CHAPTER 5 Primary Energy

Chapter 5 Primary Energy

5-1 Current State of Primary Energy in Nigeria

The current state of primary energy in Nigeria has been studied. The energy resources studied include fossil energy sources such as coal, crude oil, oil products, and natural gas as well as renewable energy including hydropower, solar, wind, biofuel, and waste. The data and information used as a base in the study are statistical data available from the International Energy Agency (IEA), Nigerian NNPC's Annual Statistical Bulletin (ASB), OPEC Annual Statistical Bulletin (ASB), and various publications related to energy from Nigerian governmental organizations. In addition, data available in publications from international study and research organizations are referred to as needed to supplement the study.

5-1-1 Overview

Table 5-1.1 and Table 5-1.2 show Nigeria's total energy balances and structure of sector-wise energy supply and consumption in 2015, respectively, based on the 2017 IEA Database. The resource columns for nuclear, heat and geothermal, solar, etc. included in the original balance table are omitted as they are either negligibly small or not applicable as of 2015.

The energy balance includes the following features.

- The IEA Energy Balance Table presents the state of energy production, energy supply, energy transformation, and total final consumption in the relevant year on a consistent basis for the whole country.
- The supply section indicates the production, import, and export balances of the Total Primary Energy Supply (TPES).
- The transformation section indicates energy balances of electric power plants, cogeneration plants, oil refineries, and others (including for coal and fuel wood transformation) as well as in-house use for those energy industries.
- The final consumption section indicates energy consumption for industry, transport, residential, commercial & public services, agriculture & forestry and fishery sectors as well as for non-specified sector and non-energy use. All numbers are expressed in million tons of oil equivalent (Mtoe: 10,000 Gcal/metric ton-LHV.).

Table 5-1.1 Energy Balance in Nigeria 2015

[Unit in Mtoe]

	Coal	Crude Oil	Oil Products[1]	Natural Gas	Hydro	Biofuel Waste	Electricity	Total
Production	0.03	106.49	0	35.68	0.49	111.57	0	254.26
Imports			10.43					10.43
Exports		-106.25	-0.12	-20.78				-127.15
International marine bunker			-0.37					-0.37

[1] Total gross oil products input: Import + Stock Change + Products from Oil Refineries = 13.00Mtoe

	Coal	Crude Oil	Oil Products[1]	Natural Gas	Hydro	Biofuel Waste	Electricity	Total
International aviation bunker			-0.36					-0.36
Stock changes		1.61	0.95					2.56
Total Primary Energy Supply (TPES)	0.03	1.86	10.53	14.90	0.49	111.57	0	139.38
Transfers		0.40	-0.35					0.05
Statistical difference				-0.87				-0.87
Transformation (incl. Energy industry own use)	0	2.25	-1.41	10.20	0.49	8.76	-2.16	18.13
Electric power plants		0	0	-5.63	-0.49		2.70	-3.33
CHP plants		0	0					0.00
Oil refineries		-1.76	1.62					-0.14
Other transformation		0	0.00			-8.76		-8.76
Energy industry own use		0	-0.17	-4.57			-0.09	-4.83
Losses		-0.49	-0.04				-0.45	-0.98
Total Final Consumption	0.03	0	11.59	3.94	0	102.80	2.16	120.52
Industry	0.03		0.43	2.56		4.15	0.36	7.50
Transport			8.43			0	0	8.43
Residential			0.54			95.88	1.24	97.66
Commercial & public services			0			2.77	0.56	3.33
Agriculture & forestry			0					0
Fishery			0					0
Other non-specified			2.16					2.16
Non-energy use			0.03	1.38				1.41
(Chemicals/petrochemicals)				(1.38)				(1.38)
Electricity generated - TWh				25.71	5.72			31.43

Source: IEA Database 2017

Notes: 1. Hydropower output is directly converted to tons of oil equivalent (1.0 GWh=86.0 toe)

2. Natural gas input is expressed in "Net", i.e. gross gas production less gas reinjected and flared.

Table 5-1.2 Constitution of Energy Supply and Consumption in 2015

	Coal %	Crude Oil %	Oil Products %	Natural Gas %	Hydro %	Biofuel Waste %	Electricity %	Total %
Production	0.0	41.9	0.0	14.0	0.2	43.9	0.0	100.0
Imports	0.0	0.0	100.0[2]	0.0	0.0	0.0	0.0	100.0
Exports	0.0	88.6	0.1	16.3	0.0	0.0	0.0	100.0
International marine bunker	0.0	0.0	100.0	0.0	0.0	0.0	0.0	100.0
International aviation bunker	0.0	0.0	100.0	0.0	0.0	0.0	0.0	100.0
Stock changes	0.0	62.9	37.1	0.0	0.0	0.0	0.0	100.0
Total Primary Energy Supply (TPES)	0.0	1.3	7.6	10.7	0.4	80.0	0.0	100.0
	Constitutions at Total Primary Energy Supply = 100 [Notes 2&3] [Note 4]							
	%	%	%	%	%	%	%	%
Transformation (incl. Energy industry own use)	0.0	121.0[3]	-10.8	68.5	100.0	7.9	0.0	13.0
Electric power plants	0.0	0.0	0.0	-37.8	-100.0	0.0	100.0	-2.5
CHP plants	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil refineries	0.0	-94.6	12.5	0.0	0.0	0.0	0.0	-0.1
Other transformation	0.0	0.0	0.0	0.0	0.0	-7.9	0.0	-6.3
Energy industry own use	0.0	0.0	-1.3	-30.7	0.0	0.0	-3.3	-3.5
Losses	0.0	-26.3	-0.3	0.0	0.0	0.0	-16.7	-0.7
Total Final Consumption	100.0	0.0	89.2	26.4	0.0	92.1	80.0	86.5

[2] For oil products, total gross input of oil products = 100 (See Note of Table 5-1.1 above)

[3] Transformation of crude oil is higher than 100%, as other feedstock is processed additionally

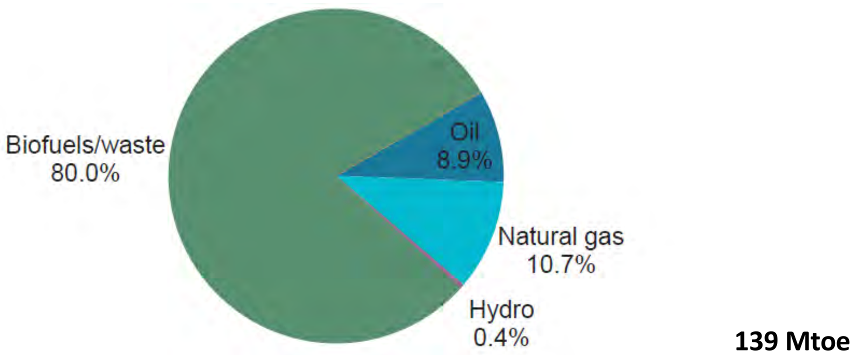
	Coal %	Crude Oil %	Oil Products %	Natural Gas %	Hydro %	Biofuel Waste %	Electricity %	Total %
Industry	100.0	0.0	3.3	17.2	0.0	3.7	13.3	5.4
Transport	0.0	0.0	64.8	0.0	0.0	0.0	0.0	6.0
Residential	0.0	0.0	4.2	0.0	0.0	85.9	45.9	70.1
Commercial & public services	0.0	0.0	0.0	0.0	0.0	2.5	20.7	2.4
Agriculture & forestry	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fishery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Non-specified	0.0	0.0	16.6	0.0	0.0	0.0	0.0	1.5
Non-energy use	0.0	0.0	0.2	9.3	0.0	0.0	0.0	1.0

Source: IEA Database 2017

(1) Features of the Energy Balance (TPES)

The most significant feature of the energy balance in Nigeria is that 80% of TPES is accounted for by a total of approx. 112 Mtoe of biofuel & waste, including municipal waste, fuel wood, agricultural crops residue, and livestock dung. No so-called biofuel like bio-ethanol, bio-diesel, etc. is produced in Nigeria at present. No breakdown of the IEA estimated energy supply from these resources is available in the database and a brief discussion of these resources is made in Section 5-1-6, “Renewable Energy”.

Next to biofuel & waste is natural gas (10.7%), followed by oil products (7.6%), crude oil (1.3%) and hydropower (0.4%). Coal accounts for a negligibly small percent (less than 0.1%). Figure 5-1.1 illustrates the share of primary energy supply in 2015.



Source: IEA Database 2017

Figure 5-1.1 Share of Total Energy Supply in 2015

(2) Constitution of Energy Consumption

Out of 35.7 Mtoe of natural gas produced, 58.2% of gas is exported either as LNG or pipeline gas and the remaining 60.7% is consumed within the country as detailed below.

Electric power plants	39.8%
Energy industry own use [4]	32.3%
Other industries	18.1%
Non-energy use[5]	9.8%

[4] For oil and gas production, treatment and handling facilities (NNPC facilities)
[5] For feedstock to chemical/petrochemical plants

Out of the 108.1 Mtoe of crude oil produced, including stock change of 1.6 Mtoe, 98.3% is exported and the remaining 1.7% is consumed in oil refineries to produce oil products. No crude oil is imported, though the import of foreign crude oil suitable for manufacture of lubes, waxes, and asphalt in the existing Kaduna Refinery is required. According to NNPC ASB 2015, the average utilization rate of the existing three old refineries with a total capacity of 445 KBCD was as devastatingly low as 5%, due to inadequate maintenance efforts and frequent vandalism attacks on oil pipelines.

Out of the 13.0 Mtoe gross oil products input consisting of imports (80.2%), stock change (7.3%), and products from refineries (12.5%), 6.5% is exported, 2.7% is used in oil refineries as blending stocks, 1.6% becomes fuel for the energy industry, 0.5% is loss, and the remaining 89.2% is routed to final consumers as detailed below. A great majority of consumption is accounted for by the transport sector. A brief discussion of oil products is found in Section 5-1-4, “Oil Products”.

Industry	3.7%
Transport	72.7%
Residential	4.7%
Non-specified	18.6%
Non-energy use (*1)	0.3%

(*1) For feedstock to chemical/petrochemical plants

Coal production in Nigeria was as low as 30 Ktoe in 2012, while no coal was imported. All domestically produced coal is used in the steel and cement industries.

Out of a total of 111.6 Mtoe of domestically produced biomass and waste, 7.9% is used for transformation (fuel wood to charcoal, etc.), and the remaining 92.1% is routed to final users; 6.8% for the industry sector, 2.8% for the commercial & public services sector, and the remaining 82.2% is used in the residential sector for cooking and heating.

5-1-2 Natural Gas

(1) Changes in Demand/Supply Balance 2003-2012

Table 5-1.3 presents the changes in demand and supply balances of natural gas in Nigeria from 2003 to 2012, based on information from the 2014 IEA Database. It should be be noted that IEA’s definition of “Production” is ”Net” deducting gas reinjected and flared from “Gross Raw Gas Production” as used in other major and international organizations’ statistical bulletins including those of OPEC, NNPC, and US EIA.

Table 5-1.3 Changes in Demand/Supply Balance of Natural Gas in Nigeria 2006-2015

[Unit in Mtoe]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	23.10	28.91	28.19	19.93	26.57	31.31	33.65	30.35	34.64	35.68
Exports	-13.66	-19.19	-19.17	-12.04	-17.75	-19.08	-21.03	-17.84	-20.37	-20.78
% Exports on production	59.1%	66.4%	68.0%	60.4%	66.8%	60.9%	62.5%	58.8%	58.8%	58.2%
Total Primary Energy Supply	9.44	9.72	9.02	7.89	8.82	12.23	12.61	12.51	14.27	14.90

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
(TPES)										
Statistical difference	0	0	0.02	0	-0.01	0.02	0	-0.13	-0.89	-0.87
Transformation (incl. Energy industry own use)	6.66	6.95	6.83	6.25	7.60	8.79	9.51	9.07	9.60	10.20
Electric power plants	-3.62	-3.60	-3.31	-3.28	-4.24	-4.55	-4.95	-5.06	-5.38	-5.63
Energy industry own use	-3.04	-3.35	-3.52	-2.97	-3.36	-4.24	-4.56	-4.01	-4.22	-4.57
Total Final Consumption	2.79	2.77	2.22	1.64	1.21	3.47	3.10	3.31	3.78	3.94
Industry	1.77	1.96	1.67	0.67	0.61	2.57	2.01	2.15	2.45	2.56
Non-energy use	1.02	0.81	0.55	0.97	0.60	0.90	1.09	1.16	1.33	1.38
Sector-wise Usage, % on TPES										
Electric power plants	38.3	37.0	36.7	41.6	48.1	37.2	39.3	40.4	37.7	37.8
Energy industry own use	32.2	34.5	39.0	37.6	38.1	34.7	36.2	32.1	29.6	30.7
Industry	18.8	20.2	18.5	8.5	6.9	21.0	15.9	17.2	17.2	17.2
Non-energy use	10.8	8.3	6.1	12.3	6.8	7.4	8.6	9.3	9.3	9.3
% (TPES - Energy industry own use) on production	27.7%	22.0%	19.5%	24.7%	20.5%	25.5%	23.9%	28.0%	29.0%	29.0%
NNPC ASB Database (Reference)										
Fuel gas to EPCL	0.18	0.22	0.18	0.19	0.12	0.22	0.36	0.19	0.41	0.36
% of total industrial use	10.3%	11.1%	10.6%	27.7%	19.7%	8.5%	17.7%	8.8%	16.7%	14.0%

Source: IEA Database 2017 and NNPC ASB 2006-2015

As can be observed in the above table, the net production rate of natural gas shows a steady increasing trend, except for a three-year period of decline between 2008 and 2010 (the lowest point being in 2009) due to the closure of the Soku gas-gathering plant as a result of vandalism in late 2008 and another dip due to the suspension of LNG exports for approximately 5 weeks in 2013. The most significant feature is that 58%-68% of net gas production has been routed to exports (less than 60% in 2006 and 2013-2015). Furthermore, natural gas routed to outside NNPC's upstream facilities, i.e. domestic markets including electric power plants was less than 25% from 2007 to 2012. However, it grew to the 28%-29% level after 2013.

The quantity of natural gas for fuel use (pipeline gas) routed to electric power plants shows a stable growth trend, except for a decline in 2009 and 2010, while the share of TPES (Total Primary Energy Supply) has remained within the 38% +/-1.5% range except for 2009, 2010 and 2013 when the share exceeded 40%.

There are similar trends in energy industry gas usage, but the level of the ups and downs is more significant. In 2009 and 2010, when Shell's Soku gas plant was suspended as described above, the quantity of gas sent to the industry decreased to 42% and 34% levels over that in 2017.

The natural gas used as feedstock for petrochemical plants (non-energy use) fluctuated over the period due to reasons that are currently unknown and its share of TPES was an average of approximately 9% over the 10-year period.

By the end of 2013, EPCL olefins complex located at Port Harcourt was the only petrochemical plant operating in Nigeria using natural gas origin feedstock (LPG/NGL).

As for the movements of non-energy use gas consumers, in mid-2014, a Chevron group company started small-scale production at a GTL (gas to liquid) plant to convert 325 Mcfd of natural gas into 33,200 bbl/d of synthetic diesel (source: US EIA 2015). As of the end of 2015, a large-scale ammonia-urea fertilizer plant was being constructed within the EPCL's site, and there are plans for other large-scale fertilizer projects using dry natural gas as feedstock.

Therefore, the demand for natural gas, both as feedstock and as fuel, is expected to increase rapidly in the near future depending on the time of completion of these projects.

(2) Records of Natural Gas Production and Utilization Based on NNPC ASB

According to notes in the IEA Database the main sources referred to for developing oil and gas related numbers are NNPC ASB and OPEC ASB. The data contained in NNPC ASB was used to conduct a brief analysis of natural gas aspects not covered by statistical data in the IEA Database, for example gross raw gas production, gas reinjected, and gas flared as well as the extent of concurrency of some selected production/consumption items between the two sources.

Table 5-1.4 summarizes the records of natural gas production and utilization from 2006 to 2015 that were acquired from the NNPC Annual Statistical Bulletin (2006-2015), while those ASBs up to NNPC ASB 2015 are open to public view on the NNPC Home Page.

Numbers 1 through 11 in the below table show the gas related data and number 12 shows crude oil production data based on NNPC sources. Numbers 13 through 18 present the results of preliminary assessments to confirm relations of the selected items between those in the NNPC ASB and the IEA Database (conducted by the JICA Study Team).

Table 5-1.5 presents a brief description of terms used in the NNPC ASB Data included in the applicable parts of Table 5-1.4.

Table 5-1.4 2006-2015 Natural Gas Production and Utilization in Nigeria (NNPC ASB)

[Unit: Bcf]

Item No	NNPC ASB Data	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
1	Raw gas produced	2,182	2,416	2,288	1,837	2,393	2,400	2,580	2.326	2,486	2,930
2	Gas used as fuel	77	77	84	81	72	105	116	129	151	159
3	Gas sold to 3rd parties	630	761	708	441	857	787	876	607	705	1,017
4	Gas sold to NGC	0	0	64	21	21	102	72	130	178	134
5	Gas reinjected	334	355	391	410	493	348	463	639	626	728
6	Fuel gas to EPCL	8	9	8	8	5	9	15	9	11	11
7	Gas for LPG/NGL to EPCL	44	35	24	42	26	39	47	56	36	42
8	Gas for LNG	241	369	332	269	167	313	330	301	391	421
9	Gas lift	45	51	59	56	169	79	73	47	102	77
10	Gas flared	804	760	619	509	582	619	589	409	286	341
	% Gas flared	36.8	31.4	27.1	27.7	24.3	25.8	22.8	17.6	11.5	11.6
11	EOR use (Sum items 5 & 9)	379	406	450	466	662	427	536	685	727	805
	% Total raw gas produced	17.4%	16.8%	19.7%	25.4%	27.7%	17.8%	20.8%	29.5	29.3	27.5
12	Crude oil produced, Mbbl	869	803	769	780	896	866	853	801	799	774
	GOR, Kcf/bbl- crude oil	2.51	3.01	2.98	2.35	2.67	2.77	3.03	2.91	3.11	3.79

Item No	NNPC ASB Data	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
	IEA Database converted from Mtoe to Bcf @ Gas HHV of 1,020 BTU/cf)[6]										
13	Production based on IEA database [A]	999	1,250	1,219	862	1,149	1,354	1,455	1,312	1.497	1,542
	NNPC (Item 1) - (Items 10& 11) [B]	1,000	1,250	1,218	862	1,149	1,354	1,456	1,231	1,473	1,784
	Ratio: [A]/[B]	0.999	1.000	1.000	1.000	1.000	1.000	0.999	1.066	1.017	0.865
14	Exports	591	830	829	520	767	825	909	771	881	898
15	Electric power plants	156	156	152	142	195	209	228	219	233	243
16	Energy industry own use	131	145	162	128	155	195	210	173	182	198
17	Industry	77	85	77	29	28	118	93	93	106	111
18	Non-energy use [C]	44	35	24	42	26	39	47	50	57	60
	NNPC Item 7 [D]	44	35	24	42	26	39	47	56	36	42
	Ratio: [C]/[D]	0.993	1.000	1.007	0.989	1.001	1.008	0.998	0.894	1.606	1.424

Source: NNPC Annual Statistical Bulletin 2003-2012 for items 1 through 11. IEA Database for items 13 through 17

Table 5-1.5 Brief Description of Terms used in Table 5-1.4

Item No.	Description	Additional Description of Terms in Brief
1	Raw gas produced	Gross gas produced before deducting gas used for reinjection
2	Gas used as fuel	Gas used as fuel for operating upstream facilities up to the delivery of crude oil and dry gas, etc.
3	Gas sold to 3rd party	Gas sold to a 3rd party including LNG plants
4	Gas sold to NGC	Gas sold to NGC (Company responsible to transport dry gas to users via a pipelines system)
5	Gas reinjected	Gas re-injected to marginal or pressure decreased oil wells for EOR (Enhanced Oil Recovery)
6	Fuel gas to EPCL	Fuel gas sent to EPCL (Petrochemical company)
7	Gas for LPG/NGL to EPCL	Gas lost in volume for recovery of LPG/NGL to be used in EPCL's petrochemical plant
8	Gas for LNG	Gas sent for LNG production
9	Gas lift	Gas used basically the same as gas re-injection, but gas is injected to transfer lines to degassing station to improve fluidity of oil in pipeline by reducing viscosity (the gas used comes back with oil)
10	Gas flared	Total volume of gas flared due to any reasons. Among other things, the great majority of associated gas forced to flaring come from the lack of required provisions, at degassing stations, for collecting and delivering gas to downstream gas processing facilities.
11	Gas for EOR use	Gas reinjected plus gas lift
12	Crude oil produced	Total crude oil produced

The main observations from the data in Table 5-1.4 are as follows:

a) Raw gas produced: In 2007, the gas production rate reached its first peak. After that gas production rates show an overall growing trend, while repeating decreasing and increasing trends until 2015. The production rate in 2015 is 1.6 times higher than that in 2006, which is equivalent to an average annual growth rate of 4.8%.

b) Crude oil produced: The first production peak was in 2006 at 869 Mbbl. After that, oil production repeatedly increased and decreased, with production at its lowest in 2008 before a new low was reached in 2015. The production rate in 2015 was 0.92 times lower than that in 2006, which is equivalent to an average annual growth rate of -0.9%. No meaningful relation was found between

[6] Definition of Production in IEA Database: (Gross production) - (Reinjection) - (Flared)

gas and oil production rates or production trends, except the increased GOR (Gas to Oil Ratio), which suggests that the percentage of gas produced from gas fields (Non-associated gas) of total raw gas produced was certainly increasing.

c) Gas re-injected plus gas lift: Although there are some small drops which depart from an otherwise consistently growing curve of gas reinjection rates, the overall growth trend is strong. The total injected gas of 379 Bcf (17.4% of total raw gas produced) in 2006 increased to 805 Bcf (27.5% of total raw gas produced) in 2015.

d) Gas flared: A steadily decreasing trend can be seen with some minor departures. 804 Bcf (36.8% of total raw gas produced) during the peak of flaring in 2006 improved to 341 Bcf (11.6% of total gas produced) in 2015.

e) IEA Database versus NNPC ASB Database: Among those production and consumption items include in the two databases, the following two can be compared directly.

IEA Database	NNPC ASB Database
Production	(Raw gas produced)– (Gas flared) – (Reinjection + Gas lift)
Non-energy use	Gas for LPG/NGL to EPCL

f) The methodology used is to first convert IEA data expressed in Mtoe into Bcf at the IEA default value for dry gas HHV of 1,020 BTU/CF (38.0 TJ/million m^3), and then to acquire the ratios of two series of data from the two different databases.

g) The results of ratio comparisons have proved that all of the ratios in 2006 to 2012 fall within the acceptable departure range from the average ratio of 1.000. What this means is that the source of gas related data in the IEA Database is the NNPC ASB and based on the standard gas HHV of 1,020 BTU/CF. Therefore, combined and comparative use of the two databases should have a certain level of viability.

h) In 2013 to 2015, however, significant departures were found between the two data sources related to gas production and consumption. These departures are due to the fact that IEA has changed either the referenced data source or the method of data treatment. Therefore, care should be taken when evaluating the trends from 2006 to 2015.

On the other hand, the related notes in the IEA Database state that the OPEC ASB is also referred to. Therefore, a comparison has been conducted between the two data sources related to net gas production (marketed production according to the OPEC definition) rates and gas exports. The results of this comparison are summarized in Table 5-1.6.

Table 5-1.6 Comparison of Key Data Related to Natural Gas Production and Exports 2006-2015 [OPEC ASB versus IEA Database]

[Unit:Bcf]

Item No		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10-year Average
	OPEC ASB Data [A]											
1	Gross gas production	2,182	2,416	2,565	2,003	2,534	2,967	2,996	2,812	3,049	3,010	
2	Marketed production	1,006	1,148	1,159	820	992	1,459	1,503	1,356	1,548	1,594	1,258.7
3	Flaring	788	788	674	471	540	504	466	428	379	342	
4	Re-injection	318	353	509	503	752	795	725	758	809	743	
5	Shrinkage	71	127	223	210	250	208	303	270	313	330	
6	Export (Part of Item 2)	621	773	726	565	835	916	998	867	946	923	817.0
	IEA Database [B]											
2	Marketed production	999	1,250	1,219	862	1,149	1,354	1,455	1,312	1,498	1,542	1,263.7
	[B]/[A] Ratio	0.992	1.089	1.051	1.051	1.157	0.927	0.968	0.967	0.967	0.967	1.004
6	Export (Part of Item 2)	591	830	829	521	767	825	909	771	881	898	782.1
	[B]/[A] Ratio	0.951	1.073	1.142	0.922	0.919	0.900	0.911	0.890	0.931	0.973	0.957

The following can be gathered from the table above.

- As an average for the 10-year period, the departure between the two data sources are not significant, for example, net gas production and exports differ by 0.4% and 4.3%, respectively. However, for the respective years, the departures are significant as IEA data fluctuate between +15.7%/-3.3% and +14.3%/-10.0% compared to OPEC data for the net production rate and gas exports, respectively.
- As no meaningful relation between the two data sources is found, it is clear that the IEA database did not refer to OPEC data, at least not for the period of 2006 to 2012. Meanwhile, for the period of 2013 to 2015, net gas production rates were constantly 0.957 times lower than that of OPEC data and it is considered probable that, after 2013, IEA stopped referring to NNPC ASB data and instead started referring to OPEC ASB to some degree.

As international research organizations engaged in providing energy related statistics use their own procedures and the same or different data sources, it is quite possible that individual numbers would differ from each other within a +/-10%-20% range. Taking into account such situations, the subsequent discussions are carried out using IEA data as the base.

(3) Gas Infrastructure for Domestic Market

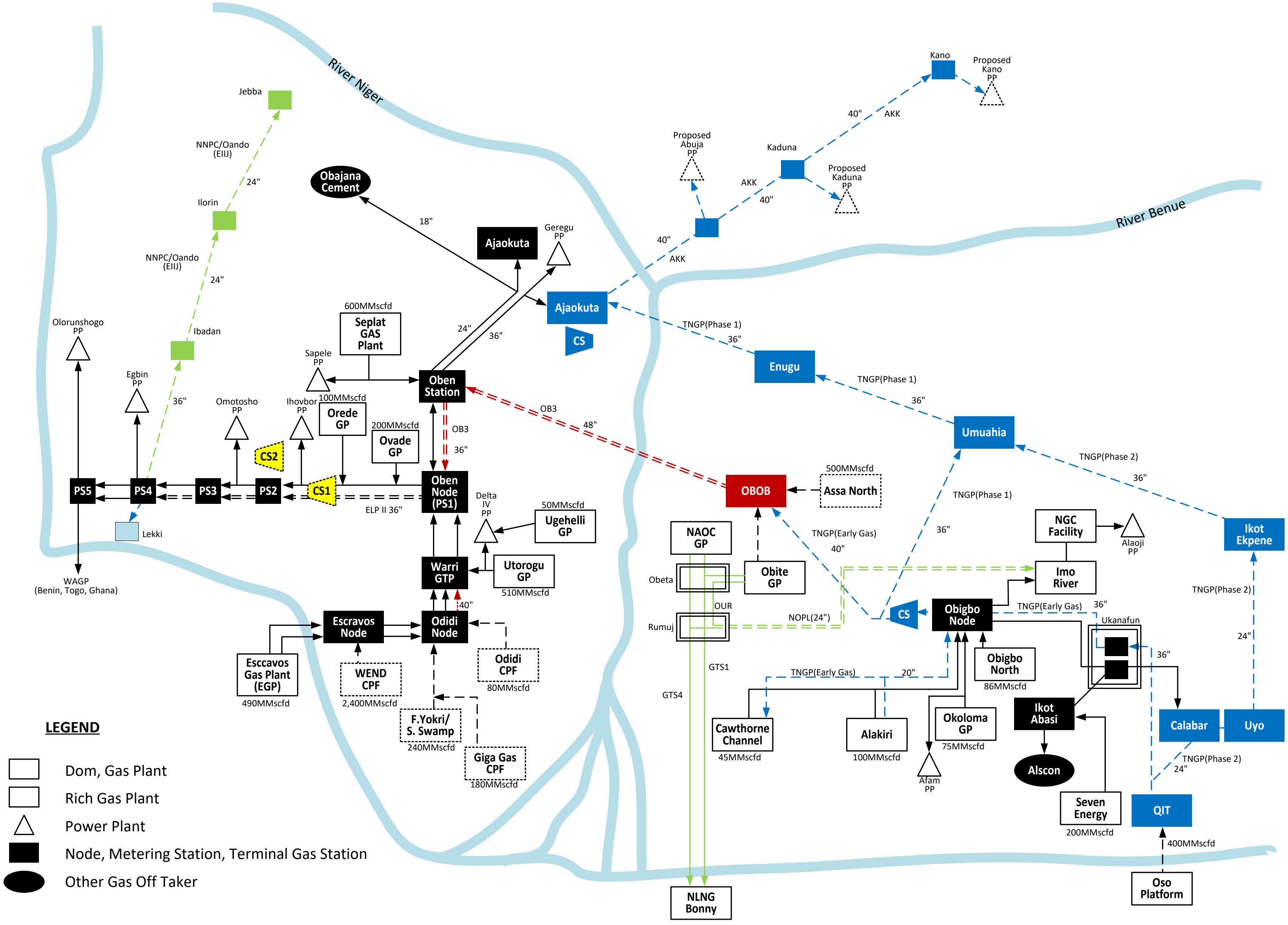
The key gas infrastructure that makes it possible to supply adequate gas for domestic users including electric power plants, industries, and natural gas-based chemical/petrochemical plants either as fuel or feedstock are countrywide dry gas pipeline systems and gas plants.

The present status and outlook for these two key aspects in the near future in Nigeria are described below, based on the information contained in Figure 5-1.2," Simplified Schematic of Major Existing and

Planned Gas Infrastructure" and Figure 5-1.3, "Map of Proposed Trans-Nigeria Gas Pipelines"

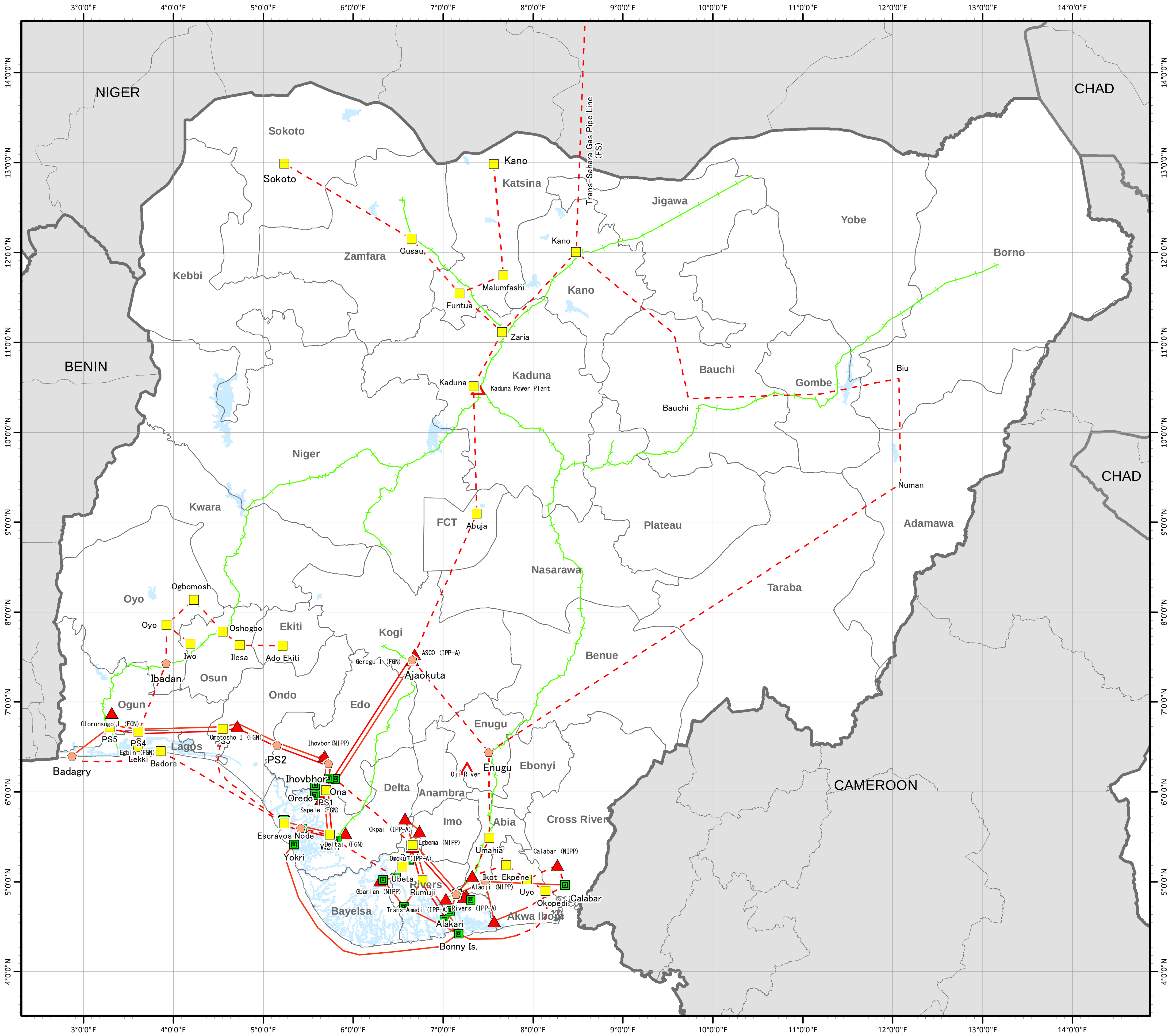
The source of Figure 5-1.2 is NNPC, and it shows the major existing and planned gas pipeline systems and gas plants as well as major pipeline gas consumers. NNPC advised that the planned pipelines and gas plants shown in the schematic are scheduled to be completed by around 2020.

The source of Figure 5-1.3 is the "Gas & Power Infrastructure Map of Nigeria 2015" prepared by Petroleum Economist for NNPC and it includes information on the proposed routes of Trans-Nigeria Gas Pipelines.



Source: NNPC

Figure 5-1.2 Simplified Schematic of Major Existing and Planned Gas Infrastructure



LEGEND

- Thermal Power Plant (Existing)
- Thermal Power Plant (Underconstruction / Plan)
- Pipeline Pigging Station
- Pipeline Compressor Station
- Gas Processing Plant
- Gas Pipeline (Only related to power plant)
- Gas Pipeline Plan, UC, Proposed
- Railway

Existing Thermal Power Plant

S/N	Point	Power Plant	Site Location	Available(MW)
1	G1	Egbin (FGN)	Lagos	941.00
2	G2	Olorunsogo I (FGN)	Ogun	277.00
3	G3	Olorunsogo II (NIPP)	Ogun	260.00
4	G4	AES (IPP-A)	Lagos	175.00
5	G5	Omotosho I (FGN)	Ondo	280.00
6	G6	Omotosho II (NIPP)	Ondo	306.00
7	G7	Delta (FGN)	Delta	463.00
8	G8	Sapele (FGN)	Edo	219.00
9	G9	Sapele (NIPP)	Edo	184.00
10	G10	Geregu I (FGN)	Kogi	328.00
11	G11	Geregu II (NIPP)	Kogi	159.00
12	G12	Ihovbor (NIPP)	Edo	374.00
13	G13	ASCO (IPP-A)	Kogi	0.00
14	G14	Afam (IV&V) (FGN)	Rivers	3.00
15	G15	Afam(VI) (IPP-A)	Rivers	587.00
16	G16	Alaoji (NIPP)	Abia	158.00
17	G17	Omoku (IPP-A)	Rivers	0.00
18	G18	Omoku II (NIPP)	Rivers	0.00
19	G19	Egbema (NIPP)	Imo	0.00
20	G20	Rivers (IPP-A)	Rivers	0.00
21	G21	Trans-Amadi (IPP-A)	Rivers	0.00
22	G22	Calabar (NIPP)	Cross River	234.00
23	G23	Okpai (IPP-A)	Delta	230.00
24	G24	Ibom (IPP-A)	Akwa Ibom	91.00
25	G25	Gbarian (NIPP)	Bayelsa	0.00
			Total	5,269.00

Under Construction Thermal Poewr Plant

No.	Point	Power Plant	Site Location	Output(MW)
1	U-1	Kaduna Power Plant	Kaduna	

[Note]
Available shows Capacity as of the end of 2015

100 50 0 100km
1:5,000,000
Only if A3

Coordinate System: GCS WGS 1984
Geodetic Reference System: WGS 1984
Unit: Degree

Location of Thermal Power Development

17 MARCH 2016

Figure 5-1.3 Map of Proposed Trans-Nigeria Gas Pipelines

1) Locations of Major Natural Gas Production and Consumption Centers

In Nigeria, most gas and oil fields are located in the Niger Delta (in the geo-political regions of South-Eastern, Rivers, and Mid-Western) and offshore, while major consumption centers are, in addition to those located in the Niger Delta and its vicinity, located far away from the Niger Delta, especially in the geopolitical regions of Western Nigeria and Lagos.

In the Northern Region of Nigeria, two gas turbine power plants and one cement plant in Koji State located at the southern-end of the region are presently operating using natural gas to a limited extent, but no other power plants or industries using natural gas are operating in the rest of the Region due to the lack of access to gas. Meanwhile, multiple large-scale IPP power plant projects are at the tendering stage for construction and another IPP power plant project as well as an industry project using natural gas could soon be realized. As such, the Northern Region will also become a new gas consumption center in the near future.

2) Existing Gas Pipeline Network

The existing gas pipeline network in Nigeria comprises three systems, namely, the Western, Eastern and Northern network systems. The areas covered by these systems basically correspond to the oldest geopolitical regions effective in 1960-1963. The former two occupy the southern part of Nigeria, approximately one fourth of the country's whole land area, and the latter occupies the remaining three-fourths.

The Western network system has the 36-inch ELP1 (Escravos-Lagos Pipeline No.1) at its center to supply natural gas to the users in Western Region. Escravos, the starting point of ELP1, is located in the Niger Delta (in the Eastern Region) and west of the Niger River.

The Southern network system covers the users in the east half of the Eastern Region east of the Niger River, where a number of power plants, petrochemical plants, and LNG plants are operating.

The Northern network system is considering covering the users in the great Northern Region, but only up to Ajaokuta in Koji State from Oben Station in the Western network system.

At present, there is no pipeline connection from the Southern network system to the Western and Northern network systems.

Nigeria Gas Company (NGC, a subsidiary of NNPC) is responsible for operation and maintenance (O&M) of the above pipeline network systems. Table 5-1.7 presents a list of the existing major gas pipelines operated by NGC as of 2014.

Table 5-1.7 Existing Main Gas Pipelines Operated by NGC in 2014

Connection from/to	Length [mile]	Length [km]	Size [inch]
Warri/Egbin node (PS4)	214	344	30
Oben/Geregu (PHCN)	123	198	20/24
Oben/Ajaokuta	123	198	24
Alakini/Ikot-Abasi (ALSCON)	73	117	24
Ikpe Anang/EHGC (UNICEM)	67	108	24
Aladja pipeline system/Aladja	65	105	6,8,14,16
Kew metal/Ogilo	63	101	6
Ajaokuta/Obajana	56	90	18
Escrabos/WGTP	36	58	36
WGTP/WRPC	36	58	36
Alagbado/Ota--Agbara distribution (SNG)	25	40	24
Alagbado/Ota--Agbara distribution (SNG)	25	40	24
KP 331/Itoki	25	40	24
Int scraper station/Ikot-Abasi (ALSCON)	23	37	24
Utorogo/Ugheli (PHCN)	22	35	18
Oben/Sapele (PHCN)	22	35	18
PS 4 Itoki /Ibese	21	34	18
Imo river/Aba (SPDC)	20	32	12
Ewekoro/Abeokuta (GOZ)	20	32	18
Ewekoro/Abeokuta (GOZ)	20	32	18
Alagbado/Ewekoro (WAPCO)	17	27	6
Total	1,096	1,763	

Source: OPEC ASB 2015

3) Existing and Planned Gas Plants

Table 5-1.8 presents a list of existing and planned major gas plants in Nigeria as of 2015. As this list has been prepared based on the information contained in Figure 5-1.2, there should actually be more gas plants and more capacity, including those gas plants dedicated to the existing LNG plant in Bonny such as Soku (1,100 Mcfd), Gbaran Ube (1,000 Mcfd), Ob-Ob (1,000 Mcfd), Oben (300 Mcfd) and Bonny (450 Mcfd) (source: Wikipedia).

Table 5-1.8 Capacity of Existing and Planned Major Gas Processing Plants in Nigeria

Name of Gas Plant	Capacity[Mcfd]	Location[7]
1. Existing Plants:		
1) Seven Energy	200	[1]
2) Okolomo GP	25	[1]
3) Obigbo North	56	[1]
4) Alakus	100	[1]
5) Carthorne Channel	45	[1]
6) Ugheli	50	[2]
7) Utorogu	510	[2]
8) Escravos Gas Plant (EGP)	490	[2]
9) Obade GP	200	[2]
10) Oredo GP	100	[2]
11) Sapele Gas Plant	600	[2]
Subtotal Existing Plants	2,376	
2. Planned Plants:		
1) OSO Platform[8]	400	[1]
2) Assa North GP	500	[1]

[7] Gas plant locations; [1] East of Niger River, [2] West of Niger River
[8] Located offshore and existing, but presently no connection to the onshore domestic gas pipeline system

Name of Gas Plant	Capacity[Mcfd]	Location[7]
3) Odidi GP	80	[2]
4) Giga Gas CPF	180	[2]
5) F. Yokiri/S. Swamp	240	[2]
6) WEND CPF	2,400	[2]
Subtotal Planned Plants	3,800	

Source: NNPC

There are a total of 11 existing gas plants with 2,376 Mcfd in capacity, of which 5 with 326 Mcfd in capacity are located west of the Niger River.

Meanwhile, there are a total of 6 planned gas plants with a combined capacity of 3,800 Mcfd, of which 2 with a capacity of 900 Mcfd are located east of the Niger River. The total dry gas production capacity after expansion will reach 6,176 Mcfd (approx. 5,250 Mcfd at 85% utilization factor) or 2.6 times the existing capacity.

4) Pipeline Network Expansion Plan

Based on the schematic shown in Figure 5-1.2 and NNPC slides presented in the India-African Hydrocarbon Conference in New Delhi (January 2016), the intention of expansion plans and their present progress are understood as follows.

a) 36" ELP2 (Escravos-Lagos Pipeline system No.2) and EIIJ (Egbin-Ibadan-Ilorin-Jebba pipeline system)
   Intent: To double gas transport capacity for the Lagos area and extend the gas supply network to the north up to Jebba (Kwara State)
   Status: The project is on-going with an expected completion in the 1st quarter, 2016

b) 48" Ob3 Pipeline (Ob/Ob-Oben pipeline system)
   Intent: To supply gas produced within the territory of Eastern Network system to the Western Network system
   Status: The project is on-going with an expected completion in 2017

c) 36" TNGP [Phase 1] (A section of Trans-Nigerian Gas Pipeline system; Obigbo-Umuahia -Enugu -Ajaokuta pipeline system)
   Intent: To supply gas produced within the territory of Eastern Network system to the Northern Network system
   Status: The project is at the tender for EPC stage with an expected completion in early 2019.

d) 40" AKK (A section of Trans-Nigerian Gas Pipeline system; Ajaokuta-Kaduna-Kano pipeline system)
   Intent: To extend gas supply in the Northern Network system far central north up to Kano
   Status: The project is at the tender for EPC stage with an expected completion in early 2019.

e) 36"/40" TNGP[Early Gas] (A section of Trans-Nigerian Gas Pipeline system; Oso – Obigbo-Ob/Ob pipeline system)

Intent: To supply gas produced within the territory of the Eastern network system to the Western and Northern network systems

Status: The project is at the tender for EPC stage with expected completion in early 2019.

f) 24”/36” TNGP [Phase 2] (A section of Trans-Nigerian Gas Pipeline system)

Intent: To further increase capability to supply gas produced within the territory of Eastern Network system to the Western and Northern network systems

Status: The project is at the preparatory stage of tender for EPC with expected completion unknown at present but presumed to be in the early 2020’s.

The completion of the expansion works described above will establish, by early the 2020’s, the first-stage full dress Northern Pipeline system as well as doubled gas transport capability for the Western Pipeline system and for gas produced within the territory of the Eastern Network system to the other two network systems.

5) Trans Nigeria Gas Pipeline System

Nigeria has been involved in the ambitious Trans-Saharan Gas Pipeline (TSGP) project since its first proposal in the early 1970’s, in which Warri near Escravos was nominated as the Nigerian starting point of TSGP (ending at Hassi R’Mel in Algeria). In Nigeria, the planned TSGP runs toward the north from Warri to the border of Niger via Abuja and Kano.

The original plan for the Trans-Nigeria Gas Pipeline (TNGP), existing since the early 1990’s, had two large loop pipelines covering the whole country, using the Warri-Abuja-Kano pipeline of the TSGP as the center pole. Figure 5-1.3 is the developed version of the original TNGP plan and only the eastern loop, i.e. Ajaokuta-Enugu-Biu-Kano pipeline is still being considered. The western loop no longer has a looped shape as the pipeline section between Jebba and Sokoto has been abandoned.

When all of the present Pipeline Network Expansion projects described in Paragraph 4) above have been completed in early the 2020’s, approximately two thirds of the total TNGP systems will be considered as achieved while a part of the eastern loop (Enugu-Biu-Kano sections) and the branched pipeline sections towards Sokoto and surrounding cities in the North-Western Region are left intact.

It is not an unrealistic assumption that most of the remaining sections of TNGP will be completed by 2030 and almost all population centers in the Northern Region will have access to natural gas.

(4) Natural Gas Reserves

According to BP Statistical Review of World Energy (2014), at the end of 2013, the proven reserve of natural gas including associated and non-associated gas is approximately 180 Tcf and the R/P ratio is in excess of 100 years. As the volume of proven reserves has remained unchanged for the last 10 years, this suggests that the finding of new reserves corresponds to the production that took place in this period.

According to a paper about NNPC (published around 2005), USGS’s estimate of Nigeria’s ultimate natural gas reserve, based on its satellite-based survey, was 600 Tcf. According to the several talks conducted with people involved in energy in Nigeria, the major concerns regarding natural gas are gas infrastructure development, costs of natural gas development, and how much IOCs would wish to invest rather than concern about the natural gas reserve itself.

Table 5-1.9 below shows Nigeria's long-term development targets for the proven reserve and production facilities of natural gas described in "National Integrated Infrastructure Master Plan, 2015".

Table 5-1.9 Targets for Proven Reserves and Production Capacity of Natural Gas

	Current	2023	2033	2043
Proven reserve - Gas, Tcf	187	191.5	-	200
Production capacity - Gas, Mcfpd	8,000	11,000	15,000	30,000

Source: NNPC GID 2016

5-1-3 LNG

(1) Natural Gas (LNG and Pipeline Gas) Exports

Nigeria's LNG exports started from the end of 1999, and all of the natural gas exports have been LNG until pipeline gas was exported to Ghana via the West Africa Gas Pipeline (WAGP) starting from 2010.

A full series of LNG export data expressed in weight covering the period 2006 to 2015 could not be found. Therefore, the JICA Study Team tried to estimate the changes in natural gas exports, either by LNG or pipeline gas, using the following data and assumptions.

- OPEC Database for total natural gas exports in 2006 to 2015
- International Gas Union (IGU) World LNG Report 2016, as referenced in Nigeria's LNG export data for 2011 to 2015 expressed in million tons
- A report, "Assessing WAGP intervention in Ghana's gas supply", by "Reporting Oil and Gas" on 2015-01-13 for pipeline gas exports to Ghana from 2010 to 2013. The realized gas exports were far lower than its target of 48 Bcf per annum.
- Gas exported as LNG: Total gas export less gas export via WAGP
- Conversion factor of natural gas (in volume) to LNG (in weight): IGU's conversion factor is as follows:

  1.0ton LNG=1,300 m^3 Gas or $45.91 x 10^3$ ft^3
- Average year-end capacity of the existing LNG plant: It is defined as an average of the previous and present year-end capacities. Refer to Table 5-1.11 for the year--end cumulative capacities of the existing LNG plant.
- LNG plant utilization rate: Percentage of LNG export in weight over the average year-end capacity of LNG plant

The results of estimates are summarized in Table 5-1.10.

Table 5-1.10 Natural Gas (LNG & Pipeline Gas) Exports 2006-2015 (Estimated value)

	Total Gas Export (OPEC)	Gas Export via WAGP	Gas Export as LNG	LNG Exports (OPEC)	LNG Exports (IGU)	Average LNG Plant Capacity	LNG Plant Utilization Rate
	[Bcf]	[Bcf]	[Bcf]	[M tons]	[M tons]	[M tons/Y]	[%]
2006	621	0	621	13.53	-	15.00	90.2
2007	723	0	723	15.75	-	17.05	92.4
2008	726	0	726	15.81	-	19.10	82.8
2009	565	0	565	12.31	-	21.15	58.2
2010	835	13	822	17.90	-	21.15	84.6
2011	888	28	860	18.73	18.75	21.15	88.6
2012	983	15	968	21.08	19.95	21.15	99.7
2013	850	17	833	18.14	16.89	21.15	85.8
2014	926	(17)	909	19.80	19.37	21.15	93.6
2015	907	(17)	890	19.98	20.36	21.15	94.5
2011-2015 Average			892	OPEC 19.43	IGU 19.06	OPEC/IGU 1.019	

Source: JICA Study Team

The following can be observed from the results of the study presented in Table 5-1.10 above.

- The estimated operating rates over the yearly average nameplate capacity of the existing LNG plant were generally as high as more than 90% except the following two periods.
- In 2008-2010, the estimated operating rates declined below the 90% level with a bottom of approx. 60% in 2009, due to a shortage of gas supply resulting from the shutdown of Shell's gas plant in the same period.
- In 2013, the estimated operating rate declined to the approximately 86% level due to stoppage of LNG export for approximately 5 weeks.
- During 2006-2015, LNG exports occupied 97%-100% of total gas exports. Even when the target gas exports to Ghana of 48Bcf per annum via WAGP were achieved from 2011, the share of pipeline gas exports would not exceed 6% level in 2011-2015.

(2) Existing and Planned LNG Plants in Nigeria

Table 5-1.11 presents a list of installed capacity of existing and proposed LNG plants in Nigeria. The existing LNG plant comprises six (6) trains with a total capacity of little over 21 million tons per annum. All of the existing plants are owned and operated by NLNG.

Table 5-1.11 Installed capacity of Existing and Planned LNG Plants in Nigeria

	Start-up Year	No. of Train	Capacity per Train [Mmt/Y]	Total Capacity [Mmt/Y]	Cumulative Capacity [Mmt/Y]
Existing Plants:					
NLNG Train 1 & 2	1999	2	2.95	5.90	5.90
NLNG Train 3	2002	1	2.95	2.95	8.85
NLNG Train 4	2005	1	4.10	4.10	12.95
MLNG Train 5	2006	1	4.10	4.10	17.05
NLNG Train 6	2008	1	4.10	4.10	21.15
Existing plants -Total		6		21.15	21.15
Proposed Plants:					
NLNG Seven plus	2018	1	8.40	8.40	
NLNG Train 8	2019	1	8.00	8.00	

	Start-up Year	No. of Train	Capacity per Train [Mmt/Y]	Total Capacity [Mmt/Y]	Cumulative Capacity [Mmt/Y]
Progress FLNG	2018	1	1.50	1.50	
OK LNG	2016+	2	6.30	12.60	
Brass LNG	2020	2	5.00	10.00	
Proposed Plants- Total		7		40.50	

Source: Gas and Power Infrastructure Map of Nigeria, Petroleum Economist

There are five (5) proposed LNG projects with a total of 7 trains and a little over 40 million tons per annum of total capacity, in other words, nearly double the capacity of the existing one.

5-1-4 Oil Products

In the IEA Database, the detailed balances of crude oil and oil products are expressed only in weight (tons) while energy balances are expressed in tons of oil equivalent (toe).

In converting tons to toe, the IEA Database uses a conversion coefficient of 1.0 for crude oil and NGL, then they are listed together as crude oil in the energy balance table. Similarly, country specific conversion factors are used for the respective oil products, which are then all listed together as oil products in the energy balance table.

(1) Crude Oil and Oil Products Balances in Nigeria in 2015 (in weight)

Table 5-1.12 presents crude oil and oil products balances in Nigeria in 2015 expressed in weight (tons).

Table 5-1.12 Crude Oil and Oil Products Balances in Nigeria in 2015 (in weight)

Unit: Million metric tons

	Crude Oil	NGL	Refinery Feedstock	LPG	Motor Gasoline	Jet Kerosene	Other Kerosene	Gas Oil/ Diesel	Fuel Oil
Production	103.13	1.18		0.03	0.26	0.02	0.19	0.30	0.40
Imports					7.11	0.32	2.37		
Exports	-102.9	-1.18							-0.09
International marine bunker								-0.12	-0.26
International aviation bunker						-0.34			
Stock changes	1.58				0.00			0.36	0.52
Total Primary Energy Supply (TPES)	1.82	0.00	0.00	0.03	7.37	0.00	2.56	0.54	0.57
Transfers			0.37						
Statistical difference									
Transformation (incl. Energy industry own use)	1.82		0.37	0.01				0.01	0.12
Electric power plants									
CHP plants									
Oil refineries	1.34		0.37						
Other transformation									
Energy industry own use				0.01				0.02	0.12
Losses	0.48								
Total Final Consumption				0.02	7.37	0.00	2.56	0.53	0.45
Industry				0.00				0.00	0.45
Transport					7..37			0.53	
Residential				0.02			0.49		
Commercial & public services							0.00	0.00	
Agriculture & forestry									

	Crude Oil	NGL	Refinery Feedstock	LPG	Motor Gasoline	Jet Kerosene	Other Kerosene	Gas Oil/ Diesel	Fuel Oil
Fishery									
Other non-specified				0.00			2.07		
Non-energy use									

Source: IEA Database 2017

As detailed discussions on trends in the movement and features of the respective oil products are made in the subsequent paragraphs, the discussion here is limited to the features of oil product balances from production up to TPES.

- Crude oil: Essentially 100% of crude oil production is exported. This is a result of the extremely low utilization of the existing oil refineries. Approx. 90% of crude oil charged to oil refineries are covered by stock changes.
- NGL: Totally exported as an independent stock
- LPG: production rate is quite low. There is no import and no export.
- Gasoline: The import is approximately 25 times higher than production, and the gasoline shortage is significant. (Gasoline accounts for two-thirds of the total final oil product consumption.)
- Jet kerosene: The balance of production and fuel supply needs in international air ports, i.e. 97%, is imported. No effect on TPES.
- Other kerosene: The import occupies approximately 93% of the final consumption.
- Gas oil/diesel: 40% of domestic production is exported as international marine bunker. Approximately 67% of domestic consumption is covered by stock change.
- Fuel oil: 90% of domestic production is exported either as international bunker or ordinal trade. Approximately 90% of the domestic consumption is covered by stock change.

As a whole, domestic production of gasoline and kerosene is far lower than domestic consumption and there is a need for large amounts of imports.

(2) LPG

Table 5-1.13 presents the changes in demand and supply balances of LPG in Nigeria for the 10-year period (2006-2015). The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- LPG consumption showed frequent ups and downs caused by the “Other non-specified sector”. It is difficult to understand the background for this.
- Consumption in the residential sector was very low.
- Production rates were also fluctuating basically in line with refineries, though quantities were not equal. From 2011 to 2013, production rates were in excess of the 100,000 tons/year level, but after 2014 they decreased sharply.

Table 5-1.13 Changes in Demand/Supply Balance of LPG in Nigeria 2006-2015

[Unit in 1,000 tons]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	5	4	65	30	84	129	104	195	72	31
Imports	0	0	0	0	0	0	0	0	0	0
Exports	0	0	0	0	0	0	0	0	0	0
Stock changes	17	1	0	0	0	0	0	0	0	0
Total Primary Energy Supply (TPES)	22	5	65	30	84	129	104	195	72	31
Statistical difference	8	1	0	0	0	0	0	1	1	-1
Transformation (incl. Energy industry own use)	10	2	39	5	12	22	19	33	11	7
Energy industry own use	10	2	39	5	12	22	19	33	11	7
Total Final Consumption	20	4	26	24	73	108	86	163	62	23
Industry	2	1	0	1	1	1	1	1	1	1
Residential	12	3	7	16	13	17	20	22	21	22
Commercial & public services	6	0	0	0	0	0	0	0	0	0
Other non-specified	0	0	19	7	59	90	65	140	40	0
LPG Production										
(NNPC ASB 2003-2012)										
Oil refineries	-5	1	27	25	72	107	85	162	61	57
Upstream joint ventures	n.a.	n.a.	194	101	162	337	356	418	472	316
Total			221	126	234	444	441	580	533	373

Source: IEA Database 2017

(3) Motor Gasoline

Table 5-1.14 presents the changes in demand and supply balances of motor gasoline in Nigeria for the 10-year period (2006-2015). The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- The domestic production rate of motor gasoline is low. During the 10-year period, the 1.0 million ton level was exceeded only three times, and after 2014 it declined sharply, concurrently with the declining utilization rate of oil refineries.
- Peak production of 1.8 million tons was achieved in 2005, but that level has never been reached again after 2006.
- As a results, the dependency rates on imports were very high. (10-year average: approximately 80%, maximum: approximately 97% in 2015). This trend suggests that the only way to reduce the dependency on gasoline imports will be to construct a new oil refinery.
- Gasoline consumption rates were fluctuating but generally showed a growth trend up to 2012. However, after 2013 it declined and bottomed out in 2014.

Table 5-1.14 Changes in Demand/Supply Balance of Motor Gasoline in Nigeria 2006-2015

[Unit in 1,000 tons]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	993	287	698	364	748	1,277	1,135	1,237	542	261
Imports	5,408	5,792	6,307	6,645	6,962	6,078	5,874	5917	5,781	7,110
Exports	-5	0	0	0	0	0	0	0	0	0
Stock changes	0	125	0	0	0	0	665	0	0	0
Total Primary Energy Supply (TPES)	6,396	6,204	7,005	7,009	7,710	7,355	7,674	7,154	6,323	7,371
Total Final Consumption	6,396	6,204	7,005	7,009	7,710	7,355	7,674	7,154	6,323	7,371
Transport	6,396	6,204	7,005	7,009	7,710	7,355	7,674	7,154	6,323	7,371
Dependency on imports	84.6%	93.4%	90.0%	94.8%	90.3%	82.6%	76.5%	82.7%	91.4%	96.5%

Source: IEA Database 2017

(4) Jet Kerosene

Table 5-1.15 presents the changes in demand and supply balances of jet kerosene in Nigeria for the 10-year period (2006-2015). The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- Consumption rates of jet kerosene for refueling to air crafts at international airports were within +/-10% range of 200,000 tons per annum except in 2008 and 2009.
- Sudden jumps in 2008 and 2009 (800,000 tons+ and 600,000 tons+, respectively) can be understood as being caused by some mix-up with other kerosene that took place in the statistical treatment process.
- Except in 2007, when two existing refineries were shut down entirely, and 2008/2009 described above, dependency rates on exports were around 60% up to 2012. It grew higher than the 75% level in 2013 and then even higher to exceed the 95% level in 2015.

Table 5-1.15 Changes in Demand/Supply Balance of Jet Kerosene in Nigeria 2006-2015

[Unit in 1,000 tons]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	81	34	69	33	67	77	62	76	47	15
Imports	144	197	764	599	96	105	110	263	255	324
Exports	0	0	0	0	0	0	0	0	0	0
International aviation bunker	-225	-231	-833	-632	-163	-182	-172	-339	-302	-339
Total Primary Energy Supply (TPES)	0	0	0	0	0	0	0	0	0	0
Dependency on imports	64.0%	85.3%	91.7%	94.8%	58.9%	57.7%	64.0%	77.6%	75.2%	95.6%

Source: IEA Database 2017

(5) Other Kerosene

Table 5-1.16 presents the changes in demand and supply balances of other kerosene in Nigeria for the 10-year period (2006-2015). The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- Other kerosene consumption rates for residential sector, mainly for kerosene lamp use, generally show decreasing trends.

- Other kerosene consumption rates for other non-specified sectors increased drastically after 2006 except in 2008/2009 (refer to the description in Jet Kerosene above). As the timing of the start in increased consumption is the same as the lifting of the price subsidy for diesel, it is possible that a portion of diesel consumption in the transport sector was shifted to other kerosene.
- The quantity and dependency of imports increased concurrently with the above trends.

Table 5-1.16 Changes in Demand/Supply Balance of Other Kerosene in Nigeria 2006-2015

[Unit in 1,000 tons]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	706	296	601	286	584	674	544	671	629	189
Imports	938	1,138	995	572	1,512	1,416	1,948	1,912	1,862	2,369
Exports	-8	-6	-12	0	0	0	0	0	0	0
Total Primary Energy Supply (TPES)	1,636	1,428	1,584	858	2,096	2,090	2,492	2,583	2,090	2,492
Total Final Consumption	1,736	1,428	1,584	858	2,095	2,090	2,492	2,095	2,491	2,558
Residential	753	414	796	573	543	732	478	482	480	493
Commercial & public services	3	4	4	4	6	1	1	1	1	1
Agriculture & forestry	1	1	2	2	2	0	0	0	0	0
Other non-specified	979	1,009	782	279	1,544	1,357	2,013	2,100	2,010	2,064
Dependency on imports	57.3%	79.7%	62.8%	66.7%	72.1%	67.8%	78.2%	74.0%	74.7%	92.6%

Source: IEA Database 2017

(6) Gas Oil/Diesel

Table 5-1.17 presents the changes in demand and supply balances of gas oil/diesel in Nigeria for the 10-year period (2006-2015). The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- Nearly 100% of domestic consumption of gas oil/diesel is in the transport sector, while that of the industry and agricultural/fishery sectors only amounts to about 2-3%.
- Contrary to the other kerosene case described above, imports stopped after 2005 and gas oil/diesel consumption in the transport sector has generally decreased.

Table 5-1.17 Changes in Demand/Supply Balance of Gas oil/Diesel in Nigeria 2006-2015

[Unit in 1,000 tons]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	1,459	1,251	2,160	1,281	638	1,186	1,030	664	647	294
Imports	1,147	211	0	0	0	0	0	86	0	0
Exports	-20	0	-30	0	-13	0	0	0	0	0
International marine bunker	-120	-132	-127	-123	-119	-109	-125	-115	-117	-116
Stock changes	423	1,728	-17	212	61	52	-368	-37	23	363
Total Primary Energy Supply (TPES)	2,889	3,058	1,986	1,370	567	1,129	537	598	553	541
Transformation (incl. Energy industry own use)	27	3	19	22	27	30	20	44	25	14
Energy industry own use	27	3	19	22	27	30	20	44	25	14
Total Final Consumption	2,862	3,055	1,967	1,348	540	1,099	517	554	528	527
Industry	12	13	15	17	7	13	6	7	6	0
Transport	2,842	3,033	1,943	1,321	529	1,078	507	543	518	523
Agriculture & forestry	8	9	9	10	4	8	4	4	4	4

Source: IEA Database 2017

(7) Fuel Oil

Table 5-1.18 presents the changes in demand and supply balances of fuel oil in Nigeria for the 10-year period (2006-2015). The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- Fuel oil quantities for international marine bunker were within a 250,000-300,000 tons per annum range in the 10-year period.
- The only domestic users of fuel oil are in-house use by the energy industry and the industry sector. Domestic fuel oil consumption was within a 600,000-700,000 tons per annum range in the 10-year period.
- Except for 2015, domestically produced fuel oil in excess of international bunker needs and domestic consumption was exported. As fuel oil exports were affected by the international market situations then prevailing, stock changes were used as buffers.
- In 2015, the domestic production of fuel oil was, due to the extremely low utilization rate of oil refineries, not enough to fulfill international bunkers and domestic needs. At that time the deficiency was covered by stock change.

Table 5-1.18 Changes in Demand/Supply Balance of Fuel Oil in Nigeria 2006-2015

[Unit in 1,000 tons]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	2,385	1,138	1,702	770	1,276	1,691	1,287	1,222	959	406
Exports	-1,951	-1,245	-834	-307	-547	-755	-322	-342	-333	-92
International marine bunker	-274	-266	-243	-258	-290	-276	-279	-256	-260	-259
Stock changes	228	633	10	132	108	-60	33	115	299	519
Total Primary Energy Supply (TPES)	388	260	635	337	547	600	719	739	665	574
Transformation (incl. Energy industry own use)	226	127	256	161	289	298	317	326	226	123
Energy industry own use	226	127	256	161	289	298	317	326	226	123
Total Final Consumption	162	123	379	176	258	302	392	413	439	451
Industry	162	123	379	176	258	302	392	413	439	451

Source: IEA Database 2017

(8) Nigeria Government's Countermeasures

Constructing several private capital-based new oil refineries with maximum gasoline configuration and reducing or eliminating gasoline imports are the short to medium-term countermeasures. As the long-term plan, increase refining capacity up to 2.5 Mbpd and change into an oil product exporter.

5-1-5 Coal

(1) Changes in Demand and Supply Balances

Table 5-1.19 presents the changes in the demand and supply balances of coal in Nigeria from 2006 to 2015. As can be observed from the below table, Nigeria's coal consumption was kept at quite a low level and the coal used in steel and cement industries was entirely covered by domestic production. During the above 10-year period, imports and exports of coal were zero.

As the proposed coal-fired power plant projects described later are completed, and the plants enter into service, Nigeria's coal demand will steadily increase.

Table 5-1.19 Changes in Demand/Supply Balance of Coal in Nigeria 2003-2012

[Unit in Ktoe]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Production	5	5	14	21	23	20	30	44	46	47
Total Primary Energy Supply (TPES)	5	5	14	21	23	20	30	44	46	47
Total Final Consumption	5	5	14	21	23	20	30	44	46	47
Industry	5	5	14	21	23	20	30	44	46	47

Source: Nigeria Coal Corporation (NCC), GSD/NGSA, SRGA

(2) Coal Reserves and Their Qualities

The total estimated reserve of coal including bituminous coal, sub-bituminous coal, and lignite in Nigeria as of around 2015 is 2.73 billion tons in total, of which 0.47 billion tons are a proven reserve, while the buildup of the total estimated reserve is approximately 42%, 46%, and 12% respectively. Bituminous and sub-bituminous coal account for a predominantly large portion of the total reserve. Meanwhile, there are only 4 functional coal fields and 194 million tons in total proven reserves.

As for the location of coal fields, almost all of them are located in the southern areas of the Niger River and Benue River as well as in the northern areas of the Benue River.

Table 5-1.20 summarizes information on existing and identified potential coal mines, namely the locations (name of city and state), type of coal, estimated reserve, proven reserve, depth of coal layer, and applicable mining method. Figure 5-1.4 indicates locations where there are coal fields.

Sub-bituminous coal in Nigeria has a favorable quality for power generation use, which occupies approximately 46% of the country's total estimated reserve, as well as all of the 7 coal fields, for which no reserve estimation has been conducted yet. In general, they are low sulfur, low ash content, and have good combustibility and grindability.

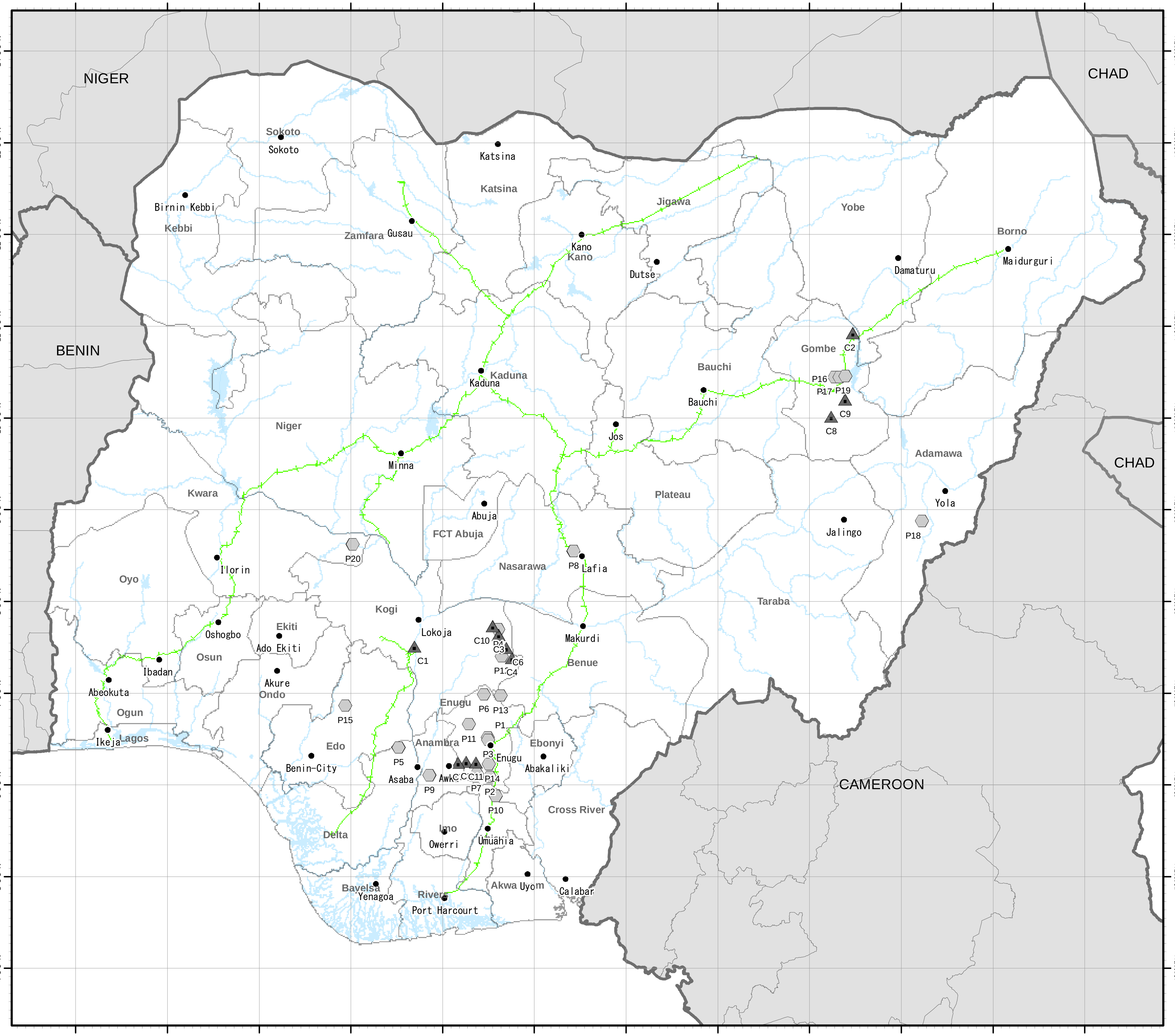
Table 5-1.20 Nigeria's Coalfields and Their Reserves

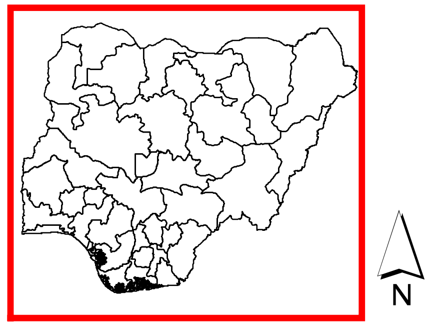
S/No.	Mine Location	State	Type of Coal	Estimated Reserve [Mmt]	Proven Reserve [Mmt]	Depth of Coal [m]	Mining Method(s)
1	Okpara (*)	Enugu	Sub-bituminous	100	24	180	Underground
2	Onyeama (*)	Enugu	Sub-bituminous	150	40	180	Underground
3	Ihioma	Imo	Lignite	40	N/A	20-80	Open-Cast
4	Ogboyoga	Kogi	Sub-bituminous	427	107	20-100	Open-Cast/ Underground
5	Ogwashi-Azagoba Obomkpa	Delta	Lignite	250	63	15-100	Open-Cast/ Underground
6	Ezimo	Enugu	Sub-bituminous	156	56	30-45	Open-Cast/ Underground
7	Inyi	Enugu	Sub-bituminous	50	20	25-78	Open-Cast/ Underground
8	Lafia/Obi	Nasarawa	Bituminous (cokable)	156	32	80	Underground
9	Oba/Nnewi	Anambra	Lignite	30	N/A	18-38	Underground
10	Afikpo/Okigwe	Ebonyi/Imo	Sub-bituminous	50	N/A	20-100	Underground
11	Amasiodo	Enugu	Bituminous (cokable)	1,000	N/A	563	Underground
12	Okaba (*)	Kogi	Sub-bituminous	250	73	20-100	Open-Cast/ Underground
13	Owukpa (*)	Benue	Sub-bituminous	75	57	20-100	Open-Cast/ Underground
14	Ogugu/Awgu	Enugu	Sub-bituminous	N/A	N/A	N/A	Underground
15	Afuji	Edo	Sub-bituminous	N/A	N/A	N/A	Underground

S/No.	Mine Location	State	Type of Coal	Estimated Reserve [Mmt]	Proven Reserve [Mmt]	Depth of Coal [m]	Mining Method(s)
16	Doho	Bauchi	Sub-bituminous	N/A	N/A	N/A	Underground
17	Kurumu-Pindasa	Gombe	Sub-bituminous	N/A	N/A	N/A	Underground
18	Lamja	Adamawa	Sub-bituminous	N/A	N/A	N/A	Underground
19	Garin Maigunga	Gombe	Sub-bituminous	N/A	N/A	N/A	Underground
20	Janata Koji	Kwara	Sub-bituminous	N/A	N/A	N/A	Underground
				2,734	472		

(*) :Functional

Source: Nigeria Coal Corporation (NCC), GSD/NGSA, SRGA





LEGEND

- Capital City
- Proposed location of Coal-fired Power
- Location of Coal Mine
- State_Boundries
- Railway
- Significant Reservoir
- Main Rivers
- Coastal Lake

Locatoin of Coal Development (Potential)

No	Mine Location	Type of Coal	State
P1	Okpara	Sub Bituminous	Enugu
P2	Onyeama	Sub Bituminous	Enugu
P3	Ihioma	Lingnite	Enugu
P4	Ogboyoga	Sub Bituminous	Kogi
P5	Ogwashi Asaba/Obomkpa	Lingnite	Delta
P6	Ezimo	Sub Bituminous	Enugu
P7	Inyi	Sub Bituminous	Enugu
P8	Lafia/Obi	Bituminous (Cokable)	Nassarawa
P9	Oba/Nnewi	Lingnite	Anambra
P10	Afikpo/Okigwe	Sub Bituminous	Ebonyi/Imo
P11	Amasiodo	Bituminous (Cokable)	Enugu
P12	Okaba	Sub Bituminous	Kogi
P13	Owukpa	Sub Bituminous	Benue
P14	Ogugu/Awgu	Sub Bituminous	Enugu
P15	Afuji	Sub Bituminous	Edo
P16	Doho	Sub Bituminous	Gombe
P17	Kurumu Pindasa	Sub Bituminous	Gombe
P18	Lamza	Sub Bituminous	Adamawa
P19	Garin Maigunga	Sub Bituminous	Gombe
P20	Janata Koji	Sub Bituminous	Kwara

[Note]
Location of No. P17 Kurumu Pindasa and No. P19 Garin Maigunga are unknown

Location of Coal-fired Development (Proposed)

No	IPP Name	Site Location	Output (MW)
C1	ASCO Power Plant	Kogi	Unknown
C2	Ashaka Cement PLC	Gombe	64
C3	Bogi Power Generation Limited	Kogi	1,000
C4	BPGL Power Plant Kogi State	Kogi	500
C5	First Capital Infrastructure Development Ltd	Enugu	500
C6	New Energy Independent Power Supply Limited	Kogi	3,600
C7	Silver Quest Nigeria Ltd	Enugu	600
C8	TPGL Power Plant	Gombe	500
C9	Trombay Power Generation Limited	Gombe	500
C10	Zuma Energy Nigeria Ltd	Kogi	1,200
C11	Ramos Electric Power Limited	Enugu	1,000

[Note]
Each location is assumed and presised locatoins are unconfirmed

100 50 0 100km

1:5,000,000
Only if A3

Coordinate System: GCS WGS 1984
Geodetic Reference System: WGS 1984
Unit: Degree

Location of Coal-fired Power Development

8 MARCH 2016

Figure 5-1.4 Coal- fields Occurrence in Nigeria

(3) Proposed Coal-Fired Power Plant Projects

Table 5-1.21 is a list of the proposed coal-fired power plant projects that have applied to connect to TCN's electricity transmission system as of the end of 2015. The total number of projects is 10 with a combined generation capacity approaching 10 GW.

Table 5-1.21 Proposed Coal-Fired Power Plants

	IPP Name	Plant Location		Capacity [MWe]
		State	Region	
	In Enugu/Benue States:			
1	First Capital Infrastructure Development Ltd	Enugu	Makurdi	500
2	Silver Quest Nigeria Ltd	Enugu	Enugu	600
3	Ramon Electric Power Ltd	Benue	Enugu	1,000
	In Kogi State:			
4	Bogi Power Generation Limited (BPCL)	Kogi	Benin	1,000
5	BPCL	Kogi	-	500
6	New Energy Independent Power Supply Ltd	Kogi	-	3,600
7	Zuma Energy Nigeria Ltd	Kogi	Benin	1,200
	In Gombe State:			
8	Ashake Cement plc	Gombe	Bauchi	64
9	TPG- Power Plant	Gombe	-	500
10	Trombay Power Generation Ltd (TPG)	Gombe	-	500
	Total			9,464

Source: TCN

The proposed locations of projects are concentrated in the three states of Enugu, Kogi, and Gombe. It should be noted that Gombe State where, as shown in Table 5-1.20, no exploration to estimate or confirm reserves has been carried out, has been selected as the proposed site of three power plants. This fact suggests a move to explore new coal mines.

(4) Relation between Size of Coal-Fired Power Plant and Required Proven Reserves

Taking a 500 MW super critical coal-fired power plant as an example and based on the following assumptions, the required annual input of typical sub-bituminous coal is estimated at 1.34 million tons.

Assumptions:

Design capacity of power plant	:	500MW
Generator-end design efficiency	:	41%
Higher heating value of coal	:	5,500 Mcal/ton
Capacity factor of power plant	:	80%

Therefore, to support a 500 MW class coal-fired power plant for 30 years, a minimum of approximately 40 million tons of proven reserve must be secured. This indicates that for large-scale coal-fired power plant, advanced consideration for the procurement of coal from multiple sources will be indispensable.

To support the 30-year operation of a total of 10GW proposed coal-fired power plants as shown in Table

5-1.21, 800 million tons of proven reserves are required. This amount is equivalent to double of the present proven reserves of 410 million tons excluding lignite, or 4 times as much as the 194 million tons of proven reserves in the presently functional coal fields. It will be essential to make exploration efforts to increase the proven reserves of coal and to convert current low-efficiency mining methods into state-of-art high-efficiency mining methods.

5-1-6 Renewable Energy

Renewable energy resources in Nigeria which have potential for power generation use have been studied for the report. The types of renewable energy being studied include hydropower, solar, wind, biomass, and its associated wastes. The data and information contained in the following ECN publications are used as a base for the study. Other published data and information referred to in the ECN publications are also used to supplement the study

- Renewable Energy Master Plan 2013 (REMP 2013: ECN/UNDP)
- Energy Implication of Vision 20: 2020 and Beyond 2014 (ECN)
- National Renewable Energy and Energy Efficiency Policy 2015 (FMP, NREEP 2015)
- The Nigerian Energy Sector – The Overview with Special Emphasis on Renewable Energy, Energy Efficiency and Rural Electrification 2015 prepared by the consulting company GIZ in Germany (GIZ Report 2015)

Among renewable energy sources, there is no significant development in Nigeria other than investigation and research projects that are underway for geothermal, wave and tidal energy. As detailed discussions regarding hydropower are included in other subsections, the discussion here is limited to solar, wind, and biofuel & waste.

(1) Changes in Demand/Supply Balance of Renewable Energy 2006-2015

Table 5-1.22 details the changes in demand and supply balances of renewable energy for the 10-year period (2006 to 2010) in Nigeria, based on information contained in the 2017 IEA Database. During the 10 year period, only energy balances of biofuel and waste are shown, as solar and wind energy contributions to total renewable energy were negligibly small. The major observations obtained from the changes in demand and supply balances for the 10-year period are as follows:

- The 2006 to 2015 ratio of biofuel & waste production was 1.30, representing an average annual growth rate of 2.7%, and it is the same as the population growth rate of 2.7%/year due to the estimation method applied by IEA.
- The 2006 to 2015 ratio of biofuel & waste demand for transformation was 1.68, representing an average annual growth rate of 5.3%. Its share of total production increased from 6.1% to 7.9%.
- The biofuel & waste demand for the industry sector increased by 1.99 times during a 7 year period up until 2012, representing an average annual growth rate of 10.4%. Meanwhile, IEA reset the ratio to the total production and its growth rate in 2013 and 2014. Consequently, growth for the 2006-2015 period decreased to 1.12 times or 1.2% per year. Its share of total production also

decreased from 4.3% to 3.7%.

- As for the demand in the commercial and public services sector, adjustments similar to those for the industry sector were made by IEA. As a result, demand during the 10-year period increased by 3.04 times, representing an average annual growth rate of 11.8%. Its share of total production increased from 1.1% to 2.5%.
- Meanwhile, the 2006 to 2015 ratio of biofuel & waste demand in the residential sector was 1.28, representing an average annual growth rate of 2.5%, which is a little lower than the population growth rate of 2.7% per year. Its share of total production decreased from 87.4% to 85.9%.
- As the demand in the transformation, industry and commercial & public services sectors is considered to be wholly fuel wood, it is suggested that share of fuel wood in the total demand of the residential sector is decreasing in comparison.

Table 5-1.22 Changes in Demand/Supply Balance of Biofuel and Waste in Nigeria 2006-2015

[Unit in Mtoe]

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2013	2015/ 2006 Ratio
Production	85.71	90.06	91.85	93.36	97.81	102.32	108.14	108.59	108.67	111.57	1.30
Total Primary Energy Supply (TPES)	85.71	90.06	91.85	93.36	97.81	102.32	108.14	108.59	108.67	111.57	
Transformation (incl. Energy industry own use)	5.22	7.76	6.74	5.78	6.68	7.68	8.84	8.26	8.53	8.76	1.68
Other transformation	-5.22	-7.76	-6.74	-5.78	-6.68	-7.68	-8.84	-8.26	-8.53	-8.76	
Total Final Consumption	79.49	82.70	85.11	87.58	91.13	94.64	99.31	100.33	100.14	1032.81	1.29
Industry	3.70	4.16	4.76	5.32	5.92	6.61	7.38	7.00	4.04	4.15	1.12
Residential	74.88	77.46	79.25	81.21	83.68	86.25	88.94	90.95	93.40	95.89	1.28
Commercial & public services	0.91	1.08	1.10	1.05	1.53	1.78	2.99	2.38	2.70	2.77	3.04

Growth Ratios (2008 =1.000)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2013	2015/ 2006 Ratio
Production, Mtoe	85.71	90.06	91.85	93.36	97.81	102.32	108.14	108.59	108.67	111.57	1.30
Production ratio, 2008=1.000	0.933	0.981	1.000	1.016	1.065	1.114	1.177	1.182	1.183	1.215	1.30
Population, Millions	143.32	147.15	151.12	155.21	159.42	163.77	168.24	172.82	177.48	168.24	1.30
Population ratio, 2008=1.000	0.948	0.974	1.000	1.027	1.055	1.084	1.113	1.144	1.174	1.206	1.30

Source: IEA Database 2017

(2) Renewable Energy Potential

Table 5-1.23 lists potential renewable energy sources and current utilization levels included in REMP 2013. Among biomass and waste, utilization levels of municipal waste and livestock dung are nearly zero.

Table 5-1.23 Renewable Energy Potential and Current Utilization Levels

Resource	Potential	Current utilization and further remarks
Large Hydropower	11,250 MW	1,900 MW exploited
Small Hydropower	3,500 MW	64.2 MW exploited
Solar	4.0-6.5 kWh/m2/day	15 MW dispersed solar PV installation (estimated)
Wind	2-4m/s @ 10m height mainland	Electronic Wind Information System [WIS] available

Resource	Potential	Current utilization and further remarks
Biomass (Non-fossile organic matter)	Municipal waste	18.5 million tons produced in 2005 and now estimated at 0.5 kg/capita/day; Utilization level is nearly zero.
	Fuel wood	43.4 million tons/yr fuel wood consumption
	Animal waste	245 million assorted animals in 2001; Utilization level is nearly zero.
	Agricultural waste	91.4 million tons/year produced
	Energy crops	28.2 million hectares of arable land, 8.5% cultivated

Source: REMP 2013, prepared by ECN&UNDP

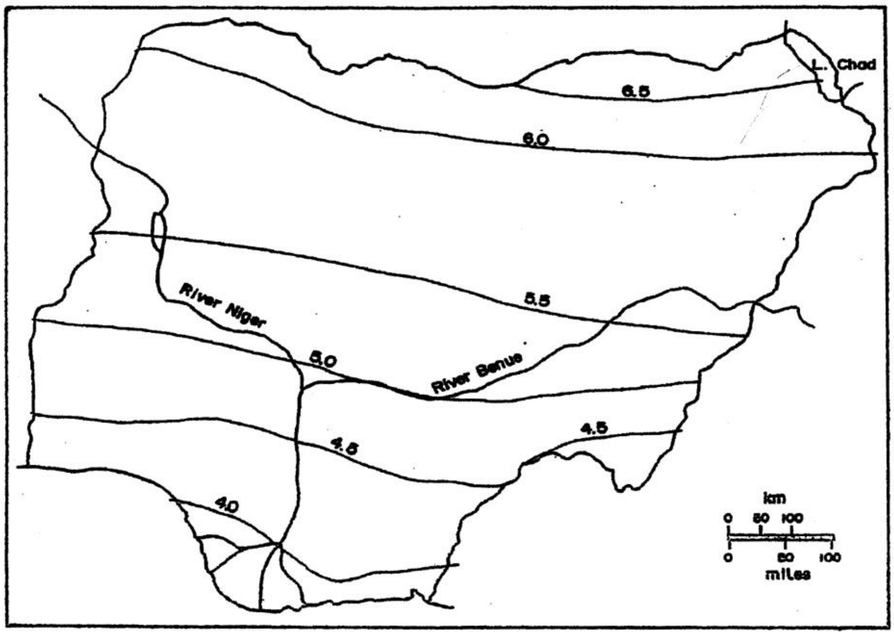
(3) Solar

The solar radiation intensity range in Nigeria is between 4.0-6.5 kWh/m2/day and the highest intensity is found in the northern areas, while it is lower in the southern areas (refer to Figure 5-1.5). As solar PV enters into an era of worldwide mass production, and its price is rapidly decreasing, PV-based power generation is moving into second place, next to hydropower, for renewable energy based electricity generation.

As of the end of 2015, there are 24 solar PV projects proposed by IPP (independent power producers) companies that have applied for connection to TCN's electricity transmission system, with a combined generation capacity of approximately 3.4GW (refer to Table 5-1.24).

More than 90% of these PV projects are located in the Northern Region, where high solar radiation intensity preferable for PV is available, and these projects are expected to improve the present electricity supply situation of the Norther Region which is currently inferior to that of the Southern Region.

In addition, solar PV projects, as a result of their unique characteristic of requiring neither fuel supply nor waste disposal arrangements, can be realized in a much shorter time (half or less) than coal-fired power generation projects for achieving in-service conditions from the start of project front-end activities. This suggests that an unintended outcome of the proposed PV projects will be a contribution to improving environmental problems related to GHG (greenhouse gas) emission as well.



Solar Radiation Distribution in Nigeria (kWh/m²/day)
Source: J. O. Ojosu (1990).

Figure 5-1.5 Solar Radiation Intensity Distributions in Nigeria

Table 5-1.24 Solar PV Projects Proposed by IPP Companies as of the End of 2015

No.	IPP Company Name	Capacity [MW]	Project Location State	Geopolitical Zone
1	99 Effects Energy Limited	50	FCT	North-Central
2	99 Effects Energy Limited	200	FCT	North-Central
3	Anjeed Kafachan Solar IPP	100	Kaduna	North-West
4	CT Communication Tower	75	Plateau	North-Central
5	KVK Power Nigeria Limited	50	Sokoto	North-West
6	LR-Aaron Solar Power Plant	100	FCT	North-Central
7	Motir Seaspire Energy Ltd.	1,200	Enugu	North-Central
8	Nigeria Solar Capital Partners NSCP	100	Bauchi	North-East
9	North South Power Company Ltd	300	Niger	North-Central
10	Nova Scotia Power Development Ltd	80	Kaduna	North-West
11	Orocevam Ltd.	150	Niger	North-Central
12	Pan Africa Solar Ltd	75	Kaduna	North-West
13	Quaint Energy Solutions	50	Plateau	North-Central
14	ROMIX Energies Ltd	50	Oyo	South-West
15	Roak Solar Investment Limited	50	-	
16	Sinosun Investment Limited	100	Katsina	North-West
17	Synergent Power Share Nigeria Ltd	50	-	
18	Avensal Solar	50	Nasarawa	North-Central
19	AfriNiger Solar	50	Nasarawa	North-Central
20	Savanah Power Projects AR	50	Kwara	North-Central
21	ASC Energy	25	Oyo	South-West
22	Protergia Clean Energy Solutions	100	Niger	North-Central
23	Enerlog Limited	100	FCT	North-Central
24	AKAY Engineering	250	Niger	North-Central
	Total capacity	3,405		

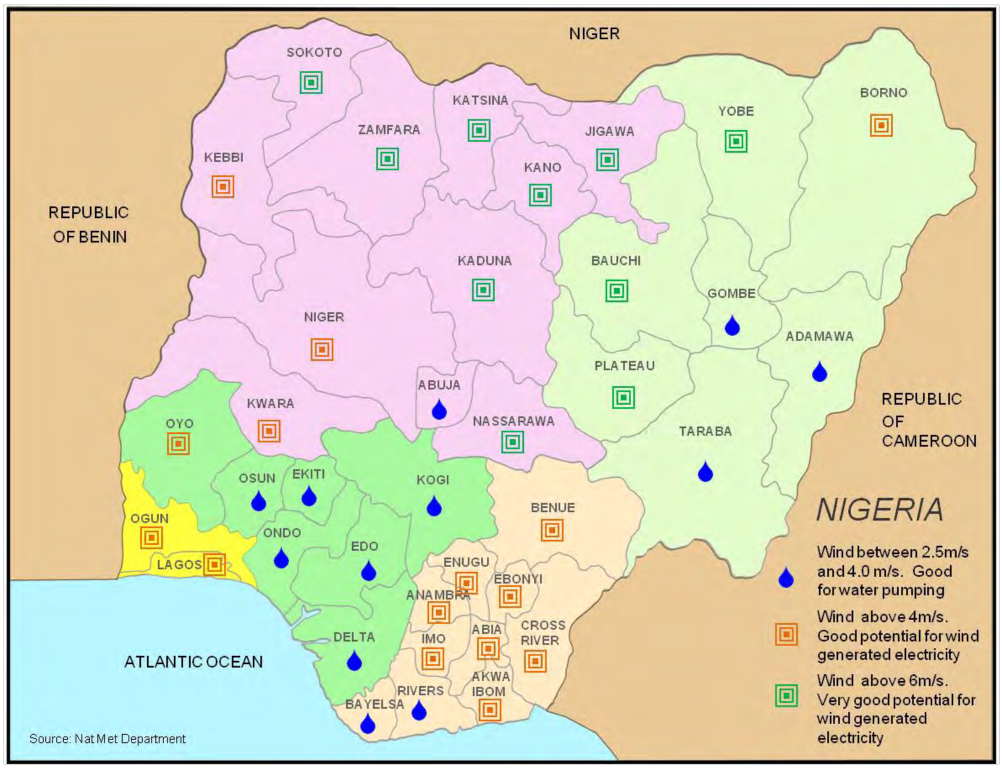
Source: TCN

(4) Wind

The average Nigerian wind velocity of 10 m above grade generally increases in strength the more north a state is located. The states with an average wind speed of 6 m/sec which is quite favorable for wind-based electric power generation are located in the northern area of the country (refer to Figure 5-1.6). Nigeria currently has the following wind-based electric power generation systems.

- 2 x 2.5kW Wind based standalone power generators
- 10MW Wind Farm in Katsina City

According to REMP 2013, wind-based power generation is ranked in third place behind solar-based generation, and to reach about one-half of the capacity of solar generation is set as the medium to long-term target. One project with 100MW capacity was approved by NERC in 2014.



Source: http://www.neenigeria.com/Nigeria_wind_NEW.png

Figure 5-1.6 Average Wind Velocity Distribution in Nigeria

(5) Biomass and its Associated Wastes

Biomass and its associated wastes in Nigeria, which have the potential for electric power generation use, include firewood, municipal waste, animal waste, and agricultural waste. The sizes of reserves and utilization levels in 2010 are presented in Table 5-1.23 earlier in the report. There is also a brief discussion concerning energy crops for biofuels (bioethanol and biodiesel) production.

(6) Estimation of Biomass Energy Constitution

A preliminary estimate of the constitution of biomass energy has been conducted, which is indicated in the IEA Database. Based on the assumptions derived from Table 5-1.23 and other published literature shown below, the composition of biomass energy as well as the total production rate have been estimated using 2008 as the base year.

Sources of information:

- Fuel wood: Table 5-1.23
- Crops residue: GIZ report 2015
- Livestock dung: FAO Livestock Sector Brief 2005 and Asian Biomass Handbook
- Municipal waste: In the IEA Database, municipal waste is included in a category separate to biomass and waste. Therefore, municipal waste is excluded from this estimate. Its utilization level in 2015 was nil.
- Energy conversion coefficient: Asian Biomass Handbook

Table 5-1.25 shows the results of the estimate. Table 5-1.26 and Table 5-1.27 shows breakdowns of production rates for crops and their residues and livestock dung, respectively, as backup data.

Table 5-1.25 Estimated Available Energy from Biomass and Waste in Nigeria 2008

	Estimated Production	Biodegradable Component		Conversion Coefficient	Available Energy	Constitution
	Mtons	%	Mtons	toe/ton	Mtoe	%
Fuel wood[9]	43.4	100%	43.4	0.44	19.1	22.5%
Agricultural waste[10]	136.7	100%	136.7	0.32	43.7	51.5%
Livestock dung[11]	44.3	100%	44.3	0.32	14.2	16.7%
Municipal waste[12]	27.6	76%	21.0	0.38	8.0	9.4%
Total	252.0		245.4		85.0	
					92.5%	of IEA Data

Note: IEA Database does not count municipal waste and industrial waste in this category.
Source: JICA Study Team

Table 5-1.26 Crops Production and Their Estimated Residues in Nigeria 2010

Crops	Production [Kmt]	Component	Available Weight [Mmt]	Total Available Energy [Pj]
Rice	3,368	Straw	7.86	125.92
		Husk	1.19	23
Maize	7,677	Stalks	10.75	211.35
		Cob	2.1	34.19
		Husk	0.92	14.32
Cassava	42,533	Stalks	17.01	297.68
		Peelings	76.56	812.30
Groudnut	3,799	Shells	1.81	28.35
		Straw	4.37	76.83

[9] 43.4 million tons in Table 5-1.23 is used as it is; to convert dry weight to oil equivalent energy a value of 0.44 toe/ton is used (range: 0.42-0.45 depending on the type of wood).

[10] 145.6 Mtons in 2010 shown in Table 5-1.26 is decreased to arrive at the 2008 value, proportional of IEA's total biomass & waste production rates in 2008 and 2010; as the energy conversion coefficient a value of 0.32 toe/ton is used as presented in the same table.

[11] In Table 5-1.27 a livestock population of 201 million in 2002 was increased to 2008 levels by applying an annual growth rate of 5.5%; as the energy conversion coefficient a value of 0.32 is used as presented in the same table.

[12] To estimate total municipal waste production, an amount of 0.5 kg/day per capita is used shown in Table 5-1.23. To arrive at the biodegradable component a percentage of 76% is used which is found by deducting the following non-biodegradable components, as estimated by K.A. Ayuba et all (2013), for FCT Abuja. Plastics (3.4%), water sachets (14.5%), glass (3.0%) and metals (3.1%); 24% in total. As the energy conversion coefficient a value between fuel wood (0.44 toe/ton) and agricultural residue (0.32 toe/ton), i.e. 0.38 toe/ton is assumed.

Crops	Production [Kmt]	Component	Available Weight [Mmt]	Total Available Energy [Pj]
Soybean	365	Straw Pods	0.91 0.37	11.27 4.58
Sugar cane	482	Bagasse Topps/Leaves	0.11 0.14	1.99 2.21
Cotton	602	Straw	2.25	41.87
Millet	5,171	Straw	7.24	89.63
Sorghum	7,141	Straw	7.14	88.39
Cowpea	3,368	Shells	4.89	95.06
Total	74,507		145.62 Energy in Mtoe Coefficient, toe/mt	1,958.94 46.8 0.32
% occupied by Cassava	57%		64%	57%

Source: Simonyan, K.J. & Facina, O. (2013)
(Excerpt from "Nigerian Energy Sector 2nd Edition 2015, prepared by GIZ)

Table 5-1.27 Estimated Livestock Dung Production Rate in Nigeria

Year 2002	Livestock Population (*1) [Million]	Dung Rate (*2) [mt/y/head]	Production Rate (Dry) [Million mt]	Coefficient of Energy (*2) [GJ/mt]	Energy Production [10^6 GJ]
Cattle	15.2	1.10	16.7	15.0	250.8
Pig	6.1	0.22	1.3	17.0	22.8
Poultry	131.1	0.04	5.2	13.5	70.8
Sheep and goat	49.0	0.18	8.8	17.8	157.0
Total	201.4	0.16	32.1	15.6 [toe/mt]	501.4 [Mtoe]
Expressed in toe				0.37	12.0

Year 2000	Livestock Population (*1) [Million]	Dung Rate (*2) [mt/y/head]	Production Rate (Dry) [Million mt]	Coefficient of Energy (*2) [GJ/mt]	Energy Production [10^6 GJ]
Cattle	15.1	1.10	16.6	15.0	249.2
Pig	5.0	0.22	1.1	17.0	18.7
Poultry	113.2	0.04	4.5	13.5	61.1
Sheep and goat	47.5	0.18	8.6	17.8	152.2
Total	180.8	0.17	30.8	15.6 [toe/mt]	481.2 [Mtoe]
Expressed in toe				0.37	11.5

Notes: Annual growth rate of livestock population between 2000 and 2002 is 5.5%.
Estimated population in 2005 is 237 million.
Estimated population in 2008 is 278 million
Source: (*1) FAO Livestock Sector Brief, March 2005, (*2) Asian Biomass Handbook

The major observations obtained from the results of the estimate are as follows:

- The estimated total energy of biomass and waste is 83.8% of the IEA Database data (91.85 Mtoe). Taking into account the differences in data sources used and the methods of statistical data processing, both numbers are considered within the acceptable departure range.
- The share of fuel wood to total energy produced is less than 25% and substantially lower than initially expected. Even if the balance needed to arrive at IEA's total number is assumed to be covered by fuel wood and wood waste, the share of wood does not exceed 37% of the total.
- The largest contributor is crop residue with an estimated share is in excess of 50%.

Based on the above observations, note should be taken of the descriptions often found in various reports that biomass fuels used in the residential sector are predominantly fuel woods. Also, concerning biomass and waste used in the residential sector detailed in the IEA Database, it should be understood that this may include an appreciable percentage of what should be treated as loss or is not used as source of energy.

1) Crops for Biofuel Production

According to REMP 2013, the Nigerian Government has a plan to increase gasoline and diesel production to blend biofuels at the predetermined ratios. The production targets of biofuels set for 2030 are based on the demand projections at a 13% per year GDP growth as presented in Table 5-1.28.

Table 5-1.28 Biofuel Production Targets

	Timeline/Quantity		
	Short Term (2015)	Medium Term (2020)	Long Term (2030)
Bioethanol (E10), ML/D	5.3	9.7	24.2
Biodiesel (E20), ML/D	2.0	3.4	11.7

Source: REMP 2013

Using crop production in Nigeria in 2010 shown in Table 5-1.29 and standard yields (liter/ton) of bioethanol and biodiesel included in the FAO Database, the crop requirements to produce the target amount of biofuel in 2030 is shown above. As for the crops for producing biofuels, cassava and soybean have been used for bioethanol and biodiesel, respectively. The results of the estimate are shown in Table 5-1.29.

Table 5-1.29 Estimated Crop Requirements for Biofuel Production

Product	Kind of Crops	Required Fuel	Efficiency	Required Crops	Production
		Million liter	Liter/ton	Kmt	Kmt
Bioethanol	Cassava	24.2	180	135	42,533
Biodiesel	Soybean	11.7	205	57	365

Source: JICA Study Team

As can be deduced from the above table, the cassava requirement for ethanol production is as small as 0.3% of the total amount of produced cassava, and no conflict with food use is predicted.

Meanwhile, the same requirement for soybean used for biodiesel production is as high at approximately 16% of total soybean production, and serious conflicts with food use are predicted. It will be necessary to either find multiple other sources for biofuel production or make efforts to increase soybean production.

5-2 Primary Energy Demand Forecasts

5-2-1 Energy Demand Forecasts of ECN

(1) Purposes and background of the forecasts

In 2014 ECN (Energy Commission of Nigeria) published the report "Energy Implications of Vision 20: 2020 and Beyond" (hereinafter, "Energy Vision"). The outline of the Energy Vision is as the follows:

- Energy Vision is a part of "Vision 20: 2020" which is the social-economic strategy of Nigeria. The strategy aims to make Nigeria the world's 20th largest economy by 2020.
- Energy Vision forecasts the energy demand including fossil energy, electric power, and non-commercial energy sources (wood, charcoal etc.) from 2010 to 2030 (actual values are used up to 2009).
- MAED (Model for Analysis of Energy Demand) software from IAEA (International Atomic Energy Agency) is used for forecasting.
- ECN established the "Country Study Team" for gathering the opinions of well-known persons from the related ministries and authorities. The ministries and authorities that participated are as shown in Table 5-2.1.

Table 5-2.1 Members of the Country Study Team

	Members of the Country Study Team	Current Member Names
1	Energy Commission of Nigeria	
2	Ministry of Power	Ministry of Power, Works and Housing
3	Nigerian Electricity Regulatory Commission	
4	National Planning Commission	Ministry of Budget and National Planning
5	Ministry of Science and Technology	
6	Ministry of Environment	
7	Ministry of Mines and Steel Development	
8	National Bureau of Statistics	
9	Transmission Company of Nigeria	
10	Nigerian National Petroleum Corporation	
11	Central Bank of Nigeria	
12	Department of Petroleum Resources	
13	Nigeria Atomic Energy Commission	

Source: Energy Implications of Vision 20: 2020 and Beyond

(2) Preconditions and forecasting methods of Energy Vision

GDP scenarios selected in the Energy Vision are as the follows:

- Reference scenario: Under BAU (Business-As-Usual) economic conditions from 2009 to 2020, the average GDP growth rate to follow the existing "Five Year Economic Plan" is assumed at 7%.
- High growth scenario: The sectoral GDP of agriculture and service sectors are kept at the current levels, while high GDP growth is projected in the other sectors (mining, industry sectors, etc.). As a result, the country GDP growth rate is expected to be 10% per year from 2010 to 2020.
- Optimistic I scenario: The scenario has a higher growth rate than the above high growth scenario. The average GDP growth rate is assumed at 11.5 % per year during the whole term.

- Optimistic II scenario: According to IMF data in 2010, the rank of Nigeria's GDP (US$ PPP base) is the 31st in the world as of 2009. The Nigerian government has a plan to increase the GDP ranking from the 31st to 20th under its "Vision 20: 2020". In order to achieve this plan, a GDP growth rate of 13.8% per year from 2010 to 2020 will be required. Therefore, a GDP growth rate of 13.8 % per year is set for the Optimistic II scenario.

The final energy demands of the Energy Vision reference scenario are shown in Table 5-2.2. Fossil energy sources such as natural gas and coal for the power sector are not included.

Table 5-2.2 Final Energy Demands of the Energy Vision Reference Scenario

Year	GDP by ECN	LPG	Gasoline (PMS)	Kerosene (ATK)	Kerosene (HHK)	Diesel (AGO)	Fuel oil	Natural gas	Coal	Wood & Charcoal	Power demand
	%	1000 ton	Million liter	Million liter	Million liter	Million liter	Million liter	Million cma	ton	1000ton	TWh
2015	7.0	1,107	14,460	278	3,510	2,302	1,800	3,480	114	58,660	150
2016	7.0	1,339	16,523	315	4,191	2,593	2,175	4,194	131	57,850	170
2017	7.0	1,619	18,881	356	5,005	2,921	2,627	5,054	149	57,051	191
2018	7.0	1,958	21,574	404	5,976	3,291	3,174	6,092	171	56,263	216
2019	7.0	2,367	24,653	457	7,136	3,708	3,834	7,341	195	55,486	244
2020	7.0	2,863	28,170	518	8,521	4,177	4,632	8,848	223	54,720	275
2021	7.0	3,177	30,181	555	9,458	4,525	5,142	9,821	249	53,660	306
2022	7.0	3,527	32,336	594	10,498	4,902	5,707	10,901	279	52,620	341
2023	7.0	3,915	34,645	637	11,652	5,310	6,335	12,101	312	51,600	380
2024	7.0	4,346	37,119	682	12,932	5,753	7,032	13,432	349	50,600	424
2025	7.0	4,824	39,769	731	14,354	6,232	7,806	14,910	390	49,620	473
2026	7.0	5,201	42,656	784	15,493	6,693	8,417	16,076	421	48,145	507
2027	7.0	5,608	45,752	841	16,723	7,187	9,075	17,333	454	46,714	543
2028	7.0	6,047	49,074	902	18,049	7,719	9,784	18,689	489	45,325	583
2029	7.0	6,519	52,636	967	19,482	8,290	10,550	20,150	527	43,977	625
2030	7.0	7,029	56,457	1,037	21,028	8,902	11,375	21,726	569	42,670	670
2030/15	7.0	13.1	9.5	9.2	12.7	9.4	13.1	13.0	11.3	−2.1	10.5

Note: Energy Vision forecasts on fossil energy sources and electric power as the final energy demand.

Note: The above red values are the forecasted values in the Energy Vision. The interval values between every five years are estimated by the "Master Plan Study on National Power System Development" (hereinafter, "PSD") team.

Note: Natural gas is not included for the demands of the LNG and power sector.

Note: Each type of energy has its own physical unit to be used in the table, so they cannot be aggregated.

Source: Energy Implications of Vision 20: 2020 and Beyond

As the GDP growth rate in the PSD (Mater Plan Study on National Power System Development) is between 5.0% to 6.5%, a GDP growth rate of 7 % in the Energy Vision reference scenario is the nearest value to that of the PSD. Therefore, final energy demand and primary energy demand of the PSD up to 2040 are estimated by means of changing GDP scenarios and elasticity between the primary energy growth rate and the GDP growth rate of Energy Vision.

As the actual values of final energy and primary energy in 2009, data from Energy Vision are used for PSD forecasting. At first, Energy Vision projects the final energy by sector and energy, and calculates final energy demand by aggregating the final energy.

Furthermore, power demand and power supply plans are established for calculating the primary energy demand, after which the fuel consumption for the power sector is calculated. Fuel consumption is then added to the final energy demand for the primary energy demand.

In the above method, the renewable energy supply is estimated under the conditions of renewable energy supply potential. As the renewable energy supply differs between Energy Vision and PSD, the renewable energy supply in PSD is selected for the primary energy forecasts. The procedures of the adjustment from Energy Vision to PSD are as follows:

Table 5-2.3 Adjustment Method from Energy Vision to PSD

Items	Procedures
Adjust GDP growth rate	The GDP growth rate of 7% from the Energy Vision is adjusted to GDP growth rate of 6.1 % from the PSD.
Adjust elasticity	As there is a comparatively large elasticity of energy growth to GDP growth in the Energy Vision, the elasticity should be adjusted. Specifically, after comparing it to the elasticity of power demand to GDP growth rate in the PSD, when the elasticity of the Energy Vision is larger than power elasticity in the PSD, the elasticity of Energy Vision should be replaced by power elasticity in the PSD. Otherwise, the elasticity of the Energy Vision is used in the PSD. This is the reason why elasticity of power demand is larger than other energy elasticity.
Adjust Renewable energy	Regarding renewable energy forecasts up to 2040, the renewable energy demands in "National Renewable Energy and Energy Efficiency Policy" created by Ministry of Power, Works and Housing published in 2015 have been selected.

Source: PSD

5-2-2 Adjustment of GDP Difference between Energy Vision and PSD

The average GDP growth rate in the reference scenario of Energy Vision is 7% per year and the average GDP growth rate in PSD is 6.1 % per year from 2015 to 2040. The real GDP trends (at 2005 price) assuming the above two growth rates from 2010 to 2040 are as shown in Table 5-2.4.

Table 5-2.4 GDP Trends of Energy Vision and PSD

Unit: Growth rate: % GDP：Billion NGN

	GDP by Energy Vision		GDP in PSMP			GDP by Energy Vision		GDP in PSMP	
	%	Billion NGN	%	Bilion NGN		%	Billion NGN	%	Bilion NGN
2010	7.0	20,682	7.0	20,682	2026	7.0	61,056	6.5	47,597
2011	7.0	22,129	5.3	21,778	2027	7.0	65,330	6.5	50,691
2012	7.0	23,679	4.2	22,693	2028	7.0	69,903	6.5	53,986
2013	7.0	25,336	5.5	23,941	2029	7.0	74,796	6.5	57,495
2014	7.0	27,110	6.2	25,425	2030	7.0	80,032	6.5	61,232
2015	7.0	29,007	3.0	26,178	2031	7.0	85,634	6.5	65,212
2016	7.0	31,038	4.0	27,217	2032	7.0	91,628	6.5	69,451
2017	7.0	33,210	4.5	28,442	2033	7.0	98,042	6.5	73,965
2018	7.0	35,535	5.0	29,864	2034	7.0	104,905	6.5	78,773
2019	7.0	38,023	5.5	31,506	2035	7.0	112,249	6.5	83,893
2020	7.0	40,684	6.0	33,396	2036	7.0	120,106	6.5	89,346
2021	7.0	43,532	6.0	35,400	2037	7.0	128,514	6.5	95,154
2022	7.0	46,579	6.0	37,524	2038	7.0	137,510	6.5	101,339
2023	7.0	49,840	6.0	39,776	2039	7.0	147,135	6.5	107,926
2024	7.0	53,329	6.0	42,162	2040	7.0	157,435	6.5	114,941
2025	7.0	57,062	6.0	44,692	40/15	7.0		6.1	

Note: The starting GDP is 20,682 billion NGN at 2005 price in 2010.
Note: The GDP growth rates of the Energy Vision after 2031 are assumed to be 7% per year.
Source: Energy Visions and PSD power demand forecasting model

Final energy demand forecasts based on the above GDP growth rate are as follows:

Table 5-2.5 Final energy demand forecasts after GDP adjustment

	GDP from Model	LPG	Gasoline (PMS)	Kerosene (ATK)	Kerosene (HHK)	Diesel (AGO)	Fuel oil	Natural gas	Coal	Wood & Charcoal	Power
	%	1000 ton	Million liter	Million liter	Million liter	Million liter	Million liter	Million cma	ton	Million kg	TWh
2015	3.0	999	13,049	251	3,168	2,077	1,624	3,141	103	58,660	136
2016	4.0	1,140	14,075	268	3,570	2,209	1,852	3,573	111	57,850	144
2017	4.5	1,327	15,482	292	4,104	2,396	2,154	4,145	122	57,051	157
2018	5.0	1,575	17,360	325	4,809	2,648	2,554	4,902	137	56,263	174
2019	5.5	1,887	19,652	364	5,689	2,955	3,056	5,852	155	55,486	194
2020	6.0	2,271	22,351	411	6,761	3,314	3,675	7,020	177	54,720	218
2021	6.0	2,509	23,835	438	7,469	3,573	4,061	7,756	197	53,660	242
2022	6.0	2,772	25,417	467	8,251	3,853	4,486	8,569	219	52,620	268
2023	6.0	3,063	27,105	498	9,116	4,154	4,957	9,467	244	51,600	298
2024	6.0	3,384	28,904	531	10,071	4,480	5,476	10,460	272	50,600	330
2025	6.0	3,739	30,823	566	11,125	4,830	6,050	11,556	303	49,620	366
2026	6.5	4,012	32,906	605	11,952	5,163	6,493	12,402	325	48,145	391
2027	6.5	4,306	35,130	645	12,840	5,519	6,968	13,309	348	46,714	417
2028	6.5	4,621	37,504	689	13,794	5,899	7,478	14,283	374	45,325	445
2029	6.5	4,959	40,039	736	14,819	6,306	8,025	15,328	401	43,977	475
2030	6.5	5,322	42,745	785	15,920	6,740	8,612	16,449	431	42,670	507
2031	6.5	5,711	45,633	838	17,103	7,205	9,242	17,653	462	41,401	545
2032	6.5	6,129	48,717	895	18,374	7,701	9,918	18,945	496	40,171	584
2033	6.5	6,578	52,010	956	19,740	8,232	10,644	20,331	532	38,976	627
2034	6.5	7,059	55,525	1,020	21,206	8,799	11,423	21,818	571	37,818	673
2035	6.5	7,575	59,277	1,089	22,782	9,406	12,258	23,414	613	36,693	722
2036	6.5	8,130	63,283	1,163	24,475	10,054	13,155	25,128	658	35,603	775
2037	6.5	8,724	67,560	1,241	26,294	10,747	14,118	26,966	706	34,544	832
2038	6.5	9,363	72,125	1,325	28,247	11,488	15,151	28,939	758	33,517	893
2039	6.5	10,048	76,999	1,415	30,346	12,279	16,259	31,056	813	32,521	958
2040	6.5	10,783	82,203	1,511	32,601	13,126	17,449	33,329	873	31,554	1,028
2040/15	6.1	10.0	7.6	7.4	9.8	7.7	10.0	9.9	8.9	-2.4	8.4

Source: Adjusted by the PSD team after referring to Energy Visions

5-2-3 Adjustment of Elasticity

The characteristics of energy demand growth rate to GDP growth rate are as follows:

- The energy elasticity to GDP is changed in line with its economic volatility. The trend in developing countries is for the elasticity to gradually change from high elasticity to low elasticity.
- Sometimes one form of energy is more competitive among the various forms of energy. The increase in use of one form of energy brings a decrease in the use of others (for example, electric power vs kerosene, electric power vs wood and charcoal).
- Electric power demand elasticity is higher than fossil energy demand elasticity in many developing countries. It shows that the maximum elasticity of fossil energy demand in developing countries does not exceed the level of electric power demand elasticity.

Elasticity of final energy demands forecasted in Energy Vision should be adjusted under the above conditions. The procedures for the adjustment are as follows:

- When energy demand elasticity (Ait: Ai energy in t-year) forecasted in the Energy Vision is higher than electric power demand elasticity (Bt: electric power demand elasticity in t-year) in PSD, Ait is replaced by Bt.
- When Ait is lower than Bt, Ait is used for the elasticity for the energy in t-year.

The above energy demand forecasting method is based on knowledge of ECN and PSD team forecasting technologies. At the same time, it means that the forecasting values are the maximum final energy demand in the base case scenario of PSD.

Table 5-2.6 Elasticity before and after adjustment

		2015	2020	2025	2030	2035	2040
ECN	LPG	19.5	3.1	1.6	1.1	1.1	1.1
Elasticity	Gasoline(PMS)	4.7	2.1	1.0	1.0	1.0	1.0
	Kerosene (ATK)	8.5	2.0	1.0	1.0	1.0	1.0
Before	Kerosene (HHK)	16.7	2.9	1.6	1.1	1.1	1.1
Adjusted	Diesel (AGO)	6.5	1.9	1.2	1.1	1.1	1.1
	Fuel oil	19.0	3.1	1.6	1.1	1.1	1.1
	Natural gas	0.2	3.1	1.6	1.1	1.1	1.1
	Coal	23.6	2.1	1.7	1.1	1.1	1.1
	Wood & Charcoal	-0.2	-0.2	-0.3	-0.5	-0.5	-0.5
	Model power demand (On+Ex)	2.2	2.0	1.5	1.2	0.8	0.8
Adjusted	LPG	2.2	2.0	1.5	1.1	0.8	0.8
Elasticity	Gasoline(PMS)	2.2	2.0	1.0	1.0	0.8	0.8
	Kerosene (ATK)	2.2	2.0	1.0	1.0	0.8	0.8
After	Kerosene (HHK)	2.2	2.0	1.5	1.1	0.8	0.8
Adjusted	Diesel (AGO)	2.2	1.9	1.2	1.1	0.8	0.8
	Fuel oil	2.2	2.0	1.5	1.1	0.8	0.8
	Natural gas	0.2	2.0	1.5	1.1	0.8	0.8
	Coal	2.2	2.0	1.5	1.1	0.8	0.8
	Wood & Charcoal	-0.2	-0.2	-0.3	-0.5	-0.5	-0.5
	Power send out (Total-Export)	2.2	1.9	1.5	1.0	0.8	0.8
	Model power demand (On+Ex)	2.2	2.0	1.5	1.2	0.8	0.8

Note: Elasticity before adjustment are forecasted in Energy Vision.
Source: Energy Vision and PSD

5-2-4 Final Energy Demand Forecasts

The following final energy demand is forecasted by using the GDP of PSD and adjusted elasticity. The demand in the Power Demand Forecasting Model of PSD is used for the power demand (send out demand) in the below forecasts.

Table 5-2.7 Final Energy Demand Forecasts (Physical unit)

	GDP from Model	LPG	Gasoline(PMS)	Kerosene (ATK)	Kerosene (HHK)	Diesel (AGO)	Fuel oil	Natural gas	Coal	Wood & Charcoal	Power generation
	%	1000 ton	Million liter	Million liter	Million liter	Million liter	Million liter	Million cma	ton	1000tons	TWh
2015	3.0	141	9,345	113	588	1,197	242	3,141	10	58,660	67
2016	4.0	152	10,072	121	634	1,273	261	3,385	11	57,850	72
2017	4.5	168	11,079	132	701	1,381	288	3,743	12	57,051	80
2018	5.0	188	12,389	147	784	1,526	322	4,185	13	56,263	89
2019	5.5	213	14,024	165	888	1,703	365	4,739	15	55,486	101
2020	6.0	241	15,884	186	1,005	1,910	414	5,368	17	54,720	114
2021	6.0	265	16,938	198	1,106	2,059	455	5,906	19	53,660	126
2022	6.0	291	18,063	211	1,216	2,220	500	6,494	21	52,620	139
2023	6.0	320	19,262	225	1,337	2,394	550	7,141	23	51,600	152
2024	6.0	352	20,541	240	1,470	2,582	605	7,847	25	50,600	167
2025	6.0	387	21,905	256	1,615	2,784	664	8,622	27	49,620	184
2026	6.5	415	23,385	273	1,735	2,975	713	9,253	29	48,145	201
2027	6.5	446	24,966	292	1,864	3,181	765	9,930	32	46,714	219
2028	6.5	478	26,653	312	2,002	3,400	821	10,657	34	45,325	239
2029	6.5	513	28,454	333	2,151	3,634	881	11,436	36	43,977	260
2030	6.5	551	30,377	355	2,311	3,884	946	12,273	39	42,670	281
2031	6.5	586	32,338	378	2,460	4,135	1,007	13,065	42	41,401	299
2032	6.5	623	34,336	401	2,612	4,391	1,069	13,872	44	40,171	317
2033	6.5	660	36,414	426	2,770	4,657	1,133	14,712	47	38,976	336
2034	6.5	698	38,522	450	2,931	4,926	1,199	15,564	50	37,818	356
2035	6.5	737	40,636	475	3,092	5,196	1,265	16,418	52	36,693	376
2036	6.5	776	42,812	500	3,257	5,475	1,333	17,297	55	35,603	396
2037	6.5	816	44,993	526	3,423	5,753	1,400	18,178	58	34,544	416
2038	6.5	857	47,257	552	3,595	6,043	1,471	19,093	61	33,517	437
2039	6.5	900	49,660	580	3,778	6,350	1,546	20,064	64	32,521	459
2040	6.5	946	52,149	610	3,967	6,669	1,623	21,069	67	31,554	482
2040/15	6.1	7.9	7.1	7.0	7.9	7.1	7.9	7.9	7.9	−2.4	8.6

Note: Power generation data comes from the power generation plan of PSD, the generation does not include export.
Source: PSD

Table 5-2.8 Final Energy Demand Forecasts (Oil equivalence unit: ktoe)

	GDP from Model	LPG	Gasoline(PMS)	Kerosene (ATK)	Kerosene (HHK)	Diesel (AGO)	Fuel oil	Natural gas	Coal	Wood & Charcoal	Power generation	Total
	%	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe
2015	3.0	154	7,417	94	488	1,045	210	2,710	6	24,931	5,371	42,426
2016	4.0	166	8,007	102	527	1,128	227	2,926	6	24,586	5,799	43,474
2017	4.5	182	8,802	112	579	1,240	250	3,216	7	24,247	6,374	45,008
2018	5.0	203	9,784	124	643	1,371	278	3,575	7	23,912	7,085	46,983
2019	5.5	228	11,016	138	724	1,523	313	4,025	8	23,582	7,977	49,535
2020	6.0	255	12,327	155	811	1,699	350	4,505	9	23,256	8,927	52,294
2021	6.0	281	13,084	164	891	1,824	385	4,954	10	22,805	9,826	54,224
2022	6.0	309	13,887	175	980	1,957	423	5,447	11	22,363	10,810	56,363
2023	6.0	339	14,739	185	1,078	2,101	465	5,990	13	21,930	11,891	58,731
2024	6.0	373	15,644	197	1,185	2,254	511	6,585	14	21,505	13,073	61,342
2025	6.0	410	16,605	209	1,303	2,419	562	7,239	15	21,089	14,370	64,221
2026	6.5	440	17,727	223	1,399	2,586	603	7,769	16	20,462	15,711	66,936
2027	6.5	472	18,925	238	1,503	2,764	647	8,337	17	19,853	17,142	69,900
2028	6.5	507	20,204	254	1,615	2,955	695	8,947	19	19,263	18,667	73,125
2029	6.5	544	21,569	271	1,735	3,158	746	9,602	20	18,690	20,322	76,658
2030	6.5	584	23,027	289	1,864	3,376	800	10,304	22	18,135	21,962	80,362
2031	6.5	622	24,519	308	1,985	3,595	852	10,972	23	17,596	23,385	83,856
2032	6.5	660	26,040	327	2,108	3,818	905	11,653	24	17,073	24,836	87,444
2033	6.5	700	27,624	347	2,236	4,050	960	12,361	26	16,565	26,346	91,215
2034	6.5	741	29,225	367	2,366	4,285	1,016	13,078	27	16,073	27,873	95,050
2035	6.5	782	30,837	388	2,496	4,521	1,072	13,799	29	15,595	29,411	98,930
2036	6.5	824	32,498	408	2,631	4,765	1,129	14,542	30	15,131	30,994	102,953
2037	6.5	866	34,161	429	2,765	5,009	1,187	15,287	32	14,681	32,581	106,999
2038	6.5	910	35,890	451	2,905	5,262	1,247	16,061	34	14,245	34,230	111,234
2039	6.5	956	37,724	474	3,054	5,531	1,311	16,881	35	13,821	35,979	115,766
2040	6.5	1,005	39,624	498	3,207	5,810	1,377	17,732	37	13,410	37,791	120,491
2040/15	6.1	7.8	6.9	6.9	7.8	7.1	7.8	7.8	7.8	−2.4	8.1	4.3

Source: PSD

5-2-5 Fossil Energy used in the Power Sector

The power generation structure in the power generation plan is as shown in Table 5-2.9. The renewable power generation category includes PV, wind, small hydro, etc.

Table 5-2.9 Power generation forecasts

	GDP	Coal	Natural gas	Hydro	Nuclear	Renewable	Total
	%	GWh	GWh	GWh	GWh	GWh	GWh
2015	3.0	0	58,404	6,123	0	0	64,527
2016	4.0	0	65,409	6,777	0	0	72,186
2017	4.5	0	72,730	7,096	0	0	79,826
2018	5.0	0	82,164	7,096	0	0	89,260
2019	5.5	0	93,795	7,096	0	175	101,066
2020	6.0	0	100,712	10,090	0	3,669	114,470
2021	6.0	0	104,158	15,382	0	6,409	125,949
2022	6.0	0	112,415	17,158	0	8,930	138,503
2023	6.0	0	124,136	17,311	0	10,837	152,284
2024	6.0	0	137,296	17,311	0	12,745	167,352
2025	6.0	6,347	134,957	18,769	9,154	14,653	183,880
2026	6.5	6,347	145,980	22,958	9,154	16,561	201,000
2027	6.5	6,347	157,895	27,412	9,154	18,469	219,276
2028	6.5	8,462	168,206	27,941	13,731	20,376	238,717
2029	6.5	8,462	182,293	28,470	18,308	22,284	259,818
2030	6.5	8,462	200,737	28,999	18,308	24,192	280,698
2031	6.5	10,578	210,912	29,528	22,885	24,916	298,820
2032	6.5	10,578	223,111	30,057	27,463	26,074	317,282
2033	6.5	10,578	240,775	30,586	27,463	27,087	336,488
2034	6.5	12,693	252,107	30,586	32,040	28,534	355,961

	GDP	Coal	Natural gas	Hydro	Nuclear	Renewable	Total
	%	GWh	GWh	GWh	GWh	GWh	GWh
2035	6.5	12,693	265,768	30,586	36,617	29,837	375,501
2036	6.5	14,809	282,018	30,586	36,617	31,573	395,603
2037	6.5	14,809	300,722	30,586	36,617	33,021	415,755
2038	6.5	14,809	320,202	30,586	36,617	34,468	436,681
2039	6.5	16,924	338,549	30,586	36,617	36,205	458,881
2040	6.5	16,924	359,816	30,586	36,617	37,941	481,884
2040/15	6.1		7.5	6.6			8.4

Note: The growth rates of coal, nuclear are estimated from 2025 to 2040.
Source: PSD

The consumption of resources and fuel for coal, natural gas, hydro, and nuclear for the power sector is as follows:

Table 5-2.10 Consumption of Resources and Fuels for power sector

	Coal	Natural gas	Hydro	Nuclear	Renewable
2015	0	11,586	527	0	0
2016	0	12,975	583	0	0
2017	0	13,636	610	0	0
2018	0	14,493	610	0	0
2019	0	15,569	610	0	15
2020	0	15,989	868	0	315
2021	0	17,318	1,323	0	551
2022	0	18,281	1,476	0	768
2023	0	19,392	1,489	0	932
2024	0	20,614	1,489	0	1,096
2025	1,193	19,885	1,614	1,831	1,260
2026	1,193	21,230	1,974	1,831	1,424
2027	1,193	22,318	2,357	1,831	1,588
2028	1,590	23,601	2,403	2,746	1,752
2029	1,590	25,367	2,448	3,662	1,916
2030	1,590	27,912	2,494	3,662	2,081
2031	1,988	29,208	2,539	4,577	2,143
2032	1,988	30,802	2,585	5,493	2,242
2033	1,988	33,082	2,630	5,493	2,329
2034	2,386	34,533	2,630	6,408	2,454
2035	2,386	36,313	2,630	7,323	2,566
2036	2,783	38,458	2,630	7,323	2,715
2037	2,783	40,944	2,630	7,323	2,840
2038	2,783	43,457	2,630	7,323	2,964
2039	3,181	45,871	2,630	7,323	3,114
2040	3,181	48,671	2,630	7,323	3,263
2040/15	6.8%	5.9%	6.6%	9.7%	6.5%

Note: The growth rates for coal, nuclear are estimated from 2025 to 2040.
Note: Energy conversion factors used for the above conversion are as per the following table.

Energy	Convertor
Natural gas	1m3 = 8,620 kcal
Hydro	1kWh = 860 kcal
Nuclear	1 kWh = 2,000 kcal
Renewable	1kWh = 860 kcal

Source: PSD

5-2-6 Primary Energy Demand Forecasts

The sum of final energy demand and the fuel consumption in power and other transformation sectors is primary energy.

Table 5-2.11 Primary Energy Demands (Physical unit)

Year	GDP from Model	LPG	Gasoline(PMS)	Kerosene (ATK)	Kerosene (HHK)	Diesel (AGO)	Fuel oil	Natural gas	Coal	Hydro	Nuclear	RE	Wood & Charcoal
	%	1000 ton	Million liter	Million liter	Million liter	Million liter	Million liter	Million cma	1000ton	ktoe	ktoe	ktoe	1000tons
2015	3.0	141	9,345	113	588	1,197	242	16,565	0	527	0	0	58,660
2016	4.0	152	10,072	121	634	1,273	261	18,419	0	583	0	0	57,850
2017	4.5	168	11,079	132	701	1,381	288	19,544	0	610	0	0	57,051
2018	5.0	188	12,389	147	784	1,526	322	20,979	0	610	0	0	56,263
2019	5.5	213	14,024	165	888	1,703	365	22,779	0	610	0	15	55,486
2020	6.0	241	15,884	186	1,005	1,910	414	23,893	0	868	0	315	54,720
2021	6.0	265	16,938	198	1,106	2,059	455	25,972	0	1,323	0	551	53,660
2022	6.0	291	18,063	211	1,216	2,220	500	27,677	0	1,476	0	768	52,620
2023	6.0	320	19,262	225	1,337	2,394	550	29,610	0	1,489	0	932	51,600
2024	6.0	352	20,541	240	1,470	2,582	605	31,733	0	1,489	0	1,096	50,600
2025	6.0	387	21,905	256	1,615	2,784	664	31,663	2,130	1,614	1,831	1,260	49,620
2026	6.5	415	23,385	273	1,735	2,975	713	33,853	2,130	1,974	1,831	1,424	48,145
2027	6.5	446	24,966	292	1,864	3,181	765	35,790	2,130	2,357	1,831	1,588	46,714
2028	6.5	478	26,653	312	2,002	3,400	821	38,002	2,840	2,403	2,746	1,752	45,325
2029	6.5	513	28,454	333	2,151	3,634	881	40,828	2,840	2,448	3,662	1,916	43,977
2030	6.5	551	30,377	355	2,311	3,884	946	44,614	2,840	2,494	3,662	2,081	42,670
2031	6.5	586	32,338	378	2,460	4,135	1,007	46,908	3,550	2,539	4,577	2,143	41,401
2032	6.5	623	34,336	401	2,612	4,391	1,069	49,563	3,550	2,585	5,493	2,242	40,171
2033	6.5	660	36,414	426	2,770	4,657	1,133	53,044	3,550	2,630	5,493	2,329	38,976
2034	6.5	698	38,522	450	2,931	4,926	1,199	55,576	4,260	2,630	6,408	2,454	37,818
2035	6.5	737	40,636	475	3,092	5,196	1,265	58,494	4,260	2,630	7,323	2,566	36,693
2036	6.5	776	42,812	500	3,257	5,475	1,333	61,858	4,970	2,630	7,323	2,715	35,603
2037	6.5	816	44,993	526	3,423	5,753	1,400	65,620	4,970	2,630	7,323	2,840	34,544
2038	6.5	857	47,257	552	3,595	6,043	1,471	69,447	4,970	2,630	7,323	2,964	33,517
2039	6.5	900	49,660	580	3,778	6,350	1,546	73,214	5,680	2,630	7,323	3,114	32,521
2040	6.5	946	52,149	610	3,967	6,669	1,623	77,464	5,680	2,630	7,323	3,263	31,554
2040/15	6.1	7.9	7.1	7.0	7.9	7.1	7.9	6.4	6.8	6.6	9.7	6.5	−2.4

Note: Natural gas for LNG is not included
Source: PSD

Table 5-2.12 Primary Energy Demand Forecasts (Oil equivalence unit: ktoe)

Year	GDP from Model	LPG	Gasoline(PMS)	Kerosene (ATK)	Kerosene (HHK)	Diesel (AGO)	Fuel oil	Natural gas	Coal	Hydro	Nuclear	RE	Wood & Charcoal	Total
	%	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe	ktoe
2015	3.0	153	7,402	94	487	1,043	210	14,296	0	527	0	0	24,900	49,111
2016	4.0	165	7,977	100	525	1,109	226	15,896	0	583	0	0	24,600	51,182
2017	4.5	183	8,775	109	580	1,203	250	16,867	0	610	0	0	24,200	52,777
2018	5.0	204	9,812	122	649	1,329	280	18,105	0	610	0	0	23,900	55,011
2019	5.5	231	11,107	136	735	1,484	317	19,659	0	610	0	15	23,600	57,894
2020	6.0	262	12,580	154	832	1,664	359	20,621	0	868	0	315	23,300	60,954
2021	6.0	288	13,415	164	915	1,794	395	22,415	0	1,323	0	551	22,800	64,061
2022	6.0	317	14,306	175	1,007	1,934	434	23,886	0	1,476	0	768	22,400	66,702
2023	6.0	348	15,256	186	1,107	2,086	478	25,554	0	1,489	0	932	21,900	69,335
2024	6.0	383	16,269	199	1,216	2,249	525	27,386	0	1,489	0	1,096	21,500	72,311
2025	6.0	421	17,349	212	1,336	2,425	577	27,326	1,193	1,614	1,831	1,260	21,100	76,643
2026	6.5	451	18,521	226	1,436	2,592	619	29,216	1,193	1,974	1,831	1,424	20,500	79,984
2027	6.5	484	19,773	241	1,542	2,770	664	30,888	1,193	2,357	1,831	1,588	19,900	83,234
2028	6.5	520	21,109	258	1,657	2,961	713	32,798	1,590	2,403	2,746	1,752	19,300	87,807
2029	6.5	558	22,536	275	1,780	3,166	765	35,237	1,590	2,448	3,662	1,916	18,700	92,633
2030	6.5	599	24,059	294	1,912	3,384	821	38,504	1,590	2,494	3,662	2,081	18,100	97,498
2031	6.5	637	25,612	313	2,036	3,602	874	40,483	1,988	2,539	4,577	2,143	17,600	102,404
2032	6.5	677	27,194	332	2,162	3,825	928	42,775	1,988	2,585	5,493	2,242	17,100	107,300
2033	6.5	718	28,840	352	2,293	4,056	984	45,779	1,988	2,630	5,493	2,329	16,600	112,062
2034	6.5	759	30,509	373	2,425	4,291	1,041	47,965	2,386	2,630	6,408	2,454	16,100	117,341
2035	6.5	801	32,184	393	2,558	4,526	1,098	50,482	2,386	2,630	7,323	2,566	15,600	122,548
2036	6.5	844	33,907	414	2,695	4,769	1,157	53,386	2,783	2,630	7,323	2,715	15,100	127,724
2037	6.5	887	35,634	435	2,833	5,012	1,216	56,632	2,783	2,630	7,323	2,840	14,700	132,925
2038	6.5	932	37,428	457	2,975	5,264	1,277	59,935	2,783	2,630	7,323	2,964	14,200	138,169
2039	6.5	979	39,331	480	3,126	5,532	1,342	63,186	3,181	2,630	7,323	3,114	13,800	144,024
2040	6.5	1,028	41,302	504	3,283	5,809	1,409	66,855	3,181	2,630	7,323	3,263	13,400	149,988
2040/15		7.9	7.1	7.0	7.9	7.1	7.9	6.4	6.8	6.6	9.7	6.5	−2.4	4.6

Note: Natural gas for LNG and export is not included
Source: PSD

5-2-7 Natural Gas Demand Forecasts

Natural gas demands for final energy demand, power sector, LNG and export are as follows:

Table 5-2.13 Natural gas demand forecasts

Year	NG for domestic	NG for Export	NG of Total use	NG for domestic	NG for Export	NG of Total	NG for domestic	NG for Export	NG of Total	NG Total + Injection.	Reserves	R/P
	ktoe	ktoe	ktoe	mmcfd	mmcfd	mmcfd	Tcf	Tcf	Tcf	Tcf	TCF	Years
2015	14,296	22,649	36,945	1,588	2,555	4,144	0.6	0.9	1.5	3.0	167.4	55.3
2016	15,896	23,215	39,112	1,766	2,619	4,385	0.6	1.0	1.6	3.2	164.3	52.1
2017	16,867	23,796	40,663	1,874	2,684	4,558	0.7	1.0	1.7	3.2	161.0	49.9
2018	18,105	24,391	42,496	2,012	2,752	4,763	0.7	1.0	1.7	3.3	157.7	47.4
2019	19,659	25,000	44,659	2,184	2,820	5,005	0.8	1.0	1.8	3.4	154.3	44.8
2020	20,621	25,625	46,246	2,291	2,891	5,182	0.8	1.1	1.9	3.5	150.8	42.9
2021	22,415	26,266	48,681	2,490	2,963	5,454	0.9	1.1	2.0	3.6	147.1	40.3
2022	23,886	26,923	50,809	2,654	3,037	5,691	1.0	1.1	2.1	3.8	143.3	38.2
2023	25,554	27,596	53,150	2,839	3,113	5,952	1.0	1.1	2.2	3.9	139.5	36.0
2024	27,386	28,286	55,672	3,043	3,191	6,234	1.1	1.2	2.3	4.0	135.5	33.8
2025	27,326	28,993	56,319	3,036	3,271	6,307	1.1	1.2	2.3	4.0	131.5	32.9
2026	29,216	29,718	58,934	3,246	3,353	6,599	1.2	1.2	2.4	4.1	127.3	30.8
2027	30,888	30,461	61,349	3,432	3,436	6,868	1.3	1.3	2.5	4.2	123.1	29.0
2028	32,798	31,222	64,020	3,644	3,522	7,166	1.3	1.3	2.6	4.4	118.7	27.1
2029	35,237	32,003	67,239	3,915	3,610	7,525	1.4	1.3	2.7	4.5	114.2	25.1
2030	38,504	32,803	71,307	4,278	3,701	7,979	1.6	1.4	2.9	4.8	109.4	23.0
2031	40,483	33,623	74,106	4,498	3,793	8,291	1.6	1.4	3.0	4.9	104.5	21.4
2032	42,775	34,463	77,238	4,753	3,888	8,640	1.7	1.4	3.2	5.0	99.5	19.8
2033	45,779	35,325	81,104	5,086	3,985	9,071	1.9	1.5	3.3	5.2	94.3	18.0
2034	47,965	36,208	84,173	5,329	4,085	9,414	1.9	1.5	3.4	5.4	88.9	16.6
2035	50,482	37,113	87,596	5,609	4,187	9,796	2.0	1.5	3.6	5.5	83.4	15.1
2036	53,386	38,041	91,427	5,932	4,292	10,223	2.2	1.6	3.7	5.7	77.7	13.6
2037	56,632	38,992	95,625	6,292	4,399	10,691	2.3	1.6	3.9	5.9	71.8	12.2
2038	59,935	39,967	99,902	6,659	4,509	11,168	2.4	1.6	4.1	6.1	65.7	10.8
2039	63,186	40,966	104,153	7,021	4,621	11,642	2.6	1.7	4.2	6.3	59.4	9.4
2040	66,855	41,990	108,845	7,428	4,737	12,165	2.7	1.7	4.4	6.5	52.9	8.1
2040/15	6.4	2.5	4.4	6.4	2.5	4.4	6.4	2.5	4.4	3.1	-4.5	-7.4

Note: R/P is calculated under proved reserve with 180 Tcf in 2013
Note: The growth rate of LNG demand is assumed to be 2.5% per year
Source: PSD

5-3 GHG Emission Projections in Nigeria

5-3-1 GHG Emission in Nigeria

Nigeria has ratified the United Nations Framework Convention on Climate Change (FCCC) and the Kyoto Protocol. Having up until now experienced a constant shortage of power and increasing demand for electricity along with economic growth, Nigeria has gradually become more active in tackling climate change. As official documents to UNFCCC, the country submitted National Communications in 2003 and 2014, INDC[13] in 2015, and a Biannual Update Report (BUR)[14] in March 2018.

According to BUR, GHG emissions of 2015 were 712.6 million t-CO2-eq in which "AFOLU (Agriculture, Forest, and Other Land Use)" comprises a majority of the emissions (67%), followed by "Energy" (including Electricity Generation) (28%) (Table 5-3.1, Figure 5-3.1). "Electricity Generation" is 45 million

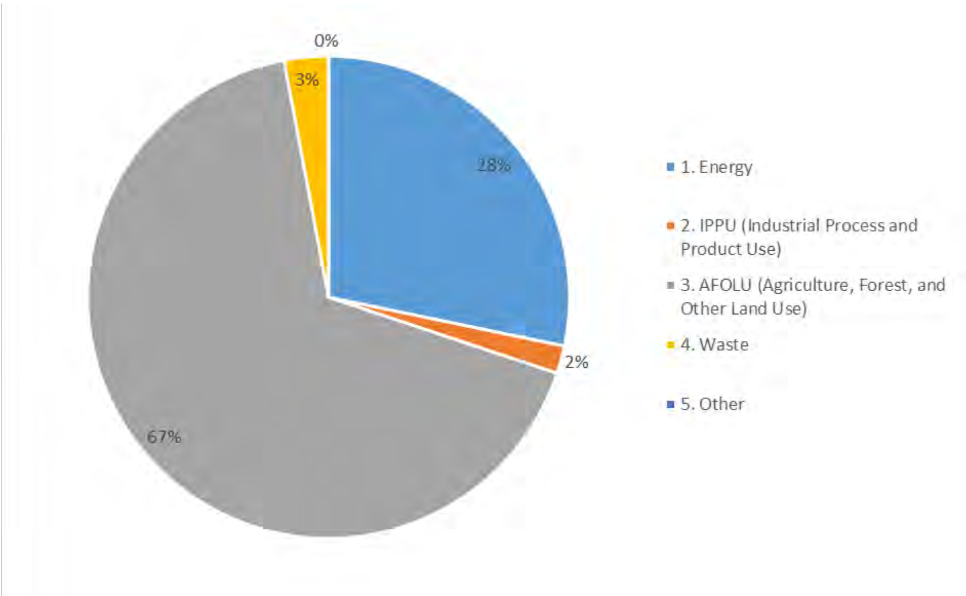
[13] INDC: Intended Nationally Determined Contributions is a term used under UNFCCC for reductions in greenhouse gas emissions that all countries signed the UNFCCC were asked to publish in the lead up to COP21 (2015).

[14] BUR: Biannual Update Report is a report to be submitted biannually by non-Annex I Parties prior to COPs. The decision was made in COP17 (2011) and stipulated in Decision 2.

t-CO2-eq, contributing 6.3% of total emissions, 22% of "Energy," and 81% of "Energy Industries" (Figure 5-3.2).

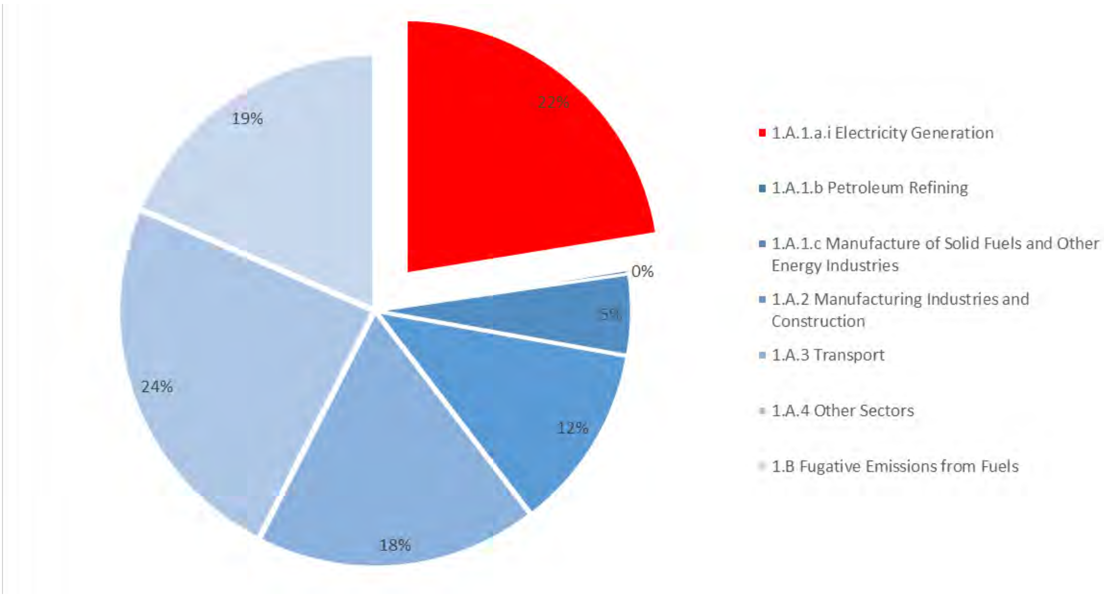
Table 5-3.1 GHG emissions in Nigeria (2015)

UNFCCC Category	GHG Emission (kt CO2-eq)
Total	**712,638**
1. Energy	201,320
1.A Fuel Combustion Activities	164,043
1.A.1 Energy Industries	55,991
1.A.1.a Main Activity Electricity and Heat Production	45,187
1.A.1.a.i Electricity Generation	**45,187**
1.A.1.b Petroleum Refining	521
1.A.1.c Manufacture of Solid Fuels and Other Energy Industries	10,284
1.A.1.c.i Manufacture of Solid Fuels	1,171
1.A.1.c.ii Other Energy Industries	9,113
1.A.2 Manufacturing Industries and Construction	23,714
1.A.3 Transport	36,022
1.A.4 Other Sectors	48,316
1.B Fugitive Emissions from Fuels	37,277
2. IPPU (Industrial Process and Product Use)	13,267
3. AFOLU (Agriculture, Forest, and Other Land Use)	476,949
4. Waste	21,103
5. Other	0



Source: JICA Study Team based on BUR (2018)

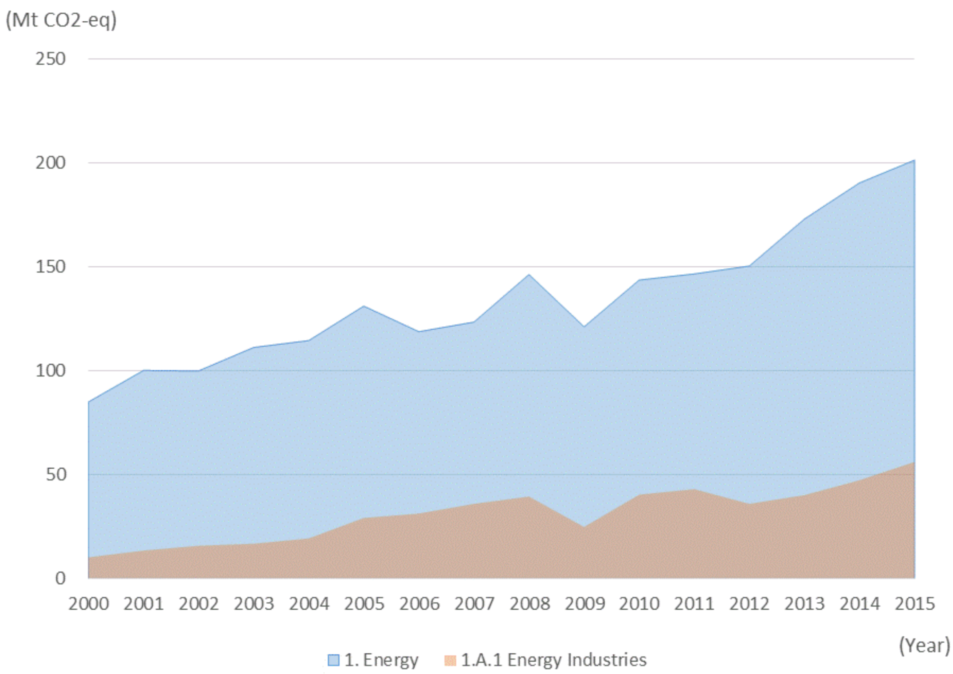
Figure 5-3.1 GHG emissions in Nigeria (2015)



Source: JICA Study Team based on BUR (2018)

Figure 5-3.2 Energy sector GHG emissions in Nigeria (2015)

Figure 5-3.3 shows GHG emission trends in the energy sector and energy industries (including electricity generation). The energy sector includes energy industries, manufacturing industries and construction, transport, and other sectors. GHG emissions from energy industries has grown year by year, emissions were approximately 12 % of the energy sector in 2000, and grew to 30 % in 2015. The ratio is likely to increase as more fossil fuel is consumed in power generation.



Source: JICA Study Team based on BUR (2018)

Figure 5-3.3 Energy sector GHG emissions in Nigeria (2000-2015)

5-3-2 GHG Emission Reduction Target in INDC

In the Conference of the Parties to UNFCCC in December 2015 (COP 21), the parties agreed on a framework (Paris Agreement) in which all countries, including developed and developing countries, would participate to tackle climate change. Prior to COP 21, each country submitted an INDC, which was subsequently submitted as formal NDCs under the Paris Agreement. The countries then continue to submit NDCs every five years thereafter[15]. An INDC/NDC describes mitigation efforts to achieve GHG reduction targets determined by each country, and its implementation is required for each country.

The Nigerian INDC indicates its policy to pursue sustainable development with consideration for climate change measures without hampering growth in Nigeria, where economic development is progressing rapidly while experiencing problems specific to developing countries such as power shortage, poverty, sanitation, and hygiene issues. With the two pillars of economic development and social development, INDC is aiming at a "GDP growth rate of 5%, improvement of standard of living, access to power for the whole nation," and then presents GHG emission targets (Table 5-3.2 and Figure 5-3.4).

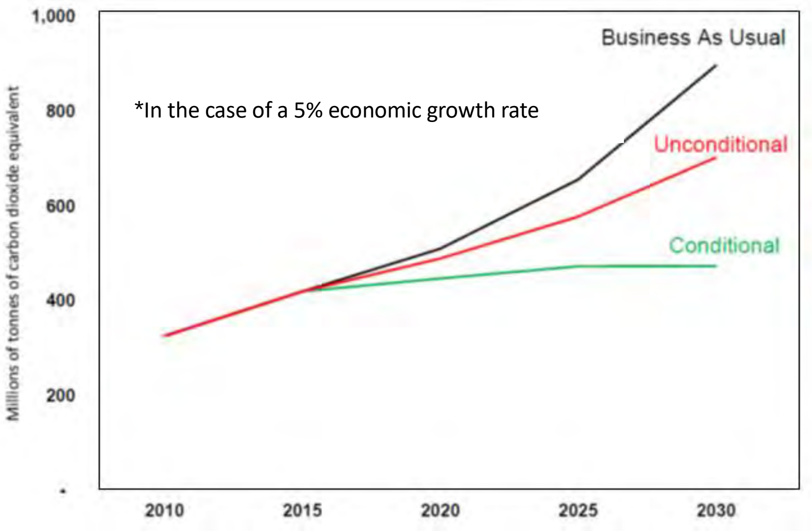
The business-as-usual (BAU) scenario with 5% economic growth predicts approximately 900 million t-CO2 of GHG emissions, while the BAU scenario with a higher growth of 7% predicts emissions of more than 1,000 million t-CO2. Based on these estimated emissions, the basic reduction target of GHG emissions is set to 20% on BAU, and a 45% of reduction is expected to be achievable with international support such as the introduction of new technology, investment, and capacity building programs.

Table 5-3.2 GHG emission reduction target (2030)

Scenario		GHG emission		GHG emission per capita	
BAU	Economic Growth Rate 5%, Population Growth Rate 2.5%, Power supply to the whole nation	Approx. 900	Million t-CO2	Approx. 3.4	t-CO2/capita
Unconditional	20% on BAU in principle	Approx. 720		Approx. 2.5	
				(Estimated by JICA Team)	
Conditional	45% on BAU with enhanced international support	Approx. 495		Approx. 2.0	

Source: JICA Study Team based on INDC (2015)

[15] Many countries, including Nigeria, in fact submitted INDC again as NDC.



Source: INDC (2015)

*The before-mentioned BUR recalculates the 2001-to-2015 emissions, which is different from the emissions in INDC.

Figure 5-3.4 GHG emission projection (2015-2030)

According to FME, the power systems in the INDC's prediction of GHG emissions includes gas-fired, coal-fired, hydro power, and renewable energy (solar, small hydro, wind power, and biomass). Nuclear power generation has not been considered as there have been no concrete plans for this up to now.

In the INDC, the following 7 items are listed as actions necessary to achieve the GHG reduction target. Particularly, high expectations for GHG reduction potential are place on the power sector. The GHG reduction target in a conditional scenario would be achieved with a 500 million t-CO2 reduction on BAU.

- Work towards ending gas flaring by 2030
- Work towards an off-grid solar PV of 13GW
- Efficient gas generators
- 2% per year energy efficiency (30# by 2030)
- Transport shift from car to bus
- Improve electricity grid
- Climate smart agriculture and reforestation

Table 5-3.3 Measures toward the GHG emission reduction targets

Measure	Potential GHG reduction in 2030	
Economy-wide energy efficiency	179	Million t-CO2
Efficient gas power stations	102	
Work toward ending of gas flaring	64	
Climate smart agriculture	74	
Reduce transmission losses	26	
Renewable energy	31	
TOTAL	476	Million t-CO2

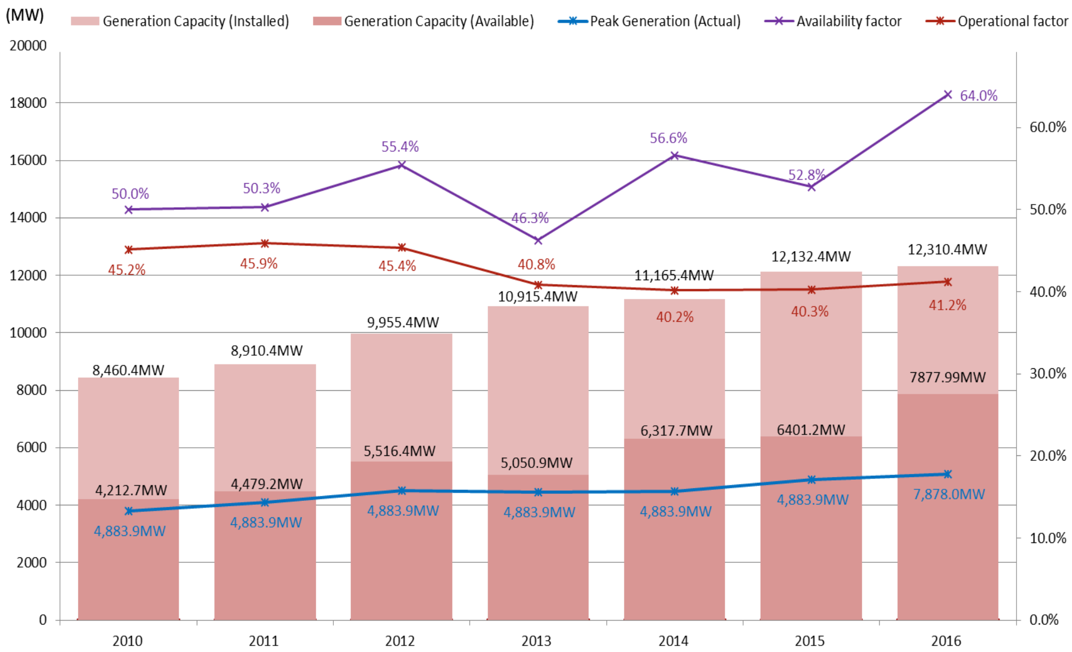
Source: INDC (2015)

CHAPTER 6 Power Generation Development Plan

Chapter 6 Power Generation Development Plan

6-1 Power Generation Situation in Nigeria

The actual power supply from 2010 to 2016 in Nigeria shows the installed generation capacity increasing every year, reaching 12,310 MW in 2016 as shown in Figure 6-1.1. Moreover, although the ratio of available generation capacity relative to installed generation capacity is improving, it declined to around 50% at its lowest point, underlining the wide gap between the available capacity and national peak demand forecast. The national peak demand benchmarks Nigeria's potential power demand assuming an unhindered power supply. Actually, due to power supply restrictions such as planned outages, the actual power supply doesn't satisfy national peak demand in Nigeria. While the available capacity was 7,743MW, the peak demand forecast was 14,630 MW[1] in 2017. This underlines the urgency of examining generation constraints as well as planning new forms of power generation.

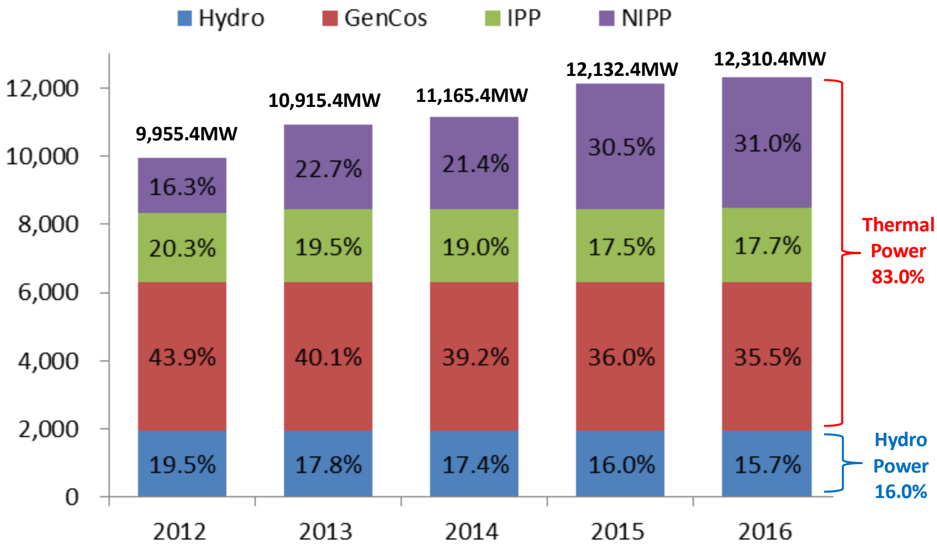


Source: TCN Annual Technical Report 2010-2016

Figure 6-1.1 Power Supply Record in Nigeria (2010-2016)

Figure 6-1.2 and Table 6-1.1 show the ratio and capacity according to operators. The ratio of thermal generation increased gradually from 2012 to 2016 in a seemingly ongoing trend with the growth in the NIPP ratio. Six out of ten NIPP power plants are 100 percent completed. Gbarain in Bayelsa State has attained 90 percent completion, Alaoji in Abia State 80 percent, Omoku in Rivers State 71 percent while Egbema achieved a 67 percent completion level.

[1] TCN, "Transmission Expansion Plan, Development of a Power System Master Plan for the Transmission Company of Nigeria", December 2017



Source: TCN Annual Technical Report 2012-2016

Figure 6-1.2 Ratio of Power Generation (2012-2016)

Table 6-1.1 Installed Power Generation Capacity (2012-2016)

		Unit	2012	2013	2014	2015	2016
Total	Total Installed Capacity	MW	9,955.4	10,915.4	11,165.4	12,132.4	12,310.4
Hydro	Hydro (Total)	MW	1,938.4	1,938.4	1,938.4	1,938.4	1,938.4
	Hydro (Total)	%	19.5%	17.8%	17.4%	16.0%	15.7%
Thermal	GenCos	MW	4,375.0	4,375.0	4,375.0	4,375.0	4,375.0
	IPP	MW	2,017.0	2,127.0	2,127.0	2,119.0	2,177.0
	NIPP	MW	1,625.0	2,475.0	2,725.0	3,700.0	3,820.0
	Thermal (Total)	MW	8,017.0	8,977.0	9,227.0	10,194.0	10,372.0
	Thermal (Total)	%	80.5%	82.2%	82.6%	84.0%	84.3%

Source: TCN Annual Technical Report 2012-2016

Table 6-1.2 shows the thermal power plants and hydropower plants currently interconnected to the national grid system as of the end of 2016 in Nigeria. For the hydropower plant, operated by the Nigerian government and power generation companies (hydropower), the government owns assets and entrusts management to a private company based on concession. Thermal power plants are owned and operated by the Nigerian government and power generation company (thermal power), which includes power generation companies that the government privatized by selling a majority of shares to the private sector. Regarding NIPP, NDPHC, a government-funded company, owns NIPP assets and operates power plants. IPP, meanwhile, is an independent power generation company that builds and operates power plants through investment by oil companies and local governments.

The total available capacity of thermal power generating facilities is 6,669 MW, which comprises more than 80% of all power generating facilities including hydropower (total 7,878 MW) connected to the national grid system in Nigeria. The breakdown of total available capacity for thermal power plants is 2,245 MW by seven private companies, 2,689 MW by eight NIPP projects and 1,243 MW by nine IPP-A (existing plants) projects.

For various reasons, including the proneness to power failure among generators, maintenance difficulties due to inadequate organization and a lack of spares, an inadequate gas supply due to the delay in constructing the pipeline, the ratio of available capacity to installed capacity (availability factor) is less than 50% in some power plants, hence the urgent need to boost available capacity.

Table 6-1.2 Existing Thermal Power Plants and Hydropower Plants

Category	Power Plant	Installed Capacity (MW)	Available Capacity (MW)	Availability Factor (%)
FGN Successor Companies (Privatized Hydro Station)	Kainji	760	320	42
	Jebba	578	441	76
	Shiroro	600	448	75
	Sub-Total	1,938	1,209	62
Total (Hydro)		**1,938**	**1,209**	**62**
FGN Successor Companies (Privatized Thermal Station)	Egbin (ST)	1,320	1002	76
	Afam (IV & V) (GT)	351	88	25
	Delta (GT)	900	585	65
	Sapele (ST)	720	234	32
	Gerugu (GT)	414	237	57
	Olorunsogo I (GT)	335	281	84
	Omotosho (GT)	335	301	93
	Sub-Total	4,375	2,737	63
NIPP (Thermal Station)	Olorunshogo (Combined)	750	584	78
	Alaoji (Combined)	500	280	56
	Gerugu (GT)	450	410	91
	Ihovbor (GT)	500	311	62
	Omotosho (GT)	500	439	88
	Sapele (GT)	500	337	67
	Odukpani (GT)	500	272	54
	Gbarain (GT)	120	55	46
	Sub-Total	3,820	2,689	70
IPP-A (Thermal Station)	Rivers (GT)	180	113	63
	Omoku (GT)	150	74	49
	ASCO (ST)	110	2	2
	Trans-Amadi (GT)	100	52	52
	Okpai (Gas)	480	323	67
	Ibom (GT)	155	111	72
	Afam VI (GT)	650	533	82
	Paras (GT)	58	36	61
	AES (GT)	294	0	0
	2,119	2,177	1,243	57
Total (Thermal)		**10,372**	**6,669**	**64**
Grand Total (Thermal + Hydro)		**12,310**	**7,878**	**64**

Note: Availability Factor = Available Capacity / Installed Capacity x 100 (%)
Source: TCN Annual Technical Report 2016

Table 6-1.3 shows power generation facilities interconnected to the national grid system in Nigeria and the future schedule of additional power generation capacity from 2017 till 2030. The current total installed capacity of all power plants is 7,743MW in 2017 and is expected to reach 41,247MW by 2030. The ratio of thermal power installed capacity was 86% in 2017, but will decline to 72% in 2030. Also, an increase in power generation capacity of around 21,000 - 28,000 MW after 2017 was scheduled for 2013, but revised down in 2014 to a lower figure of less than 15,000 MW, even after 2020. This is due not only to transmission constraints such as power evacuation difficulties, heat capacity limitations of transmission lines and capacity limitations of transformer, but also generation constraints such as inadequacy of gas supplies, frequent power failures of generators, numerous equipment failures affecting many power plants for extended periods, long span O&M of generation facilities due to insufficient organization or a lack of spares, etc. In particular, equipment failures and insufficient O&M are very serious problems, which may render many generators unusable all year round in many power plants.

Table 6-1.3 The future schedule of the additional power generation capacity

Generation type	Category	Installed Capacity (MW)	Available Capacity (MW)			
			2017	2020	2025	2030
Thermal	Existing	10549	6534	8099	9245	7925
	Under construction	1418	113	1343	1418	1418
	Proposed	25307	0	966	12301	20452
	Total	**37274**	**6647**	**10408**	**22964**	**29795**
Hydro	Existing	1938	1056	1807	1967	1842
	Under construction	809	30	809	809	809
	Proposed	5096	0	0	1163	4181
	Total	**7843**	**1086**	**2616**	**3939**	**6832**
Nuclear	Existing	-	-	-	-	-
	Under construction	-	-	-	-	-
	Proposed	2400	0	0	1,200	2,400
	Total	**2400**	**0**	**0**	**1200**	**2400**
PV・Wind	Existing	-	-	-	-	-
	Under construction	10	10	10	10	10
	Proposed	2230	0	1080	1410	2210
	Total	**2240**	**10**	**1090**	**1420**	**2220**
Grand Total		**49786**	**7743**	**14114**	**29523**	**41247**

Source: JICA Study Team base of information by TCN and other related agencies

IPP of new thermal power plants with private investment was started from 2001 in Nigeria and the Nigerian government adopts a policy to sell control of each power plant to a private company. Many existing power plants owned by the government are so prone to equipment failures that many generators in such power plants are almost unusable, whereas IPPs are expected to spread more widely in future. In particular, projects achieving PPA agreement such as Azura, Zuma and those licensed by NERC such as Bresson, Ibom, Century, are highly likely to achieve the target installed capacity in future, because evacuation studies and EIA studies of those projects have already been approved by NERC. PHCN impose an obligation on private companies to restore available capacity to the installed level within a specified period. Private companies should prepare necessary spare parts and execute O&M within a fixed period at their discretion to improve equipment failures and lack of O&M organization and restore available capacity. However, many private companies cannot improve O&M organization or purchase spare parts because the necessary payments have not been made by the Nigerian government. In conclusion, private companies should only formulate an O&M plan after PPA agreement and the Nigerian government should execute the necessary payments when approving said O&M plan of the private company. At the same time, the government should support efforts to construct natural gas pipelines and the necessary infrastructure from outside the power plant for a private company. After the government has completed payment, the private company should improve equipment failures, O&M organization and available capacity at their discretion.

6-1-1 Thermal Power Generation Facilities

(1) Availability status and unavailability cause of each power plant

The ratio of thermal power installed capacity will exceed 80% of the total installed capacity in 2015. However, the ratio of available capacity to installed capacity (availability factor) is very low, about or less than 50%, hence the need to investigate and analyze the unavailability cause of each power plant. Table 6-1.4 shows the availability status and unavailability causes.

For gas turbine machinery, the main causes of long-term stoppage are recorded such as high vibration of turbine rotors, turbine blade failure, inlet guide vane problem, combustion problem, abnormally high exhaust temperature, cooling water system problem, lube oil system problem, etc. As for electrical equipment, excitation problems and high winding temperature of generators, burning of transformers and associated switchgear are also causes of gas turbine stoppages. Besides, many generators have been decommissioned due to obsolete spares. It is also assumed that O&M organizations are not arranged at all in many power plants.

Additionally, a lack of gas supply also renders generators usable for extended periods. The gas problem is one resulting in low availability of generators, but the ratio to all unavailable spans of all power plants is small. In addition, transmission problem such as trip on reverse power, high or low frequency and collapsed towers happen in various places.

Ultimately, several problems exist with gas supply and transmission, but equipment failures and the lack of O&M organizations are the top priorities and the main reasons behind lower available capacity. If equipment failures improve after executing superior O&M, there is scope to improve the available capacity.

Table 6-1.4 Availability status and unavailability cause of each power plant

Power Station	Type	Unit	Jan.	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Main unavailability causes
Omotosho	Gas	GT1													・Excitation problem of generator ・Rehabilitation of power generation equipment
		GT2													
		GT3													
		GT4													
		GT5													
		GT6													
		GT7													
		GT8													
Omoku	Gas	GT1													・Collapsed towers
		GT2													
		GT3													
		GT4													
		GT5													
		GT6													
Delta	Gas	GT1													・Transformer breakdown ・High vibration of turbine rotor ・Turbine blade failure ・Maintenance ・Awaiting implementation of maintenance
		GT2													
		GT3													
		GT4													
		GT5													
		GT6													
		GT7													
		GT8													
		GT9													
		GT10													
		GT11													
		GT12													
		GT13													
		GT14													
		GT15													
		GT16													
		GT17													
		GT18													
		GT19													
		GT20													
Trans Amadi	Gas	GT1													・Trip on reverse power
		GT2													
		GT3													
		GT4													
ASCO	Steem	ST1													・Fire outbreak on generator
		ST2													
Afam VI	Gas	GT11													・Condensate of steem in gas turbine ・Collapsed towers ・Maintenance
		GT12													
		GT13													
		ST1													
Ibom	Gas	GT1													・Inlet guide vane problem ・Low gas or gas constraints
		GT2													
		GT3													
Afam I - V	Gas	GT1													・Compressor blade failur of gas turbine ・Burnt of switchgear ・Decommissioned due to obsolete spares ・Maintenance
		GT2													
		GT3													
		GT4													
		GT5													
		GT6													
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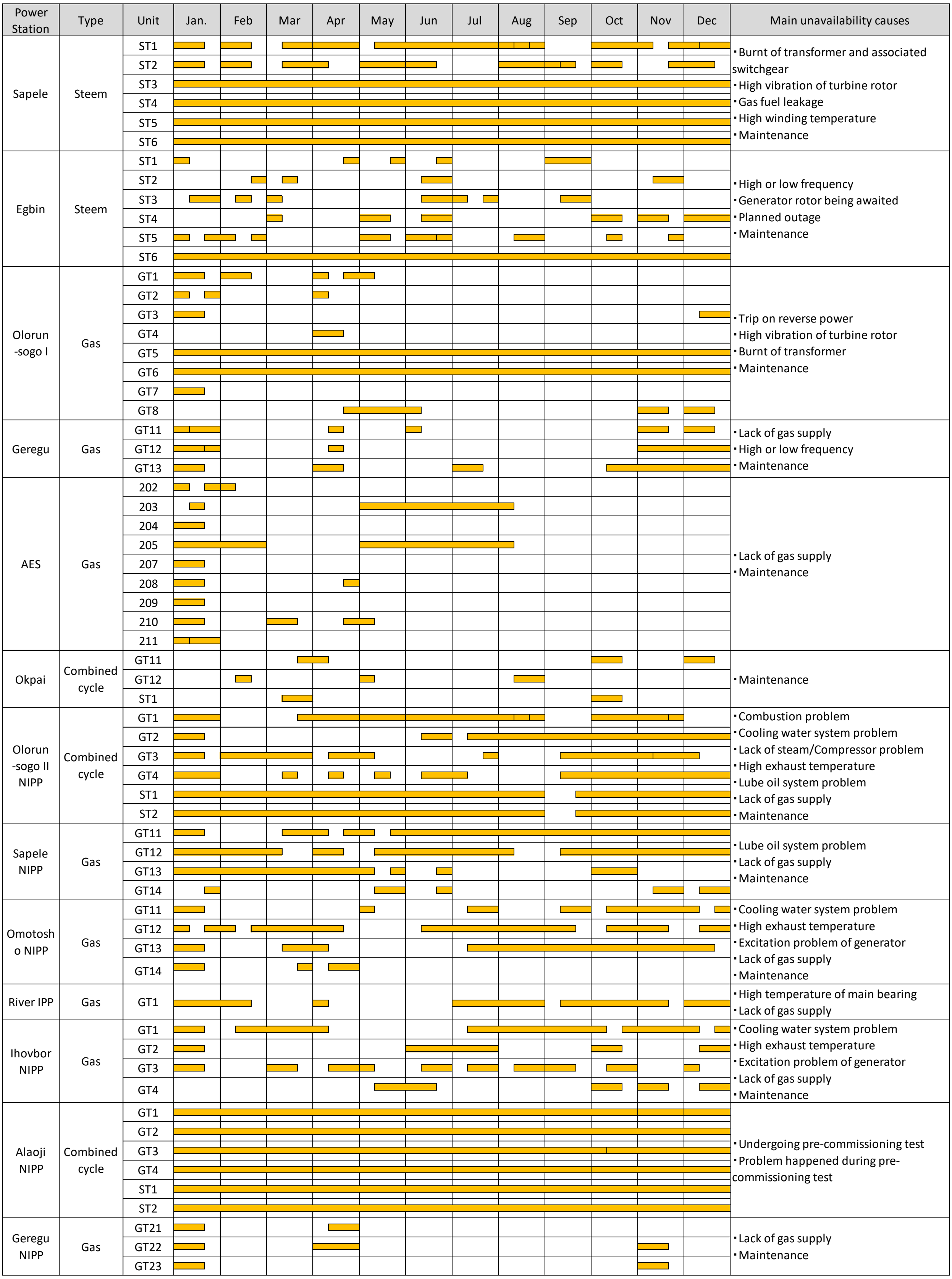


Note: Unavailable

Source: TCN Annual Technical Report 2014

(2) Natural gas supply to thermal stations and operation fuel

All thermal power stations use natural gas for fuel in Nigeria and thermal companies are major consumers of natural gas marketed by the Nigerian Gas Company (NGC) for power generation. Table 6-1.5 shows the volume of gas consumed, the cost of gas against energy generated and the yearly average operational fuel cost (for generation and transmission) in 2014.

Table 6-1.5 Natural gas supply to thermal stations and operation fuel

Power Plant	Quantity of Gas Consumed (10^6 x SCF)	Cost of Gas against Energy Generated (10^6 x NAIRA)	Yearly Average Operation Fuel Cost (NAIRA / kWh)	
			Generated	Sent Out
Egbin	45,960	13,900	2.97	3.19
AES	3,200	970	2.69	2.75
Delta	32,440	9,810	3.50	3.69
Sapele	5,910	1,790	4.38	4.69
Sapele II	9,570	2,890	3.17	3.18
Afam VI	23,860	7,210	2.16	2.21
Afam IV	4,060	1,230	4.28	4.31
Omotosho	11,130	3,360	3.48	3.56
Omotosho II	11,830	3,580	3.24	3.27
Geregu I	10,360	3,130	3.34	3.37
Geregu II	6,160	1,870	1.74	1.78
Ihovbor	17,250	5,250	3.43	3.47
Olorunsogo I	1,253	379	3.50	3.52
Olorunsogo II	1,117	338	3.99	4.05
Total	**184,100**	**55,707**		
	Monthly Thermal Average		**3.28**	**3.36**

Source: TCN Annual Technical Report 2014

During the dry season, although the yearly peak load is desired, water levels of dams decline and hydropower plants cannot meet the peak load requirement. Instead of hydropower plants, all gas thermal plants have to correspond to peak generation and provide crucial relief. Okpai and Afam VI power plants rarely have gas problems and contribute significantly to peak generation during the dry season because they own and maintain their gas wells themselves.

Although the volume of gas supplied by NGC increased by 13% in 2015, it remains insufficient for the generation required and a yearly power shortfall of about 2,000 ~ 3,000 MW is reported due to gas constraints. Moreover, the quality of gas is also insufficient because many impurities like sulfur are incompletely removed, causing multiple problems, e.g. frequent forced outages due to generator problems, inability to generate power and unstable frequency and voltage due to system disturbances. As well as gas supply inadequacy, the fuel gas cost increased by 13% in 2015. In some thermal power plants such as Egbin and AES, the volume of gas consumed decreased compared to 2014 while the operational fuel cost increased. If this trend persists, it might make it more difficult for these thermal power plants to procure gas supplied by NGC and continue generation.

To supply adequate natural gas for all thermal power plants in Nigeria, it is crucial to arrange natural gas pipelines covering the whole of Nigeria as well as gas plants preparing for dry gas. All existing gas pipelines are concentrated in the southern part of Nigeria, comprising a network of two gas pipelines. One gas pipeline network mainly comprises ELP (Escravos-Lagos pipeline), starting from Escravos, in the western part of the Niger river in the Niger Delta, to Lagos. The other pipeline network is that of the Eastern part of Niger river. There are also a total of 11 existing gas plants with total capacity of 2,376 MSCFD（Million Standard Cubic Feet per Day), five gas plants with capacity of 326 MSCFD located in the eastern part of Niger river. Currently, 36” ELP2 (Escravos-Lagos pipeline No. 2) and other new pipeline expansion plans and new plans for a total of six gas plants with total capacity of 3,800 MSCFD are ongoing. If these expanded pipelines and gas plants were completed right on schedule by the 2020s, significantly improved gas supply to all thermal power plants is expected.

Total raw gas production from all existing gas plants increased about 1.4 times in the decade up to 2012 and the supply of natural gas to NGC, from which all thermal power plants purchase gas, recovered, despite decreasing slightly over the period 2005 ~ 2010. Moreover, the quantity of flared gas, rather than recovered or extra gas, also halved over this decade, reflecting the increase in the ratio of available gas to total raw gas production. By further improving the pipeline plans above and the available volume of gas, significantly improved gas supply conditions are expected, even in some thermal power plants having problems, where the volume of gas consumed decreased amid increasing operation fuel costs.

(3) System disturbances on power supply

Table 6-1.6 shows the system disturbances (system failure, sudden and drastic change of frequency or voltage, excess power demand, etc., caused by generation faults, transmission faults and unknown causes) over the last 17 years (from 2000 to 2016).

Table 6-1.6 System disturbances on power supply

Year	Generation Faults		Transmission Faults		Unknown		Total Number of Disturbances
	Actual Number	% of Total	Actual Number	% of Total	Actual Number	% of Total	
2000	2	18.18%	9	81.82%	0	0.00%	11
2001	9	47.37%	10	52.63%	0	0.00%	19
2002	19	46.34%	22	53.66%	0	0.00%	41
2003	14	26.42%	39	73.58%	0	0.00%	53
2004	20	38.46%	32	61.54%	0	0.00%	52
2005	15	41.67%	21	58.33%	0	0.00%	36
2006	8	26.67%	22	73.33%	0	0.00%	30
2007	3	11.11%	24	88.89%	0	0.00%	27
2008	8	19.05%	32	76.19%	2	4.76%	42
2009	8	20.51%	31	79.49%	0	0.00%	39
2010	9	21.43%	29	69.05%	4	9.52%	42
2011	0	0.00%	17	89.47%	2	10.53%	19
2012	1	4.35%	19	82.61%	3	13.04%	23
2013	2	8.33%	22	91.67%	0	0.00%	24
2014	2	15.38%	10	76.92%	1	7.69%	13
2015	0	0.00%	10	100.00%	0	0.00%	10
2016	8	29.63%	19	70.37%	0	0.00%	27

Source: TCN Annual Technical Report 2016

Though the numbers are less than those of disturbances by transmission faults, however, disturbances by generation faults have been caused yearly for the past 15 years. Two system disturbances were caused by generation faults due to a sudden decline in generation capacity and a drastic change of frequency in 2016.

Major disturbances by transmission faults are reported in simultaneous transmission lines and sometimes faults affecting multiple transmission lines simultaneously. Numerous other reports include disturbances in the form of transmission faults featuring burnt transformers, distribution panels, breakers and battery chargers.

(4) IPP

Amid structural reforms to the Nigerian power sector, the construction of new thermal power plants has been done with private investment by IPP since 2001. Moreover, proposals from private companies to purchase thermal power plants from the former PHCN will be treated as power plant rehabilitation project submissions and restoration of available capacity to the installed capacity level within the specified period. Currently, Nigeria has more than 100 IPP project evacuation studies and EIA studies completed. Table 6-1.7 shows the present status of PPA agreement on 18 thermal IPP projects completely licensed from NERC.

Table 6-1.7 The Status of PPA agreements (Thermal IPP Projects Status)

IPP	Type	Fuel	Capacity (MW)	Location	PPA Agreement
Abuja Power Company	GT	Gas	300	Niger, Shiroro	Not Yet
AES Nigeria Barge Limited	-	-	150	Lagos, Lagos	Not Yet
ALSCON	GT	Gas	350	Akwa Ibom, Port Harcourt	In progress
Anambra State IPP	GT	Gas	528	Anambra, Enugu	In progress
ASIPGCL	-	-	528	Anambra	Not Yet
Azikel Independent Power	GT	Gas	489	Bayelsa, Port Harcourt	Not Yet
Azura West Africa Limited	GT	Gas	450	Benin, Benin	Yes
Bresson Flexible Power	GT	Gas	350	Delta, Benin	Not Yet
Century Power Generation Ltd	GT	Gas	495	Anambra, Enugu	In progress
Geometric Power Limited	GT	Gas	1,080	Imo, Port Harcourt	In progress
Hudson Power Limited	GT	Gas	150	-	Not Yet
Ibom Power Company	GT	Gas	504	Akwa Ibom, Port Harcourt	In progress
ICS	GT	Gas	631	Abia, Enugu	Not Yet
Lafarage Cement WAPCO Nigeria plc (Phase I)	GT	Gas	50	Ogun, Lagos	In progress
Lafarage Cement WAPCO Nigeria plc (Phase II)	GT	Gas	220	Ogun, Lagos	In progress
Oma Power Generation Company Limited	GT	Gas	1,080	Abia, Enugu	In progress
Paras Energy & Natural Res. Dev Ltd	GT	Gas	60	Lagos, Lagos	In progress
Zuma Energy Nigeria Ltd	ST	Coal	1,200	Kogi, Benin	Yes

Source: TCN Queue List for Thermal IPP projects (2015)

Among the 18 thermal IPP projects above, PPA agreement of two projects completed and negotiation on nine projects is underway, while PPA negotiation of other projects remains pending. Those 18 projects of Table 6-1.7 are highly likely to achieve the expected target installed capacity in future, because evacuation and EIA studies of those projects have already been approved by NERC. Only one project is coal thermal with steam turbine (ST), while the other 17 projects are gas turbine (GT) thermal. Some projects involve a transfer from government to IPP as the extension to expand existing power plants, but many projects remain in the planning stage and depend on new power stations being constructed. Those projects in the planning stage are all those for which PPA negotiation is ongoing or pending and where gas procurement and supply issues for most projects remain unresolved. Those issues should be resolved to execute and complete all thermal IPP projects. To spread IPP projects widely, improve equipment failures and the lack of O&M organization, major causes of low available capacity, based on proper discretion by private companies, necessary payment or capital investment by the Nigerian government for private companies, should be addressed as soon as the PPA agreement is concluded. The government should also support efforts of private companies to resolve all issues outside power plants, such as natural gas constraints.

6-1-2 Present Status and Outlook for Hydropower

Basic information on hydropower generation in Nigeria is shown in Table 6-1.8, while the power generation results of existing hydropower plants, Kainji, Jebba and Shiroro, are shown in

Table 6-1.9. Since all started commercial operation in 1968 to 1990, their equipment is aging and the Kainji hydropower plant in particular is still experiencing operational problems. The average available capacity of the Kainji hydropower plant was recorded as 140 to 413 MW in 2010 to 2016 compared to the maximum output of 760 MW, which shows that the facility usage rate remains low.

Table 6-1.8 Basic information on hydropower generation

Average precipitation (1970-2009)	National average	1,150 mm/year
	North	400 mm/year
	Niger Delta	3,000 mm/year
Inflow volume	Niger river (at HA-2)	67,400 Mm^3/year
	The Benue river and its tributaries	102,300 Mm^3/year
Potential hydropower capacity	Large scale	11,250 MW
	Small-scale	3,500 MW
Installed hydropower capacity plant		1,938 MW
Hydropower capacity plant under construction		2,708 MW
Hydropower capacity plant proposed		3,450 MW

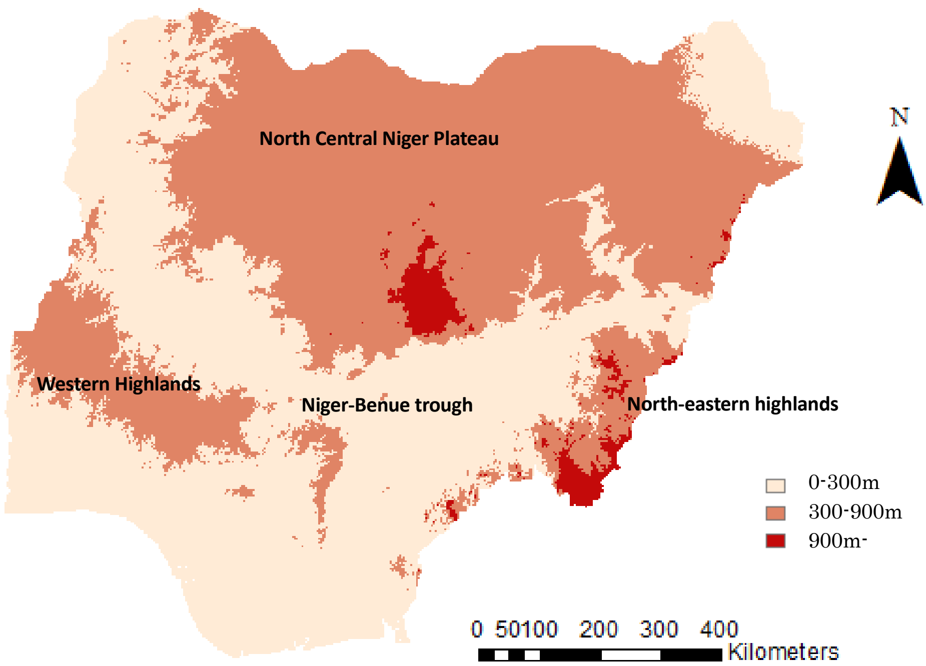
Table 6-1.9 Power generation of existing hydropower plants

Power Plant	Commercial operation date	Installed Capacity (MW)	item	Actual results						
				2010	2011	2012	2013	2014	2015	2016
Kainji	1968-1978	760	Average available capacity (MW)	413	382	295	170	140	225	321
			Annual power generation (GWh/year)	2404	1776	1394	967	735	1504	2410
Jebba	1983-1988	578	Average available capacity (MW)	432	431	414	381	415	387	441
			Annual power generation (GWh/year)	2699	2564	2389	2653	2423	2200	3013
Shiroro	1990	600	Average available capacity (MW)	390	393	498	462	439	477	448
			Annual power generation (GWh/year)	2434	2381	2652	2498	2077	1833	2671

(1) Topography

Nigeria is located in the African shield in geomorphological terms, with characteristic of wide plateaus and few steep mountains. The country is classified into two large geomorphological categories as plateau and lowland.

Areas of plateau are at an altitude of 300 to 900m, while lowland is less than 300m. The land classification and geological setting are closely related. The foundation complex constitutes plateau, while sedimentary rocks constitute lowland.



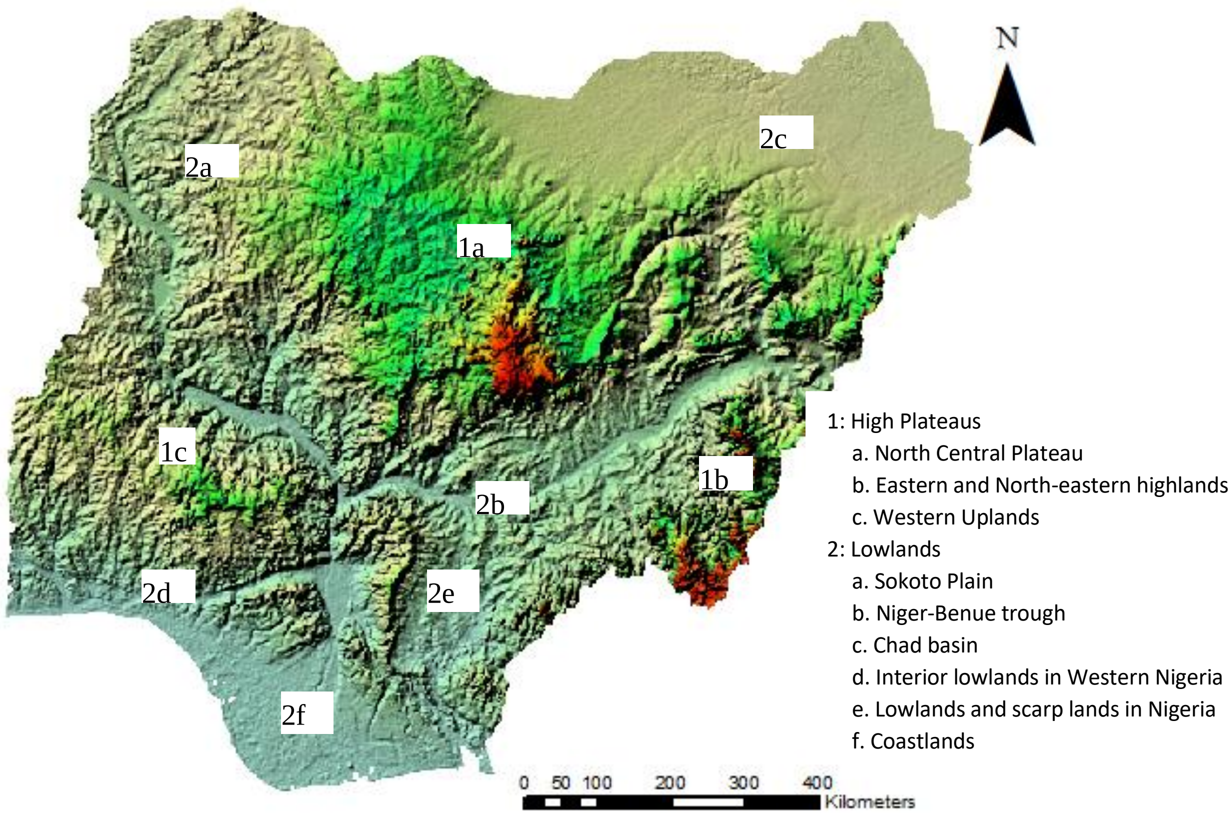
Source: Geography of Nigeria, 1980

Figure 6-1.3 Geomorphological Classification of Nigeria (1)

The Niger and Benue rivers flow into an area of lowland named the Niger-Benue trough. The plateau of Nigeria is divided into three areas, namely: the North-Central Niger Plateau, North-eastern Highlands and Western Uplands by the Niger and Benue rivers.

Jos plateau (at around 1,800m above sea level) and high mountains bordering at Cameroon, including the Adamawa plateau (around 2,400m a.s.l) show an altitude exceeding 900 m and a flat surface due to erosion. A special landscape is created by isolated steep hills of different sizes rising from the flat plain named Inserberg. Lowlands are classified into six areas as Sokoto plains, the Niger-Benue trough, Chad basin, Interior coastal lowlands of western Nigeria, Lowlands and scarp lands of southeastern Nigeria and Coastlands.

Lowlands are located along large rivers and areas of coastline with an altitude of less than 300m. However, characteristically, lowlands are located even in interior areas such as the Sokoto plain and Chad basin. The geomorphological classification of Nigeria is shown in Figure 6-1.4.



Source: Geography of Nigeria, 1980

Figure 6-1.4 Geomorphological Classification of Nigeria (2)

(2) Geology

Nigeria is roughly classified into foundation and sedimentary rocks, with the former further subdivided into three types as Gneiss and Migmatite rock, Schist belts and younger Granite. Gneiss and Migmatite rocks, meanwhile, comprise those dating back to the pre-Cambrian era, while the Schist belts comprise metamorphic sedimentary rocks such as schist, phyllite, marble, dolomites and amphibolite and are enclosed with Gneiss and Migmatite rocks in the western half of Nigeria. The younger granite comprises rhyolite, quart-diorite and granite from the Jurassic period and is distributed in an SSW-NNE direction in the central part of Nigeria. They are ring-dike intrusions into the older foundations of rock. The foundation rocks form the plateau and highlands covering almost half of Nigeria.

Sedimentary rocks overlie foundation rock in an uneven arrangement and are distributed over lowland areas, clearly in contrast to foundation rock. Sedimentary basin is identified into six areas as Benue-Niger Trough, Middle-Niger/Bida Basin, Sokoto Basin, Chad basin, Niger Delta and Dahomey Basin.

(3) Geological Process

The main continental sediments were deposited with significant thickness in the Cretaceous period and include main shale/limestone and continental sandstone of the Cretaceous period. Thick sediments were deposited in Benue Trough in particular, which is named "Graben structure" and developed when the African and South American continents began separating from each other. Sedimentation also began at this period in the Niger Delta.

Cretaceous rocks in each basin were covered widely with tertiary sediments such as sandstone, claystone and limestone and tertiary sediment was deposited in the Niger Delta following the Cretaceous period. Conversely, there were volcanic activities in the Jos Plateau and Benue Trough areas, including basaltic lava eruptions.

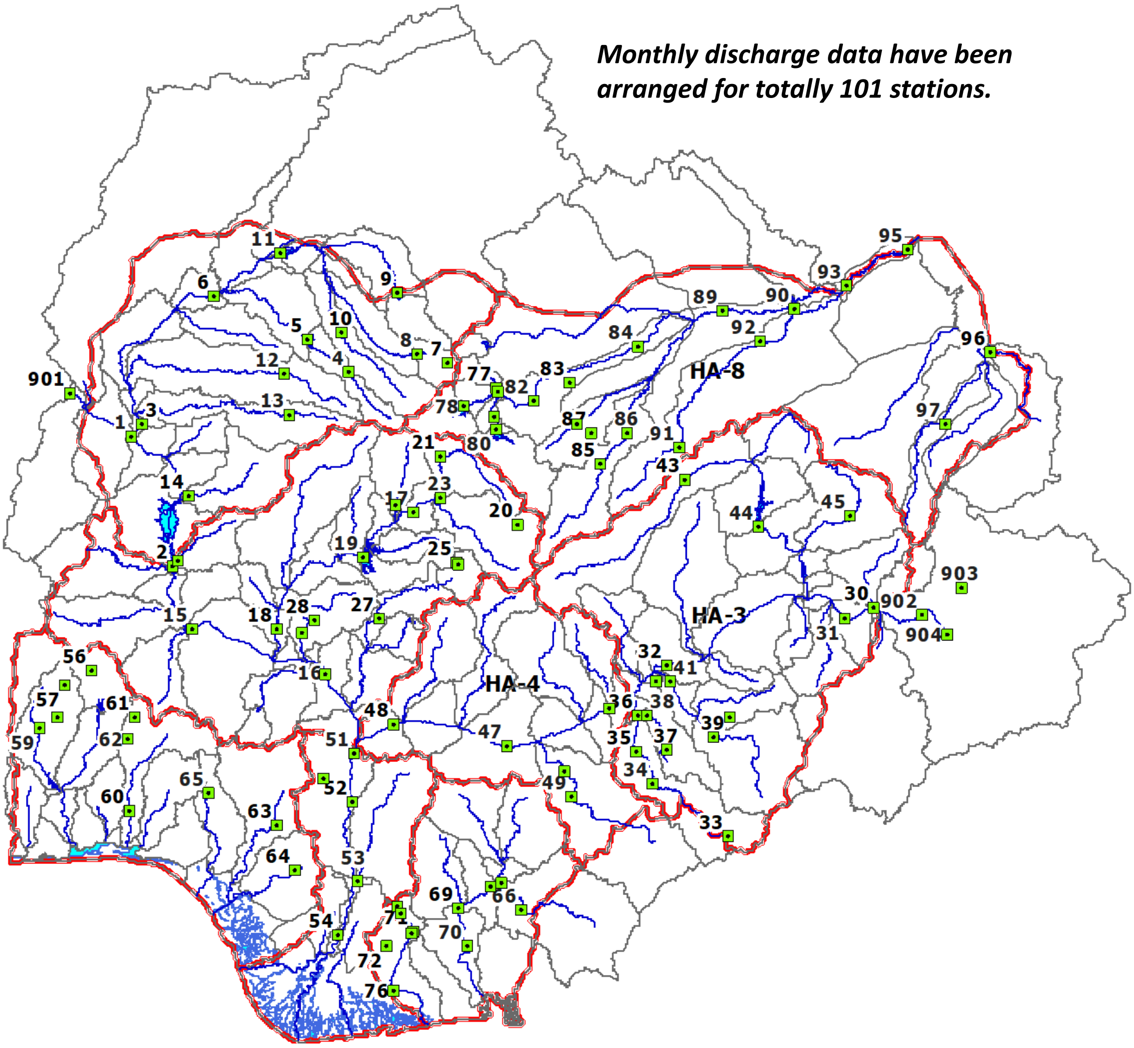
Thick clay and sand formation were deposited in Chad and Sokoto basins during the Quaternary period as well as in the Niger Delta.

(4) Meteorology

The annual average precipitation and annual mean air temperature in Nigeria over the last 40 years (1970-2009) are estimated at 1,150mm/year and 26.6 °C, respectively.

The annual precipitation varies from over 3,000mm in the Niger Delta area to about 400mm in the northernmost part of the country. As the annual potential evapotranspiration is affected by altitude, in areas of high elevation along the country border in the south-east as well as around Jos, the annual potential evapotranspiration becomes small. The spatially averaged annual precipitation, annual mean air temperature and annual potential evapotranspiration for each HA are summarized in Table 6-1.10.

The Nigeria Hydrological Service Agency (NIHSA) is the agency responsible for hydrological monitoring in Nigeria and provides 101 stations throughout Nigeria as shown in Figure 6-1.5.

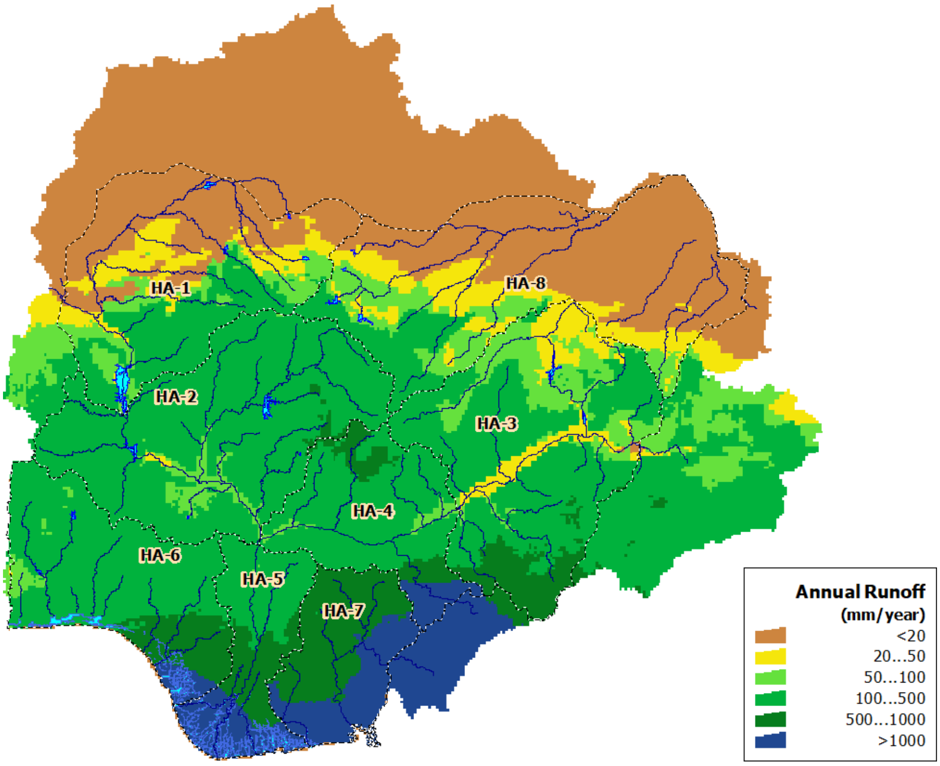


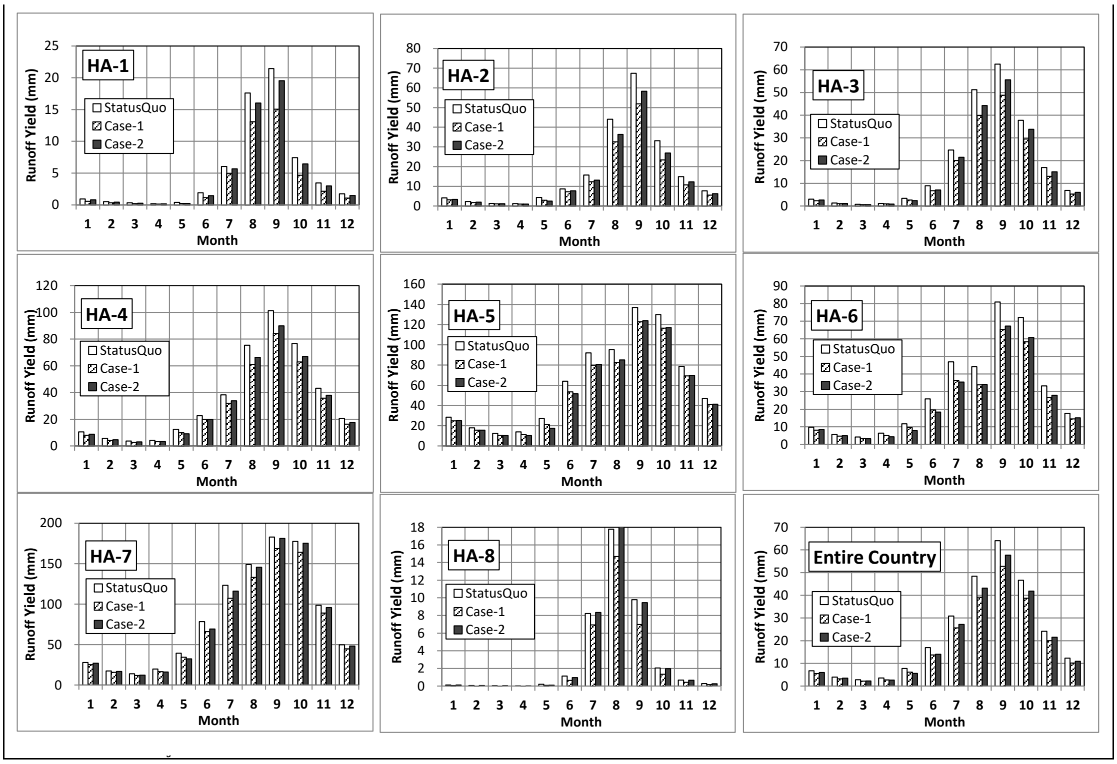
Source: Nigeria Hydrological Service Agency (NIHSA)

Figure 6-1.5 Location of Hydrological Stations in Nigeria

There are two seasons with clear dry and wet seasons in a year nationwide and annual precipitation peaks in each of the areas shown in Figure 6-1.6. In the northern HAs, there is almost no precipitation during the dry season.

The spatial distribution of the average annual run-off yield is shown in Figure 6-1.6 and the average annual run-off yield varies significantly nationwide. In the northernmost part of the country, the run-off yield is less than 20mm/year, but this exceeds 1,000mm/year at the southern end.





Note: Duration of data is applied from 1970 to 2009 (40years).

Source: Nigeria Water Resources M/P (JICA, 2014)

Figure 6-1.6 Distribution of Average Annual Run-off Yield

At the Niger-Nigeria national border along Niger river, the average inflow volume is estimated at 26,500Mm^3/year. The total annual run-off volume at the HA-1 and HA-2 border becomes 35,100Mm^3/year added the run-off from HA-1. At HA-2, it increases to 67,400 Mm^3/year and joining to

Benue river the total run-off reaches to 169,690Mm^3/year.

The Benue river and its tributaries provide larger run-off volume than that in Niger river, which is 102,300Mm^3/year at the confluence of Niger river. The inflow from Cameroon to Benue river is also large as 19,790Mm^3/year. It comes 2,870Mm^3/year from upper Donga river and 15,040 Mm^3/year from the upper Katsina-Ala river.

The total annual run-off volume from Cross River and other catchment in HA-7 reaches to 79,860Mm^3/year, 23,670Mm^3/year of which is provided from the territory of Cameroon.

In the delta areas in HA-5, the total annual run-off volume is estimated at 25,790 Mm^3/year.

In HA-8, the total generated run-off is estimated at 7,220 Mm^3/year. However, only 1,570 Mm^3/year reaches to HA-8 that is Lake Chad, due to significant loss in the large wetland area.

(5) Hydrology

The catchment areas of Benue and Niger rivers, the area of which is downstream of Benin, are divided into eight areas as shown in Figure 6-1.6.

A total of 168 SHAs (Sub Hydrological Areas) have been delineated, with three (3) located completely outside Nigeria and others partially outside. These SHAs are further subdivided by the national boundary of Nigeria, which results in a total of 194 subdivided SHAs. The aggregate portion of SHAs inside Nigeria for specific HA (Hydrological Areas) coincides with the HA boundary. The features of hydrological areas are shown in Table 6-1.10.

Table 6-1.10 Features of Hydrological Areas

Hydrological Area(HA)		1	2	3	4	5	7	6	8	Total
Area (km^2)		135,128	154,616	156,546	74,519	53,914	57,440	99,333	178,483	909,979
Num. of related SHAs		27	36	30	11	6	10	22	26	168
Num. of SHAs divided by National Boundary	Total	36	38	34	12	6	11	24	33	194
	Inside Nigeria	28	36	29	11	6	10	22	26	168
Average Annual Precipitation (mm/year)		767	1,170	1,055	1,341	2,132	2,106	1,541	610	1,148
Average Annual Runoff Yield (Height) (mm/year)		62	205	218	415	744	978	359	40	268
Average Specific Discharge (liter/s/km^2)		2	7	7	13	24	31	11	1	9
Average Annual Runoff Yield(Mm^3/year)		35,100	32,300	102,300		94,180		35,700	7,200	306,780
Annual Precipitation (mm/year)		767	1,170	1,055	1,341	2,132	2,106	1,541	610	1,148
Annual Mean Air Temperature (degree Celsius)		27	17	26	27	27	27	27	27	27
Annual Potential Evapotranspiration (mm/year)		1,419	1,318	1,290	1,338	1,325	1,338	1,314	1,347	1,337
Expected Annual Output(MWh)		69,722	383,971	537,402	69,929	26,900	39,934	60,359	0	1,188,217

Remarks:

1) The values in the table show the internal production of run-off from the territory of Nigeria.
2) Duration of data is used for the period 1970-2009 (40 years).
3) For Expected Annual Output (MWh), potential sites for hydropower generation would be examined at a conceptual level based on updated results for water resources.

The Present Status and Outlook for hydropower in Nigeria is shown in Table 6-1.11.

Table 6-1.11 Present Status and Outlook for Hydropower in Nigeria

No	EXISTING HYDROPOWER STATIONS	HYDROPOWER STATIONS (CONSTRUCTION ONGOING).
1.	KAINJI HYDROPOWER STATION (Niger state): Plant was completed with installed total capacity of 760MW from eight units in 1968. An additional four units have not yet been installed.	GURARA 1 HYDROPOWER STATION (Niger State): It was completed with a total installed capacity of 30MW in 2012. As the transmission line is still under construction, generation remains pending.
2.	JEBBA HYDROPOWER STATION (Niger state): It was completed with a total installed capacity of 578MW in 1985. Rehabilitation of one unit finished in 2016.	DADIN KOWA HYDROPOWER PROJECT (Bauchi State): Total capacity is 40MW. It is ready for commissioning in 2018.
3.	SHIRORO HYDROPOWER STATION (Niger state): It was completed with a total installed capacity of 600MW from four units in 1990. It has been in operation since 2016, after three units were overhauled in 2014.	ZUNGERU HYDROPOWER PROJECT (Niger State): Total capacity is 700MW. It is scheduled to start operations in 2019.
4.	KASHIMBILLA HYDROPOWER PROJECT (Taraba State): Total capacity is 40MW It has been in operation from 2017.	KAINJI HYDROPOWER PROJECT (Niger State): Total capacity is 720MW. The rehabilitation project is incomplete.

Source: JICA Study Team

6-2 Condition of Power Development Planning

6-2-1 Policy of Power Development Planning

6-2-1-1 Thermal power

Thermal power development in future will be covered by private investment due to the privatization of thermal power in the power sector.

Projects under construction mentioned in Chapter 6-1 and NERC-licensed IPPs in thermal power development are defined as already decided. NERC-licensed projects are judged as highly likely and with high-grade maturity. Table 6-2.1 shows the list of information required for NERC-license applications.

Table 6-2.1 Information necessary for NERC-license applications

No.	Information / Contents of documents
1.	Application form for license
2.	Certificate of Establishment of a company
3.	Certificate of Land acquisition
4.	The completion certificate of tax payment (Last three years)
5.	Audit accounts report (Last three years)
6.	Curriculum vitae for management and technical staff
7.	Location of proposed power plat
8.	Single line diagram
9.	Design drawings for the power plant
10.	Layout plan for the power plant
11.	Corporate business plan (ten years)
12.	Permission of grid connection
13.	License of EIA or certificate of submission / under examination, administrative plan of industrial waste
14.	Contract document on fuel supply or certificate of fuel supply from fuel supplier / transporter
15.	Contract document with Federal Ministry of Water Resources (if necessary)
16.	Expression of Interest (EOI) from the EPC Contractor or MOU (Memorandum of Understanding)
17.	Expression of Interest (EOI) from the engineering partner or MOU (Memorandum of Understanding)
18.	Acknowledgement of gird connection capacity issued by TCN
19.	Loan agreement with bank
20.	Schedule for commercial operation of the power plant (if several different capacitive generators will be commissioned at different timings)

Source: NERC website; http://nercng.org/nercdocs/Mandatory-Requirements-for-Licences.pdf

Thermal power projects under construction and planned by the private sector are shown in Table 6-2.2~6.

Table 6-2.2 Thermal power projects under construction

No.	Name of power plant	Type	Year of operation	Number of units	Simgle unit capacity (MW)	Total capacity (MW)
1	GBARAIN / UBIE I	Gas turbine	2018	1	113	113
2	EGBEMA I - NIPP	Gas turbine	2018	1	113	113
	EGBEMA I - NIPP	Gas turbine	2019	1	113	113
	EGBEMA I - NIPP	Gas turbine	2019	1	113	113
3	KADUNA IPP	Gas turbine	2019	1	215	215
4	OMOKU - NIPP	Gas turbine	2018	1	113	113
	OMOKU - NIPP	Gas turbine	2019	1	113	113
5	AFAM Fast Power	Gas turbine	2018	8	30	240
6	ELEME	Gas turbine	2021	1	75	75
	Total					**1,208**

Source: TCN

Table 6-2.3 Gas power projects for which NERC licenses have been granted

No.	Name of power plant	Type	Year of operation	Number of units	Simgle unit capacity (MW)	Total capacity (MW)
1	QUA IBOE POWER PLANT	Gas turbine	2021	4	130	520
2	OMA POWER GENERATION COMPANY LTD	Gas turbine	2022			500
3	PROTON	Gas turbine	2023	1	150	150
4	CENTURY IPP	Gas turbine	2022	4	124	496
5	BRESSON Nigeria Ltd	Gas turbine	2022	2	45	90
6	Cummins Power Gen. LTD.	Gas turbine	2021	1	150	150
7	ONDO IPP - King Line	Gas turbine	2021	1	200	200
8	ONDO IPP - King Line	Gas turbine	2026	1	150	150
9	ONDO IPP - King Line	Gas turbine	2029-2032	2	100	200
10	TURBINE DRIVE	Gas turbine	2021	3	167	501
11	ZUMA (Egbema)	Gas turbine	2021		374	374
	Total					**3,331**

Source: TCN

Table 6-2.4 Gas power projects proposed by the private sector

No.	Name of power plant	Type	Year of operation	Number of units	Simgle unit capacity (MW)	Total capacity (MW)
1	OKPAI IPP II - AGIP (NNPC POWER BUSINESS PLAN)	Combined cycle	2020	2	150	300
			2020	1	150	150
2	DELTA III 2+	Gas turbine	2023	1	143	143
		Gas turbine	2023	4	148.5	594
3	EGBIN 2+	Combined cycle	2021	4	300	1200
			2021	2	350	700
4	SAPELE POWER PLC	Gas turbine	2021	30	20	600
		Gas turbine	2022	1	100	100
5	GEREGU FGN1-2	Gas turbine	2029	3	138	414
6	GEREGU NIPP 2	Combined cycle	2027	1	285	285
			2030	3	148	444
7	OMOTOSHO II 2+ (Steam turbine add on)	Combined cycle	2027	2	127	254
8	CALABAR / ODUKPANI - NIPP	Combined cycle	2029	2	127	254
			2030	4	141	564
9	EGBEMA II (Steam turbine add on)	Combined cycle	2030	1	127	127
10	IHOVBOR (EYAEN) 2 - NIPP (Steam turbine add on)	Combined cycle	2030	2	127	254
11	GBARAIN / UBIE 2 (Steam turbine add on)	Combined cycle	2029	1	115	115
12	GBARAIN / UBIE 2	Gas turbine	2030	8	113	904
13	ALSCON	Gas turbine	2024	1	100	100
		Gas turbine	2026	2	130	260
14	ALAOJI 2+ NIPP (Steam turbine add on)	Combined cycle	2025	1	285	285
15	IKOT ABASI	Gas turbine	2025	2	125	250
16	IBOM II	Gas turbine	2020	4	138	552
17	SAPELE 2 - NIPP	Gas turbine	2028	3	151	453
18	TOTALFINAELF (OBITE)(NNPC POWER BUSINESS PLAN)	Gas turbine	2031			420
19	CHEVRON AGURA(NNPC POWER BUSINESS PLAN)	Gas turbine	2030			780
20	SUPERTEK	Gas turbine	2030	5	100	500
21	LAFARAGE PHASE I	Gas turbine	2023	1	50	50
22	LAFARAGE PHASE II	Gas turbine	2025	2	110	220
23	ANAMBRA STATE IPP	Gas turbine	2031	2	264	528
24	BENCO	Gas turbine	2033	7	100	700
25	DELTA STATE IPP	Gas turbine	2032	5	100	500
26	MBH	Gas turbine	2030	2	150	300
27	OATS	Gas turbine	2028	7	100	700
28	YELLOW STONE	Gas turbine	2024	2	180	360
29	KNOX	Gas turbine	2031	3	167	501
30	CALEB INLAND	Combined cycle	2023	2	250	500
			2025	2	250	500
			2027	2	250	500
31	WESTCOM	Gas turbine	2030	2	250	500
32	HUDSON POWER	Gas turbine	2030	1	150	150
33	BRESSON AS NIGERIA	Gas turbine	2030	3	150	450
34	PARAS	Gas turbine	2022	2	150	300
35	AZIKEL IPP	Gas turbine	2030	1	76	76
		Gas turbine	2030	1	250	250
		Gas turbine	2030	1	163	163
36	ETHIOPE	Combined cycle	2022	2	172	344
			2022	1	156	156
			2024	2	172	344
			2024	1	156	156
37	FORTUNE ELECTRIC	Gas turbine	2035	5	100	500
		Gas turbine	2035	5	100	500
38	ESSAR	Gas turbine	2026	6	110	660
39	KADUNA (NNPC POWER BUSINESS PLAN)	Gas turbine	2035			900
40	KANO (NNPC POWER BUSINESS PLAN)	Gas turbine				900
41	GWAGWALADA (CCGT)	Combined cycle	2037			1350
	Total					**24,060**

Source: TCN

Table 6-2.5 Coal power projects for which an NERC license has been granted

No.	Name of power plant	Type	Number of units	Simgle unit capacity (MW)	Total capacity (MW)
1	ZUMA (Itobe)	Coal	4	300	1200

Source: TCN

Table 6-2.6 Coal power projects proposed by the private sector

No.	Name of power plant	Type	Number of units	Simgle unit capacity (MW)	Total capacity (MW)
1	ASHAKA	Coal	1	64	64
2	RAMOS	Coal	2	500	1000
3	ASHAKA / TPGL	Coal	2	250	500
4	GEREGU III COAL POWER	Coal			1500
5	NASARAWA COAL POWER	Coal			500
6	BENUE COAL POWER	Coal			1200
7	ENUGU COAL POWER	Coal			2000
	Total				**6,764**

Source: TCN

Future possible power development, excluding the development decided upon, will be input to the power development formulation software (WASP: Wien Automatic System Planning Package).

Table 6-2.7 shows the parameters of combined cycle, simple-cycle gas turbine and planned coal-fired power plant to be targeted as candidate model plants for power development planning in this study; notwithstanding the possibility of domestic fuel and already launched in Nigeria.

Various factors for candidate thermal power development are established based on documents[2] of "Gas turbine world", "U.S. Department of Energy, U.S. Energy Information Administration" and from other power system master plan study[3].

Candidate sites for hydropower development include the existing planned sites as shown in Table 6-1.10, Table 6-2.11 and Table 6-2.12. Those candidate power development conditions are entered into WASP modules such as Module-2 FIXSYS and Module-3 VARYSYS and form combinations of least-cost development candidates.

[2] U.S. Energy Information Administration (April 2013) "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants"
[3] JICA Power System Master Plan Study in Tanzania (March, 2014)

Table 6-2.7 Parameters of candidates on thermal power development

Type	Model [degree Celsius]	Capacity	Heat efficiency[4]	Unit Price[5]	Construction Period	Lifetime
Simple-cycle gas turbine	1,100-degree centigrade class	100MW class	30.8%	US $980/kW	Two years	30 years
	1,100-degree centigrade class	200MW class	34.7%	US $680/kW	Two years	30 years
Combined-Cycle Gas Turbine	1,100-degree centigrade class, Single Shaft	300MW class	51.4%	US $980/kW	Three years	30 years
	1,300-degree centigrade class, Single Shaft	500MW class	54.0%	US $941/kW	Three years	30 years
	1,300-degree centigrade class, Multiple spindle	1,000MW class	55.1%	US $842/kW	Three years	30 years
Coal-fired	Subcritical pressure	300MW class	40.7%	US $2,500/kW	Four years	40 years
	Ultra-supercritical	700MW class	42.1%	US $2,000/kW	Four years	40 years
	Ultra-supercritical	1,000MW class	43.0%	US $2,000/kW	Four years	40 years

Table 6-2.8 shows the parameters to be entered into WASP.

[4] HHV (Higher Heating Value) basis
[5] "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants" (US-EIA), Gas Turbine World Handbook

Table 6-2.8 Parameters for the existing thermal power plants (WASP input data)

Name of Thermal Plant	Owner	Plant ID	number of identical units in the power station at start of study	minimum operating level of each unit (MW)	maximum unit generating capacity (MW)	fuel (plant) type number 0:Gas fired GT 1:Gas fired Steam 2:Gas fired Combined 3:Coal	heat rate at minimum operating level (kcal/kWh)	average incremental heat rate between minimum and maximum operating levels (kcal/kWh)	unit spinning reserve (as % of maximum generating capacity)	unit equivalent forced outage rate (%)	number of days per year required for scheduled maintenance of each unit	maintenance class size (MW)	domestic fuel costs (¢/10^6 kcal) - MYTO-II gas price in 2016, $2.44/mmBtu is applied	foreign fuel costs (¢ /10^6 kcal)	fixed component of non-fuel operation and maintenance cost ($/kW-month) of each unit	variable component of non-fuel operation and maintenance cost ($/MWh) of each unit	heat value of the fuel used by plant, measuring the heat equivalent of 1 kg fuel used (kcal/kg)	emission factor of the first pollutant (default: SO2), the ratio of emitted pollutant and fuel used in plant (%)	emission factor of the second pollutant (default: NOx), the ratio of emitted pollutant and fuel used in plant (%)	Fuel consumption (ton/GWh)
EGBIN (STEAM)	PHCN	EGBI	6	88	220	1	2,917	2,324	10	30	45	220	968	0	1.20	3.43	12,228	0.000189	0.0142	219.3
AFAM IV (GAS)	PHCN	AFA4	1 (6)	30	75	0	4,074	2,240	10	30	15	75	968	0	0.58	3.43	12,228	0.000189	0.0566	243.2
AFAM V (GAS)	PHCN	AFA5	0 (2)	55	138	0	4,074	2,240	10	30	15	138	968	0	0.58	3.43	12,228	0.000189	0.0566	243.2
DELTA-1 (GAS)	PHCN	DLT1	3 (12)	10	25	0	3,919	2,155	10	30	15	25	968	0	0.58	3.43	12,228	0.000189	0.0566	234.0
DELTA-2 (GAS)	PHCN	DLT2	2 (6)	40	100	0	3,919	2,155	10	30	15	100	968	0	0.58	3.43	12,228	0.000189	0.0566	234.0
GEREGU (GAS)	PHCN	GERP	3	55	138	0	4,119	2,265	10	30	15	138	968	0	0.58	3.43	12,228	0.000189	0.0566	245.9
OLORUNSOGO (GAS)	PHCN	OLRP	3 (8)	15	38	0	3,878	2,132	10	30	15	38	968	0	0.58	3.43	12,228	0.000189	0.0566	231.5
OMOTOSHO (GAS)	PHCN	OMTP	3 (8)	17	42	0	4,072	2,239	10	30	15	42	968	0	0.58	3.43	12,228	0.000189	0.0566	243.1
SAPELE (STEAM)	PHCN	SAPS	0 (6)	48	120	1	3,178	2,750	10	30	45	120	968	0	1.20	3.43	12,228	0.000189	0.0142	238.9
SAPELE (GT)	PHCN	SAPG	4	30	75							75								
ALAOJI NIPP (Gas turbine only)	NDHPC	ALAG	2 (4)	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
ALAOJI NIPP (GAS/STEAM)	NDHPC	ALAN	0 (1)	282	705	2	2,245	1,496	10	15	30	126	968	0	1.20	3.43	12,228	0.000189	0.0566	165.2
SAPELE (NIPP)	NDPHC	SAPN	4	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
OLORUNSOGO NIPP (GAS/ST)	NDPHC	OLRN	0 (2)	136	339	2	2,245	1,496	10	15	30	125	968	0	1.20	3.43	12,228	0.000189	0.0566	165.2
OMOTOSHO NIPP GAS	NDPHC	OMTN	4	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
CALABAR	NDPHC	CALA	0 (5)	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
EGBEMA	NDPHC	EGBE	0 (3)	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
IHOVBOR	NDPHC	IHOV	0 (4)	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
GBARAN	NDPHC	GBAR	0 (2)	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
OMOKU	NDPHC	OMKN	0 (6)	10	25	0	4,567	2,511	10	15	15	25	968	0	0.58	3.43	12,228	0.000189	0.0566	323.0
GEREGU NIPP	NDPHC	GERN	0 (3)	58	145	0	3,834	2,046	10	15	15	145	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
A.E.S IPP (GAS)	Private (IPP)	AESI	9	12	30	0	4,542	2,498	10	30	15	30	968	0	0.58	3.43	12,228	0.000189	0.0566	271.1
AFAM VI IPP (GAS/STEAM)	Private (IPP)	AFA6	1	260	650	2	2,245	1,496	10	25	30	144	968	0	1.20	3.43	12,228	0.000189	0.0566	165.2
IBOM POWER IPP-1 (GAS)	Private (IPP)	IBM1	2	15	38	0	4,542	2,498	10	30	15	38	968	0	0.58	3.43	12,228	0.000189	0.0566	271.1
IBOM POWER IPP-2 (GAS)	Private (IPP)	IBM2	1	45	112	0	3,834	2,046	10	30	15	112	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
OKPAI IPP (GAS/STEAM)	Private (IPP)	OKPI	1	192	480	2	2,245	1,496	10	15	30	179	968	0	1.20	3.43	12,228	0.000189	0.0566	165.2
OMOKU IPP (GAS)	Private (IPP)	OMKI	0 (6)	10	25	0	4,567	2,511	10	15	15	25	968	0	0.58	3.43	12,228	0.000189	0.0566	323.0
RIVERS IPP	Private (IPP)	RIVR	1	72	180	0	3,834	2,046	10	15	15	180	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
TRANS AMADI	Private (IPP)	TRNS	2 (4)	10	25	0	4,567	2,511	10	30	15	25	968	0	0.58	3.43	12,228	0.000189	0.0566	323.0
ABA Geometric Power			1	56	140	0						140								
KADUNA (FGN)	FGN	KADU	0 (8)	10	25	0	4,567	2,511	10	15	15	25	968	0	0.58	3.43	12,228	0.000189	0.0566	323.0
Simple cycle gas turbine (Variable candidate)	-	VSGT	-	45	113	0	3,834	2,046	10	15	15	113	968	0	0.58	3.43	12,228	0.000189	0.0566	271.2
Combined cycle (Variable candidate)	-	VCCL	-	150	375	2	2,245	1,496	10	15	30	125	968	0	1.20	3.43	12,228	0.000189	0.0566	165.2
COAL (Variable candidate)	-	VCOA	-	100	250	3	2,510	2,022	10	15	45	250	1,333	0	2.47	4.25	6,000	0.68581	0.41148	375.2

Plant type
0 Gas fired gas turbine
1 Gas fired conventional (Steam)
2 Gas fired combined cycle (Steam+GT)
3 Coal

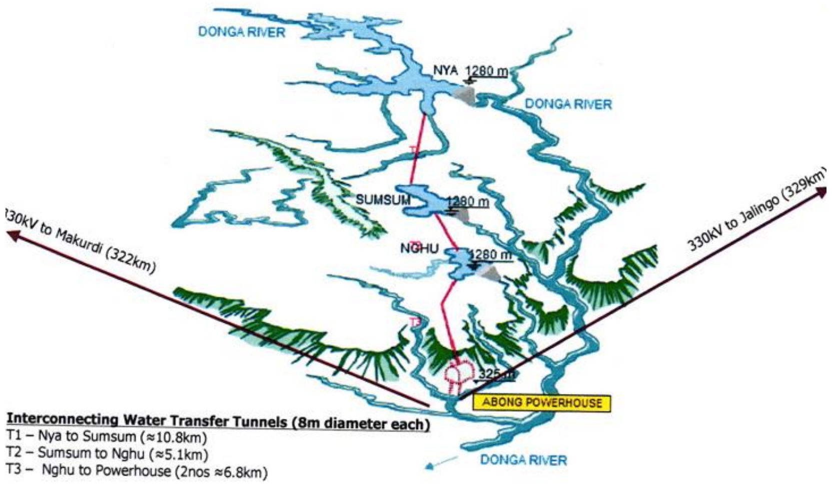
MYTO-II Gas price	Year	Price	Unit
	Y2013	1.80	$/mmBtu
	Y2014	2.30	$/mmBtu
	Y2015	2.37	$/mmBtu
	Y2016	2.44	$/mmBtu
	Y2013	714	cent/10^6kcal
	Y2014	913	cent/10^6kcal
	Y2015	940	cent/10^6kcal
	Y2016	968	cent/10^6kcal

6-2-1-2 Hydropower

(1) Hydropower projects under planning

1) Mambilla Hydro(P=3,050MW)

The Federal Government approved the contract to construct the 3,050-MW Mambilla hydropower plant, with a total cost of $5.792 billion in September 2017. Mambilla, on the Donga river in the eastern Taraba State, had been on the radar for development since the early 1980s. Four dams will be built, between 50 and 150 m tall and the government expects the plant to be complete in 2024. The Chinese Import-Export Bank will finance 85% of the development, with the Nigerian government contributing 15%.



Source: Mambilla F/S Report, FMP

Figure 6-2.1 Mambilla Project bird-eye view

An outline of the Mambilla hydropower project is shown in Table 6-2.9.

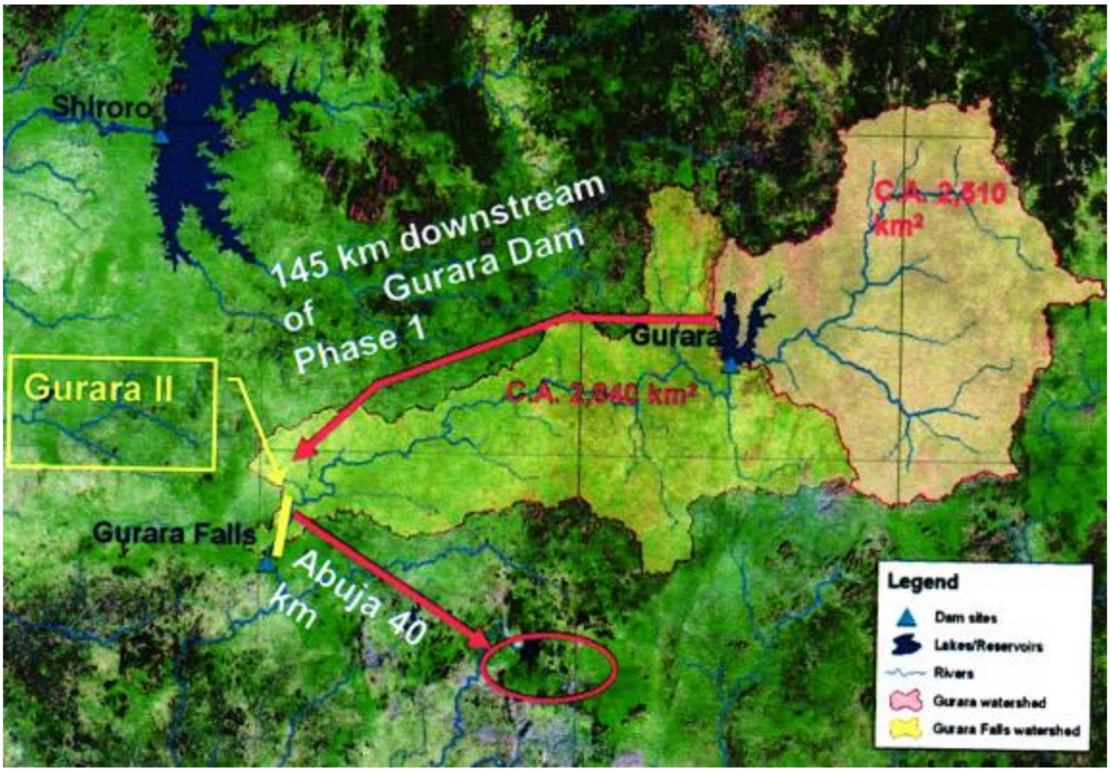
Table 6-2.9 Outline of Mambilla Hydropower Project

Project Name	Mambilla Hydropower Station		
Power Output	254.2MW/unit@12units=3,050 MW		
Power Discharge	186.5m^3/sec@2=373m^3/sec		
Rated Net Head	927m		
Annual Power Output	5,291GWH		
Dam			
H.W.L	1,280m		
L.W.L	1,265m		
	Height(m)	Length(m)	Reservour
Nya Dam(RCC)	23	420	1,900
Sumsum Dam(RCC)	70	510	167
Nghn Dam(RCC)	75	447	156
Api Weir(RCC)	148.5	1,300	4
Spillway	Free overflow type		
Waterway			
Interconnecting Tunne	(Pressure tunnel)		
Nya-Sumsum	10.8km		
Sumsum-Nghu	5.08km		
Headrace Tunnel	(Pressure tunnel)		
HL1	3.45km		
HL2	3.39km		
Surge Tank	Vertical Shaft@2		
Penstock	Inclined shaft@2		
Type of Generation	Dam+waterway type		
Powerhouse	Underground type		
L*W*H	329m*25m*45m		
Transformer room	Underground type		
Tailrace Tunnel	(Non pressure tunnel)		
TL1	3.67km		
TL2	3.82km		
Tailrace Surge Tank	Vertical shaft@2		
Turbine	Vertical shaft Perton@12units, P= 254.3MW/unit		
Generator	Vertical shaft, suspended type, P=282.4MW/unit		
Transformer	33/132KV GIS type, 12 units		
Switchyard	330/132KVA, Conventional type, 12 units		
Transmission Line	330KVA, L=650km		

Source: Mambilla F/S Report, FMP

2) Gurara-II Hydropower (P=360MW)

Gurara-II is a multi-purpose dam for irrigation and power generation which is planned at a point 145 km downstream of the Gurara I dam located in the southeastern part of Niger state. Rated capacity of the hydropower plant is 360 MW and expected annual generation is 1,130 GWh with the total construction cost of US$ 1,240 million (Dam construction: US$ 800 million, irrigation: US$ 400 million and compensation: US$ 40 million). The project will be jointly developed by the Federal Ministry of Water Resources (for the dam) and Power Works and Housing (for hydropower).



Source: Gurara 2 F/S Report, FMP

Figure 6-2.2 Location of Gurara-II

3) Itisi Hydropower (P=40MW) (IPP)

The Itisi hydropower site is located in southern Kaduna city in Kaduna state, with construction underway by a private company.

(2) New hydropower development sites

1) Method of candidate site selection

Tractebel Engineering (France) has surveyed potential hydropower sites in Nigeria, which comprise those already identified sites by FMPWH and additional potential sites newly identified. The latter category is based on the "National Water Resources Master Plan 2013, Supporting Report 04" executed by JICA (January 2014), which presents the coordinates of potential sites and most of the main dam characteristics.

Additional potential sites newly identified are found by Tractebel Engineering using an ISHY tool in conjunction with ArcGIS software and Google Earth research. The ISHY tool is used to automatically identify potential hydropower sites where the river slope could create a significant hydraulic head between a dam upstream and a powerhouse downstream with a reasonable height. The research is based on identifying the steepest river slopes and identifies sites with a significant hydraulic head, including possible redirection of river bends. All the project sites identified are categorized into three types as small (5～20 MW), medium (20～100 MW) and large (>100 MW) installed capacity respectively.

Those potential sites are tabled in river basin, project location, project cost, economic feasibility and project environmental status adoption comments as shown in Table 6-2.10, Table 6-2.11 and Table 6-2.12 for large-, medium- and small-scale, respectively.

Tractebel Engineering has estimated the average annual inflow volume at the sites identified using the run-off coefficient given in the bibliography and calculated from currently available data. The estimated run-off data are applied to develop a preliminary relationship between the mean annual precipitation and annual run-off for sub-basins within the Benue basin.

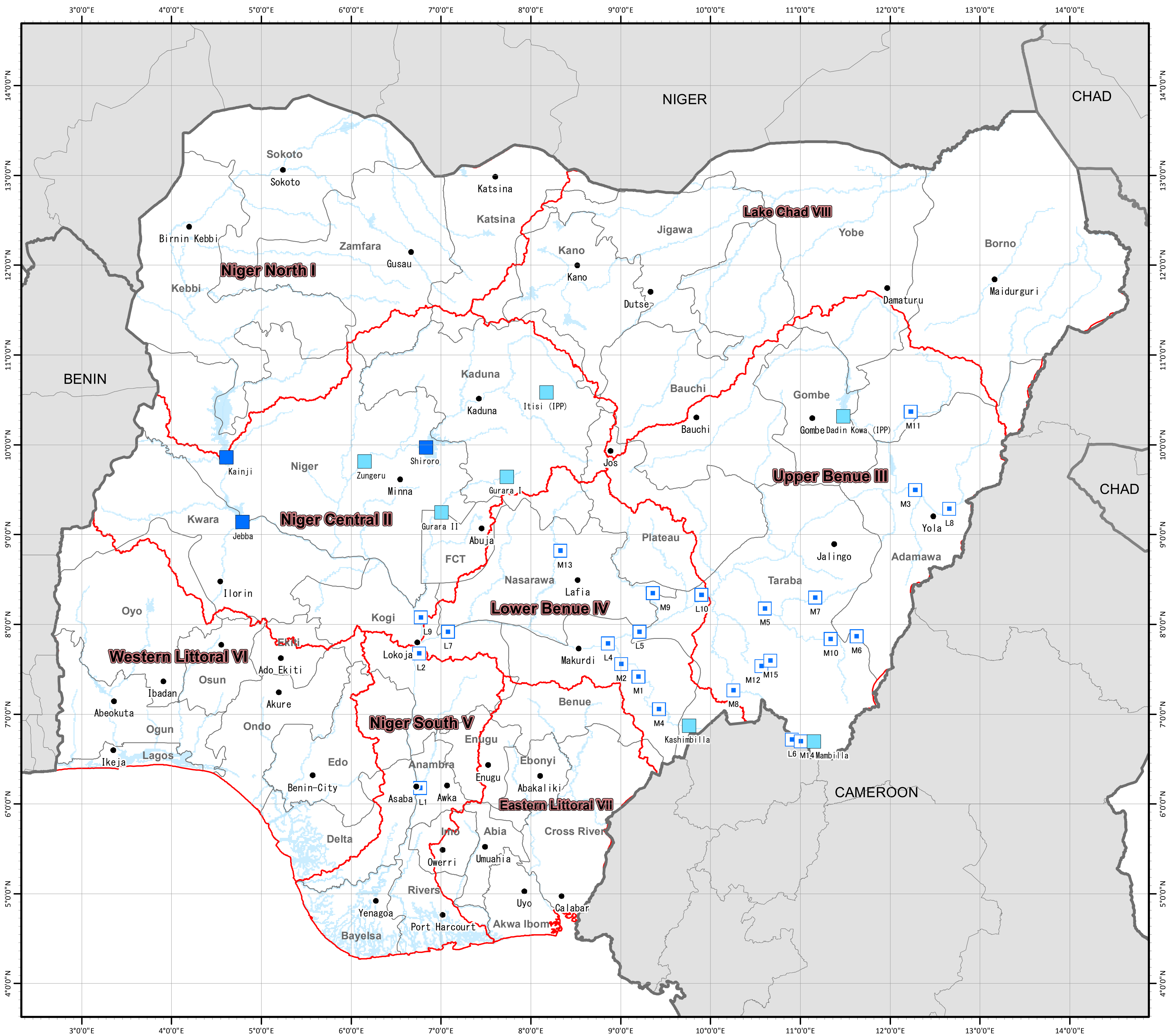
Data from literature was corroborated by available data for the Faro and Donga sub-basins, while run-off coefficients for the Faro, Taraba, Donga, Katsina-Ala and Gongola sub-basins are taken from literature. The relationship was developed from a plot of the estimated run-off against mean annual catchment rainfall, whereupon the run-off for the other sub-basins was then estimated by the exponential relationship.

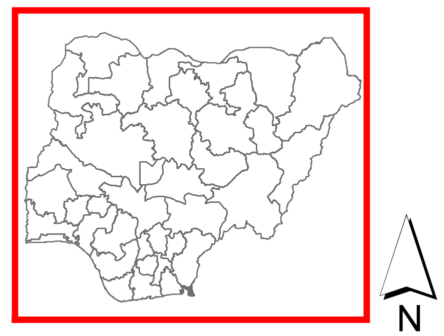
A similar method is applied to derive preliminary estimates of the mean annual discharges of the Benue river at selected sites, given available discharge data at three discharge observatories (Garoua, Makurdi and Umaisha) as well as catchment precipitation at these stations and each of the selected sites on the Benue. For sites along the Niger river, annual run-off values at selected sites are estimated by applying a catchment area ratio based on the discharges observed at the Lokoja and Baro stations.

To estimate the average annual turbined volume, a relationship has been established between Vtu /Vin and the simplified reservoir capacity Vre /Vin.

This relationship of Vtu/Vin= 0.3 is obtained by running a simulation program taking into account the hydrological conditions of the Benue basin, which are a typical series of monthly inflows in the Benue basin (during 2Three years from 1966 to 1989) typical evaporation in the same basin and several values of capacity/surface of reservoir (the characteristics of Zungeru and Gurara reservoirs are used).

The embankment volume of dam would be calculated according to the assumptions, namely a crest width of 10 m, an upstream slope of 1V:3.0H and downstream slope of 1V:2.5H, for all sites, to compare topographical site efficiency, while the unit cost of the dam embankment refers to the unit cost of the Zungel hydropower project under construction in Niger State by Chinese contractors.





LEGEND

- Capital City
- Hydro Power Plant (Existing)
- Hydro Power Plant (Under construction / Plan)
- Hydro Power Plant (Large Scale, Medium Scale Potential)
- Significant Reservoir
- Main Rivers
- Coastal Lake

Existing Hydro Power Plant

No	Power Plant	Site Location	Output(MW)
1	Kainji	Niger	760
2	Jebba	Niger	578
3	Shiroro	Niger	600

Under construction / Plan Hydro Power Plant

No	Power Plant	Site Location	Output(MW)
1	Zungeru	Niger	700
2	Mambilla	Taraba	3,050
3	Gurara I	Kaduna	30
4	Gurara II	Niger	330
5	Kashimbilla	Taraba	40
6	Dadin Kowa (IPP)	Gombe	40
7	Itisi (IPP)	Kaduna	40

Potential Hydro Power Plant (Large Scale, Medium Scale)

	No	Site ID	Site Name	Site Location	Output(MW)
◎	L1	NIG03	Onitsha	Edo	190
◎	L2	NIG02	Lokoja	Kogi	266
◎	L3	BEN06-85	Makurdi	Benue	265
	L4	BEN05-85		Benue	239
○	L5	BEN04-90		Nassarawa	138
	L6	DON05	Old Mambilla	Benue	198
	L7	BEN07		Nassarawa	196
	L8	BEN01-180		Adamawa	138
	L9	NIG01		Kogi	134
	L10	BEN03		Taraba	101
◎	M1	KAT04		Benue	36
◎	M2	KAT07	Katsina-Ala	Benue	52
	M3	BEN02		Adamawa	35
◎	M4	KAT02		Benue	67
◎	M5	TAR12	Garin Dali	Taraba	77
	M6	TAR06		Taraba	31
	M7	TAR10	Kam	Taraba	58
	M8	DON09		Taraba	33
	M9	ANK13		Nassarawa	20
○	M10	TAR08	Baudeau	Taraba	38
	M11	GON10-300		Borno	24
	M12	DON12	Kwossa	Taraba	45
	M13	MAD05-360		Nassarawa	29
	M14	DON04		Taraba	56
	M15	DON11		Taraba	21

[Note]
・Potential Hydro Power Plant (Large Scale, Medium Scale) is in order
・Large Scale (>100MW) : L-number, Medium Scale (20-100MW):M-number
・Tentative potential condition =◎: High ○: Average

100 50 0 100km

1:5,000,000
Only if A3

Coordinate System: GCS WGS 1984
Geodetic Reference System: WGS 1984
Unit: Degree

Location of
Hydro Power Development

23 MARCH 2016

Figure 6-2.3 Location of Hydro Power Development candidates

Table 6-2.10 Sites of hydropower development candidates (Large scale)

No	Location			Cordination		Project Features										Project Cost	Unit Indices			Evaluation					
	Site ID	Site Location	River Basin	Latitude	Longitude	HWL	Reservour Area	Reservour Volume	Dam Height	Catchment Area	Annual Inflow	Effective Head	Annual Output	Design Discharge	Output	Total Cost	OM Cost	Const. Cost	Const. Cost	Natural Environment		Social Environment		General Comments	Site Retainment
			River	(N)	(E)	(masl)	(km^2)	(Mm^3)	(m)	(km^2)	(Mm^3)	(m)	(GWh)	(m^3/sec)	(MW)	(MUSD)	(USD/kW.mo)	(USD/kW)	(USD/kWh)	Comment	Unacceptable (Y/N)	Comment	Unacceptable (Y/N)		(Y/N)
1	NIG03	Edo	Niger main stream	6.18	6.77	25.00	718.66	1,395.65	11.00	1,095,066.00	182,731.00	6.30	833.60	3,554.10	190.30	230.70		1,212	0.02767	Forest reserves near the site	N	Agricultural/residential area observed (level 3) (Onitcha)	Y	A large amount of compensation.	
2	NIG02	Kogi	Niger main stream	7.68	6.76	40.00	222.21	56,763.00	14.00	1,084,042.00	180,891.00	9.00	1,163.70	3,473.10	265.70	323.36		1,217	0.02779	Overlapped with forest reserve	N	Agricultural/residential area observed (level 3) (Lokoja)	Y	A large amount of compensation.	
3	BEN05-85	Benue	Benue main stream	7.79	8.86	85.00	431.59	2,596.88	20.00	300,196.00	95,149.00	14.40	1,047.80	1,954.40	239.20	457.95		1,914	0.04371	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N		
4	BEN06-85	Benue	Benue main stream	7.74	8.68	85.00	598.59	4,099.07	21.00	300,387.00	95,204.00	15.30	1,161.30	2,038.80	265.10	519.90		1,961	0.04477	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N		
×	BEN04-90	Nassarawa	Benue main stream	7.92	9.21	90.00	335.29	1,301.49	19.00	274,689.00	59,371.00	13.50	604.00	1,201.80	137.90	274.43		1,990	0.04544	No protected areas	N	Agriculture areas and houses in the reservoir (level 2)	N	BEN04-85 is employed.	N
5	BEN07	Nassarawa	Benue main stream	7.92	7.08	50.00	381.29	1,381.39	16.00	336,858.00	107,955.00	10.80	856.70	2,130.60	195.60	395.85		2,024	0.04621	No protected areas	N	Agriculture areas and houses in the reservoir (level 2)	N		
×	BEN06-80	Benue	Benue main stream	7.74	8.68	80.00	361.63	1,739.95	16.00	300,387.00	95,204	10.80	767.10	1,907.90	175.10	366.29		2,092	0.04775	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N		N
6	DON05	Benue	Donga	6.72	10.91	660.00	34.00	607.00	32.00	3,821.00	3,474.00	234.00	865.30	99.30	197.50	413.91		2,096	0.04783	No protected areas	N	Agricultural/residential area observed (Level 1), boarder with Cameroon	N		
7	BEN01-185	Adamawa	Benue main stream	9.29	12.66	185.00	1,219.47	11,080.93	32.00	103,477.00	24,400.00	25.20	888.40	946.90	202.80	474.22		2,338	0.05338	No protected areas	N	Agricultural/residential area observed (level 3)	Y	Invade national border between Cameroon and Nigeria.	
×	BEN06-90	Benue	Benue main stream	7.74	8.68	90.00	1,006.29	8,037.40	26.00	300,387.00	95,204.00	19.80	1,664.00	2,257.40	379.90	890.72		2,345	0.05353	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N	BEN06-85 is employed.	N
×	BEN01-180	Adamawa	Benue main stream	9.29	12.66	180.00	851.73	5,943.58	27.00	103,477.00	24,400	20.70	604.40	784.30	138.00	326.28		2,364	0.05398	No protected areas	N	Agricultural/residential area observed (Level 2)	N	BEN01-185 is employed.	N
×	BEN05-90	Benue	Benue main stream	7.79	8.86	90.00	791.41	5,588.38	25.00	300,196.00	95,149	18.90	1,492.00	2,120.40	340.60	815.36		2,394	0.05465	Overlapped with forest reserve	N	Agricultural/residential area observed (level 2)	N	BEN05-85 is employed.	N
8	NIG01	Kogi	Benue main stream	8.08	6.78	0.00	477.65	1,522.71	21.00	774,889.00	49,525.00	15.30	584.90	1,026.80	133.50	448.40		3,359	0.07666	Forest reserves near the site	N	Agricultural/residential area observed (Level 2)	N		
9	BEN03	Taraba	Benue main stream	8.33	9.90	105.00	879.92	4,269.10	18.00	252,988.00	36,959.00	12.60	441.00	940.10	100.70	850.38		8,445	0.19283	Forest reserves near the site	N	Agricultural/residential area observed (level 1)	N		
×	GON10-400	Borno	Gongola	10.37	12.23	400.00	691.13	31,351.88	159.00	9,817.00	1,141.00	139.50	490.20	94.40	111.90	4,612.58		41,221	0.94096	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N	GON10-350 is employed.	N

Note: Following evaluation is based on Visual observation on Google earth and protected area map

Natural Environmer National parks and internationally protected areas inside/ovelapped with the site-->Y
Protected areas near the site-->N
No protected areas near the site-->N
forest reserves inside/overlapped with-->N

Social Environment Level 1: Residential houses/agricultual areas are sparse --> N
Level 2: Residential houses/agricultual areas are moderate -->N
Level 3: Residential houses/agricultual areas are dense -->Y

Table 6-2.11 Sites of hydropower development candidates (Medium scale)

No	Location			Cordination		Project Features									Project Cost	Unit Indices			Evaluation					
	Site ID	Site Location	River Basin	Latitude	Longitude	HWL	Reservoir Area	Reservoir Volume	Dam Height	Catchment Area	Effective Head	Annual Output	Design Discharge	Output	Total Cost	OM Cost	Const. Cost	Const. Cost	Natural Environment		Social Environment		General Comments	Site Retainment
			River	(N)	(E)	(masl)	(km^2)	(Mm^3)	(m)	(km^2)	(m)	(GWh)	(m^3/sec)	(MW)	(MUSD)	(USD/kM.mo)	(USD/kW)	(USD/kWh)	Comment	Unacceptable (Y/N)	Comment	Unacceptable (Y/N)		(Y/N)
1	BEN04-85	Nassarawa	Benue main stream	7.92	9.21	85.00	94.65	299.53	14.00	274,689.00	9.00	384.10	1,146.20	87.70	146.18		1,667	0.03806	No protected areas	N	Agricultural/residential area observed (level 2)	N		
2	KAT04	Benue	Katsina-Ala	7.42	9.20	100.00	29.00	109.00	13.00	20,656.00	8.10	157.10	521.10	35.90	99.92		2,783	0.06360	No protected areas	N	Agricultural/residential area observed (level 2)	N		
3	KAT07	Benue	Katsina-Ala	7.56	9.01	90.00	52.00	233.00	16.00	22,360.00	10.80	229.40	570.50	52.40	147.15		2,808	0.06414	No protected areas	N	Agricultural/residential area observed (level 2)	N		
4	BEN02	Adamawa	Benue main stream	9.50	12.28	155.00	136.29	369.18	13.00	112,628.00	8.10	152.70	506.40	34.90	100.32		2,874	0.06570	No protected areas	N	Agricultural/residential area observed (Level 2)	N		
×	BEN01-165	Adamawa	Benue main stream	9.29	12.66	165.00	68.88	162.56	12.00	103,477.00	7.10	126.90	473.30	29.00	86.38		2,979	0.06807	No protected areas	N	Agricultural/residential area observed (level 2)	N	BEN10-185 is employed.	N
5	KAT02	Benue	Katsina-Ala	7.06	9.43	156.00	57.00	361.00	27.00	14,535.00	20.70	294.80	382.50	67.30	346.59		5,150	0.11757	No protected areas	N	Agricultural/residential area observed (level 2)	N		
6	TAR12	Taraba	Taraba	8.18	10.61	160.00	368.00	3,297.00	31.00	20,400.00	24.30	336.00	371.40	76.70	444.18		5,791	0.13220	No protected areas	N	Agricultural/residential area observed (level 1)	N		
7	DON09	Taraba	Donga	7.27	10.26	190.00	61.00	583.00	26.00	9,463.00	19.80	144.50	196.00	33.00	308.02		9,334	0.21316	No protected areas	N	Agricultural/residential area observed (Level 2)	N		
8	ANK13	Nassarawa	Ankwe	8.35	9.36	120.00	38,192.00	2,897.21	24.00	9,525.00	8.00	89.50	133.50	20.40	255.19		12,509	0.28512	No protected areas	N	Agricultural/residential area observed (Level 2)	N		
×	ANK11-160	Plateau	Ankwe	8.64	8.96	160.00	330.83	4,805.05	34.00	6,063.00	27.00	103.80	103.30	23.70	335.83		14,170	0.32353	Inside Ramsar site	Y	No agricultural/residential area observed	N	Environmental Constraint	N
9	TAR08	Taraba	Taraba	7.84	11.34	255.00	58.00	588.00	40.00	10,372.00	32.40	164.50	136.40	37.60	669.78		17,813	0.40716	National Park near the site (Gashaka-Gumti)	N	Agricultural/residential area observed (level 1)	N		
×	PAI02	Bauchi	Pai	9.62	10.49	280.00	337.05	6,059.40	66.00	8,896.00	55.80	185.80	89.40	42.40	1,161.37		27,391	0.62506	Inside game reserve (Yankari)	Y	No agricultural/residential area observed	N	Environmental Constraint	N
×	PAI01	Bauchi	Pai	9.79	10.56	280.00	210.50	3,060.10	52.00	6,801.00	43.20	102.20	63.50	23.30	733.68		31,488	0.71789	Inside game reserve (Yankari)	Y	No agricultural/residential area observed	N	Environmental Constraint	N
10	TAR10	Taraba	Taraba	8.30	11.17	280.00	327.00	6,606.00	88.00	2,665.00	75.60	251.80	89.40	57.50	2,005.64		34,881	0.79652	No protected areas	N	No agricultural/residential area observed	N		
11	TAR06	Taraba	Taraba	7.87	11.63	330.00	89.00	1,471.00	64.00	2,636.00	54.00	133.40	66.40	30.50	1,083.28		35,518	0.81206	National Park near the site (Gashaka-Gumti)	N	No agricultural/residential area observed	N		
12	GON10-300	Borno	Gongola	10.37	12.23	300.00	69.68	1,588.08	59.00	9,817.00	49.50	106.80	58.00	24.40	930.41		38,131	0.87117	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N		
13	GON10- 350	Borno	Gongola	10.37	12.23	350.00	253.85	8,561.62	109.00	9,817.00	94.50	276.30	78.50	63.10	2,982.66		47,269	1.07950	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N		
14	DON12	Taraba	Donga	7.54	10.57	300.00	32.00	888.00	99.00	1,621.00	85.50	196.30	61.70	44.80	2,463.86		54,997	1.25515	No protected areas	N	Agricultural/residential area observed (Level 1)	N		
15	MAD05-360	Nassarawa	Mada	8.82	8.33	360.00	18.31	494.24	79.00	4,608.00	67.50	126.60	50.40	28.90	1,634.36		56,552	1.29097	No protected areas	N	Agricultural/residential area observed (Level 2)	N		
16	DON04	Taraba	Donga	6.70	11.01	780.00	5.00	247.00	121.00	2,803.00	105.30	243.80	62.20	55.70	3,592.44		64,496	1.47352	No protected areas	N	Agricultural/residential area observed (Level 1), boarder with Cameroon	N		
17	DON11	Taraba	Donga	7.60	10.67	500.00	9.00	122.00	99.00	1,241.00	85.50	89.90	28.00	20.50	2,429.62		118,518	2.70258	No protected areas	N	No agricultural/residential area observed	N		

Note: Following evaluation is based on Visual observation on Google earth and protected area map

Natural Environment
National parks and internationally protected areas inside/ovelapped with the site-->Y
Protected areas near the site-->N
No protected areas near the site-->N
forest reserves inside/overlapped with-->N

Social Environment
Level 1: Residential houses/agricultual areas are sparse --> N
Level 2: Residential houses/agricultual areas are moderate -->N
Level 3: Residential houses/agricultual areas are dense -->Y

Table 6-2.12 Location of hydropower development candidates (Small-scale)

No	Location: Site ID	Location: Site Location	Location: River Basin	Cordination: Latitude (N)	Cordination: Longitude (E)	Project Features: Reservoir Area (km^2)	Reservoir Volume (Mm^3)	Dam Height (m)	Catchment Area (km^2)	Effective Head (m)	Annual Output (GWh)	Design Discharge (m^3/sec)	Output (MW)	Project Cost (MUSD)	Unit Cost (USD/kW)	Unit Cost (USD/kWh)	Evaluation: Natural Environment: Comment	Natural Environment: Unacceptable (Y/N)	Social Environment: Comment	Social Environment: Unacceptable (Y/N)	General Comments	Site Retainment (Y/N)
1	DON13	Taraba	Donga	7.63	10.15	21.00	92.00	14.00	11,110	9.00	66.10	197.20	15.10	33.70	2,232	0.051	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
2	DON15	Taraba	Donga	8.07	10.07	33.00	64.00	9.00	14,189	4.50	41.70	248.90	9.50	25.70	2,705	0.062	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
3	GON08	Borno	Gongola	10.06	11.82	15.12	52.11	14.00	38,504	9.00	29.50	88.10	6.70	24.20	3,612	0.082	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 2)	N		Y
4	DON06	Taraba	Donga	6.92	10.84	38.00	314.00	14.00	4,522	9.00	32.00	95.60	7.30	27.00	3,699	0.084	No protected areas	N	Agricultural/residential area observed (Level 1), boarder with Cameroon	N		Y
5	GON09	Borno	Gongola	10.05	11.88	30.32	132.15	17.00	38,820	11.70	40.60	93.20	9.30	34.90	3,753	0.086	Forest reserves near the site	N	Agricultural/residential area observed (Level 2)	N		Y
6	TAR13	Taraba	Taraba	8.38	10.50	96.00	522.00	11.00	21,470	6.30	57.20	243.70	13.00	62.40	4,800	0.109	No protected areas	N	Agricultural/residential area observed (Level 1)	N		Y
7	TAR05	Taraba	Taraba	7.68	11.48	24.00	229.00	26.00	5,115	19.80	47.10	63.90	10.70	52.90	4,944	0.112	National park near the site (Gashaka-Gumti)	N	No agricultural/residential area observed	N		Y
8	GON06-370pow	Bauchi	Gongola	10.34	10.29	5.94	55.82	39.00	11,452	49.50	52.40	28.40	12.00	65.60	5,467	0.125	No protected areas	N	Agricultural/residential area observed (Level 1)	N		Y
9	AHI03	Nassarawa	Ahini	8.46	7.59	12.73	120.65	35.00	6,836	27.90	49.70	47.80	11.30	72.70	6,434	0.146	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
10	AHI04	Nassarawa	Ahini	8.34	7.44	16.40	163.32	42.00	7,591	34.20	69.40	54.50	15.90	118.40	7,447	0.171	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
11	GON06-390pow	Bauchi	Gongola	10.34	10.29	5.94	55.82	39.00	11,452	31.50	33.30	28.40	7.60	58.90	7,750	0.177	No protected areas	N	Agricultural/residential area observed (Level 1)	N		Y
12	TAR07	Adamawa	Taraba	7.90	11.55	24.00	302.00	39.00	2,715	31.50	51.30	43.70	11.70	95.20	8,137	0.186	National park near the site (Gashaka-Gumti)	N	No agricultural/residential area observed	N		Y
13	DON01	Taraba	Donga	6.76	11.32	14.00	215.00	34.00	988	27.00	28.80	28.70	6.60	55.90	8,470	0.194	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
14	TAR11	Taraba	Taraba	8.29	10.86	38.00	255.00	22.00	3,562	16.20	30.00	49.80	6.90	60.20	8,725	0.201	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
15	MAD01	Plateau	Mada	9.49	8.64	0.55	11.02	49.00	531	216.00	29.50	3.70	6.70	61.00	9,104	0.207	Overlapped with forest reserve	N	No agricultural/residential area observed	N		Y
16	ANK11-150	Plateau	Ankwe	8.64	8.96	206.26	2,138.21	24.00	6,063	18.00	58.90	87.80	13.40	137.40	10,254	0.233	Inside Ramsar site	Y	No agricultural/residential area observed	N	Environmental Constraint	N
17	TAR03	Taraba	Taraba	7.38	11.38	108.00	1,564.00	49.00	1,917	40.50	79.00	52.40	18.00	233.70	12,983	0.296	Inside National park (Gashaka-Gumti)	Y	No agricultural/residential area observed	N	Environmental Constraint	N
18	MAD05-320	Nassarawa	Mada	8.82	8.33	4.35	63.05	39.00	4,608	31.50	35.20	30.00	8.00	106.80	13,350	0.303	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
19	MAY-02	Adamawa	Mayo Ine	9.10	12.23	71.00	934.00	34.00	4,596	27.00	51.30	51.00	11.70	220.00	18,803	0.429	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
20	TAR04	Taraba	Taraba	7.56	11.77	4.00	164.00	104.00	1,163	90.00	68.00	20.30	15.50	305.00	19,677	0.449	Inside National park (Gashaka-Gumti)	Y	No agricultural/residential area observed	N	Environmental Constraint	N
21	FAN04	Taraba	Fan	8.60	11.18	67.00	831.00	43.00	1,337	35.10	26.70	20.50	6.10	170.00	27,869	0.637	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
22	KIL07-300	Adamawa	Kilunga	9.79	12.76	18.70	376.78	60.00	2,438	50.40	29.80	15.90	6.80	245.40	36,088	0.823	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
23	DON07	Taraba	Donga	7.03	10.89	11.00	596.00	115.00	191	99.90	38.90	10.50	8.90	342.60	38,494	0.881	No protected areas	N	Agricultural/residential area observed (Level 1)	N		Y
24	ANK07	Nassarawa	Ankwe	8.86	8.51	14.93	259.26	49.00	1,131	40.50	22.40	14.90	5.10	206.50	40,490	0.922	No protected areas	N	Agricultural/residential area observed (Level 2)	N		Y
25	TAR01	Taraba	Taraba	7.34	11.53	18.00	717.00	99.00	875	85.50	76.10	23.90	17.40	739.80	42,517	0.972	Inside National park (Gashaka-Gumti)	Y	No agricultural/residential area observed	N	Environmental Constraint	N
26	MAD03	Kaduna	Mada	9.46	8.23	10.90	376.90	109.00	702	94.50	39.80	11.30	9.10	388.90	42,736	0.977	Overlapped with forest reserve	N	Agricultural/residential area observed (Level 1)	N		Y
27	DON08	Taraba	Donga	7.05	10.83	7.00	379.00	104.00	185	90.00	31.50	9.40	7.20	399.60	55,500	1.269	No protected areas	N	No agricultural/residential area observed	N		Y
28	GON03	Bauchi	Gongola	9.82	9.36	7.94	274.46	87.00	1,380	74.70	23.60	8.50	5.40	330.10	61,130	1.399	No protected areas	N	No agricultural/residential area observed	N		Y
29	ANK02	Ankwe	Ankwe	9.04	8.92	2.95	120.46	152.00	382	133.20	26.80	5.40	6.10	460.60	75,508	1.719	No protected areas	N	No agricultural/residential area observed	N		Y

Note: Following evaluation is based on Visual observation on Google earth and protected area map

Natual Environment
- National parks and internationally protected areas inside/ovelapped with the site-->Y
- Protected areas near the site-->N
- No protected areas near the site-->N
- forest reserves inside/overlapped with-->N

Social Environment
- Level 1: Residential houses/agricultual areas are sparse --> N
- Level 2: Residential houses/agricultual areas are moderate -->N
- Level 3: Residential houses/agricultual areas are dense -->Y

Table 6-2.13 Hydropower development sites identified (as of 2015)

	Small	Medium	Large	Total
	(5-20MW)	(20-100MW)	(>100MW)	
Already identified	10	7	6	23
Newly identified	16	10	5	31
Total	26	17	11	54

These potential sites are checked, evaluated and prioritized by taking the topography, nature/social environmental impacts, agricultural land and infrastructures into consideration as well as those affected by the coming into existence of the reservoir. In particular, the natural/social environmental impacts are evaluated based on JICA's Environmental Guideline (April, 2004).

With economic evaluation, the sites are ranked in order from the lowest to the highest unit construction cost of maximum output (USD/kW) and annual generation (USD/kWh). The marginal unit construction cost would be about 0.06 USD/kWh assuming from the price list of "Wholesale Generation Prices for Successor Large Hydro Plants" issued by NBET (The Nigerian Bulk Electricity Trading Plc.) as of 2015.

2) Dam and Reservoir

Several reservoir levels have been considered at the same site, namely minimum, intermediary and maximum and it was well-known that as the reservoir level increased, the installed capacity, inundated area and social and environmental impacts would intensify. Basically, the maximum water level (FSL: Full Surface Level and/or HWL: High Water Level) is selected to avoid saddle dams around the reservoir.

The total hydraulic head is the difference in height between the HWL (estimated reservoir full supply level) and the tailrace water level. The type of dam applied is the rock-fill type because rock-fill dams can be built on most foundations. The assumed crest width is 10 m, the upstream slope is 1V:3.0H and the downstream slope 1V:2.5H to compare topographical site efficiency.

3) Energy Production

Firm energy (Ef, primary/guaranteed energy) means that the hydropower station produces power with supply reliability of 95% through its life period as expressed by the duration curve of energy production. Total firm energy could be expressed per life period with annual output multiplied by the number of periods.

Secondary energy (E_s) is energy produced but not firm and is only effective to reduce the fuel cost in the power market.

The total energy (E_t) is Et=E_f+Es, which means direct output from the hydropower station. From the total hydraulic head (effective head) and the average annual inflow volume, the installed capacity (P) is obtained. The annual firm energy with a guarantee of 95% (E_f) is estimated by the following formula:

$$\mathbf{E_f = (8.6 \times V_{tu} \times H_e) / 3{,}600\ (GWh)}$$

Where: E_f: Firm energy (GWh/year)

V_{tu}: Average annual turbined volume (Mm^3)
H_e: Effective hydraulic head (m) $=0.9\times H_t$ (m)
H_t: Gross head (m)

The total hydraulic head (H_t) is the difference between the reservoir high water level (HWL) and the tailrace water level under normal operation. The effective hydraulic head (H_e) is calculated by reducing hydraulic losses from the total hydraulic head (H_t). The hydraulic losses are estimated at about 10% of the total hydraulic head (H_t).

The plant factor (P_f) of the hydropower station is the ratio of its actual energy production to potential energy production over a period of time if operated at full installed capacity continuously over the same period (P_f=1). The records of the plant factor at existing hydropower stations such as Kainji, Jebba and Shiroro and from 2006 to 2014 are shown as below, assuming a maximum plant factor (P_f) of 0.50 for this study.

Table 6-2.14 Records of Plant Factor from 2006 to 2014

Power Station	Output (MW)	Potential annual generation (MWh)	Actual generation (Max) (MWh)	Max.Pf	Actual generation (Min) (MWh)	Min.Pf	Actual generation (Ave) (MWh)	Ave.Pf
Kainji	760	6,657,600	2,816,750	0.42	733,916	0.11	1,944,213	0.29
Jebba	578	5,063,280	2,794,976	0.55	2,171,747	0.43	2,580,262	0.51
Shiroro	600	5,256,000	2,664,630	0.51	1,941,344	0.37	2,323,290	0.44
Average		16,976,880	8,276,356	0.49	4,847,007	0.29	6,847,765	0.40

*Kainji power station has not been working with stable condition due to aging of turbines and generators for recent 9 years.

The installed hydropower capacity station would be obtained from the annual firm energy (E_f) and the plant factor (P_f).

$$\mathbf{P = E_f\times 1{,}000/\ (24\times 365\times P_f)\ (MW)}$$

Where: P: Maximum installed capacity (MW)
E_f: Firm energy (MWh/year)
P_f: Plant factor (0.5)

4) Project cost

The project cost estimated in the preliminary/feasibility study comprises the total expenses of Preparatory works, Compensation (Land, resettlement etc.), Environmental mitigation, Civil work, Hydraulic equipment, Electro-mechanical equipment, Transmission lines, Administration cost, Engineering service cost, Taxes, Physical contingency, Price contingency and Interest during construction.

The project cost is estimated to constitute the combined dam cost with auxiliary facilities/equipment such as spillway, bottom outlet, intake, penstock and tailrace etc. and powerhouse including turbines, generators and transformers etc. The cost of the dam and auxiliary facilities/equipment is estimated by multiplying the volume of the dam body by an aggregated unit cost, which comes from the unit cost of the Zungel and/or Mambilla hydropower project(s) under construction at present in Nigeria by Chinese contractors. The cost of power station equipment and facilities is estimated by multiplying the installed capacity (MW) by an aggregated unit price of 0.5 MUSD/MW, while the annual operation and maintenance (O/M) cost is estimated as 1% of the project cost according to proceeding records and past experience in Nigeria.

The unit construction cost per installed capacity (MUSD/MW) is obtained by dividing the project cost by the installed capacity (MW). The unit construction cost per annual generation (USD/kWh) is obtained by dividing the annual O/M cost over depreciation cost by the annual generation (MWh). The unit costs of installed capacity and annual generation are applied to determine economic feasibility, given the scope for direct comparison with the current wholesale power tariff (USD/kWh).

5) Screening of hydropower development candidates

The hydropower development candidates shown in Table 6-2.10, 11 and 12 include some very costly sites with a unit construction cost exceeding US$ 124,306/kW, meaning it is unreasonable to include all the sites shown in Table 6-2.10, 11 and 12 as generation expansion candidates. Hydropower development sites for which generation is costlier than simple-cycle gas turbines and their relatively high generation cost will be excluded from the candidates. Table 6-2.15 shows the result of screening hydropower candidates. Thirteen sites, Nos. 1 to 13, will be considered as candidates for the generation expansion plan.

Table 6-2.15 Screening of hydropower development candidates

No.	Plant name	Plant ID	Type	Installed Capacity (MW)	Energy generation (MWh/y)	Unit const. cost (USD/kW)	Generation cost (US$/kWh)
1	BEN04-85	BEN4	RoR	88	1,047,800	1,667	0.0141
2	KAT04	KAT4	RoR	36	441,000	2,783	0.0229
3	NIG03	NIG3	RoR/Dam	190	833,600	1,212	0.0279
4	NIG02	NIG2	RoR/Dam	266	1,163,700	1,217	0.0280
5	KAT07	KAT7	Dam	52	384,188	2,808	0.0386
6	BEN05-85	BEN5	Dam	239	1,161,300	1,914	0.0398
7	BEN07	BEN7	RoR	196	865,300	2,024	0.0461
8	DON05	DON5	Dam	198	888,400	2,096	0.0470
9	BEN06-85	BEN6	Dam	265	856,700	1,961	0.0612
10	BEN02	BEN2	RoR	35	157,100	2,874	0.0644
11	BEN01-185	BEN1	Dam	203	584,900	2,336	0.0818
12	TAR12	TR12	Dam	77	294,800	5,791	0.1520
13	NIG01	NIG1	Dam	134	229,400	3,359	0.1971
14	DON09	DON9	Dam	33	144,500	9,334	0.2150
15	KAT02	KAT2	Dam	67	152,700	5,150	0.2289
16	BEN03	BEN3	Dam	101	336,000	8,445	0.2553
17	ANK13	AK13	RoR	20	89,500	12,509	0.2876
18	TAR08	TAR8	Dam	38	164,500	17,813	0.4107
19	TAR10	TR10	Dam	58	251,800	34,881	0.8034
20	TAR06	TAR6	Dam	31	133,400	35,518	0.8190
21	DON04	DON4	Dam	56	196,300	43,620	1.2483
22	GON10-300	GN10	Dam	24	240,911	122,240	1.2487
23	DON12	DN12	Dam	45	106,800	36,481	1.5435
24	DON11	DN11	RoR	21	126,600	98,038	1.6011
25	MAD05-360	MAD5	Dam	29	89,900	124,306	4.0304

Remarks: Hydropower development sites to be included in the generation expansion plan

Source: TRACTEBEL ENGINEERING S.A. (Sep. 2015) "Screening of potential hydropower options with associated water resources developments in the Niger basin - Interim Report"

6-2-1-3 Nuclear

In March 2016, the minister of FMPWH declared that all procurement activities for the first nuclear power plant with a generation capacity of 1,200MW to the national grid by 2025 would be performed as scheduled. The two sites selected by the Nigeria Atomic Energy commission are located in Geregu in the Ajaokuta Local Government Area of Kogi-State and the Itu Local Government Area of Akwa Ibom State. These projects are to be financed through Public-Private Participation policy for infrastructural development nationwide, aiming to increase it to 4,800MW by 2035.[6]

Also, the IAEA (International Atomic Energy Agency) periodically dispatches its mission to Nigeria to monitor preparation for nuclear power development, which it deems smooth. Furthermore, according to the NAEC (Nigeria Atomic Energy Commission) there is no problem with LGA (Local Government Area) and communities in and around the nuclear power development sites and the reactor type is WWER-1200 to be constructed under BOT (Build Operate and Transfer) scheme by a Russian company.

Based on the above, it is judged that nuclear power development is proceeding in line with Nigeria's energy policy and nuclear power is considered as a generation expansion candidate.

6-2-1-4 Renewable energy

Renewable energy power projects such as solar and wind are to be developed as IPP by the private sector. Therefore, ongoing and planned renewable power projects shown in Table 6-2.16 are considered candidates for the generation expansion plan. The unit construction costs to be used for economic evaluation are shown in Table 6-2.17.

Table 6-2.16 Renewable power candidates

Name of projects	Type	Rated capacity (MW)
PAN AFRICA SOLAR	Solar	75
NIGERIA SOLAR CAPITAL PARTNERS	Solar	100
NOVA SOLAR	Solar	100
MOTIR DUSABLE	Solar	100
LR AARON SOLAR POWER PLANT	Solar	100
MIDDLE BAND SOLAR	Solar	100
AFRINERGIA SOLAR	Solar	50
NOVA SCOTIA POWER	Solar	80
KVK POWER NIGERIA LTD	Solar	55
QUAINT ENERGY SOLUTIONS	Solar	50
ANJEED KAFACHAN SOLAR IPP	Solar	100
CT COSMOS	Solar	70
ORIENTAL	Solar	50
EN Consulting & Projects - Kaduna	Solar	100
KAZURE (KANO DisCo)	Solar	1000
JBS Wind Power Plant	Wind	100

Source: TCN

[6] Federal Ministry of Power, Works and Housing, Press and Public Relations (Power) (16 March, 2016) "FG Committed to diversifying Electricity Generation with Nuclear Energy- Fashola"

Table 6-2.17 Unit construction cost of renewable energy

Source of energy	Type	Unit construction cost
Solar	Grid-connected	US $1,200/kW
Wind	On shore	US $1,571/kW

Source: IRENA (2018)Renewable Power Generation Costs in 2017

6-2-2 Optimal Power Development Plan

6-2-2-1 Method for compiling the least-cost power generation development plan

To examine the least-cost power generation development plan combining various types of power generation and development patterns, WASP (Wien Automatic System Planning Package, Version -IV), which is a power generation development planning software package developed by the International Atomic Energy Agency (IAEA), will be used.

WASP-IV can select an optimal power source development plan that meets constraints such as supply reliability (LOLP), reserve capacity, fuel limitations and restrictions on environmental pollutant emissions, etc. over the next 30 years. The optimal power source development plan refers to that in which the general cost is discounted as current prices bottom out. The following paragraphs outline the WASP calculation model.

The combination of all power generation plants (power generation development plan) that meet constraints and are added to the power system is evaluated based on objective functions comprising the following items:

- Depreciable investment cost: Equipment and installation cost (I)
- Residual investment cost (S)
- Non-depreciable investment cost: Fuel store, replacement parts, etc. (L)
- Fuel cost (F)
- Non-fuel operation and maintenance cost (M)
- Non-supplied power cost (O)

The cost function evaluated in WASP is expressed by the following formula:

$$B_j = \sum_{t=1}^{T} [\, \bar{I}_{j,t} - \bar{S}_{j,t} + \bar{L}_{j,t} + \bar{F}_{j,t} + \bar{M}_{j,t} + \bar{O}_{j,t} \,]$$

Where:

B_j : Cost function of the power source development plan j

t : Year of the power source development plan (1, 2, ..., T)

T : Term of the power source development plan (all years)

The bars above each symbol indicate prices discounted at the discount rate i by the set time. The optimal power source development plan is that at which the cost function B_j in all development plan candidates j bottoms out.

Figure 6-2.4 shows a simplified flowchart of WASP-IV indicating the flow of information and data files between various WASP modules.

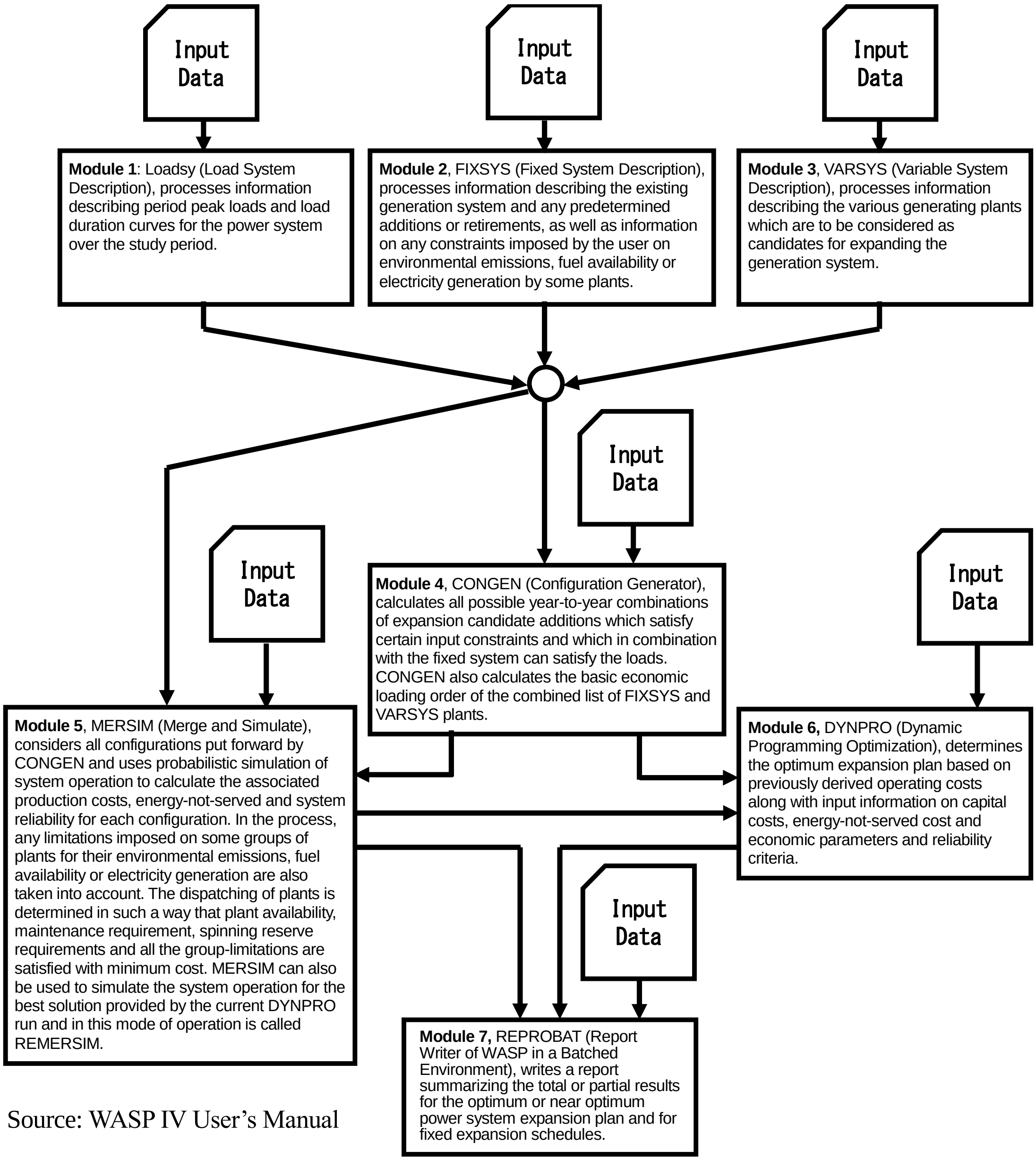


Figure 6-2.4 WASP-IV Flowchart

6-2-2-2 Examination Condition

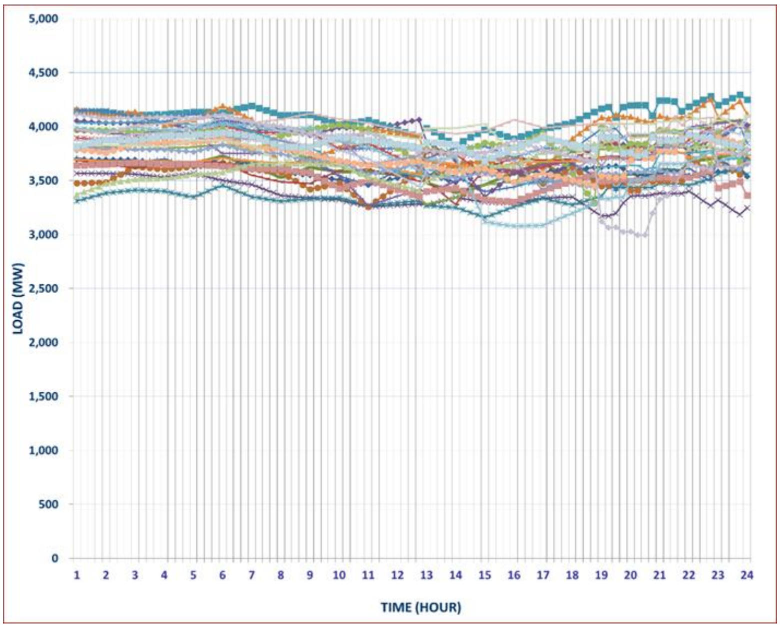
(1) Power demand forecast for Power development planning

The power demand forecast to be used for power development planning is base-case from some Scenarios mentioned in Chapter 4. Peak demand is used as gross peak demand, including transmission and distribution losses and generation-end peak demand, whereby gross peak demand is added with in-station use power (2.4% as of 2014) used for the power development formulation.

(2) Load duration curve

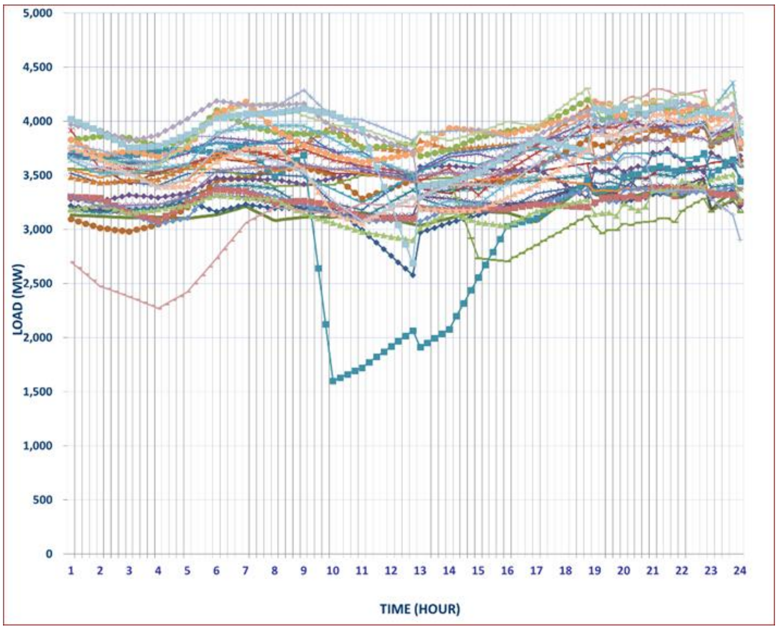
In Nigeria, the current daily load curve has become almost flat from daytime to night due to daily load shedding. Figure 6-2.5 and 6-2.6 show examples of the daily load curve during dry and rainy seasons, respectively. As a general rule, the daily load peaks in the evening and declines at night in developing countries, but the daily load in Nigeria has become almost flat.

Under these circumstances, future power development planning is not considered real and reflecting actual load, including suppressed demand. Accordingly, in this study, an assumed load curve (Figure 6-2.7 and Table 6-2.18) created by the "National Load Demand Study in 2009" is adapted.



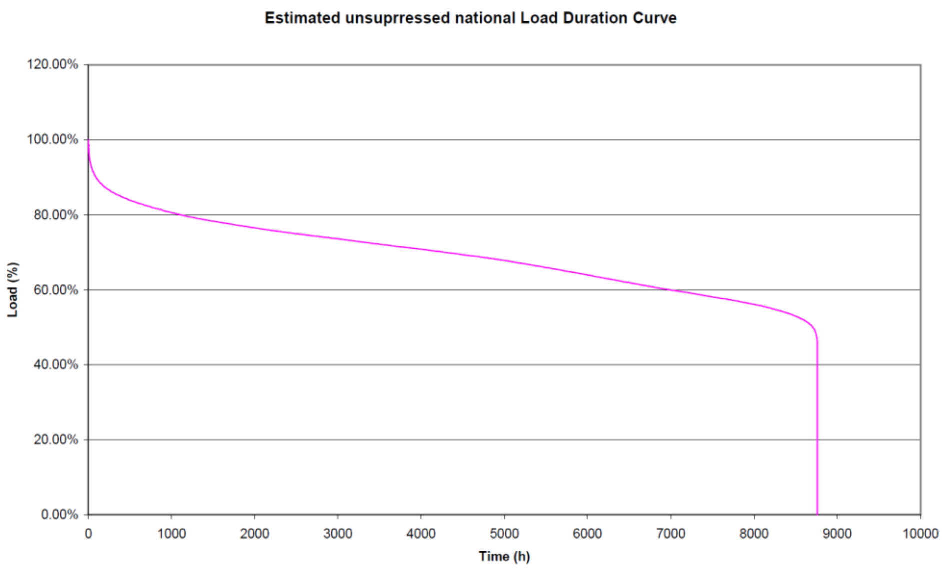
Source: TCN

Figure 6-2.5 Daily Load Curve in the dry season (1-28 February, 2014)



Source: TCN

Figure 6-2.6 Daily Load Curve in the rainy season (1-31 August, 2014)



Source: Tractebel Engineering (Apr.2009) "National Load Demand Study Final Report - Volume 1 - National Load Demand Forecast"

Figure 6-2.7 Load curve in Nigeria (Assumption by Tractebel Engineering)

Table 6-2.18 Load curve in Nigeria (Assumption by Tractebel Engineering)

Unsuppressed National Load Duration Curve			
step	hour	Min of range	average of range
1	1	100.00%	100.00%
2	31	94.15%	96.00%
3	238	88.31%	90.51%
4	935	82.46%	84.91%
5	2470	76.62%	79.21%
6	4513	70.77%	73.74%
7	6080	64.93%	68.03%
8	7582	59.08%	62.01%
9	8569	53.24%	56.63%
10	8760	47.39%	51.49%

Source: Tractebel Engineering (Apr. 2009) "National Load Demand Study Final Report - Volume 1 - National Load Demand Forecast"

(3) Power supply reliability

Loss of Load Probability (LOLP) is adapted as an indicator to assess power supply reliability and power development planning with necessary marginal supply capability to satisfy targeted LOLP.

LOLP is widely adapted as a global marker for power supply reliability and the North American Electric Reliability Corporation: NERC (US) sets 1 day/10 years, PLN (Indonesia) and the Philippines set 1 day/1 year and the Ceylon Electricity Board: CEB (Sri Lanka) sets 3 days/1 year as standard.

In terms of GDP per capita as an economic indicator, Nigeria archives US3,300 / person (assumed nominal GDP by the IMF in 2014), compared to US3,534 / person in Indonesia, US2,862 / person in the Philippines and US3,534 / person in Sri Lanka, thus with similar economic levels to Indonesia and the Philippines taken into consideration, 1 day/1 year (LOLP) will be taken in this study for Nigeria.

(4) Lifetime and rehabilitation plan for the existing power plant

In this study, a 40-year lifetime will be assumed for thermal power plants. For hydropower plants rehabilitation of water-wheel generators should be done after half a century.

(5) Fuel cost

The natural gas cost refers to the selling price for domestic power companies, but the cost for coal-fired power refers to international trading prices of Australia and South Africa to set fuel cost (2015) for the engineering economy of power development planning, given the lack of benchmark indicators in Nigeria.

The price for the unit calorific value is almost equivalent between natural gas and coal and although price escalation is not taken into consideration when determining the WASP input cost, the real-time price is taken.

Table 6-2.19 Fuel Cost

Classification	Calorific value	Price	Price for unit calorific value
Natural gas	9,460 kcal/Nm^3 (HHV)	US$ 2.80/mmBtu	¢ 1.11/Mcal*
Coal (subbituminous coal / bituminous coal)	5,600 kcal/kg (HHV)	US$ 56.00/ ton	¢ 1.00/Mcal*

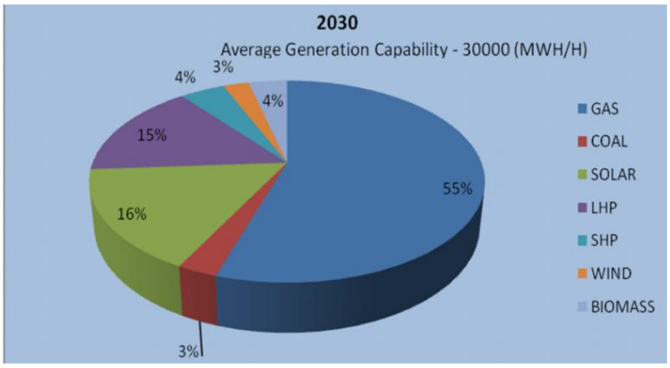
Source: NNPC, NERC, World Bank

Note: *M (Mega)means a prefix of 10^6 and Mcal is 10^6cal＝1,000 kcal

6-3 Analysis on Generation Expansion Scenarios

6-3-1 Scenario Setting for Generation Expansion Plans

In Nigeria, the energy mix target in power generation toward 2030 is set as shown in Figure 6-3.1. Since the power generation sector in Nigeria is already privatized, all power generation other than hydro and nuclear power which will be developed as a national project shall be developed by private investors. Accordingly, three generation expansion Scenarios as shown in Table 6-3.1 are set based on ongoing and planned IPP projects as well as hydro and nuclear power projects to be implemented by the Federal Government.



Source: Federal Ministry of Power Works and Housing (June 2016)
"The Nigerian Power Sector Investment Opportunities and Guidelines"

Figure 6-3.1 Energy mix target in power generation

Table 6-3.1 Generation Expansion Scenarios

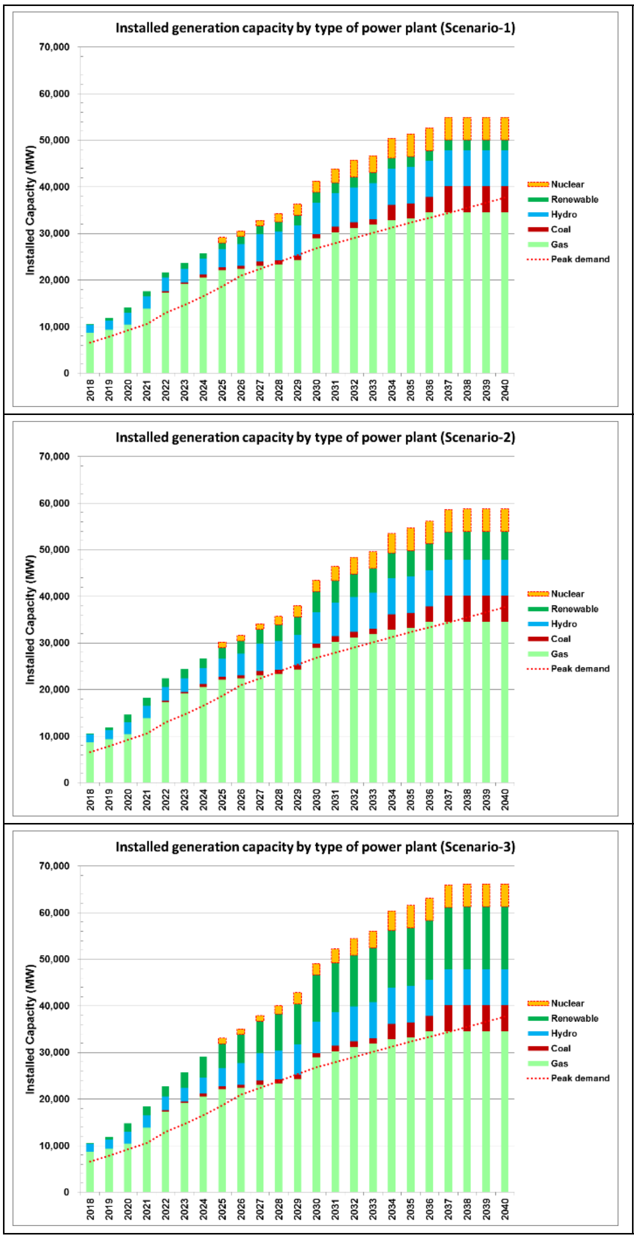
Type	Energy Mix Target of Nigeria	Scenario 1 In line with ongoing and planned IPPs	Scenario 2 More renewable than Scenario 1	Scenario 3 In line with the Energy Mix Target
Gas	55%	70%	65%	55%
Coal	3%	3%	3%	3%
Hydro	Total: 19% Large: 15% Small: 4%	16%	16%	16%
Renewable Energy	Total: 23% Solar: 16% Wind: 3% Biomass: 4%	5%	10%	20%
Nuclear	-	6%	6%	6%
Non-carbon origin*	42%	27%	32%	42%

Remarks: *: The total of hydro, renewable and nuclear
The% shares indicated in the above table are calculated based on the rated generation capacity

Source: JICA Study Team

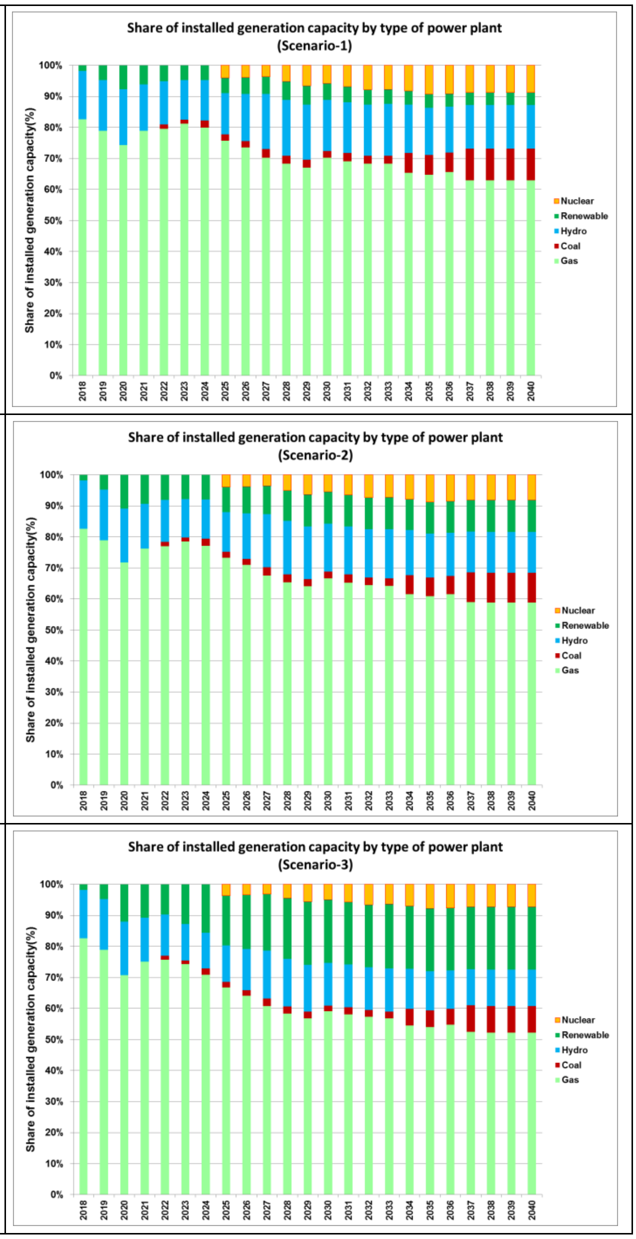
6-3-2 Capacity and Energy Generated in Each Scenario

The generation capacity and energy generated in each Scenario are shown in Figure 6-3.2/6-3.3 and Figure 6-3.4/6-3.5, respectively.



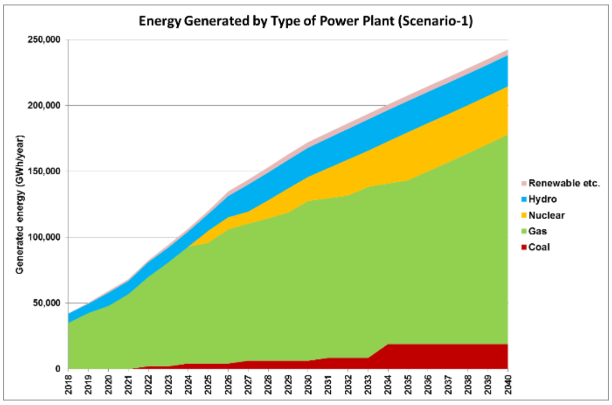
Source: JICA Study Team

Figure 6-3.2 Generation capacity



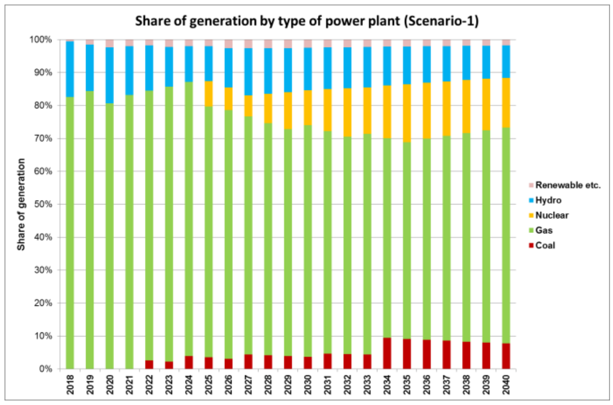
Source: JICA Study Team

Figure 6-3.3 Share of generation capacity



Source: JICA Study Team

Figure 6-3.4 Energy generated



Source: JICA Study Team

Figure 6-3.5 Share of energy generated

6-3-3 Comparison of Generation Expansion Scenarios

The summarized total generation costs and the CO_2 emissions in each Scenario are shown in Table 6-3.2.

Table 6-3.2 Comparison of generation expansion Scenarios

	1	2	3
Total generation capacity as of 2040	54,927MW (Base)	58,727MW (+7%)	66,127MW (+20%)
Accumulated total generation cost by 2040 (Investment +fuel +O&M)	US$ 204,556 million (Base)	US$ 210,315 million (+3%)	US$ 214,646 million (+5%)
Accumulated CO_2 emissions by 2040	1,008 million tons (Base)	1,002 million tons (-1%)	957 million tons (-5%)
Need for power system stabilization measures due to increased renewable energy	Not necessary	Necessary	Necessary

Remarks: Figures in parentheses indicate the rate of increase or decrease compared to Scenario 1.

(1) Generation capacity

For the time being, the daily load in Nigeria seems to peak in the evening, hence solar power cannot contribute to peak generation. Accordingly, apart from the renewable energy generation capacity, conventional power generation capacity must also be secured to meet peak load. As such, the total generation capacity rises with an increasing share of renewable energy. The incremental generation capacities in Scenarios 2 and 3 are 7 and 20% respectively compared to Scenario 1.

(2) Total generation cost

Fuel cost decreases as the share of renewable energy increases. However, as described above, renewable energy is deemed additional investment and total investment cost increases along with the higher share of renewable energy. Comparing the fuel reduction and increment of investment by renewable energy, the former is lower than the latter. Accordingly, the total cost of Scenarios 2 and 3 exceeds Scenario 1 by 3 and 5% respectively. In general, short term fluctuation will affect frequency and voltage stability and long-term fluctuation will affect the balance of supply and demand in case the ratio of renewable energy in generation exceeds 10%. Accordingly, some kinds of power system stabilization measures are required in Scenarios 2 and 3 although the cost of such measures is not included in the total cost shown in Table 6-3.2.

Due to the increased capacity of grid-connected renewable energy generation, the power supply system becomes instable, which forces Japanese electric utilities to limit the scope of grid connection and take system stabilization measures. For example, Kyushu Electric Power constructed and put Buzen Battery Station (50MW and 300MWh) into operation in March 2016, targeting an improved demand and supply balance by introducing a large-scale power storage system. The construction cost of the battery station is 20 billion Japanese Yen (approximately US$ 180 million) and its unit construction cost per kW is 40 thousand Japanese Yen (approximately US$ 3,600). Considering the huge investment cost of the power system stabilization system, the total cost of Scenarios 2 and 3 will increase, which is why Scenario 1 remains most preferable in terms of investment cost.

(3) CO_2 Emissions

CO_2 emissions decline with an increasing share of renewable energy; Scenarios 2 and 3 generate 1 and 5% lower CO_2 respectively than Scenario 1. Table 6-3.3 shows the CO_2 emission factors used to calculate CO_2 emissions. The INDC (Intended Nationally Determined Contribution) of Nigeriam which was formulated in accordance with the Paris Convention, aims to reduce greenhouse gas emissions by 20% (Unconditional) and 45% (Conditional) by 2030 compared to BAU (Business As Usual). INDC determines reduction measures in the power sector such as introducing off-grid solar PV (13,000MW) and efficient gas-fired power.

Table 6-3.3 CO_2 Emission Factors

Fuel	CO_2 Emission Factors	Remarks
Natural gas	56,100 kg-GHG/TJ-fuel	Assuming: Heat value: 38,348kJ/Nm^3 Specific gravity: 0.822kg/Nm^3
Coal	101,000 kg-GHG/TJ-fuel	Lignite

Source: IPCC

6-4 Evaluation of Generation Expansion Scenarios

6-4-1 Evaluation of Generation Expansion Scenarios

While Scenario 1 is optimal in overall cost terms, Scenario 3 wins out in environmental aspects, so both have pros and cons. Under these circumstances, it would be preferable to consider options to reduce CO_2 emissions in Scenario 1 and total costs in Scenario 3.

As for Scenario 1, 70% of gas-fired power plants included in the expansion candidates are simple-cycle gas turbines while the remaining 30% are combined-cycle. The thermal efficiency of the combined cycle outperforms the simple-cycle gas turbine, while when both are compared in terms of energy generated, the combined cycle consumes 33% less fuel compared to the simple-cycle gas turbine. By converting simple cycle to be developed as IPP to combined cycle, CO_2 emissions can be reduced. For example, by converting 50% of the simple-cycle gas turbine included in Scenario 1 to combined cycle, CO_2 emissions from Scenario 1 can be reduced by 10%. The unit construction cost of the 100MW class gas turbine is almost equivalent to that of the 300MW class combined cycle, meaning no huge burden on private investors from this conversion.

As for Scenario 2, further cost reduction depends on renewable energy power plants becoming cheaper and grid stability systems. Although these costs will be reduced in future, but it is difficult to forecast when and how much. Furthermore, such cost reduction cannot be controlled by the regulations and incentives of the government.

Generation expansion Scenarios are evaluated from the perspectives of overall generation cost, CO_2 emissions and the impact on power system stability. As shown in Table 6-4.1, Scenario 1 is top-ranked of the three Scenarios. Under the circumstances described above, it would be better and more realistic to take Scenario 1 as the basis of the generation expansion plan and improve it by converting simple-cycle gas turbines to combined-cycle with government regulations and incentives. Efficient gas-fired power generation is recommended by INDC as a measure to reduce greenhouse gases. Accordingly, this Scenario conforms to the government' policy on climate change. A generation expansion plan based on Scenario 1 is shown in Annex 6.1.

Table 6-4.1 Evaluation of generation expansion Scenarios

	Scenario-1	Scenario-2	Scenario-3
Total generation cost	3	2	1
CO_2 emissions	1	2	3
Impact on power system stability	3	2	1
Overall rating (Total)	7	6	5

Remarks: As for ratings, three is the highest and one the lowest.

6-4-2 Technical Challenges to Introduce Renewable Energy

In July 2018, the *5th Basic Energy Plan* was approved by the cabinet of Japan; indicating an energy mix target to be achieved by 2030 and the basic energy policy direction toward 2050. The generation mix target by 2030 comprises 56% thermal (namely 27% LNG, 3% Oil and 26% Coal), 20-22% Nuclear and 22-24% renewable respectively.

The introduction of renewable energy had been promoted in Japan after the disaster of Fukushima Nuclear Power. Among the areas in Japan, solar power has been largely introduced in Kyushu because it is located in the south part and has abundant solar radiation. Accordingly, the share of renewable energy generation reaches up to 20% in Kyushu Electric Power, which is close to the target set by the 5th Basic Energy Plan, but Kyushu Electric Power is forced to reduce output from renewable energy generation during the daytime when clear weather and lower demand prevails. Even if the thermal power output is reduced and pumped storage hydro is operated, excessive generation from renewable energy might trigger instability of the power grid. Accordingly, a forced reduction in renewable power output is unavoidable to maintain power system stability.

The share of 20% renewables sets a very difficult target for electric utility companies in terms of power system operation, even in Japan. Currently, system operation criteria prescribed by the Grid Code are not complied with in Nigeria, which hampers frequency adjustment functions and significant limit the capacity to accept renewable energy and its very fluctuating output.

Promoting renewable energy generation in Nigeria depends on: (i) fully utilizing the adjustment capacity of thermal power, (ii) expanding the interconnection transmission capacity and (iii) fitting system stabilization measures such as pumped storage hydro and battery systems. Furthermore, power system operation compliant with the Grid Code is the precondition for introducing grid-connected renewable energy.