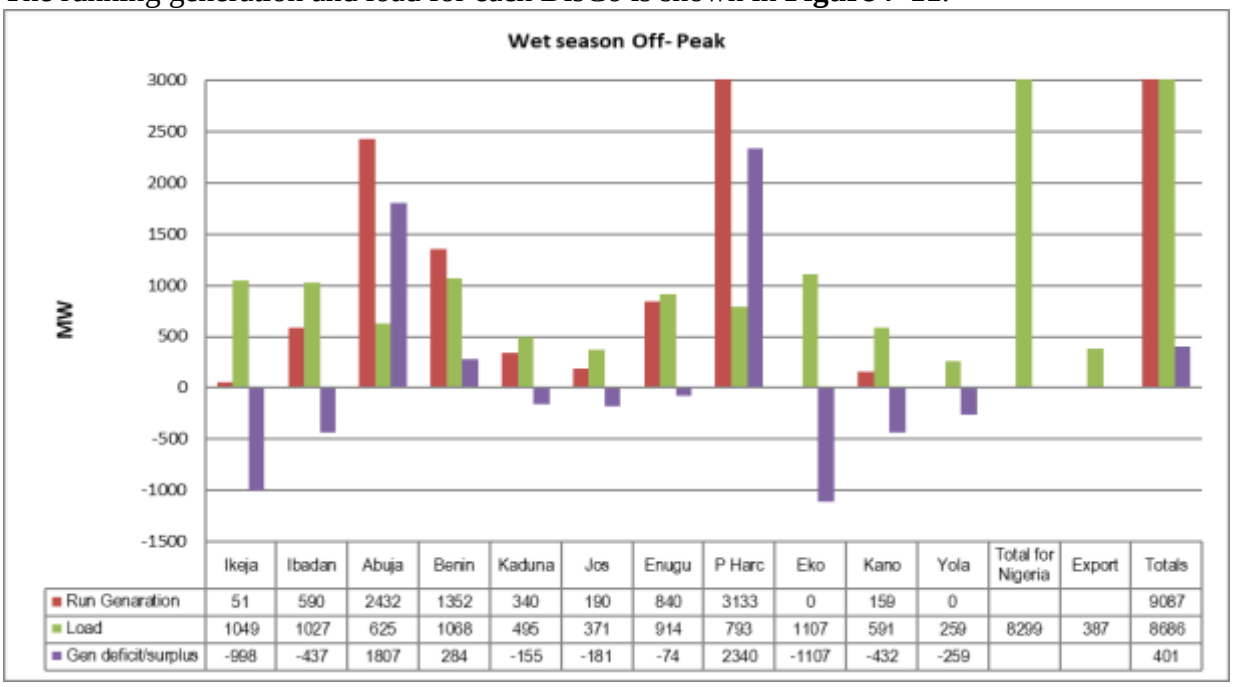


Figure 7-11 Wet Season Off-Peak generation and load per DisCo

7.2.5.1 Voltage violations

No voltages are outside the 0.85-1.05pu range in the 330, 132 and 33 kV system.

7.2.5.2 Overloads of lines and transformers

The base case (N-0) overloaded 132 kV lines are listed in **Table 7-13.**

Table 7-13: 2020 Wet Season Off-peak - Overloaded Lines (base case)

From Bus no	Bus name	To Bus no	Bus name	CKT	Contingency label	Rating	Flow [MVA]	Loading [%]
12017	ALAGBON 1 132.00	12024	IIJORA 1 132.00	1	BASE CASE	125.7	142	113
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	1	BASE CASE	125.7	125.9	100.2
82019	OMOKU 1 132.00	82036	RUMUSOI 1 132.00	2	BASE CASE	125.7	125.9	100.2
82024	IBOM IPP 1 132.00	82031	IKOT_ABASI 132.00	1	BASE CASE	125.7	172	137

The overloaded lines are the same as in the dry season peak case, although the overloads are less. The overloaded transformers are also less.

7.3 2020 Contingency analysis load flow results

An N-1 contingency analysis using ACCC in PSS/E has been carried out for the 330 kV and 132 kV transmission lines, using their RATE B as a short time overload ratings.

The N-1 criterion is not applicable for transformer circuits. The results are summarized in Tables from **Table 7-14** to **Table 7-18.**

The base case overloaded 132 kV lines are shown in bold fonts and the 330 kV lines overloaded under N-1 are shown in red fonts.

Table 7-14: Non-converged cases

Contingency	Description						
SINGLE 53001-53005(2)	OPEN LINE	FROM BUS 53001	KANO 3	330	TO BUS 53005	KANO_NEW330	CKT 2
SINGLE 63000-63002(1)	OPEN LINE	FROM BUS 63000	GOMBE 3	330	TO BUS 63002	YOLA 3	CKT 1
SINGLE 63000-63007(1)	OPEN LINE	FROM BUS 63000	GOMBE 3	330	TO BUS 63007	DAMATURU 3	CKT 1
SINGLE 63005-63007(1)	OPEN LINE	FROM BUS 63005	MAIDUGURI 3	330	TO BUS 63007	DAMATURU 3	CKT 1
SINGLE 32003-32041(3)	OPEN LINE	FROM BUS 32003	BKEBBI 1	132	TO BUS 32041	KVKPOWER PV	CKT 3
SINGLE 32016-32041(3)	OPEN LINE	FROM BUS 32016	SOKOTO 1	132	TO BUS 32041	KVKPOWER PV	CKT 3
SINGLE 52015-52016(1)	OPEN LINE	FROM BUS 52015	ZARIA 1	132	TO BUS 52016	FUNTUA 1	CKT 1

In the above contingency cases of loss of 330 kV lines from Gombe to Yola and Damaturu, and from Damaturu to Maiduguri the load flow case did not converge, as expected, due to absence of a second parallel circuit and insufficient support from alternative routes.

A conversion to a double circuit will resolve these issues.

The overloads reported for the 132 kV circuits, will have to be resolved by either reinforcing these lines or providing new alternative routes for the power flow.

In all N-1 contingencies a number of 132 kV voltages are lower than the minimum permissible level of 0.8p.u.

However, this is due to overloads of the associated 132 kV lines and transformers and the remedial actions for the U/V is linked with the solutions required first for the overloads of these circuits.

7.3.1 2020 Dry Season Peak Case-ACCC

The Base case and N-1 contingency analysis results are shown in **Table 7-15**.

It can be seen that the loadings of all the 330 kV lines are within their thermal rating limits with the exception of the Double Circuit 330 kV lines from Benin to Omotosho and from Shiroro to Kaduna.

Table 7-15 shows the overloaded 330 kV and 132 kV lines.

Table 7-15: 2020 Dry Season Peak - Overloaded Lines (base case and under N-1)

FROM Bus no	Bus name	TO Bus no	Bus name	circuit	Contingency label	Rating	Flow (MVA)	%
330 kV								
23002	OMOTOSHO3	43002	BENIN 3	2	SINGLE 23002-43002(1)	855.1	1138.7	133.2
23002	OMOTOSHO3	43002	BENIN 3	1	SINGLE 23002-43002(2)	855.1	1138.7	133.2
33020	SHIRORO 3	53000	KADUNA 3	2	SINGLE 33020-53000(1)	855.1	865.6	101.2
33020	SHIRORO 3	53000	KADUNA 3	1	SINGLE 33020-53000(2)	855.1	865.6	101.2
132 kV								
12017	**ALAGBON 1**	**12024**	**IJORA 1**	**1**	**BASE CASE**	**125.7**	**179.8**	**143.1**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**1**	**BASE CASE**	**125.7**	**133**	**105.8**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**2**	**BASE CASE**	**125.7**	**133**	**105.8**
82024	**IBOM IPP 1**	**82031**	**IKOT_ABASI**	**1**	**BASE CASE**	**125.7**	**161.3**	**128.3**
12001	AKANGBA 1	12027	ISOLO 1	2	SINGLE 12001-12027(1)	138.3	142.4	103
12001	AKANGBA 1	12027	ISOLO 1	1	SINGLE 12001-12027(2)	138.3	142.4	103
12002	EGBIN 1	12025	IKORODU	2	SINGLE 12002-12025(1)	138.3	157.6	114
12002	EGBIN 1	12025	IKORODU	1	SINGLE 12002-12025(2)	138.3	157.6	114
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	2	SINGLE 12003-12019(1)	138.3	182.8	132.2
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	1	SINGLE 12003-12019(2)	138.3	182.8	132.2
12016	AKOKA 1	12017	ALAGBON 1	1	SINGLE 12017-12024(1)	138.3	162.8	117.7
22002	OSOGBO 4T2	22008	IWO 1	1	SINGLE 22000-22006(1)	138.3	202.7	146.6
22001	OSOGBO 1	22029	ILESHA TEE1	9	SINGLE 22001-22029(1)	138.3	151	109.2
22001	OSOGBO 1	22029	ILESHA TEE1	1	SINGLE 22001-22029(9)	138.3	151	109.2

FROM Bus no	Bus name	TO Bus no	Bus name	circuit	Contingency label	Rating	Flow (MVA)	%
22000	AYEDE 1	22006	IBADAN NORTH	1	SINGLE 22002-22008(1)	138.3	195.5	141.3
22009	ILESHA 1	22029	ILESHA TEE1	1	SINGLE 22007-22029(1)	138.3	155	112.1
22007	IFE 1	22029	ILESHA TEE1	1	SINGLE 22009-22029(1)	138.3	150.5	108.8
52015	ZARIA 1	52016	FUNTUA 1	1	SINGLE 32016-52004(1)	99.3	110.5	111.3
42004	BENIN 1	42008	IRRUA 1	1	SINGLE 42000-42009(1)	138.3	191.3	138.3
42002	UGHELLI 1	42003	DELTA 1	2	SINGLE 42002-42003(1)	138.3	147.8	106.9
42002	UGHELLI 1	42003	DELTA 1	1	SINGLE 42002-42003(2)	138.3	147.8	106.9
42003	DELTA 1	42014	EFFURUN 1	2	SINGLE 42003-42014(1)	99.3	136.7	137.7
42003	DELTA 1	42014	EFFURUN 1	1	SINGLE 42003-42014(2)	99.3	136.7	137.7
42000	AJAOKUTA 1	42009	OKENE 1	1	SINGLE 42004-42008(1)	138.3	216.5	156.5
42004	BENIN 1	42008	IRRUA 1	1	SINGLE 42009-42010(1)	138.3	158.7	114.8
52003	KADUNA TOWN	52033	MANDO T4A BB	2	SINGLE 52003-52033(1)	138.3	140.9	101.9
52003	KADUNA TOWN	52033	MANDO T4A BB	1	SINGLE 52003-52033(2)	138.3	140.9	101.9
52033	MANDO T4A BB	52035	KUDENDA 1	2	SINGLE 52033-52035(1)	138.3	175.8	127.1
52033	MANDO T4A BB	52035	KUDENDA 1	1	SINGLE 52033-52035(2)	138.3	175.8	127.1
82001	ALAOJI 1	82026	ABA 1	2	SINGLE 82001-82026(1)	138.3	155.3	112.3
82001	ALAOJI 1	82026	ABA 1	1	SINGLE 82001-82026(2)	138.3	155.3	112.3
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82005-82024(1)	150.4	185.1	123.1
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82005-82024(2)	150.4	185.1	123.1
82007	PHCT MAIN1	82036	RUMUSOI 1	2	SINGLE 82007-82036(1)	138.3	172.8	124.9
82007	PHCT MAIN1	82036	RUMUSOI 1	1	SINGLE 82007-82036(2)	138.3	172.8	124.9
82017	YENAGOA 1	82018	AHOADA 1	2	SINGLE 82017-82018(1)	138.3	184.6	133.5
82017	YENAGOA 1	82018	AHOADA 1	1	SINGLE 82017-82018(2)	138.3	184.6	133.5
82017	YENAGOA 1	82022	GBARAIN UBIE	2	SINGLE 82017-82022(1)	138.3	208.2	150.5
82017	YENAGOA 1	82022	GBARAIN UBIE	1	SINGLE 82017-82022(2)	138.3	208.2	150.5
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82024-82031(1)	150.4	183.8	122.2
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82024-82031(1)	150.4	183.8	122.2

7.3.2 2020 Wet Season Peak case-ACCC

The Base case and N-1 contingency analysis results are shown in **Table 7-16**.

Table 7-16: 2020 Wet Season Peak - Overloaded Lines (base case and under N-1)

FROM Bus no	Bus name	TO Bus no	Bus name	cct	Contingency label	Rating	Flow (MVA)	%
330 kV								
23002	OMOTOSHO3	43002	BENIN 3	2	SINGLE 23002-43002(1)	855.1	1272.7	148.8
23002	OMOTOSHO3	43002	BENIN 3	1	SINGLE 23002-43002(2)	855.1	1272.7	148.8
33020	SHIRORO 3	53000	KADUNA 3	2	SINGLE 33020-53000(1)	855.1	934.9	109.3
33020	SHIRORO 3	53000	KADUNA 3	1	SINGLE 33020-53000(2)	855.1	934.9	109.3
132 kV								

FROM Bus no	Bus name	TO Bus no	Bus name	cct	Contingency label	Rating	Flow (MVA)	%
12017	**ALAGBON 1**	**12024**	**IJORA 1**	**1**	**BASE CASE**	**125.7**	**177.9**	**141.6**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**1**	**BASE CASE**	**125.7**	**133.6**	**106.3**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**2**	**BASE CASE**	**125.7**	**133.6**	**106.3**
82024	**IBOM IPP 1**	**82031**	**IKOT_ABASI**	**1**	**BASE CASE**	**125.7**	**162.1**	**128.9**
12001	AKANGBA 1	12027	ISOLO 1	2	SINGLE 12001-12027(1)	138.3	142.5	103
12001	AKANGBA 1	12027	ISOLO 1	1	SINGLE 12001-12027(2)	138.3	142.5	103
12002	EGBIN 1	12025	IKORODU	2	SINGLE 12002-12025(1)	138.3	148.6	107.5
12002	EGBIN 1	12025	IKORODU	1	SINGLE 12002-12025(2)	138.3	148.6	107.5
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	2	SINGLE 12003-12019(1)	138.3	186.7	135
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	1	SINGLE 12003-12019(2)	138.3	186.7	135
12016	AKOKA 1	12017	ALAGBON 1	1	SINGLE 12017-12024(1)	138.3	161.2	116.5
22002	OSOGBO 4T2	22008	IWO 1	1	SINGLE 22000-22006(1)	138.3	203.3	147
22001	OSOGBO 1	22029	ILESHA TEE1	9	SINGLE 22001-22029(1)	138.3	151	109.2
22001	OSOGBO 1	22029	ILESHA TEE1	1	SINGLE 22001-22029(9)	138.3	151	109.2
22000	AYEDE 1	22006	IBADAN NORTH	1	SINGLE 22002-22008(1)	138.3	195.4	141.3
22009	ILESHA 1	22029	ILESHA TEE1	1	SINGLE 22007-22029(1)	138.3	155	112.1
22007	IFE 1	22029	ILESHA TEE1	1	SINGLE 22009-22029(1)	138.3	150.5	108.8
52015	ZARIA 1	52016	FUNTUA 1	1	SINGLE 32016-52004(1)	99.3	110.6	111.4
42004	BENIN 1	42008	IRRUA 1	1	SINGLE 42000-42009(1)	138.3	191.3	138.3
42002	UGHELLI 1	42003	DELTA 1	2	SINGLE 42002-42003(1)	138.3	147.9	106.9
42002	UGHELLI 1	42003	DELTA 1	1	SINGLE 42002-42003(2)	138.3	147.9	106.9
42003	DELTA 1	42014	EFFURUN 1	2	SINGLE 42003-42014(1)	99.3	136.7	137.6
42003	DELTA 1	42014	EFFURUN 1	1	SINGLE 42003-42014(2)	99.3	136.7	137.6
42000	AJAOKUTA 1	42009	OKENE 1	1	SINGLE 42004-42008(1)	138.3	211.5	152.9
42004	BENIN 1	42008	IRRUA 1	1	SINGLE 42009-42010(1)	138.3	158.4	114.6
52003	KADUNA TOWN	52033	MANDO T4A BB	2	SINGLE 52003-52033(1)	138.3	140.8	101.8
52003	KADUNA TOWN	52033	MANDO T4A BB	1	SINGLE 52003-52033(2)	138.3	140.8	101.8
52033	MANDO T4A BB	52035	KUDENDA 1	2	SINGLE 52033-52035(1)	138.3	175.1	126.6
52033	MANDO T4A BB	52035	KUDENDA 1	1	SINGLE 52033-52035(2)	138.3	175.1	126.6
82001	ALAOJI 1	82026	ABA 1	2	SINGLE 82001-82026(1)	138.3	154.5	111.7
82001	ALAOJI 1	82026	ABA 1	1	SINGLE 82001-82026(2)	138.3	154.5	111.7
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82005-82024(1)	150.4	184.9	122.9
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82005-82024(2)	150.4	184.9	122.9
82007	PHCT MAIN1	82036	RUMUSOI 1	2	SINGLE 82007-82036(1)	138.3	173.9	125.7
82007	PHCT MAIN1	82036	RUMUSOI 1	1	SINGLE 82007-82036(2)	138.3	173.9	125.7
82017	YENAGOA 1	82018	AHOADA 1	2	SINGLE 82017-82018(1)	138.3	184.7	133.5
82017	YENAGOA 1	82018	AHOADA 1	1	SINGLE 82017-82018(2)	138.3	184.7	133.5
82017	YENAGOA 1	82022	GBARAIN UBIE	2	SINGLE 82017-82022(1)	138.3	208.2	150.6
82017	YENAGOA 1	82022	GBARAIN UBIE	1	SINGLE 82017-82022(2)	138.3	208.2	150.6
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82024-82031(1)	150.4	183.7	122.1
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82024-82031(1)	150.4	183.7	122.1

7.3.3 2020 Dry Season Off-Peak Case-ACCC

The Base case and N-1 contingency analysis results are shown in **Table 7-17.**

Table 7-17: 2020 Dry Season Off-Peak - Overloaded Lines (base case and under N-1)

FROM Bus no	Bus name	TO Bus no	Bus name	circuit	Contingency label	Rating	Flow (MVA)	%
12017	**ALAGBON 1**	**12024**	**IJORA 1**	**1**	**BASE CASE**	**125.7**	**144.2**	**114.7**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**1**	**BASE CASE**	**125.7**	**127.1**	**101.1**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**2**	**BASE CASE**	**125.7**	**127.1**	**101.1**
82024	**IBOM IPP 1**	**82031**	**IKOT_ABASI**	**1**	**BASE CASE**	**125.7**	**172.7**	**137.4**
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	2	SINGLE 12003-12019(1)	138.3	152.6	110.4
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	1	SINGLE 12003-12019(2)	138.3	152.6	110.4
22002	OSOGBO 4T2	22008	IWO 1	1	SINGLE 22000-22006(1)	138.3	223.7	161.7
22000	AYEDE 1	22006	IBADAN NORTH	1	SINGLE 22002-22008(1)	138.3	157.5	113.9
42003	DELTA 1	42014	EFFURUN 1	2	SINGLE 42003-42014(1)	99.3	113.4	114.2
42003	DELTA 1	42014	EFFURUN 1	1	SINGLE 42003-42014(2)	99.3	113.4	114.2
42004	BENIN 1	42008	IRRUA 1	1	SINGLE 42009-42010(1)	138.3	161.3	116.6
52033	MANDO T4A BB	52035	KUDENDA 1	2	SINGLE 52033-52035(1)	138.3	175.8	127.1
52033	MANDO T4A BB	52035	KUDENDA 1	1	SINGLE 52033-52035(2)	138.3	175.8	127.1
82000	AFAM 1-2-3	82002	AFAM IV	2	SINGLE 82000-82002(1)	138.3	149.8	108.3
82000	AFAM 1-2-3	82002	AFAM IV	1	SINGLE 82000-82002(2)	138.3	149.8	108.3
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82005-82024(1)	150.4	169.3	112.6
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82005-82024(2)	150.4	169.3	112.6
82007	PHCT MAIN1	82036	RUMUSOI 1	2	SINGLE 82007-82036(1)	138.3	175	126.5
82007	PHCT MAIN1	82036	RUMUSOI 1	1	SINGLE 82007-82036(2)	138.3	175	126.5
82013	*ONNE 1*	*82040*	*TRAMADI*	*2*	*SINGLE 82013-82040(1)*	*138.3*	*138.8*	*100.4*
82013	*ONNE 1*	*82040*	*TRAMADI*	*1*	*SINGLE 82013-82040(2)*	*138.3*	*138.8*	*100.4*
82017	YENAGOA 1	82018	AHOADA 1	2	SINGLE 82017-82018(1)	138.3	189.7	137.1
82017	YENAGOA 1	82018	AHOADA 1	1	SINGLE 82017-82018(2)	138.3	189.7	137.1
82017	YENAGOA 1	82022	GBARAIN UBIE	2	SINGLE 82017-82022(1)	138.3	209.9	151.8
82017	YENAGOA 1	82022	GBARAIN UBIE	1	SINGLE 82017-82022(2)	138.3	209.9	151.8
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82024-82031(1)	150.4	183.9	122.3
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82024-82031(1)	150.4	183.9	122.3

7.3.4 2020 Wet Season Off-Peak case-ACCC

The Base case and N-1 contingency analysis results are shown in **Table 7-18.**

Table 7-18: 2020 Wet Season Off- peak - Overloaded Lines (base case and under N-1)

FROM Bus no	Bus name	TO Bus no	Bus name	cir-cuit	Contingency label	Rating	Flow (MVA)	%
330 kV								
23002	OMOTOSHO3	43002	BENIN 3	2	SINGLE 23002-43002(1)	855.1	1332.9	155.9
23002	OMOTOSHO3	43002	BENIN 3	1	SINGLE 23002-43002(2)	855.1	1332.8	155.9
132 kV								
12017	**ALAGBON 1**	**12024**	**IJORA 1**	**1**	**BASE CASE**	**125.7**	**142**	**113**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**1**	**BASE CASE**	**125.7**	**125.9**	**100.2**
82019	**OMOKU 1**	**82036**	**RUMUSOI 1**	**2**	**BASE CASE**	**125.7**	**125.9**	**100.2**
82024	**IBOM IPP 1**	**82031**	**IKOT_ABASI**	**1**	**BASE CASE**	**125.7**	**172.4**	**137.2**
62009	*BIU 1*	*62026*	*DADINKOWA 1*	*1*	*SINGLE 63005-63007(1)*	*76.7*	*108.6*	*141.5*
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	2	SINGLE 12003-12019(1)	138.3	159.9	115.6
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	1	SINGLE 12003-12019(2)	138.3	159.9	115.6
22002	OSOGBO 4T2	22008	IWO 1	1	SINGLE 22000-22006(1)	138.3	214.9	155.4
22000	AYEDE 1	22006	IBADAN NORTH	1	SINGLE 22002-22008(1)	138.3	159.2	115.1
42003	DELTA 1	42014	EFFURUN 1	2	SINGLE 42003-42014(1)	99.3	113.8	114.6
42003	DELTA 1	42014	EFFURUN 1	1	SINGLE 42003-42014(2)	99.3	113.8	114.6
42004	BENIN 1	42008	IRRUA 1	1	SINGLE 42009-42010(1)	138.3	163.7	118.3
52033	MANDO T4A BB	52035	KUDENDA 1	2	SINGLE 52033-52035(1)	138.3	175.9	127.2
52033	MANDO T4A BB	52035	KUDENDA 1	1	SINGLE 52033-52035(2)	138.3	175.9	127.2
82000	AFAM 1-2-3	82002	AFAM IV	2	SINGLE 82000-82002(1)	138.3	147.2	106.5
82000	AFAM 1-2-3	82002	AFAM IV	1	SINGLE 82000-82002(2)	138.3	147.2	106.5
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82005-82024(1)	150.4	169.6	112.7
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82005-82024(2)	150.4	169.6	112.7
82007	PHCT MAIN1	82036	RUMUSOI 1	2	SINGLE 82007-82036(1)	138.3	172.7	124.9
82007	PHCT MAIN1	82036	RUMUSOI 1	1	SINGLE 82007-82036(2)	138.3	172.7	124.9
82013	*ONNE 1*	*82040*	*TRAMADI*	*2*	*SINGLE 82013-82040(1)*	*138.3*	*139.3*	*100.7*
82013	*ONNE 1*	*82040*	*TRAMADI*	*1*	*SINGLE 82013-82040(2)*	*138.3*	*139.3*	*100.7*
82017	YENAGOA 1	82018	AHOADA 1	2	SINGLE 82017-82018(1)	138.3	189.6	137.1
82017	YENAGOA 1	82018	AHOADA 1	1	SINGLE 82017-82018(2)	138.3	189.6	137.1
82017	YENAGOA 1	82022	GBARAIN UBIE	2	SINGLE 82017-82022(1)	138.3	209.9	151.8
82017	YENAGOA 1	82022	GBARAIN UBIE	1	SINGLE 82017-82022(2)	138.3	209.9	151.8
82005	EKET 1	82024	IBOM IPP 1	1	SINGLE 82024-82031(1)	150.4	183.9	122.2
82005	EKET 1	82024	IBOM IPP 1	2	SINGLE 82024-82031(1)	150.4	183.9	122.2

7.4 Summary of results of load flow analysis for 2020

The results of the static security analysis for 2020 are summarized as follows:

7.4.1 Overloaded 330 kV and 132 kV transmission lines

a) There are no overloads in 330 kV lines under normal operation.
However, in case of tripping the 330 kV lines from Gombe to Yola and Damaturu, and from Damaturu to Maiduguri the load flow case did not converge, as expected, due to absence of a second parallel circuit and insufficient support from alternative routes. A conversion to a double circuit will resolve these issues.

b) Under N-1, in case of tripping any of the following 132 kV lines, the case will also not converge:

From BKebbi to KVK Power PV
From Zaria to Funtua

These 132 kV N-1 cases will have to be resolved by providing new alternative routes for the power flow.

c) The 132 kV lines which are shown to be overloaded under *normal (N-0)* and *contingency (N-1)* conditions are tabulated in **Table 7-15**.

Priority is to resolve the overloads occurring under *normal (N-0)* operation of the 132 kV lines shown in **Table 7-19.**

Table 7-19: Reinforcements of 132 kV lines overloaded under N-0

From	To	Proposed Solution
Alagbon	Ijora	convert to DC
Omoku	Rumusoi (DC)	Reconductoring of the DC
Ibom IPP	Ikot Abasi	convert to DC

d) As a next priority, the overloaded 330 kV and 132 kV lines under N-1 contingencies must be reinforced. This entails either re-conductoring to higher rating conductors or, in case of SC, conversion to DC by installing a 2nd parallel circuit.

The lines in **Table 7-20** are ranked according to their percentage of overload:

Table 7-20: Reinforcements of 132 kV lines overloaded under N-1

FROM Bus no	Bus name	TO Bus no	Bus name	Contingency label	Rating	Flow MVA	%
330 kV							
23002	OMOTOSHO3	43002	BENIN 3	SINGLE 23002-43002(2)	855.1	1138.7	133.2
33020	SHIRORO 3	53000	KADUNA 3	SINGLE 33020-53000(1)	855.1	865.6	101.2
132 kV							
42000	AJAOKUTA 1	42009	OKENE 1	SINGLE 42004-42008(1)	138.3	216.5	156.5
82017	YENAGOA 1	82022	GBARAIN UBIE	SINGLE 82017-82022(1)	138.3	208.2	150.5
22002	OSOGBO 4T2	22008	IWO 1	SINGLE 22000-22006(1)	138.3	202.7	146.6
62009	BIU 1	62026	DADINKOWA 1	SINGLE 63005-63007(1)	76.7	108.6	141.5
22000	AYEDE 1	22006	IBADAN NORTH	SINGLE 22002-22008(1)	138.3	195.5	141.3
42004	BENIN 1	42008	IRRUA 1	SINGLE 42000-42009(1)	138.3	191.3	138.3
42003	DELTA 1	42014	EFFURUN 1	SINGLE 42003-42014(1)	99.3	136.7	137.7
82017	YENAGOA 1	82018	AHOADA 1	SINGLE 82017-82018(1)	138.3	184.6	133.5
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	SINGLE 12003-12019(1)	138.3	182.8	132.2
52033	MANDO T4A BB	52035	KUDENDA 1	SINGLE 52033-52035(1)	138.3	175.8	127.1
82007	PHCT MAIN1	82036	RUMUSOI 1	SINGLE 82007-82036(1)	138.3	172.8	124.9
82005	EKET 1	82024	IBOM IPP 1	SINGLE 82005-82024(1)	150.4	185.1	123.1
12016	AKOKA 1	12017	ALAGBON 1	SINGLE 12017-12024(1)	138.3	162.8	117.7
12002	EGBIN 1	12025	IKORODU	SINGLE 12002-12025(1)	138.3	157.6	114
12002	EGBIN 1	12025	IKORODU	SINGLE 12002-12025(1)	138.3	157.6	114
82001	ALAOJI 1	82026	ABA 1	SINGLE 82001-82026(1)	138.3	155.3	112.3
22009	ILESHA 1	22029	ILESHA TEE1	SINGLE 22007-22029(1)	138.3	155	112.1
52015	ZARIA 1	52016	FUNTUA 1	SINGLE 32016-52004(1)	99.3	110.5	111.3
22001	OSOGBO 1	22029	ILESHA TEE1	SINGLE 22001-22029(1)	138.3	151	109.2
22007	IFE 1	22029	ILESHA TEE1	SINGLE 22009-22029(1)	138.3	150.5	108.8
12001	AKANGBA 1	12027	ISOLO 1	SINGLE 12001-12027(1)	138.3	142.4	103
52003	KADUNA TOWN	52033	MANDO T4A BB	SINGLE 52003-52033(1)	138.3	140.9	101.9
82013	ONNE 1	82040	TRAMADI	SINGLE 82013-82040(1)	138.3	138.8	100.4

Note: It should be noted that with regards to the overloaded 330 kV lines in 2020 (Benin-Omotosho and Shiroro-Kaduna), remedial actions are already planned and these lines will not be overloaded in 2025, as shown in section 7.5.

7.4.2 Overloaded transformers

7.4.2.1 Overloads above 100% of transformer ratings

e) The 330/132 kV 3-W and A/T transformers overloaded above their 100% rating MVA under normal (base case) operation, listed in **Table 7-21**, must be upgraded:

Table 7-21: Upgrading requirements of 330/132 kV transformers overloaded under N-0

Bus#	Name	Base kV	Name	Loading [MVA]	Rating [MVA]	Loading [%]
43011	B.NORTH_3	330	BENIN 9T1	129.7	67.5	192.1
43002	BENIN 3	330	BENIN TR1	218.4	150	145.6
43002	BENIN 3	330	BENIN TR2	218.4	150	145.6
43002	BENIN 3	330	BENIN TR3	218.4	150	145.6
33002	BKEBBI 3	330	B_KEBBI T1	185.5	150	123.7
12000	AJA 132	132	AJA T4	55.3	45	122.8
23003	GANMO 3	330	GANMO TR2A	171.7	150	114.4
12001	AKANGBA 1	132	AKANGBA5T4A	127	112.5	112.9
12001	AKANGBA 1	132	AKANGBA5T4B	127	112.5	112.9
22000	AYEDE 1	132	AYEDE TR2	120.7	112.5	107.2
22000	AYEDE 1	132	AYEDE TR3	120.7	112.5	107.2
22000	AYEDE 1	132	AYEDE TR1	120.3	112.5	106.9
12005	IKJW T1BT2B	132	IKW T2B	126.8	120	105.6
13000	AJA 3	330	AJA T2A	153.3	150	102.2

f) The 132/33 kV and 132/11 kV transformers overloaded above their 100% rating MVA under normal (base case) operation, listed in **Table 7-22**, must be upgraded:

Table 7-22: Upgrading requirements of 132/33 kV and 132/11 kV transformers overloaded under N-0

Bus#	Name	Base kV	Bus#	Name	Base kV	Loading [MVA]	Rating [MVA]	Loading [%]
32017	SULEJA 1	132	36016	SULEJA 11	11	15.8	7.5	211.2
42004	BENIN 1	132	45029	BENIN T22 33	33	120.1	60	200.2
42004	BENIN 1	132	45031	BENIN T24 33	33	115.8	60	193
42004	BENIN 1	132	45030	BENIN T23 33	33	112.9	60	188.2
42005	B_N0RTH 1	132	45015	B_NORTH_33	33	102.3	60	170.4
12000	AJA 132	132	15003	AJA 33	33	84	60	140.1
52001	KANO 1	132	55058	KUMB T3 MOB	33	41.9	30	139.8
52016	FUNTUA 1	132	56000	FUNTUA 11	11	9.6	7.5	127.7
12029	OJO 1	132	15030	OJO 33	33	37.5	30	125.1
22015	OMUARAN 1	132	25016	OMUARAN 33	33	36.9	30	122.9
42002	UGHELLI 1	132	45001	UGHELLI 33	33	73.1	60	121.9
62001	JOS 1	132	65005	JOS T4 60MVA	33	71.8	60	119.7
82005	EKET 1	132	85002	EKET T1B	33	53	45	117.7
22013	OFFA 1	132	25015	OFFA 33	33	35.3	30	117.7
12029	OJO 1	132	15047	OJO T3_T4	33	69	60	115
22005	AKURE 1	132	25028	AKURE T2A	33	33.6	30	111.9
52016	FUNTUA 1	132	56005	FUNTUA T2	11	8	7.5	106.1
22022	GANM0 T1 BB	132	25032	GANMO T1	33	63.6	60	106.1
52016	FUNTUA 1	132	55003	FUNTUA 33	33	31.7	30	105.8

Bus#	Name	Base kV	Bus#	Name	Base kV	Loading [MVA]	Rating [MVA]	Loading [%]
12023	EJIGBO 1	132	15128	EJIGBO 33	33	31.2	30	104
12055	ODOGUNYAN 1	132	15063	ODOGUNYA 33	33	62.3	60	103.8
82000	AFAM 1-2-3	132	86000	AFAM 11	11	66.3	64	103.7
12044	AJA 132 BBII	132	15112	AJA 2 33	33	61.6	60	102.6
42004	BENIN 1	132	45000	BENIN 33	33	60.1	60	100.1
12027	ISOLO 1	132	15028	ISOLO 33	33	60.1	60	100.1

7.4.2.2 Overloads above 85% of transformer ratings

Table 7-23 shows 132/33 kV and 132/11 kV transformers which are overloaded above their 85% rating MVA under normal (base case) operation and shall be considered for upgrading. Transformers loaded between 85-100% are greyed out.

Table 7-23: Upgrading requirements of 330/132 kV, 132/33 kV and 132/11 kV transformers overloaded over 85% under N-0

From bus no	Bus name	kV	To bus no	Bus name	wind	circuit	Loading	Rating	%
330/132 kV transformers									
52001	*KANO 1*	*132*	*3WNDTR*	*KANO T3A*	*WND 2*	*1*	*114.2*	*120*	*95.1*
22012	*JERICHO 1*	*132*	*3WNDTR*	*JERICO TR1*	*WND 1*	*1*	*42.1*	*45*	*93.5*
12002	*EGBIN 1*	*132*	*3WNDTR*	*EGBIN IBTR2*	*WND 2*	*1*	*111.9*	*120*	*93.2*
12027	*ISOLO 1*	*132*	*3WNDTR*	*ISOLO TR3*	*WND 1*	*1*	*41.9*	*45*	*93.1*
22001	*OSOGBO 1*	*132*	*3WNDTR*	*OSOGBO 4T1*	*WND 2*	*1*	*111*	*120*	*92.5*
22001	*OSOGBO 1*	*132*	*3WNDTR*	*OSOGBO 4T6*	*WND 2*	*1*	*111*	*120*	*92.5*
22001	*OSOGBO 1*	*132*	*3WNDTR*	*OSOGBO N T5*	*WND 2*	*5*	*111*	*120*	*92.5*
12016	*AKOKA 1*	*132*	*3WNDTR*	*AKOKA T1*	*WND 1*	*1*	*41.1*	*45*	*91.3*
73007	*NNEWI 3*	*330*	*3WNDTR*	*NNEWI T2A*	*WND 2*	*1*	*61.1*	*67.5*	*90.5*
72001	*ONITSHA 1*	*132*	*3WNDTR*	*ONITSHA T4*	*WND 2*	*1*	*101*	*112.5*	*89.8*
132/33 kV and 132/11 kV transformers									
12029	*OJO 1*	*132*	*15030*	*OJO 33*	*33*	*2*	*29.7*	*30*	*99.1*
12019	*ALIMOSHO 1*	*132*	*15072*	*ALIMOSHO T1*	*33*	*3*	*29.7*	*30*	*98.9*
22027	*SAGAMU 1*	*132*	*25035*	*SAGAMU 33*	*33*	*1*	*29.2*	*30*	*97.4*
22005	*AKURE 1*	*132*	*25003*	*AKURE 33*	*33*	*1*	*28.8*	*30*	*96*
12037	*PARAS_1*	*132*	*15116*	*AFR FOUNDRY*	*33*	*1*	*38.3*	*40*	*95.8*
22008	*IWO 1*	*132*	*25002*	*IWO 33*	*33*	*1*	*14.4*	*15*	*95.7*
12016	*AKOKA 1*	*132*	*15067*	*AKOKA T2*	*33*	*1*	*37.9*	*40*	*94.7*
22012	*JERICHO 1*	*132*	*25013*	*JERICHO2 33*	*33*	*1*	*37.8*	*40*	*94.4*
12024	*IJORA 1*	*132*	*15046*	*IJORA T2B*	*33*	*2*	*27.7*	*30*	*92.2*
12004	*AKANGBA BBII*	*132*	*15053*	*AKANGBA 33*	*33*	*1*	*54.9*	*60*	*91.5*

From bus no	Bus name	kV	To bus no	Bus name	wind	circuit	Loading	Rating	%
62020	JALINGO 1	132	65015	JALINGO 33B	33	1	27.2	30	90.7
22005	AKURE 1	132	25018	AKURE T3A 33	33	1	54.3	60	90.4
12020	ITIRE 1	132	16034	ITERE T3	11	2	36.2	40	90.4
22028	IJEBU ODE 1	132	25038	IJEBU ODE 33	33	1	27.1	30	90.2
42015	AMUKPE 1	132	45026	AMUKPE BB 33	33	1	54.1	60	90.1
12020	ITIRE 1	132	16032	ITIRE 11	11	1	26.9	30	89.7
82010	UYO 1	132	85007	UYO 33	33	3	53.5	60	89.2
62012	SAVANNAH 1	132	65010	SAVANNAH 33	33	1	13.3	15	88.8
12006	AJA 132BBIII	132	15113	AJA BB3 33	33	1	87.7	100	87.7
42008	IRRUA 1	132	45002	IRRUA 33	33	1	52	60	86.6
52001	KANO 1	132	55057	KUMB T2	33	1	34.6	40	86.4
32016	SOKOTO 1	132	35050	SOKOTO T3	33	3	25.8	30	86.2
12017	ALAGBON 1	132	15008	ALAGBON 33	33	1	56.4	66	85.5
12024	IJORA 1	132	15045	IJORA T1A&B	33	2	25.5	30	85.1
12023	EJIGBO 1	132	15014	EJIGBO 33	33	1	25.5	30	85.1

7.4.3 Undervoltages under N-1 conditions

In all N-1 contingencies a number of 132 kV voltages are lower than the minimum permissible level of 0.8p.u.

However, this is due to overloads of the associated 132 kV lines and transformers and the remedial actions for the under-voltages (U/V) is linked with the solutions required first for the overloads of these circuits, as well as with the implementation of reactive power compensation equipment, as detailed in the following section.

7.4.4 Reactive power compensation requirements

The reactive power requirements, i.e. the need to have existing reactors and capacitors in operation and/or install new ones by 2020, including the necessity for new SVCs, are summarized in the following sections.

The new equipment is marked in bold.

7.4.4.1 SVC requirements

No SVC at Gombe is necessary by 2020.

7.4.4.2 Reactors

The status of reactors required in ***Dry Season Peak*** case is shown in **Table 7-24**. It can be seen that only reactors at Gombe and Yola are required:

Table 7-24: Reactor requirements for 2020 dry season peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVar]
63002	YOLA 3	330	1	1	-75
63000	GOMBE 3	330	1	1	-50
65001	YOLA T1 33	33	1	1	-30
65014	GOMBE T4A	33	1	1	-30
13003	IKEJA W 3	330	1	0	-75
13003	IKEJA W 3	330	2	0	-75
13026	OKE_ARO_3	330	1	0	-75
23001	OSOGBO 3	330	1	0	-75
33001	KATAMPE 3	330	1	0	-75
33003	JEBBA T.S.3	330	2	0	-75
33003	JEBBA T.S.3	330	3	0	-75
33007	GWAGW BB1	330	2	0	-75
43002	BENIN 3	330	2	0	-75
53000	KADUNA 3	330	1	0	-75
53001	KANO 3	330	1	0	-75
53005	KANO_NEW330	330	1	0	-75
63001	JOS 3	330	1	0	-75
63005	MAIDUGURI 3	330	2	0	-75
73001	ONITSHA 3	330	1	0	-75
73003	MAKURDI_3	330	1	0	-75
83002	ALAOJI 3	330	1	0	-75
63002	YOLA 3	330	2	0	-75
73001	ONITSHA 3	330	2	0	-69
63000	GOMBE 3	330	2	0	-50
63006	JALINGO_3	330	1	0	-10

The status of reactors required in ***Dry Season Off-Peak*** case is shown in **Table 7-25**.

The new reactor required (at Maiduguri) is shown in bold:

Table 7-25: Reactor requirements for 2020 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVarR]
53001	KANO 3	330	1	1	-75
63002	YOLA 3	330	1	1	-75
63005	**MAIDUGURI 3**	**330**	**2**	**1**	**-75**
63000	GOMBE 3	330	1	1	-50
63000	GOMBE 3	330	2	1	-50
65001	YOLA T1 33	33	1	1	-30
65014	GOMBE T4A	33	1	1	-30
63002	YOLA 3	330	2	0	-75
13003	IKEJA W 3	330	1	0	-75
13003	IKEJA W 3	330	2	0	-75
13026	OKE_ARO_3	330	1	0	-75
23001	OSOGBO 3	330	1	0	-75
33001	KATAMPE 3	330	1	0	-75
33003	JEBBA T.S.3	330	2	0	-75
33003	JEBBA T.S.3	330	3	0	-75

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVarR]
33007	GWAGW BB1	330	2	0	-75
43002	BENIN 3	330	2	0	-75
53000	KADUNA 3	330	1	0	-75
53005	KANO_NEW330	330	1	0	-75
63001	JOS 3	330	1	0	-75
73001	ONITSHA 3	330	1	0	-75
73003	MAKURDI_3	330	1	0	-75
83002	ALAOJI 3	330	1	0	-75
73001	ONITSHA 3	330	2	0	-69
63006	JALINGO_3	330	1	0	-10

7.4.4.3 Capacitors

The status of capacitors required in ***Dry Season Peak*** case is shown in **Table 7-26**. The new equipment required is shown in bold:

Table 7-26: Capacitor requirements for 2020 dry season peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
53001	KANO 3	330	2	1	50
62021	MAIDUGURI 1	132	1	1	10.8
52022	HADEJIA 1	132	1	1	20
22017	**ONDO2 1**	**132**	**1**	**1**	**24**
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
22015	**OMUARAN 1**	**132**	**1**	**1**	**50**
12004	AKANGBA BBII	132	1	1	72
15011	ABEOKUTA OLD	33	2	1	20
15037	NEW ABEOK 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
15002	AGBARA 33	33	1	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
75017	YANDEV 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15080	OLD ABEOK T2	33	3	1	24

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
15128	EJIGBO 33	33	1	1	24
25011	ILORIN 33	33	1	1	24
45027	**IRRUA BBII33**	**33**	**1**	**1**	**24**

The status of capacitors required in ***Dry Season Off-Peak*** case is shown in **Table 7-27**. The new equipment required is shown in bold:

Table 7-27: Capacitor requirements for 2020 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
62021	MAIDUGURI 1	132	1	1	10.8
52022	HADEJIA 1	132	1	1	20
22017	**ONDO2 1**	**132**	**1**	**1**	**24**
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
22015	**OMUARAN 1**	**132**	**1**	**1**	**50**
12004	AKANGBA BBII	132	1	1	72
15002	AGBARA 33	33	1	1	20
15011	ABEOKUTA OLD	33	2	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
75017	YANDEV 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15080	OLD ABEOK T2	33	3	1	24
15128	EJIGBO 33	33	1	1	24
25011	ILORIN 33	33	1	1	24
45027	**IRRUA BBII33**	**33**	**1**	**1**	**24**

7.4.4.4 Power factor correction at DisCo`s level

With reference to the Grid Code requirements (ref. article 15.6 on *Demand power factor corrections and 16.7 on provision of voltage control* stating that *The Off-takers shall maintain a Power*

Factor not less than 0.95 at the Connection Point), since the resulting power factor of loads connected at 33 kV level and below is less than the 0.95 required, all DisCos shall be required to undertake a program of having capacitors installed at distribution level to ensure the power factor at all 33 kV S/S is not less than 0.9 by 2020 and 0.95 by 2025, in line with the Grid Code requirements. (Note: the loads in the 2025 model however have been based on a conservative power factor of 0.9 and only the 2030 loads have pf of 0.95)

7.4.5 Summary of *new* transmission lines required for 2020

In addition to the projects proposed by JICA in the Lagos area (330 kV lines and substations Omotosho-Ogijo-MFM, Ikeja West, Arigbajo, New Agbara), as shown in the SLDs of Annex 7.2 and 7.3, the transmission lines shown in **Table 7-28** are required to be implemented by 2020:

Table 7-28: New transmission lines required by 2020

No		From	To		kV	km	Remarks	Priority /Ranking
1	Part of North East Ring	Damaturu	Maiduguri	DC	330	260	a SC already exists	1
2		Gombe	Damaturu	DC	330	180	a SC already exists	1
3		Gombe	Yola	DC	330	240	a SC already exists	1
4		Yola	Jalingo	DC	330	160	Can be delayed beyond 2020 but asap thereafter. One circuit via Mayo Belwa.	3
5		Jos	Gombe	DC	330	270	Should be completed by 2020 or asap thereafter. A SC already exists	1
6	Part of North West ring							
7		Kainji	Birnin Kebbi	DC	330	310	A SC already exists. Needs to be expedited by 2020 if possible or asap thereafter.	3
8		Kaduna	Kano	DC	330	230	Undertaken by TCN as part of the NTEP to be financed by IDB. Needs to be expedited by 2020 if possible or asap thereafter.	2
9		Akangba	Alagbon	DC	330	14		2
10		Ugwuaji	Abakaliki	DC	330	85		1
11		Osogbo	Arigbajo	DC	330	183	If not undertaken by JICA	
12		Ayede	Ibadan North	DC	132	15		1
13		New Agbara	Agbara	DC	132	18		2
14		Ogijo	Redeem	DC	132	14	If not undertaken by JICA	
15		Birnin Kebbi	Dosso	DC	132	128	a SC already exists	2
15		Ibom IPP	Ikot Abasi	DC	132	30		1

Notes:

- The lines recommended for the North East ring above are required in order to comply with the N-1 static security criterion, as well as to improve the voltage stability of the area. It is recognized however that in terms of implementation it will be challenging to complete all by 2020. However, if not possible to implement by 2020 they should be implemented as soon as possible thereafter within the period 2020-2025 and therefore the investment plan, detailed in section 9, has been based on this assumption.
- The JICA project of new 330 kV lines (DC) from Ogijo to Arigbajo is not considered necessary, as it is lightly loaded under all scenarios.
- The JICA project of new 330 kV lines (DC) from Arigbajo to New Agbara is not considered necessary for 2020, as it is lightly loaded. It is necessary only for meeting the N-1 criterion for the export lies to Sakete.

7.4.6 Demand-Side Management

Despite the rigorous generation and transmission expansion program proposed in this study, the problem of deficit in the generation-load balance in Nigeria will remain in the short and medium term, as for practical reasons the generation increase by the commissioning of new power plants will always lag behind the demand forecast detailed in section 5.

It is therefore necessary to apply all available means and methods for load control, in addition to load shedding which will be unavoidable in certain periods and circumstances. A method which has evolved significantly over the last few years is Demand Side Management.

With Demand-Side Management (DSM), loads are controlled to respond to power imbalances by reducing or increasing power demand. Part of the demand can be time-shifted (for example heating or cooling) or simply switched on or off, according to price signals. This enables a new balance between generation and consumption, without the need to adjust generation levels.

Today, the adjustment of generation levels is more common than DSM. The availability of this solution depends on load management possibilities (for example in industrial processes such as steel treatment) and the financial benefits offered by flexible load contracts (cost of power cuts and power increases versus lower bills).

Demand-side management, particularly demand response (DR), and electricity storage are possible sources of flexibility for future power systems with large amounts of variable generation. They can often offer quite fast response and are therefore candidates for a wide spectrum of power system services. The most obvious uses are in energy balancing and peak load shedding, but they can also be used for different reserves, reactive power management, and congestion management. They can also provide reactive power management and congestion management in future distribution grids exhibiting more observability and control.

DSM is expected to evolve significantly in the next years as it is already included in ENTSO-E Network Code on Demand Connection (2012).

In a number of European countries a new regulatory framework has been introduced to provide contracts between the TSOs and large HV clients that allow for load interruptions.

7.5 2025 load flow analysis

The network configuration for the year 2025 is shown in the PSS/E SLD of **Annex 7.5.**

7.5.1 2025 Load demand

Table 7-29 shows that the increase in load demand follows approximately the same increase (in percentage) in load forecast as detailed in section 5.4.2.

Table 7-29: Load demand per DisCo

DISCO		Load Demand 2020 [MW]	Increase 2020-2025	Load Demand 2025 [MW]
IKEDC	1-Ikeja	1250	16.08%	1451
IBEDC	2-Ibadan	1225	45.31%	1780
AEDC	3-Abuja	745	35.70%	1011
BEDC	4-Benin	1273	37.47%	1750
KAEDCO	5-Kaduna	590	78.31%	1052
JEDC	6-Jos	442	48.64%	657
EEDC	7-Enugu	1090	22.29%	1333
PHEDC	8-Port Harcourt	946	55.39%	1470
EKEDC	9-Eko	1320	25.08%	1651
KEDCO	10-Kano	705	34.04%	945
YOLA	11-Yola	309	99.03%	615
Total		**9895**	38.61%	**13715**
Export*		387		1540*
Total load		**10282**		**15255**

(*) Ref 330 kV export lines: To Sakete 360MW, To Faraku 400MW, To Zabori 631MW

7.5.2 Evacuation from Mambila HPP

7.5.2.1 New transmission lines

A major development for the year 2025 is the operations of the first units of the Mambilla HPP.

The new transmission lines required to evacuate the power from Mambilla will have to be designed for the evacuation of the full power. Assuming a power of 2400 MW is to be evacuated from Mambilla Hydro Power Plant:

1. If the N-1 criterion is to be maintained, as per current Grid Code, the following is proposed:
   a) 330/132/33 kV substation at Wukari
   b) Double Circuit with QUAD Bison conductors from Mambilla to Wukari
   c) Double Circuit with QUAD Bison conductors from Wukari to Makurdi

d) Double Circuit with QUAD Bison conductors from Mambila to Jalingo (to close the 330 kV loop)

2. Due to the importance of the power station and in line with international practice by other Utilities, it is proposed to apply the N-2 criteria only for the transmission lines leaving the power plant. If this is adopted, it would be necessary to have:

   a) Two Double Circuits with QUAD Bison conductors from Mambila to Wukari

   b) Two Double Circuits with QUAD Bison conductors from Mambila to Jalingo

Each Quad Bison circuit will be rated 1550MVA approx. The scheme is shown on the Single Line Diagram of **Figure 7-12.**

In both cases it is necessary to maintain two evacuation routes (one towards Makurdi and another towards Jalingo) at all times, since 2400MW will not be able to be evacuated through one route only, as bottlenecks will occur downstream, beyond Makurdi and Jalingo respectively.

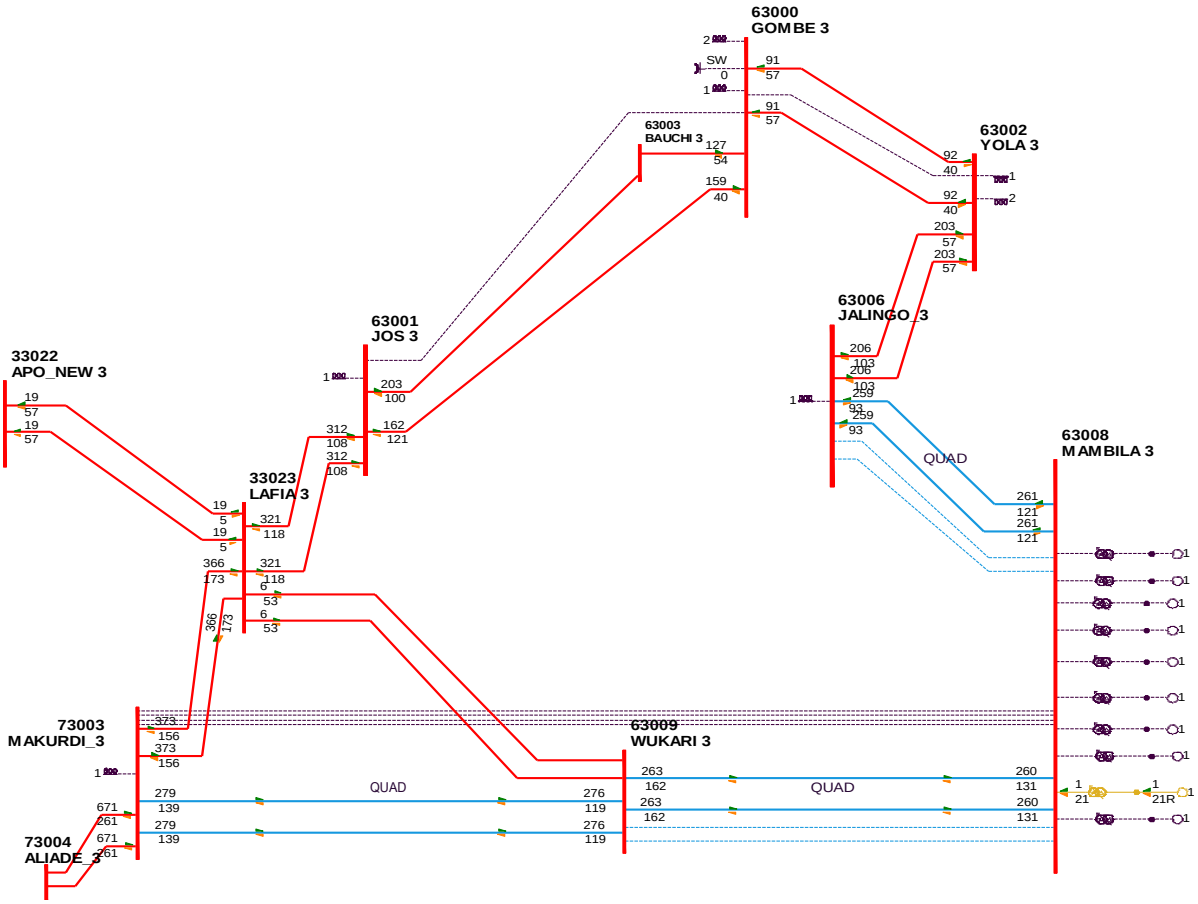


Figure 7-12 Evacuation from Mambila HPP

7.5.2.2 PV analysis

A PV analysis was carried out to determine the maximum power that can be evacuated from Mambilla HPP (MHPP).
The starting scenario was set up with an initial generation of 1000 MW at MHPP. The analysis was performed for both base case and contingency (N-1) conditions. It was determined that:

- Under base case (normal) conditions, an additional 2000 MW can be evacuated, i.e. a total of 3000 MW, before a 330 kV line in the TCN system reaches its limit.
- Under contingency conditions, an additional 1700 MW can be evacuated, i.e. total 2700 MW, before a line in the TCN system reaches its thermal limit (777 MVA), in this case the Gombe-Yola 330 kV line (cct1) when the other Gombe-Yola line (circuit 2) is tripped. This is sown in the graphs of **Figure 7-13.**

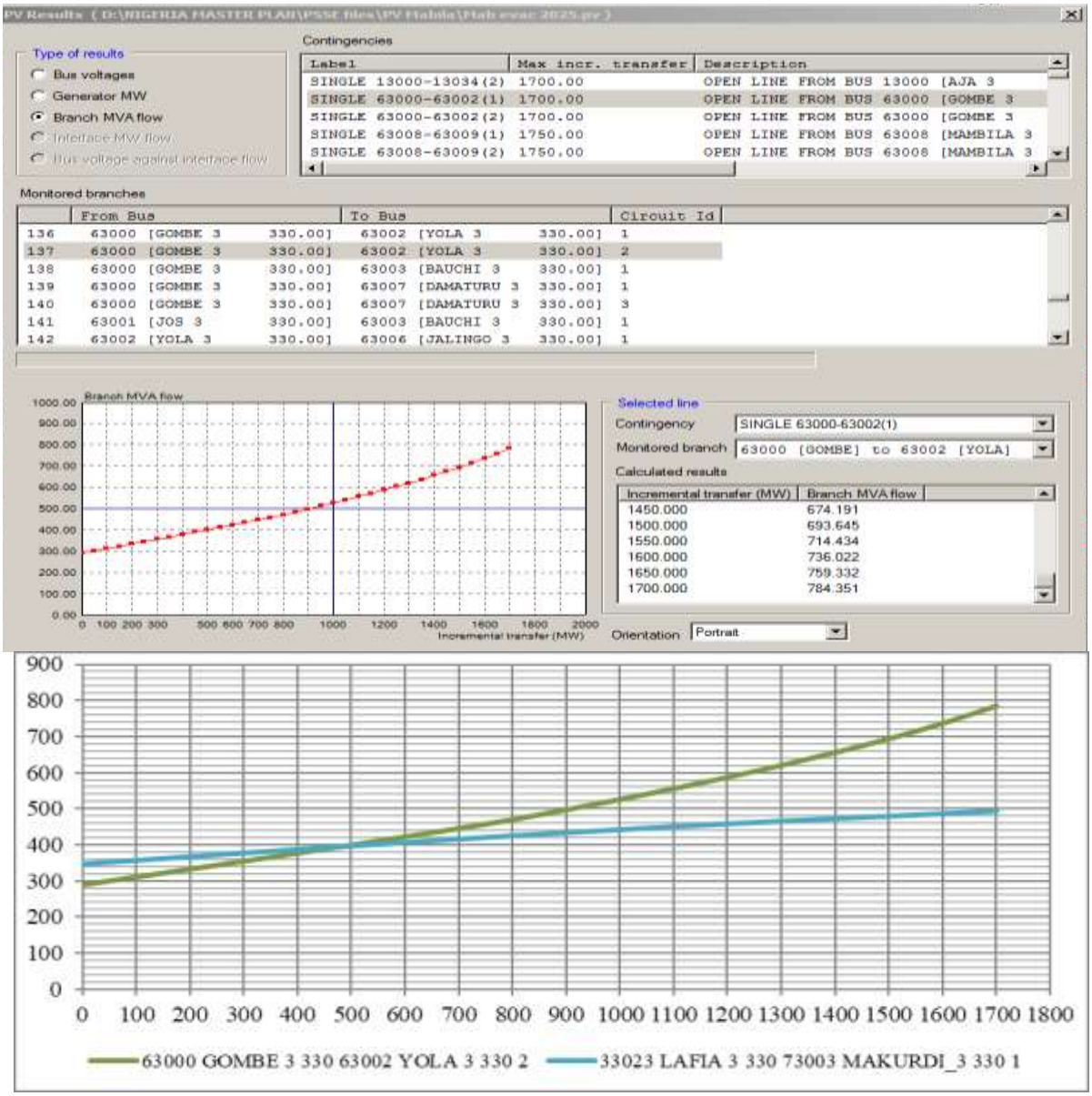


Figure 7-13 PV analysis for Mambila evacuation

Considering that the Mambilla plant is rated 3000 MW and that it is highly unlikely to reach a production of more than 2400 MW, it is concluded that the entire power can be evacuated without the need for any additional reinforcements in the transmission system.

7.5.2.3 Specifications

The following data is used: the 330 kV conductor is 4-bundle ACSR350 per phase, spaced at 400 mm. The conductor types (aluminium conductor steel reinforced):

ACSR 350 'Bison' (381-AL1/49-ST1A; 54 Al wires dia 3.0 mm; 7 Fe wires dia 3.0 mm, i.e. 54/7), Outside diameter 27 mm. The Basic Conductor Characteristics are in **Table 7-30**

Table 7-30 Basic Conductor Characteristics for 330 kV OHL

Description	
Cross section	
Aluminum [mm^2]	381.6
Steel [mm^2]	49.4
Total [mm^2]	431
Stranding and wire diameter	
Aluminum [mm]	54 / 3.0
Steel [mm]	7 / 3.0
Overall diameter [mm]	27

7.5.2.4 330 kV Transmission Line R, X and B

The tower design is shown in **Figure 7-14** and the conductors arrangements in **Figure 7-15**

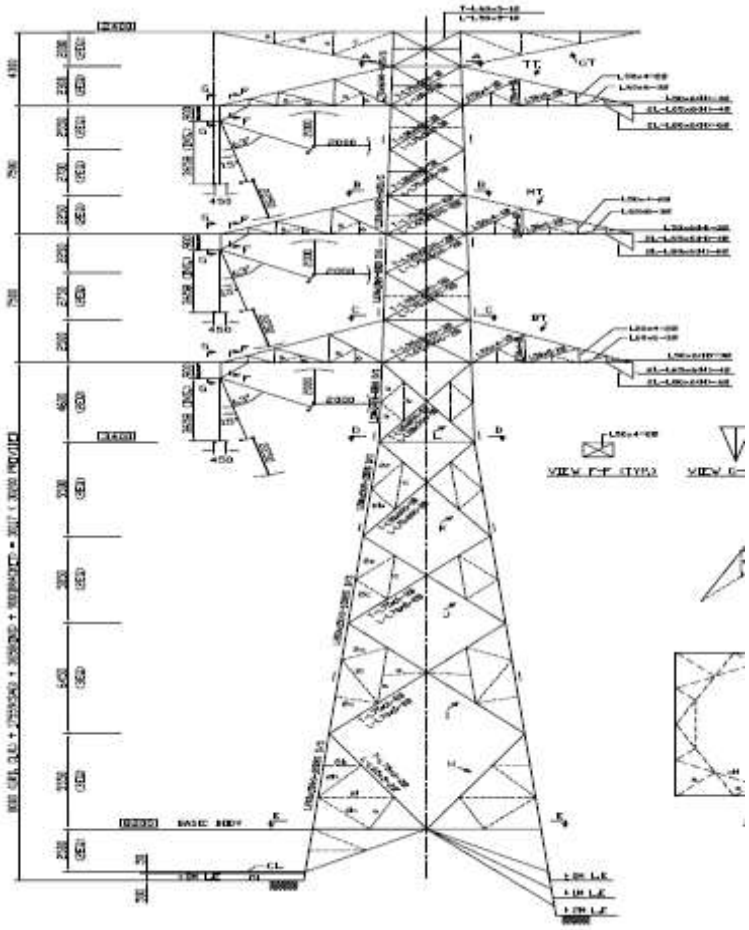


Figure 7-14: Tower Design

On the basis of the above, with d=400mm (1.32 ft):

d=400mm=1.32ft

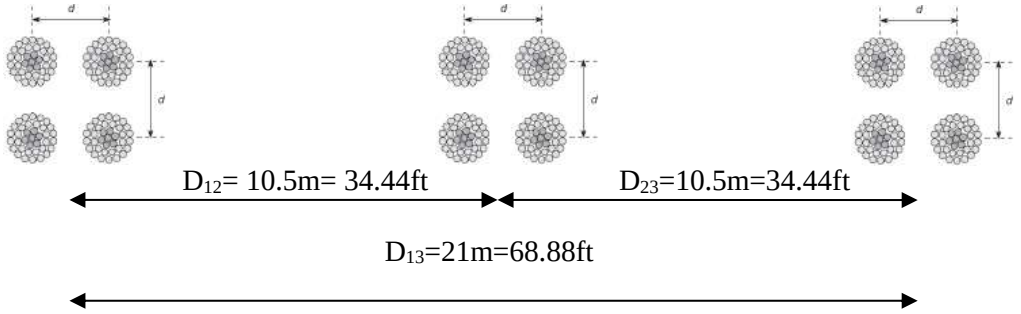
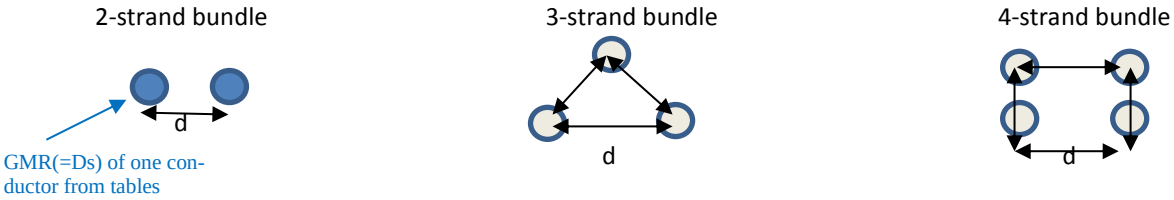


Figure 7-15: Conductors Spacing 330 kV Line

In general:



The Geometric Mean Radius (GMR) of bundled conductors:

$$D_s^b = \sqrt{D_s . d} \qquad D_s^b = \sqrt[3]{D_s . d^2} \qquad D_s^b = 1.09 \sqrt[4]{D_s . d^3}$$

where Ds is the GMR of one stranded conductor.

For Bison conductors, the GMR (=Ds) of one conductor, as taken from tables, is:

GMR=Ds=0.0363 ft

For bundled conductors the equivalent GMR is

$D_s^b = \sqrt{D_s . d}$ for 2-bundle conductors (1)

$D_s^b = \sqrt[3]{D_s . d^2}$ for 3-bunlde conductors (2)

$D_s^b = 1.09 \sqrt[4]{D_s . d^3}$ for 4-bundle conductors (3)

In this case, for 4-b (Quad):

$$D_s^b = 1.09 \sqrt[4]{D_s . d^3} = 1.09 \sqrt[4]{0.0363 \times 1.32^3} = 0.586\ ft$$

The equivalent spacing between phases is:

$$D_{eq} = D_m = \sqrt[3]{D_{12} . D_{23} . D_{31}} = \sqrt[3]{34.44 \times 34.44 \times 68.88} = 43.4\ ft$$

Inductive Reactance:

$X_L = 4.657 \,.\, 10^{-3} \,.\, f \,.\, \log \frac{D_m}{D_s^b} = 0.4353$ ohms/mile $= 0.27$ ohms/km (for SC)

$= 0.25$ ohms/km (for DC)

Capacitance:

$$C_n = \frac{0.0388}{\log \frac{D_{eq}}{D_{s\,c}^b}} \quad \mu F/\text{mile}$$

where $D_{s\,c}^b$ is the equivalent GMR for capacitance calculations and is derived from eq (1), (2) and (3) used for inductance calculations, except that the D_s is replaced by the radius r of the conductor in ft, i.e

$r = \frac{D_{out}}{2 \times 12}$ ft, where D_{out} is the conductor outside diameter in inches

Therefore, for capacitance:

$D_{s\,c}^b = \sqrt{r.d}$ for 2-bundle conductors (4)

$D_{s\,c}^b = \sqrt[3]{r.d^2}$ for 3-bundle conductors (5)

$D_{s\,c}^b = 1.09 \sqrt[4]{r.d^3}$ for 4-bundle conductors (6)

For Bison conductors: $r = \frac{D_{out}}{2 \times 12} = \frac{1.062}{2 \times 12} = 0.04425$ ft

$D_{s\,c}^b = 1.09 \sqrt[4]{r.d^3} = 1.09 \sqrt[4]{0.04425 \times .1.32^3} = 0.6156\, ft$

$C_n = \frac{0.0388}{\log \frac{D_{eq}}{D_{s\,c}^b}} = \frac{0.0388}{\log \frac{43.4}{0.6156}} = 0.021\, \mu F/mile = 0.013\, \mu F/km$ (for SC)

$= 0.014\, \mu F/km$ (for DC)

Susceptance B=ωC=314 x 0.013 = 4.08 μmho/km = 4.08 μS/km), for SC

= 4.39 μS/km), for DC

Resistance: R=0.0762 ohms/km (R=0.019 ohms/km for 4 bundle conductors)

The electrical parameters in PSS/E of the DC 330 kV line Mambila-Wukari and Mambila-Jalingo are summarized in **Table 7-31**.

Table 7-31: Double Circuit 330 kV line characteristics

							PSS/E input data		
From	To	L (km)	R Ω/km	L mH/km	X Ω/km	C μF/km	R (ohms)	X (ohms)	C (μF)
Mambila	Wukari	159	**0.019**	0.7962	**0.25**	**0.014**	**3.021**	**39.750**	**2.2260**
Mambila	Jalingo	95	**0.019**	0.7962	**0.25**	**0.014**	**1.805**	**23.750**	**1.3300**

7.6 Line surge impedance and thermal rating

7.6.1 Surge Impedance Loading Limits - Natural Line Rating

As power flows along a transmission line, there is an electrical phase shift, which increases with distance and with power flow. As this phase shift increases, the system in which the line is embedded can become increasingly unstable during electrical disturbances.

Typically, for very long lines, the power flow must be limited to what is commonly called the Surge Impedance Loading (SIL) of the line.

Surge Impedance Loading is equal to the product of the end bus voltages divided by the surge (characteristic) impedance of the line. Since the characteristic impedance of various HV and EHV lines is not dissimilar, the SIL depends approximately on the square of system voltage:

$$SIL = \frac{kV^2}{Zs}$$

where Zs is the surge impedance of the line: $Zs = \sqrt{\frac{L}{C}} = \sqrt{\frac{0.7962x1000}{0.014}}$ = 238.5 ohms

$$\boldsymbol{SIL = \frac{330^2}{238.5} = 456\ MW}$$

Typically, stability limits may determine the maximum allowable power flow on lines that are more than approx. up to 250 km in length.

7.6.2 Thermal Limits

Thermal power flow limits on overhead lines are intended to limit the temperature attained by the energized conductors and the resulting sag and loss of tensile strength. In most cases, the maximum conductor temperature applied to modern transmission lines reflect ground clearance concerns rather than annealing of aluminum.

Thermal limit are not a function of line length. Thus for a given line design, a line 1 km long and one 500 km long typically have the same thermal limit.

The thermal transmission capacities of the 330 kV OHL has been calculated as follows:

Voltage	330 kV
Conductor Type	3 x AC 381/49
Wind Speed	0.6 m/s
Air temperature	40°C
Maximum conductor temperature	75°C

Thermal Ratings:

Capacity	**1555 MVA**
Capacity	**1400 MW**

7.7 Static security analysis, year 2025

7.7.1 Study cases 2025

Table 7-32 shows the two scenarios which have been studied for 2025, to capture the extreme combinations of generation and load.

Table 7-32: 2025 study cases

Case		Description	Generation	Load [MW]	
Dry Season Peak	DP	Dry Night Peak Load	Reduced HPP generation No PV generation Increased requirement from GTs	Peak load (night)	13715 + export
Dry Season Off-Peak	DOP	Dry Day Off-Peak Load	Reduced HPP generation PV generation Increased requirement from GTs	Off-Peak load (day)	11650 + export

The results of each of the above cases studied are shown diagrammatically in the SLDs of **Annex 7.6.**

7.7.2 Modifications to the 2020 case

In addition to the projects undertaken by TCN and NIPP, the 330 kV and 132 kV lines of **Table 7-33** are included in the 2025 model. These lines are also in addition to those that have been included in the 2020 model.

Table 7-33: Additional lines required by 2025 (1)

No		From	To		kV	km	Remarks	Priority/ Ranking
1		Arigbajo	Ayede	SC	330	50		1
2	Part of North West Ring	Birnin Kebbi	Sokoto	DC	330	130	in parallel of existing 132 kV	3
3		Sokoto	Talata Mafara	DC	330	100		3
4		Talata Mafara	Gusau	DC	330	125		3
5		Gusau	Funtua	DC	330	70		2
6		Funtua	Zaria	DC	330	70		2
7		Olorunsogo	Arigbajo	DC	330	20	Already a DC. 4 circuits are required.	3
8		Katsina	Daura	DC	330	40	Undertaken by TCN as part of the Northern Corridor Transmission projects 2, to be financed by AFD	2
9		Daura	Kazaure	DC	330	25	Undertaken by TCN as part of the Northern Corridor Transmission projects 2, to be financed by AFD	2
10	Part of North	Damaturu	Maiduguri	DC	330	260	If not by 2020, implement as soon as possible thereafter	3

No		From	To		kV	km	Remarks	Priority/ Ranking
	East Ring						(a SC already exists)	
11		Gombe	Damaturu	DC	330	160	If not by 2020, implement as soon as possible thereafter (a SC already exists)	3
12		Gombe	Yola	DC	330	240	If not by 2020, implement as soon as possible thereafter (a SC already exists)	3
13		Yola	Jalingo	DC	330	160	If not by 2020, implement as soon as possible thereafter (1 SC via Mayo Belwa)	3
14	Mam-bila evac-uation	Mambila	Jalingo	2xDC	330	95	2xDC only if N-2 is adopted, otherwise 1xDC	1
15		Mambila	Wukari	2xDC	330	159	2xDC only if N-2 is adopted, otherwise 1xDC	1
16		Wukari	Makurdi	DC	330	159		1
16		Wukari	Lafia	DC	330	95	after 2025	3
18		Shiroro	Kaduna	DC	330	96	or upgrade to 4-b (Quad). Two DC project with quad conductors is un-dertaken by TCN as part of the Northern Corridor Transmission projects 2, to be financed by AFD	3
19		Arigbajo	New Agbara	DC	330	40	JICA.	
20		Arigbajo	Ogijo	DC	330	48	JICA.	
21		New Agbara	Badagry	DC	132	32	JICA.	
22		Arigbajo	New Ajeokuta	DC	132	37	JICA.	

Furthermore, since a number of undervoltages were encountered in the Dry Season Peak case, and also in order to meet the N-1 security criterion, the additions shown in **Table 7-34** were made at 132 kV level:

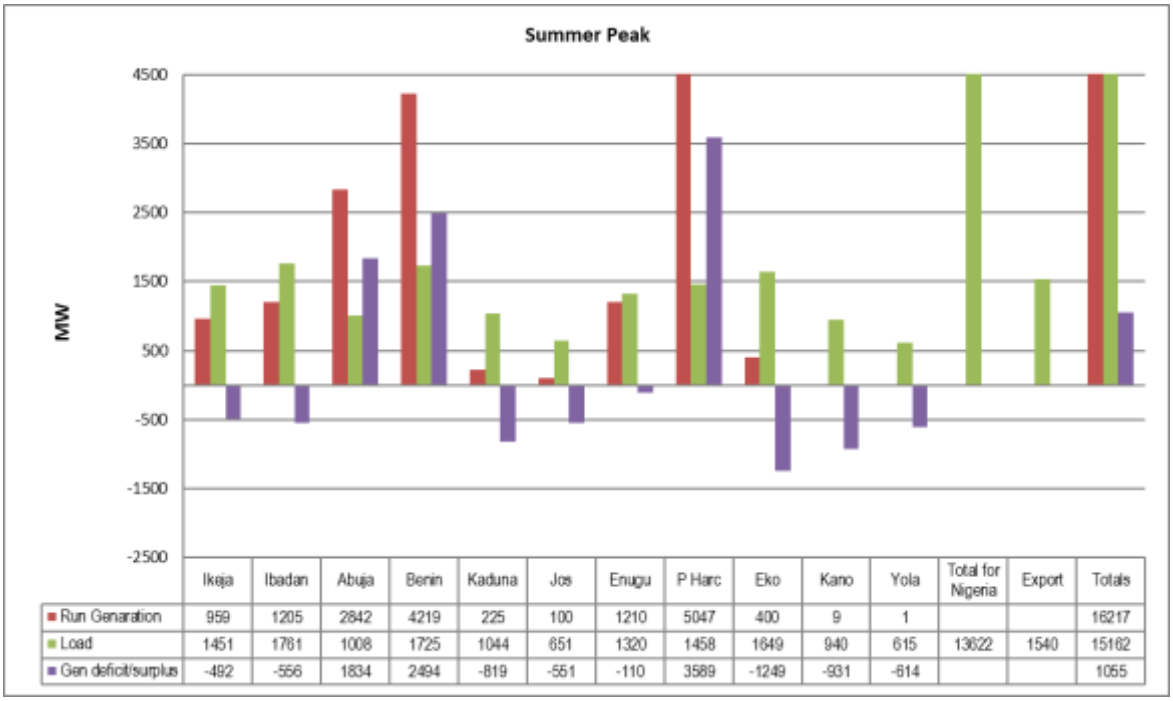
Table 7-34: Additional lines required by 2025 (2)

No	From	To		kV	km	Remarks	Priority/ Ranking
1	Shiroro	Tegina	SC	132	65	SC only exists. Add DC	1
2	Tegina	Kontagora	SC	132	90	SC only exists. Add DC	1
3	Kontagora	Yelwa-Yauri	SC	132	88	SC only exists. Add DC	1
5	Ganmo	Ilorin	SC	132	10.5	check if DC exists	3
6	Obajana	Egbe	DC	132	97	new DC	1
7	Omotosho	Ondo	DC	132	98	new DC	1
8	Benin	Irrua	DC	132	88	SC only exists. Add DC	2
9	Irrua	Ukpilla	DC	132	43	SC only exists. Add DC	2

No	From	To		kV	km	Remarks	Priority/ Ranking
10	Ukpilla	Okene	DC	132	33	SC only exists. Add DC	3
11	Sagamu	Ijebu Ode	SC	132	41	SC only exists. Add DC	3
12	Dakata	Gagarawa	SC	132	89	SC only exists. Add DC	3
13	Gagarawa	Hadejia	SC	132	60	SC only exists. Add DC	3
14	Dakata	Kumbotso	SC	132	30	SC only exists. Add DC	3

7.7.3 Dry Season Peak-2025

Assumptions: (a) Generation from PVs = 0 and (b) Reduced generation from HPP plants of 1458 MW, and the running generation and load for each DisCo is as shown in **Figure 7-16**.



	Ikeja	Ibadan	Abuja	Benin	Kaduna	Jos	Enugu	P Harc	Eko	Kano	Yola	Total for Nigeria	Export	Totals
Run Generation	959	1205	2842	4219	225	100	1210	5047	400	9	1			16217
Load	1451	1761	1008	1725	1044	651	1320	1458	1649	940	615	13622	1540	15162
Gen deficit/surplus	-492	-556	1834	2494	-819	-551	-110	3589	-1249	-931	-614			1055

Bus Name	PGen (MW)		Bus Name	PGen (MW)		Bus Name	PGen (MW)
AES BERG202	28		EGBIN ST 1	85.3		OLOR NIPPST1	100
AES BERG203	28		EGBIN ST 2	85.3		OLOR NIPPST2	100
AES BERG204	28		EGBIN ST 3	85.3		OLORNIPPGT11	100
AES BERG205	28		EGBIN ST 4	85.3		OLORNIPPGT21	100
AES BERG207	28		EGBIN ST 5	85.3		OLORNIPPGT22	100
AES BERG208	28		EGBIN ST 6	85.3		OLORUNSO GT1	30
AES BERG209	28		EGBIN ST_123	108		OLORUNSO GT2	30
AFAM VI GT11	150		ELEME	25		OLORUNSO GT5	30
AFAM VI GT12	150		ETHIOPE	50		OLORUNSO GT6	30
AFAM VI GT13	150		ETHIOPE GTS	200		OLORUNSO GT7	30
AFAM VI ST10	210		ETHIOPE ST	100		OLORUNSO GT8	30
AFAM2 GT5-6	48		GBARAIN_GTB1	112.5		OMA_GT	400

Bus Name	PGen (MW)		Bus Name	PGen (MW)		Bus Name	PGen (MW)
AFAM2GT 7-8	48		GBARAIN_GTB2	112.5		OMOKU1 GT1	41
AFAM3 GT9-10	50		GEN_AMADI	90		OMOKU1 GT2	41
AFAM4GT13-14	130		GEN_KADUNA	200		OMOKU2 GT1	113
AFAM4GT15-16	130		GER NIPPGT21	140		OMOKU2 GT2	120
AFAM4GT17-18	120.1		GER NIPPGT22	140		OMOTNIPP GT1	110
AFAMV GT 19	125		GER NIPPGT23	140		OMOTNIPP GT3	110
AFAMV GT 20	125		GEREGU GT11	130		OMOTNIPP GT4	110
ALAOJI_GTB1	112.5		GEREGU GT12	130		OMOTOSHO 2+	220
ALAOJI_GTB2	112.5		GEREGU GT13	130		OMOTOSO GT1	70
ALAOJI_GTB3	112.5		GURARA GBUS	25		OMOTOSO GT3	70
ALAOJI_GTB4	112.5		IBOM GT1	32		OMOTOSO GT5	62
ALAOJI2_STB1	250		IBOM GT2	32		OMOTOSO GT7	62
ALSCON GT1	100		IBOM GT3	32		ONDO IPP	200
ASCO G1	50		IBOM II	390		PARAS	280
ASCO G2	50		IHOVBOR_GTB1	110		PARASGT1-9	63
AZURA GT	280		IHOVBOR_GTB2	110		PROTON	50
BRESSON GTS	80		IHOVBOR_GTB3	110		QUA IBOE PP	150
CABLE INLAND	400		IHOVBOR_GTB4	110		RIVERS _GT1	170
CALABAR_GTB1	100		JBS WIND	70		SAP_NIPP_GT1	100
CALABAR_GTB2	100		JEBBA 2G1	90		SAP_NIPP_GT2	100
CALABAR_GTB3	100		JEBBA 2G2	90		SAP_NIPP_GT3	100
CALABAR_GTB4	100		JEBBA 2G6	90		SAPELE GT1-2	300
CENTURY IPP	480		KAINJ 1G5	96		SAPELE GT3-4	300
CUMMINS	50		KAINJ 1G6	96		SAPELE ST1	80
DELT3 GT9-11	45		KAINJ 1G7-8	160		SAPELE ST2	80
DELT3GT12-14	30		KAINJ 1G9-10	80		SAPELE ST3	80
DELTA IV 2-1	140		KT WF 33	9		SAPELE ST4	80
DELTA IV 2-2	140		LAFARAGE 1	45		SAPELE ST5	80
DELTA IV 2-3	140		LAFARAGE 2	200		SHIROR 411G1	140
DELTA2 GT3-5	45		MAMBILA GT1	1		SHIROR 411G2	140
DELTA2 GT6-8	45		NIPP2 ST	250		TURBINE DR	100
DELTAIV GT19	100		OKPAI GT11	145		YELLOW STONE	150
DKOWA G1	30		OKPAI GT12	145		ZUMA	100
EGBEMA_GTB1	100		OKPAI GT4PH2	100		ZUMA (GAS)	200
EGBEMA_GTB2	100		OKPAI GT5PH2	100		ZUNGE_G1	150
EGBEMA_GTB3	100		OKPAI ST18	140		ZUNGE_G2	150
			OKPAI STPH2	100		ZUNGE_G4	150

Figure 7-16 Dry Season Peak Generation and Load per DisCo

The power flows are shown in **Figure 7-17**

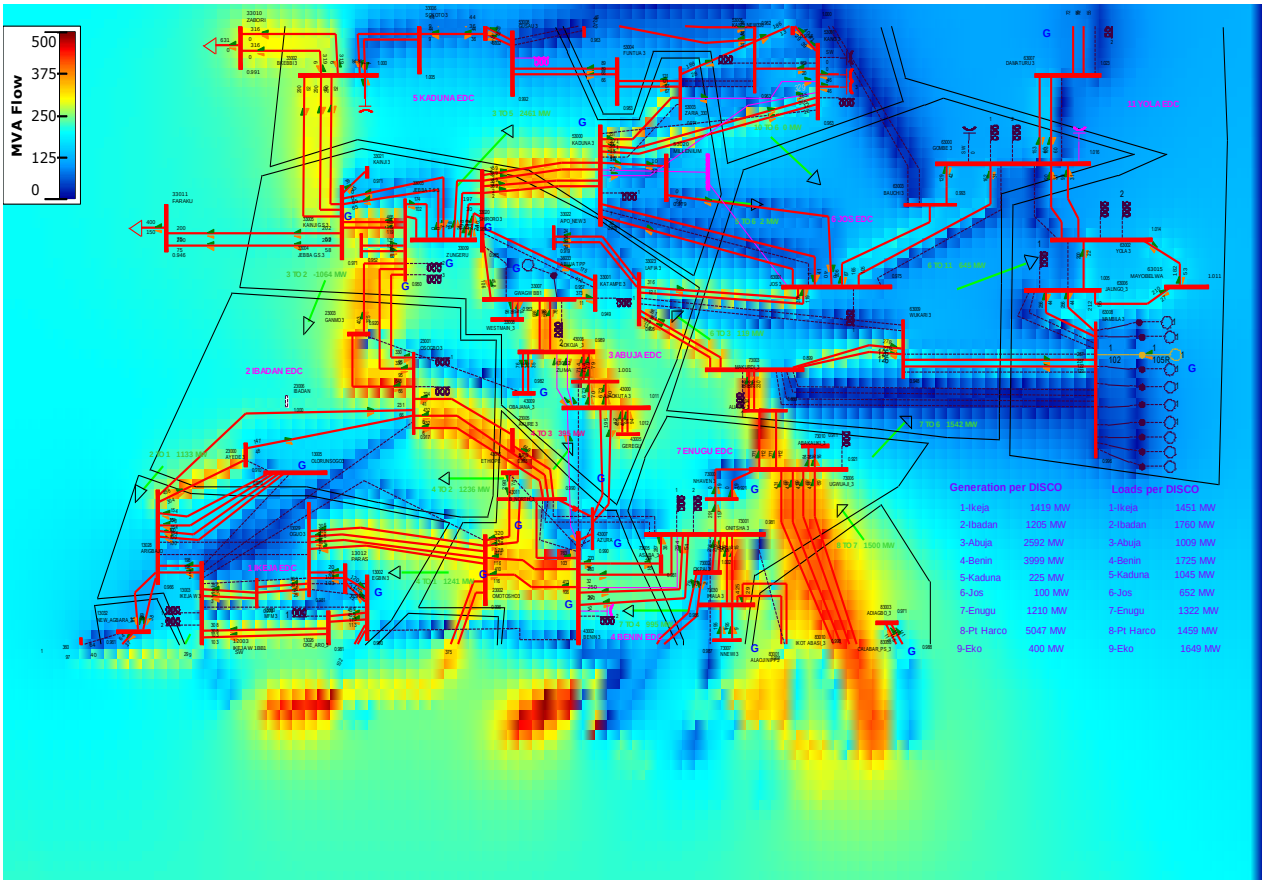
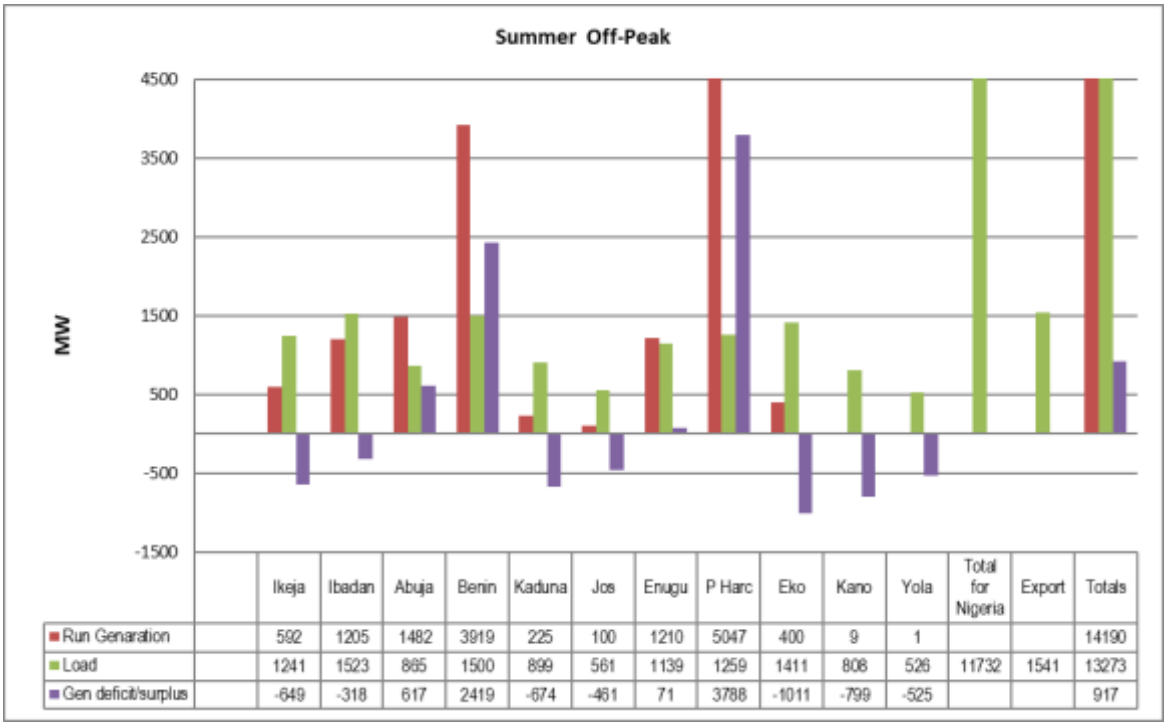


Figure 7-17 2025 Dry Season Peak Power Flows in 330 kV System

7.7.4 Dry Season Off-Peak-2025

Assuming:
(a) Generation from PVs = 0 and
(b) Reduced generation from HPP plants of 1158 MW,

The running generation and load for each DisCo is shown in **Figure 7-18**



	Ikeja	Ibadan	Abuja	Benin	Kaduna	Jos	Enugu	P Harc	Eko	Kano	Yola	Total for Nigeria	Export	Totals
Run Genaration	592	1205	1482	3919	225	100	1210	5047	400	9	1			14190
Load	1241	1523	865	1500	899	561	1139	1259	1411	808	526	11732	1541	13273
Gen deficit/surplus	-649	-318	617	2419	-674	-461	71	3788	-1011	-799	-525			917

Figure 7-18 Dry Season Off-Peak Generation and Load per DisCo

The power flows are shown in **Figure 7-19**

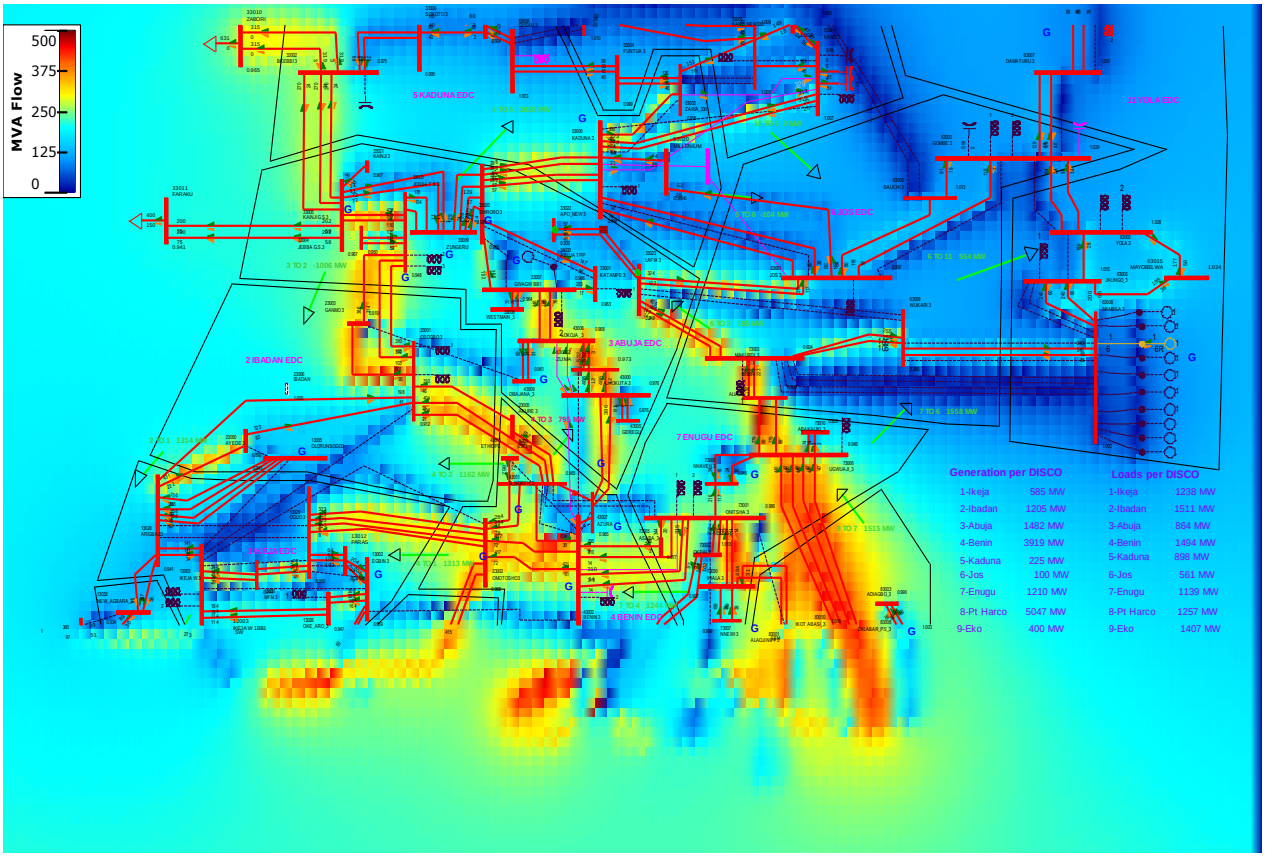


Figure 7-19 2025 Dry Season Off- Peak Power Flows in 330 kV System

7.8 2025 base case load flow results

7.8.1 Voltage violations

No voltage violations are reported, following the additional lines as reported in section 7.7.2 and the additional reactive power equipment (reactors and capacitors) required by 2025. Only the voltage at Uyo 132 kV S/S is 0.82 pu under certain loading conditions and is expected to be corrected when the upgrading of transformers and lines is implemented and additional voltage support by approx 250 MVar capacitors or SVC is provided in the Ikeja area as proposed in section 7.8.3.

7.8.2 Overloads of lines and transformers

The 132 kV lines which are overloaded under normal operation (base case), *in addition to those reported for the 2020 case*, are listed in **Table 7-35.**

Table 7-35: Overloaded 132 kV lines under N-0

From bus no	Bus name	kV	To bus no	Bus name	kV	cct	Loading (MVA)	Rating (MVA)	%
12046	OGIJO 1	132	22027	SAGAMU 1	132	1	168.7	125.7	134.2
12046	OGIJO 1	132	22027	SAGAMU 1	132	2	168.7	125.7	134.2
62026	DADINKOWA 1	132	62039	KWAYA KUSAR	132	2	71.1	69.7	102
82007	PHCT MAIN1	132	82009	PHCT TOWN2 1	132	1	126.9	125.7	100.9

It is noted that most of the above lines have been reported in the 2020 case, but only under N-1 conditions.

(a) The 330/132 kV 3-W and A/T transformers overloaded above their 100% rating MVA under normal (base case) operation, *in addition to those reported for the 2020 case*, are listed in **Table 7-36** and must be upgraded.

Table 7-36: Overloaded 330/132 kV transformers

From bus no	Bus name	kV	To bus no	Bus name	kV	cct	Loading (MVA)	Rating (MVA)	%
83003	ADIAGBO_3	330	3WNDTR	ADIAGB T1A	WND 1	1	159	150	106
83003	ADIAGBO_3	330	3WNDTR	ADIAGB T1B	WND 1	2	159	150	106
12016	AKOKA 1	132	3WNDTR	AKOKA T1	WND 1	1	48.7	45	108.2
23005	AKURE 3	330	3WNDTR	AKURE T1A	WND 1	1	182.2	150	121.5
23005	AKURE 3	330	3WNDTR	AKURE T1B	WND 1	2	182.2	150	121.5
42003	DELTA 1	132	43003	DELTA IV 3	330	1	193.4	150	128.9
42003	DELTA 1	132	43003	DELTA IV 3	330	2	193.4	150	128.9
22003	GANMO TR2 BB	132	3WNDTR	GANMO TR2A	WND 2	1	137.2	120	114.3
73030	IHIALA 3	330	3WNDTR	IHIALA TR	WND 1	1	158.3	150	105.5
12027	ISOLO 1	132	3WNDTR	ISOLO TR3	WND 1	1	49.6	45	110.3
22012	JERICHO 1	132	3WNDTR	JERICO TR1	WND 1	1	59.5	45	132.1
53000	KADUNA 3	330	3WNDTR	KADUNA T3A	WND 1	1	165.9	150	110.6
73007	NNEWI 3	330	3WNDTR	NNEWI T2A	WND 2	1	99.1	67.5	146.8
12046	OGIJO 1	132	3WNDTR	OGIJO T1A	WND 2	1	248.5	240	103.6

From bus no	Bus name	kV	To bus no	Bus name	kV	cct	Loading (MVA)	Rating (MVA)	%
12046	OGIJO 1	132	3WNDTR	OGIJO T2A	WND 2	2	248.5	240	103.6
22014	OMOTOSHO 1	132	3WNDTR	OMOTOSHO TR1	WND 2	1	130.4	120	108.7
22024	OMOTOSHO 2	132	3WNDTR	OMOTOSHO TR2	WND 2	1	133.8	120	111.5
72004	ONITSHA BBII	132	3WNDTR	ONITSH T3A	WND 2	1	135.2	112.5	120.2
72001	ONITSHA 1	132	3WNDTR	ONITSHA T4	WND 2	1	121.5	112.5	108
82028	OWERRI 1	132	3WNDTR	OWERRI T1A	WND 3	1	135.1	130	103.9

(b) The 132/33 kV and 132/11 kV transformers overloaded above their 100% MVA rating under normal (base case) operation, listed in **Table 7-37**, are *in addition* to those overloaded in 2020 and must be upgraded. Some of these transformers, shown in blue fonts, have already been reported in the 2020 case as being overloaded above their 85% rating:

Table 7-37: Overloaded 132/33 kV transformers

From bus no	Bus name	kV	To bus no	Bus name	kV	cct	Loading (MVA)	Rating (MVA)	%
22027	SAGAMU 1	132	25035	SAGAMU 33	33	1	44.2	30	147.4
12029	OJO 1	132	15030	OJO 33	33	1	43.3	30	144.4
32016	SOKOTO 1	132	35050	SOKOTO T3	33	3	41.5	30	138.3
82010	UYO 1	132	85007	UYO 33	33	3	81.5	60	135.9
62025	KAFANCHAN 1	132	65037	KAFANC M TR1	33	3	54.3	40	135.8
52011	GUSAU 1	132	55004	GUSAU 33	33	1	40.3	30	134.3
22012	JERICHO 1	132	25013	JERICHO2 33	33	1	53.2	40	132.9
62012	SAVANNAH 1	132	65010	SAVANNAH 33	33	1	19.7	15	131.1
22008	IWO 1	132	25002	IWO 33	33	1	19	15	126.4
22008	IWO 1	132	25002	IWO 33	33	2	50.6	40	126.4
22005	AKURE 1	132	25018	AKURE T3A 33	33	1	75.3	60	125.6
62020	JALINGO 1	132	65015	JALINGO 33B	33	1	36.4	30	121.4
22005	AKURE 1	132	25003	AKURE 33	33	1	36.3	30	121.1
22000	AYEDE 1	132	25045	AYEDE 33	33	3	71.9	60	119.8
52002	KADUNA 1	132	55041	KAD T2	33	3	71.4	60	119
52011	GUSAU 1	132	55046	GUSAU T1	33	2	35.2	30	117.4
32033	B/KEBBI II	132	35051	BKEBBI T8	33	2	69.4	60	115.7
12019	ALIMOSHO 1	132	15072	ALIMOSHO T1	33	3	34.6	30	115.5
42008	IRRUA 1	132	45002	IRRUA 33	33	1	69.2	60	115.4
22006	IBADAN NORTH	132	25007	IBADAN NORTH	33	1	69.1	60	115.2
82031	IKOT_ABASI	132	85092	IKOT ABAS 33	33	1	45.4	40	113.4
82031	IKOT_ABASI	132	85092	IKOT ABAS 33	33	2	45.4	40	113.4
12037	PARAS_1	132	15116	AFR FOUNDRY	33	1	44.9	40	112.2
12024	IJORA 1	132	15046	IJORA T2B	33	2	33.5	30	111.7
12016	AKOKA 1	132	15067	AKOKA T2	33	1	44.5	40	111.2
82010	UYO 1	132	85030	UYO T2B	33	1	44.4	40	110.9
82010	UYO 1	132	85030	UYO T2B	33	2	44.4	40	110.9

From bus no	Bus name	kV	To bus no	Bus name	kV	cct	Loading (MVA)	Rating (MVA)	%
52003	KADUNA TOWN	132	55006	KADUNA TOWN	33	1	33	30	110.1
52003	KADUNA TOWN	132	55061	KD TWN T1	33	2	33	30	110.1
52003	KADUNA TOWN	132	55069	KD TWN T2	33	3	66	60	110.1
52003	KADUNA TOWN	132	55072	KD TWN T3	33	4	66	60	110.1
82005	EKET 1	132	85003	EKET 33	33	2	65.7	60	109.4
62026	DADINKOWA 1	132	66005	DKOWA G1	11	1	32.7	30	109.1
22001	OSOGBO 1	132	25029	OSOGBO T1	33	1	32.6	30	108.6
62024	MAKERI 1	132	65033	MAKERI 33	33	1	32.3	30	107.7
12023	EJIGBO 1	132	15014	EJIGBO 33	33	1	31.7	30	105.7
12023	EJIGBO 1	132	15014	EJIGBO 33	33	2	31.7	30	105.7
12004	AKANGBA BBII	132	15053	AKANGBA 33	33	1	63.4	60	105.6
52001	KANO 1	132	55057	KUMB T2	33	1	42	40	105.1
42015	AMUKPE 1	132	45026	AMUKPE BB 33	33	1	62.8	60	104.7
12020	ITIRE 1	132	16034	ITERE T3	11	2	41.8	40	104.5
12020	ITIRE 1	132	16032	ITIRE 11	11	1	31.1	30	103.6
12024	IJORA 1	132	15045	IJORA T1A&B	33	2	31	30	103.5
22006	IBADAN NORTH	132	25042	IBADAN T2 BB	33	2	61.2	60	102
82036	RUMUSOI 1	132	85060	RUMUSOI T133	33	1	60.6	60	101
82036	RUMUSOI 1	132	85061	RUMUSOI T233	33	1	60.6	60	101
52015	ZARIA 1	132	55060	ZARIA 33	33	1	60.5	60	100.9
12017	ALAGBON 1	132	15008	ALAGBON 33	33	1	66.3	66	100.5
12017	ALAGBON 1	132	15008	ALAGBON 33	33	2	66.3	66	100.5
62009	BIU 1	132	65040	BIU T2	33	1	30	30	100.1
62025	KAFANCHAN 1	132	65032	KAFANCHAN 33	33	1	60	60	100

7.8.3 Reactive power compensation requirements

The reactive power requirements, i.e. the need to have existing reactors and capacitors in operation and/or install new ones by 2025, including the necessity for new SVCs, are summarized in the following sections. The new equipment is marked in bold.

7.8.3.1 SVC requirements

There is no requirement for an SVC in 2025. More detailed and dedicated studies will be necessary at a later stage to determine any need for such equipment in the period beyond 2025.

In 2025, in addition to the reactors and capacitors listed in tables **Table 7-38, Table 7-39, Table 7-40** and **Table 7-41**, reactive power compensation (150 MVar capacitors) will be required at Birnin Kebbi due to export requirements to WAPP.

With regards to Gombe, should additional reactive power compensation be required at lightly loaded conditions, instead of SVC a more cost effective option would be to relocate from other S/S to Gombe approximately 100-150 MVAR of reactors, as it has been shown in this analysis, that are not needed there anymore.

As it is shown in the static security analysis for 2025, a more appropriate candidate for an SVC (or in fact only Capacitors as there is insufficient supply of MVars) could be the Lagos / Ikeja/Eko region, where there is a reactive power deficit of approximately 400-500 MVar. It should be noted however that this deficit is expected to be greatly reduced when the DisCos implement the reactive power control program at distribution level, as proposed and in line with the Grid Code requirements, as well as when transmission lines and transformers are upgraded, as it has been shown in previous chapters of this report.

7.8.3.2 Reactors

The status of reactors required in ***Dry Season Peak*** case is shown in **Table 7-38.**
The table shows that there is no requirement for reactors in this case.

Table 7-38: Reactor requirements for 2025 dry season peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt (MVar)
13003	IKEJA W 3	330	1	0	-75
13003	IKEJA W 3	330	2	0	-75
13026	OKE_ARO_3	330	1	0	-75
23001	OSOGBO 3	330	1	0	-75
23001	OSOGBO 3	330	2	0	-75
33001	KATAMPE 3	330	1	0	-75
33003	JEBBA T.S.3	330	2	0	-75
33003	JEBBA T.S.3	330	3	0	-75
33007	GWAGW BB1	330	2	0	-75
43002	BENIN 3	330	2	0	-75
53000	KADUNA 3	330	1	0	-75
53001	KANO 3	330	1	0	-75
53005	KANO_NEW330	330	1	0	-75
63001	JOS 3	330	1	0	-75
63002	YOLA 3	330	1	0	-75
63002	YOLA 3	330	2	0	-75
63005	MAIDUGURI 3	330	2	0	-75
73001	ONITSHA 3	330	1	0	-75
73003	MAKURDI_3	330	1	0	-75
83002	ALAOJI 3	330	1	0	-75
73001	ONITSHA 3	330	2	0	-69
63000	GOMBE 3	330	1	0	-50
63000	GOMBE 3	330	2	0	-50
63006	JALINGO_3	330	1	0	-10
65001	YOLA T1 33	33	1	0	-30
65014	GOMBE T4A	33	1	0	-30

The status of reactors required in ***Dry Season Off-Peak*** case is shown in **Table 7-39.**

Table 7-39: Reactor requirements for 2025 dry season off-peak

Bus Number	Bus Name	kV	Id	In Ser-vice	B-Shunt (MVar)
63005	**MAIDUGURI 3**	**330**	**2**	**1**	**-75**
65014	GOMBE T4A	33	1	1	-30

7.8.3.3 Capacitors

The status of capacitors required in ***Dry Season Peak*** case is shown in **Table 7-40.**

Table 7-40: Capacitor requirements for 2025 dry season peak

Bus Number	Bus Name	kV	Id	In Ser-vice	B-Shunt (MVar)
53001	KANO 3	330	2	1	50
53001	KANO 3	330	3	1	50
42015	AMUKPE 1	132	1	1	20
52022	HADEJIA 1	132	1	1	20
22017	**ONDO2 1**	**132**	**1**	**1**	**24**
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
22015	**OMUARAN 1**	**132**	**1**	**1**	**50**
82010	**UYO 1**	**132**	**1**	**1**	**50**
12004	AKANGBA BBII	132	1	1	72
15002	AGBARA 33	33	1	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
35009	KONTAGORA 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15128	EJIGBO 33	33	1	1	24
25011	ILORIN 33	33	1	1	24
45027	**IRRUA BBII33**	**33**	**1**	**1**	**24**

Reference should also be made to the recommendation made in 7.8.3.1 regarding reactive power support in Ikeja West area.

The status of capacitors required in ***Dry Season Off-Peak*** case is shown in **Table 7-41**.

Table 7-41: Capacitor requirements for 2025 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt (MVar)
53001	KANO 3	330	2	1	50
53001	KANO 3	330	3	1	50
42015	AMUKPE 1	132	1	1	20
52022	HADEJIA 1	132	1	1	20
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
12004	AKANGBA BBII	132	1	1	72
15002	AGBARA 33	33	1	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
35009	KONTAGORA 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15128	EJIGBO 33	33	1	1	24

7.8.4 Contingency (N-1) analysis for 330 kV circuits

The contingency N-1 analysis carried out for the 330 kV lines has shown that the following 330 kV DC lines are overloaded and require reinforcement by converting to Quad conductors.

Table 7-42: Overloaded 330 kV lines under N-1

From	To
ALIADE	UGWUAJI
MAKURDI	ALIADE
AJA	LEKKI
GWAGWALADA	LOKOJA
LOKOJA	AJAOKUTA

7.9 2030 base cases load flow analysis and results

7.9.1 Load demand

The increase in load demand follows approximately the same increase (in percentage) in load forecast as detailed in section 5.4.2. Therefore, the demand load in 2030 in each DisCo area is shown in **Table 7-43.**

Table 7-43: Load demand per DisCo

DISCO		Load Demand 2025 [MW]	Increase 2025-2030	Load Demand 2030 [MW]
IKEDC	1-Ikeja	1451	39.57%	2025
IBEDC	2-Ibadan	1780	50.28%	2675
AEDC	3-Abuja	1011	66.92%	1688
BEDC	4-Benin	1750	39.98%	2450
KAEDCO	5-Kaduna	1052	93.96%	2040
JEDC	6-Jos	657	86.06%	1222
EEDC	7-Enugu	1333	25.22%	1669
PHEDC	8-Port Harcourt	1470	43.42%	2108
EKEDC	9-Eko	1651	35.51%	2237
KEDCO	10-Kano	945	59.22%	1505
YOLA	11-Yola	615	83.14%	1126
Total		**13715**	51.26%	**20746**
Export*		1540		1831*
Total load		**15255**		**22577**

(*) Ref 330 kV export lines: To Sakete 550MW, To Faraku 500MW, To Zabori 631MW

The total generation assumed to be running in each DisCo area is shown in **Table 7-44**, as well as in **Figure 7-21**. It includes 640 MW from PV and 3047 MW from HPP.

Table 7-44: Generation per Disco running in 2030

DisCo		Generation [MW]
IKEDC	1-Ikeja	1720
IBEDC	2-Ibadan	1805
AEDC	3-Abuja	3611
BEDC	4-Benin	5479
KAEDCO	5-Kaduna	125
JEDC	6-Jos	100
EEDC	7-Enugu	1210
PHEDC	8-Port Harcourt	6797
EKEDC	9-Eko	1200
KEDCO	10-Kano	649
YOLA	11-Yola	1251

Analytically, the generation assumed running is listed in **Table 7-45**.

Table 7-45: Generation running in 2030

Bus Name	Code	PGen (MW)		Bus Name	Code	PGen (MW)		Bus Name	Code	PGen (MW)
AARON PV	2	0		ESSAR GTS	2	450		NSCP PV	2	0
AES BERG202	2	28		ESSAR ST	2	100		O REN SOL PV	2	0
AES BERG203	2	28		ETHIOPE	2	300		OATS	2	500
AES BERG204	2	28		ETHIOPE GTS	2	200		OBAJANA	4	0
AES BERG205	2	28		ETHIOPE ST	2	100		ODUGPANI NIP	2	200
AES BERG207	2	28		GBARAIN 2 GT	2	600		ODUGPANI NIP	2	300
AES BERG208	2	28		GBARAIN_GTB1	2	112.5		OKPAI GT11	2	145
AES BERG209	2	28		GBARAIN_GTB2	2	112.5		OKPAI GT12	2	145
AES BERG210	-2	0		GEN DANGOTE	4	0		OKPAI GT4PH2	2	100
AES BERG211	-2	0		GEN_AMADI	-2	90		OKPAI GT5PH2	2	100
AFAM VI GT11	2	150		GEN_KADUNA	2	100		OKPAI ST18	2	140
AFAM VI GT12	2	150		GEOMETRIC_AB	4	0		OKPAI STPH2	2	100
AFAM VI GT13	2	150		GER NIPPGT21	2	140		OKPAI_IPPII	4	300
AFAM VI ST10	2	210		GER NIPPGT22	2	140		OLOR NIPPST1	-2	100
AFAM1GT1-2	4	0		GER NIPPGT23	2	140		OLOR NIPPST2	-2	100
AFAM1GT3-4	4	0		GEREGU 2	2	300		OLORNIPPGT11	-2	100
AFAM2 GT5-6	-2	48		GEREGU 2	2	320		OLORNIPPGT12	-2	100
AFAM2GT 7-8	-2	48		GEREGU GT11	4	130		OLORNIPPGT21	-2	100
AFAM3 GT9-10	2	50		GEREGU GT12	4	130		OLORNIPPGT22	-2	100
AFAM3GT11-12	4	0		GEREGU GT13	4	130		OLORUNSO GT1	-2	30
AFAM4GT13-14	2	130		GR COWRI PV	2	0		OLORUNSO GT2	-2	30
AFAM4GT15-16	2	130		GURARA GBUS	2	25		OLORUNSO GT3	4	0
AFAM4GT17-18	2	120.1		HUDSON	2	100		OLORUNSO GT4	4	0
AFAMV GT 19	2	125		IBOM GT1	2	32		OLORUNSO GT5	-2	30
AFAMV GT 20	2	125		IBOM GT2	2	32		OLORUNSO GT6	-2	30
AFRINEGIA PV	-2	0		IBOM GT3	2	32		OLORUNSO GT7	-2	30
ALAOJI_GTB1	2	112.5		IBOM II	2	390		OLORUNSO GT8	-2	30
ALAOJI_GTB2	2	112.5		IHOVBOR 2	2	200		OMA_GT	2	300
ALAOJI_GTB3	2	112.5		IHOVBOR_GTB1	2	110		OMOKU1 GT1	-2	41
ALAOJI_GTB4	2	112.5		IHOVBOR_GTB2	2	110		OMOKU1 GT2	-2	41
ALAOJI2_STB1	2	250		IHOVBOR_GTB3	2	110		OMOKU2 GT1	2	113
ALAOJI2_STB2	4	0		IHOVBOR_GTB4	2	110		OMOKU2 GT2	2	120
ALSCON GT1	2	100		IJORA GT 4-6	4	0		OMOTNIPP GT1	2	110
ALSCON GT2	2	100		JBS WIND	2	70		OMOTNIPP GT2	-2	0
ANJEED PV	-2	0		JEBBA 2G1	-2	80		OMOTNIPP GT3	2	110
ASCO G1	2	50		JEBBA 2G2	-2	80		OMOTNIPP GT4	2	110
ASCO G2	2	50		JEBBA 2G3	-2	80		OMOTOSHO 2+	2	220
AZIKEL	2	400		JEBBA 2G4	-2	80		OMOTOSO GT1	2	70
AZURA GT	2	280		JEBBA 2G5	4	0		OMOTOSO GT3	2	70

Bus Name	Code	PGen (MW)		Bus Name	Code	PGen (MW)		Bus Name	Code	PGen (MW)
AZURA ST	-2	0		JEBBA 2G6	-2	80		OMOTOSO GT5	2	62
BRESSON	2	120		KAINJ 1G11	-2	80		OMOTOSO GT7	2	62
BRESSON GTS	2	80		KAINJ 1G12	4	80		ONDO IPP	2	200
CABLE INLAND	2	1200		KAINJ 1G5	-2	80		PAN AFRIC PV	2	0
CALABAR_GTB1	2	100		KAINJ 1G6	-2	80		PARAS	2	280
CALABAR_GTB2	2	100		KAINJ 1G7-8	-2	160		PARASGT1-9	-2	63
CALABAR_GTB3	2	100		KAINJ 1G9-10	-2	160		PROTON	2	50
CALABAR_GTB4	2	100		KASHIMB HP2	4	0		QUA IBOE PP	2	150
CALABAR_GTB5	4	0		KASHIMB HP3	4	0		QUAINT PV	2	0
CENTURY IPP	2	480		KASHIMB HP4	4	0		RIVERS _GT1	-2	170
CHEVRON TEX	2	500		KASHIMB HPP	2	0		RIVERS_GT2	4	100
CT COSMO PV	2	0		KAZAURE PV1	2	80		SAP_NIPP_GT1	2	100
CUMMINS	2	50		KAZAURE PV10	4	80		SAP_NIPP_GT2	2	100
DELT3 GT9-11	-2	45		KAZAURE PV2	2	80		SAP_NIPP_GT3	2	100
DELT3GT12-14	-2	30		KAZAURE PV3	2	80		SAP_NIPP_GT4	4	0
DELTA IV 2-1	2	140		KAZAURE PV4	2	80		SAPELE GT1-2	2	300
DELTA IV 2-2	2	140		KAZAURE PV5	2	80		SAPELE GT3-4	2	300
DELTA IV 2-3	2	140		KAZAURE PV6	2	80		SAPELE ROT	2	140
DELTA IV 2-4	4	140		KAZAURE PV7	2	80		SAPELE ROT 2	2	140
DELTA1 GT1	4	0		KAZAURE PV8	2	80		SAPELE ROT 2	2	130
DELTA1 GT2	4	0		KAZAURE PV9	4	0		SAPELE ST1	2	80
DELTA2 GT3-5	-2	45		KT WF 33	-2	9		SAPELE ST2	2	80
DELTA2 GT6-8	-2	45		KVKPOWER PV	2	0		SAPELE ST3	2	80
DELTAIV GT19	2	100		LAFARAGE 1	2	45		SAPELE ST4	2	80
DELTAIV GT20	4	100		LAFARAGE 2	2	200		SAPELE ST5	2	80
DKOWA G1	2	30		MAMBILA GT1	2	1		SAPELE ST6	4	0
DUSABLE PV	-2	0		MAMBILA GT10	-2	0		SHIROR 411G1	2	120
EGBEMA II	2	100		MAMBILA GT2	2	250		SHIROR 411G2	2	120
EGBEMA_GTB1	2	100		MAMBILA GT3	2	250		SHIROR 411G3	2	120
EGBEMA_GTB2	2	100		MAMBILA GT4	-2	0		SHIROR 411G4	4	0
EGBEMA_GTB3	2	100		MAMBILA GT5	2	250		SINOSUN PV	4	0
EGBIN ST 1	3	17.2		MAMBILA GT6	-2	0		SYNER GEN PV	4	0
EGBIN ST 2	3	17.2		MAMBILA GT7	-2	0		TURBINE DR	2	300
EGBIN ST 3	3	17.2		MAMBILA GT8	2	250		WESCOM	2	150
EGBIN ST 4	3	17.2		MAMBILA GT9	2	250		YELLOW STONE	2	150
EGBIN ST 5	3	17.2		MBH	2	180		ZUMA	2	100
EGBIN ST 6	3	17.2		MIDBAND PV	2	0		ZUMA (GAS)	2	200
EGBIN ST_123	3	21.5		NIPP2 ST	2	250		ZUNGE_G1	2	150
ELEME	2	25		NOVA SCOT PV	2	0		ZUNGE_G2	2	150
EN ARFICA PV	4	0		NOVA SOLA PV	2	0		ZUNGE_G3	2	1
								ZUNGE_G4	2	150

7.9.2 Requirement for new voltage level (500 or 750 kV)

The load flow simulations with generation and load as detailed in the previous section has shown that without major upgrade of the transmission system, there will be widespread undervoltages and overloads throughout the system and at all voltage levels.

Consequently, the system losses will be high. It is therefore considered necessary and appropriate at this stage to introduce a new "supergrid", i.e. a backbone for bulk transmission at 330, 500 or 750 kV.

A number of configurations have been examined and compared in terms of their efficacy in voltage support, system losses and relieve of line loadings of existing and planned 330 kV system.
The optimum configuration of a 330, 500 or 750 kV EHV grid is shown in **Figure 7-21**.

The supergrid will encompass the following substations, shown in **Table 7-46**:

Table 7-46: New EHV grid Substations

Name of new EHV substations								
Ikot Ekpene	Benin	New Agbara	Osogbo	Gwagwalada	Makurdi	Ajaokuta	Funtua	Kainji

With regards to the conductor necessary for each supergrid option, the following arrangements are recommended:

- At 330 kV a Double Circuit is proposed with 4-bundle (Quad) Bison conductors for each circuit.
- At 500 kV a Single Circuit is proposed with 4-bundle (Quad) Bison conductors.
- At 750 kV a Single Circuit is proposed with 5-bundle Bison conductors, which is typical at this voltage level due to corona phenomenon.

The main electrical characteristics are summarized in the **Table 7-47.**

Table 7-47: Conductor parameters for proposed super grid

Volt-age level		No of Con-duc-tors of bundle	R [ohms/km]	L [mH/km]	X [Ω/km]	C [µF/km]	C [nF/km]	Ther-mal rat-ing [MVA]	Zs [ohms]	SIL [MW]
330 kV	DC	4	0.019	0.7962	0.25	0.014	14	2x1550	238.5	456
500 kV	SC	4	0.019	0.8908	0.2797	0.0127	12.7	2350	264.8	944
750 kV	SC	5	0.015	0.9201	0.2889	0.0123	12.3	4400	273.5	2057

The proposed tower configurations for typical SC 500 and/or 750 kV EHV grid are shown in **Figure 7-20.**

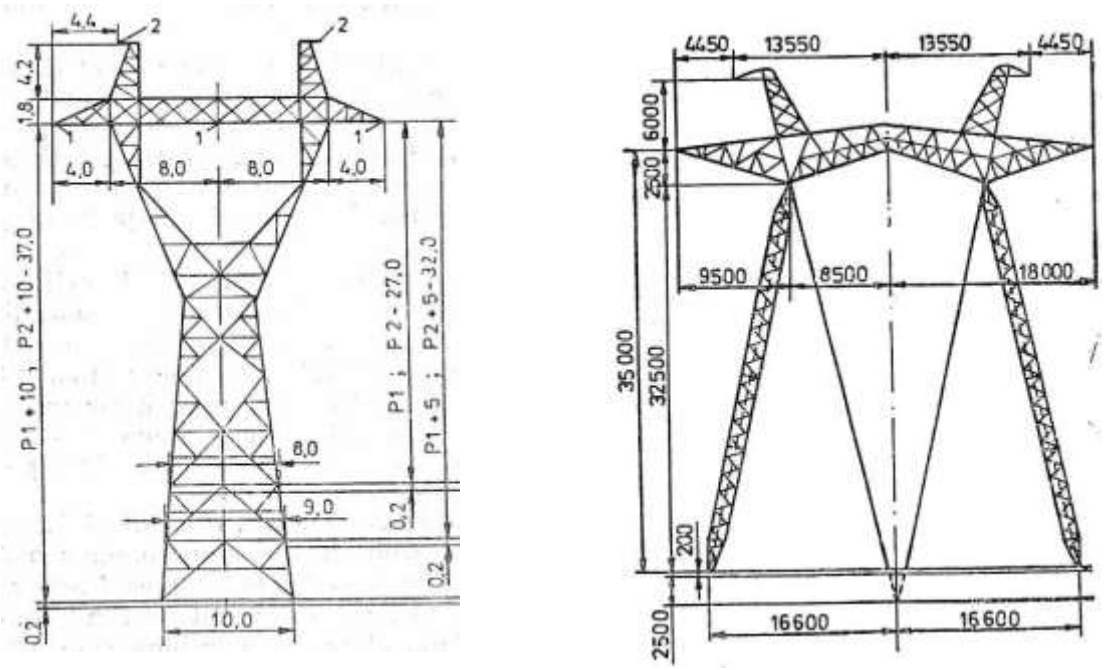


Figure 7-20: Towers for 500 and 750 kV EHV grid

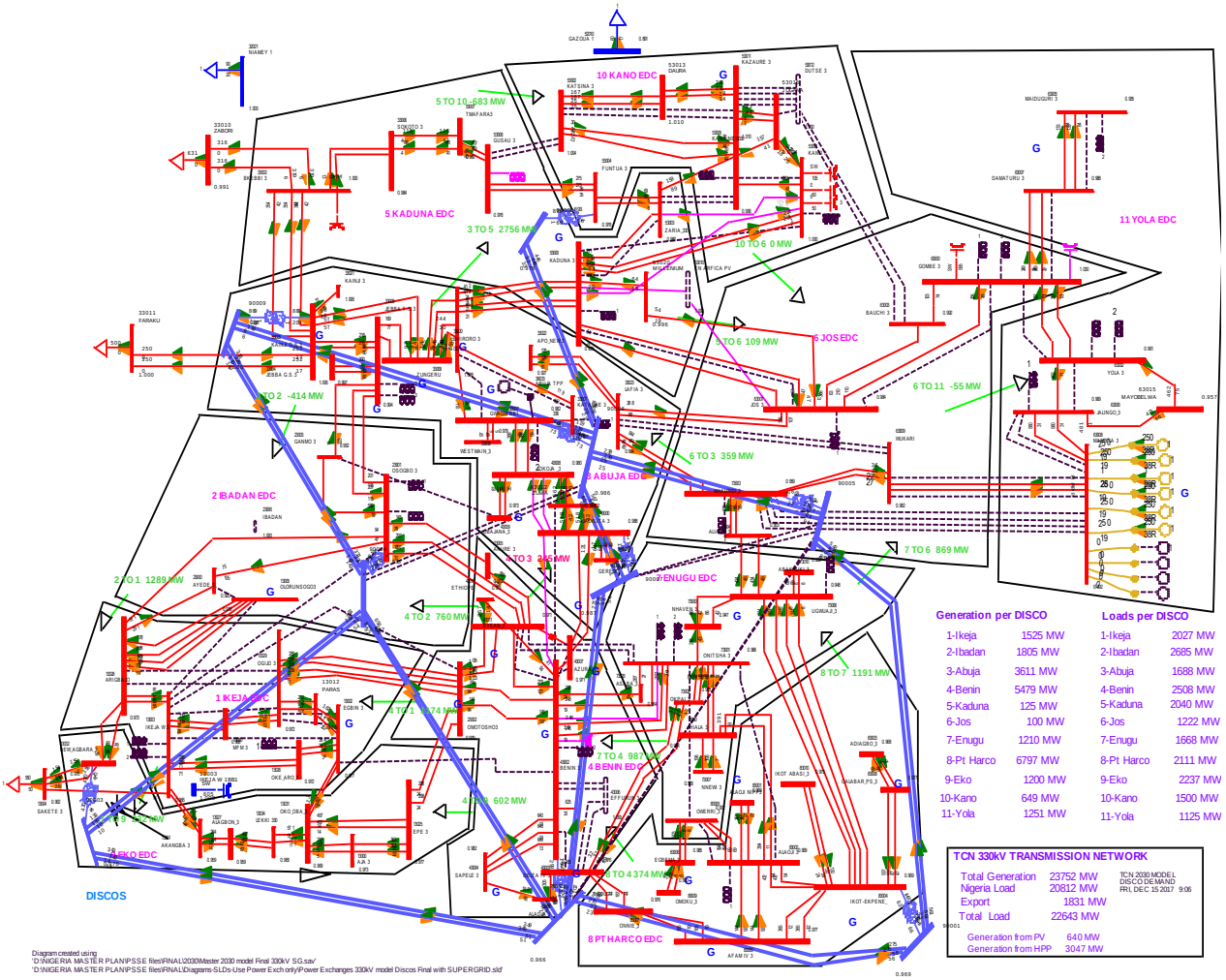


Figure 7-21: Configuration of 330, 500 or 750 kV grid in 2030

7.9.3 Summary of load flow calculations for 2030

The loading of the transmission system is shown in **Figure 7-22**.

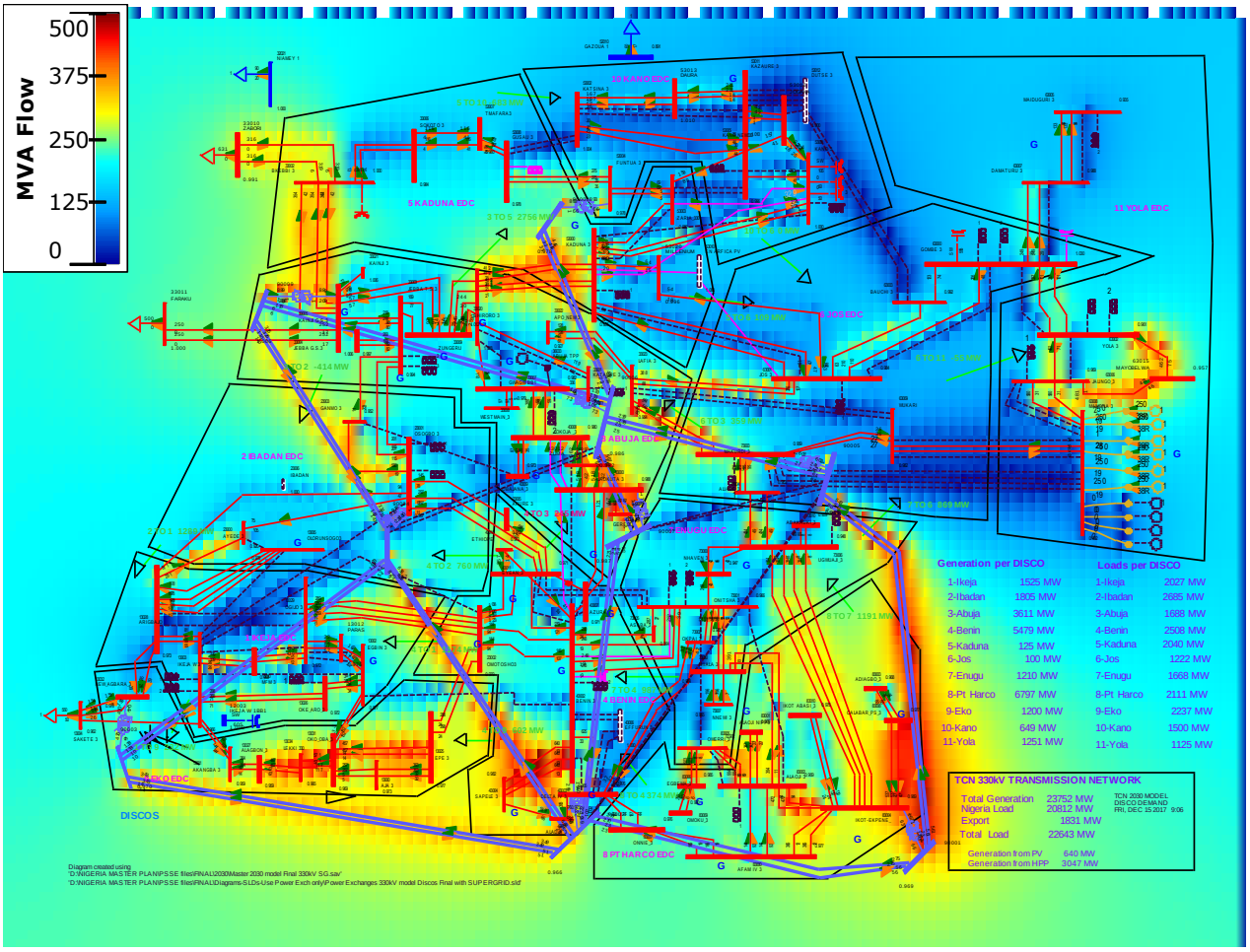


Figure 7-22: Transmission line loadings in 2030

The comparison of load flow results for 2030 between the two EHV options are summarized in **Table 7-48**.

Table 7-48: LF results for 2030

Voltage level	Generation [MW]	O/V and U/V of 330 kV and above (outside 0.9-1.05)	O/L of 330 kV above 80%	Losses [MW]	Remarks
330 kV	23935	none	7 circuits*	1124 (4.69%)	lower losses than 500 kV (line losses are higher but no transformer losses are involved)
500 kV	24056	none	12 circuits *	1264 (5.25%)	206 MW (0.85%) higher losses compared to 750 kV option
750 kV	23904	none	6 circuits**	1058 (4.42%)	slighter lower losses than the 330 kV option

(*) 330 kV

BUS#	X-- NAME	--X	BASKV	AREA	BUS#	X-- NAME	--X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
23001	OSOGBO 3		330.00*	2	23003	GANMO 3		330.00	2	1	626.5	777.3	80.6
23005	AKURE 3		330.00	2	43011	EYEAN_3		330.00*	4	3	641.0	777.3	82.5
43000	AJAOKUTA 3		330.00	4	43005	GEREGU		330.00*	4	1	647.7	777.3	83.3
43000	AJAOKUTA 3		330.00	4	43005	GEREGU		330.00*	4	2	647.7	777.3	83.3
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	1	648.7	777.3	83.5
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	2	648.7	777.3	83.5
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	3	648.7	777.3	83.5

(*) 500 kV

BUS#	X-- NAME	--X	BASKV	AREA	BUS#	X-- NAME	--X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
13000	AJA 3		330.00*	1	13034	LEKKI 330		330.00	1	1	637.0	777.0	82.0
13000	AJA 3		330.00*	1	13034	LEKKI 330		330.00	1	2	637.0	777.0	82.0
13028	ARIGBAJO		330.00*	1	23000	AYEDE 3		330.00	2	1	689.7	777.3	88.7
23001	OSOGBO 3		330.00*	2	23003	GANMO 3		330.00	2	1	651.0	777.3	83.7
23005	AKURE 3		330.00	2	43011	EYEAN_3		330.00*	4	3	760.6	777.3	97.9
43000	AJAOKUTA 3		330.00	4	43005	GEREGU		330.00*	4	1	648.6	777.3	83.4
43000	AJAOKUTA 3		330.00	4	43005	GEREGU		330.00*	4	2	648.6	777.3	83.4
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	1	651.2	777.3	83.8
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	2	651.2	777.3	83.8
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	3	651.2	777.3	83.8
43008	LOKOJA _3		330.00	4	43012	ZUMA		330.00*	4	1	662.9	777.3	85.3
43008	LOKOJA _3		330.00	4	43012	ZUMA		330.00*	4	2	662.9	777.3	85.3

(**) 750 kV

BUS#	X-- NAME	--X	BASKV	AREA	BUS#	X-- NAME	--X	BASKV	AREA	CKT	LOADING	RATING	PERCENT
23005	AKURE 3		330.00	2	43011	EYEAN_3		330.00*	4	3	648.8	777.3	83.5
43000	AJAOKUTA 3		330.00*	4	43005	GEREGU		330.00	4	1	662.1	777.3	85.2
43000	AJAOKUTA 3		330.00*	4	43005	GEREGU		330.00	4	2	662.1	777.3	85.2
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	1	631.4	777.3	81.2
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	2	631.4	777.3	81.2
43002	BENIN 3		330.00	4	43004	SAPELE 3		330.00*	4	3	631.4	777.3	81.2

7.9.4 Conclusion on supergrid/EHV options for 2030

On the basis of technical considerations both the 330 and 500 kV options are adequate. Furthermore, taking into considerations that:

- Capacity of 330 kV supergrid lines: 3100 MVA
- Capacity of 500 kV supergrid lines: 2350 MVA
- Difference in losses between 330 and 500 kV supergrids: Marginal
- Impact on O/U voltages and overloads: 330 kV advantageous
- Higher static N-1 security of the 330 kV supergrid due to double circuit lines involved

It appears that the 330 kV supergrid system is technically the preferred option.

There is no justification to adopt and/or consider further any higher (750 kV) option for the EHV grid, particularly when the implications in cost differences are taken into account, as detailed in section 9.

The higher transmission capacity (4400 MVA) is not required at this stage and the marginal differences in losses cannot offset the high investment cost required in the planning horizon of this Master Plan.

7.10 2035 base cases load flow analysis and results

7.10.1 Load demand

Table 7-49 shows that the increase in load demand follows approximately the same increase (in percentage) as in the load forecast detailed in section 5.4.2.

Table 7-49: Load demand per DisCo

DISCO		Load Demand 2030 [MW]	Increase 2030-2035	Load Demand 2035 [MW]
IKEDC	1-Ikeja	2025	13.66%	2302
IBEDC	2-Ibadan	2675	23.94%	3315
AEDC	3-Abuja	1688	49.86%	2529
BEDC	4-Benin	2450	16.54%	2855
KAEDCO	5-Kaduna	2040	21.82%	2486
JEDC	6-Jos	1222	10.40%	1350
EEDC	7-Enugu	1669	11.36%	1859
PHEDC	8-Port Harcourt	2108	17.70%	2481
EKEDC	9-Eko	2237	13.38%	2537
KEDCO	10-Kano	1505	31.23%	1975
YOLA	11-Yola	1126	51.78%	1710
Total		**20746**	22.42%	**25397**
Export*		1831		2000*
Total load		**22577**		**27397**

(*) Ref 330 kV export lines: To Sakete 550MW, To Faraku 550MW, To Zabori 750MW

The total generation assumed to be running in each DisCo area is shown in **Table** 7-50**,** as well as in **Figure 7-23**. It includes 640 MW from PV and 3300 MW from HPP.

Table 7-50: Generation per DisCo running in 2035

DisCo		Generation [MW]
IKEDC	1-Ikeja	2801
IBEDC	2-Ibadan	1805
AEDC	3-Abuja	4211
BEDC	4-Benin	5779
KAEDCO	5-Kaduna	625
JEDC	6-Jos	100
EEDC	7-Enugu	1660
PHEDC	8-Port Harcourt	7997
EKEDC	9-Eko	1099
KEDCO	10-Kano	5844
YOLA	11-Yola	1501

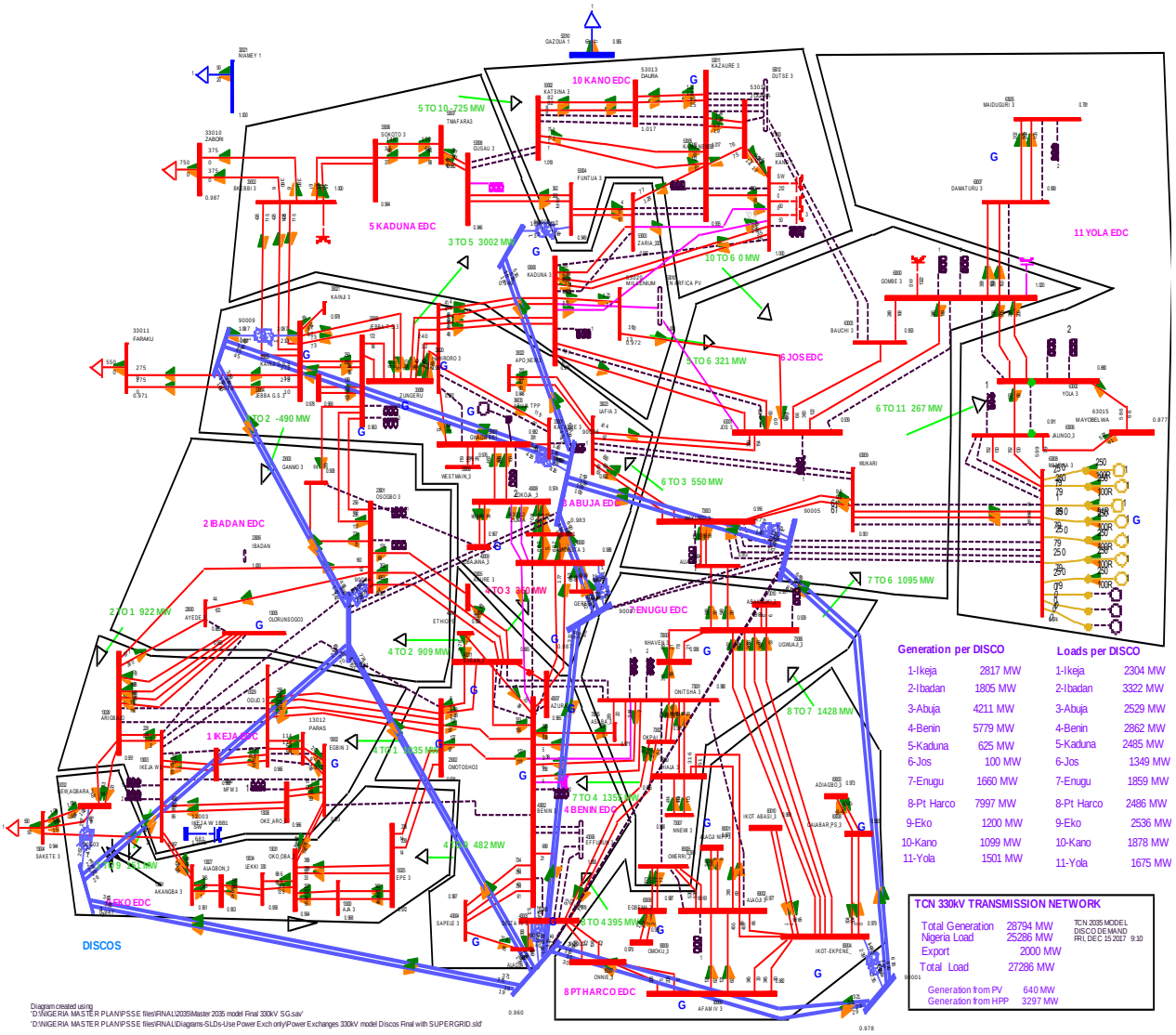


Figure 7-23: Configuration of 330, 500 or 750kV grid in 2035

7.10.2 Summary of load flow calculations for 2035

The loading of the transmission system is shown in **Figure 7-24.**

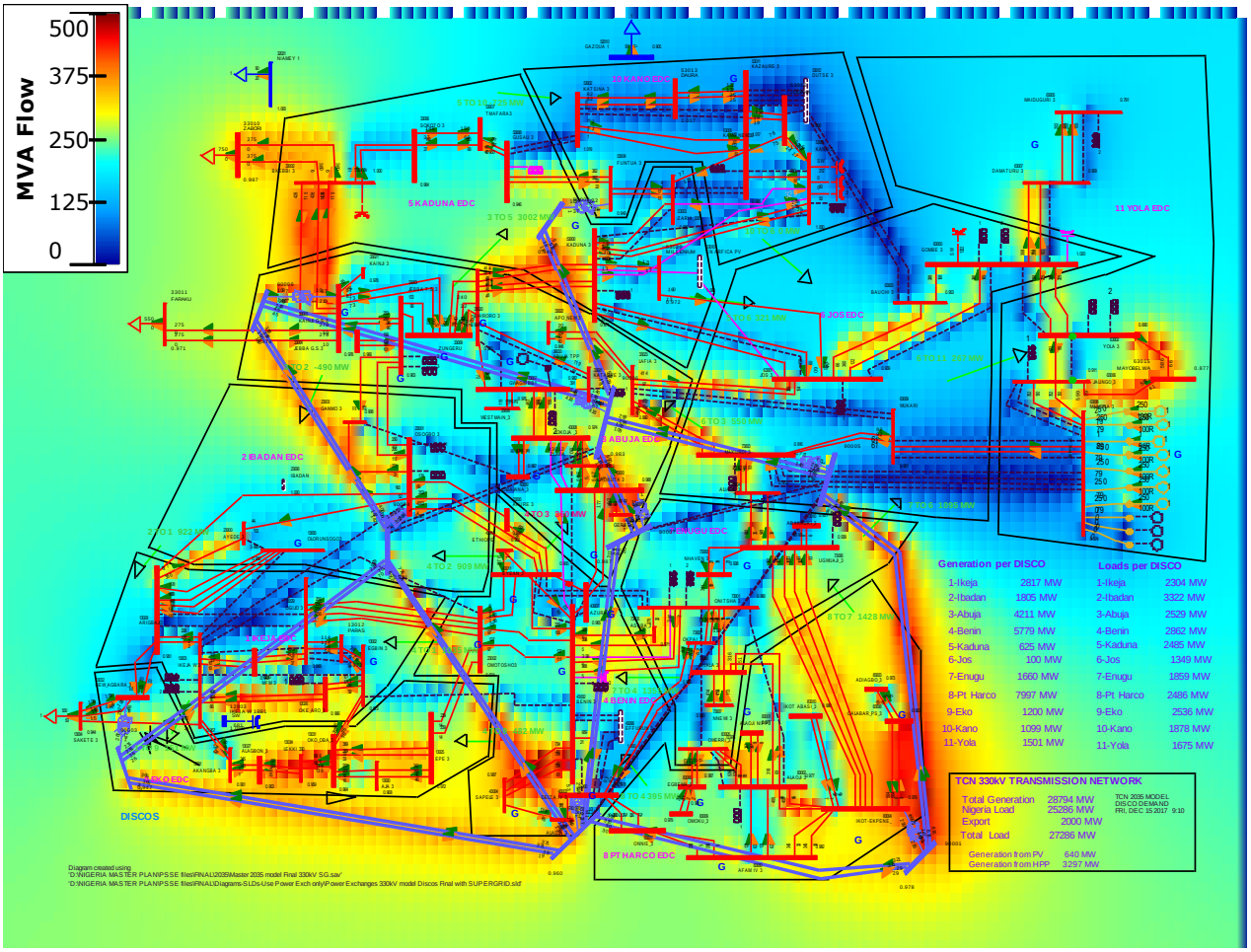


Figure 7-24: Transmission line loadings in 2035

The comparison of load flow results for 2035 between the two EHV options are summarized in **Table 7-51.**

Table 7-51: LF results for 2035

Voltage level	Generation [MW]	O/V and U/V of 330 kV and above (outside 0.9-1.05)	O/L of 330 kV above 80%	Losses [MW]	Remarks
330 kV	28763	5 buses	16 circuits*	1471 (5.11%)	slightly lower losses compared to the 500 kV option
500 kV	28974	10 buses	20 circuits *	1737 (5.99%)	266 MW (0.91%) higher losses compared to the 330 kV option
750 kV	28688	1 bus	12 circuits**	1359 (4.73%)	slightly lower losses compared to the 330 kV option

(*) 330 kV

FROM BUS BUS#	NAME	BASKV	AREA	TO BUS BUS#	NAME	BASKV	AREA	CKT	LOADING	RATING	PERCENT
13000	AJA 3	330.00*	1	13034	LEKKI 330	330.00	1	1	691.9	777.0	89.1
13000	AJA 3	330.00*	1	13034	LEKKI 330	330.00	1	2	691.9	777.0	89.1
13028	ARIGBAJO	330.00*	1	23000	AYEDE 3	330.00	2	1	779.3	777.3	100.3
23001	OSOGBO 3	330.00*	2	23003	GANMO 3	330.00	2	1	782.9	777.3	100.7
23005	AKURE 3	330.00	2	43011	EYEAN_3	330.00*	4	3	767.9	777.3	98.8
33023	LAFIA 3	330.00	3	73003	MAKURDI_3	330.00*	7	1	658.4	777.3	84.7
33023	LAFIA 3	330.00	3	73003	MAKURDI_3	330.00*	7	2	658.4	777.3	84.7
43000	AJAOKUTA 3	330.00	4	43005	GEREGU	330.00*	4	1	646.7	777.3	83.2
43000	AJAOKUTA 3	330.00	4	43005	GEREGU	330.00*	4	2	646.7	777.3	83.2
43000	AJAOKUTA 3	330.00*	4	43012	ZUMA	330.00	4	1	668.8	777.3	86.0
43000	AJAOKUTA 3	330.00*	4	43012	ZUMA	330.00	4	2	668.8	777.3	86.0
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	1	753.5	777.3	96.9
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	2	753.5	777.3	96.9
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	3	753.5	777.3	96.9
43008	LOKOJA _3	330.00	4	43012	ZUMA	330.00*	4	1	716.0	777.3	92.1
43008	LOKOJA _3	330.00	4	43012	ZUMA	330.00*	4	2	716.0	777.3	92.1

(*) 500 kV

FROM BUS BUS#	NAME	BASKV	AREA	TO BUS BUS#	NAME	BASKV	AREA	CKT	LOADING	RATING	PERCENT
13000	AJA 3	330.00*	1	13034	LEKKI 330	330.00	1	1	753.7	777.0	97.0
13000	AJA 3	330.00*	1	13034	LEKKI 330	330.00	1	2	753.7	777.0	97.0
13002	EGBIN 3	330.00*	1	13026	OKE_ARO_3	330.00	1	1	687.8	777.3	88.5
13002	EGBIN 3	330.00*	1	13026	OKE_ARO_3	330.00	1	2	687.8	777.3	88.5
13028	ARIGBAJO	330.00*	1	23000	AYEDE 3	330.00	2	1	898.2	777.3	115.5
23001	OSOGBO 3	330.00*	2	23003	GANMO 3	330.00	2	1	796.7	777.3	102.5
23005	AKURE 3	330.00	2	43011	EYEAN_3	330.00*	4	3	931.6	777.3	119.9
33023	LAFIA 3	330.00	3	73003	MAKURDI_3	330.00*	7	1	637.3	777.3	82.0
33023	LAFIA 3	330.00	3	73003	MAKURDI_3	330.00*	7	2	637.3	777.3	82.0
43000	AJAOKUTA 3	330.00	4	43005	GEREGU	330.00*	4	1	650.6	777.3	83.7
43000	AJAOKUTA 3	330.00	4	43005	GEREGU	330.00*	4	2	650.6	777.3	83.7
43000	AJAOKUTA 3	330.00*	4	43012	ZUMA	330.00	4	1	789.0	777.3	101.5
43000	AJAOKUTA 3	330.00*	4	43012	ZUMA	330.00	4	2	789.0	777.3	101.5
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	1	761.6	777.3	98.0
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	2	761.6	777.3	98.0
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	3	761.6	777.3	98.0
43008	LOKOJA _3	330.00	4	43012	ZUMA	330.00*	4	1	836.3	777.3	107.6
43008	LOKOJA _3	330.00	4	43012	ZUMA	330.00*	4	2	836.3	777.3	107.6
73004	ALIADE_3	330.00	7	73006	UGWUAJI_3	330.00*	7	1	693.8	777.3	89.3
73004	ALIADE_3	330.00	7	73006	UGWUAJI_3	330.00*	7	2	693.8	777.3	89.3

(**) 750 kV

FROM BUS BUS#	NAME	BASKV	AREA	TO BUS BUS#	NAME	BASKV	AREA	CKT	LOADING	RATING	PERCENT
13000	AJA 3	330.00*	1	13034	LEKKI 330	330.00	1	1	693.7	777.0	89.3
13000	AJA 3	330.00*	1	13034	LEKKI 330	330.00	1	2	693.7	777.0	89.3
13028	ARIGBAJO	330.00*	1	23000	AYEDE 3	330.00	2	1	774.0	777.3	99.6
23001	OSOGBO 3	330.00*	2	23003	GANMO 3	330.00	2	1	660.0	777.3	84.9
23005	AKURE 3	330.00	2	43011	EYEAN_3	330.00*	4	3	782.7	777.3	100.7
43000	AJAOKUTA 3	330.00*	4	43005	GEREGU	330.00	4	1	654.4	777.3	84.2
43000	AJAOKUTA 3	330.00*	4	43005	GEREGU	330.00	4	2	654.4	777.3	84.2
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	1	728.9	777.3	93.8
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	2	728.9	777.3	93.8
43002	BENIN 3	330.00	4	43004	SAPELE 3	330.00*	4	3	728.9	777.3	93.8
43008	LOKOJA _3	330.00	4	43012	ZUMA	330.00*	4	1	653.3	777.3	84.0
43008	LOKOJA _3	330.00	4	43012	ZUMA	330.00*	4	2	653.3	777.3	84.0

7.10.3 Conclusion on EHV options for 2035

The conclusions are the same as for the year 2030 cases. On the basis of technical considerations both the 330 and 500 kV options are adequate. Furthermore, taking into considerations that:

- Capacity of 330 kV supergrid lines: 3100 MVA
- Capacity of 500 kV supergrid lines: 2350 MVA
- Difference in losses between 330 and 500 kV supergrids: Marginal
- Impact on O/U voltages and overloads: 330 kV advantageous
- Higher static N-1 security of the 330 kV supergrid due to double circuit lines involved

It appears that the 330 kV supergrid system is technically the preferred option.

There is no justification to adopt and/or consider further any higher (750 kV) option for the EHV grid, particularly when the implications in cost differences are taken into account, as detailed in section 9. The higher transmission capacity (4400 MVA) is not required at this stage and the marginal differences in losses cannot offset the high investment cost required in the planning horizon of this Master Plan.

7.11 Fault Analysis

7.11.1 General

Short circuit calculations were carried out for three phase faults under all load scenarios. As result of the calculations, design parameters for new substation and lines, short circuit levels on existing substations and the impact of the expansion measures are shown. The calculation of short circuit currents is important since they are a measure to indicate the strength of both systems which will be interconnected.

The short-circuit calculations were performed according to IEC 60909 standard. The following values have been determined at all 330 kV and 132 kV substations of the TCN network:

- 3-phase symmetrical short circuit power S_{k3} (MVA)
- $I_{k3"}$ total symmetrical short-circuit current for three phase solid faults

The calculations are based on the operational condition that is available in the corresponding load flow scenarios.

7.11.2 Short circuit results year 2020

The results of the preliminary fault analysis, carried out according to IEC 60909, are summarized in **Annex 7.8** (Table 1) for all 330 kV and 132 kV substations.

The most critical 330 kV and 132 kV substations are shown in **Table 7-52.**

Table 7-52: Fault analysis results 2020

Bus no	Name	kV	I [A]		Bus no	Name	kV	I [A]
43002	BENIN 3	330	34978.1		12003	IKEJA W	132	29639.5
83000	AFAM IV	330	28281.1		82000	AFAM 1-	132	29215.9
83002	ALAOJI	330	27392.5		12042	OKE_ARO	132	26949.7
43004	SAPELE	330	26899.1		12019	ALIMOSH	132	25650.4
23002	OMOTOSH	330	25766.4		82001	ALAOJI	132	23479

The most critical 330 kV substations are BENIN, OMOTOSHO, SAPELE, ALAOJI and AFAM IV, with fault levels ranging from 34.9 kA to 25.7 kA for a 3ph busbar fault.

The most relatively critical 132 kV substation is IKEJA WEST, with fault level of 29.6 kA.

It is clear from this analysis that the TCN standard switchgear ratings of 31.5 kA are inadequate in future when new power plants are to be commissioned in the following years.

7.11.3 Short circuit results year 2025

The results of the preliminary fault analysis, carried out according to IEC 60909, are summarized in **Annex 7.8** (Table 2) for all 330 kV and 132 kV substations.

The most critical 330 kV and 132 kV substations are shown in **Table 7-53.**

Table 7-53: Fault analysis results 2025

Bus no	Name	kV	I [A]		Bus no	Name	kV	I [A]
43002	BENIN 3	330	54312		12003	IKEJA W	132	39306
23002	OMOTOSH	330	52626		12042	OKE_ARO	132	34791
43007	AZURA	330	51856		12019	ALIMOSH	132	33070
43011	B_NORTH	330	51856		82000	AFAM 1-	132	30109
13002	EGBIN 3	330	42069		82002	AFAM IV	132	30035

The most critical 330 kV substations are BENIN, OMOTOSHO, AZURA, EGBIN and BENIN, with fault levels ranging from 54.3 kA to 42 kA for a 3ph busbar fault.

The most relatively critical 132 kV substation is IKEJA WEST, with fault level of 39.3 kA.

It is clear from this analysis that the TCN standard switchgear ratings of 31.5 kA are inadequate in future when new power plants are to be commissioned in the following years.

7.11.4 Remedial measures

In order to solve the violations detected in the substations of TCN network, the following solutions could be adopted:

a) Install switchgear with breakers with a higher breaking capacity (63 kA).

b) Study different topological configurations of the elements connected to the different bus sections, performing dedicated analyses aimed at verifying that the new configuration satisfies the security criteria adopted by TCN.

c) Install Current Limiting Reactors (CLR) aimed at reducing the short circuit currents contributions from adjacent bus sections. This solution allows a general reduction of the short circuits current while maintaining electrically connected the bus sections.

7.12 Dynamic simulations

7.12.1 Evaluation Criteria

In this study, the stability and performance criteria described in this section are used to evaluate the simulation results.

Stability
The stability of the power systems is considered with respect to angle, voltage, and frequency stability defined as follows:

i. Angle stability of the system is assessed by the time evolution of all synchronous generator rotor angles relative to that of a chosen reference machine operating in the same AC system. When the relative time evolution of any synchronous generator rotor angle increases a periodic to a 180-electrical degrees threshold without bound, that machine and thus the system is assessed to be transiently unstable.

ii. Voltage stability is assessed in terms of steady-state feasibility, i.e. power flow solution converges for all pre-contingency conditions, and dynamic recovery, i.e. bus voltages in the TCN power system recover to sufficiently acceptable steady-state levels for all post-contingency conditions. A dynamic recovery with sustained oscillations is also considered to be voltage-unstable.

iii. Frequency stability is assessed in terms of dynamic recovery, i.e. system recovery to acceptable steady-state levels for all post-contingency conditions causing load-generation imbalance. A dynamic recovery with sustained oscillations is also considered to be frequency-unstable.

Performance
The frequency, voltage, and fault-clearing performance standards used in this study are in accordance with the TCN's Grid Code.

The frequency ranges are defined as follows, in accordance with the Grid Code, stating:
The nominal Frequency of the system shall be 50Hz. The National Control Centre will endeavour to control the System Frequency within a narrow operating band of +/- 0.5% from 50Hz (49.75 – 50.25 Hz), but under System Stress the Frequency on the Power System could experience variations within the limits of 50 Hz +/- 2.5% (48.75 – 51.25 Hz).

Under extreme system fault conditions all Generating Units are permitted to disconnect (unless otherwise agreed in writing with the System Operator):
(a) at a Frequency greater than or equal to 51.50 Hz, provided that for frequency excursions up to 51.75 Hz of no more than 15 seconds it shall remain synchronized with the system; or

(b) at a Frequency less than or equal to 47.5 Hz.

Frequency Range:

(i)	Normal range	49.75 – 50.25 (+/-0.5%)	Hz
(ii)	Under transient disturbed conditions	48.75 – 51.25 (+/-2.5%)	Hz

The voltage ranges are defined as follows:

Voltage Range:

	Operation of 330 kV system	Min (%)	Max (%)
(i)	Under normal operation	85	105
(ii)	Under contingency conditions	80	110

Fault-Clearing
The TCN Grid Code states that typical fault clearance times for main protection schemes are as follows:
(a) 60 ms for faults cleared by busbar protection at 330 kV and 132 kV.
(b) 80 ms for faults cleared by distance protection on 330 kV and 132 kV overhead lines.
(c) 80 ms for faults cleared by transformer protections on HV transformers.

In these simulations the maximum fault clearing times considered are 100 ms, as a more conservative (and hence safer) approach.

7.12.2 Dynamic models

7.12.2.1 Conventional generation

Generators, exciters and governors are represented in PSS/E by the following models:

Generators: GENROU, GENSAL
Exciters: SEXS, EXST1
Governors: WSIEG1,GAST

7.12.2.2 PV and wind generation

The modeling approach of wind and PV generation is based on PSSE wind and PV models with typical parameters. Certain model parameters may be modified in cases requiring improved performance.

Standard, valid, generic, non-confidential stability models have been developed for studies such as this one. The term generic refers to a model that is standard, public, and not specific to any vendor, so that it can be parameterized in order to reasonably emulate the dynamic behavior of a wide range of equipment while not directly representing any actual turbine controls.

Models are and will continue to be implemented by the software developers, so that the wind turbine manufacturers can then describe the model for a specific wind turbine by reference to a model and a set of the corresponding model parameters.

As variable RES penetration increases, the power system security assessment becomes more complicated. Often the snapshots typically chosen for transmission planning studies include high-load and low-load situations. However, high RES plant output during shoulder periods may create new transmission system loading patterns and lead to high stress periods on the transmission system, which had not been previously experienced and now needs to be analyzed. Wind and PV power means adding more situations to be studied than just some snapshots, preferably a high number of cases to represent possible wind and load situations.

On modeling, it has been widely recognized in the last years that the power system industry needs dynamic models of wind (and PV) power plants and their components as RES power plants represent a relatively new type of generation with unique characteristics, e.g., they are comprised of a large number of individual units, cover large geographical areas, and often make use of power electronic converters to perform different control functions. Of particular interest to the industry are positive-sequence dynamic models of the type routinely used for simulation of large-scale power system networks.

The PSSE models cover all 4 types of WTG:

- Type 1: Conventional Induction generator
- Type 2: Variable rotor-resistance induction generator
- Type 3: Double fed asynchronous generator
- Type 4: Full converter module

The model for PV plant is based on type 4 WTG model, with additional ability to simulate output changes due to solar irradiation

The Western Electric Coordinating Council (WECC) Renewable Energy Modeling Task Force (REMTF), in North America and the IEEE Working Group on Dynamic Performance of Renewable Energy Systems have jointly developed a set of generic renewable energy system models that capture wind generation, photovoltaic (PV) generation and battery energy storage. These so-called 2nd generation models have been implemented in various commercial software, including PSS/E v33 (PSS/E v32 contains only 1st generation models).

In this study each of the equivalent PV and Wind generators is modeled by one set of the following PSS/E models:

- REGCAU1 (Renewable Energy Generator/Converter Model)
- REECBU1* (Generic Electrical Control Model for large scale PV)
- REPCAU1 (Generic Renewable Plant Control Model)

(*) REECAU1 is for Wind

Each PV plant model can simulate functions typically applied in PV plants such as:

- Various reactive power/voltage control modes such power factor control or voltage control at POI
- Low voltage ride through capability and dynamic reactive current injection
- Active power reduction in case of over-frequency

7.12.3 Study cases

Table 7-54 shows the cases which have been simulated for 2020 and 2025, as a typical representation of extreme scenarios.

Table 7-54: Dynamic study cases

Case	Scenario	Fault at bus	Trip line / disturbance
F1	2020 Dry Season Peak	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo
F2		Benin 330 kV	Trip 330 kV line from Benin to Omotosho
F3		Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi
F4		Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji
F5		Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro
F6		Afam 330 kV	Trip largest generating unit Afam VI
F7	2020 Dry Season Off-Peak	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro
F8	2025 Dry Season Peak	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo
F9		Benin 330 kV	Trip 330 kV line from Benin to Omotosho
F10		Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi
F11		Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji
F12		Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro

7.12.4 Simulation Cases for Peak 2020 Dry Season Peak

Table 7-55 shows the cases which have been simulated for 2020.

Table 7-55: Dynamic simulation study cases

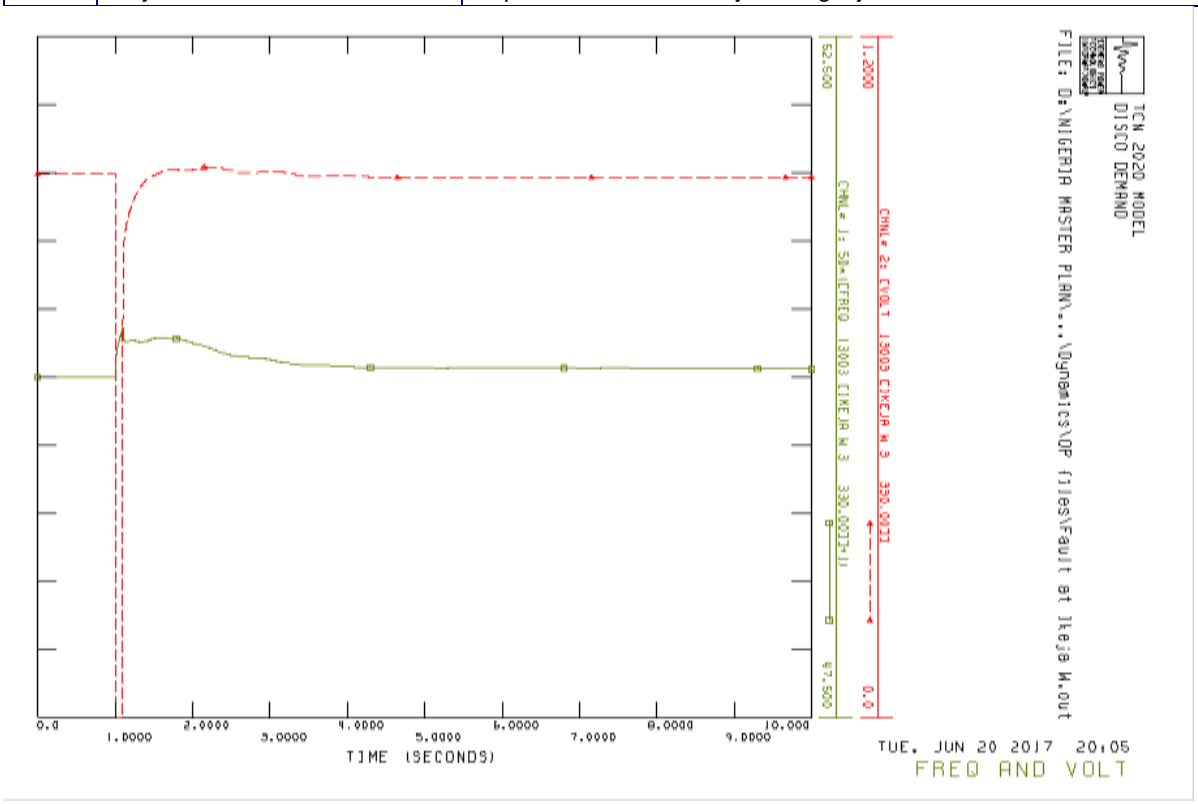
Case	Fault at bus	Trip line / disturbance
F1	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo
F2	Benin 330 kV	Trip 330 kV line from Benin to Omotosho
F3	Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi
F4	Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji
F5	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro
F6	Afam 330 kV	Trip largest generating unit Afam VI

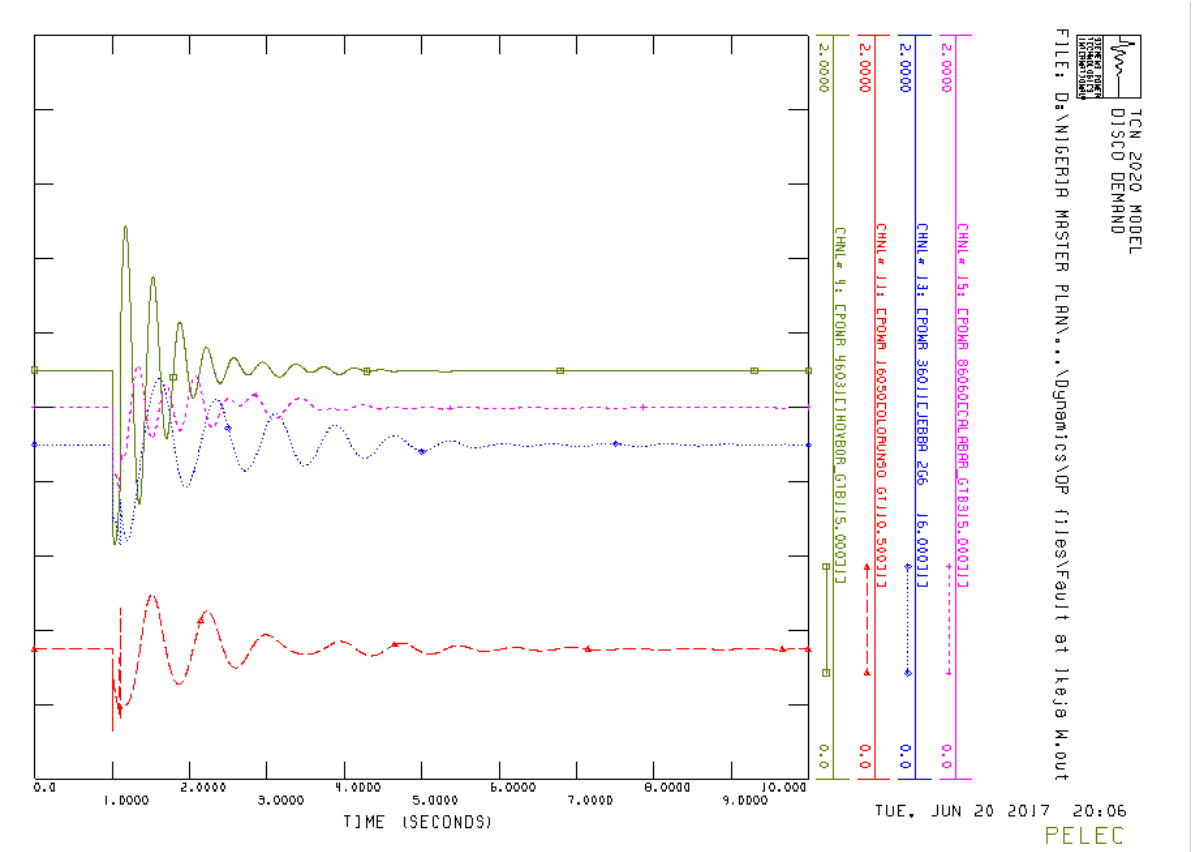
The three plots for each case show:

1. The frequency and bus voltage profile at the faulty bus
2. The electrical power of generators at Ihovbor, Olorunsogo, Kainji and Calabar
3. The rotor angles of generators at Ihovbor, Olorunsogo, Sapele and Calabar

7.12.4.1 Case F1

Case	Fault at bus	Trip line / disturbance
F1	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo





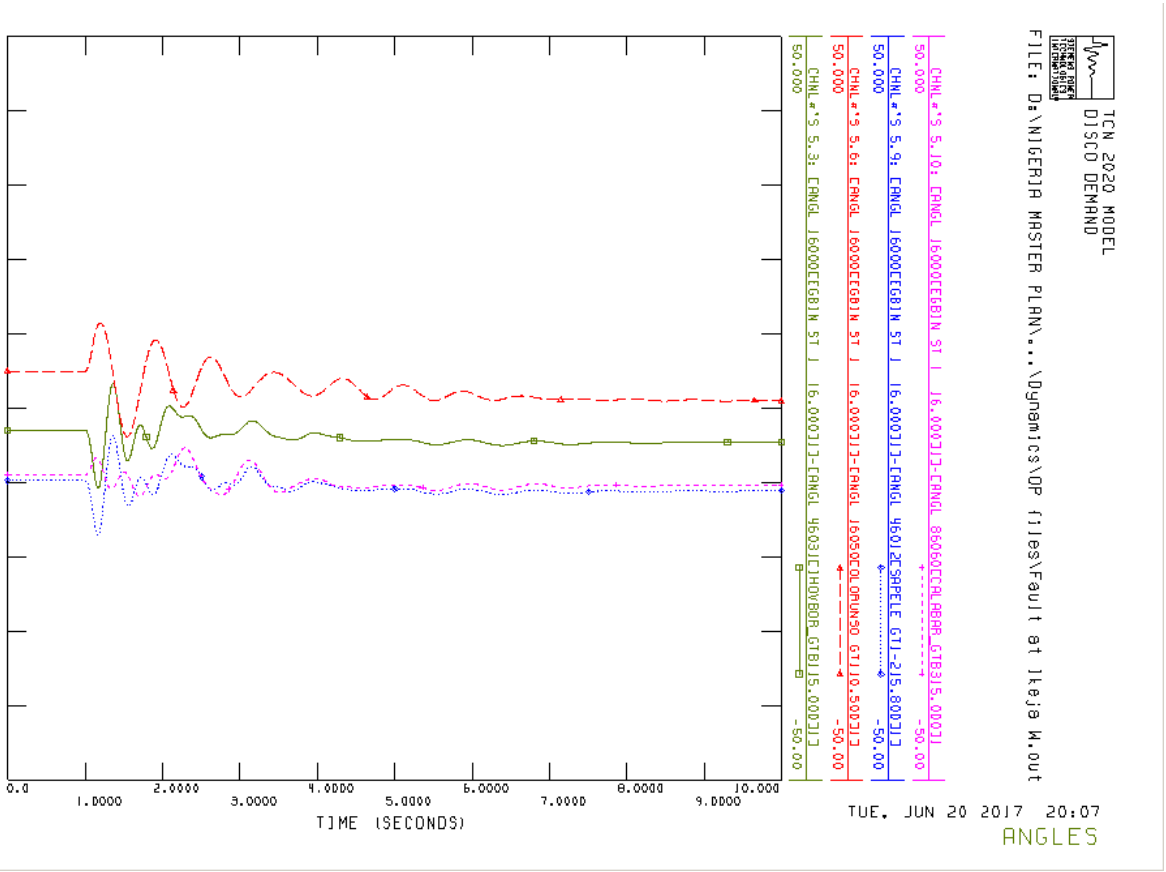
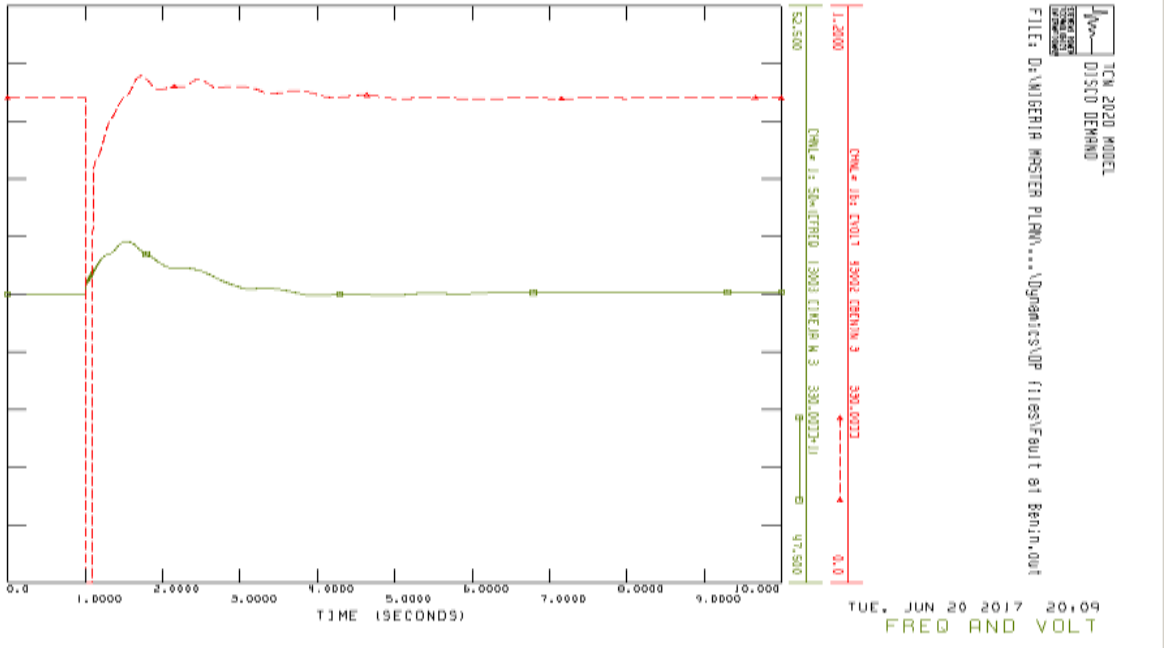


Figure 7-25: Plots Frequency, bus voltages, machine angles and electrical power for fault F1

7.12.4.2 Case F2

Case	Fault at bus	Trip line / disturbance
F2	Benin 330 kV	Trip 330 kV line from Benin to Omotosho



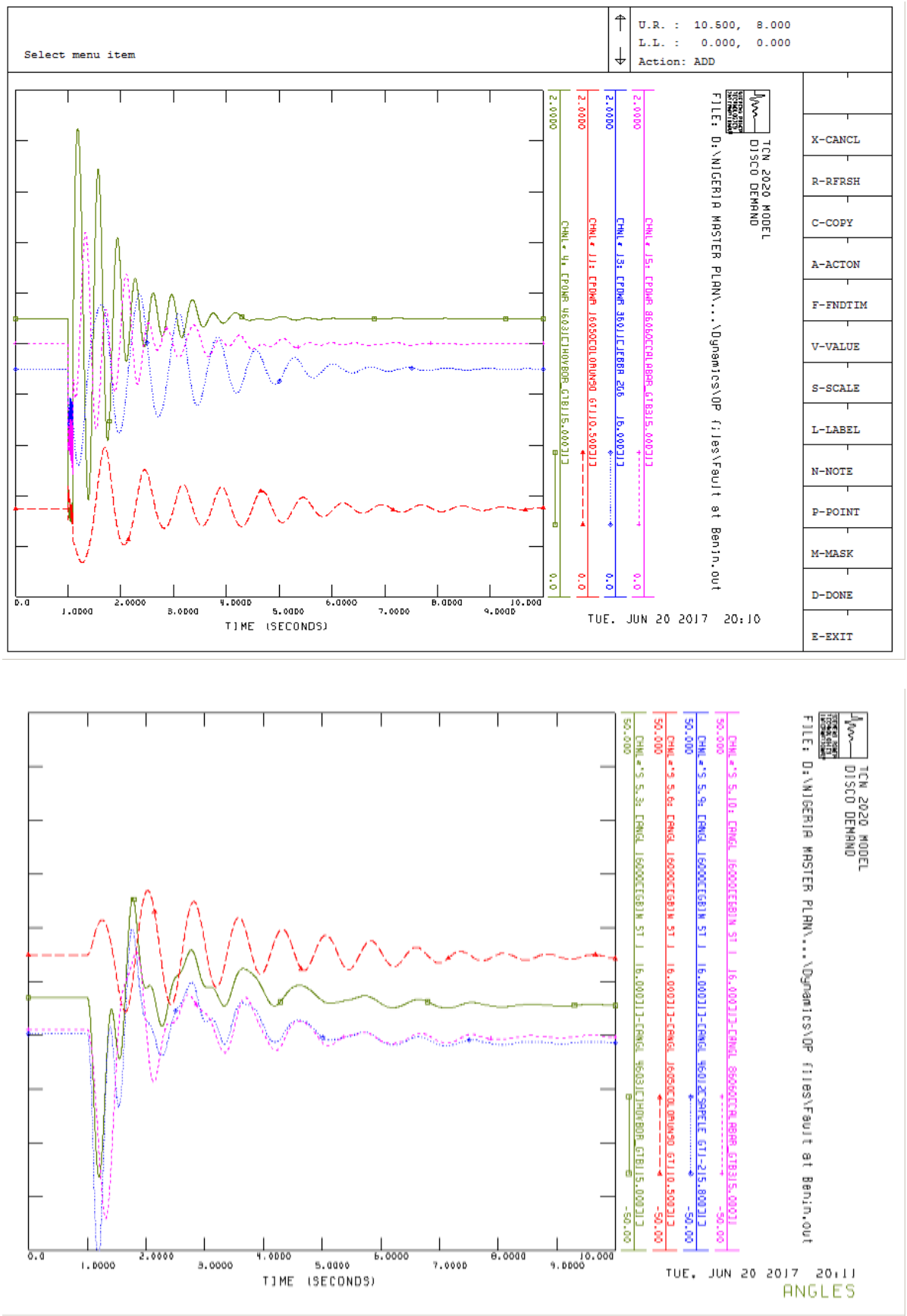
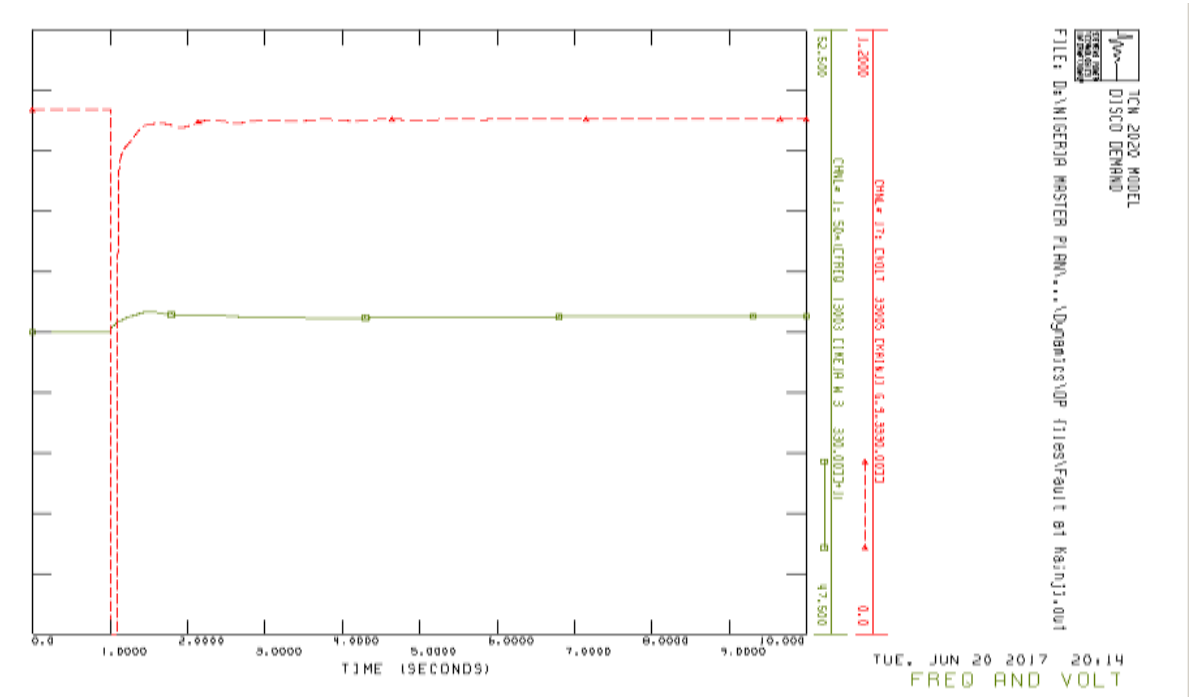
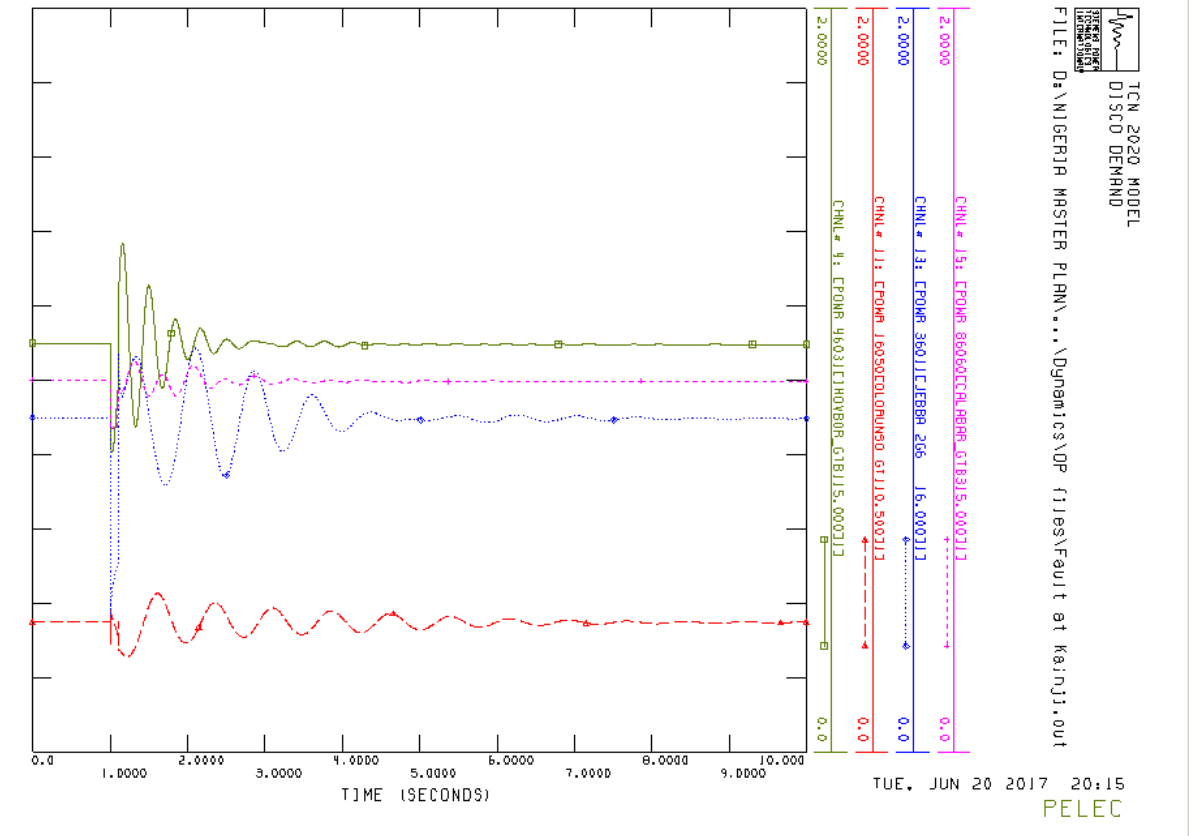


Figure 7-26: Plots Frequency, bus voltages, machine angles and electrical power for fault F2

7.12.4.3 Case F3

Case	Fault at bus	Trip line / disturbance
F3	Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi





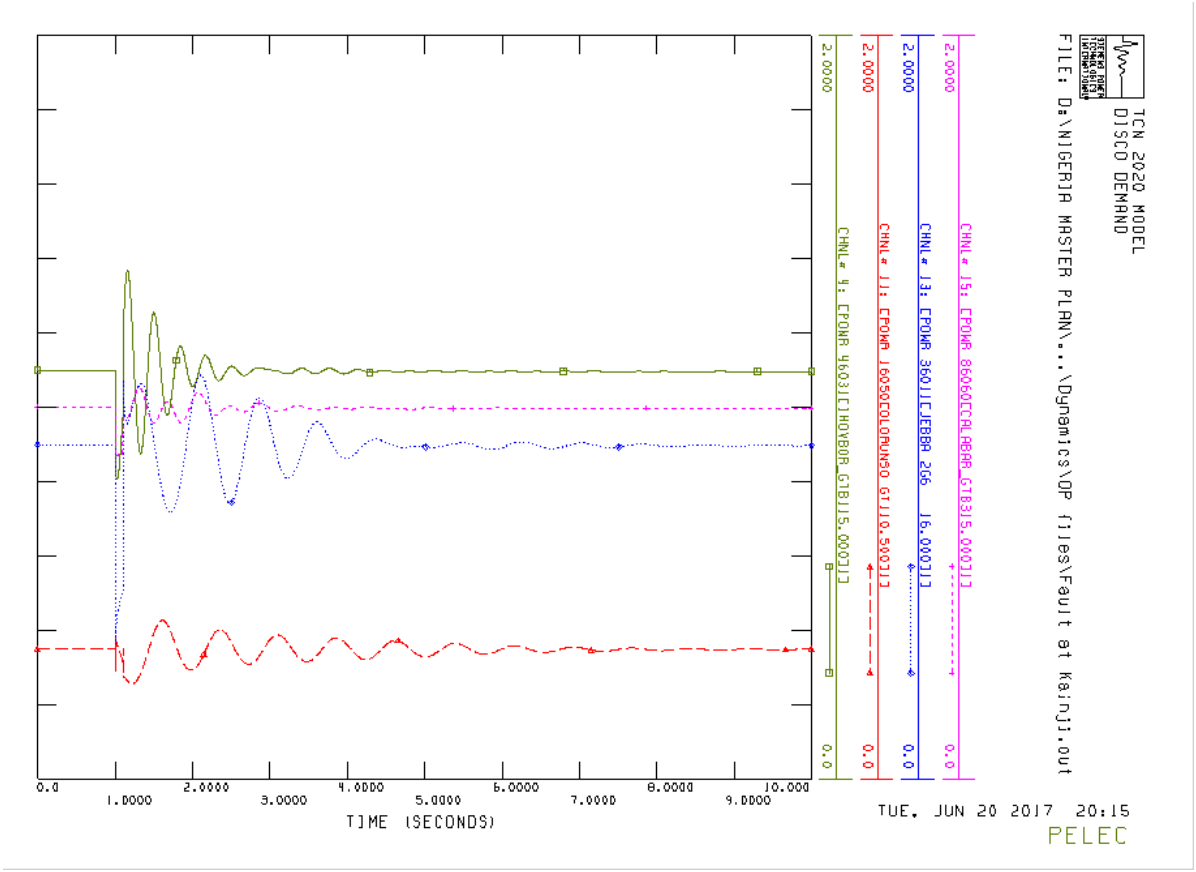
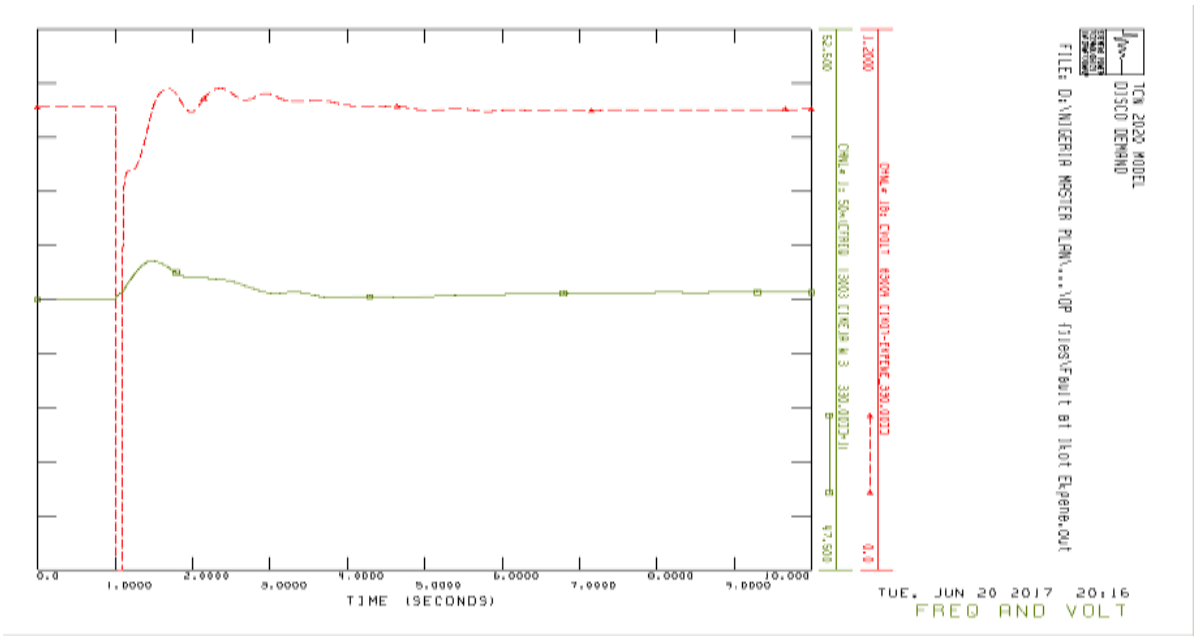
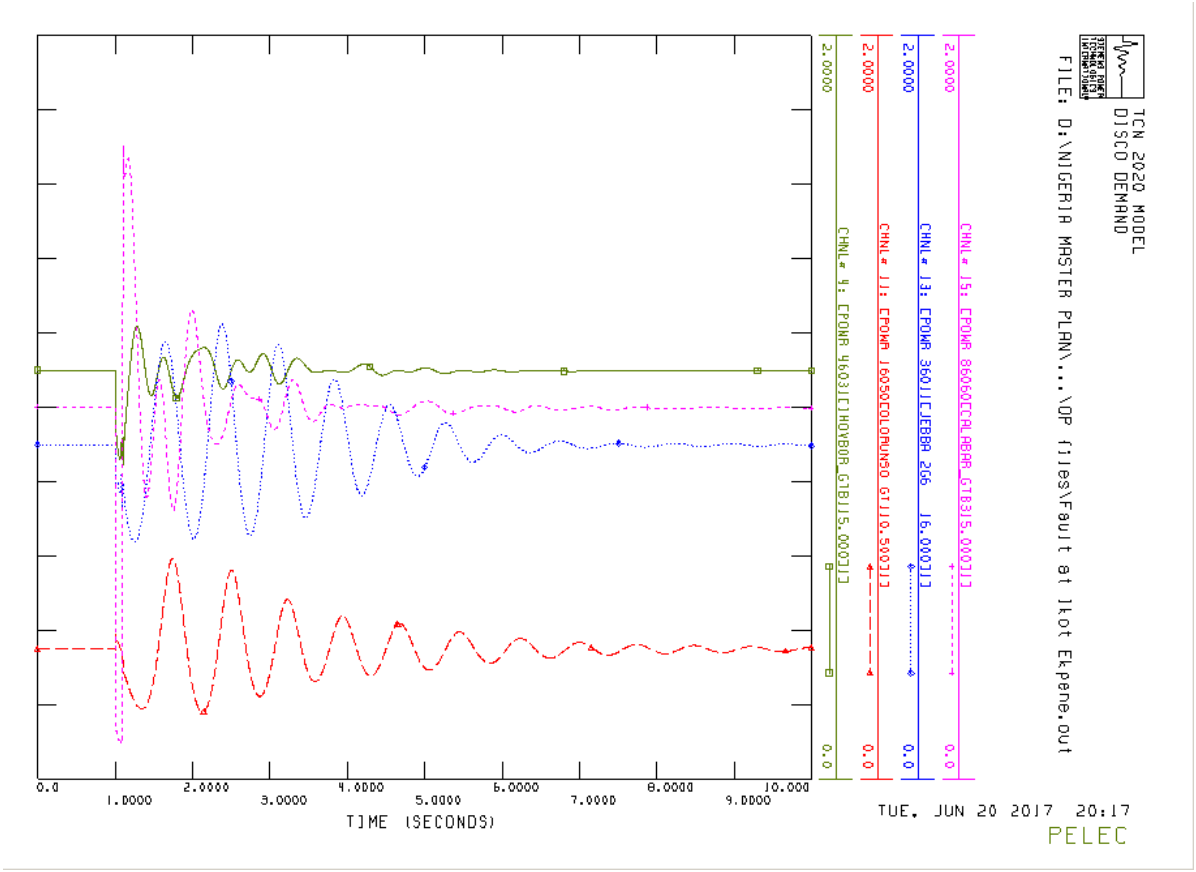


Figure 7-27: Plots Frequency, bus voltages, machine angles and electrical power for fault F3

7.12.4.4 Case F4

Case	Fault at bus	Trip line / disturbance
F4	Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji





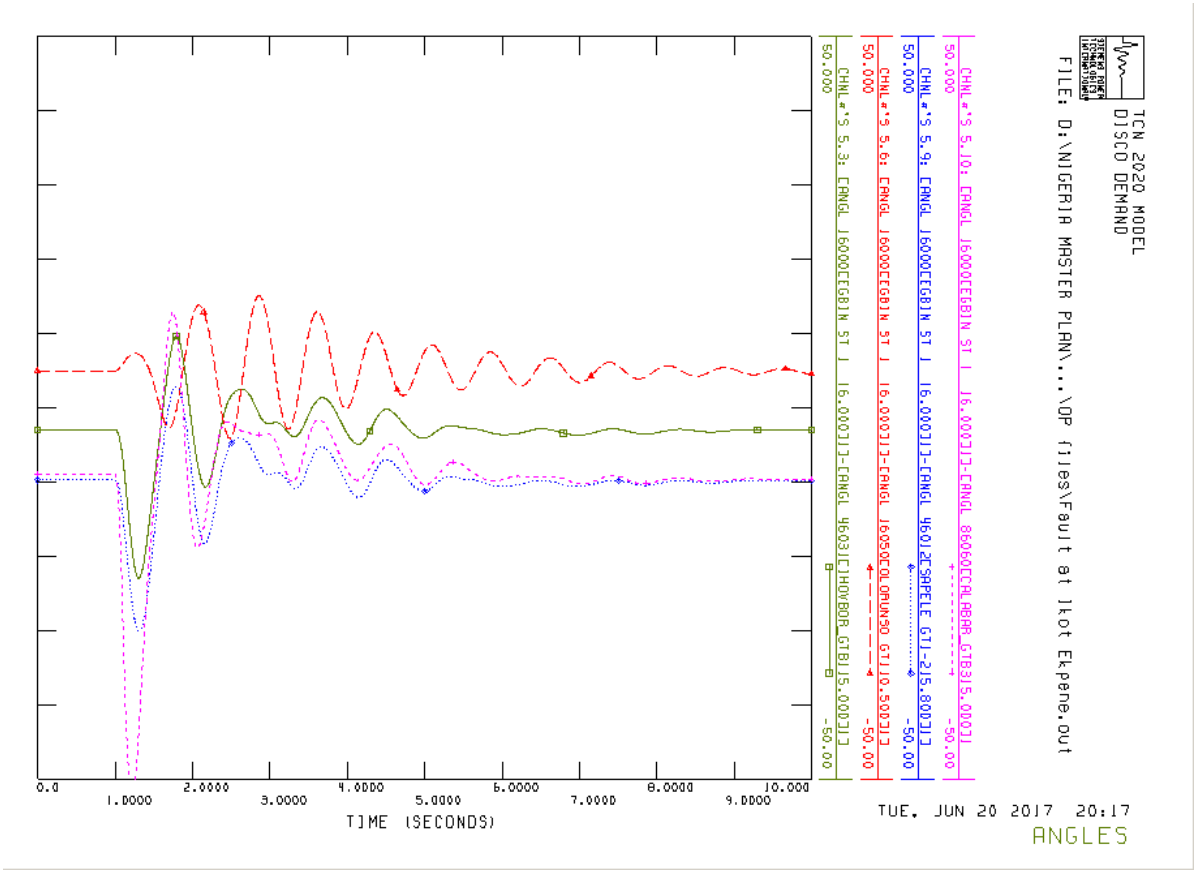
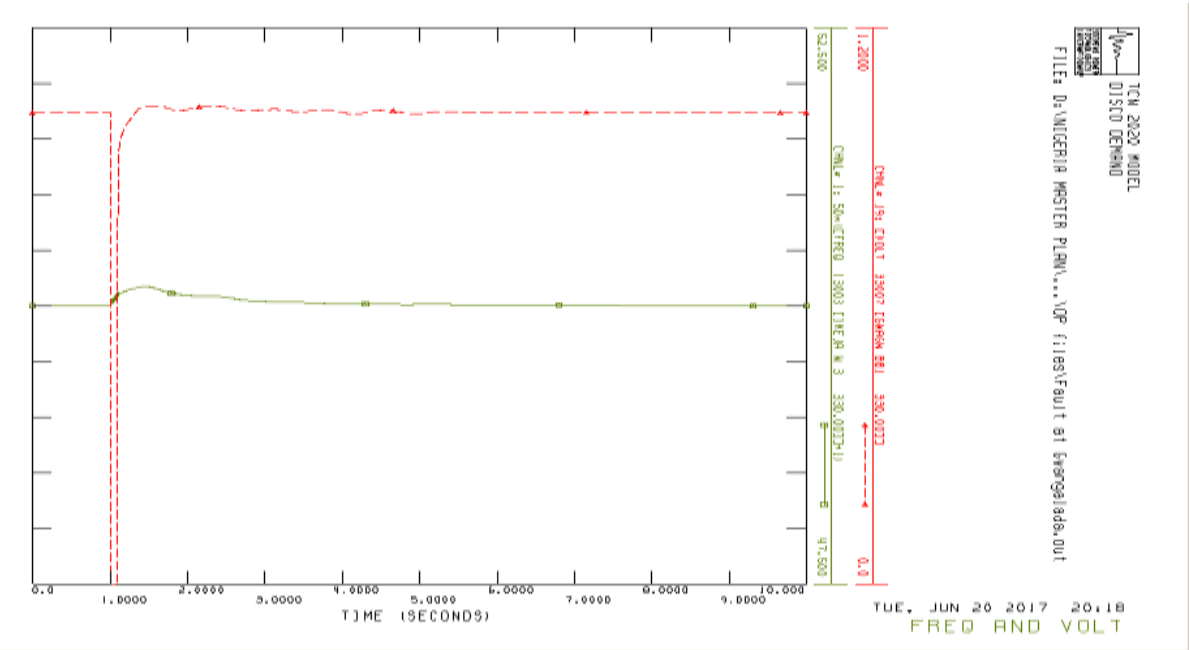
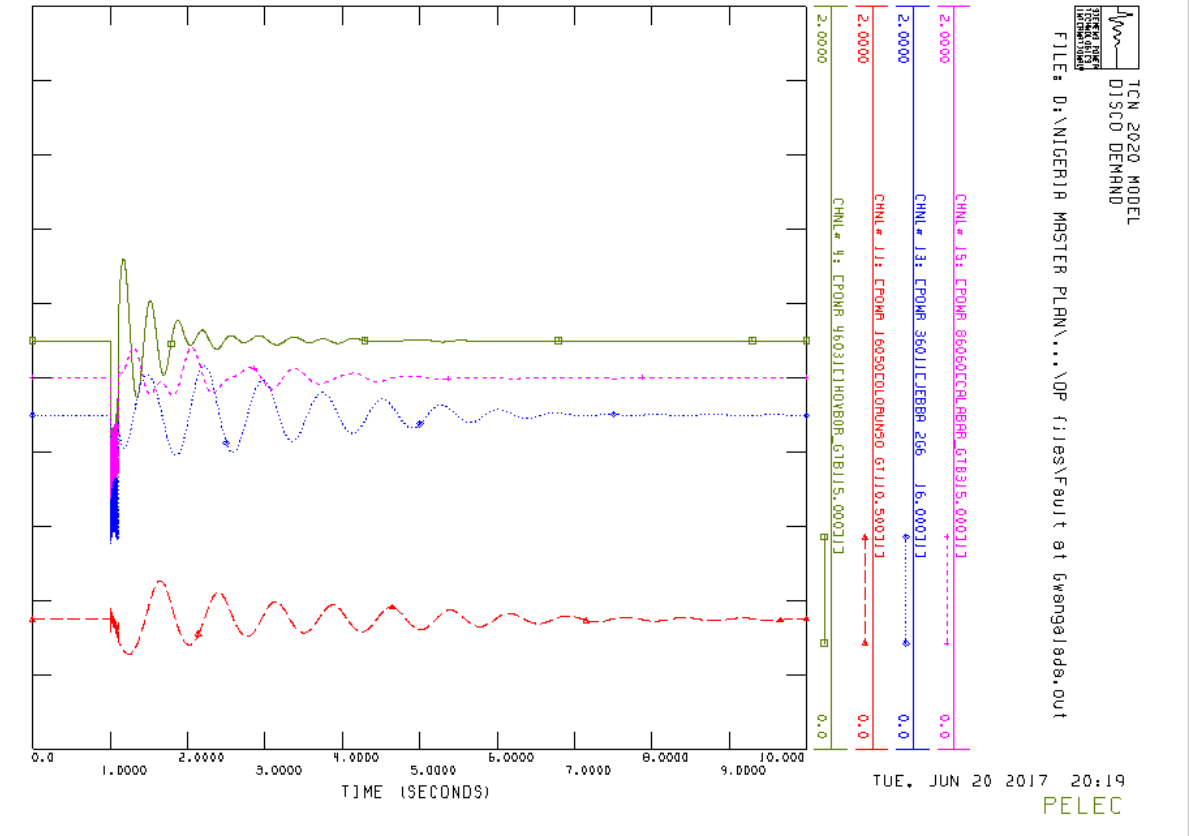


Figure 7-28: Plots Frequency, bus voltages, machine angles and electrical power for fault F4

7.12.4.5 Case F5

Case	Fault at bus	Trip line / disturbance
F5	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro





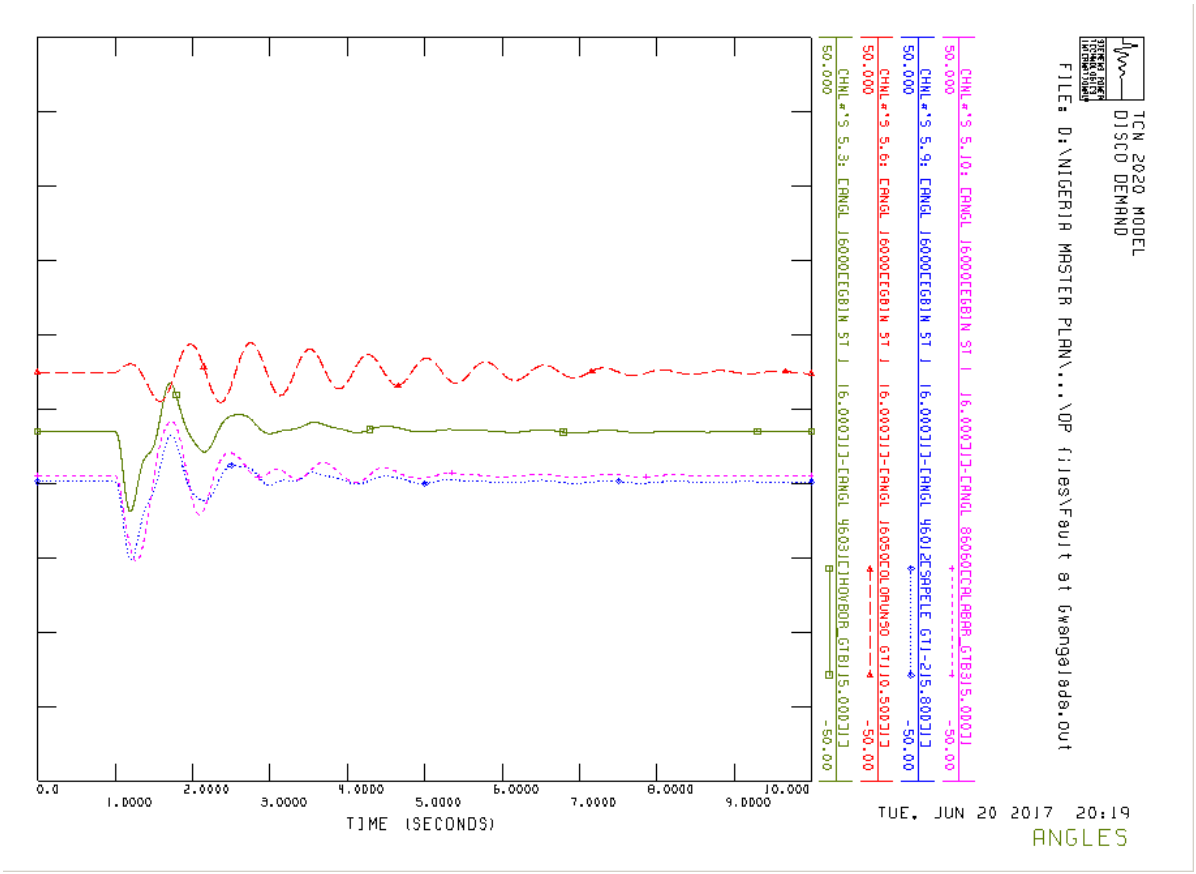
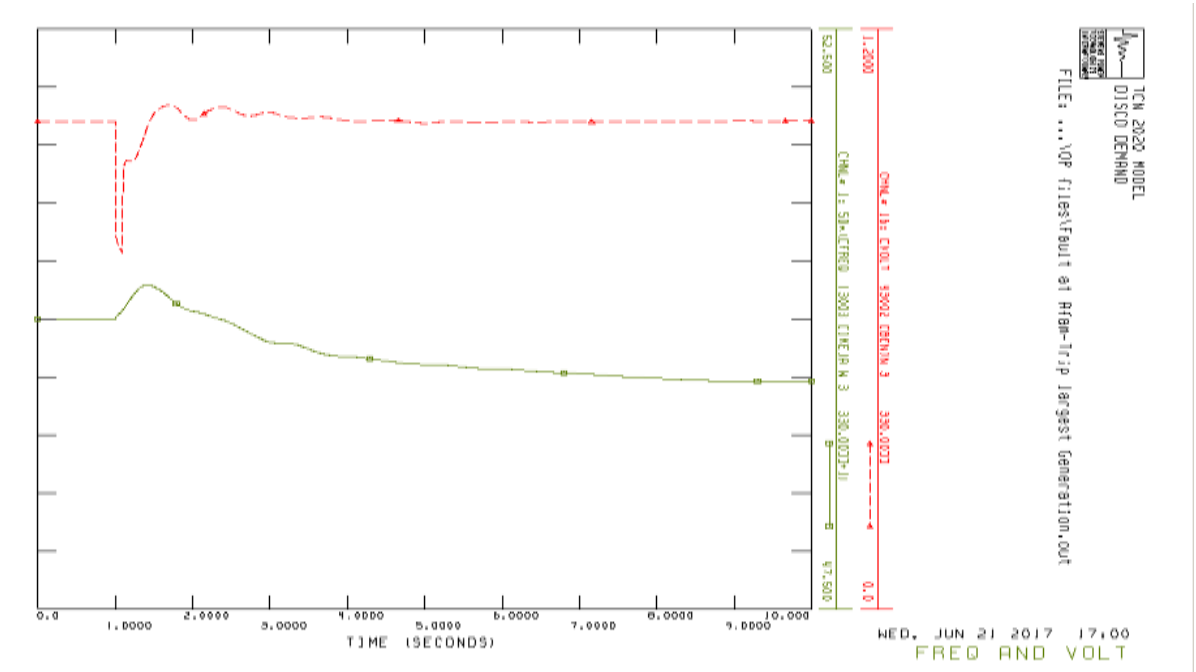


Figure 7-29: Plots Frequency, bus voltages, machine angles and electrical power for fault F5

7.12.4.6 Case F6

Case	Fault at bus	Trip line / disturbance
F6	Fault at Afam	Trip largest generating unit Afam VI



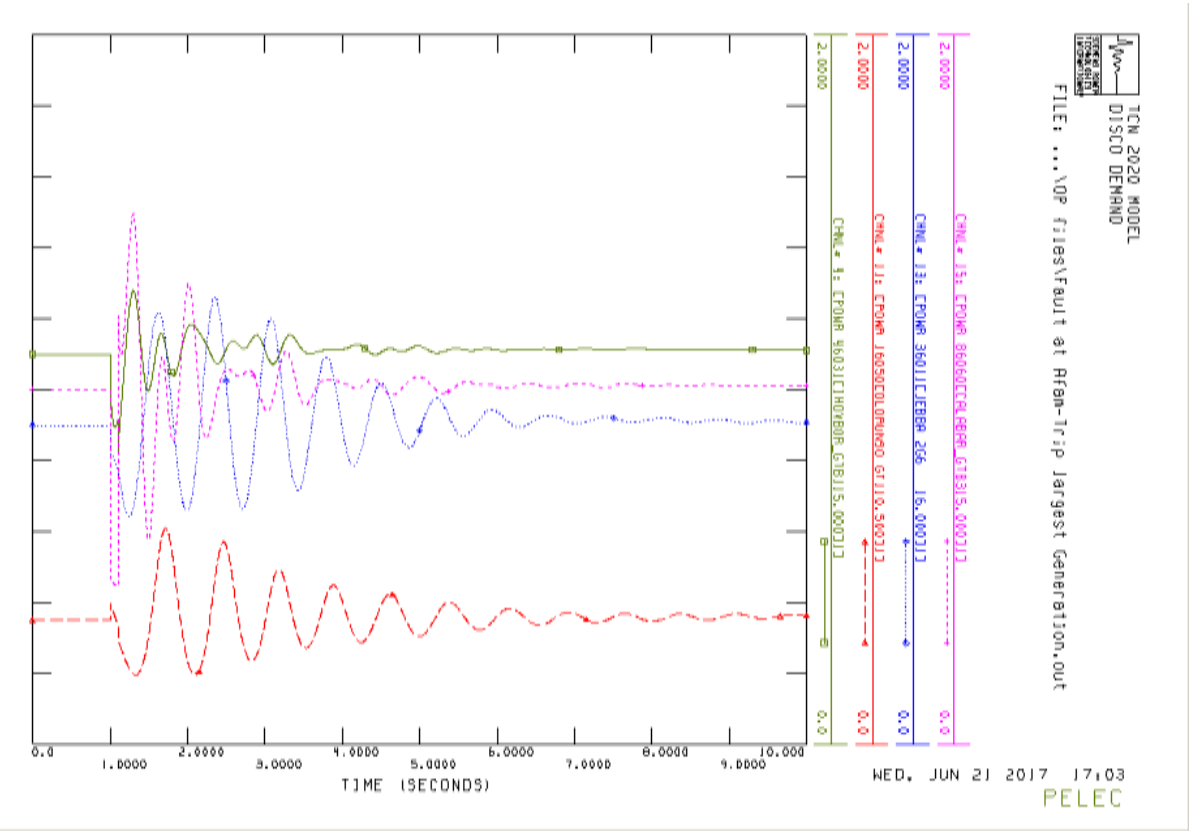


Figure 7-30: Plots Frequency, bus voltages and electrical power for fault F6

7.12.5 Simulation Cases for 2020 Dry Season off-Peak

Table 7-56 shows the cases which have been simulated for 2020 Dry Season off-Peak:

Table 7-56: Dynamic simulation study cases

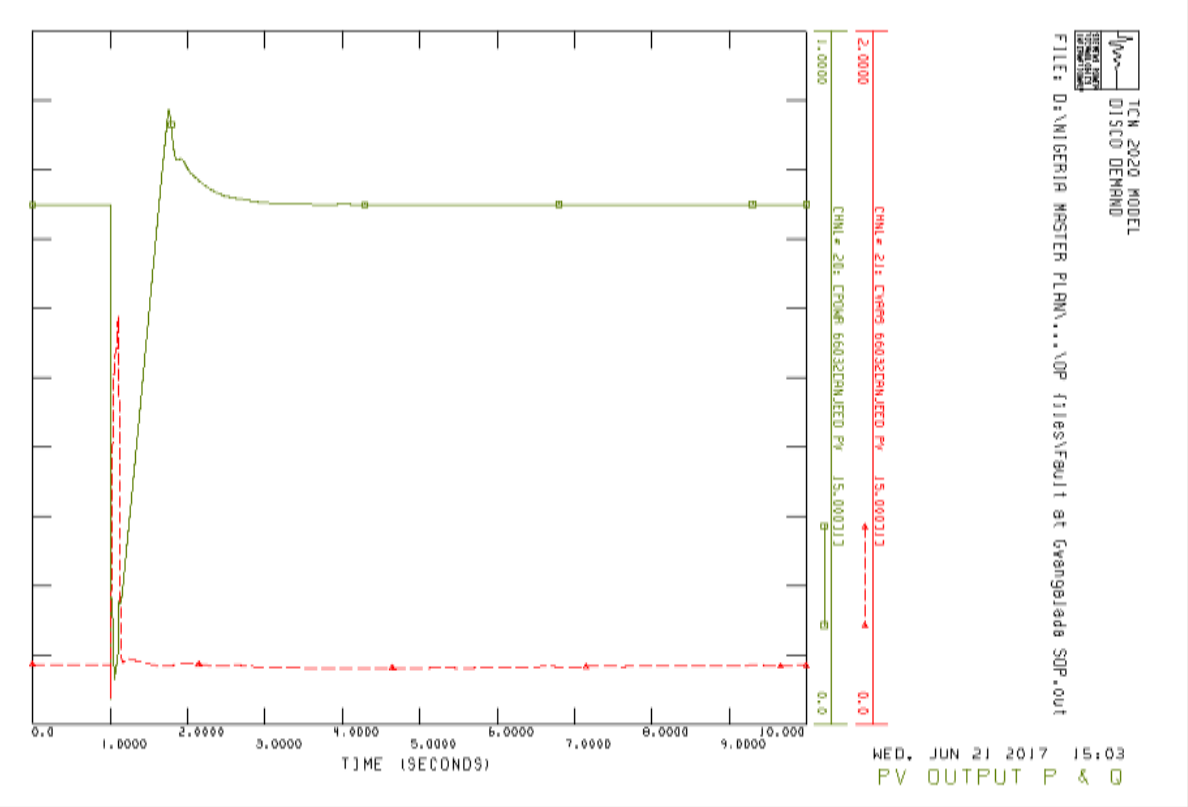
Case	Fault at bus	Trip line / disturbance
F7	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro

The plots for each case show:

1. The frequency and bus voltage profile
2. The electrical power of generators at Ihovbor, Olorunsogo, Kainji and Calabar
3. The active and reactive power of PV plants

7.12.5.1 Case F7

Case	Fault at bus	Trip line / disturbance
F7	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro



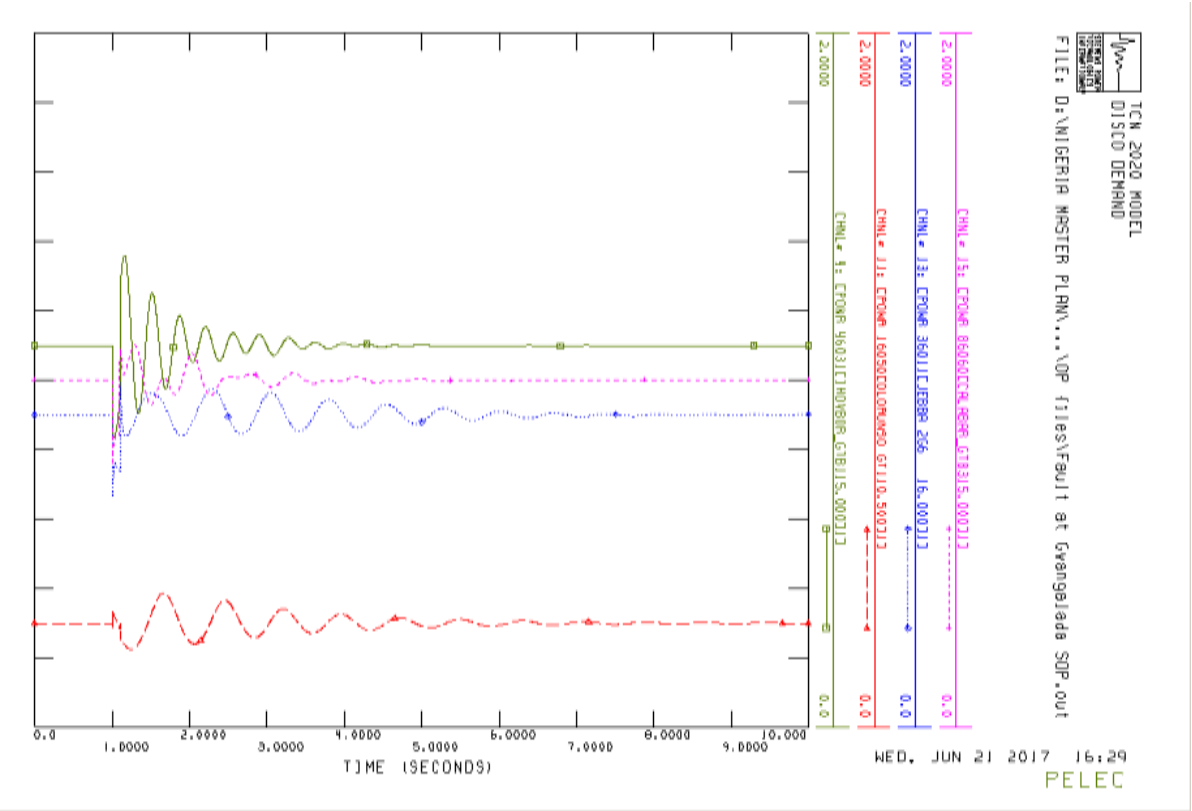


Figure 7-31: **Plots of (a) active and reactive power of Anjeed PV plant and (b) conventional generation Pelec for fault F7**

7.12.6 Simulation Cases for 2025 Dry Season off-Peak

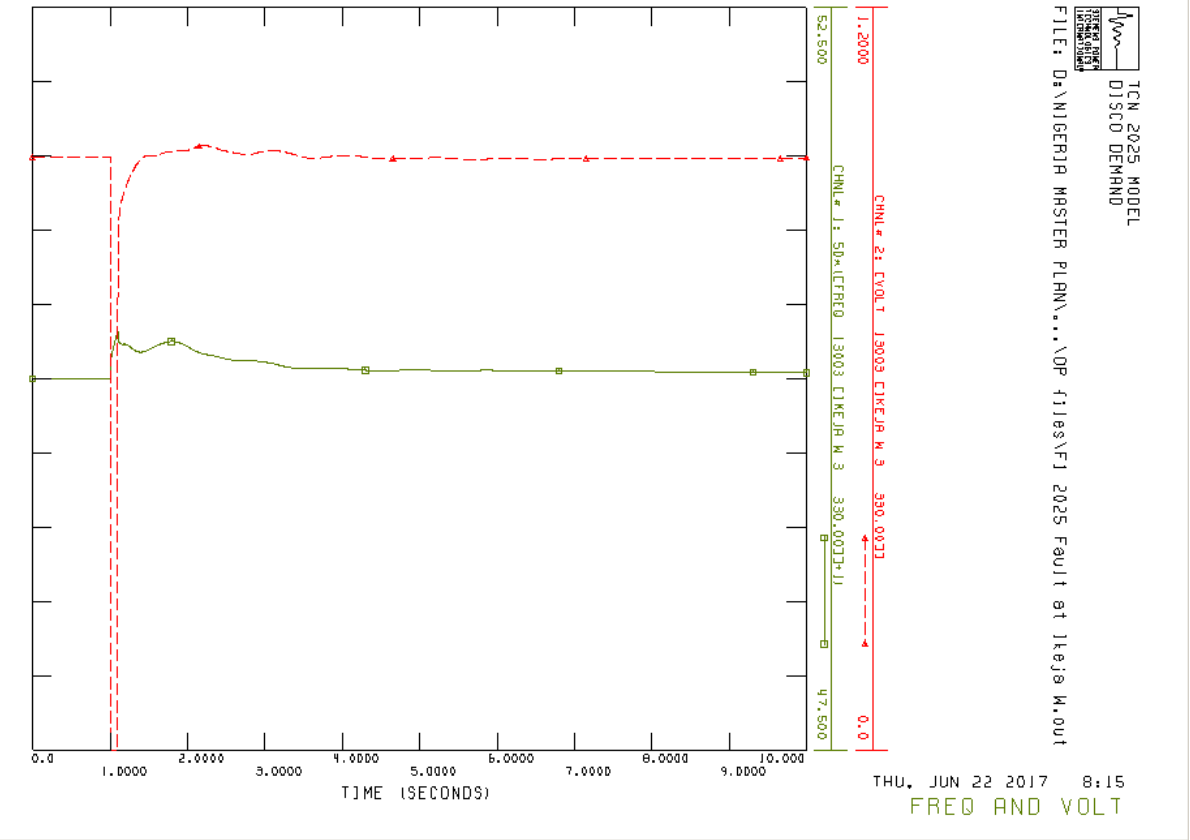
Table 7-57 shows the cases which have been simulated for Dry Season off-Peak:

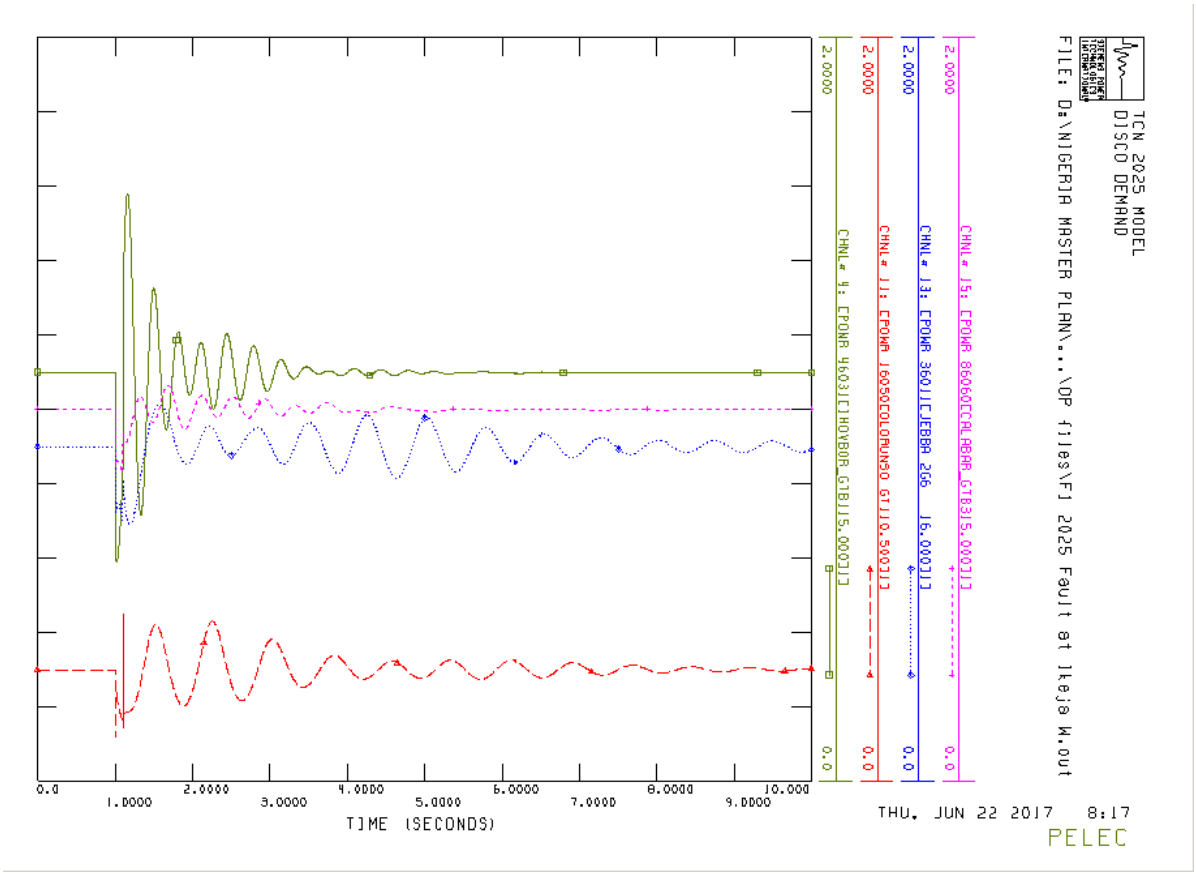
Table 7-57: **Dynamic simulation study cases**

Case	Fault at bus	Trip line / disturbance
F8	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo
F9	Benin 330 kV	Trip 330 kV line from Benin to Omotosho
F10	Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi
F11	Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji
F12	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro

7.12.6.1 Case F8

Case	Fault at bus	Trip line / disturbance
F8	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo





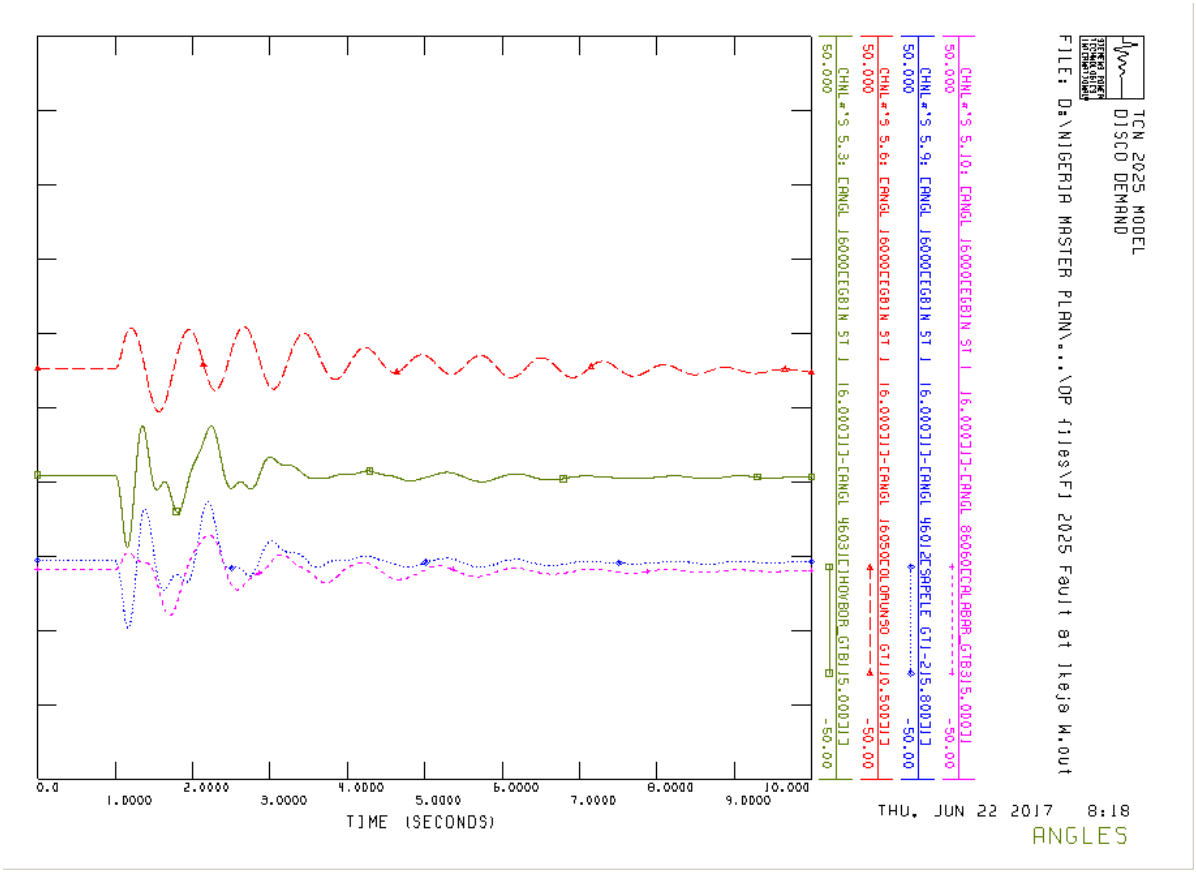
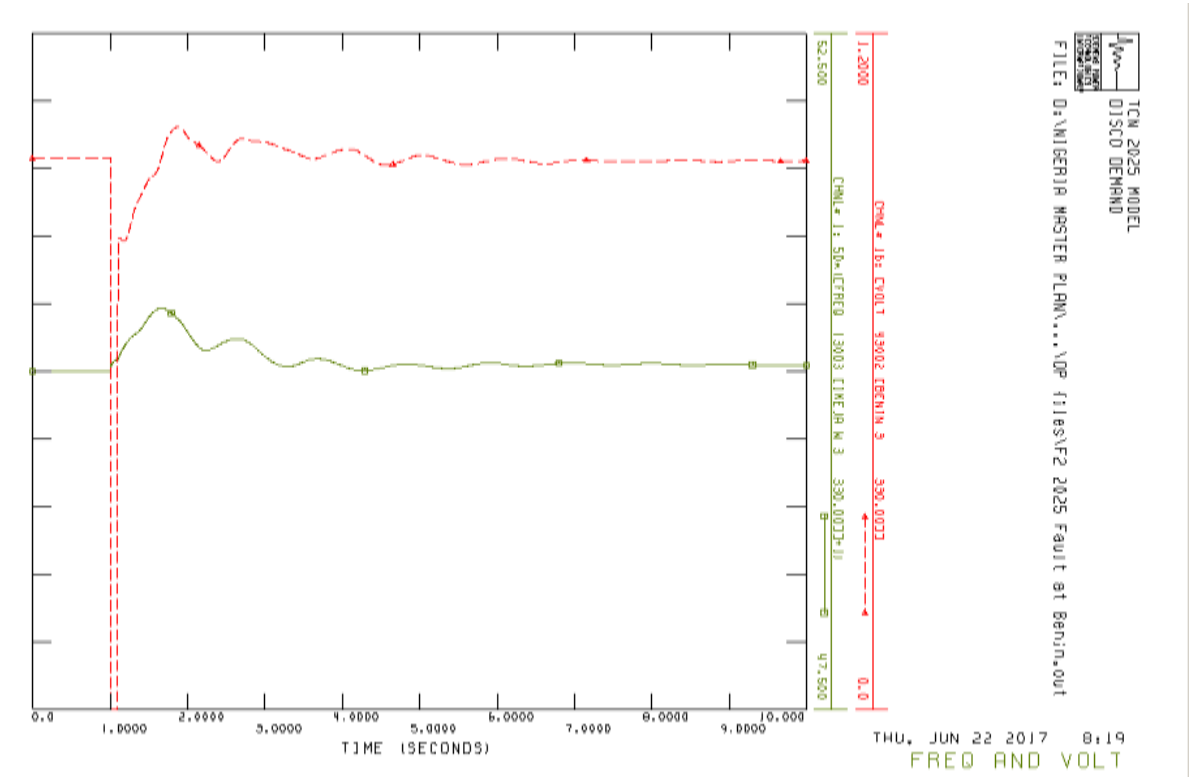
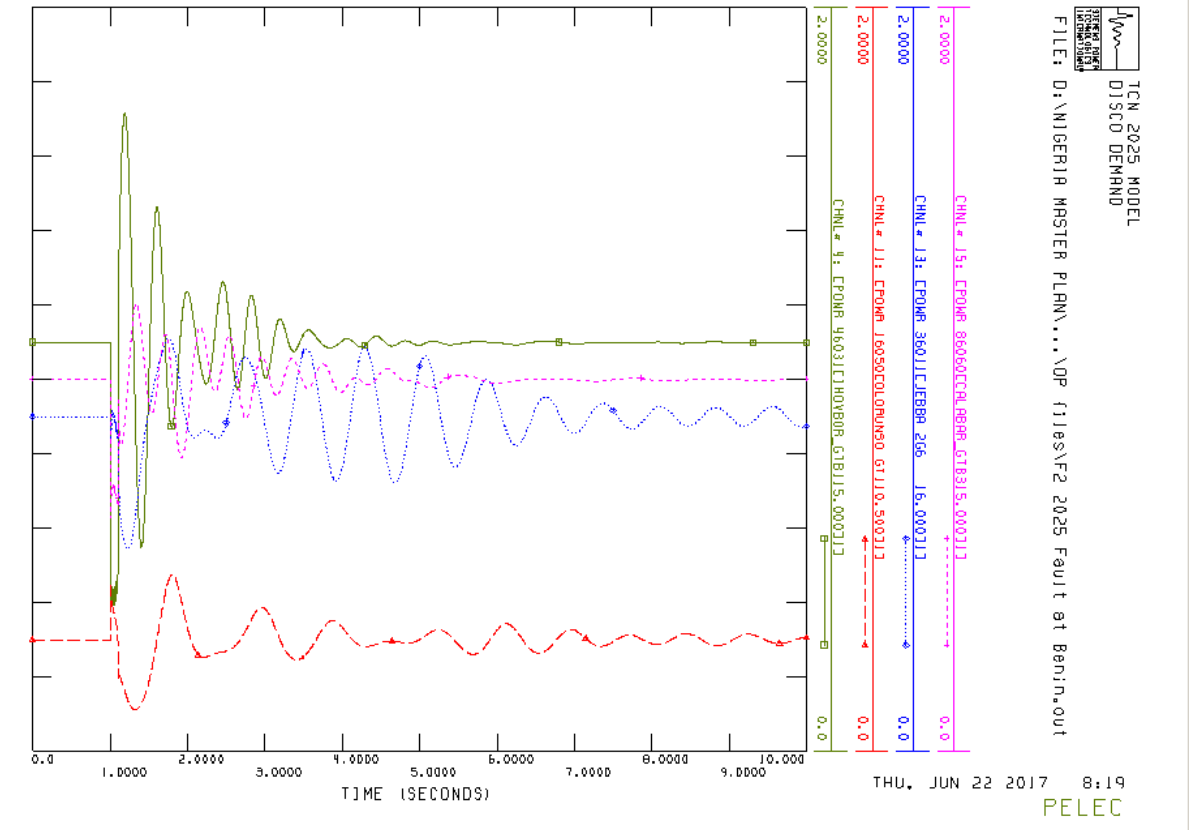


Figure 7-32: Plots Frequency, bus voltages, machine angles and electrical power for fault F8

7.12.6.2 Case F9

Case	Fault at bus	Trip line / disturbance
F9	Benin 330 kV	Trip 330 kV line from Benin to Omotosho





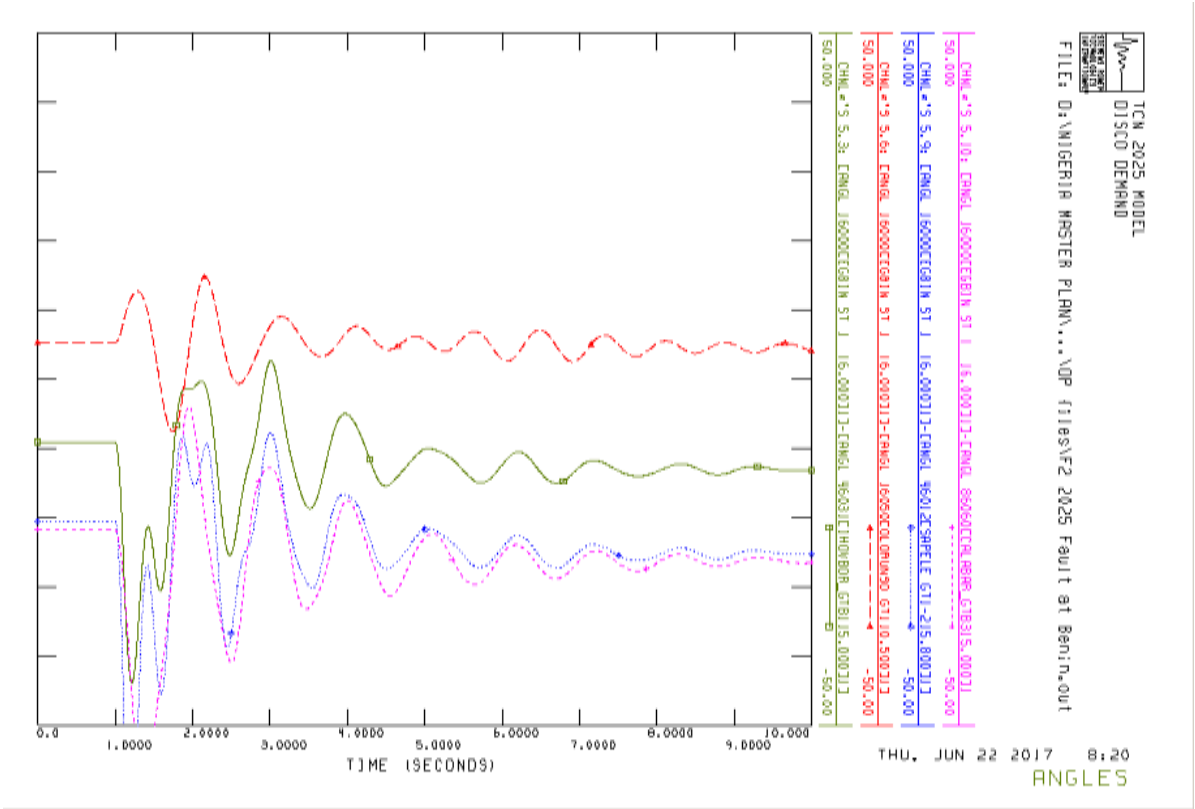
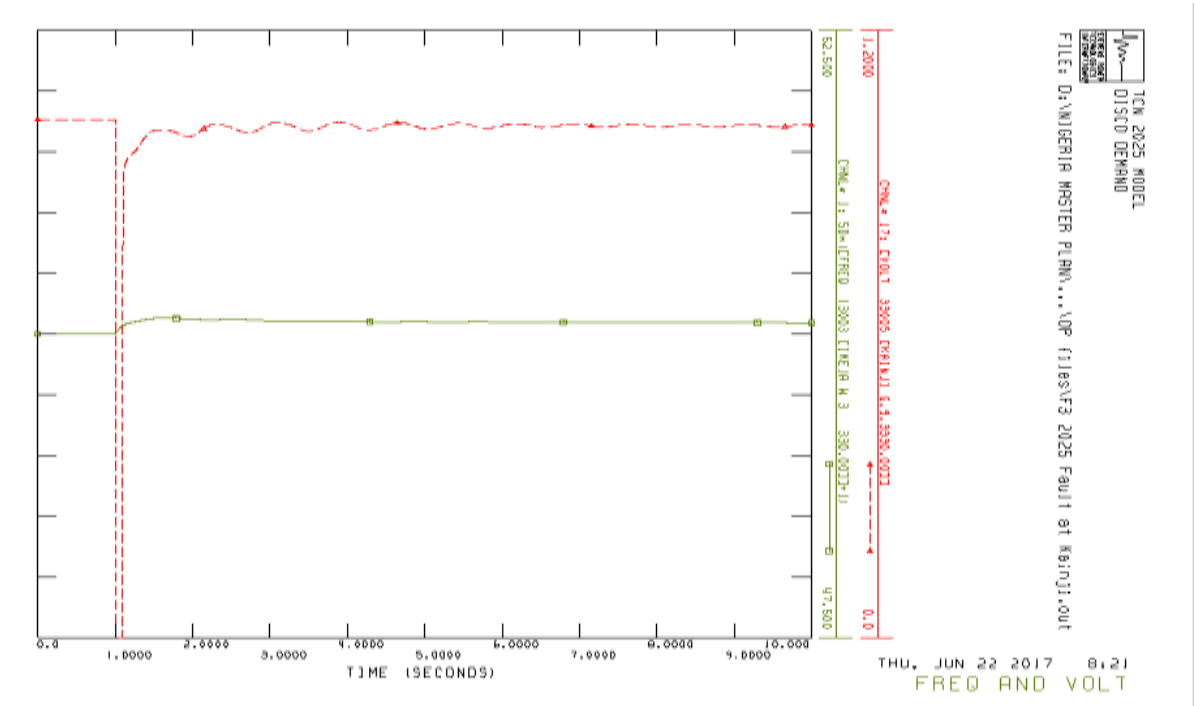


Figure 7-33: Plots Frequency, bus voltages, machine angles and electrical power for fault F9

7.12.6.3 Case F10

Case	Fault at bus	Trip line / disturbance
F10	Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi



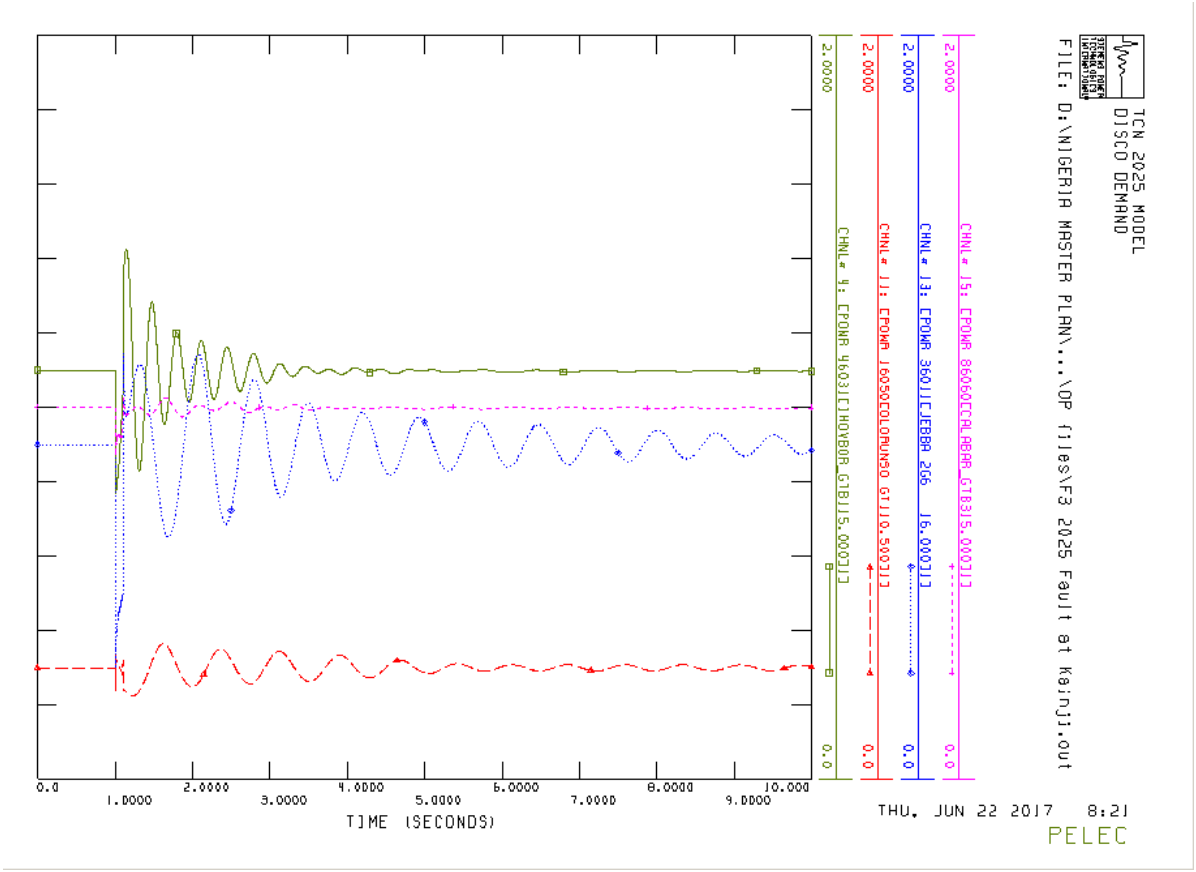
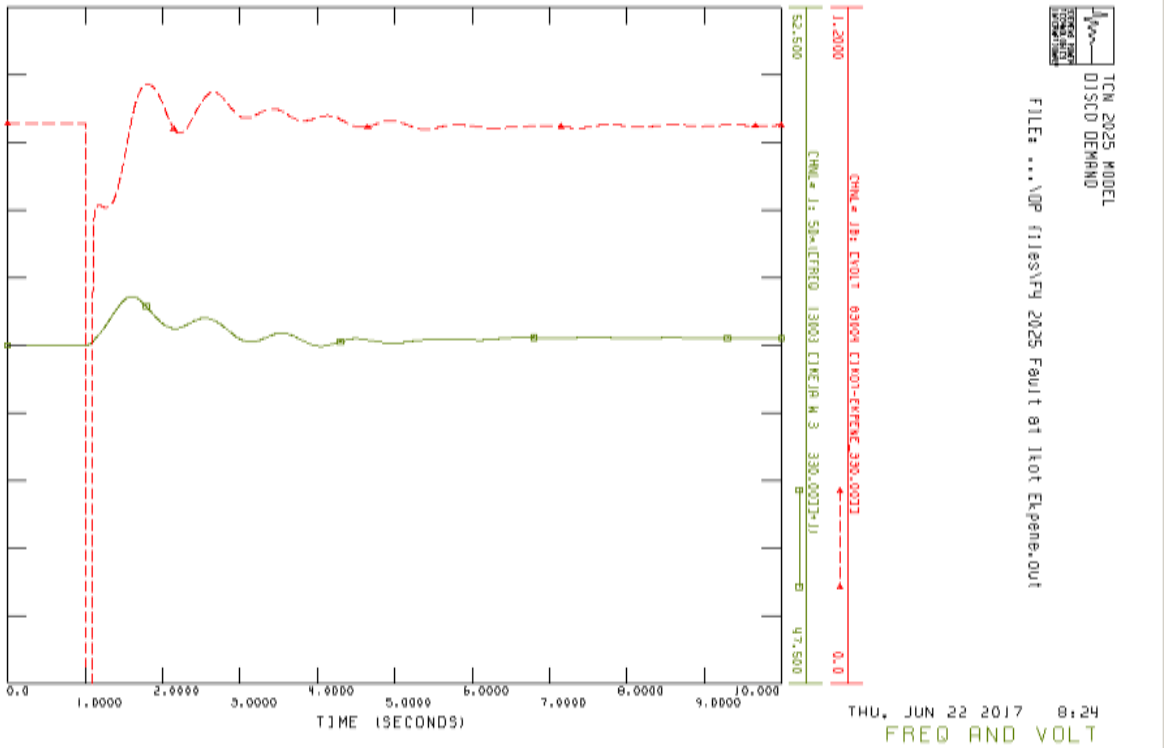
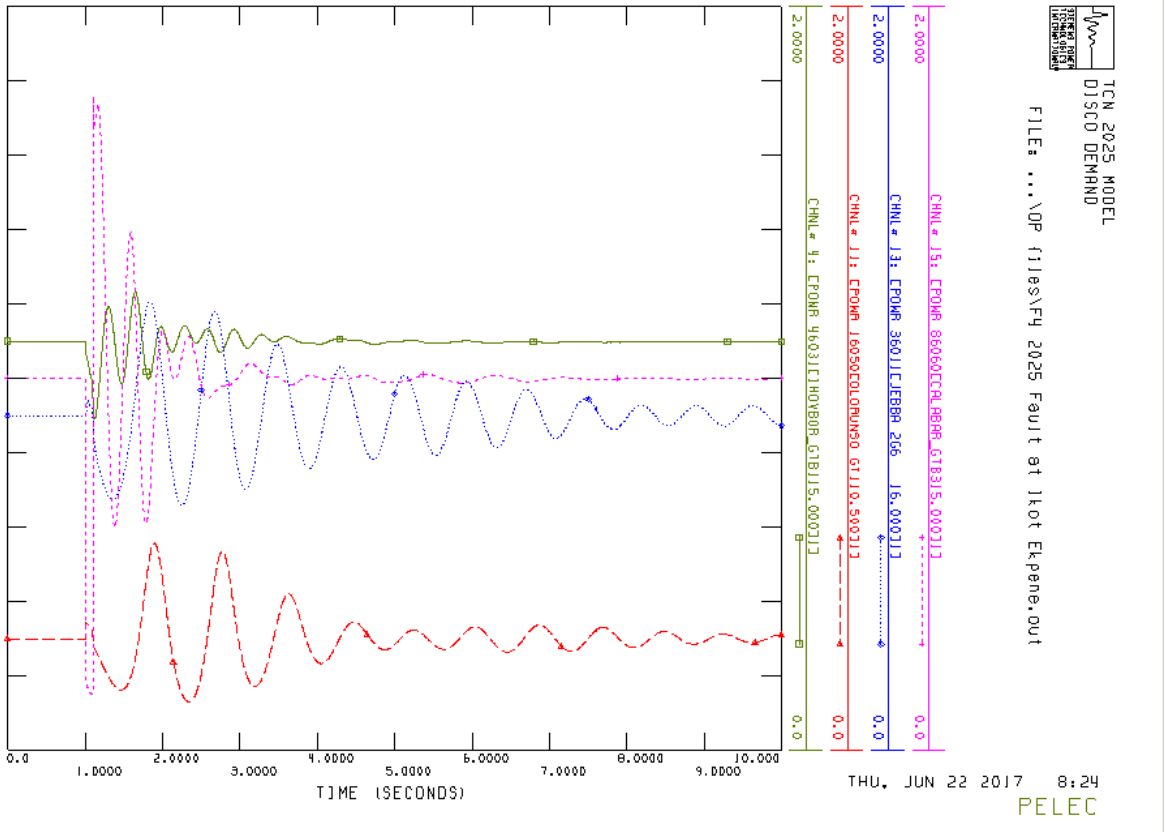


Figure 7-34: Plots Frequency, bus voltages, machine angles and electrical power for fault F10

7.12.6.4 Case F11

Case	Fault at bus	Trip line / disturbance
F11	Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji





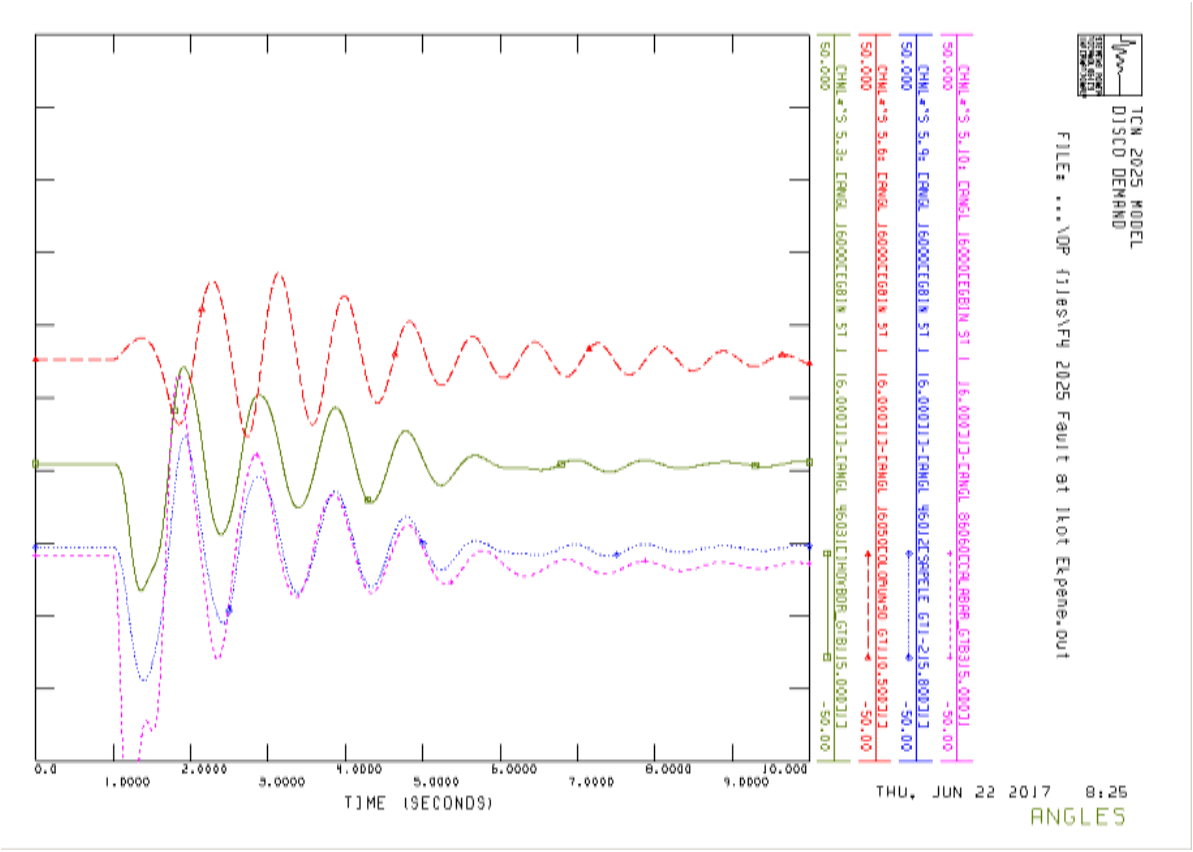
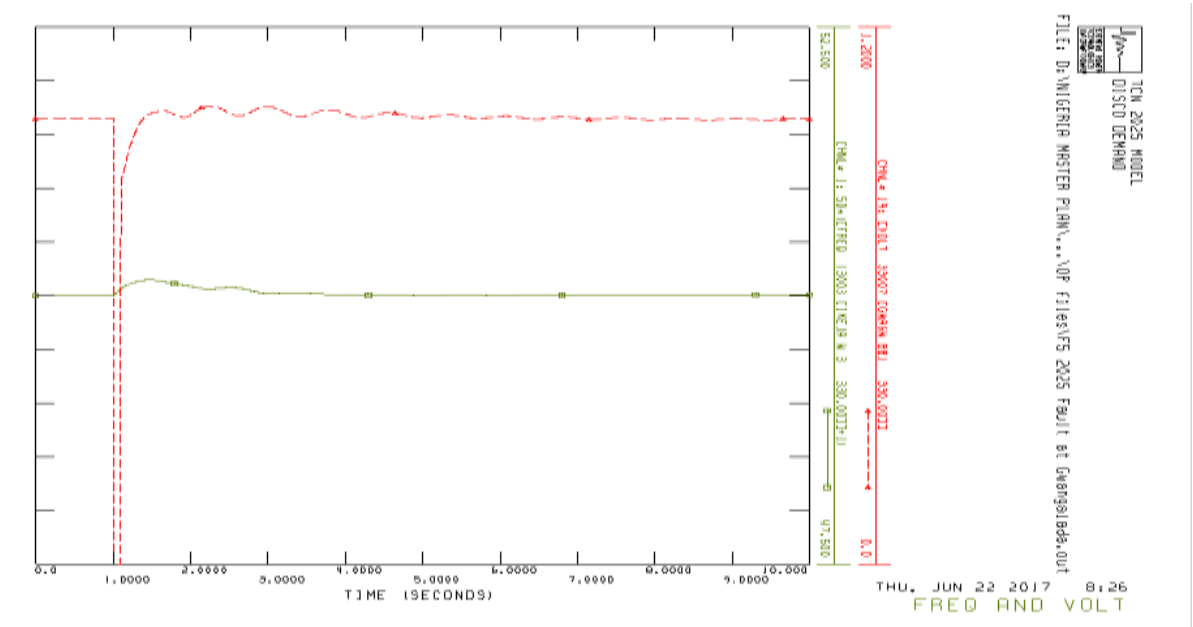
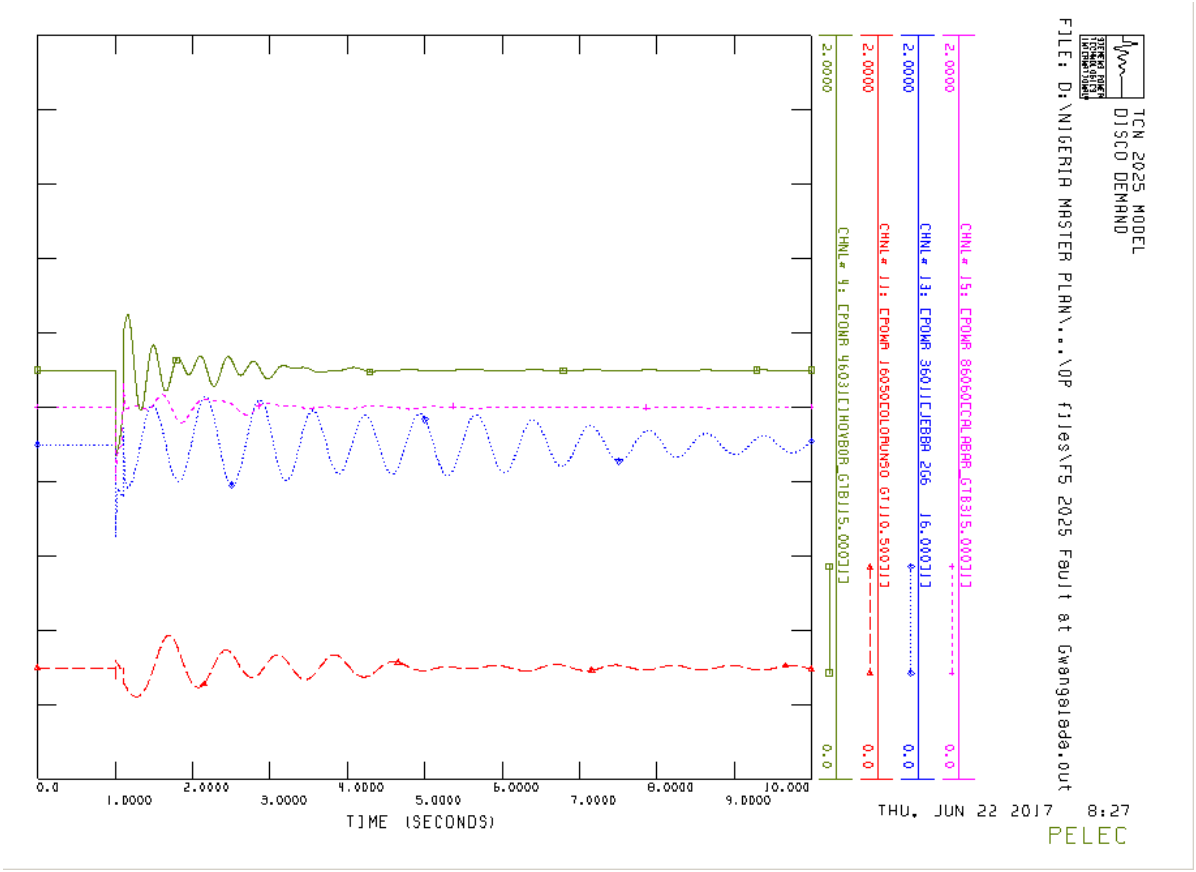


Figure 7-35: Plots Frequency, bus voltages, machine angles and electrical power for fault F11

7.12.6.5 Case F12

Case	Fault at bus	Trip line / disturbance
F12	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro





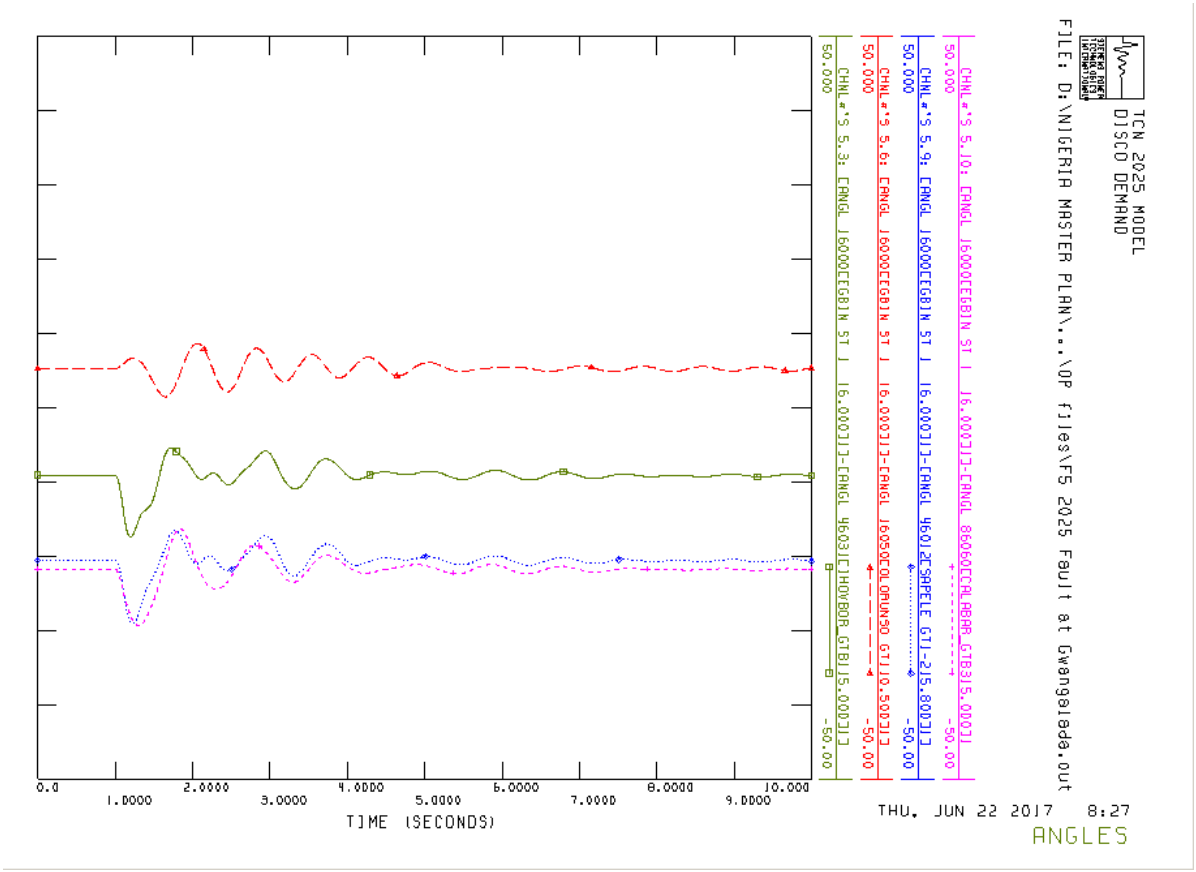


Figure 7-36: Plots Frequency, bus voltages, machine angles and electrical power for fault F12

7.12.7 Conclusions on dynamic studies

The results of the dynamic simulations have shown that the system remains stable and all generating machines, including the PV and wind generation, remain synchronized for all cases studies, as summarised in **Table 7-58.**

Table 7-58: Results of dynamic simulations

Case	Scenario	Fault at bus	Trip line / disturbance	Results
F1	2020 Dry Season Peak	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo	System remains stable
F2		Benin 330 kV	Trip 330 kV line from Benin to Omotosho	System remains stable
F3		Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi	System remains stable
F4		Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji	System remains stable
F5		Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro	System remains stable
F6		Afam 330 kV	Trip largest generating unit Afam VI	System remains stable
F7	2020 Dry Season Off-Peak	Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro	System remains stable
F8	2025 Dry Season Peak	Ikeja West 330 kV	Trip 330 kV line from Ikeja to Arigbajo	System remains stable
F9		Benin 330 kV	Trip 330 kV line from Benin to Omotosho	System remains stable
F10		Kainji 330 kV	Trip 330 kV line from Kainji to Birnin Kebbi	System remains stable
F11		Ikot Ekpene 330 kV	Trip 330 kV line from Ikot Ekpene to Ugwuaji	System remains stable
F12		Gwagwalada 330 kV	Trip 330 kV line from Gwagwalada to Shiroro	System remains stable

8. Generation and Transmission Analysis with GTMax

8.1 Introduction to GTMax

With the aid of the software GTMax the Consultant has identified the most economic generation and transmission expansion program for Nigeria for the period 2020 - 2037.

The GTMax analysis takes into account the topology of the power systems, the interconnection transfer capacity, the chronological hourly loads, and the different generation costs of the generation facilities. The program simulates the dispatch of the generating units for covering the demand and the power exports.

The inputs and outputs for the GTMax program and the integration of GTMax in the extended model for generation and transmission planning used in this study are indicated in **Figure 8-1.**

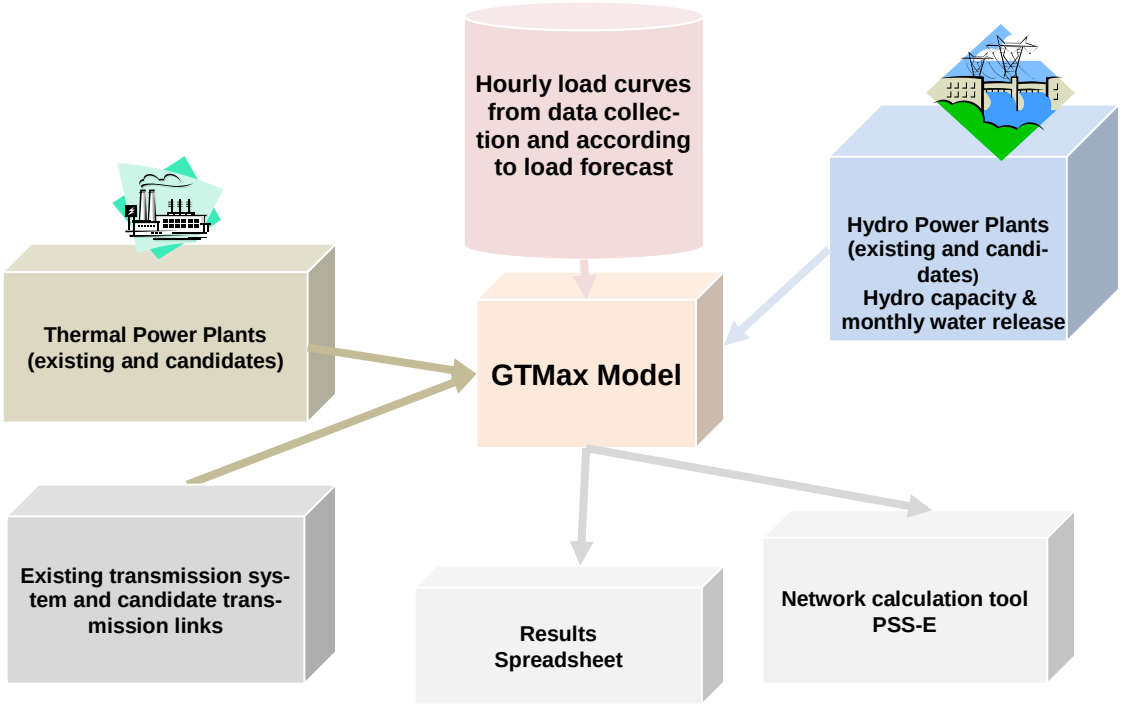


Figure 8-1: Extended model for generation and transmission planning using GTMax

The program has a detailed representation of the power system components. Thermal and hydropower plants are represented with all their characteristics.

On the load side, the loads are represented chronologically at user-specified load centers.

For identification of the optimal generation and transmission system expansion plan it is important to consider both: cost of new transmission lines and cost of electricity generation.

The GTMax program output includes the generated power on the dispatched units and the amount of power that should be generated and sold on an hourly basis.

GTMax calculates the electricity sales or purchases in different regions of the power network, taking into account the capacity constraints on the interconnection lines. The model optimizes the transactions in order to minimize the overall operating cost in the region.

8.2 Elaboration of Existing Nigeria Power System Model in GTMax

8.2.1 Modelling of Network Topology and Loads

As a basis for future generation and transmission network expansion planning the Consultant modeled the existing generation and transmission system of Nigeria in the GTMax Tool. The model is based on the DisCos areas with the main 330 kV substations and the 330 kV transmission lines between them, the main thermal and hydro power generation centers and the main load centers in each of the DisCos areas.

The Consultant considers two characteristic weeks in the year: one in the dry season (July) and one in the wet season (January). In this manner, the seasonal operation of the hydro power can be taken into consideration.

For modeling of the loads, the hourly load profile for two characteristic days (working day and weekend), as given from the dispatch center in Osogbo was used. Each working day in the week was considered to have the same load profile. The daily load curve according to Section 3.5, Figure 3-4 has been modeled for the GTMax Tool.

8.2.2 Modelling of Hydro Power Plants

The mode of operation for the hydro power plants was used as presented in TCN's Annual Report 2015. **Figure 8-2 - Figure 8-4** show the hydrographs of Jebba HPP, Kainji HPP and Shiroro HPP for the years 1997 to 2015 (source: TCN Annual Report 2015).

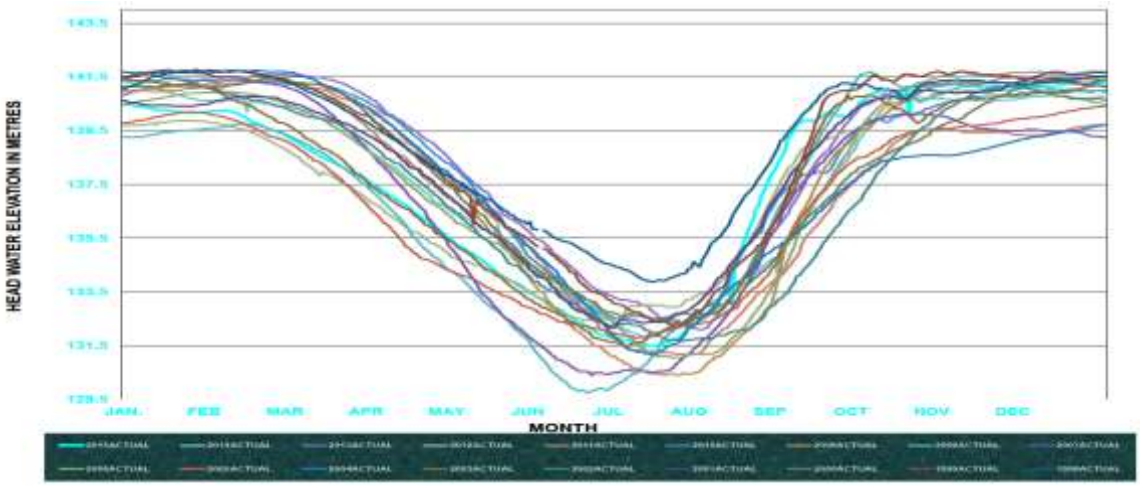


Figure 8-2: Kainji Hydrograph 1998 - 2015 Source: TCN Annual Report

Figure 8-3: Jebba Hydrograph 1997 - 2015 Source: TCN Annual Report

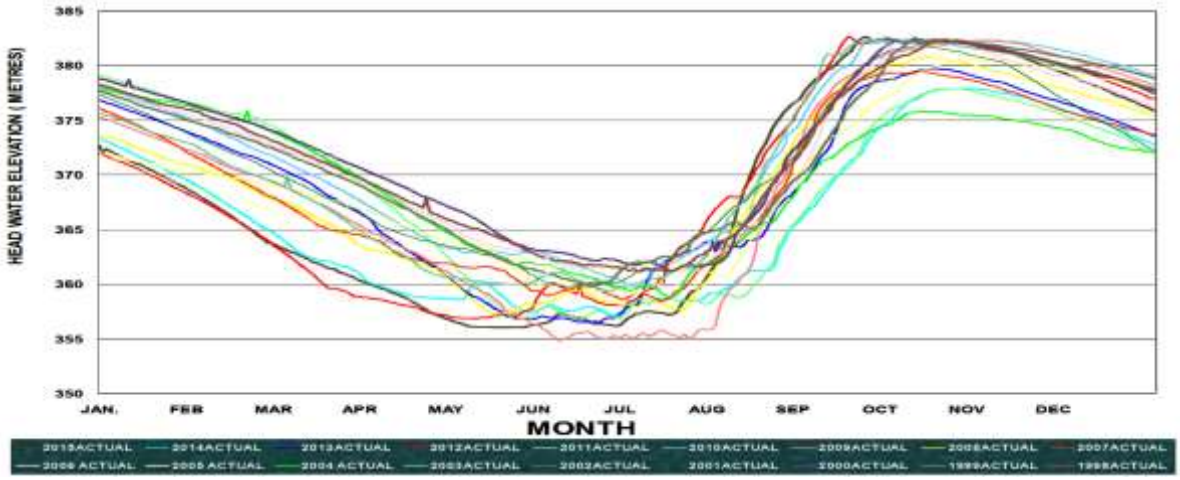


Figure 8-4: Shiroro Hydrograph 1997 - 2015 Source: TCN Annual Report

The generation for the hydro power plants was considered as in the **Table 8-1** and **Table 8-2.** The information is based on the historical data of the last 5 year Annual Reports from TCN. For Kainji, Jebba and Shiroro, data from the Annual Report 2010 were used and for the planned hydro power at Zungeru the same curve as for Shiroro has been used and scaled according to the installed power.

Table 8-1: Monthly generation considered per hydro power plant for 2020

Monthly Generation per Power Plant	Kainji (GWh)	Jebba (GWh)	Shiroro (GWh)	Zungeru (GWh)
January	294.193	242.250	212.457	148.335
February	261.319	216.480	205.529	150.069
March	256.710	195,760	195.863	178.002
April	204.302	197.670	160.178	207.687
May	123.655	258.330	61.683	149.934
June	180.218	178.200	21.389	153.450
July	114.599	141.930	258.360	148.335
August	118,285	211.770	265.433	148.335
September	154.760	222.950	271.054	150.001
October	176.972	297.420	196.372	250.848
November	179.127	298.530	186.732	222.502
December	236.851	232.450	193.561	222.502
Totals	**2300.991**	**2693,740**	**2421,120**	**2130.000**

Table 8-2: Monthly Running Capacity per hydro power plant

Monthly Running Capacity per Power Plant	Kainji (MW)	Jebba (MW)	Shiroro (MW)	Zungeru (MW)
January	409	336	295	393
February	363	301	285	398
March	357	272	272	472
April	284	275	222	551
May	172	359	86	398
June	250	248	30	407
July	159	197	359	393
August	164	294	369	393
September	215	310	376	398
October	246	413	273	665
November	249	415	259	590
December	329	323	269	590

8.2.3 Modelling of Thermal Power Plants

For the existing thermal generation, the heat rate, costs and efficiency have been considered, as presented in **Table 8-3**.

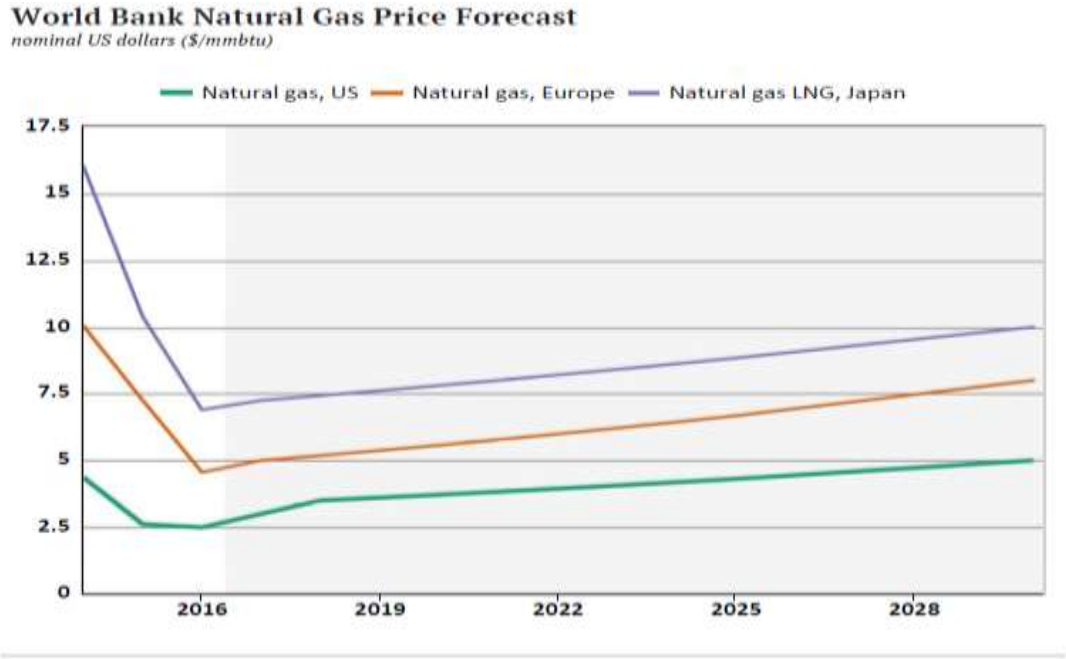
Table 8-3: Heat rate of existing thermal power plants

Nigeria Gas Fired Power Plants - Gas Consumption - Cost - Efficiency / Heat Rate							
TCN - Annual Report 2015	Table 12		Table 13	Table 7B			
Power Plant	Quantity of Gas Consumed in 2015	Calloric Value	Cost of Gas	Energy Sent Out	Efficientcy based on Energy Sent-Out	Heat Rate	
	[SCF]	[MWh]	[Naira]	[MWh]	kWhe/kWhg	[kWhg/kWhe]	[GJ/MWh]
1	2		3	4	5	6	7
Egbin	53.965.156.491	16.567.303	163.190.633	5.192.951	0,31	3,19	11,5
Delta	35.372.927.009	10.859.489	106.967.731	2.761.016	0,25	3,93	14,2
Sapele	7.632.762.897	2.343.258	23.081.475	550.937	0,24	4,25	15,3
Sapele NIPP	8.448.997.178	2.593.842	25.549.767	919.606	0,35	2,82	10,2
AfamVI	23.935.446.666	7.348.182	72.380.791	2.991.284	0,41	2,46	8,8
Omotosho	16.588.767.738	5.092.752	50.164.434	1.448.663	0,28	3,52	12,7
Omotosho NIPP	15.160.500.000	4.654.274	45.845.352	1.089.840	0,23	4,27	15,4
Geregu	11.748.628.000	3.606.829	35.527.851	1.165.646	0,32	3,09	11,1
Geregu NIPP	1.246.166.000	3.762.933	3.762.933	1.165.646	0,31	3,23	11,6
Ibom	6.223.319.000	1.910.559	38.801.673	510.565	0,27	3,74	13,5
Okpai	19.868.522.319	6.099.636	96.721.990	2.604.661	0,43	2,34	8,4
Ihovbor	12.461.912.480	3.825.807	40.564.065	1.106.267	0,29	3,46	12,4
Olorunsogo 1	31.984.785.036	9.819.329	18.064.572	1.522.245	0,16	6,45	23,2
Olorunsogo NIPP	13.414.042.652	4.118.111	60.082.411	1.113.488	0,27	3,70	13,3
	1 J = 1 Ws		Nigeria Gas - 1 Qubic Feet :		1047 BTU =	0,307 kWh	
	3,600 J = 1 Wh						

The basis for the calculation are the quantity of gas consumed in 2015, its caloric value and cost, as well as the energy sent out, for each existing thermal power plant, as presented in the Annual Report of 2015 from TCN. The heat content considered for Nigerian fuel is 1.047 BTU/cubic feet.

For the gas fuel cost, the Consultant used the data presented in **Figure 8-5** from the Nigeria Data Portal and the Source of the Information is the World Bank Commodity Forecast Price Data from January 2017.

The **Figure 8-6** presents the price of the US Liquefied Natural Gas Imports from Nigeria.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Natural gas, US	4.37	2.61	2.49	3.00	3.50	3.61	3.71	3.83	3.94	4.06
Natural gas, Europe	10.05	7.26	4.56	5.00	5.18	5.37	5.57	5.78	5.99	6.21
Natural gas LNG, Japan	16.04	10.40	6.90	7.25	7.43	7.62	7.81	8.00	8.20	8.41

Figure 8-5: World Bank Natural Gas Price Forecast

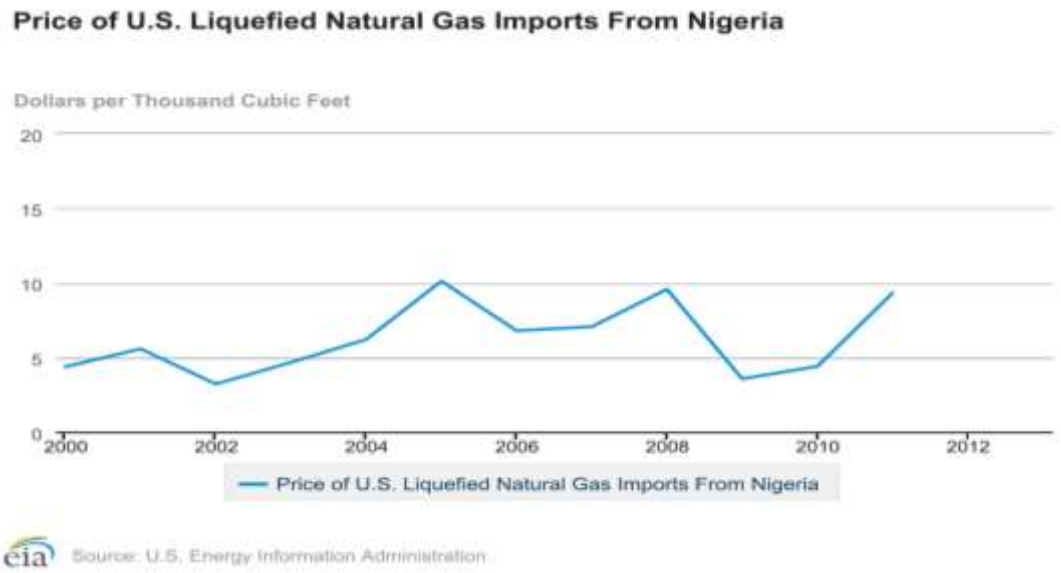


Figure 8-6: US Liquefied Natural Gas Imports from Nigeria

8.3 Elaboration of Future Nigeria Power System Model in GTMax

For the future years, the Consultant added into the GTMax model the potential generation options in all regions of Nigeria, the demand forecast and the corresponding transmission expansion.

8.3.1 Modelling of Expansion Stage 2020

The topology of the Nigerian grid for year 2020 is presented in **Annex 8.3.1**.

The generation model besides the existing generation includes following generation options:

- Thermal power options in the DisCos: Ikeja, Benin, Ibadan, Abuja, Enugu, Kaduna and Port Harcourt,
- Hydro power option: Zungeru in DisCo Abuja,
- Renewable power options: photovoltaic in DisCos - Abuja, Jos, Kaduna and Kano and wind generation project JBS at the Jos Plateau.

For the generation output of the hydro power option Zungeru HPP, data from the Zungeru HPP feasibility study have been used.

The transmission grid includes the main connections between the DisCos as an equivalent impedance of all transmission lines between the corresponding DisCos. The total capacity of the transmission links between DisCos has been accumulated. In this manner, the additional necessary transmission capacity for power exchange between the DisCos can be determined, when accumulated transmission capacity is exceeded.

Based on the data of the agreed generation expansion plan and the demand forecast in each of the DisCos in Nigeria and the DC load flow, the power flow between the DisCos was obtained. This defines the necessary voltage level and capacity of the required additional transmission lines between DisCos.

The GTMax model includes also the interconnections to Benin/Togo and Niger:

- the existing and planned 330 kV interconnections to Benin and Togo,
- the existing 132 kV line to Niger,
- the planned 330 kV interconnection to Niger (WAPP Project)

In the period 2017 - 2020 the Consultant considered year increase in the generation capacity, as per Annex 6.1 (Generation Assets Table).

For the fuel cost increase up to year 2020 costs, as presented in **Figure 8-6**, were considered.

8.3.1.1 Modelling of Thermal Power Options

For year 2020, the Consultant considered the generation expansion as per **Annex 6.1** and **Annex 6.2**.

For the new combined cycle power plant, the Consultant considered:

- heat rate of 6.927 GJ/MWh and variable O&M costs 2.74 $/MWh

For the new open cycle power plant the Consultant considered:

- heat rate of 10.711 GJ/MWh and variable O&M costs 3.2 $/MWh

8.3.1.2 Modelling of Solar Power Plants

For the modeling of the solar power plants the Consultant used the solar radiation database as presented in **Figure 8-7**. The solar power projects are located in the north of Nigeria where the solar radiation is the highest.

Figure 8-7: Solar radiation database for Nigeria

The data used in the study are presented in **Figure 8-8** and **Figure 8-9**.

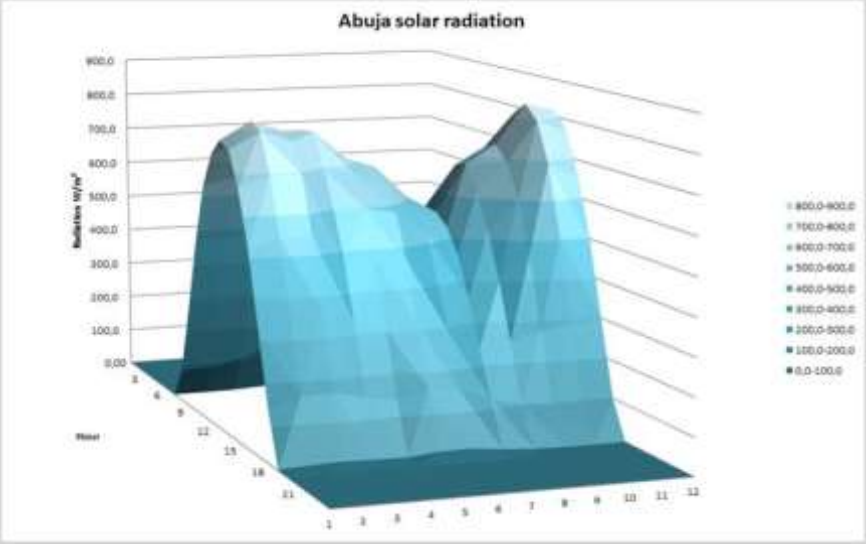


Figure 8-8: Solar radiation database for Abuja

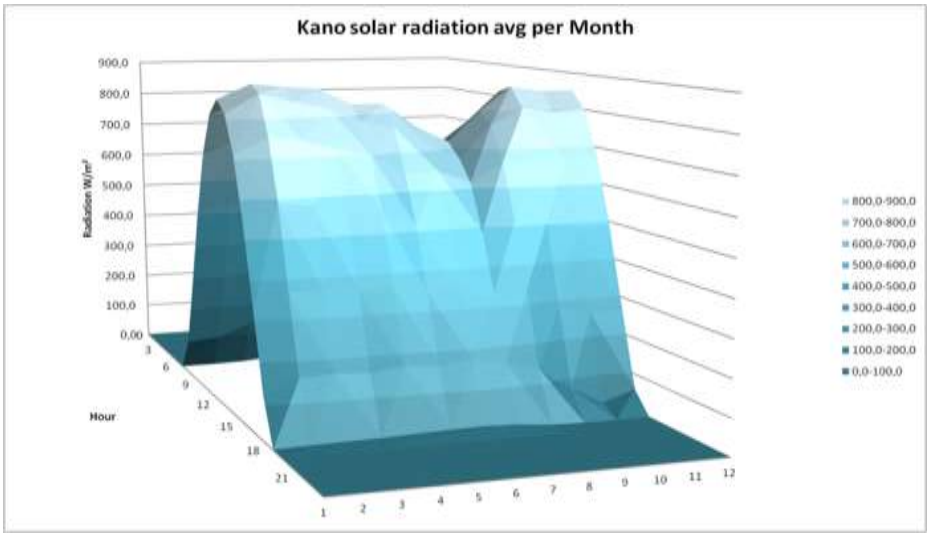


Figure 8-9: Solar radiation database for Kano

8.3.1.3 Modelling of Wind Power Plants

The Consultant extracted data on the wind speeds for Nigeria from the Wind Atlas presented in the WAPP Masterplan elaborated by TRACTEBEL in 2011. These are presented in **Figure 8-10**. Marked are locations with high wind speeds.

For the Masterplan for Nigeria, the Consultant considered the location at the Jos Plateau. According to the wind atlas for Nigeria the wind speeds at Jos Plateau are presented in **Figure 8-11**.

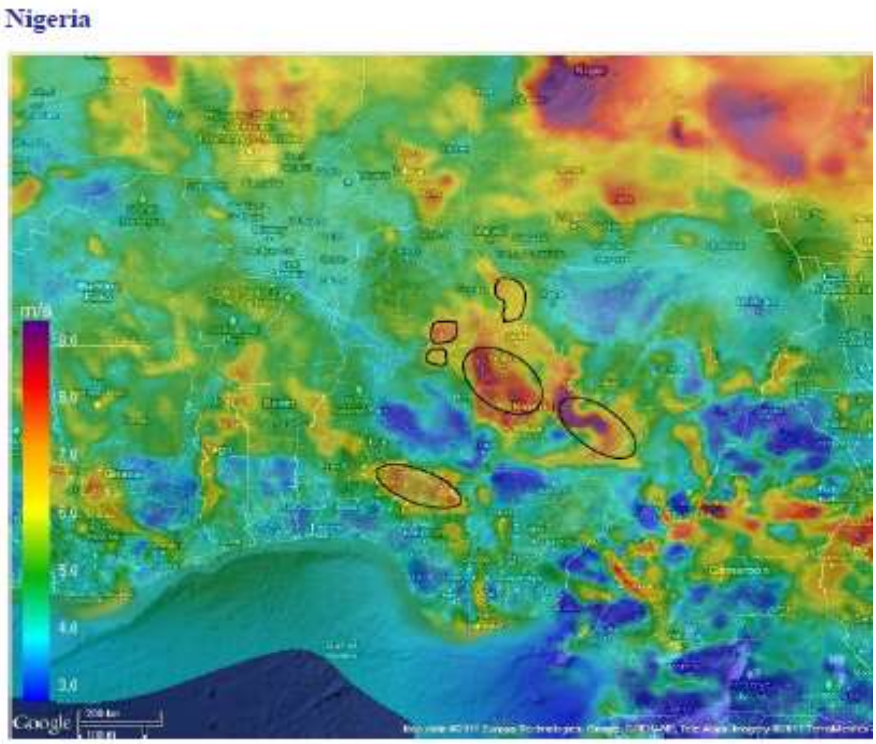


Figure 8-10: Wind Atlas for Nigeria Source: WAPP Masterplan

Figure 8-11 shows wind speed data for the Jos Plateau for the characteristic weeks (January and August) was considered in the Masterplan Study.

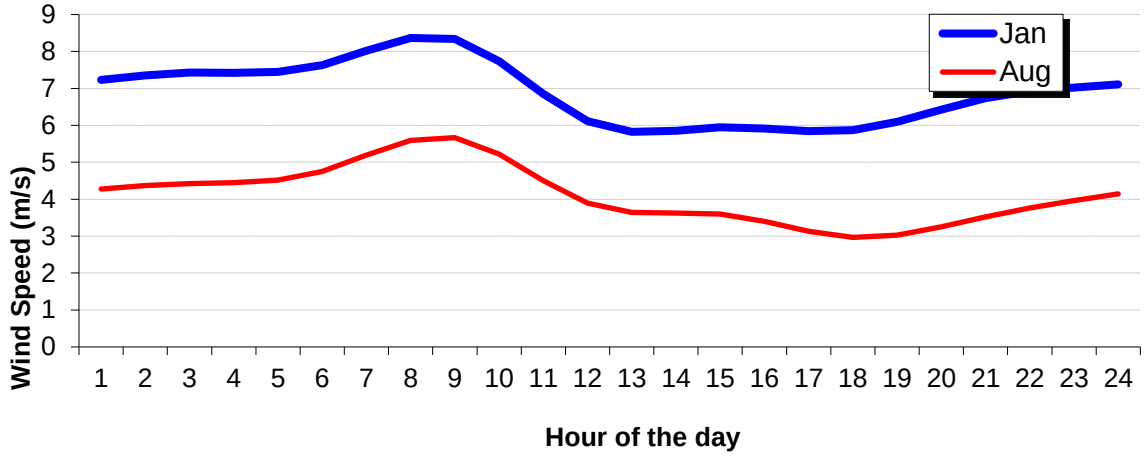


Figure 8-11: Wind Speed at Jos Plateau in Nigeria

8.3.2 Modelling of Expansion Stage 2025

The topology of the Nigerian grid for year 2025 is presented **Annex 8.3.2**.

For the generation and transmission expansion up to year 2025, the Consultant considered the following two development Options:

- Adding of thermal generation only in South of Nigeria - Option 1
- Adding of thermal generation in South and in North of Nigeria - Option 2

For the expansion stage 2025 the Consultant considered as highest priority the replacement of old generation capacity with low efficiency which has reached the end of the techno-economic life-cycle. It has been assumed that the new power plants will be combined cycle power plants (CCPP) with high efficiency and that it will be possible to double the generation at existing locations, like: Delta, Egbin, Gbarain, Sapele, etc. This has the advantage that the gas supply system is already available as well as the transmission line connections of the power plants to the national grid.

As renewable resources in addition to the solar projects and the wind generation project JBS implemented in 2020, the Consultant considered new solar projects in Abuja, Kano, Kaduna, Jos and Yola. The Mambila HPP was considered with 300 MW and the Kazaure PV plant with 200 MW output.

In Option 2, as thermal generation candidates in the north following locations: Abuja, Kaduna and Kano were considered.

In the period 2021 - 2025 the Consultant considered yearly increase in the generation capacity, as per Annex 6.1 (Generation Assets Table).

8.3.2.1 Modelling of Thermal Power Options

For year 2025, the Consultant considered the generation expansion as per **Annex 6.1** and **Annex 6.2**.

For the new combined cycle power plant the Consultant considered:

- heat rate of 6.927 GJ/MWh and variable O&M costs 2.74 $/MWh

For the new open cycle power plant the Consultant considered:

- heat rate of 10.711 GJ/MWh and variable O&M costs 3.2 $/MWh

For the coal power option the Consultant considered:

- heat rate of 8.650 GJ/MWh and variable O&M costs 15 $/MWh

8.3.3 Modelling of Expansion Stage 2030

The topology of the Nigerian grid for year 2030 is presented **Annex 8.3.3**.

For the generation and transmission expansion up to year 2030, the Consultant considered the development Option 2:

- Adding of thermal generation in South and in North of Nigeria.
- In Option 2, as thermal generation candidates in the north following locations: Abuja, Kaduna and Kano were considered.

Thermal generation candidates have been considered as per Annex 6.1.

As renewable resources in addition to the solar projects and the wind generation project JBS implemented in 2025, the Consultant considered new solar projects in Kano. The Mambila HPP was considered with 900 MW and the Kazaure PV plant with 1000 MW output.

In the period 2025 - 2030 the Consultant considered yearly increase in the generation capacity of 1000 - 1500 MW/year.

8.3.4 Modelling of Expansion Stage 2035

The topology of the Nigerian grid for year 2035 is presented **Annex 8.3.4**.

For the generation and transmission expansion up to year 2035, the Consultant considered the development Option 2:

- Adding of thermal generation in South and in North of Nigeria.
- In Option 2, as thermal generation candidates in the north following locations: Abuja, Kaduna and Kano were considered.

Thermal and renewable generation candidates have been considered as per Annex 6.1.

In the period 2030 - 2035 the Consultant considered yearly increase in the generation capacity, as per Annex 6.1 (Generation Assets Table).

8.4 Transmission and Generation Expansion Study Results for 2020

8.4.1 GTMax Results for 2020

The Consultant performed two sets of calculation:

- Potential total Load in Nigeria to be supplied 8 GW
- Potential total Load in Nigeria to be supplied 10 GW

It has been assumed that all existing thermal power plants, that need rehabilitation, will be rehabilitated until 2020. Power plant projects that are presently under construction will be commissioned by 2020 as planned.

Furthermore, it has been assumed that gas supply will be sufficient to operate all power plants.

Under these assumptions the potential demand of 8 GW as well as 10 GW can be supplied.

Referring to Annex 6.1 the total installed capacity in Nigeria (including the PV power plants) will be 13,155 MW. Considering the fact that the peak load occurs at 9 p.m. (when PV power is not available), and reaches the value of 12,600 MW. Taking into consideration that all existing power plants will be running at 70% due to repair and maintenance, about 7 GW of existing thermal power will be in service for covering the base load. The peaking will be done by the existing hydro and hydro power under construction (in total about 2 GW), as well as by some of the existing thermal power plants and power plants under construction (about 1.5 GW).

In the **Annexes 8.4.1** and **8.4.2** the results of the GTMax calculations for the two characteristic weeks (wet season - week 1 - January (Annex 8.4.1) and dry season - week 27 - July (Annex 8.4.2)) for the case - supplying of 10GW potential load are presented.

8.4.2 Conclusions from GTMax Results for 2020

Studying the results of the GTMax calculations for 2020 in both: dry and wet season, the following conclusions can be made:

- In order to supply the potential demand of 10 GW a generation set-up as per Annex 6.1 for year 2020 is necessary. Each location is considered to be run at least by 70% of the installed power at all times,
- Due to the low availability of hydro power projects in Nigeria compared to thermal power generation, the peaking is done also by thermal power plants,
- The main generation facilities are located in the DisCos: Abuja, Benin, Ikeja and Port Harcourt,

- Only the DisCos Abuja, Benin, Ikeja and Port Harcourt are self sufficient concerning the balance of generation and load,
- DisCos without generation facilities are: Kano, Yola and Eko. Jos has only small amount of wind generation,
- Solar power does not contribute for the evening peaking, but for the daily peaking does,
- The power flows between the DisCos in Nigeria for the peaking hours in dry season in 2020 are from the south to the north, from the east to the west.
- The power flows between the DisCos in Nigeria for the off peak hours in dry season in 2020 remain the same: from the south to the north, from the east to the west.

The power flows [MW] among the DisCos are as presented in **Table 8-4**.

The values presented indicate the maximal power flows on each connection. These don't occur in the same hour in the week. These values are an indication if additional transmission infrastructure between the DisCos is necessary up to 2020.

As presented in **Table 8.4** the power flows among the DisCos are lower than 2 GW. The highest power flows are from Port Harcourt to Enugu, followed by Benin to Ibadan, Ikeja to Eko and Abuja to Kaduna.

There are small differences in the power flows in wet and dry season, mostly due to the availability of hydro power and other renewable resources.

Based on the results presented in the **Table 8-4** and in the **Annexes 8.4.1** and **8.4.2**, it can be concluded that the installed transmission infrastructure can carry the required power flows and no additional transmission links between the DisCos are necessary up to 2020.

Table 8-4: Power Flows [MW] among DisCos in year 2020

Region	Week 1	Week 27
Abuja-Benin	0.0	0.0
Benin-Abuja	323.7	382.3
Kaduna-Kano	743.2	742.9
Kano-Kaduna	0.0	0.0
Abuja-Kaduna	819.0	785.0
Kaduna-Abuja	0.0	0.0
Kano-Yola	7.1	6.6
Yola-Kano	0.0	0.0
Benin-Pt Harco	0.0	0.0
Pt Harco-Benin	666.0	692.3
Benin-Ibadan	1,492.6	1,580.6
Ibadan-Benin	0.0	0.0
Ikeja-Ibadan	0.0	0.0
Ibadan-Ikeja	568.0	492.8
Ikeja-Eko	853.1	896.3
Eko-Ikeja	0.0	0.0
Ibadan-Eko	698.7	644.2
Eko-Ibandan	0.0	0.0
Abuja-Jos	431.9	363.6
Jos-Abuja	0.0	0.0
Kaduna-Jos	0.0	0.0
Jos-Kaduna	395.2	428.6
Benin-Enugu	0.0	0.0
Enugu-Benin	380.8	375.1
Abuja-Ibadan	534.3	316.4
Ibandan-Abuja	0.0	37.7
Jos-Yola	281.9	282.2
Yola-Jos	0.0	0.0
Jos-Enugu	0.0	0.0
Enugu-Jos	632.2	744.5
Pt Harco-Enugu	1,620.9	1,719.6
Enugu-Pt Harco	0.0	0.0

8.5 Transmission and Generation Expansion Study Results for 2025

Based on the load forecast, the transmission and the generation expansion plan for Nigeria, the Consultant performed two sets of calculation for 2025:

- new thermal generation only in South of Nigeria - Option 1
- new thermal generation in South and in North of Nigeria - Option 2

With the consideration that the part of the generation facilities in Nigeria will be rehabilitated and part will be retired because they have reached the end of the economic life-cycle (as per Annex 6.1), as well as considering that all power plant projects that are presently under construction will be in service up to 2020, the potential demand of 13 GW can be supplied.

The focus of the work was on evaluation of a list of least cost candidates of thermal power projects located in different DisCos and use different fuel (gas, coal) or different technology (combined cycle or open cycle).

Considering that the variable operation costs for the open cycle thermal power plants are higher than the one for the combined cycle, the latter are preferred by the simulation tool. Considering the fact that the size of most of the thermal power options is similar, the transmission facilities for connection to the grid of all power options require similar infrastructure.

8.5.1 GTMax Results for 2025 - Option1

In the **Annexes 8.5.1** to **8.5.2** the results of the GTMax calculations for the two characteristic weeks (dry season - week 1 - January (Annex 8.5.1) and wet season - week 27 - July (Annex 8.5.2)) for the Option 1 - supplying of 13GW potential load in 2025 are presented.

All thermal power combine cycle options, as well as the coal option, are taken by the optimization model for 2025, and considered necessary for covering the demand.

8.5.2 Conclusions from GTMax Results for 2025 - Option1

Studying the results of the GTMax calculations for year 2025 for Option 1 in both: dry and wet season, the following conclusions can be made:

- In order to supply the potential demand of 13 GW a generation set-up as per **Annex 6.1** for year 2025 is necessary. Each location of the existing, committed and presently under construction sites is considered to be run at least by 70% of the installed power at all times,
- The main generation facilities are located in the DisCos: Abuja, Benin, Ikeja and Port Harcourt,
- Installing of generation facilities in Ibadan DisCo has advantages for the overall system (lowering losses, improving voltage profile)
- Only the DisCos Abuja, Benin, Ikeja and Port Harcourt are self sufficient concerning the balance of generation and load,
- DisCos without conventional generation facilities are: Kano, Yola, Eko and Jos. Jos has only small amount of wind generation, and Kano and Yola have PV installations.
- Solar power does not contribute for the evening peaking, but for the daily peaking does,
- The power flows between the DisCos in Nigeria for the peaking hours in dry season also in 2025 remain the same like in 2020, from the south to the north, from the east to the west.

The power flows [MW] among the DisCos are as presented in **Table 8-5** and present the maximal power flows on each of the connections in the investigated four weeks.

Table 8-5: Power Flows [MW] among DisCos in year 2025, Option 1

Region	Week 1	Week 19	Week 27	Week 40
Abuja-Benin	0.0	0.0	0.0	0.0
Benin-Abuja	369.6	500.6	478.1	685.5
Kaduna-Kano	883.6	882.6	882.7	882.9
Kano-Kaduna	0.0	0.0	0.0	0.0
Abuja-Kaduna	1,154.9	1,095.8	1,103.7	1,923.4
Kaduna-Abuja	0.0	0.0	0.0	0.0
Kano-Yola	0.0	0.0	0.0	0.0
Yola-Kano	21.0	22.0	21.9	29.6
Benin-Pt Harco	0.0	0.0	0.0	0.0
Pt Harco-Benin	245.2	325.1	321.5	315.0
Benin-Ibadan	2,099.2	2,417.6	2,379.8	2,294.5
Ibadan-Benin	0.0	0.0	0.0	0.0
Ikeja-Ibadan	0.0	0.0	0.0	21.1
Ibadan-Ikeja	990.0	990.0	990.0	990.0
Ikeja-Eko	1,542.3	1,542.3	1,542.3	1,542.3
Eko-Ikeja	0.0	0.0	0.0	0.0
Abuja-Jos	585.3	448.8	466.2	575.0
Jos-Abuja	0.0	0.0	0.0	0.0
Kaduna-Jos	0.0	0.0	0.0	0.0
Jos-Kaduna	605.2	663.4	655.6	1,322.5
Ibadan-Eko	207.5	207.5	207.5	207.5
Eko-Ibadan	0.0	0.0	0.0	0.0
Benin-Enugu	0.0	0.0	3.1	0.0
Enugu-Benin	178.7	291.3	275.4	292.9
Jos-Yola	308.3	309.0	308.9	308.8
Yola-Jos	0.0	0.0	0.0	0.0
Abuja-Ibadan	311.9	169.8	89.3	253.3
Ibadan-Abuja	285.1	388.1	367.4	1,074.3
Jos-Enugu	0.0	0.0	0.0	0.0
Enugu-Jos	674.2	880.6	863.8	1,095.8
Pt Harco-Enugu	1,666.4	1,940.8	1,931.8	1,916.3
Enugu-Pt Harco	0.0	0.0	0.0	0.0

The values presented indicate the maximal power flows on each connection, these to not occur in the same hour in the week. These values are an indication if additional transmission infrastructure between the DisCos is necessary up to 2025.

As presented in **Table 8-5** the power flows among the DisCos are lower than 2.5 GW. The highest power flows are from Benin to Ibadan, followed by Pt Harcourt to Enugu, Ikeja to Eko and Abuja to Kaduna and Kaduna to Kano.

There are small differences in the power flows between the seasons, mostly due to the availability of hydro power and other renewable resources. Due to seasonal availability of hydro generation and especially due to the high installed capacity of renewable energies in the center, also power flow from Abuja to Ibadan is registered.

Based on the results presented in the **Table 8-5** and in the **Annexes 8.5.1** and **8.5.2**, it can be concluded that the installed transmission infrastructure can carry the required power flows and no additional transmission links between the DisCos are necessary up to 2025.

8.5.3 GTMax Results for 2025 - Option2

In the **Annexes 8.5.3** and **8.5.4** the results of the GTMax calculations for the two characteristic weeks (dry season - week 1 - January (Annex 8.5.3) and wet season - week 27 - July (Annex 8.5.4)) for the Option 2 - supplying of 13GW potential load in 2025 are presented.

8.5.4 Conclusions from GTMax Results for 2025 - Option2

Studying the results of the GTMax calculations for year 2025 for Option 2 in both: wet and dry season, the following conclusions can be drawn:

- the main generation facilities are located in the DisCos: Abuja, Benin, Ikeja and Pt Harcourt, Kano and Kaduna
- installing generation facilities for base load power on the north lowers the necessity of installation of thermal power plants in the south east (Pt Harcourt) and lowers the overall losses and transmission power flows within the DisCos
- installing of generation facilities in Ibadan DisCo has advantages for the overall system (generation closer to the big demand centre Lagos)
- only the DisCos: Kano, Abuja, Benin, Ikeja and Pt Harcourt are self-sufficient concerning the balance of generation and load,
- DisCos without conventional generation facilities are: Yola, Eko and Jos. Jos has only small amount of wind generation, and Yola has PV installations.
- solar power does not contribute for the evening peaking, only for the daily peaking,
- the power flows between the DisCos in Nigeria for the peaking hours in dry and wet season in 2020 are party from the north to the south (Pt Harcourt to Enugu), but also from the north to the southwest (Kano to Kaduna, Kaduna to Abuja, Abuja to Ibadan, Abuja to Benin). The power flows from the east to the west in the southern part of the country remain the same (Pt Harcourt to Benin, Benin to Ibadan).

The power flows [MW] among the DisCos are shown in **Table 8-6** and present the maximal power flows on each of the connections in the investigated four weeks.

Table 8-6: Power Flows [MW] among DisCos in year 2025, Option 2

Region	Week 1	Week 19	Week 27	Week 40
Abuja-Benin	388.3	298.2	235.2	354.4
Benin-Abuja	0.0	51.0	44.8	278.1
Kaduna-Kano	0.0	0.0	0.0	0.0
Kano-Kaduna	573.0	619.1	553.0	611.3
Abuja-Kaduna	289.0	253.3	262.5	1,059.7
Kaduna-Abuja	287.3	347.7	296.6	335.6
Kano-Yola	20.1	20.4	19.0	20.5
Yola-Kano	0.0	0.0	0.0	0.0
Benin-Pt Harco	0.0	0.0	0.0	0.0
Pt Harco-Benin	261.8	256.6	243.3	257.8
Benin-Ibadan	2,089.9	1,942.4	1,847.3	1,957.9
Ibadan-Benin	0.0	0.0	0.0	0.0
Ikeja-Ibadan	0.0	0.0	0.0	0.0
Ibadan-Ikeja	1,616.7	1,280.9	1,145.5	1,484.2
Ikeja-Eko	1,542.3	1,542.3	1,542.3	1,528.6
Eko-Ikeja	0.0	0.0	0.0	0.0
Abuja-Jos	450.8	367.0	388.6	398.0
Jos-Abuja	0.0	0.0	0.0	0.0
Kaduna-Jos	354.5	349.6	316.8	360.4
Jos-Kaduna	0.0	0.0	0.0	662.7
Ibadan-Eko	255.4	229.8	218.3	235.9
Eko-Ibadan	0.0	0.0	0.0	0.0
Benin-Enugu	0.0	0.0	0.0	0.0
Enugu-Benin	443.9	414.1	364.3	418.6
Jos-Yola	288.5	288.9	288.9	288.8
Yola-Jos	0.0	0.0	0.0	0.0
Abuja-Ibadan	1,298.1	1,060.0	882.6	1,209.9
Ibadan-Abuja	0.0	0.0	0.0	214.8
Jos-Enugu	253.7	195.0	133.0	235.3
Enugu-Jos	127.0	245.6	242.6	582.4
Pt Harco-Enugu	1,313.6	1,348.8	1,345.8	1,346.2
Enugu-Pt Harco	0.0	0.0	0.0	0.0

The values presented indicate the maximal power flows on each connection, these do not occur in the same hour in the week. These values are an indication if additional transmission infrastructure between the DisCos is necessary up to 2025.

As presented in **Table 8-6**, the power flows among the DisCos are lower than 2.5 GW. The highest power flows are from Benin to Ibadan, followed by Ibadan to Ikeja, Ikeja to Eko and Pt Harcourt to Enugu.

The power flows: Abuja to Kaduna and Kaduna to Kano are much lower than in the Option 1, due to the fact that there is new thermal generation in the North in Kano and additional thermal generation in Kaduna and Abuja.

There are small differences in the power flows between the seasons, mostly due to the availability of hydro power and other renewable resources.

Taking into consideration that in Option 2, new conventional generation options (thermal) are also located in the north of the country in DisCo Kano and that additional thermal generation has been added to Kaduna and Abuja, power flows from Kano to Kaduna, Kano to Yola, Kaduna to Jos, Jos to Enugu, Abuja to Benin and Abuja to Ibadan are noted. Installing thermal generation in the north has advantage for supplying the high demand in the north with local resources, lower transmission losses, balancing the power flows in the grid and hence improving the overall static security of the system.

Based on the results presented in the **Table 8-6** and in the **Annexes 8.5.3** and **8.5.4**, it can be concluded that the installed transmission infrastructure can carry the required power flows and no additional transmission links between the DisCos are necessary up to 2025.

8.6 Transmission and Generation Expansion Study Results for 2030

8.6.1 GTMax Results for 2030

The Consultant considered a potential total load of 19.2 GW to be supplied in Nigeria in 2030.

It has been considered that Egbin thermal power plant is not retired.
Furthermore, it has been assumed that gas supply will be sufficient to operate all power plants.

Referring to Annex 6.1 the total installed capacity in Nigeria (including the PV power plants) will be 35.6 GW. Considering the fact that the peak load occurs at 9 p.m. (when PV power is not available), and reaches the value of 19.2 GW.

In **Annexes 8.6.1** and **8.6.2** the results of the GTMax calculations for the two characteristic weeks (dry season - week 1 - January (**Annex 8.6.1**) and wet season - week 27 - July (Annex 8.6.2)) for the case - supplying of 19.2 GW potential load are presented.

8.6.2 Conclusions from GTMax Results for 2030

Studying the results of the GTMax calculations for 2030 in both: dry and wet season, the following conclusions can be dawn:

- in order to supply the potential demand of 19.2 GW a generation set-up as per Annex 6.1 for year 2030 is necessary. Each location of the currently existing power plants is considered to be run at least by 70% of the installed power at all times,

- due to the low availability of hydro power projects in Nigeria compared to thermal power generation, the peaking is done also by thermal power plants,
- the main generation facilities are located in the DisCos: Abuja, Benin, Ikeja and Port Harcourt,
- only the DisCos Abuja, Benin, Ikeja and Port Harcourt are self-sufficient concerning the balance of generation and load,
- solar power does not contribute for the evening peaking, but for the daily peaking does,
- the power flows between the DisCos in Nigeria for the peaking hours in dry season in 2030 are from the south to the north, from the east to the west.
- the power flows between the DisCos in Nigeria for the off-peak hours in dry season in 2030 remain the same: from the south to the north, from the east to the west.

The power flows [MW] among the DisCos are as presented in **Table 8-7**.

The values presented indicate the maximal power flows on each connection. These don't occur in the same hour in the week. These values are an indication if additional transmission infrastructure between the DisCos is necessary up to 2030.

As presented in **Table 8-7** the power flows among the DisCos are lower than 2.5 GW. The highest power flows are from Port Harcourt to Enugu, followed by Abuja to Kaduna, Ikeja to Eko, Ibadan to Abuja and Kaduna to Kano.

There are small differences in the power flows in wet and dry season, mostly due to the availability of hydro power and other renewable resources.

Based on the results presented in **Table 8-7** and in **Annexes 8.6.1** and **8.6.2**, it can be concluded that the installed transmission infrastructure cannot carry the required power flows and additional transmission links between the DisCos are necessary up to 2030. Following connections are recommended:

- Pt Harcourt - Enugu
- Abuja - Kaduna
- Ikeja - Eko
- Jos - Kaduna

Table 8-7: Power Flows [MW] among DisCos in year 2030

Region	Week 1	Week 19	Week 27	Week 40
Abuja-Benin	0.0	0.0	0.0	0.0
Benin-Abuja	744.5	749.7	687.2	693.8
Kaduna-Kano	1,378.0	1,227.3	1,412.5	1,427.9
Kano-Kaduna	0.0	20.0	0.0	0.0
Abuja-Kaduna	2,058.1	1,779.7	1,530.7	1,850.1
Kaduna-Abuja	0.0	0.0	0.0	0.0
Kano-Yola	0.0	6.1	0.0	0.0
Yola-Kano	26.4	23.9	79.6	39.8
Benin-Pt Harco	0.0	0.0	0.0	0.0
Pt Harco-Benin	353.4	352.7	428.9	386.6
Benin-Ibadan	1,021.2	1,008.7	1,372.4	1,304.7
Ibadan-Benin	0.0	0.0	0.0	0.0
Ikeja-Ibadan	1,369.4	1,380.3	1,354.5	1,387.5
Ibadan-Ikeja	0.0	0.0	0.0	0.0
Ikeja-Eko	1,641.1	1,654.1	1,623.2	1,662.8
Eko-Ikeja	0.0	0.0	0.0	0.0
Abuja-Jos	1,165.4	991.4	228.8	754.2
Jos-Abuja	0.0	0.0	453.7	0.0
Kaduna-Jos	0.0	0.0	0.0	0.0
Jos-Kaduna	989.5	860.7	1,612.0	1,120.2
Ibadan-Eko	0.0	0.0	0.0	0.0
Eko-Ibadan	0.0	0.0	0.0	0.0
Benin-Enugu	90.0	99.2	0.0	12.8
Enugu-Benin	201.2	191.4	468.6	373.1
Jos-Yola	549.6	546.3	1,077.0	679.4
Yola-Jos	0.0	0.0	0.0	0.0
Abuja-Ibadan	0.0	0.0	0.0	0.0
Ibadan-Abuja	1,353.1	1,370.3	1,090.1	1,244.8
Jos-Enugu	0.0	0.0	0.0	0.0
Enugu-Jos	1,361.3	1,380.2	1,082.3	1,193.8
Pt Harco-Enugu	2,455.3	2,495.1	2,488.8	2,403.7
Enugu-Pt Harco	0.0	0.0	0.0	0.0

8.7 Transmission and Generation Expansion Study Results for 2035

8.7.1 GTMax Results for 2035

The Consultant considered a potential total load of 24.3 GW to be supplied in Nigeria in 2035.

Furthermore, it has been assumed that gas supply will be sufficient to operate all power plants.

Referring to **Annex 6.1** the total installed capacity in Nigeria (including the PV power plants) will be 43.2 MW. Considering the fact that the peak load occurs at 9 p.m. (when PV power is not available), and reaches the value of 24.300 MW.

In **Annexes 8.7.1** and **8.7.2** the results of the GTMax calculations for the two characteristic weeks (dry season - week 1 - January (**Annex 8.7.1**) and wet season - week 27 - July (Annex 8.7.2)) for the case - supplying of 24.3 GW potential loads are presented.

8.7.2 Conclusions from GTMax Results for 2035

Studying the results of the GTMax calculations for 2035 in both: dry and wet season, the following conclusions can be drawn:

- in order to supply the potential demand of 24.3 GW a generation set-up as per Annex 6.1 for year 2035 is necessary. Each location of the currently existing power plants is considered to be run at least by 70% of the installed power at all times,
- due to the low availability of hydro power projects in Nigeria compared to thermal power generation, the peaking is done also by thermal power plants,
- the main generation facilities are located in the DisCos: Abuja, Benin, Ikeja and Port Harcourt,
- only the DisCos Abuja, Benin, Ikeja and Port Harcourt are self-sufficient concerning the balance of generation and load,
- solar power does not contribute for the evening peaking, but for the daily peaking does,
- the power flows between the DisCos in Nigeria for the peaking hours in dry season in 2030 are from the south to the north, from the east to the west.
- the power flows between the DisCos in Nigeria for the off-peak hours in dry season in 2030 remain the same: from the south to the north, from the east to the west.

The power flows [MW] among the DisCos are as presented in **Table 8-8.**

The values presented indicate the maximal power flows on each connection. These don’t occur in the same hour in the week. These values are an indication if additional transmission infrastructure between the DisCos is necessary up to 2035.

As presented in **Table 8-7** the power flows among the DisCos are lower than 3.5 GW. The highest power flows are from Port Harcourt to Enugu, followed by Abuja to Kaduna, Ikeja to Eko, Ibadan to Abuja and Kaduna to Kano.

There are small differences in the power flows in wet and dry season, mostly due to the availability of hydro power and other renewable resources.

Table 8-8: Power Flows [MW] among DisCos in year 2035

Region	Week 1	Week 19	Week 27	Week 40
Abuja-Benin	0.0	0.0	0.0	0.0
Benin-Abuja	883.4	1,041.8	829.1	889.6
Kaduna-Kano	1,534.5	1,456.1	1,612.8	1,525.1
Kano-Kaduna	0.0	0.0	0.0	0.0
Abuja-Kaduna	2,173.4	2,045.9	1,809.1	2,035.9
Kaduna-Abuja	0.0	0.0	0.0	0.0
Kano-Yola	3.4	7.1	0.0	0.0
Yola-Kano	17.8	18.9	73.2	33.1
Benin-Pt Harco	0.0	0.0	0.0	0.0
Pt Harco-Benin	551.9	632.3	478.8	552.8
Benin-Ibadan	1,542.0	1,779.4	1,363.3	1,571.5
Ibadan-Benin	0.0	0.0	0.0	0.0
Ikeja-Ibadan	1,418.9	1,429.4	1,409.6	1,399.1
Ibadan-Ikeja	0.0	0.0	0.0	0.0
Ikeja-Eko	1,700.4	1,713.1	1,689.3	1,676.8
Eko-Ikeja	0.0	0.0	0.0	0.0
Abuja-Jos	1,216.3	1,063.3	612.7	863.8
Jos-Abuja	0.0	0.0	240.7	0.0
Kaduna-Jos	0.0	0.0	0.0	0.0
Jos-Kaduna	1,042.2	1,054.9	1,682.1	1,209.4
Ibadan-Eko	4.2	4.6	4.6	3.8
Eko-Ibadan	0.4	0.0	0.0	0.8
Benin-Enugu	0.0	0.0	0.0	0.0
Enugu-Benin	555.9	709.2	548.9	578.9
Jos-Yola	818.6	818.2	1,347.3	949.6
Yola-Jos	0.0	0.0	0.0	0.0
Abuja-Ibadan	0.0	0.0	0.0	0.0
Ibadan-Abuja	1,528.9	1,760.9	1,434.7	1,474.4
Jos-Enugu	0.0	0.0	0.0	0.0
Enugu-Jos	1,780.5	1,973.0	1,431.9	1,660.2
Pt Harco-Enugu	3,083.5	3,305.8	2,598.6	3,014.1
Enugu-Pt Harco	0.0	0.0	0.0	0.0

Based on the results presented in the **Table 8-8** and in **Annexes 8.7.1** and **8.7.2**, it can be concluded that the installed transmission infrastructure cannot carry the required power flows and additional transmission links between the DisCos are necessary up to 2035. Following connections are recommended:

- Pt Harcourt - Enugu
- Abuja - Kaduna
- Ikeja - Eko
- Enugu - Jos
- Jos - Kaduna
- Kaduna - Kano.

9. Cost Estimation

9.1 Basis for Cost Estimation

For calculation of cost of new transmission lines and substations of the proposed transmission system expansions, a simplified cost model has been prepared. For transmission lines it is based on cost per km of transmission line for each voltage level.

For substations, the costs for high voltage feeders have been estimated. They consist of two components: one for high voltage equipment and another for all other substation components (civil works, steel protection & control equipment, auxiliary power supply, etc.). Furthermore, costs for main power transformers, reactors and capacitors have been estimated.

For new 132/33 kV substations the costs for new 33 kV switchgear have been taken into account. In case of increase of transformer capacity in existing 132/33 kV substations it has been assumed that additional 33 kV switchgear will also be installed.

Based on this approach, an accuracy of the cost estimation of ±25% can usually be assumed.

Table 9-1 below shows the cost components considered in the cost estimation.

Table 9-1: Cost components considered in the cost estimation

Unit costs	
Transmission Lines	
	[Million US$ / km]
132 kV DC Line	0.26
330 kV DC Line	0.45
500 kV SC Line	0.28
750 kV SC Line	0.35
Substations	
	Cost per HV feeder
	[Million US$]
132 kV HV equipment	0.70
330 kV HV equipment	1.00
500 kV HV equipment	1.30
750 kV HV equipment	2.20
60 MVA Transformer 132/33 kV	0.80
150 MVA Transformer 330/132 kV	1.50
1000 MVA Transformer 750/330 kV	10.00
33 kV Switchgear	0.70
Civil Works, Steel, Protection, Station Control, Auxiliary Power Supply, Installation etc.	0.90

9.2 Transmission Reinforcements Required by 2020

The power system studies have shown that most of the transmission system expansion required until 2025 are necessary in the north of Nigeria, particularly for the 330 kV system. Under the current transmission system expansion program of TCN and NIPP (see Annexes 4.2a and 4.2b) most of the transmission system expansions have been commissioned in the south and central parts of Nigeria. Some of transmission system expansions have already been completed and it is expected that the remaining will be commissioned by 2020.

Based on the results of the Chapter 7: Power System Analysis, costs for additional 330 kV and 132 kV transmission lines, additional 330/132 kV, 132/33 kV and 132/11 kV transformers as well as additional shunt reactors and shunt capacitors have been estimated. Although it will be challenging to implement all measures by 2020, they are required for a 10 GW power supply of the Nigerian transmission network. A major part of the network expansions are related to the 132 kV network and to additional 330/132 kV and 132/33 kV transformers.

Table 9-2 to **Table 9-8** show the cost estimations for the individual groups of system expansion measures, i.e. transmission lines, transformers and reactive power compensation.

Table 9-9 shows a summary of all additional investments in transmission lines and substations until 2020 to establish a 10 GW transmission network.

Table 9-2: Additional transmission lines to relieve existing lines by 2020 under normal conditions (N-0)

Cost Estimation of Proposed Transmission System Expansions												
		Additional Transmission Lines to Relieve Existing Lines by 2020										
No.	Project	Transmission Lines				Substations						
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]	
	Overhead Lines											
1	Alagbon - Ijora	132	4	0.26	**1.0**							
2	Omoku - Rumusoi	132	12	0.26	**3.1**							
4	Ibom IPP - Ikot Abasi	132	30	0.26	**7.8**							
	Subtotal I				**12.0**							
	Substations											
1	Alagbon						2	0	0	0	**3.2**	
2	Ijora						2	0	0	0	**3.2**	
3	Omoku						2	0	0	0	**3.2**	
4	Rumusoi						2	0	0	0	**3.2**	
5	Ikot Abasi						2	0	0	0	**3.2**	
6	Ibom IPP						2	0	0	0	**3.2**	
7												
	Subtotal II										**19.2**	
	Grand Total	**31.2**										

Reference: Chapter 7: Table 7-19

Table 9-3: Additional transmission lines to relieve existing lines by 2020 under N-1 outage conditions

Cost Estimation of Proposed Transmission System Expansions												
		Additional Transmission Lines to Relieve Existing Lines by 2020										
No.	Project	Transmission Lines				Substations						
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]
	Overhead Lines										
1	Ajaokuta - Okene	132	60.0	0.26	**15.6**						
2	Yenagoa - Gbarain	132	5.0	0.26	**1.3**						
3	Osogbo - Iwo	132	80.0	0.26	**20.8**						
4	Biu - Dadinkowa	132	82.0	0.26	**21.3**						
5	Ayede - Idaban North	132	12.0	0.26	**3.1**						
6	Benin - Irrua	132	88.0	0.26	**22.9**						
7	Delta - Effurun	132	36.0	0.26	**9.4**						
8	Yenagoa - Ahoada	132	46.0	0.26	**12.0**						
9	Ikeja West - Alimoso	132	3.5	0.26	**0.9**						
10	Mando - Kudenda	132	20.0	0.26	**5.2**						
11	PHCT Main - Rumusoi	132	10.0	0.26	**2.6**						
12	Eket - Ibom IPP	132	45.0	0.26	**11.7**						
13	Akoka - Alagbon	132	12.0	0.26	**3.1**						
14	Egbin - Ikorodu	132	20.0	0.26	**5.2**						
15	Alaoji - Aba	132	10.0	0.26	**2.6**						
16	Ilesha - Ilesha Tee	132	20.0	0.26	**5.2**						
17	Zaria - Funtua	132	7.0	0.26	**1.8**						
18	Osogbo - Ilesha Tee	132	15.0	0.26	**3.9**						
19	Ife - Ilesha Tee	132	20.0	0.26	**5.2**						
20	Akangba - Isolo	132	4.5	0.26	**1.2**						
21	Kaduna Town - Mando	132	20.0	0.26	**5.2**						
	Onne - Tramadi	132	10.0	0.26	**2.6**						
	Subtotal I				**162.8**						
	Substations										
1	Ajaokuta						2	0	0	0	**3.2**
2	Okene						2	0	0	0	**3.2**
3	Yenagoa						4	0	0	0	**6.4**
4	Gbarain						2	0	0	0	**3.2**
5	Osogbo						4	0	0	0	**6.4**
6	Iwo						2	0	0	0	**3.2**
7	Biu						2	0	0	0	**3.2**
8	Dadinkowa						2	0	0	0	**3.2**
9	Ayede						2	0	0	0	**3.2**
10	Idaban North						2	0	0	0	**3.2**
11	Benin						2	0	0	0	**3.2**
12	Irrua						2	0	0	0	**3.2**
13	Delta						2	0	0	0	**3.2**
14	Effurun						2	0	0	0	**3.2**
15	Ahoada						2	0	0	0	**3.2**
16	Ikeja West						2	0	0	0	**3.2**
17	Alimosho						2	0	0	0	**3.2**
18	Mando						2	0	0	0	**3.2**
19	Kudenda						2	0	0	0	**3.2**
20	PHCT Main						2	0	0	0	**3.2**
21	Rumusoi						2	0	0	0	**3.2**
22	Eket						2	0	0	0	**3.2**
23	Ibom IPP						2	0	0	0	**3.2**
24	Akoka						2	0	0	0	**3.2**
25	Alagbon						2	0	0	0	**3.2**
26	Egbin						2	0	0	0	**3.2**
27	Ikorodu						2	0	0	0	**3.2**
28	Alaoji						2	0	0	0	**3.2**
29	Aba						2	0	0	0	**3.2**
30	Ilesha						2	0	0	0	**3.2**
31	Ilesha Tee						6	0	0	0	**9.6**
32	Zaria						2	0	0	0	**3.2**
33	Funtua						2	0	0	0	**3.2**
34	Ife						2	0	0	0	**3.2**
35	Akangba						2	0	0	0	**3.2**
36	Isolo						4	0	0	0	**6.4**
37	Kaduna Town						2	0	0	0	**3.2**
38	Onne						2	0	0	0	**3.2**
39	Tramadi						2	0	0	0	**3.2**
	Subtotal II										**140.8**
	Grand Total	**303.6**									

Chapter 7: Reference: Table 7-20

Table 9-4: Additional 330/132 kV transformers to relieve existing overloaded transformers by 2020 under normal conditions (N-0)

Reference: Chapter 7: Table 7-21: Additional 330/132 kV Transformers

Cost Estimation of Proposed Transmission System Expansions												
		Other Transmission Expansions by 2020										
No.	Project	Transmission Lines				Substations						
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]	
	Overhead Lines											
	Subtotal I				**0.0**							
	Substations											
1	Benin North					1	1	0	1	0	**5.0**	
2	Adiagbo					1	1	0	1	0	**5.0**	
3	Ganmo					1	1	0	1	0	**5.0**	
4	Benin					1	1	0	1	0	**5.0**	
5	Birnin Kebbi					1	1	0	1	0	**5.0**	
6	Akangba					1	1	0	1	0	**5.0**	
7	Aja					1	1	0	1	0	**5.0**	
8	Ayede					1	1	0	1	0	**5.0**	
9	Ikeja West					1	1	0	1	0	**5.0**	
	Subtotal II										**35.0**	
	Grand Total	**35.0**										

Table 9-5: Additional 132/33 kV and 132/11 kV transformers to relieve existing overloaded transformers by 2020 under normal conditions (N-0)

Cost Estimation of Proposed Transmission System Expansions													
		Other Transmission Expansions by 2020											
No.	Project	Transmission Lines				Substations							
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No. 11 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	No. Transformer 30 MVA, 132/11 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]								[Million US$]
	Overhead Lines												
	Subtotal I				**0.0**								
	Substations												
1	Suleja					0	1	0	1	0	0	1	**2.7**
2	Benin					0	3	3	0	0	3	0	**9.3**
5	Benin North					0	1	1	0	0	1	0	**3.1**
6	Kano					0	1	1	0	0	1	0	**3.1**
7	Aja					0	3	3	0	0	2	0	**8.5**
8	Funtua					0	1	0	1	0	0	1	**2.7**
9	Ojo					0	1	1	0	0	1	0	**3.1**
10	Omuaran					0	1	1	0	0	1	0	**3.1**
11	Ughelli					0	1	1	0	0	1	0	**3.1**
12	Jos					0	1	1	0	0	1	0	**3.1**
13	Eket					0	1	1	0	0	1	0	**3.1**
14	Offa					0	1	1	0	0	1	0	**3.1**
15	Ojo					0	1	1	0	0	1	0	**3.1**
16	Akure					0	1	1	0	0	1	0	**3.1**
18	Funtua					0	1	1	0	0	1	0	**3.1**
19	Ganmo					0	1	1	0	0	1	0	**3.1**
20	Funtua					0	1	0	1	0	0	1	**2.7**
21	Odogunyan					0	1	1	0	0	1	0	**3.1**
22	Afam					0	1	0	1	0	0	1	**2.7**
24	Benin					0	1	1	0	0	1	0	**3.1**
25	Isolo					0	1	1	0	0	1	0	**3.1**
	Ejigbo					0	1	1	0	0	1	0	**3.1**
	Subtotal II												**78.2**
	Grand Total	**78.2**											

Reference: Chapter 7: Table 7-22: Additional 132/33 and 132/11 kV Transformers

Table 9-6: Additional 330/132 kV and 132/33(11) kV transformers to upgrade substation with transformers loaded above 85% by 2020 under normal conditions (N-0)

Cost Estimation of Proposed Transmission System Expansions														
		Other Transmission Expansions by 2020												
No.	Project	Transmission Lines				Substations								
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No. 11 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	No. Transformer 30 MVA, 132/11 kV	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]								[Million US$]	
	Overhead Lines													
	Subtotal I				**0.0**									
	Substations													
4	Kano					1	2	1	1	1	0	1	**8.4**	
6	Jericho					1	2	1	0	1	1	0	**8.1**	
7	Isolo					1	2	1	0	1	1	0	**8.1**	
8	Osogbo					1	2	1	1	1	0	1	**8.4**	
9	Akoka					1	2	1	0	1	1	0	**8.1**	
10	Onitsha					1	2	1	0	1	1	0	**8.1**	
15	Uyo					0	1	1	0	0	1	0	**3.1**	
17	Jalingo					0	1	1	0	0	1	0	**3.1**	
18	Savannah					0	1	1	0	0	1	0	**3.1**	
20	Kano					0	1	1	1	0	0	1	**3.4**	
21	Irrua					0	1	1	0	0	1	0	**3.1**	
22	Amukpe					0	1	1	1	0	0	1	**3.4**	
24	Irrua					0	1	1	0	0	1	0	**3.1**	
25	Sokoto					0	1	1	0	0	1	0	**3.1**	
26	Ijebu Ode					0	1	1	0	0	1	0	**3.1**	
27	Akure					0	1	1	0	0	1	0	**3.1**	
29	Akure					0	1	1	0	0	1	0	**3.1**	
30	Iwo					0	1	1	0	0	1	0	**3.1**	
31	Itire					0	2	1	1	0	0	2	**5.6**	
32	Paras					0	1	1	0	0	1	0	**3.1**	
33	Aja					0	1	1	0	0	1	0	**3.1**	
34	Akoka					0	1	1	0	0	1	0	**3.1**	
35	Akangba BBII					0	1	1	0	0	1	0	**3.1**	
36	Ijora					0	2	2	0	0	2	0	**6.2**	
37	Ejigbo					0	1	1	0	0	1	0	**3.1**	
38	Alagbon					0	1	1	0	0	1	0	**3.1**	
	Egbin					1	1	0	0	1	0	0	**5.0**	
	Ojo					0	1	1	0	0	1	0	**3.1**	
	Alimosho					0	1	1	0	0	1	0	**3.1**	
	Shagamu					0	1	1	0	0	1	0	**3.1**	
	Subtotal II												**131.7**	
	Grand Total	**131.7**												

Reference: Chapter 7: Table 7-23: Additional 132/33 and 132/11 kV Transformers

Table 9-7: Additional shunt reactors and shunt capacitors by 2020

Cost Estimation of Proposed Transmission System Expansions													
		Other Transmission Expansions by 2020											
No.	Project	Transmission Lines				Substations							
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No. 11 kV Switchgear	132 kV Capacitor	132 kV Reactors	33 kV Reactors	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]								[Million US$]
	Overhead Lines												
	Subtotal I				**0.0**								
	Substations												
1	Maiduguri					1	0	0	0	0	1	0	**2.70**
2	Omuaran					0	2	0	0	2	0	0	**3.80**
3	Ondo2					0	1	0	0	1	0	0	**1.90**
4	Yauri					0	1	0	0	1	0	0	**1.90**
5	Irrua					0	1	0	0	1	0	0	**1.90**
	Subtotal II												**18.9**
	Grand Total	**18.9**											

Reference: Chapter 7: Tables 7-24 to 7-27: New Reactors and Capacitors

Table 9-8: New Transmission Lines by 2020

Cost Estimation of Proposed Transmission System Expansions											
		New Transmission Lines by 2020									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]
	Overhead Lines										
1	Akangba - Alagbon	330	14	0.45	**6.3**						
2	Ugwaji - Abakaliki	330	85	0.28	**23.8**						
3	Osogbo - Arigbajo	330	183	0.35	**64.1**						
4	Ayede - Ibadan North	132	15	0.26	**3.9**						
5	New Agbara - Agbara	132	18	0.26	**4.7**						
6	Ogijo - Redeem	132	14	0.26	**3.6**						
7	Birmin Kebbi - Dosso	132	128	0.26	**33.3**						
8	Ibom IPP - Ikot Abasi	132	30	0.26	**7.8**						
	Subtotal I				**147.5**						
	Substations										
1	Akangba					2	0	0	0	0	**3.8**
2	Alagbon					2	0	0	0	0	**3.8**
3	Ugwaji					2	0	0	0	0	**3.8**
4	Abakaliki					2	0	0	0	0	**3.8**
5	Osogbo					0	2	0	0	0	**3.2**
6	Arigbajo					0	2	0	0	0	**3.2**
7	Ayede					0	2	0	0	0	**3.2**
8	Ibadan North					0	2	0	0	0	**3.2**
9	New Agbara					0	2	0	0	0	**3.2**
10	Agbara					0	2	0	0	0	**3.2**
11	Ogijo					0	2	0	0	0	**3.2**
12	Redeem					0	2	0	0	0	**3.2**
13	Birmin Kebbi					0	2	0	0	0	**3.2**
14	Dosso					0	2	0	0	0	**3.2**
15	Ibom IPP					0	2	0	0	0	**3.2**
16	Ikot Abasi					0	2	0	0	0	**3.2**
	Subtotal II										**53.6**
	Grand Total	**201.1**									

Reference: Chapter 7: Table 7-28

9.2.1 Summary of Additional Investments until 2020

Table 9-9 summarizes the investment necessary until 2020.

Table 9-9: Summary of all additional investments in transmission lines and substations until 2020 to establish a 10 GW transmission network

Transmission System Expansions	Reference to Chapter 7	Transmission Lines	Substations	Total
		Million US$	Million US$	Million US$
Additional Transmission Lines to Relieve Existing Lines by 2020 (N-0)	Table 7-19	12.0	19.2	**31.2**
Additional Transmission Lines to Relieve Existing Lines by 2020 (N-1)	Table 7-20	162.8	140.8	**303.6**
Additional 330/132 kV Transformers	Table 7-21	0.0	35.0	**35.0**
Additional 132/33 and 132/11 kV Transformers to relieve existing transformers loaded above 100%	Table 7-22	0.0	78.2	**78.2**
Additional 132/33 and 132/11 kV Transformers to relieve existing transformers loaded above 85%	Table 7-23	0	131.7	**131.7**
New Reactors and Capacitors	Table 7-24 to 7-27	0	18.9	**18.9**
New Transmission Lines by 2020	Table 7-28	147.5	53.6	**201.1**
Total Additional Investment Cost by 2020				**799.6**

9.3 Transmission System Expansions up to 2025

For the time period between 2020 and 2025 additional 330 kV and 132 kV transmission lines as well as the installation of additional 330/132 kV and 132/33(11) kV transformers will be necessary to cope with the growing electricity demand.

The additional 330 kV transmission lines they are mainly located in the North of Nigeria. Most of the 330 kV transmission lines can be allocated to the following three groups ("Projects"):

Project 1: 330 kV North West Ring
Project 2: 330 kV North East Ring
Project 3: 330 kV Lines for connection of Mambila HPP

The project areas of these three projects are indicated on the map of **Annex 9.3.1**

The "Projects" have been defined under consideration that the benefits depend on the completion of a project rather than on completion of individual lines. These three projects have been selected for financial analysis, see Chapter 10.

The cost estimation of the three projects is shown in **Table 9-10**, **Table 9-11** and **Table 9-12**. The cost estimate for additional 132 kV lines, 330/132 kV transformers and 132/33 (11) kV transformers is shown in **Table 9-13** to **Table 9-15**.

Table 9-17 shows a summary of all additional investments in transmission lines and substations until 2023 to establish a 13 GW transmission network.

Table 9-10: Project 1 - 330 kV North West Ring

Cost Estimation of Proposed Transmission System Expansions											
		Project 1: 330 kV North West Ring									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]
	Overhead Lines										
1	Kanji - Birnin Kebbi 330 kV DC Line	330	310	0.45	**139.5**						
2	Birnin Kebbi - Sokoto 330 kV DC Line	330	130	0.45	**58.5**						
3	Sokoto - Talata Mafara 330 kV DC Line	330	125	0.45	**56.3**						
4	Talata Mafara - Gusau 330 kV DC Line	330	85	0.45	**38.3**						
5	Gusau - Funtua 330 kV DC Line	330	70	0.45	**31.5**						
6	Funtua - Zaria 330 kV DC Line	330	70	0.45	**31.5**						
	Subtotal I				**355.5**						
	Substations										
1	Kainji					2	0	0	0	0	**3.8**
2	Birnin Kebbi					7	1	1	1	1	**17.9**
3	Sokoto					7	9	1	2	1	**32.2**
4	Talata Mafara					7	9	1	2	1	**32.2**
5	Gusau					7	9	1	2	1	**32.2**
6	Funtua					7	9	1	2	1	**32.2**
7	Zaria					4	2	1	2	1	**15.3**
	Subtotal II										**165.8**
	Grand Total	**521.3**									

Reference: Chapter 7: Table 7-33

Table 9-11: Project 2 - 330 kV North East Ring

Cost Estimation of Proposed Transmission System Expansions												
		Project 2: 330 kV North East Ring										
No.	Project	Transmission Lines				Substations						
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]	
	Overhead Lines											
1	Jos - Gombe 330 kV DC Line	330	270	0.45	**121.5**							
2	Gombe - Damaturu 330 kV DC Line	330	180	0.45	**81.0**							
3	Damaturu - Maiduguri 330 kV DC Line	330	260	0.45	**117.0**							
4	Gombe - Yola 330 kV DC Line	330	240	0.45	**108.0**							
5	Yola - Jalingo 330 kV DC Line	330	160	0.45	**72.0**							
	Subtotal I				**499.5**							
	Substations											
1	Jos					2	0	0	0	0	**3.8**	
2	Gombe					9	7	1	2	2	**33.6**	
3	Damaturu					7	7	1	2	2	**29.8**	
4	Maiduguri					5	5	1	2	2	**22.8**	
5	Yola					7	7	1	2	2	**29.8**	
6	Jailingo					7	9	1	2	1	**32.2**	
	Subtotal II										**152.0**	
	Grand Total	**651.5**										

Reference: Chapter 7: Table 7-33

Table 9-12: Project 3 - 330 kV Mambila Network Connections

Cost Estimation of Proposed Transmission System Expansions												
		Project 3: 330 kV Mambilla Network Connections										
No.	Project	Transmission Lines				Substations						
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]	
	Overhead Lines											
1	Mambilla - Wukari 330 kV DC Line	330	150	0.45	**67.5**							
2	Mambilla - Jailingo	330	95	0.45	**42.8**							
3	Wukari - Makurdi	330	160	0.45	**72.0**							
4	Wukari - Lafia	330	160	0.45	**72.0**							
	Subtotal I				**254.3**							
	Substations											
1	Mambilla					2	0	0	0	0	**3.8**	
2	Wukari					5	5	0	2	2	**22.1**	
3	Makurdi					2	0	0	0	0	**3.8**	
4	Lafia					2	0	0	0	0	**3.8**	
5	Jalingo					2	0	0	0	0	**3.8**	
	Subtotal II										**37.3**	
	Grand Total	**291.6**										

Reference: Chapter 7: Table 7-33

Table 9-13: Additional Transmission Lines to Provide N-1 Reliability by 2025

Cost Estimation of Proposed Transmission System Expansions											
		Additional Transmission Lines to Provide N-1 Reliability by 2025									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]
	Overhead Lines										
1	Shiroro - Tegina	132	65	0.26	**16.9**						
	Tegina - Kontagora	132	90	0.26	**23.4**						
	Kontagora - Yelwa-Yauri	132	88	0.26	**22.9**						
	Ganmo - Ilorin	132	10.5	0.26	**2.7**						
	Obajana - Egbe	132	97	0.26	**25.2**						
	Omotosho - Ondo	132	98	0.26	**25.5**						
	Benin - Irrua	132	88	0.26	**22.9**						
	Irrua - Ukpilla	132	43	0.26	**11.2**						
	Ukpilla - Okene	132	33	0.26	**8.6**						
	Shamagu - Ijebu Ode	132	41	0.26	**10.7**						
	Dakata - Gagarawa	132	89	0.26	**23.1**						
	Gagarawa - Hadejia	132	60	0.26	**15.6**						
	Dakata - Kumbotso	132	30	0.26	**7.8**						
	Subtotal I				**216.5**						
	Substations										
1	Shiroro						2	0	0	0	**3.2**
2	Tegina						2	0	0	0	**3.2**
3	Kontagora						2	0	0	0	**3.2**
4	Yelwa-Yauri						2	0	0	0	**3.2**
5	Ganmo						2	0	0	0	**3.2**
6	Ilorin						2	0	0	0	**3.2**
7	Obajana						2	0	0	0	**3.2**
	Egbe						2	0	0	0	**3.2**
	Omotosho						2	0	0	0	**3.2**
	Ondo						2	0	0	0	**3.2**
	Benin						2	0	0	0	**3.2**
	Ukpilla						2	0	0	0	**3.2**
	Shamagu						2	0	0	0	**3.2**
	Ijebu Ode						2	0	0	0	**3.2**
	Dakata						2	0	0	0	**3.2**
	Gagarawa						2	0	0	0	**3.2**
	Hadejia						2	0	0	0	**3.2**
	Dakata						2	0	0	0	**3.2**
	Kumbotso						2	0	0	0	**3.2**
	Birmin Kebbi						2	0	0	0	**3.2**
	Dosso						2	0	0	0	**3.2**
	Subtotal II										**67.2**
	Grand Total	**283.7**									

Reference: Chapter 7: Table 7-34

Table 9-14: Additional 132 kV transmission lines to relieve overloaded lines under normal conditions (N-0)

Cost Estimation of Proposed Transmission System Expansions											
		Additional Transmission Lines to Relieve Existing Lines by 2025									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]
	Overhead Lines										
1	PHCT Main - PHCT Town	132	6	0.26	**1.6**						
	Ogijo - Shagamu	132	16	0.26	**4.2**						
	Dadinkowa - Kwaya Kusar	132	41	0.26	**10.7**						
	Subtotal I				**16.4**						
	Substations										
1	Delta						2	0	0	0	**3.2**
2	Effurun						2	0	0	0	**3.2**
3	Eket						2	0	0	0	**3.2**
4	Ibom IPP						2	0	0	0	**3.2**
5	PHCT Main						2	0	0	0	**3.2**
6	PHCT Town						2	0	0	0	**3.2**
7	Omoku						2	0	0	0	**3.2**
8	Rumusoi						2	0	0	0	**3.2**
	Subtotal II										**25.6**
	Grand Total	**42.0**									

Reference: Chapter 7: Table 7-35

Table 9-15: Additional 330/132 kV transformers to relieve overloaded transformers under normal conditions (N-0)

Cost Estimation of Proposed Transmission System Expansions											
		Other Transmission Expansions by 2025									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]						[Million US$]
	Overhead Lines										
	Subtotal I				**0.0**						
	Substations										
1	Ogijo					2	2	0	2	0	**10.0**
2	Ganmo					1	1	0	1	0	**5.0**
3	Akure					1	1	0	1	0	**5.0**
4	Adiagbo					1	1	0	1	0	**5.0**
5	Nnewi					1	1	0	1	0	**5.0**
6	Delta IV					1	1	0	1	0	**5.0**
7	Ihiala					1	1	0	1	0	**5.0**
8	Kaduna					1	1	0	1	0	**5.0**
9	Akoka					1	1	0	1	0	**5.0**
10	Isolo					1	1	0	1	0	**5.0**
11	Jericho					0	1	1	0	1	**3.1**
12	Nnewi					1	1	0	1	0	**5.0**
13	Omotosho					1	1	0	1	0	**5.0**
14	Onitsha					1	1	0	1	0	**5.0**
15	Owerri					1	1	0	1	0	**5.0**
	Subtotal II										**78.1**
	Grand Total	**78.1**									

Reference: Chapter 7: Table 7-36: Additional 330/132 kV Transformers

Table 9-16: Additional 132/33(11) kV transformers to relieve overloaded transformers under normal conditions (N-0)

Cost Estimation of Proposed Transmission System Expansions													
		Other Transmission Expansions by 2020											
No.	Project	Transmission Lines				Substations							
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV feeder	No. of 132 kV feeder	No. 33 kV Switchgear	No. 11 kV Switchgear	No.Transformer 150 MVA, 330/132 kV	No. Transformer 60 MVA, 132/33 kV	No. Transformer 30 MVA, 132/11 kV	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]								[Million US$]
	Overhead Lines												
	Subtotal I				**0.0**								
	Substations												
1	Eket					0	1	1	0	0	1	0	**3.1**
2	Uyo					0	1	1	0	0	1	0	**3.1**
3	Jericho					0	1	1	0	0	1	0	**3.1**
4	Kafanchan					0	1	1	0	0	1	0	**3.1**
5	Gusau					0	1	1	0	0	1	0	**3.1**
6	Ibadan North					0	2	2	0	0	2	0	**6.2**
7	Kaduna					0	1	1	0	0	1	0	**3.1**
8	Gusau					0	1	1	0	0	1	0	**3.1**
9	Birnin Kebbi					0	1	1	0	0	1	0	**3.1**
10	Ikot Abasi					0	1	1	0	0	1	0	**3.1**
11	Zaria					0	1	1	0	0	1	0	**3.1**
12	Kaduna Town					0	4	4	0	0	4	0	**12.4**
13	Osogbo					0	1	1	0	0	1	0	**3.1**
14	Makeri					0	1	1	0	0	1	0	**3.1**
15	Rumusoi					0	2	2	0	0	2	0	**6.2**
16	Kafanchan					0	1	1	0	0	1	0	**3.1**
17	Biu					0	1	1	0	0	1	0	**3.1**
18	Akure												
	Subtotal II												**68.2**
	Grand Total	**68.2**											

Reference: Chapter 7: Table 7-37: Additional 132/33 and 132/11 kV Transformers

9.3.1 Summary of Additional Investments until 2025

Table 9-17: Summary of all additional investments in transmission lines and substations until 2025 to establish a 13 GW transmission network

Transmission System Expansions	Reference to Chapter 7	Transmission Lines	Substations	Total
		Million US$	Million US$	Million US$
Project 1: 330 kV North West Ring		355.5	165.8	**521.3**
Project 2: 330 kV North East Ring		499.5	152	**651.5**
Project 3: 330 kV Mambilla Network Connections		254.25	37.3	**291.6**
Additional Transmission Lines to Provide N-1 Reliability by 2025	Table 7-34	216.45	67.2	**283.7**
Additional Transmission Lines to Relieve Existing Lines by 2025	Table 7-35	16.4	25.6	**42.0**
Additional 330/132 kV Transformers by 2025	Table 7-36	0.0	78.1	**78.1**
Additional 132/33 and 132/11 kV Transformers	Table 7-37	0.0	68.2	**68.2**
New Reactive Power Compensation in Lagos Region				**50.0**
Costs for converting 330 kV DC lines to quad conductors	Table 7-42			**90.0**
Total Additional Investment Cost by 2025				**2076.3**

9.4 Comparison of Costs of Super Grid for 330 kV, 500 kV and 750 kV Voltage Levels

According to Terms of Reference, the Consultant shall study the future need for a grid with higher transmission voltage of 500 kV and 750 kV nominal voltage (respectively 550 kV and 800 kV rated voltage).

This section compares the cost of a super grid based on 330 kV (presently highest voltage) with the costs of a super grid based on 500 kV and 750 kV voltages.

- In case of 330 kV super grid it is assumed that the transmission lines will be double circuit lines with quad Bison conductors.
- In case of 500 kV super grid it is assumed that the transmission lines will be single circuit lines with quad Bison conductors.
- In case of 750 kV super grid it is assumed that the transmission lines will be single circuit lines with five-bundle Bison conductors.

Regarding substations it is assumed that for 330 kV *double busbar* system with auxiliary busbar and bus coupler will be installed whereas for 500 kV and 750 kV *one-and-half* circuit breaker schemes will be installed.

Table 9-18, Table 9-19 and **Table 9-20** show the cost estimation for the three voltage levels.

Table 9-18: 330 kV Super Grid

Cost Estimation of Proposed Transmission System Expansions									
		330 kV Super Grid							
No.	Project	Transmission Lines				Substations			
		Rated Voltage	Length	Cost per km	Total Cost	No. of 330 kV Line feeder	No. of 330 kV Transf. feeder	No. 330 kV Shunt Reactor	Total Cost
		[kV]	[km]	[Million US$/km]	[Million US$]				[Million US$]
	Overhead Lines								
1	Ikot Ekpene - Benin	330	300	0.45	**135**				
2	Ikot Ekpene - Makurdi	330	300	0.45	**135**				
3	Benin - New Agbara	330	250	0.45	**113**				
4	Benin - Osogbo	330	160	0.45	**72**				
5	Benin - Ajaokuta	330	300	0.45	**135**				
6	New Agbara - Osogbo	330	160	0.45	**72**				
7	Osogbo - Gwagwalad	330	260	0.45	**117**				
8	Makurdi - Gwagwalad	330	200	0.45	**90**				
9	Makurdi - Ajaokuta	330	200	0.45	**90**				
10	Ajaokuta - Gwagwalad	330	200	0.45	**90**				
11	Gwagwalad - Funtua	330	250	0.45	**113**				
	Subtotal I				**1161**				
	Substations								
1	Ikot Ekpene	330				9	2	2	**25**
2	Benin	330				11	2	2	**29**
3	Makurdi	330				11	2	2	**29**
4	Osogbo	330				11	2	2	**29**
5	New Agbara	330				9	2	2	**25**
6	Ajaokuta	330				11	2	2	**29**
7	Gwagwalad	330				13	2	2	**33**
8	Funtua	330				7	2	2	**21**
9									
	Subtotal II								**220**
	Grand Total	**1381**							

Table 9-19: 500 kV Super Grid

Cost Estimation of Proposed Transmission System Expansions											
		500 kV Super Grid									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 500 kV feeder	No. of 330 kV feeder	No.Transformer 500 MVA 500/330 kV	No. 500 kV Shunt Reactor	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]					[Million US$]	
	Overhead Lines										
1	Ikot Ekpene - Benin	500	300	0.28	**84**						
2	Ikot Ekpene - Makurdi	500	300	0.28	**84**						
3	Benin - New Agbara	500	250	0.28	**70**						
4	Benin - Osogbo	500	160	0.28	**45**						
5	Benin - Ajaokuta	500	300	0.28	**84**						
6	New Agbara - Osogbo	500	160	0.28	**45**						
7	Osogbo - Gwagwalad	500	260	0.28	**73**						
8	Makurdi - Gwagwalad	500	200	0.28	**56**						
9	Makurdi - Ajaokuta	500	200	0.28	**56**						
10	Ajaokuta - Gwagwalad	500	200	0.28	**56**						
11	Gwagwalad - Funtua	500	250	0.28	**70**						
	Subtotal I				**722**						
	Substations										
1	Ikot Ekpene	500				6	2	2	2	**64**	
2	Benin	500				8	2	2	2	**72**	
3	Makurdi	500				7	2	2	2	**68**	
4	Osogbo	500				7	2	2	2	**68**	
5	New Agbara	500				6	2	2	2	**64**	
6	Ajaokuta	500				7	2	2	2	**68**	
7	Gwagwalad	500				8	2	2	2	**72**	
8	Funtua	500				5	2	2	2	**60**	
9											
	Subtotal II									**533**	
	Grand Total	**1256**									

Table 9-20: 750 kV Super Grid

Cost Estimation of Proposed Transmission System Expansions											
		750 kV Super Grid									
No.	Project	Transmission Lines				Substations					
		Rated Voltage	Length	Cost per km	Total Cost	No. of 750 kV feeder	No. of 330 kV feeder	No.Transformer 500 MVA, 750/330 kV	No. 750 kV Shunt Reactor	Total Cost	
		[kV]	[km]	[Million US$/km]	[Million US$]					[Million US$]	
	Overhead Lines										
1	Ikot Ekpene - Benin	750	300	0.35	**105**						
2	Ikot Ekpene - Makurdi	750	300	0.35	**105**						
3	Benin - New Agbara	750	250	0.35	**88**						
4	Benin - Osogbo	750	160	0.35	**56**						
5	Benin - Ajaokuta	750	300	0.35	**105**						
6	New Agbara - Osogbo	750	160	0.35	**56**						
7	Osogbo - Gwagwalad	750	260	0.35	**91**						
8	Makurdi - Gwagwalad	750	200	0.35	**70**						
9	Makurdi - Ajaokuta	750	200	0.35	**70**						
10	Ajaokuta - Gwagwalad	750	200	0.35	**70**						
11	Gwagwalad - Funtua	750	250	0.35	**88**						
	Subtotal I				**903**						
	Substations										
1	Ikot Ekpene	750				6	2	2	2	**82**	
2	Benin	750				8	2	2	2	**92**	
3	Makurdi	750				7	2	2	2	**87**	
4	Osogbo	750				7	2	2	2	**87**	
5	New Agbara	750				6	2	2	2	**82**	
6	Ajaokuta	750				7	2	2	2	**87**	
7	Gwagwalad	750				8	2	2	2	**92**	
8	Funtua	750				5	2	2	2	**77**	
9											
	Subtotal II									**686**	
	Grand Total	**1589**									

9.4.1 Summary of cost comparison for 3 voltage levels

The cost comparison is summarized in **Table 9-21.**

Table 9-21: Summary of cost comparison

Voltage level	Transmission Lines [million US$]	Substations [million US$]	Total [million US$]
330 kV	1161	220	1381
500 kV	722	533	1256
750 kV	903	686	1589

The comparison indicates that the 500 kV super grid will require the lower investment cost. However, the cost difference to 330 kV is relatively small.

Considering that in terms of technical performance (MVA transmission capacity, losses, impact on under/over-voltages and overloads as well as static security issues) the 330 kV system appears to be more advantageous as detailed in Sections 0 and **7.10.3**, its 10% higher investment cost could be justified.

In view of the above, it is apparent that more detailed studies are required to confirm the conclusions of this study.

It is therefore recommended to have these detailed studies carried out in due course and as soon as possible, before a final decision can be made on the selection of the voltage level (330 kV or 500 kV) for a future super grid.

The cost for 750 kV is considerably higher compared to 330 kV and 500 kV. The transmission capacity of a 330 kV double circuit line and a 500 kV single circuit line are 3100 and 2350 MVA respectively, compared to 4400 MW for a 750 kV single circuit line. The network calculations (Chapter 7), however, have indicated that the transmission capacity of the 330 kV and 500 kV supergrid systems is sufficient.

10. Financial Analysis

The following three transmission projects are subject to a financial analysis with the objective of assessing their financial viability.

Project 1: 330 kV North West Ring
Project 2: 330 kV North East Ring
Project 3: 330 kV Lines for connection of Mambilla HPP

The "Projects" have been defined under consideration that the benefits depend on the completion of a project rather than on completion of individual lines. However, the actual implementation sequence may be different.

If the financial analysis shows that these typical projects are viable, then the carried out assessment can be applied to projects in other locations independent of the time of implementation.

10.1 Methodology

The Terms of Reference require a financial assessment that determines the viability of a project from the investor's point of view. The key question in this context is whether revenues are sufficient to cover investment costs and operating costs.

All costs and benefits in the financial assessment are expressed in market prices and in US Dollar. The costs include project investment costs and O&M costs of 1% of the project investment costs. The figure of 1% is based on Fichtner's experience and backed by the database available with Fichtner. It seems to be reasonable to stick to the 1% as O&M cost, even more when considering future efforts of the transmission line operators to bring O&M costs down. The total project costs include cost of new transmission lines and substations as well as physical and price contingencies and estimates of engineering, consulting and environment costs. Taxes and duties are not considered since it is assumed that the projects will be donor-financed and thus exempted from taxes and duties. The financial analysis is carried out with 2018 prices in order to make the various projects comparable. **Table 10-1** presents the total financing cost of the project investment (excluding price contingencies) of the three projects.

Table 10-1: Cost estimates

Cost Estimates			Project 1	Project 2	Project 3
1. Transmission line		US$ million	355.60	499.50	254.30
2. Substations		US$ million	165.80	152.00	37.30
Total estimated equipment		**US$ million**	**521.40**	**651.50**	**291.60**
3. Engineering - foreign	5%	US$ million	26.07	32.58	14.58
4. Owners Engineer	3%	US$ million	15.64	19.55	8.75
5. Other Consulting Services, ESIA	1%	US$ million	5.21	6.52	2.92
6. Environmental Safeguard	1%	US$ million	5.21	6.52	2.92
7. Land acquisition, Resettlement	1%	US$ million	5.21	6.52	2.92
Total CAPEX		**US$ million**	**578.75**	**723.17**	**323.68**
Physical Contingencies	5%	US$ million	28.94	36.16	16.18
Project investment cost		**US$ million**	**607.69**	**759.32**	**339.86**

A project is deemed financially viable when the revenues cover the project costs and provide the investor with an adequate profit at a given transmission tariff. A cost-covering tariff which provides also an adequate profit must be at least as high as the financial levelized electricity costs (LECs).

Calculation of the financial LECs is therefore the first step in the financial assessment. The financial LECs are calculated as the net present value of the total costs including the project investment cost and operating cost, divided by the net present value of energy transmitted. The financial LECs are based on market prices and derived with a financial discount rate, the Weighted Average Cost of Capital (WACC). The WACC, which measures the project's cost of funds, is determined based on the source and cost of financing. 70 % debt financing and 30% equity financing is assumed. The calculated WACC is then used as a benchmark to compare with the FIRR and FNPV. The project is considered financially viable if the FIRR exceeds the WACC. The WACC is calculated as the weighted average cost of equity and debt used to fund the project**. Table 10-2** provides a summary of the financing assumptions in the WACC calculation.

Table 10-2: WACC calculation

WACC

	Loans	Equity	Total
A Amount US$ million			
B Portion of financing	**70.00%**	**30.00%**	**100.00%**
C Nominal cost	**3.13%**	**20.00%**	
D Tax rate	**30.00%**	**0.00%**	
E Nominal cost adjusted by tax, C*(1-D)	**2.19%**	**20.00%**	
F Inflation rate	**1.47%**	**17.46%**	
G Real cost adjusted by tax, (1+E)/(1+F)-1	**0.71%**	**2.16%**	
H Cost of type of capital, B*G	**0.50%**	**0.65%**	**1.15%**

WACC **1.15%**

Fichtner has calculated the WACC based on reliable figures available from different sources. In addition, the report also refers to a sensitivity analysis in which the discount rate has been increased to 2% and 4% respectively.

As a next step, the financial viability is assessed in a comparison of costs and revenues of the project at a given tariff. This comparison is based on a cash flow analysis which shows the costs and revenues of the project on an annual basis. The key indicators of financial viability, financial NPV, and financial internal rate of return (FIRR) are calculated on the basis of the discounted cash flows.

The NPV is calculated according to the formula below as the difference between net present value of revenues and net present value of costs, and thus represents the discounted sum of all net revenues.

$$NPV = \sum_{t=1}^{n} \frac{Revenue_t}{(1+r)^t} - \sum_{t=1}^{n} \frac{Cost_t}{(1+r)^t}$$

where:

$Revenue_t$	= revenue in year t
$Cost_t$	= cost in year t
r	= discount rate
n	= total number of years.

The NPV describes by how much the revenues of a project exceed its costs over the lifetime of the project. A project is financially feasible when its NPV at a given discount rate is greater than zero.

The FIRR is calculated as the discount rate at which the net present value of costs equals the net present value of revenues, that is, when the net present value of the net cash flow equals zero, as expressed in the following equation:

$$\sum_{t=1}^{n} \frac{Cost_t}{(1+i)^t} = \sum_{t=1}^{n} \frac{Revenue_t}{(1+i)^t}$$

Where

$Cost_t$	= cost in year t
$Revenue_t$	= revenue in year t
i	= internal rate of return
n	= total number of years.

The FIRR describes the return (profit) that a project earns over its entire lifetime. A project is financially feasible when its FIRR is at least equal to the financial discount rate.

A discount rate of 1.15%, equal to the WACC, is used for discounting. In the sensitivity analysis, WACCs of 2% and 4% are applied.

The cash flows are set up over the construction period and the operating period. The operating period is 35 years, equivalent to the lifetime of the project.

The financial benefits of project are generally the revenues of the utility for the services rendered. In a liberalized market, a transmission company has revenues from wheeling the power. The transmission charges are regulated and ensure cost recovery and an adequate return on assets.

While the LECs indicate the tariff level required to make the project financially viable at a given discount rate, the cash flow analysis serves to determine the profitability and financial viability of the project at a given tariff. Assessing the adequacy of the existing tariffs to finance the investment projects is thus an integral part of the financial assessment. The transmission charges of N 2,743.16 per MWh or USD 0.0085 US$ per kWh are included in the financial assessment. The tariff is based on the NERC Order No. NERC/REG/3/2015.

Furthermore, the disbursement schedule for each project is set up as part of this financial analysis, in order to identify the total financing requirements and the disbursements of the

loans. It is assumed that 70% of the financing requirements of each project are funded by loans from World Bank or other donors. The remaining 30% is assumed to be Government contributions. The disbursement schedule is shown in **Table 10-3**. Project 1 and Project 2 will start construction in 2018 and operation in 2025. Project 3 will start construction in 2022 and operation in 2025.

Table 10-3: Disbursement schedule

Year	Project 1 [million US$]	Project 2 [million US$]	Project 3 [million US$]
2018	110.78	165.62	0.00
2019	110.78	165.62	0.00
2020	0.00	0.00	0.00
2021	96.53	107.02	0.00
2022	96.53	107.02	113.29
2023	96.53	107.02	113.29
2024	96.53	107.02	113.29
Total Investment Cost	**607.69**	**759.32**	**339.86**

10.2 Project 1

Project 1 has financial investment costs of US$ 607.69 million. Starting from year 2025, O&M costs amount to US$ 6.1 million annually.

The amounts of energy transmitted increase from 455 GWh in the 2021, 2,510 GWh in 2025 and 10,120 GWh in 2037.

Based on the energy transmitted, the project revenues increase from US$ 3.9 million in 2020 with limited operation, up to US$ 21.4 million in 2025 when full operation starts, to US$ 86.2 million in 2037 to the end of the investigation period .

Under these assumptions, the financial LECs of the project are US$ 0.0033 per kWh at a discount rate of 1.15 %. The LECs increase to US$ 0.0039 and US$ 0.0055 per kWh when the discount rate is increased to 2% and 4% respectively.

The LECs of US$ 0.0033 per kWh at a discount rate of 1.15% are below the current average transmission tariff in Nigeria, which is estimated at US$ 0.0085 per kWh. At the current tariff, the project has an FIRR of 6.79 % and could thus be considered financially feasible.

Table 10-4 summarizes the results of the analysis.

Table 10-4: Financial indicators of Project 1

Results				Project 1
LECs				
LEC		WACC 1.15%	US$/kWh	0.0033
		WACC 2%	US$/kWh	0.0039
		WACC 4%	US$/kWh	0.0055
Base Case				
Project investment cost			US$ million	607.69
NPV				
	WACC	1.15%	US$ million	1,174
	WACC	2.00%	US$ million	848
	WACC	4.00%	US$ million	348
FIRR			%	6.79%
Benefit/Cost Ratio				2.55
Payback Period			years	19.8

The Cash flow for the project under investigation is provided in **Annex 10.1**.

10.3 Project 2

Project 2 has financial investment costs of US$ 759.32 million. Starting from year 2025, O&M costs amount to US$ 7.6 million annually.

The amounts of energy transmitted increase from 45 GWh in the 2020, 67 GWh in 2025 and 4,963 GWh in 2037.

Based on the energy transmitted, the project revenues increase from US$ 0.4 million in 2020 with limited operation up to US$ 0.6 million in 2025 and US$ 4,963 million in 2037 to the end of the investigation period under full capacity.

Under these assumptions, the financial LECs of the project are US$ 0.0094 per kWh at a discount rate of 1.15 %. The LECs increase to US$ 0.0111 and US$ 0.0163 per kWh when the discount rate is increased to 2% and 4% respectively.

The LECs of US$ 0.0094 per kWh at a discount rate of 1.15% are above the current average transmission tariff in Nigeria, which is estimated at US$ 0.0085 per kWh. At the current tariff, the project has an FIRR of 0.63 %, below the WACC and a slightly negative NPV. Thus, under the current assumptions Project 2 would not be considered financially feasible. However, if it is assumed that the tariffs in Nigeria will further rise, the project will become viable. Also, it has to be considered that the load is relatively low due to the remote and challenging location and investment costs are high.

Table 10-5 summarizes the results of the analysis.

Table 10-5: Financial indicators of Project 2

Results				Project 2
LECs				
LEC		WACC 1.15%	US$/kWh	0.0094
		WACC 2%	US$/kWh	0.0111
		WACC 4%	US$/kWh	0.0163
Base Case				
Project investment cost			US$ million	759.32
NPV				
	WACC	1.15%	US$ million	-91
	WACC	2.00%	US$ million	-208
	WACC	4.00%	US$ million	-374
FIRR			%	0.63%
Benefit/Cost Ratio				0.90
Payback Period			years	38.1

The Cash flow for the project under investigation is provided in **Annex 10.2**.

10.4 Project 3

Project 3 has financial investment costs of US$ 339.86 million. Starting from year 2025, O&M costs amount to US$ 3.4 million annually.

The amounts of energy transmitted increase from 501 GWh in 2025 and 5,010 GWh in 2037.

Based on the energy transmitted, the project revenues increase from US$ 4.3 million in 2025 with limited operation up to US$ 42.7 million in 2033 when full operation starts to the end of the investigation period in year 2057.

Under these assumptions, the financial LECs of the project are US$ 0.0035 per kWh at a discount rate of 1.15 %. The LECs increase to US$ 0.0040 and US$ 0.0054 per kWh when the discount rate is increased to 2% and 4% respectively.

The LECs of US$ 0.0035 per kWh at a discount rate of 1.15% are below the current average transmission tariff in Nigeria, which is estimated at US$ 0.0085 per kWh. At the current tariff, the project has an FIRR of 7.31 % and could thus be considered financially feasible.

Table 10-6 summarizes the results of the analysis.

Table 10-6: Financial indicators of Project 3

Results				Project 3
LECs				
LEC		WACC 1.15%	US$/kWh	0.0035
		WACC 2%	US$/kWh	0.0040
		WACC 4%	US$/kWh	0.0054
Base Case				
Project investment cost			US$ million	339.86
NPV				
	WACC	1.15%	US$ million	610
	WACC	2.00%	US$ million	459
	WACC	4.00%	US$ million	65
FIRR			%	7.31%
Benefit/Cost Ratio				2.43
Payback Period			years	15.7

The Cash flow for the project under investigation is provided in **Annex 10.3**.

10.5 Sensitivity and Conclusion

The financial feasibility of the project was assessed by comparison of the total costs over the project lifetime with the total benefits based on the discounting technique.

Projects 1 and 3 are financially feasible with a FIRR of 6.79% and 7.31% respectively. Project 2 has a FIRR of 0.63% below the WACC and negative NPV. However, the low load and high investment costs due to the remote and challenging location account for this result.

A sensitivity analysis was conducted to assess the impacts of:

- increases in project investment cost by 25%
- reduction of project investment cost of 25%
- increases in operating costs to 2%
- increases in transmission charges to US$ 0.0095 per kWh
- increases in the volume of energy transmitted by 10%, and a
- reduction of volume of energy transmitted by 10%.

The sensitivity results show the robustness of projects 1 and 3. If the transmission tariff increases to US$ 0.0095 per kWh, Project 2 also becomes financial feasible with a FIRR of 1.19% at WACC and a NPV of US$ 8 million.

The results of each project are summarized in **Table 10-7**, **Table 10-8** and **Table 10-9**.

Table 10-7: Sensitivity results of Project 1

Sensitivity Results		Project 1			
		FIRR	FNPV at WACC	FNPV 2%	FNPV 4%
		%	US$ million	US$ million	US$ million
Base case		**6.79%**	**1,174**	**848**	**348**
Increase Project investment cost by 25%		5.36%	985	671	193
Reduction Project investment cost by 25%		8.77%	1,363	1,025	503
Increase O&M to	2%	6.01%	997	700	248
Increase transmission charges to US$/kWh	0.0095	7.52%	1,397	1,027	459
Increase volume of energy transmitted by	10%	7.43%	1,367	1,003	444
Reduction volume of energy transmitted by	10%	6.11%	981	692	251

Table 10-8: Sensitivity results of Project 2

Sensitivity Results		Project 2			
		FIRR	FNPV at WACC	FNPV 2%	FNPV 4%
		%	US$ million	US$ million	US$ million
Base case		**0.63%**	**-91**	**-208**	**-374**
Increase Project investment cost by 25%		-0.54%	-329	-431	-570
Reduction Project investment cost by 25%		2.11%	146	15	-178
Increase O&M to	2%	-0.77%	-314	-394	-501
Increase transmission charges to US$/kWh	0.0095	1.19%	8	-130	-327
Increase volume of energy transmitted by	10%	1.12%	-5	-140	-334
Reduction volume of energy transmitted by	10%	0.08%	-177	-277	-415

Table 10-9: Sensitivity results of Project 3

Sensitivity Results		Project 3			
		FIRR	FNPV at WACC	FNPV 2%	FNPV 4%
		%	US$ million	US$ million	US$ million
Base case		**7.31%**	**610**	**459**	**214**
Increase Project investment cost by 25%		5.63%	503	357	121
Reduction Project investment cost by 25%		9.66%	717	561	306
Increase O&M to	2%	6.49%	516	379	157
Increase transmission charges to US$/kWh	0.0095	8.17%	729	559	281
Increase volume of energy transmitted by	10%	8.06%	714	546	272
Reduction volume of energy transmitted by	10%	6.50%	506	372	155

11. Environmental Impact Costs

11.1 Scope of work and methodology

Main objective of the environmental considerations to the Development of the Power System Master Plan for the Transmission Company of Nigeria is to identify and describe the environmental costs (and eventually) benefits from the planned expansion of the transmission system.

Within the overall Power System Master Plan, 29 transmission lines have been identified and are being analysed regarding their technical, economic and financial feasibility. Out of these, 4 transmission lines **(Table 11-1** and **Map 11-1**)-have been selected for an exemplary discussion of possible environmental and social implications in different regions of Nigeria.

At this stage of planning, the future corridor of the envisaged lines is not yet known. As a replacement, a straight line has been drawn and is considered in the following. Thus, the focus of the study is on general environmental considerations and on impacts that are likely to occur in the respective region.

Table 11-1: Selected Transmission Lines

No.	From	To	kV	km	Region	State
1	Gombe	Damaturu	330	160	North East	Gombe/Yobe
2	Mambila	Jalingo	330	240	North East	Taraba
3	Ugwuaji	Abakaliki	330	85	South East	Enugu / Ebony
4	Gusau	Funtua	330	100	North West	Zamfara / Katsina

Map 11-1: Overview selected Transmission Lines

11.2 General World Bank requirements

For all projects of the World Bank, the Equator Principles apply. The Operational Manual OP 4.01 is the basis for the Environmental Assessment for World Bank Projects. International Finance Corporation Performance Standards on social and environmental sustainability and the Environmental, Health, and Safety Guidelines of the World Bank Group have to be implemented.

Therefore, further assessments have to be based on the following IFC guidelines:

- IFC General EHS Guidelines;
- IFC EHS Guidelines on Electric Transmission and Distribution
- IFC Performance Standards (PS) including the referring guidance notes (2012):
  - PS 1: Assessment and Management of Environmental and Social Risks and Impacts
  - PS 2: Labour and Working Conditions
  - PS 3: Resource Efficiency and Pollution Prevention
  - PS 4: Community Health, Safety, and Security
  - PS 5: Land Acquisition and Involuntary Resettlement
  - PS 6: Biodiversity Conservation and Sustainable Management of Living Natural Resources
  - PS7: Indigenous Peoples
  - PS 8: Cultural Heritage
  - IFC Handbook for Preparing a Resettlement Action Plan

11.3 Policy, Legal, and Administrative Framework

Since 2006, the Federal Ministry of Environment, Housing & Urban Development (FMEH & UD, formerly FMEnv) is responsible for the implementation of the environmental management and planning policy in Nigeria. Its mission is "To ensure environmental protection and natural resources conservation for a sustainable development."[2] Therefore, it is also in charge for EIA issues. For this purpose, its Environmental Assessment Department has set up the Environmental Impact Assessment (EIA) Division which is charged with the mandate of implementing the provisions of the EIA Acts No. 86 of 1992.

Other important departments of the FMEH & UD are:

- Drought and Desertification Amelioration
- The Federal Department of Forestry
- Pollution Control and Environmental Health
- Erosion, Flood and Coastal Zone Management
- Climate Change [3]

For the effective enforcement of environmental laws, standards and regulations in the country, the National Environmental Standards and Regulations Enforcement Agency (NESREA), a parastatal of the Federal Ministry of Environment has been created in 2007.

[2] http://climatechange.gov.ng/about-the-federal-ministry-of-environment-fme-nigeria/
[3] Source : http://environment.gov.ng/environmental.html

11.3.1 National Legislative Framework

The basis for the protection of the environment is laid in the Constitution of Nigeria of 1999. It states that "The State shall protect and improve the environment and safeguard the water, air and land, forest and wildlife of Nigeria".

Being a federal republic, there are laws both on National and on State level. Some of the most important national environmental laws concerning the project are:

- The Land Use Act, 1978
- The Nigerian Urban and regional Planning Act 1992
- Harmful Waste (Special Criminal Provisions) Act 1988
- Water resources Act 1993
- Natural Resources Conservation Act 1989
- River basin Development Authorities Act 1986
- Endangered Species Act 1985
- National Parks Service Act 1999[4]

Additionally, there are more than 30 environmental regulations formulated by NESREA. Among those the most important are:

- National Environmental (Watershed, Mountainous, Hilly and Catchments Areas) Regulations, 2009;
- National Environmental (Sanitation and Wastes Control) Regulations, 2009;
- National Environmental (Permitting and Licensing System) Regulations, 2009;
- National Environmental (Noise Standards and Control) Regulations, 2009;
- National Environmental (Construction Sector) Regulations, 2011;
- National Environmental (Control of Bush, Forest Fire and open Burning) Regulations, 2011;
- National Environmental (Control of Vehicular Emissions from Petrol and Diesel Engines) Regulations, 2011;
- National Environmental (Desertification Control and Drought Mitigation) Regulations, 2011;
- National Environmental (Electrical/Electronic Sector) Regulations, 2011;
- National Environmental (Protection of Endangered Species in International Trade) Regulations, 2011;
- National Environmental (Soil Erosion and Flood Control) Regulations, 2011;
- National Environmental (Surface and Ground Water Quality Control) Regulations, 2011;
- National Environmental (Alien and Invasive Species) Regulations, 2012;
- National Environmental (Air Quality Control) Regulations, 2013;
- National Environmental (Energy and Energy Efficiency) Regulations, 2013.[5]

[4] Source : http://www.lawnigeria.com/Federationlaws-ALL.html
[5]Source : http://www.nesrea.gov.ng/regulations/index.php

11.3.2 International Agreements

Nigeria signed and ratified many of the major international conventions that foster conservation of natural resources. Some of the most important are the following:

- African convention on the Conservation of Nature and Natural Resources
- Agreement on the Conservation of African-Eurasian Migratory Waterbirds
- The Agreement on the Conservation of Gorillas and Their Habitats
- Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and Their Disposal
- Convention on Biological Diversity (CBD)
- Convention on the Conservation of Migratory Species of Wild Animals
- Kyoto Protocol
- International Plant Protection Convention (IPPC)

11.4 EIA permitting structure

The main Nigerian law regulating the process for obtaining certifications of FMEH & UD is the Environment Impact Assessment Decree 86 of 1992 (EIA Act). According to the EIA Decree an EIA is mandatory for activities relating to 19 vital sectors of the economy and for any project likely to have adverse impacts on the environment. The EIA must be prepared and approved prior to implementation.

As transmission lines are not included in the list of mandatory projects, it depends on a screening if they need a full EIA to obtain a permit by FMEH & UD.

Procedural guidelines have been issued in 1995 as a vital link between the Decree 86 and its implementation. These guidelines indicate the steps to be followed from the conception of a project to the commissioning as well as the actors in each stage.

11.5 Environmental Situation/ Baseline data

11.5.1 General Situation

The Federal Republic of Nigeria (commonly referred to as Nigeria) is a federally organized presidential republic with 36 states and one federal capital territory.

Map 11-2 shows a general overview of Nigeria, including its administrative divisions.

Map 11-2: Map of Nigeria

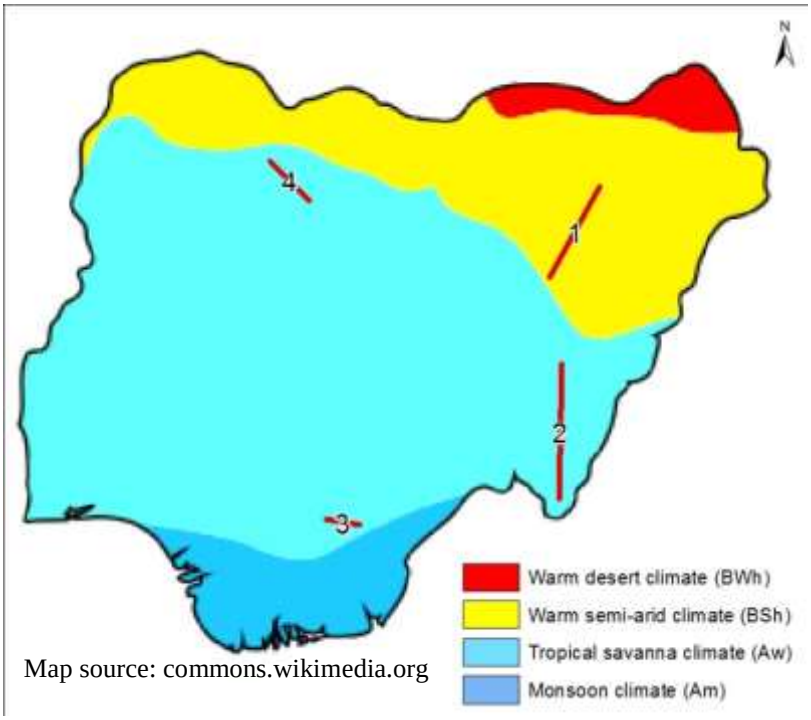
11.5.2 Geography

Nigeria is a very diverse country. Its landscape vary from the coastline (about 850 km), the lowlands in the lower Niger valley with tropical rain forest up to dry savannah in the north. There are three highland areas found in Nigeria: the Yoruba highland in the west, the Jos plateau in the middle and the mountains at the border to Cameroon.

The two biggest rivers of Nigeria are the Niger and the Benue Rivers. They converge at Lokoja and flow together towards the Atlantic sea, forming the Niger Delta.

11.5.2.1 Climate

The climate is tropical with a generally high temperature (22 to 36 C). There are basically two seasons: a rainy season from April to October and a dry season from November till March which begins with the dry dusty winds of Harmattan. In general, climate gets drier from south to north. According to Köppen-Geiger classification, Nigeria has 4 different climatic zones, ranging from the warm arid zone in the North (BWh and BSh) over the tropical savanna climate (Aw) to a humid monsoon climate (Am) in the South (see **Map 11-3**).



Map 11-3: Climate zones of Nigeria; including 1-4 selected OHL corridors

Map 11-3 shows that 3 of the selected lines are located in the tropical savanna climate which covers the biggest part of Nigeria.

As an example for the typical Aw – climate, **Figure 11-1** gives the graph of Jalingo (located at line 2).

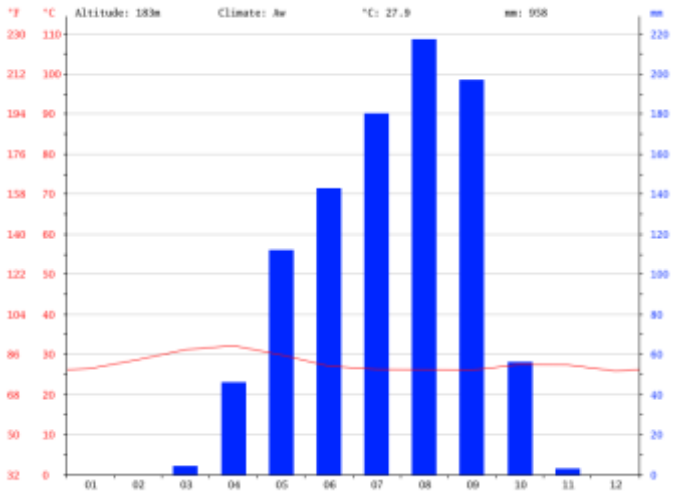


Figure 11-1: Climate in Jalingo[6]

Line number 1 is located in the warm semi-arid climate of the North (BSh, see **Figure 11-2**).

[6] Source: https://en.climate-data.org

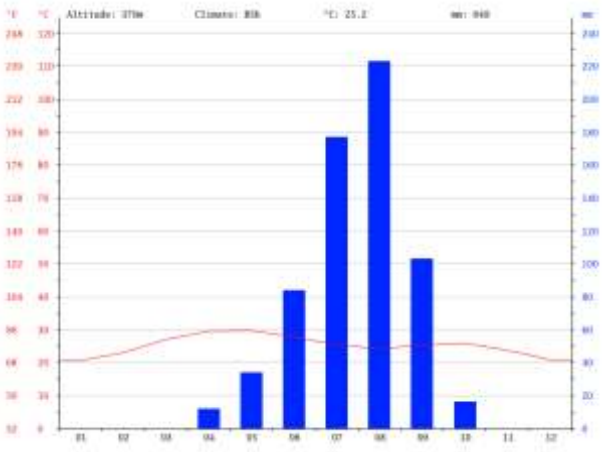
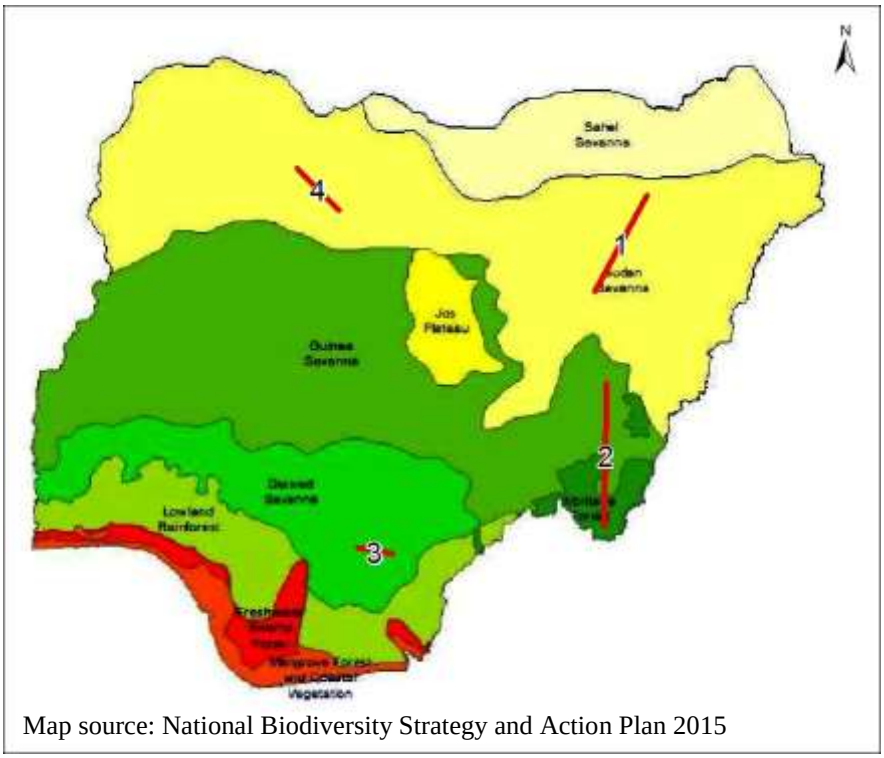


Figure 11-2: Climate in Damaturu[7]

In most of Nigeria the climate change is already perceivable in increasing temperature and decreasing rainfall. As a result of these generally drier conditions, desertification became observable in the North, with an ongoing reduction of arable land due to encroaching desert. Additionally, a shift of the dry season from August to July has been reported.

As for the coastal region, precipitation did increase and sea level rise can be observed[8].

11.5.2.2 Ecological zones and vegetation



Map source: National Biodiversity Strategy and Action Plan 2015

Map 11-4: Ecological zones of Nigeria; including 1-4 selected OHL corridors

[7] Source: https://en.climate-data.org
[8] Source: Akpodiogaga (2010)

Nowadays, a large part of the Nigerian area is covered with Savannahs. The far North, with its warm desert climate is part of the Sahelian Zone with Sahel savannah (grasses, open thorn scrub, scattered thorny trees). To the south a warm semi-arid climate with the Sudan Savannah adjoins, in which the OHL 1 and 4 are located. It is dominated by grassland with some shrubs and trees, the plant community comprises typically Anogeissus, Combretum, Affrormosia, Detarium. As climate gets drier towards the north, Acacia becomes the predominant species.

The following Guinea Savannah is characterized by open woodland with tall grasses and fire-resistant trees, including areas of mixed deciduous and semi-deciduous woodlands. In the mountains to the east, at the border with Cameroon, the last patches of montane forest can be found. Line 2 includes both Guinea Savanna and Montane forest. This OHL is also mounting the Mambila plateau which averages around 1,800 m, has a pleasant climate and is mainly covered with grassland. This makes it suitable not only for tourism, but also for cattle rising.

Line 3 is situated in the derived savannah, between the savannah and the forest belt in the south. This region has undergone large-scale anthropogenic modifications and is nowadays characterized by extensive agricultural areas, containing some forest relict patches.

The still existing lowland rainforest belt is also highly degraded due to excessive exploitation of timber, agricultural encroachment, and other anthropogenic changes. The largest remaining tracts of rainforest are primarily found in Cross River, Edo, Delta and Ondo states (see Map 11-5).

Map 11-5: Regions with las patches of rainforest

Almost the whole coastline is covered with mangrove forest, which reaches 16 to 90 km inland. Further inland they are replaced by freshwater swamp forests (source: USAID 2008).

Deforestation is a major problem in Nigeria. In the last decades, Nigeria ranged between the countries with the highest deforestation rate. Each year, it loses about 410 000 ha, resulting in a deforestation rate of up to 4 % from 2005 - 2010. As a result, only 10 % of the surface was still forested in 2010, most of the forest highly degraded. Things are even

worse regarding primary forest (see **Table 11-2**). As n.s. means “not significant”, there is literally none left. [9]

Table 11-2: Losses of Primary Forest

Country/area	Area of primary forest (1 000 ha)				Annual change rate					
	1990	2000	2005	2010	1990–2000		2000–2005		2005–2010	
					1 000 ha/yr	%	1 000 ha/yr	%	1 000 ha/yr	%
Mali	0	0	0	0	0	–	0	–	0	–
Niger	220	220	220	220	0	0	0	0	0	0
Nigeria	1 556	736	326	n.s.	-82	-7.21	-82	-15.03	-65	–
Rwanda	7	7	7	7	0	0	0	0	0	0
Saint Helena, Ascension and Tristan da Cunha	–	–	–	–	–	–	–	–	–	–
Sao Tome and Principe	11	11	11	11	0	0	0	0	0	0
Senegal	1 759	1 653	1 598	1 553	-11	-0.62	-11	-0.67	-9	-0.57
Sierra Leone	224	157	133	113	-7	-3.49	-5	-3.26	-4	-3.21
Togo	0	0	0	0	0	–	0	–	0	–

[9] Source: FAO, 2010

As stated before, Nigeria is heavily affected by global change. It has been estimated that 15 % of Nigerians surface is prone to desertification. Affected are mainly the states in the already dry north (see **Map 11-6**).

Map 11-6: States prone to desertification

11.5.2.3 Flora and Fauna

As Nigeria is diverse in climate and landscape pattern, it has a corresponding high number of niches harboring many different species of plants and animals. 2,772 species have been assessed for the Red List resulting in a list of threatened species (including Critically Endangered, Endangered, Vulnerable) given in **Table 11-3**.

Table 11-3: Number of threatened species of Nigeria

Taxonomic Group	Number of Threatened Species
Mammals	30
Birds	22
Reptiles	12
Amphibians	13
Fishes	71
Molluscs	1
Other Inverts	16
Plants	196
TOTAL	**361**

Source: IUCN Red List version 2017-1[10]

[10] http://cmsdocs.s3.amazonaws.com/summarystats/2017-1_Summary_Stats_Page_Documents/2017_1_RL_Stats_Table_5.pdf

There are several groups of primates represented in Nigeria. In the Cross River State to the west, across the border with Cameroon, the Critically Endangered Cross River Gorilla (*Gorilla gorilla diehli*) occurs. Their 100-250 remaining individuals are found primarily in remote areas of high relief. Another endangered primate living in Cross River State is the Mandrillus (Mandrillus leucophaeus). A subpopulation of the endangered Chimpanzees, *Pan troglodytes ellioti* is living in the east of Taraba State[11]. Additionally, Nigeria is homeland for a number of guenons, three of them endemic to the country.

For other taxonomic groups, information is quite sparse. Nigeria is said to be home to around 900 bird species, 135 reptile and109 amphibian and 247 non-marine fish species. According to invertebrates, their numbers are highly speculated. For the Cross River Regions alone, more than 1.000 species of butterflies were detected (source: USAID 2008).

The savanna grasslands of the biggest part of Nigeria are supposed to be populated by large herds of elephants, lions, wild dogs, giraffes. These populations are nowadays reduced to small numbers and forced back into the protected areas.

Envisaged line 2 is crossing a very diverse and ecologically important region. Due to its relative isolation and unique microclimate, the montane forest is a very important area for biodiversity, providing habitats for many endemic plant and animal species. Thus, a quite large area has been formed into the National Park of Gashaka Gumti (see also next chapter). It is home of many endangered animals. 366 species of birds have been recorded making it the ornithological most diverse site of Nigeria and justifying the classification of parts of the park as an International Bird Area (IBA).

Besides, more than 100 species of mammals have been recorded, among those the above mentioned Chimpanzees, the endangered African Elephant *Loxodonta africana* and Wild dog *Lycaon pictus.* Other mammals, listed as “least concern” by IUCn red list are: Roan Antilope *Hippotragus equinus, Redunca fulvorufula* and the Giant forest hog *Hylochoerus meinertzhageni (LC).*

About 55 species of fish and some 300–500 species of butterflies are also believed to occur in the poorly exploded area.

Typical plants of the forest are *Terminalia superba, Khaya grandifoliola, Milicia excelsa, Syzygium guineense, Prunus Africana, Ilex mitis, Loudetia simplex, Andropogon* spp., *Daniellia oliveri, Lophira lanceolata, Afzelia africana, Isoberlinia doka* and *Burkea Africana*[12]

[11] Source: http://www.iucnredlist.org/
[12] Source : http://datazone.birdlife.org/site/factsheet/gashaka-gumti-national-park-iba-nigeria

11.5.2.4 Protected and restricted areas

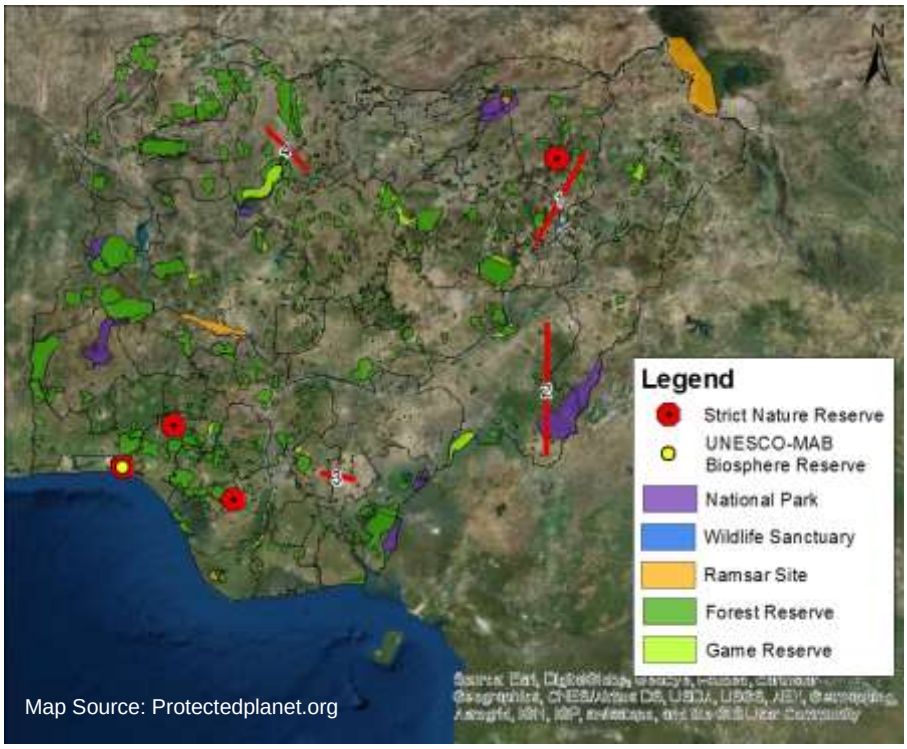
There are different types of protected areas in Nigeria, as shown in **Table 11-4**.

Table 11-4: Protected and restricted areas in Nigeria

National parks	7
RAMSAR	11
UNESCO MAB biosphere reserve	1
Forest reserve	933
Wildlife Sanctuary	2
Strict Nature Reserve	5
Game reserve	35
Community Forest	1
IBAs	27

Source: https://www.protectedplanet.net/country/NG
Birdlife.org ; nigeriaparkservice.org

As shown in **Map 11-7**, the national parks span across the various ecological zones of Nigeria (with the exception of the marine ecosystem). They cover a total land area of approximately 20,156 km², i.e. about three percent (3%) of the country total land area (i.e. 932,768 km^2).” They are managed by the Nigeria National Park Service (NNPS) whose job is to preserve, enhance, protect and manage vegetation and wild animals in the National Parks [13] .



Map 11-7: Overview of the protected and restricted areas in Nigeria

[13] Source : http://nigeriaparkservice.org/

All the four lines have several protected areas nearby. The numbers given in the following refer to a distance of maximum 50 m.

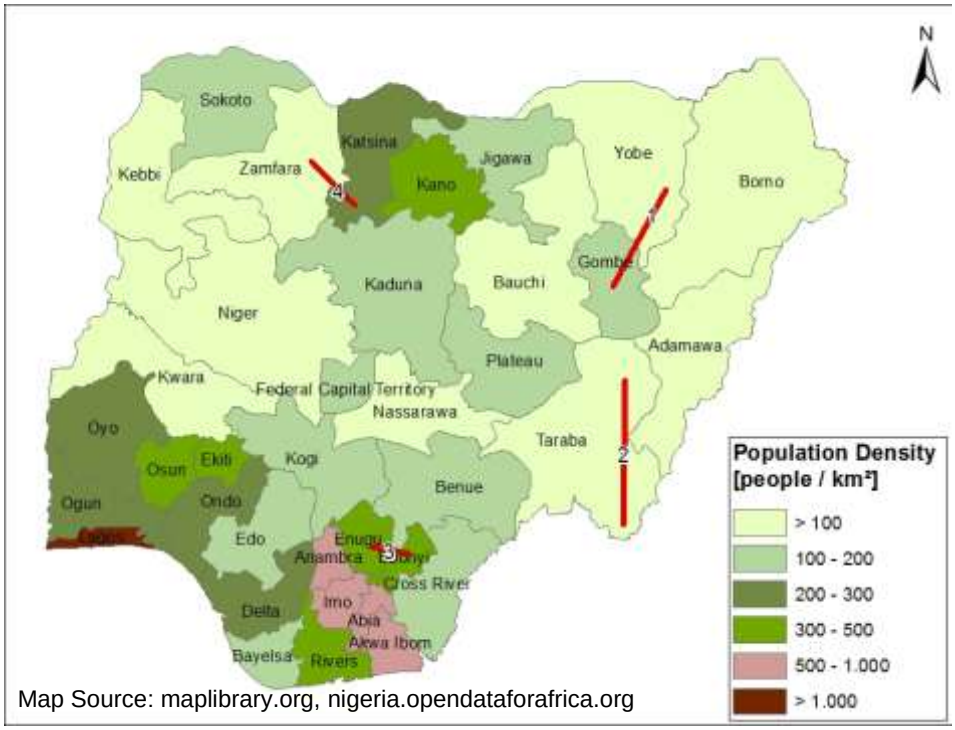
There are five Strict Nature reserves, one of which holds also title of UNESCO MAB biosphere reserve (Omo, see **Map 11-7**, yellow dot).

Forest reserves, game reserves and the community forest are dedicated to a restricted use. There are almost 1,000 forest reserves in Nigeria, spread throughout the country. Most of them are highly degraded and have hardly any forest left. For further information of the forest reserves, see **Table 11-10**.

11.5.2.5 Demography

In 2015, the young and fast growing population of Nigeria was at over 180 million inhabitants[14]. About half of them are living in urban areas, Lagos being the biggest of them with almost 14 million inhabitants in 2016[15].

The population density varies from state to state, but is generally declining from south to north (see **Map 11-8**).



Map 11-8: Population density of Nigeria (2006)

Regarding the selected lines, its line 3 that is located in the most populated region. Enugu with about 430 and Ebonyi with 340 people per square km belong to the most densely populated states of Nigeria.

[14] http://data.worldbank.org/country/nigeria?view=chart
[15] http://www.un.org/en/development/desa/population/publications/pdf/urbanization/the_worlds_cities_in_2016_data_booklet.pdf

The other 3 lines are situated in less populated regions. Taraba and Yobe (line 2 and 1) have both less than 50 persons per km² and are therefore the least populated of the whole of Nigeria.

11.5.2.6 Ethnic groups and religion

From a cultural aspect, Nigeria is very diverse. Numbers go up to 400 ethnic groups with over 500 different languages[16]. In 1995, 6 geopolitical regions have therefore been created by the government to amalgamate related groups. So, the languages and cultures within these regions are relatively similar.

The three biggest ethnical groups are the Yoruba in the South west, the Igbo (or Ibo) in the South east and the Hausa in the North West.[17]

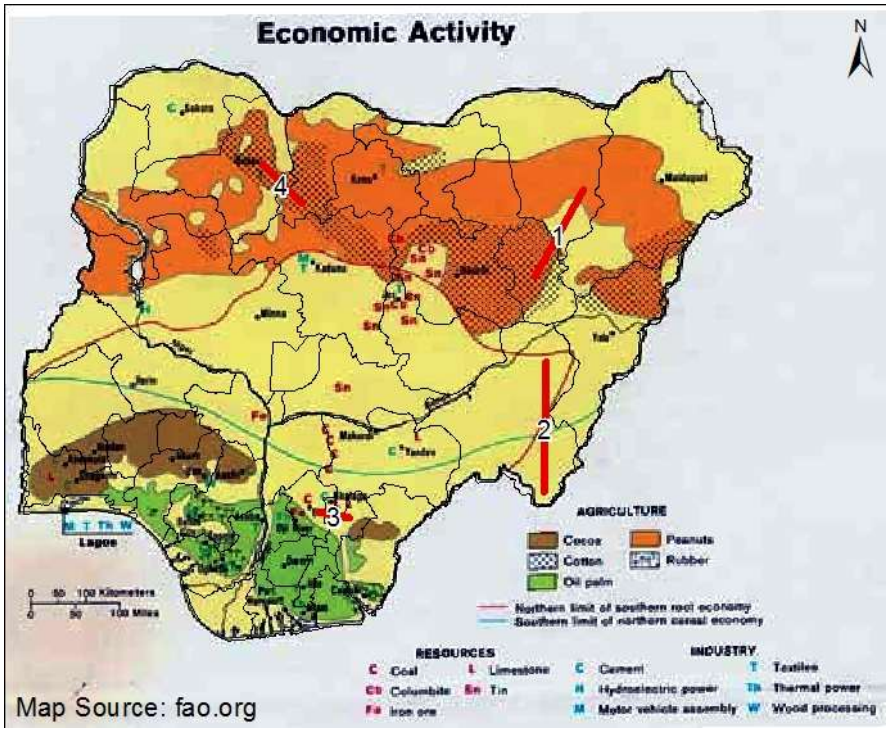
As for religion, the population of Nigeria is almost equally divided to Christianity and Islam, whereas Christians are predominant in the South and Muslims in the North.

Map 11-9: Geopolitical zones of Nigeria

11.5.3 Economy and Agriculture

Nigeria is an emerging market with a mixed economy. It is rich in natural resources; among whose the oil has to be mentioned. Petroleum industry is located above all in the Niger Delta.

[16] https://www.ethnologue.com/country/NG
[17] https://infoguidenigeria.com/top-6-geopolitical-zones-nigeria/



Map 11-10: Economic Activity in Nigeria

Even though agriculture remains the main source of income for one third of the Nigerians, the sector is struggling with numerous constraints. The most important are: an outdated land tenure system, a very low level of irrigation, low use of technologies, etc.

The most important crop both in production and consumption is rice. Although Nigeria is the largest producer of rice in Africa, large scale imports are necessary. This is mainly due to the fact that it is also an essential cash crop and their mainly small-scale producers sell about 80 % of their harvest.

The second most important crop is cassava, Nigeria being the largest producer in the world. Two-thirds of the production is in the southern part of the country, another 30 % are in North Central Zone.

Livestock farming is above all important in the semi-arid zone in the north of the country, 60 % of the ruminant livestock population is found there. Still, the production is far below the national demand, resulting in large imports[18].

11.5.4 Tensions and Conflicts

Since its foundation in 2003, the militant Islamic group “Boko Haram” was responsible for numerous attacks and kidnapping mainly in the North of Nigeria (most famous the “Chibok girls” in 2014).

In 2015, they have been pushed into a final stronghold in the Sambisa Forest in northeastern Nigeria. Nonetheless they still operate, mainly with attack by suicide bombers throughout Nigeria.[19] The three most affected states are Borno, Adamawa and Yobe, where almost

[18] Source: http://www.fao.org/nigeria/
[19] Source : http://web.stanford.edu/group/mappingmilitants/cgi-bin/groups/view/553?highlight=boko+haram

7 million people are in need of humanitarian assistance. Others escaped and are looking for shelter in the relative safety of urban areas. Due to the conflict, agriculture is mainly left unexploited, as for the fourth year in a row farmers have been prevented from planting. A severe food shortage is the result. Some 5.2 million people are food insecure with the onset of the rainy and lean season (June-September 2017)[20].

The region of envisaged line 1 has been affected severely by Boko Haram. The distance from Damaturu to Sambisa forest, where Boko Haram currently has its stronghold, is about 160 km.

11.6 Summary and recommendation for selected transmission lines

The voltage level of the lines roughly assesses in the following is 330 kV. For such a voltage level a corridor of 50 m is normally required (see e.g. SAPP 2010).

11.6.1 Line 1: Gombe to Damaturu

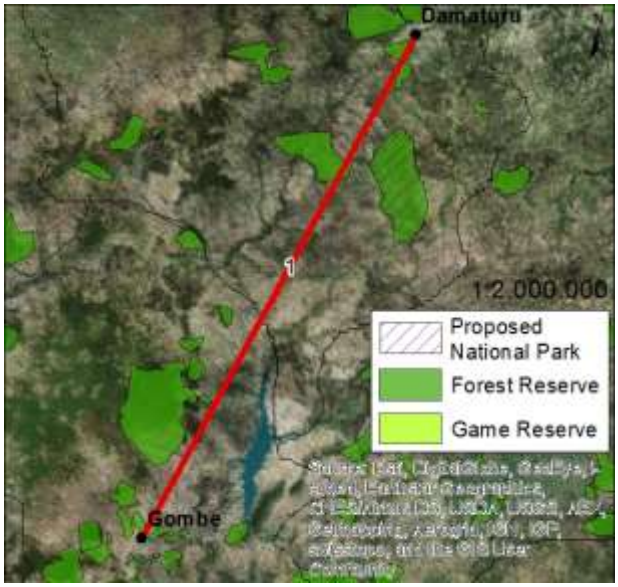
Table 11-5: Overview baseline data envisaged line 1

Climate	Warm semi-arid
Ecological zone	Sudan Savannah
Ecological problems	prone to desertification
Flora and Fauna	No endangered species found
Protected and restricted areas	One site proposed for National Park nearby
Population density [persons/ km²]	Yobe: 49.8 Gombe: 138.31
Ethnic group	Mainly Hausa-Fulani
Religion	Mainly Islam
Agriculture	Above all in the floodplains
Tensions and conflicts	Region affected by Boko Haram

This transmission line will run parallel to the corridor of the already existing 330 kV Line Gombe – Damaturu.

The line passes from the border of the savannah climate into the semi- arid climate. This is reflected in sparser vegetation on the ground. The small forest reserves (see Map 11-11) existing along the line have to be avoided. As the region is prone to desertification, special care has to be taken to protect every type of vegetation and to prevent dust generation.

[20] http://www.unocha.org/nigeria/about-ocha-nigeria/about-crisis



In close proximity to envisaged line 1, there is one site proposed for a National Park (Gujba) and 38 Forest Reserves.

Map 11-11: Protected areas near line 1

As the corridor passes through very little populated states, it can be assumed that resettlement costs will be less.

The Gongola is the biggest tributary of the Benue River. It has to be crossed north of Gombe. Its fertile floodplains are used for agriculture: Cotton, peanuts, and sorghum as cash crops; millet, beans, cassava, onions, corn and rice for the own use. Additionally, it serves as grazing ground for cattle, goats, sheep, horses, and donkeys.[21] . The line should not pass in this valley, because it would result in elevated resettlement costs.

This line passes quite close to the artificial lake Dadin Kowa (see Map 11-12). The dam has been built in 1984 for the purpose of irrigation.

Map 11-12: Lake Dadin Kowa

For this lake, no status of protection has been reported and no endangered species were found there. Nonetheless, it is an important habitat for aquatic and terrestrial bird species, including both Afro-tropical residents and Palearctic migrants[22].

Birds, especially the bigger and heavier waterfowl, are likely to collide with transmission lines, if they are built too close to their stretch of water. A reasonable distance should therefore be kept to avoid collisions. Additional mitigation measures could be the installation of bird diverters.

To sum it up it can be stated that resettlement costs are less and only slight deviations are needed to avoid the forests and forest reserves.

[21] https://www.britannica.com/place/Gongola-River#ref256551
[22] source : Adang et al.2015

11.6.1.1 Line 2: Jalingo to Mambila

Table 11-6: Overview baseline data envisaged line 2

Climate	Tropical Savanna climate
Ecological zone	Guinea Savannah and montane forest
Ecological Problems	in the north prone to desertification, in the south deforestation
Flora and Fauna	Several endangered species found
Protected and restricted areas	Gashaka Gumti National Park (including an IBA)
Population density [persons/ km²]	40.77
Ethnic group	Mainly Jukum and Mambila people
Religion	Mainly Islam
Agriculture	Slash and burn practiced in the north
Tensions and conflicts	None reported

As this OHL is planned in the least populated state of Nigeria, it can be assumed that resettlement costs will be less.

The envisaged line can be split into two quite different sections:

The first 120 km of the envisaged OHL from Jalingo lies in the Savannah and in an area with traditional slash and burn agriculture practiced by the peasant farmers. This is contributing to an ongoing desertification and deteriorating soil erosion[23]. Nonetheless, the line can follow an existing road (Bali-Jalingo Road) which should reduce the impacts. As the region is prone to Desertification, special care has to be taken to protect every type of vegetation and to prevent dust generation.

The following section has to be seen very critical from an ecological point of view. The drawn straight line is crossing the Gashaka Gumti National Park which is the largest of Nigeria's eight National Parks. Part of it is situated on the mountainous Mambila Plateau and is, therefore, part of a westward extension of the Cameroon mountains.

[23] Source : http://www.onlinenigeria.com/taraba-state/?blurb=375#ixzz4jyHnGbcz

Envisaged line 2 is crossing a National Park (Gashaka Gumti) if constructed straight forward. This Park includes an IBA. Besides, there are 22 smaller Forest Reserves in close proximity.

Map 11-13: Protected areas near line 2

The National Park has to be detoured by all means.

One option to do so is to follow the "Mambila Plateau Road". This road lies within a valley connecting several villages before climbing up to Mambila Plateau (see **Figure 11-3**).

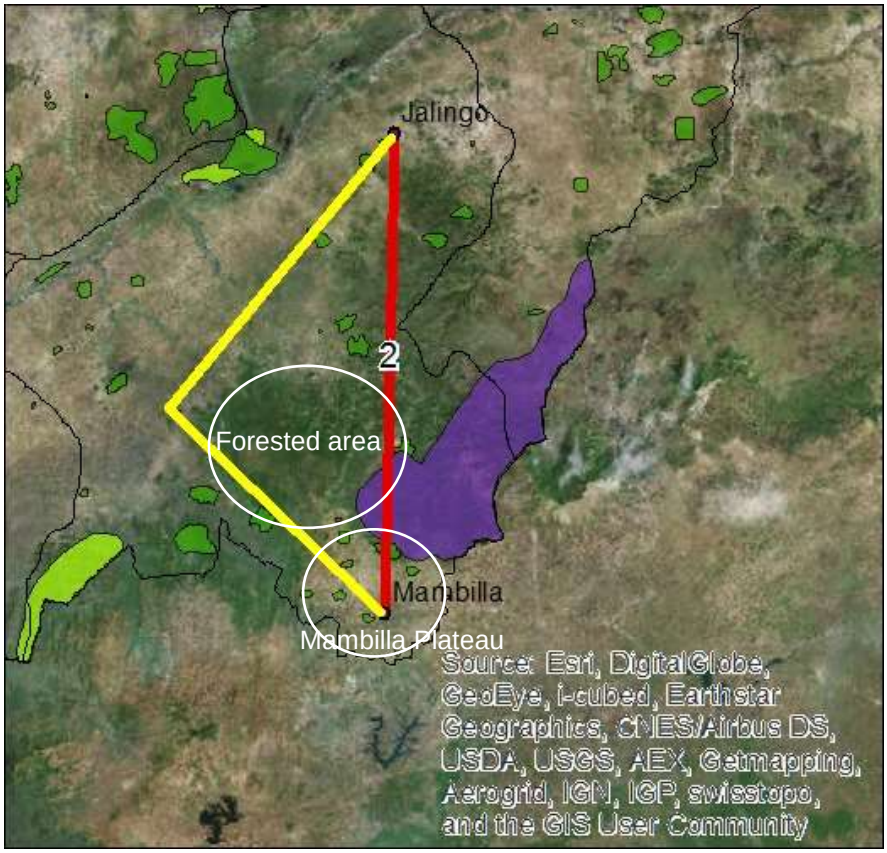
Figure 11-3: Scenic view on Mambila Plateau Road

This is problematic due to several reasons:

- It is a scenic view obviously used for touristic advertising, a transmission line built there would be a major impact for the landscape;
- It is doubtful if construction machines will be able to pass these streets without making bigger investments necessary;
- The terrain is rugged and hilly, provoking elevated costs for construction.

The second option is to bypass more widely. Unfortunately, the forested area is not restricted to the National Park and deforestation is a major problem in Nigeria which makes it priority to save the remaining patches.

Almost 160 km of the line are within forested area, including the ecologically very valuable montane forest. Due to its extension; this forest is hard to avoid (it would result in a detour of about 150 km, see **Map 11-14**, yellow line, roughly following existing roads). Even then, around 80 km of the line would still be in the forest.



Map 11-14: Possible detour line 2

11.6.1.2 Line 3: Ugwuaji to Abakaliki

Table 11-7: Overview baseline data envisaged line 3

Climate	Tropical Savannah Climate
Ecological zone	Derived Savannah
Ecological Problems	Zone already anthropologically modified
Flora and Fauna	No endangered species found
Protected and restricted areas	No National Park nearby
Population density [persons/ km²]	Enugu: 433.75 Ebonyi:340.15
Ethnic groups	Mainly Igbo
Religion	Mainly Christianity
Agriculture	Quite intensively used
Tensions and conflicts	None reported

This line lies completely in the anthropologically modified zone of derived savanna. In this zone, only smaller patches of forest are left (i.e. riparian forest). There is one river which has to be crossed (Nyaba; close to Enugu).

Most of the area is agriculturally used. The most important crops produced in the Ebonyi State are: rice, yam, oil palm products, cocoa, maize, groundnut, plantain, banana, cassava, melon, sugar cane, beans, fruits and vegetables[24]. Due to the relatively intensive agriculture, compensation is quite probably to become an issue, even though most of the crops can be overspanned.

As shown in the following map, there is no National Park or bigger protected area nearby. The small forest reserves should be avoided.

In close proximity to line 3, there are 11 smaller Forest Reserves.

Map 11-15: Protected areas near line 3

The states Ebony and Enugu also belong to the most densely populated of Nigeria. The line crosses several villages and reaches Abakaliki and the outskirts of Enugu. Buildings have to be contoured to avoid physical relocation. Resettlement costs are prone to become a major issue.

[24] Source: http://www.ebonyionline.com/about-ebonyi-state/

11.6.1.3 Line 4: Gusau to Funtua

Table 11-8: Overview baseline data envisaged line 4

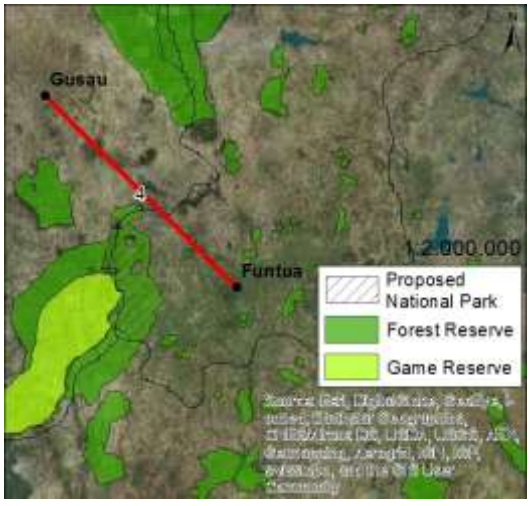
Climate	Tropical Savannah Climate
Ecological zone	Sudan Savannah
Ecological Problems	Prone to desertification
Flora and Fauna	No endangered species found
Protected and restricted areas	One site proposed for National Park nearby
Population density [persons/ km²]	Katsina: 246.24 Zamfara: 86.44
Ethnic group	Mainly Hausa-Fulani
Religion	Mainly Islam
Agriculture	Above all in the Sokoto floodplains
Tensions and conflicts	None reported

This line will be parallel to the corridor of the already existing 132 kV Line from Gusau to Funtua.

As the region is prone to Desertification, special care has to be taken to protect every type of vegetation and to prevent dust generation.

The region is not very densely populated; therefore, resettlement costs will be less.

The following map shows that the envisaged line passes near on area proposed for National Park. This has to be contoured.



In close proximity to line 4, there is one Game Reserve (Kuyambana) and 20 Forest Reserves. One of the forest reserves is proposed for National Park (Kogo).

Map 11-16: Protected areas near line 4

Close to Funtua is the source of the river Sokoto, which passes south of Gusau and later becomes a tributary of the Niger. It is therefore parallel to the envisaged line over its entire length. The alluvial valley and plains formed by the Sokoto River are extensively cultivated; peanuts, cotton, tobacco, swamp rice, onions, sugarcane, and indigo are grown. The line should not pass in this valley, because it would result in elevated resettlement costs.

To sum it up it can be stated that resettlement costs are less and only slight deviations are needed to avoid the forests and forest reserves.

11.7 Environmental Impact Cost

As the future corridors of the envisaged line are not yet known, an exact calculation of the environmental impact costs is not possible at this stage of planning. In chapter 6, the ecological impacts most likely to occur in the respective regions have been analysed. Based on these analyses and the predicted impacts / necessary mitigation measures, the following estimations were prepared.

For all 4 lines, a straight line was the base for any considerations, but of course, the corridor of the future transmission line will be adapted to the situation on the ground in the further planning process from the beginning. From an ecological point of view, slight deviations are above all necessary to avoid all protected and / or forested areas, and to reduce resettlement costs to a minimum. This will result in a bigger number of angle towers needed.

In chapter 6 was shown that a bigger deviation (of approx. 360 km) will be necessary for line 2. This would result in additional 120 km compared to the direct line.

As the fixation of the corridor of the lines is part of the planning process, the costs caused by the deviations mentioned above (an elevated number of angle towers needed and additional length of the line) are not environmental costs in the true sense of the word, but are included in the planning.

The costliest impact is resettlement, including both physical relocation and compensation for loss of land and goods. This impact is predicted to be most severe in the densely populated states. In our case, this is above all concerning line 3. Thus, an elevated price per km has been used for the calculation for this line.

The cost estimation has been based on the experience from my other projects in Africa.

Table 11-9 includes the costs for RAP (Resettlement Action Plan) implementation, livelihood improvement measures and the costs for monitoring of the established management plan (EMP), including audits. Not considered were the costs for setting up the RAP and the ESIA.

Table 11-9: Social and environmental costs estimated for the envisaged lines

	Distance		Predicted costs
	straight line [km]	Including prop. detour	[1 000 USD / km]
Line 1	160	/	15-20
Line 2	240	360	15-20
Line 3	85	/	20-25
Line 4	100	/	15-20

11.8 Conclusion

On example of 4 lines the possible environmental and social impacts have been identified. These fits to all lines eventually planned in Nigeria.

Degradation is a major problem in Nigeria; the processes of desertification and deforestation are of special concern. Especially the fact that almost all primary forest is lost and only very little and degraded forest is left makes the cutting of trees inconceivable. Existing forest patches have therefore to be contoured. Depending on the type of forests, they can eventually be spanned.

All protected areas have to be strictly avoided. This includes the one existing National Park (Gashatka Gumti) and also the forest reserves concerned (including the two of them being proposed for the formation of new National Parks).

Second issue for Nigeria is the regionally very high population density. Physical relocation has to be avoided whenever possible. In the more populated areas, this might not always be feasible and resettlements might become necessary. However, the number of affected people has to be kept to a minimum. Wherever fruit trees must be cut or agriculturally used fields have to be used for the masts, compensation has to be paid.

So, there are two major requirements: spare the national resources and avoid physical relocation of people. Therefore, deviations and numerous costly angle towers might become necessary.

Table 11-10: Name and size of Forest Reserves close to envisaged lines

Line 1		Line 2		Line 3		Line 4	
Name	approx area [m²]	Name	approx area [m²]	Name	approx area [m²]	Name	approx area [m²]
Wuro Biriji	3	River Amboi	102	Mai Samari	4,10	Kwankiro	5
Wuro Bamusa	2	Mai Samari	4	Ngel - Nyaki	30,24	Kwaimbana	2619
Yamaltu	34	Ngel - Nyaki	30	Kurmin Danki	11,24	Name Unknown (NGA) No.32	5
Kanawa	4	Kurmin Danki	11	River Nwum	17,66	Name Unknown (NGA) No.34	3
Kalalawa	209	River Nwum	18	Kakara	21,69	Zamfara	2100
Jajere	209	Kakara	22	Nguroje	16,07	Fahu	46
Gundulwa	27	Nguroje	16	Mayo Ndaga	21,45	Yan Tumaki	139
Bam Ngelzarma	108	Mayo Ndaga	21	Gembu	17,57	Tudun Mani	28
Dusuwa	22	Gembu	18	Dorofi	6,02	Ruma	817
Wagur	211	Seri	103	Seri	102,94	Kukar Jangara	330
Gujba	410	Kamatan	77	Kamatan	76,68	Dutsin Dorowa	19
Jangasiri	6	Kiri	17	Bakin Dutse	49,39	Gura	16
Gudi Hill	69	Kambari	361	Wuro Mallum	5,56	Bokori	16
Malechana	39	Bakin Dutse	49	Jalingo	0,73	Marbe	343
Nafada	38	Wuro Mallum	6	Zing	2,55	Tudun Iyo	14
Ako	55	Jalingo	1	Monkin	2,77	Dogan Dawa	409
Gombe	4	Zing	3	Garba Shege	63,38	Kogo	643
Dandadu	36	Monkin	3	Dakka	62,10	Jare	45
Tukulma	112	Garba Shege	63	Gangoro	45,94	Tandama	42
Kalsingi Hills	28	Dakka	62	Mai Hula	2,42	Gambare	20
Shebangel Hills	12	Gangoro	46	Wurkam River	51,02		
Liji Hills	17	Mai Hula	2	Gangume	81,39		
Kafarati	18	Wurkam River	51				
Jankai	26	Gangume	81				
Gadam	47						
Wawa	534						
Tongo	7						
Bodor Hill	29						
Abba Isari	22						
Bage	18						
Buratai	53						
Meringa North West	67						
Divana	89						
Kwaya Tera	18						
Wuyo Gube	49						
Name Unknown (NGA) No.22	157						
Name Unknown (NGA) No.25	44						
Name Unknown (NGA) No.39	12						

As the future corridors of the envisaged line are not yet known, an exact calculation of the environmental impact costs is not possible at this stage of planning. In chapter 6, the ecological impacts most likely to occur in the respective regions have been analysed. Based on these analyses and the predicted impacts / necessary mitigation measures, the following estimations were prepared.

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Line 4	100	/	15-20

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12. Proposed Transmission Expansion Plan

12.1 Methodology overview

The methodology of the power system analysis performed in section 7 is summarized as follows:

a) *Definition of the Security Reference Level*
The goal of the study is to propose the necessary updates and reinforcements to the TCN power system in order to achieve the secure operation of the system for the years 2020 to 2037. The analysis is first carried out on the present system model, taking into account the recently completed and ongoing TCN and NIPP projects that are scheduled to be completed by 2020. It has also been assumed that certain projects in the Lagos area undertaken by JICA will be completed by 2020.

b) *Execution of the analyses on the 2020 model*
The initial analysis is related to the static security assessment. Using the outcome of this analysis, a first reinforcement list and recommendations for new lines and transformers is provided. The dynamic security analysis is based on the results of the static analysis and considering the reinforcements list, as detailed in section 7.

c) *Execution of the analysis on the 2025, 2030 and 2037 model*
Considering the recommendations and reinforcements provided in b) already implemented in the 2020 network model, the same analysis are carried out on the 2025, 2030 and 2035/2037 scenarios. The reinforcements and recommendations for these years is the outcome of this analysis.

The proposed transmission expansion projects from 2020 to 2035/7 are detailed in the following sections.

The justification and benefits of major projects (North West Ring, North East Ring and Mambilla evacuation transmission lines) are summarized in **Table 12-16**.

12.2 Expansion plan for 2020

12.2.1 Transmission lines

As shown in section 7, the first priority is to resolve the overloads occurring under *normal (N-0)* operation of the following 132 kV lines shown in **Table 12-1**:

Table 12-1: Reinforcements of 132 kV lines overloaded under N-0

From	To	Proposed solution
Alagbon	Ijora	convert to DC
Omoku	Rumusoi (DC)	Reconductoring of the DC
Ibom IPP	Ikot Abasi	convert to DC

As a next priority, the overloaded lines under N-1 contingencies must be reinforced. This entails either re-conductoring to higher rating conductors or, in case of SC, conversion to DC by installing a 2nd parallel circuit.

The lines in **Table 12-2** are ranked according to their percentage of overload:

Table 12-2: Reinforcements of 132 kV lines overloaded under N-1

FROM Bus no	Bus name	TO Bus no	Bus name	Contingency label	Rating	Flow MVA	%
330 kV							
23002	OMOTOSHO3	43002	BENIN 3	SINGLE 23002-43002(2)	855.1	1138.7	133.2
33020	SHIRORO 3	53000	KADUNA 3	SINGLE 33020-53000(1)	855.1	865.6	101.2
132 kV							
42000	AJAOKUTA 1	42009	OKENE 1	SINGLE 42004-42008(1)	138.3	216.5	156.5
82017	YENAGOA 1	82022	GBARAIN UBIE	SINGLE 82017-82022(1)	138.3	208.2	150.5
22002	OSOGBO 4T2	22008	IWO 1	SINGLE 22000-22006(1)	138.3	202.7	146.6
62009	BIU 1	62026	DADINKOWA 1	SINGLE 63005-63007(1)	76.7	108.6	141.5
22000	AYEDE 1	22006	IBADAN NORTH	SINGLE 22002-22008(1)	138.3	195.5	141.3
42004	BENIN 1	42008	IRRUA 1	SINGLE 42000-42009(1)	138.3	191.3	138.3
42003	DELTA 1	42014	EFFURUN 1	SINGLE 42003-42014(1)	99.3	136.7	137.7
82017	YENAGOA 1	82018	AHOADA 1	SINGLE 82017-82018(1)	138.3	184.6	133.5
12003	IKEJA W 1BB1	12019	ALIMOSHO 1	SINGLE 12003-12019(1)	138.3	182.8	132.2
52033	MANDO T4A BB	52035	KUDENDA 1	SINGLE 52033-52035(1)	138.3	175.8	127.1
82007	PHCT MAIN1	82036	RUMUSOI 1	SINGLE 82007-82036(1)	138.3	172.8	124.9
82005	EKET 1	82024	IBOM IPP 1	SINGLE 82005-82024(1)	150.4	185.1	123.1
12016	AKOKA 1	12017	ALAGBON 1	SINGLE 12017-12024(1)	138.3	162.8	117.7
12002	EGBIN 1	12025	IKORODU	SINGLE 12002-12025(1)	138.3	157.6	114
12002	EGBIN 1	12025	IKORODU	SINGLE 12002-12025(1)	138.3	157.6	114
82001	ALAOJI 1	82026	ABA 1	SINGLE 82001-82026(1)	138.3	155.3	112.3
22009	ILESHA 1	22029	ILESHA TEE1	SINGLE 22007-22029(1)	138.3	155	112.1
52015	ZARIA 1	52016	FUNTUA 1	SINGLE 32016-52004(1)	99.3	110.5	111.3
22001	OSOGBO 1	22029	ILESHA TEE1	SINGLE 22001-22029(1)	138.3	151	109.2
22007	IFE 1	22029	ILESHA TEE1	SINGLE 22009-22029(1)	138.3	150.5	108.8
12001	AKANGBA 1	12027	ISOLO 1	SINGLE 12001-12027(1)	138.3	142.4	103
52003	KADUNA TOWN	52033	MANDO T4A BB	SINGLE 52003-52033(1)	138.3	140.9	101.9
82013	ONNE 1	82040	TRAMADI	SINGLE 82013-82040(1)	138.3	138.8	100.4

Note: It should be noted that with regards to the overloaded 330 kV lines in 2020 (Benin-Omotosho and Shiroro-Kaduna), remedial actions are already planned and these lines will not be overloaded in 2025, as shown in section 7.5.

Finally, in addition to the projects proposed by JICA in the Lagos area (330 kV lines and substations Omotosho-Ogijo-MFM, Ikeja West, Arigbajo, New Agbara), as shown in the

SLDs of Annex 7.2 and 7.3, the transmission lines shown in **Table 12-3** are required to be implemented by 2020:

Table 12-3: New transmission lines required by 2020

No		From	To		kV	km	Remarks	Priority /Ranking
1	Part of North East Ring	Damaturu	Maiduguri	DC	330	260	a SC already exists	1
2		Gombe	Damaturu	DC	330	180	a SC already exists	1
3		Gombe	Yola	DC	330	240	a SC already exists	1
4		Yola	Jalingo	DC	330	160	Can be delayed beyond 2020 but asap thereafter. One circuit via Mayo Belwa.	3
5		Jos	Gombe	DC	330	270	Should be completed by 2020 or asap thereafter. A SC already exists	1
6	Part of North West ring							
7		Kainji	Birnin Kebbi	DC	330	310	A SC already exists. Needs to be expedited by 2020 if possible or asap thereafter.	3
8		Kaduna	Kano	DC	330	230	Undertaken by TCN as part of the NTEP to be financed by IDB. Needs to be expedited by 2020 if possible or asap thereafter.	2
9		Akangba	Alagbon	DC	330	14		2
10		Ugwuaji	Abakaliki	DC	330	85		1
11		Osogbo	Arigbajo	DC	330	183	If not undertaken by JICA	
12		Ayede	Ibadan North	DC	132	15		1
13		New Agbara	Agbara	DC	132	18		2
14		Ogijo	Redeem	DC	132	14	If not undertaken by JICA	
15		Birnin Kebbi	Dosso	DC	132	128	a SC already exists	2
15		Ibom IPP	Ikot Abasi	DC	132	30		1

Notes:

- The lines recommended for the North East ring above are required in order to comply with the N-1 static security criterion, as well as to improve the voltage stability of the area. It is recognized however that in terms of implementation it will be challenging to complete all by 2020. However, if not possible to implement by 2020 they should be implemented as soon as possible thereafter within the period 2020-2025 and therefore the investment plan, detailed in section 9, has been based on this assumption.
- The JICA project of new 330 kV lines (DC) from Ogijo to Arigbajo is not considered necessary, as it is lightly loaded under all scenarios.
- The JICA project of new 330 kV lines (DC) from Arigbajo to New Agbara is not considered necessary for 2020, as it is lightly loaded. It is necessary only for meeting the N-1 criterion for the export lines to Sakete.

12.2.2 Transformers

- The upgrading of 14 x 330/132 kV 3-W and A/T transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-21**.

- The upgrading of 25 x 132/33 kV and 132/11 kV transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-22**

- The upgrading of the following types of transformers overloaded above their 85% rating MVA under normal (base case) operation shall be upgraded, as listed in **Table 7-23**:

  c) 10 x 330/132 kV 3-w and A/T,
  d) 25 x 132/33 kV and 132/11 kV transformers

12.2.3 Reactive power compensation

12.2.3.1 SVC requirements

No SVC at Gombe is necessary by 2020.

12.2.3.2 Reactors

The status of reactors required in ***Dry Season Peak*** case is shown in **Table 12-4**. It can be seen that only four reactors at Gombe and Yola are required and it is assumed they are existing and are in good working order. If not, new reactors will be required:

Table 12-4: Reactor requirements for 2020 dry season peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
63002	YOLA 3	330	1	1	-75
63000	GOMBE 3	330	1	1	-50
65001	YOLA T1 33	33	1	1	-30
65014	GOMBE T4A	33	1	1	-30

The status of reactors required in ***Dry Season Off-Peak*** case is shown in **Table 12-5**. The new reactor required (at Maiduguri) is shown in bold:

Table 12-5: Reactor requirements for 2020 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
53001	KANO 3	330	1	1	-75
63002	YOLA 3	330	1	1	-75
63005	**MAIDUGURI 3**	**330**	**2**	**1**	**-75**
63000	GOMBE 3	330	1	1	-50
63000	GOMBE 3	330	2	1	-50
65001	YOLA T1 33	33	1	1	-30
65014	GOMBE T4A	33	1	1	-30

12.2.3.3 Capacitors

The status of capacitors required in ***Dry Season Peak*** case is shown in **Table 12-6**. The new equipment required is shown in bold:

Table 12-6: Capacitor requirements for 2020 dry season peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
53001	KANO 3	330	2	1	50
62021	MAIDUGURI 1	132	1	1	10.8
52022	HADEJIA 1	132	1	1	20
22017	**ONDO2 1**	**132**	**1**	**1**	**24**
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
22015	**OMUARAN 1**	**132**	**1**	**1**	**50**
12004	AKANGBA BBII	132	1	1	72
15011	ABEOKUTA OLD	33	2	1	20
15037	NEW ABEOK 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
15002	AGBARA 33	33	1	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
75017	YANDEV 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15080	OLD ABEOK T2	33	3	1	24
15128	EJIGBO 33	33	1	1	24
25011	ILORIN 33	33	1	1	24
45027	IRRUA BBII33	33	1	1	24

The status of capacitors required in ***Dry Season Off-Peak*** case is shown in **Table 12-7**. The new equipment required is shown in bold. Regarding the existing ones it is assumed they will be in good working order by 2020:

Table 12-7: Capacitor requirements for 2020 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
62021	MAIDUGURI 1	132	1	1	10.8
52022	HADEJIA 1	132	1	1	20
22017	**ONDO2 1**	**132**	**1**	**1**	**24**
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
22015	**OMUARAN 1**	**132**	**1**	**1**	**50**
12004	AKANGBA BBII	132	1	1	72
15002	AGBARA 33	33	1	1	20
15011	ABEOKUTA OLD	33	2	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
75017	YANDEV 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15080	OLD ABEOK T2	33	3	1	24
15128	EJIGBO 33	33	1	1	24
25011	ILORIN 33	33	1	1	24
45027	**IRRUA BBII33**	**33**	**1**	**1**	**24**

12.2.3.4 Power factor correction at DisCos level

With reference to the Grid Code requirements (ref. article 15.6 on *Demand power factor corrections and 16.7 on provision of voltage control* stating that *The Off-takers shall maintain a Power Factor not less than 0.95 at the Connection Point*), since the resulting power factor of loads connected at 33 kV level and below is less than the 0.95 required, all DisCos shall be required to undertake a program of having capacitors installed at distribution level to ensure the power factor at all 33 kV S/S is not less than 0.9 by 2020 and 0.95 by 2025, in line with the Grid Code requirements.

(Note: the loads in the 2025 model however have been based on a conservative power factor of 0.9 and only the 2030 loads have pf of 0.95)

12.2.4 Fault level remedial measures

The fault analysis of section 7.11 has shown that the most critical 330 kV substations are BENIN, OMOTOSHO, SAPELE, ALAOJI and AFAM IV, with fault levels ranging from 34.9 kA to 25.7 kA for a 3ph busbar fault.

The most relatively critical 132 kV substation is IKEJA WEST, with fault level of 29.6 kA.

It is clear from this analysis that the TCN standard switchgear ratings of 31.5 kA are inadequate in future when new power plants are to be commissioned in the following years.
In order to solve the violations detected in the substations of TCN network, the following solutions could be adopted:

a) Install switchgear with breakers of higher breaking capacity (63 kA).

b) Study different topological configurations of the elements connected to the different bus sections, performing dedicated analyses aimed at verifying that the new configuration satisfies the security criteria adopted by TCN.

c) Install Current Limiting Reactors (CLR) aimed at reducing the short circuit currents contributions from adjacent bus sections. This solution allows a general reduction of the short circuits current while maintaining electrically connected the bus sections.

12.3 Expansion plan for 2025

12.3.1 Transmission lines

In addition to the projects undertaken by TCN and NIPP, the following 330 kV and 132 kV lines, shown in **Table 12-8**, are included in the 2025 model. These lines are also in addition to those that have been included in the 2020 model.

Table 12-8: Additional lines required by 2025 (1)

No		From	To		kV	km	Remarks	Priority/ Ranking
1		Arigbajo	Ayede	SC	330	50	JICA	1
2	Part of North West Ring	Birnin Kebbi	Sokoto	DC	330	130	in parallel of existing 132 kV	3
3		Sokoto	Talata Mafara	DC	330	100		3
4		Talata Mafara	Gusau	DC	330	125		3
5		Gusau	Funtua	DC	330	70		2
6		Funtua	Zaria	DC	330	70		2
7		Olorunsogo	Arigbajo	DC	330	20	Already a DC. 4 circuits are required.	3
8		Katsina	Daura	DC	330	40	Undertaken by TCN as part of the Northern Corridor Transmission projects 2, to be financed by AFD	2
9		Daura	Kazaure	DC	330	25	Undertaken by TCN as part of the Northern Corridor Transmission projects 2, to be financed by AFD	2
10	Part of North East Ring	Damaturu	Maiduguri	DC	330	260	If not by 2020, implement as soon as possible thereafter (a SC already exists)	3
11		Gombe	Damaturu	DC	330	160	If not by 2020, implement as soon as possible thereafter (a SC already exists)	3
12		Gombe	Yola	DC	330	240	If not by 2020, implement as soon as possible thereafter (a SC already exists)	3
13		Yola	Jalingo	DC	330	160	If not by 2020, implement as soon as possible thereafter (1 SC via Mayo Belwa)	3
14	Mambila evacuation	Mambila	Jalingo	2xDC	330	95	2xDC only if N-2 is adopted, otherwise 1xDC	1
15		Mambila	Wukari	2xDC	330	159	2xDC only if N-2 is adopted, otherwise 1xDC	1
16		Wukari	Makurdi	DC	330	159		1
16		Wukari	Lafia	DC	330	95	after 2025	3
18		Shiroro	Kaduna	DC	330	96	or upgrade to 4-b (Quad).	3

No		From	To		kV	km	Remarks	Priority/ Ranking
							Two DC project with quad conductors is undertaken by TCN as part of the Northern Corridor Trans-mission projects 2, to be financed by AFD	
19		Arigbajo	New Agbara	DC	330	40	JICA.	
20		Arigbajo	Ogijo	DC	330	48	JICA.	
21		New Agbara	Badagry	DC	132	32	JICA.	
22		Arigbajo	New Ajeokuta	DC	132	37	JICA.	

Furthermore, since a number of undervoltages were encountered in the Dry Season Peak case, and also in order to meet the N-1 security criterion, the following additions, shown in **Table 12-9**, were made at 132 kV level:

Table 12-9: Additional 132 kV lines required by 2025 (2)

No	From	To		kV	km	Remarks	Priority/ Ranking
1	Shiroro	Tegina	SC	132	65	SC only exists. Add DC	1
2	Tegina	Kontagora	SC	132	90	SC only exists. Add DC	1
3	Kontagora	Yelwa-Yauri	SC	132	88	SC only exists. Add DC	1
5	Ganmo	Ilorin	SC	132	10.5	check if DC exists	3
6	Obajana	Egbe	DC	132	97	new DC	1
7	Omotosho	Ondo	DC	132	98	new DC	1
8	Benin	Irrua	DC	132	88	SC only exists. Add DC	2
9	Irrua	Ukpilla	DC	132	43	SC only exists. Add DC	2
10	Ukpilla	Okene	DC	132	33	SC only exists. Add DC	3
11	Sagamu	Ijebu Ode	SC	132	41	SC only exists. Add DC	3
12	Dakata	Gagarawa	SC	132	89	SC only exists. Add DC	3
13	Gagarawa	Hadejia	SC	132	60	SC only exists. Add DC	3
14	Dakata	Kumbotso	SC	132	30	SC only exists. Add DC	3

The 132 kV lines which are overloaded under normal operation (base case) requiring reinforcements, in addition to those reported for the 2020 case, are listed in **Table 12-10**:

Table 12-10: Overloaded 132 kV lines under N-0

From bus no	Bus name	kV	To bus no	Bus name	kV	cct	Loading (MVA)	Rating (MVA)	%
12046	OGIJO 1	132	22027	SAGAMU 1	132	1	168.7	125.7	134.2
12046	OGIJO 1	132	22027	SAGAMU 1	132	2	168.7	125.7	134.2
62026	DADINKOWA 1	132	62039	KWAYA KUSAR	132	2	71.1	69.7	102
82007	PHCT MAIN1	132	82009	PHCT TOWN2 1	132	1	126.9	125.7	100.9

It is noted that some of the above lines have been reported in the 2020 case, but only under N-1 conditions.

12.3.2 Contingency (N-1) analysis for 330 kV circuits in 2025

The contingency N-1 analysis carried out for the 330 kV lines has shown that the following 330 kV DC lines are overloaded and require reinforcement by converting to Quad conductors.

Table 12-11: Overloaded 330 kV lines under N-1

From	To
ALIADE	UGWUAJI
MAKURDI	ALIADE
AJA	LEKKI
GWAGWALADA	LOKOJA
LOKOJA	AJAOKUTA

12.3.3 Transformers

The following upgrades are required, in addition to those reported for the 2020 case:

- The upgrading of 20 x 330/132 kV 3-W and A/T transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-36**.

- The upgrading of 51 x 132/33 kV and 132/11 kV transformers which are overloaded above their 100% rating MVA under normal (base case) operation, is required, as listed in **Table 7-37**. 25 of these transformers have already been reported as overload above their 85% rating in 2020.

12.3.4 Reactive power compensation

The reactive power requirements, i.e. the need to have existing reactors and capacitors in operation and/or install new ones by 2025, including the necessity for new SVCs, are summarized in the following sections. The new equipment is marked in bold.

12.3.4.1 SVC requirements

There is no requirement for an SVC in 2025. More detailed and dedicated studies will be necessary at a later stage to determine any need for such equipment in the period beyond 2025.

In 2025, in addition to the reactors and capacitors listed in **Table 12-12**, **Table 12-13**, **Table 12-14** and **Table 12-15**, reactive power compensation (120MVar capacitors) will be required at Birnin Kebbi due to export requirements to WAPP.

With regards to Gombe, should additional reactive power compensation be required at lightly loaded conditions, instead of SVC a more cost effective option would be to relocate from other S/S to Gombe approximately 100-150 MVAR of reactors that, as it has been shown in this analysis, are not needed there anymore.

As it is shown in the static security analysis for 2025, a more appropriate candidate for an SVC could be the Lagos / Ikeja/Eko region, where there is a reactive power deficit of approximately 400-500 MVar. It should be noted however that this deficit is expected to be greatly reduced when the DisCos implement the reactive power control program at distribution level, as proposed and in line with the Grid Code requirements, as well as when transmission lines and transformers are upgraded, as it has been shown in previous chapters of this report.

12.3.4.2 Reactors

The status of reactors required in ***Dry Season Peak*** case is shown in **Table 12-12**. There are no requirements for reactors in this case.

Table 12-12: Reactor requirements for 2025 dry season peak

Bus Number	Bus Name		Id	In Service	B-Shunt [MVAR]
All buses	all		-	0	0

The status of reactors required in ***Dry Season Off-Peak*** case is shown in **Table 12-13**:

Table 12-13: Reactor requirements for 2025 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt [MVAR]
63005	**MAIDUGURI 3**	**330**	**2**	**1**	**-75**
65014	GOMBE T4A	33	1	1	-30

12.3.4.3 Capacitors

The status of capacitors required in ***Dry Season Peak*** case is shown in **Table 12-14**. New equipment is shown in bold. It is assumed that the existing ones will be in good working order:

Table 12-14: Capacitor requirements for 2025 dry season peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt (MVar)
53001	KANO 3	330	2	1	50
53001	KANO 3	330	3	1	50
42015	AMUKPE 1	132	1	1	20
52022	HADEJIA 1	132	1	1	20
22017	**ONDO2 1**	**132**	**1**	**1**	**24**
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
22015	**OMUARAN 1**	**132**	**1**	**1**	**50**
82010	**UYO 1**	**132**	**1**	**1**	**50**
12004	AKANGBA BBII	132	1	1	72
15002	AGBARA 33	33	1	1	20

Bus Number	Bus Name	kV	Id	In Service	B-Shunt (MVar)
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
35009	KONTAGORA 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15128	EJIGBO 33	33	1	1	24
25011	ILORIN 33	33	1	1	24
45027	**IRRUA BBII33**	**33**	**1**	**1**	**24**

Reference should also be made to the recommendation made in 7.8.3.1 regarding reactive power support in Ikeja West area.

The status of capacitors required in ***Dry Season Off-Peak*** case is shown in **Table 12-15**:

Table 12-15: Capacitor requirements for 2025 dry season off-peak

Bus Number	Bus Name	kV	Id	In Service	B-Shunt (MVar)
53001	KANO 3	330	2	1	50
53001	KANO 3	330	3	1	50
42015	AMUKPE 1	132	1	1	20
52022	HADEJIA 1	132	1	1	20
42008	**IRRUA 1**	**132**	**1**	**1**	**24**
12004	AKANGBA BBII	132	1	1	72
15002	AGBARA 33	33	1	1	20
15022	IKORODU 33	33	2	1	20
15027	ILUPEJU 33	33	1	1	20
25004	AYEDE 33	33	1	1	20
25012	ISEYIN 33	33	1	1	20
25018	AKURE T3A 33	33	1	1	20
25035	SAGAMU 33	33	1	1	20
25038	IJEBU ODE 33	33	1	1	20
35009	KONTAGORA 33	33	1	1	20
45003	OKENE 33	33	1	1	20
55001	DAN AGUNDI 3	33	2	1	20
55010	KATSINA 33	33	1	1	20

Bus Number	Bus Name	kV	Id	In Service	B-Shunt (MVar)
15006	AKANGBA 33	33	1	1	24
15007	AKOKA T1 33	33	1	1	24
15009	ALAUSA 33	33	1	1	24
15010	ALIMOSHO 33	33	1	1	24
15014	EJIGBO 33	33	1	1	24
15015	IJORA 33	33	1	1	24
15018	OGBA 33	33	1	1	24
15028	ISOLO 33	33	1	1	24
15079	OTTA T2	33	1	1	24
15128	EJIGBO 33	33	1	1	24

12.3.4.4 Fault level remedial measures

The most critical 330 kV substations are BENIN, OMOTOSHO, AZURA, EGBIN and BENIN, with fault levels ranging from 54.3 kA to 42 kA for a 3ph busbar fault.

The most relatively critical 132 kV substation is IKEJA WEST, with fault level of 39.3 kA. The recommended remedial measures are the same as those described for the 2020 case.

12.4 Justifications and benefits for major projects

12.4.1 Benefits of major projects

The benefits of major projects (North West Ring, North East Ring and Mambilla evacuation transmission lines) are summarized in the **Table 12-16**.

Table 12-16: Benefits of major transmission projects

No	From	To	Type	kV	km	Benefits	Remarks
North East Ring							
1	Damaturu	Maiduguri	DC	330	260	Load in Maiduguri is supplied by a 330 kV SC line. If tripped, load of 55-83MW will be lost between 2020-2025 and 200MW by 2035. Widespread undervotlages may result in tripping additional load. A new DC 330 kV will prevent this and will increase system security, by meeting the N-1 criterion.	Ref Table 12.16 (a)
2	Gombe	Damaturu	DC	330	180	Load in Damaturu and Maiduguri is mainly supplied by a 330 kV SC from Gombe. If the line from Gombe is tripped, load of 135-482MW (2020-2035) will be lost. Widespread undervotlages may result in tripping additional load. A new DC 330 kV Gombe-Damaturu will prevent this and will increase system security by meeting the N-1 criterion	
3	Gombe	Yola	DC	330	240	Load in Yola is supplied by a 330 kV SC from Gombe and a 132 kV SC line fro Jalingo. If the line from Gombe is tripped, load of 140-500 MW (2020-2035) will be lost. Widespread un dervotlages may result in tripping additional load. A new DC 330 kV Gombe-Yola will prevent this and will increase system security by meeting the N-1 criterion	
4	Yola	Jalingo	DC	330	160	Load in Jalingo is supplied by a 132 kV SC from Yola. If the line from Yola is tripped, load of at least 45-160MW will be lost (2020-2035). Widespread	

No	From	To	Type	kV	km	Benefits	Remarks
North East Ring							
						undervoltages may result in tripping additional load. A new DC 330 kV Yola-Jalingo will prevent this and will increase system security	
5	Jos	Gombe	DC	330	270	If only one 330 kV circuit is in operation, voltage stability issues would necessitate additional reactive power compensation at Gombe. If this line trips voltage collapse will result in heavy load loss (400-1428MW in 2020 and 2035 respectively). Since the second line is needed anyway to meet N-1 too, it recommended to have it implemented as soon as possible and save the cost of reactive power compensation at Gombe.	
North West Ring							
1	Kainji	Birnin Kebbi	DC	330	310	Required for N-1. If not installed, tripping the existing SC 330 kV line will result in voltage collapse and heavy loss of load, 240-900MW (2020-2035)	Ref Table 12.16 (b)
2	Birnin Kebbi	Sokoto	DC	330	130	Mainly voltage stability and prevention of load shedding. Required by 2025. If the lines are not installed by 2025, the loads will be fed via the 132 kV system only, resulting in widespread undervoltages, which would necessitate load shedding of approx 350MW in 2025 and 800MW in 2035 in order to stabilize the voltage.	
3	Sokoto	Talata Mafara	DC	330	125	Mainly voltage stability and prevention of load shedding. Required by 2025. If the lines are not installed by 2025, the loads will be fed via the 132 kV system only, resulting in widespread undervoltages, which would necessitate load shedding of approx 240MW in 2025 and 550MW in 2035 in order to stabilize the voltage	
4	Talata Mafara	Gusau	DC	330	85	Mainly voltage stability and prevention of load shedding. Required by 2025. If the lines are not installed by 2025, the loads will be fed via the 132 kV system only, resulting in widespread undervoltages, which would necessitate load shedding of approx 160MW in 2025 and 400MW in 2035 in order to stabilize the voltage	
5	Gusau	Funtua	DC	330	70	Mainly voltage stability and prevention of load shedding. Required by 2025. If the lines are not installed by 2025, the loads will be fed via the 132 kV system only, resulting in widespread undervoltages, which would necessitate load shedding of approx 100MW in 2025 and 150MW in 2035 in order to stabilize the voltage	
6	Funtua	Zaria	DC	330	70	Required by 2020. The area is supplied via 132 kV lines only. If the 132 kV line from Zaria to Funtua trips, approx 90 MW of load will be lost in 2020 and 120 MW by 2025. A new DC 330 kV will prevent this and will increase system security.	
Mambilla evacuation							
9	Mambila	Jalingo	DC	330	95	To evacuate the power from Mambilla HPP, rated 3000MW, it is necessary to maintain two evacuation routes, one towards Makurdi and another towards north to Jalingo. If the generation from Mambilla exceeds 1400MW, a DC only of Quad conductors cannot meet the N-1 requirements, hence the need to have the DC Mambilla-Jalingo. Additional reasons include voltage stability.	Ref Table 12.16 (c)
10	Mambila	Wukari	DC	330	150		

12.4.2 Estimated Energy Not Served (EENS)

The Estimated Energy Not Served for each of the projects of **Table 12-16** is tabulated in **Table 12-17**.

Table 12-17: Estimated Energy Not Served

(a) North East Ring: Estimated Energy Not Served (EENS per year) Calculations																
					total failures	MTTR	2020 Load	2025 Load	2030 Load	2035 Load	2037 Load	2020 EENS	2025 EENS	2030 EENS	2035 EENS	2037 EENS
Line	From	To	km	λ /km/yr	per yr	hrs	Served MW	Served MW	Served MW	Served MW	Served MW	MWh	MWh	MWh	MWh	MWh
330 kV	Damaturu	Maiduguri	260	0.02	5.2	12	55	83	140	196	206	**3,432**	**5,148**	**8,752**	**12,252**	**12,865**
330 kV	Gombe	Damaturu	180	0.02	3.6	12	135	203	344	482	506	**5,832**	**8,748**	**14,872**	**20,820**	**21,861**
330 kV	Gombe	Yola	240	0.02	4.8	12	140	210	357	500	525	**8,064**	**12,096**	**20,563**	**28,788**	**30,228**
330 kV	Yola	Jalingo	160	0.02	3.2	12	45	68	115	161	169	**1,728**	**2,592**	**4,406**	**6,169**	**6,477**
330 kV	Jos	Gombe	270	0.02	5.4	12	400	600	1,020	1,428	1,499	**25,920**	**38,880**	**66,096**	**92,534**	**97,161**
											Total for North East Ring	**44,976**	**67,464**	**114,689**	**160,564**	**168,593**

(b) North West Ring: Estimated Energy Not Served (EENS per year) Calculations																
					total failures	MTTR	2020 Load	2025 Load	2030 Load	2035 Load	2037 Load	2020 EENS	2025 EENS	2030 EENS	2035 EENS	2037 EENS
Line	From	To	km	λ /km/yr	per yr	hrs	Served MW	Served MW	Served MW	Served MW	Served MW	MWh	MWh	MWh	MWh	MWh
330 kV	Kainji	Birnin Kebbi	310	0.02	6.2	12	240	384	710	902	947	**10,416**	**16,666**	**30,831**	**39,156**	**41,114**
330 kV	Birnin Kebbi	Sokoto	130	0.02	2.6	12	220	352	651	827	868	**6,864**	**3,095**	**5,726**	**7,272**	**7,635**
330 kV	Sokoto	Talata Mafara	125	0.02	2.5	12	150	240	444	564	592	**4,500**	**1,680**	**3,108**	**3,947**	**4,145**
330 kV	Talata Mafara	Gusau	85	0.02	1.7	12	105	168	311	395	414	**2,142**	**1,632**	**3,019**	**3,834**	**4,026**
330 kV	Gusau	Funtua	70	0.02	1.4	12	65	104	192	244	257	**1,092**	**1,693**	**3,133**	**3,979**	**4,178**
330 kV	Funtua	Zaria	70	0.02	1.4	12	5	8	15	19	20	**84**	**269**	**497**	**632**	**663**
											Total for North West Ring	**25,098**	**25,035**	**46,315**	**58,819**	**61,760**

(c) Mambila evacuation Estimated Energy Not Served (EENS per year) Calculations																
					total failures	MTTR	2020 Load	2025 Load	2030 Load	2035 Load	2037 Load	2020 EENS	2025 EENS	2030 EENS	2035 EENS	2037 EENS
Line	From	To	km	λ /km/yr	per yr	hrs	Served MW	Served MW	Served MW	Served MW	Served MW	MWh	MWh	MWh	MWh	MWh
330 kV	Mambila	Jalingo	95	0.02	1.9	12	0	220	1,040	1,040	1,040	**0**	**5,016**	**23,712**	**23,712**	**23,712**
330 kV	Mambila	Wukari	150	0.02	3	12	0	100	1,260	1,260	1,260	**0**	**3,600**	**45,360**	**45,360**	**45,360**
											Total for Mambila evacuation	**0**	**8,616**	**69,072**	**69,072**	**69,072**

12.5 Expansion plan and “supergrid” options for 2030 and 2035

The load flow simulations with generation and load as detailed in the previous section has shown that without major upgrade of the transmission system, there will be widespread undervoltages and overloads throughout the system and at all voltage levels.

Consequently, the system losses will be high. It is therefore considered necessary and appropriate at this stage to introduce a new “supergrid”, i.e. a backbone for bulk transmission at 330, 500 or 750 kV.

A number of configurations have been examined and compared in terms of their efficacy in voltage support, system losses and relieve of line loadings of existing and planned 330 kV system.

The optimum configuration of a 330, 500 or 750 kV EHV grid is shown in **Figure 7-21**.

The supergrid will encompass the following substations, shown in **Table 12-18**:

Table 12-18: New EHV grid Substations

Name of new EHV substations							
Ikot Ekpene	Benin	New Agbara	Osogbo	Gwagwalada	Makurdi	Ajeokuta	Funtua

With regards to the conductor necessary for each supergrid option, the following arrangements are recommended:

- At 330 kV a Double Circuit is proposed with 4-bundle (Quad) Bison conductors for each circuit.
- At 500 kV a Single Circuit is proposed with 4-bundle (Quad) Bison conductors.
- At 750 kV a Single Circuit is proposed with 5-bundle Bison conductors, which is typical at this voltage level due to corona phenomenon.

The main electrical characteristics are summarized in the **Table 12-19** :

Table 12-19: Conductor parameters for proposed supergrid

Voltage level		no of bundles	R (ohms/km)	L (mH/km)	X (Ω/km)	C (µF/km)	C (nF/km)	Thermal rating (MVA)	Zs ohms	SIL MW
330 kV	**DC**	**4**	**0.019**	0.7962	**0.25**	**0.014**	**14**	**2x1550**	**238.5**	**456**
500 kV	**SC**	**4**	**0.019**	0.8908	**0.2797**	**0.0127**	**12.7**	**2350**	**264.8**	**944**
750 kV	**SC**	**5**	**0.015**	0.9201	**0.2889**	**0.0123**	**12.3**	**4400**	**273.5**	**2057**

The cost comparison of supergrid options is shown in **Table 12-20**

Table 12-20: Cost comparison of supergrid options

Supergrid	Investment cost (m US$)
330 kV	1381
500 kV	1256
750 kV	1589

The comparison indicates that the 500 kV super grid will require the lower investment cost. However, the cost difference to 330 kV is relatively small.

The conclusions for the year 2030 and 2035 cases are the same. On the basis of technical considerations both the 330 and 500 kV options are adequate. Furthermore, taking into considerations that:

- Capacity of 330 kV supergrid lines: 3100 MVA
- Capacity of 500 kV supergrid lines: 2350 MVA
- Difference in losses between 330 and 500 kV supergrids: Marginal
- Impact on O/U voltages and overloads: Similar
- Higher static N-1 security of the 330 kV supergrid due to double circuit lines involved

It appears that the 330 kV supergrid system is technically the preferred option.

Considering that in terms of technical performance (MVA transmission capacity, losses, impact on U/O voltages and overloads as well as static security issues), as detailed in sections **7.9.4** and **7.10.3,** the 330 kV system appears to be more advantageous, its 10% higher investment cost could be justified.

In view of the above, it is apparent that more detailed studies are required to confirm the conclusions of this study.

It is therefore recommended to have these detailed studies carried out in due course and as soon as possible, before a final decision can be made on the selection of voltage level (330 kV or 500 kV) for a future super grid.

There is no justification to adopt and/or consider further any higher (750 kV) option for the EHV grid, particularly when the implications in cost differences are taken into account, as detailed in section 9. The higher transmission capacity (4400MVA) is not required at this stage and the marginal differences in losses cannot offset the high investment cost required in the planning horizon of this Master Plan.

The costs for 750 kV are considerably higher compared to 330 kV and 500 kV. The transmission capacity of a 330 kV double circuit line and a 500 kV single circuit line are 2350 and 3100 MVA respectively, compared to about 4400 MW for a 750 kV single circuit line. The network calculations (Chapter /7), however, indicated that a transmission capacity of the 330 kV and 500 kV supergrid system is sufficient.

12.6 Appraisal criteria for TCN network expansions

Each of the main 330 and 132 kV project has been appraised using the ENTSO-E methodology. As such the benefit of each project is assessed against a number of indicators ranging from technical and socio-economic issues to environmental impact.

The analysis has been performed for projects planned for implementation in the transmission network by 2025. Applying the ENTSO-E methodology, expected benefits where weighted and applied individually for each project. For this study, the projects were appraised against the following criteria:

Increase of Network Transfer Capacity, providing estimate of the incremental power transfer capacity between two points of transmission system (MW);

Social and Environmental Impacts, reflecting level of certainty with respect to the planned commissioning time of the project and its impacts on the environment;

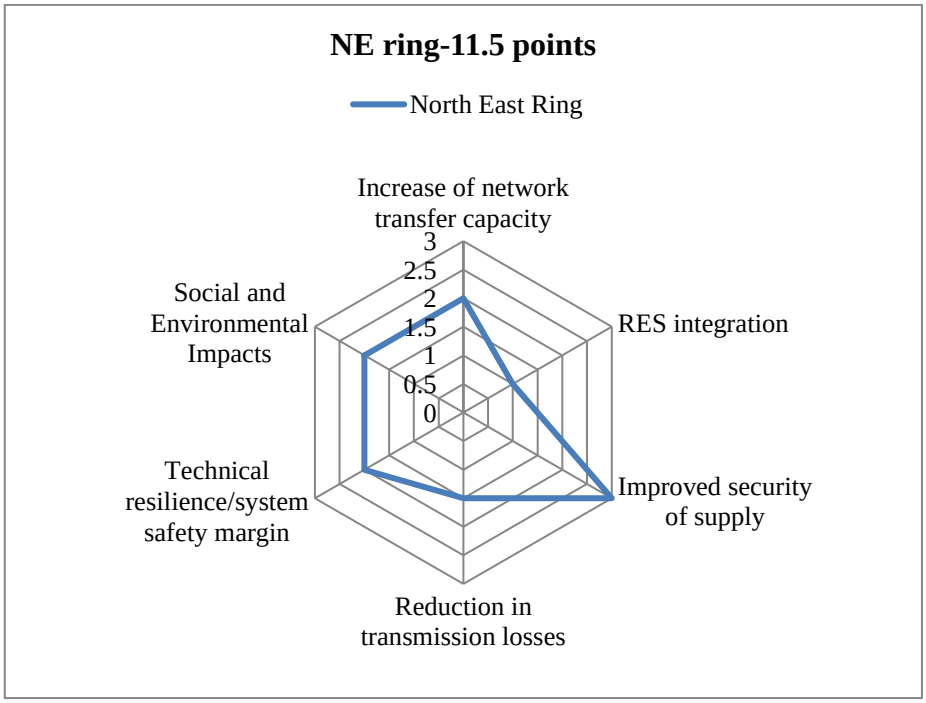
Security of Power Supply, evaluating project impact on reliability status of the connected part of the network;

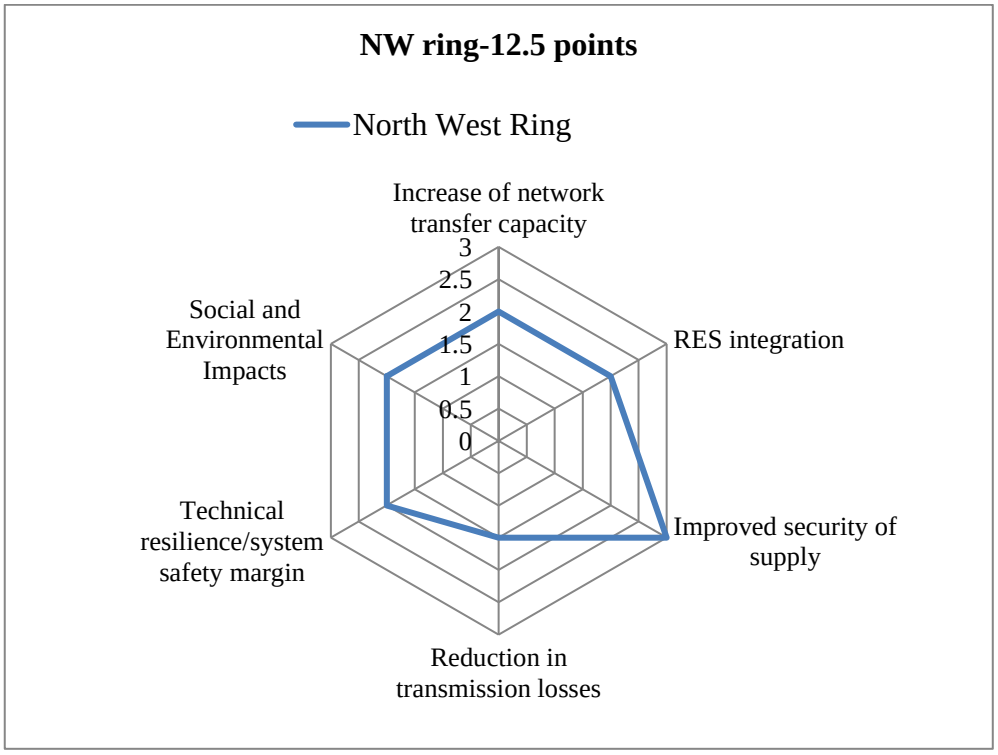
Integration of Renewable Energy Sources (RES), Support to RES integration is defined as the ability of the system to allow the connection of new RES plants and unlock existing and future "green" generation;

Effect on Transmission Losses (Energy Efficiency), comparing losses (in MWs) relevant to the scenarios with and without project (or its specific components);

Technical resilience / system safety margin, evaluating project influence on entire system reliability;

The radar format graphs of **Figure 12-1** show, as an example, the points scored by certain projects and hence their priority ranking:


NE ring-11.5 points
North East Ring
Increase of network transfer capacity
RES integration
Improved security of supply
Reduction in transmission losses
Technical resilience/system safety margin
Social and Environmental Impacts
3
2.5
2
1.5
1
0.5
0


NW ring-12.5 points
North West Ring
Increase of network transfer capacity
RES integration
Improved security of supply
Reduction in transmission losses
Technical resilience/system safety margin
Social and Environmental Impacts
3
2.5
2
1.5
1
0.5
0

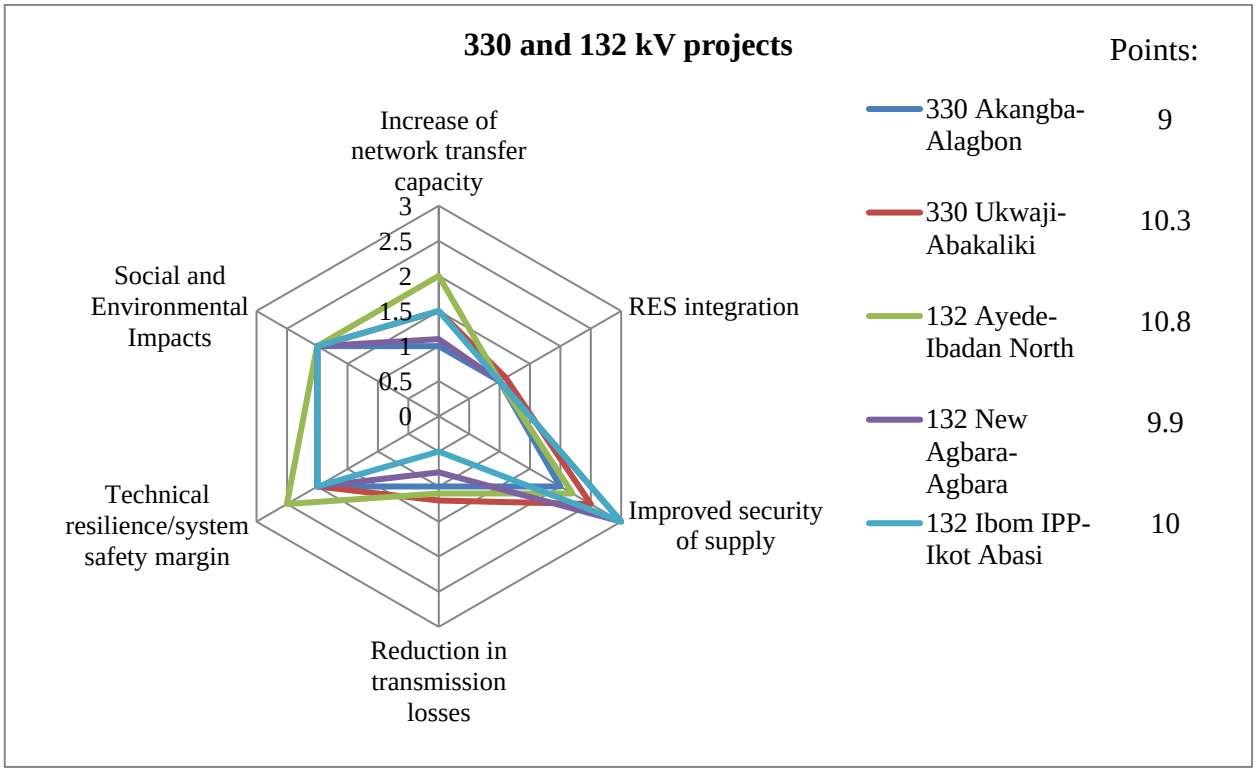


Figure 12-1: Project appraisal criteria and scores