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INDEPENDENT SYSTEM OPERATOR (ISO)

Part 4

Generation Adequacy Report

Outlook for 2017 - 2027

By

Market Operator

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Definitions of Terms and Acronyms

ANE	Available Net Energy Represents the electrical energy that is available from the power stations. It includes the capacity restrictions (as in ANGC) as well as energy constraints. It is typically expressed as an average power in MWh/h.
ANGC	Available Net Generation Capacity Represents the available capacity, as recorded in the Daily Operational Reports. It includes the values declared by the generation companies and takes planned and Forced Outages into consideration.
CCGT	Combined Cycle Gas Turbines
Forced Outage	Shutdown of equipment due to failure, normally initiated automatically by protection relay(s).
GGC	Active Gross Generation Capacity = Installed generation capacity – Capacity of units permanently not available.
NGC	Net Generation Capacity = GGC – Auxiliary power of power plants – Power plant losses.
OCGT	Open Cycle Gas Turbines
PH	Period Hours (PH) or active hours is the number of hours a unit was in Active state.
POF	Planned Outage Factor (POF) = (POH/PH) * 100.
POH	Planned Outage Hours (POH) are the number of hours a unit was in Planned Outage state.
RANGC	Reliably Available Net Generation Capacity Represents the ANGC that is achieved 99% of the time
REM	Remaining Energy Margin (REM) = ANE – Energy Demand.
RM	Remaining Capacity Margin, also called Remaining Margin Excess capacity of reliably available generation, taking into consideration generation constraints, operating reserves and the peak demand.
UOF	Unplanned Outage Factor (UOF) = (UOH/PH) * 100.
UOH	Unplanned Outage Hours (UOH) are the number of hours a unit was in Unplanned Outage state.

1. Introduction

Generation adequacy is a measure of whether the generation of electricity in a system meets the demand reliably, without considering transmission or distribution constraints.

The generation adequacy outlook will show the future development from 2017 to 2027 of energy and capacity margins considering demand forecast, planned generation expansion, technical availability of power plants and constraints of primary energy (gas and water).

2. Methodology

2.1. Introduction

Adequate generation must be able to generate sufficient electrical energy for supplying the energy demand of all customers, and it must be able to make the required amount of energy available at every moment in time.

Additionally, the available generation must be able to provide sufficient Operating Reserve at any moment in time for ensuring system stability.

In line with the Generation Adequacy retrospective report of the Nigerian power system [1], this generation outlook quantifies Generation Adequacy by two main indices, which are Remaining Energy Margin (REM) and the Remaining Capacity Margin (RM).

In a system with fully adequate generation, both indices (REM and RM) are greater than zero, indicating that the capability of generation to produce electrical energy is larger than energy demand and that the system is able to deliver the required energy at any moment in time.

In systems with inadequate generation, one of the two indices or even both are less than zero, indicating that generation is not capable to generate the required amount of electrical energy (REM<0) or that it cannot supply demand adequately at any moment in time (RM<0).

This is visualized by the example according to Figure 1, showing typical diurnal demand variations over one week and three levels of generation availability.

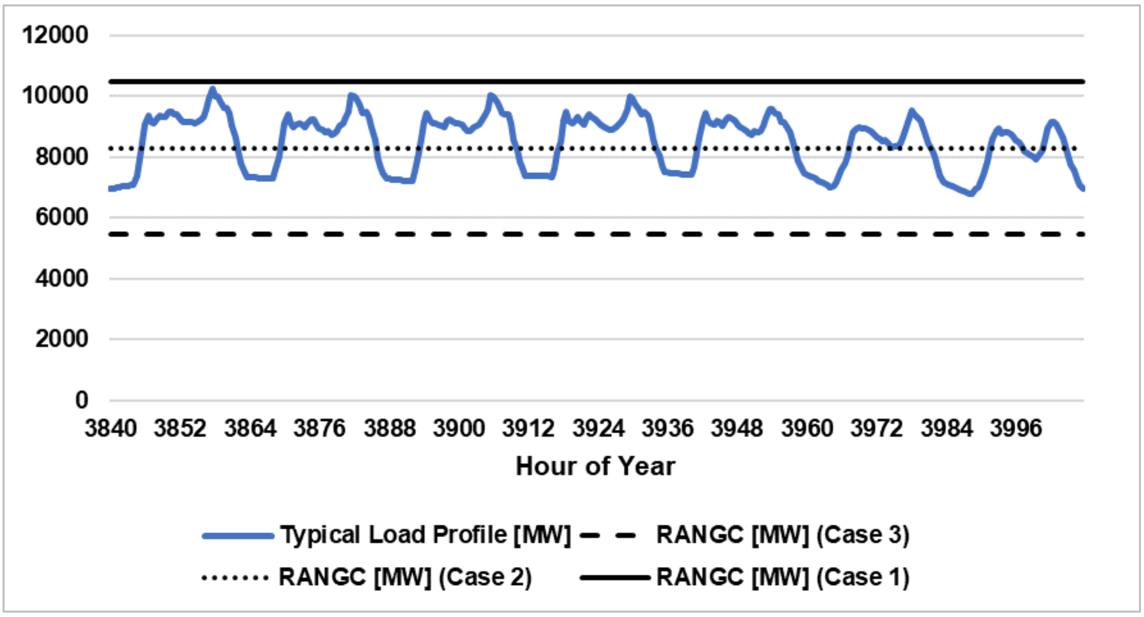

Figure 1 – Energy and capacity deficit

Depending on the level of available generation, we can differentiate three types

- Case 1 = No deficit (REM > 0 and RM >0)
- Case 2 = No energy deficit, but a capacity deficit (REM > 0 and RM <0)
- Case 3 = Energy and capacity deficit (REM < 0 and RM < 0)

In case 1 (solid line) the available generation capacity is always higher than the demand, even during peak load hours. In this case generation is able to timely deliver the required amount of energy at any moment in time.

In case 2 (dashed line), the available generation capacity is sometimes higher and sometimes lower than demand. On average, it would actually be higher than demand, which means that generation would be able to generate the required weekly energy demand but there are times during which generation capacity is lower than demand and consequently, it would not be possible to supply demand adequately at all times. Such a system would be characterized by a Remaining Energy Margin >0 and a Remaining Capacity Margin <0.

In case 3, generation capability is always below demand. In such a system both indices REM and RM would be less than zero, indicating that there is an energy and a capacity deficit in the system.

The Nigerian power system currently operates according to case 3, meaning that there is both, an energy deficit and a capacity deficit.

2.2. Remaining Energy Margin

Remaining Energy Margin (REM) expresses the excess of the Available Net Energy (ANE) in comparison to the Energy Demand of the system (see equation 2.1).

Remaining Energy Margin:

$$REM = ANE - Demand\ (energy) \tag{2.1}$$

The Available Net Energy depends on two main factors, which are

- Installed capacity and availability of power plants.
- Available primary energy resources (in Nigeria mainly gas, water and from 2019 on solar energy).

The Available Net Energy can be limited by both, limited availability of power plants and primary energy constraints (gas fuel constraints or water constraints).

Figure 2 shows an example, in which the Available Net Energy (ANE) is limited by the availability of primary fuel and not by ANGC.

The area below the ANGC curve (minus Operating Reserve) is equivalent to the energy that the generators could deliver to the system if sufficient primary energy (hydro and gas) was available. However, as shown in the example according to Figure 2, limited primary energy will lead to gas and water constraints in this example and consequently limit the amount of electrical energy that can be generated and delivered.

Figure 3 shows a system, in which there is sufficient availability of primary energy, and ANE is just limited by the technical availability of the power plants.

The Nigerian system currently corresponds to a system according to Figure 2.

It is assumed in the analyses, that the primary energy can be made available at any time. The monthly variation in energy from hydro plants and from PV plants is considered. In the case of gas plants, the total available energy is limited.

The storage dams of Kainji and Shiroro are in a range that justifies the assumption that energy can be used at any time within a monthly interval. The hydro power plants Jebba and the planned hydro power plant Zungeru have smaller storage but their inflow is directly linked to Kainji and Shiroro respectively and consequently, the above assumption also applies.

In the case of gas supply, it is more complex, because gas constraints can depend on various aspects, like constrained volumes of gas delivery (annually), economic constraints (e.g. unpaid bills), vandalism etc. Because insufficient information is available for quantifying each of these effects individually and because it is almost impossible to predict the different aspects, an equal availability of gas resources in every month is assumed.

Because of the above described seasonal variation of the available hydro energy, the Remaining Energy Margin (REM) is not only calculated annually but also at monthly timescales.

A negative monthly REM indicates that there is an energy deficit, and this could be due to seasonal variations of hydro energy. The corresponding annual REM could still be positive if the annually available primary energy was sufficient for fully supplying the annual energy demand.

The Remaining Energy Margin (REM) is an energy index. Therefore, it is usually expressed in MWh (or GWh). In this report, generally energy indices are expressed by an equivalent average power. To distinguish clearly between energy and capacity, the unit MWh/h is used for energy indices and MW for capacity indices.

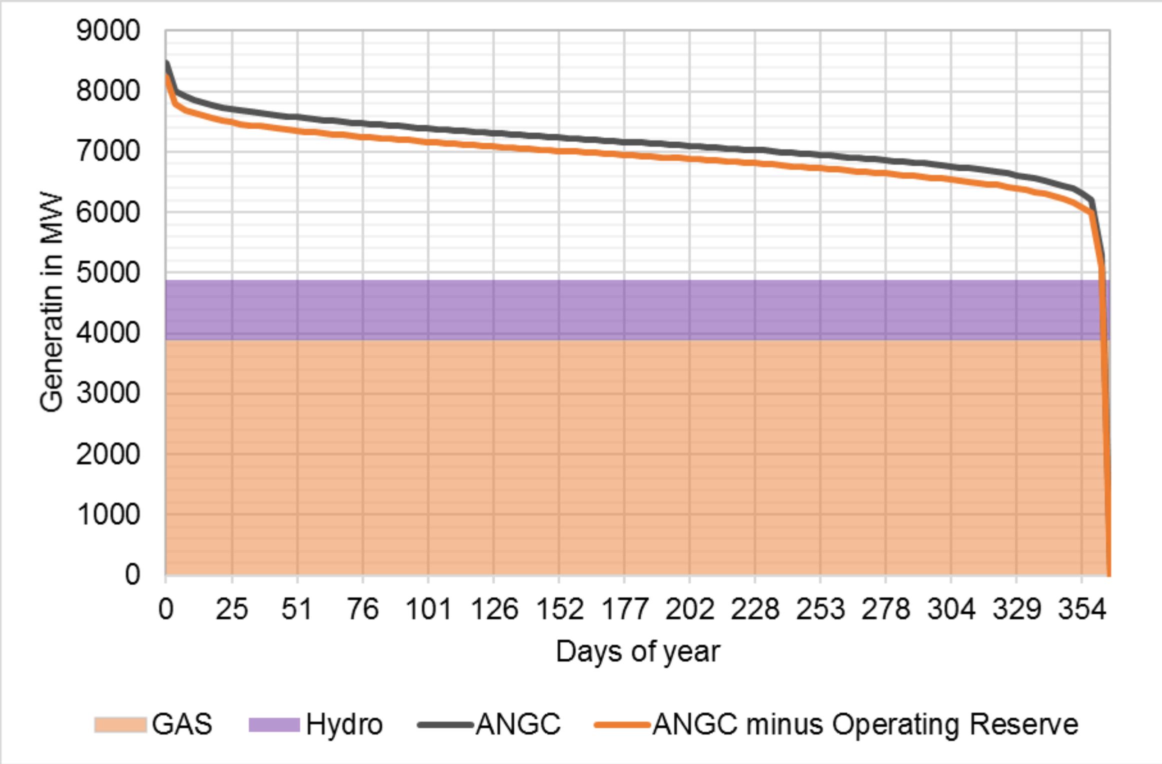

Figure 2: Available Net Generation Capacity and Availability of Primary Energy (system with primary energy deficit, generic example)

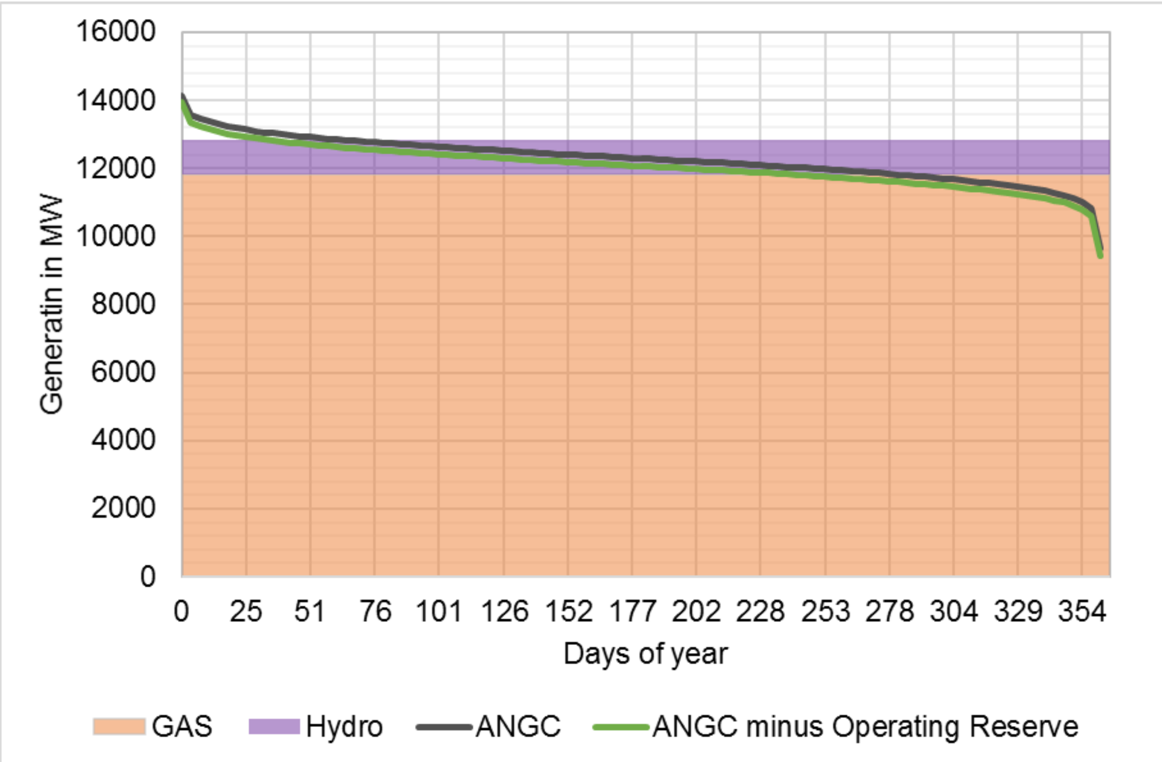

Figure 3: Available Net Generation Capacity and Availability of Primary Energy (system without deficit of primary energy, generic example)

2.3. Remaining Capacity Margin

The second relevant index is the Remaining Capacity Margin (RM). RM characterises the ability of the generation system to supply demand and to provide the required operating reserves at any moment in time, including times with very high demand and low availability of generation.

Because the availability of generation depends on stochastic processes (unplanned outages), and follows a probabilistic distribution, the probability of not being able to supply demand is never equal to zero, even not in highly adequate power systems.

Therefore, a remaining probability of not being able to supply demand (deficit probability) must be introduced. In this generation adequacy outlook report a value of 1% is used. This value is typical for most international systems and is based on the requirement that only one hour with a generation deficit may occur within ten years (on average). Assuming that there are around 10 peak load hours per year and the probability of not being able to supply demand was equal to 1% (deficit probability), the frequency of a generation deficit would be equal to 0.1 per year, which is equal to one incident in ten years.

In the Nigerian context, in which demand is generally much less than the available generation, the definition of a Reliably Available Net Generation Capacity at a deficit probability of 1% (or confidence level of 99%) generally means that during 99% of all times (8672 h per year on average) there is more capacity available than RANGC and during 87.6h per year, there is less capacity available. In a system with an energy deficit, the practical implication of RANGC and Remaining Capacity Margin is therefore quite low compared to the energy indices ANE and REM. A negative value of RM defines the amount of generation capacity which would be needed for reliable supply of demand during all times if sufficient energy was available.

The definition of RM is shown below (2.2).

Remaining Capacity Margin:

$$RM = RANGC - allowance\ for\ operating\ reserves - total\ peak\ demand \qquad (2.2)$$

- RANGC = Reliably Available Net Generation Capacity at confidence level of 99%.

The perspective performance of the available generation is calculated using a non-sequential Monte Carlo analysis with monthly resolution for the complete time frame of the outlook (10 years ahead) considering unplanned and planned outages of power plants.

Planned outages are considered by deterministic monthly maintenance plans. The impact of unplanned outages on the Available Net Generation Capacity (ANGC) is calculated using Monte Carlo Analysis.

Because Reliably Available Net Generation Capacity defines the probability of supplying peak demand, the model for calculating RM only considers the availability of generators during peak load hours and it is assumed that peak load hours are in the evening (see also Figure 1). This means that photovoltaic solar energy (PV) has generally no impact on the Remaining Capacity Margin (only on the Remaining Energy Margin).

2.4. Demand Forecast

The demand forecast of the Base Case of this study uses the 'on-grid demand' calculated in the On-grid Demand Forecast [2] (see Annex 1 – On-grid Demand Forecast) which includes demand from TCN, auto-producers and exports. Demand growth was mainly assessed based on the GDP growth and other aspects such as population growth.

Table 1 - Demand forecast and GDP growth

Case	GDP growth rate per year in %
High case	7.3 % (8% after 2020)
Base case	6.1% (6.5% after 2020)
Low case	4.8% (5.0% after 2020)

2.5. Gas Outlook

To predict the availability of gas for fuelling existing and planned gas fired power stations, the gas outlook of the OG Analysis [3] was used. In this report, predicted gas volumes, which will be available for electricity supply are derived based on a linear regression of historical gas supply data from the Nigerian National Petroleum Corporation (NNPC) and considering varying factors, which are known to influence gas demand in Nigeria's domestic gas market - so-called demand drivers. This regression model was used to determine weighting factors for each driver. Table 1 shows the weighting factors assigned to each of the demand drivers.

Table 2 – Gas demand drivers [3]

Driver	Weight
Unmet demand	0.23
Marketed gas production	0.32
GDP	0.15
Disposable income	0.15
Government targets and planned power projects	0.15

Future gas supply to the power sector is then estimated using weighted averages and projections for each demand driver. The impact of vandalism, new project capacity and other industry trends are added based on expert judgement.

Global gas prices were not considered in the model, because data were not sufficiently available to estimate their effect. Furthermore, the price of exporting gas has vastly reduced since the advent of shale gas and the difference between global LNG prices and domestic gas prices are no longer as wide as pre-2014 levels.

2.6. Generation Expansion Plan

The perspective load growth and the performance of the generation system was assessed for a time-frame of 10 years ahead.

In absence of a valid generation expansion plan, generators with “advanced permitting status” (according TCN list of candidates / C1-candidates [4]) have been considered for assessing generation adequacy. The commissioning date of generating projects, which are just at the beginning of the permitting process (C2-candidates), was considered to be out of the time-frame of this report (or realisation probability was too low).

More details about the considered Generation Expansion Plan are described in section 3.3.

2.7. Generation Reliability

Planned and unplanned outage rates for future generation were calculated based on historical data [5, 6] of the “remarks” section of table 1.7 of the *Daily Operational Reports* of 2015/16 of NCC/TCN.

Each “remark” for each individual generator was classified according to the definitions of the IEEE standard 762-2006 [7].

Unit states are divided into two mayor groups, namely “Deactivated Shutdowns” and “Active” states:

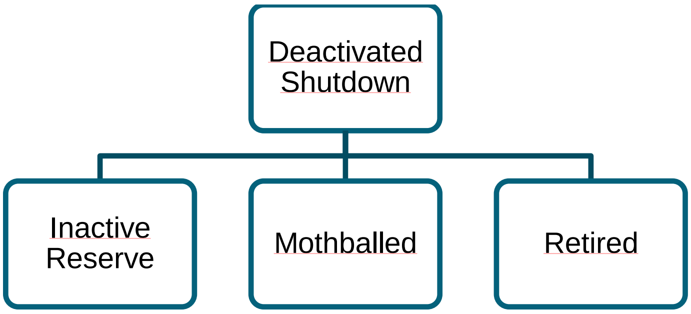

Figure 4 - Deactivated Shutdown States [7]

Table 3 - Deactivated Shutdown State Definition

Unite State	Definition according to IEEE Std 762-2006
Deactivated Shutdown	The Deactivated Shutdown state is where a unit is unavailable for service for an extended period of time for reasons not related to the equipment.
Inactive Reserve	The Inactive Reserve state is where a unit is unavailable for service, but can be brought back into service in a relatively short period of time, typically measured in days.
Mothballed	The Mothballed state is where a unit is unavailable for service, but can be brought back into service with appropriate amount of notification, typically weeks or months.
Retired	The Retired state is where a unit is unavailable for service and not expected to return to service in the future.

And for the “Active” unit states:

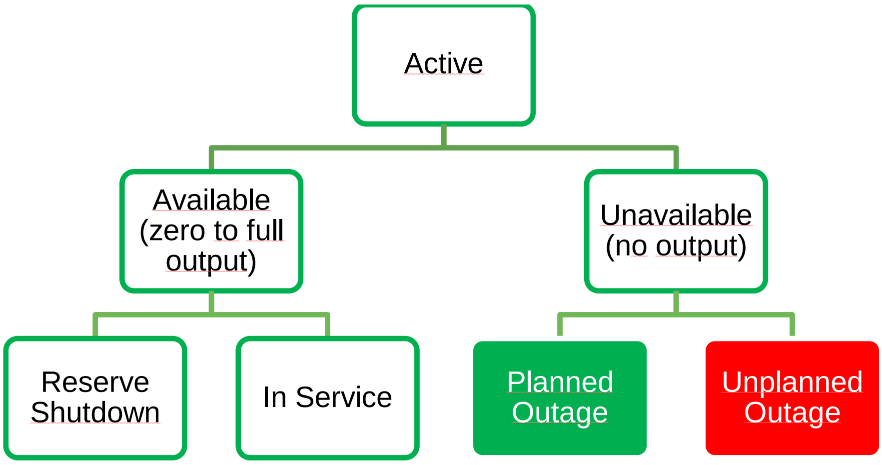

Figure 5 - Active States [7]

Table 4 - Active State Definition [7]

Unit State	Definition according to IEEE Std 762-2006
Active	The active state is where a unit is in the population of units being reported.
Available	The available state is where a unit is capable of providing service, regardless of whether it is actually in service and regardless of the capacity level that can be provided
In Service	The In Service state is where a unit is electrically connected to the system and performing generation function.
Reserve Shutdown	The Reserve Shutdown state is where a unit is available, but not in service.
Unavailable	The Unavailable state is where a unit is not capable of operation because of operational or equipment failures, external restrictions, testing, work being performed, or an adverse condition.
Planned Outage	The Planned Outage state is where a unit is unavailable due to inspection, testing, nuclear refuelling, or overhaul. A Planned Outage is scheduled well in advance.
Unplanned Outage	The Unplanned Outage state is where a unit is unavailable but is not in the Planned Outage state.

Based on the result of this classification, Planned and Unplanned Outage Factors for each generator were calculated according to the formulas defined in the IEEE Std 762-2006 [7] :

Planned Outage Factor (POF):

$$POF = \left(\frac{POH}{PH}\right) x\ 100 \qquad (2.2)$$

- Planned Outage Hours (POH): The number of hours a unit was in Planned Outage state.
- Period Hours (PH) or active hours is the number of hours a unit was in Active state.

Unplanned Outage Factor (UOF):

$$UOF = \left(\frac{UOH}{PH}\right) x\ 100 \qquad (2.3)$$

- Unplanned Outage Hours (UOH): The number of hours a unit was in Unplanned Outage state.

Results of the historical assessment of reliability factors per plant are summarized in Annex 4 - Plant Outage Factors 2015/16.

2.8. Hydro Power Generation

Hydro power generation was modelled based on long-term historical discharge data (1990 - 2010) of Kainji, Jebba and Shiroro hydro power station (see Annex 5 - Long-Term Hydro Power Station Discharge). For the planned hydro power station "Zungeru" additional data was provided by TCN (Annex 6 - Zungeru Hydro Power Station).

Using hydro power station discharge data instead of reservoir inflow data is considered more pertinent, because it already includes complex aspects, such as water management, spillage or flood control.

To transform discharge data into power generation, the following formula was applied:

$$P = Q \cdot h \cdot g \cdot \rho \cdot \eta \qquad (2.4)$$

$P = power\ [MW]$

$Q = turbine\ discharge\ [\frac{m}{s^3}]$

$h = head\ [m]$

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

$\rho = desndisty\ of\ water\ \left[\frac{g}{cm^3}\right]$

$\eta = efficiency$

The following key-parameters were used for modelling Nigeria's hydro power plants. They are based on the Daily Operational Reports [5] and other information obtained from TCN:

Table 5: Parameters per hydro power station

Plant	Density of water in g/cm³	Gravity in m/s²	Avg. efficiency in %	Avg. head (m)
Jebba	0.9982	9.801	89.6	27.04
Kainji			91.71	34.85
Shiroro			87.22	110
Zungeru			87.22	92

As shown in Figure 1 for the example of Jebba hydro power station, the model matches very well to the historical data set of 2015 [5].

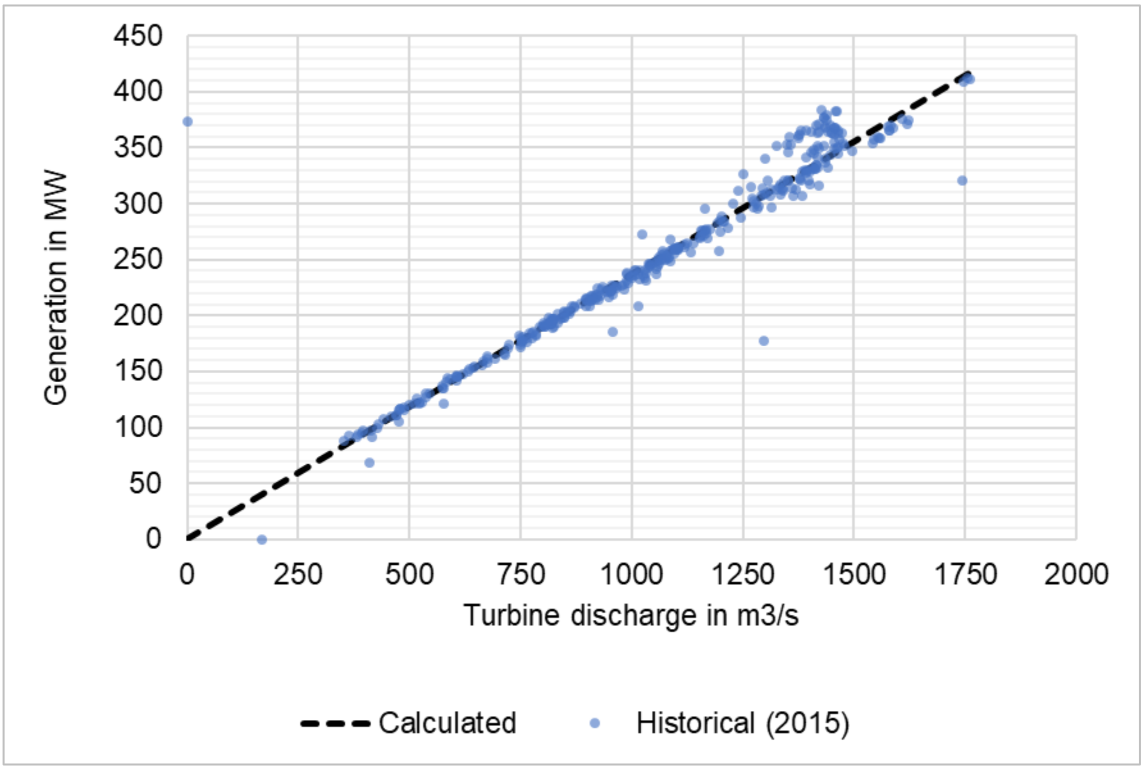

Figure 6 - Historical and calculated energy sent out from Jebba Hydro Power Station

3. Base Case Definition

3.1. Introduction

The Base Case of this generation adequacy outlook uses data and assumptions with respect to:

- Energy demand and peak demand forecast from 2017 to 2027
- Yearly generation expansion from 2017 to 2027
- Generation reliability for generator types and states
- Yearly gas supply forecast from 2017 to 2027
- Monthly long-term hydro generation for one year for each hydro power station
- Monthly long-term PV generation for one year for each PV power station.

3.2. Energy Demand and Peak Demand Forecast

Energy demand and peak demand forecast are based on the concept described in section 2.4. As shown in Table 1, the Base Case scenario assumes a GDP growth rate between 6.1% and 6.5%. The resulting energy demand and peak demand is shown in Figure 7 and Table 6.

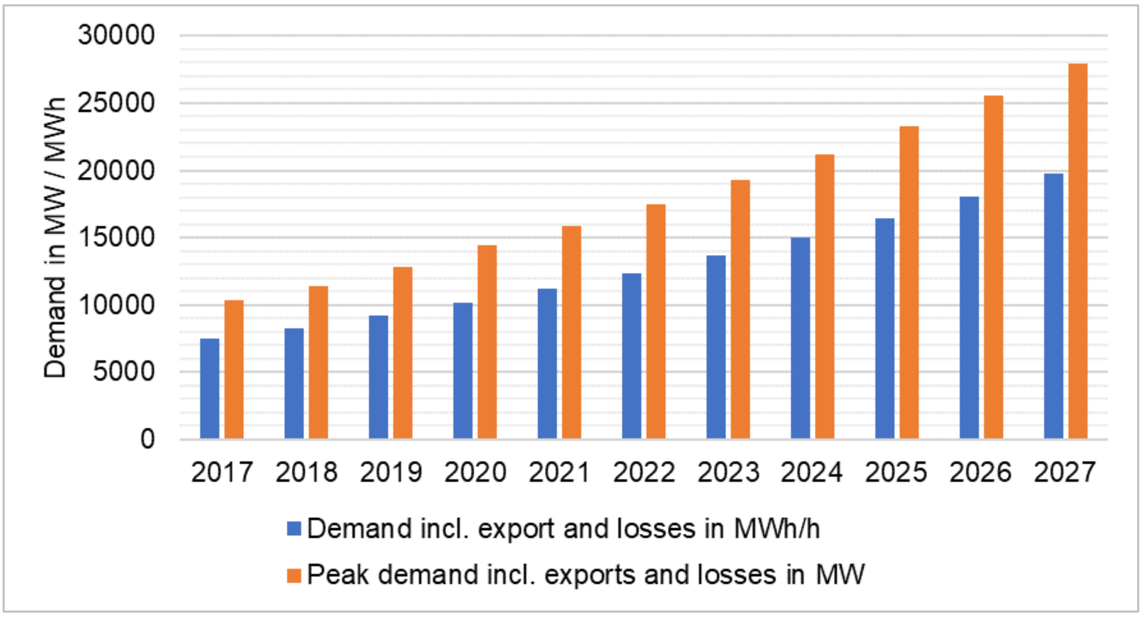

Figure 7 - Demand forecast (Base Case)

Table 6: Demand forecast (Base Case)

Year	Demand incl. export and losses in MWh/h	Peak demand incl. exports and losses in MW
2017	7537	10364
2018	8244	11417
2019	9172	12792
2020	10181	14402
2021	11234	15894
2022	12383	17521
2023	13634	19294
2024	14993	21221
2025	16467	23311
2026	18054	25560
2027	19755	27972

3.3. Generation Expansion

By the time that this report was prepared, there was no valid generation expansion plan available. Therefore, this generation adequacy outlook study considers only planned power plant projects, which are in an advanced permitting stage, as per the list of TCN reported in the Preliminary Transmission Expansion Plan [4]. Newly planned power plants are mainly new gas turbine generators (OCGT and CCGTs) and the 700MW Zungeru power station, which is planned to be commissioned in 2018.

From 2019 on, an installed capacity of 1080 MW of utility scale PV power plants is considered to be in operation. The actual PV plants, which have been considered in this outlook report are listed in Annex 3 - Committed PV Projects.

Power plant retirements, particularly gas-fired steam turbines, are considered according to the Preliminary Transmission Expansion Plan [4].

The resulting generation expansion of the Base Case of this generation adequacy outlook report is visualized in Figure 8 and summarized in Table 7. For more details see Annex 2 - Generation Expansion (without PV Projects) and Annex 3 - Committed PV Projects.

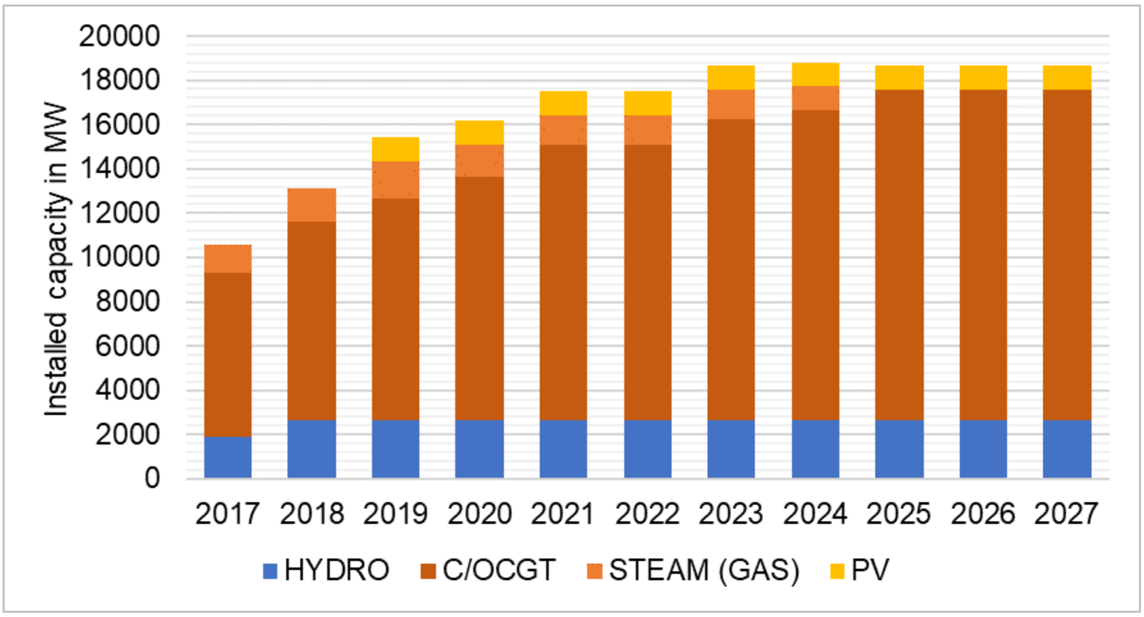

Figure 8 - Total installed capacity per generator type and year

Table 7 - Installed capacity in MW per generator type and year

	C/OCGT	STEAM (GAS)	HYDRO	PV	TOTAL
2017	7 399	1 240	1 930	0	10 569
2018	8 977	1 520	2 630	0	13 127
2019	10 047	1 670	2 630	1 080	15 427
2020	11 008	1 460	2 630	1 080	16 178
2021	12 444	1 320	2 669	1 080	17 513
2022	12 444	1 320	2 669	1 080	17 513
2023	13 590	1 320	2 669	1 080	18 659
2024	13 950	1 100	2 669	1 080	18 799
2025	14 910	0	2 669	1 080	18 659
2026	14 910	0	2 669	1 080	18 659
2027	14 910	0	2 669	1 080	18 659

Based on the Preliminary Transmission Expansion Plan [4] existing and planned generators are classified by different so-called expansion states as shown in Table 8.

Figure 9 and Table 9 summarize the generation expansion plan according to expansion state of the different power plants. Figure 9 shows that around 2 GW of old generation (state "O") will be decommissioned until 2025. Starting with 2019, power plant projects with advanced permitting status including utility-scale PV generation (Annex 1) will get added to the power system.

Table 8 - Expansion states

Status	Definition
O	Old generation and soon to be replaced
G	Existing generation in good condition and rather new
N	Existing generation of less than 7 years old
C1	Candidates of TCN list with advanced permitting status

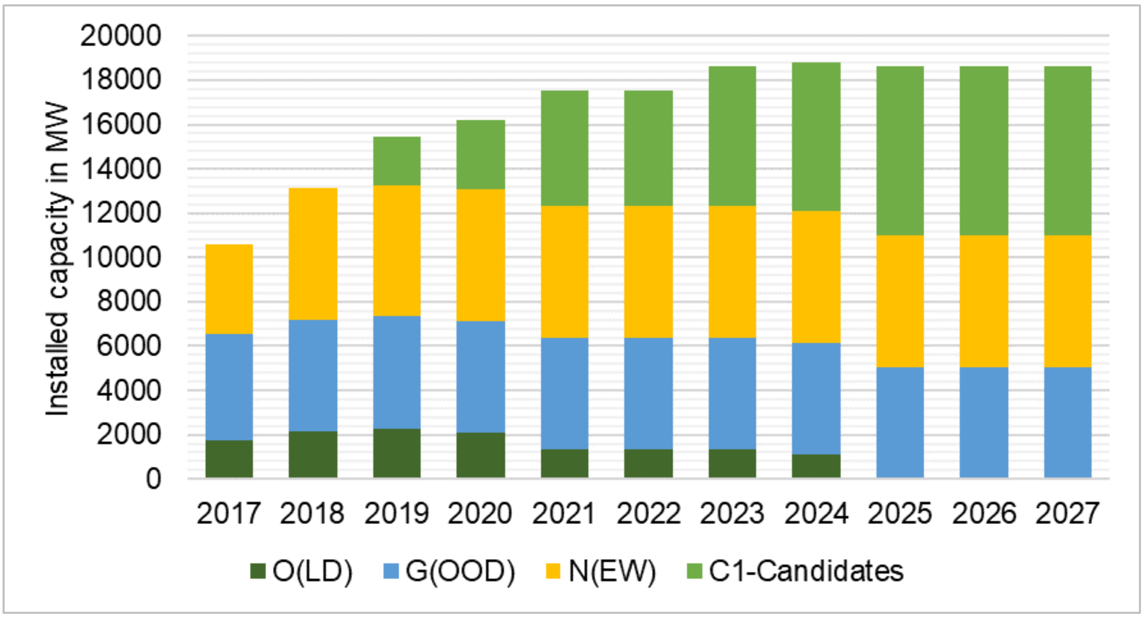

Figure 9 - Total installed capacity per expansion state and year

Table 9 - Installed capacity in MW per expansion state and year

	O(LD)	G(OOD)	N(EW)	C1-Candidates	TOTAL
2017	1 752	4 768	4 049	0	10 569
2018	2 135	5 068	5 924	0	13 127
2019	2 285	5 068	5 924	2 150	15 427
2020	2 075	5 068	5 924	3 111	16 178
2021	1 320	5 068	5 924	5 201	17 513
2022	1 320	5 068	5 924	5 201	17 513
2023	1 320	5 068	5 924	6 347	18 659
2024	1 100	5 068	5 924	6 707	18 799
2025	0	5 068	5 924	7 667	18 659
2026	0	5 068	5 924	7 667	18 659
2027	0	5 068	5 924	7 667	18 659

3.4. Reliability Indices of Individual Power Plants

Generation reliability factors were extracted for each individual power plant from historical data [5, 6] applying the methodology described in section 2.6. Since only two years of data were evaluated, reliability indices for each power station may not be stochastically representative. To obtain more representative values, the average reliability factors per "expansion status" according to Table 8 and generator type were calculated and used for the different power plants of same type and expansions status in the simulations.

The resulting planned and Unplanned Outage Factors (POF and UOF) are shown in Figure 10, Table 10 and Table 11 below.

Figure 10 - Planned and Unplanned Outage Factors

Table 10 - Planned Outage Factors from historical assessment

STATUS	GAS	HYDRO	STEAM	STEAM_CCGT
O(LD)	11%		24%	11%
G(OOD)	16%	17%	3%	16%
N(EW)	10%	17%	3%	10%

Table 11 - Unplanned Outage Factors from historical assessment

STATUS	GAS	HYDRO	STEAM	STEAM_CCGT
O(LD)	35%		22%	35%
G(OOD)	16%	22%	5%	16%
N(EW)	22%	25%	5%	22%

Not for all generator types and states, historical data were available, and hence some reliability factors needed to be estimated based on plausible assumptions and other international sources. Those assumed values are marked in grey in Table 10 and Table 11.

In addition to this, it is expected that generation with an initial status "N(EW)" will age over time and that its reliability factors will change. To approximate the aging effect the status "G(OOD)" was assigned to these generations from 2021 on.

3.5. Gas Supply Forecast

The gas supply forecast is based on the OG Analysis report [3] (see also section 2.5) and is depicted in Figure 11 below.

As these figures show, gas supply is consider to increase by almost 270% between 2017 and 2027, which is equivalent to an annual growth rate of around 10%.

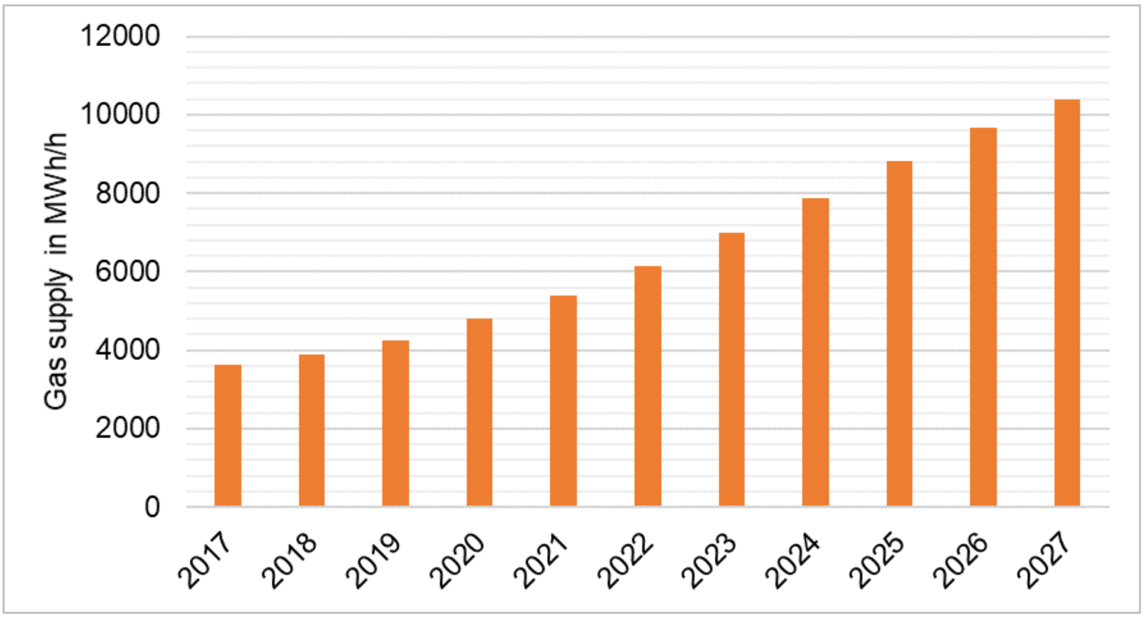

Figure 11 - Base Case scenario for future gas supply to the Nigerian power sector

Table 12 - Gas supply (Base Case)

Year	Gas supply in MWh/h
2017	3619
2018	3904
2019	4247
2020	4795
2021	5400
2022	6142
2023	6986
2024	7877
2025	8813
2026	9669

3.6. Hydro Power Generation

As explained in section 2.8, hydro power generation was modelled based on long-term discharge data of existing and planned hydro power stations. As a result, a typical hydro generation profile for an average year was calculated for each hydro power plant, as shown in Figure 12 and Table 13.

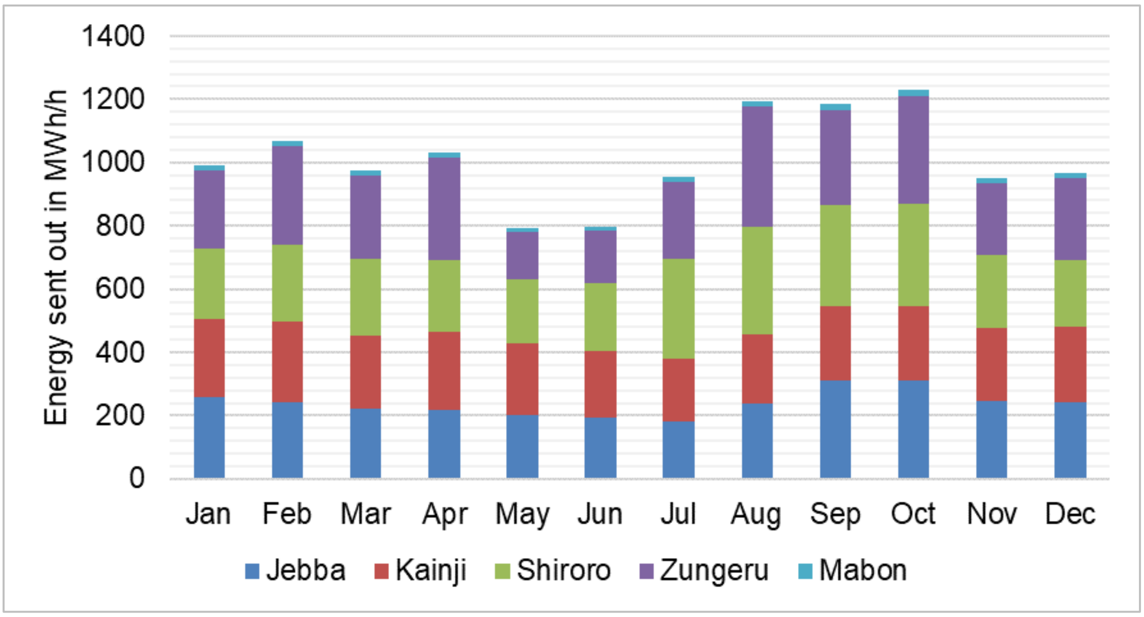

Figure 12 – Long-term hydro generation profile per hydro power station

Table 13 - Long-term hydro generation profile per hydro power station

Month	Energy sent out in MWh/h				
	Jebba	Kainji	Shiroro	Zungeru	Mabon
Jan	259	245	222	248	15
Feb	242	255	245	313	16
Mar	220	234	240	266	15
Apr	219	248	224	326	15
May	204	225	200	149	12
Jun	195	208	217	164	12
Jul	182	198	317	241	14
Aug	236	222	337	381	18
Sep	313	233	318	302	18
Oct	311	236	325	340	18
Nov	246	232	230	227	14
Dec	240	240	212	258	14

3.7. PV Generation

In analogy to the hydro power generation a long-term PV generation profile for each PV plant was calculated. The resulting profile is depicted in Figure 13 and Table 13.

A comparison between the hydro generation profile according to Figure 12 and the PV generation profile according to Figure 13 shows that the seasonal correlation between hydro generation and PV generation is reasonably well, in a sense that there is high PV generation during dry the period and rather less PV generation during the raining season.

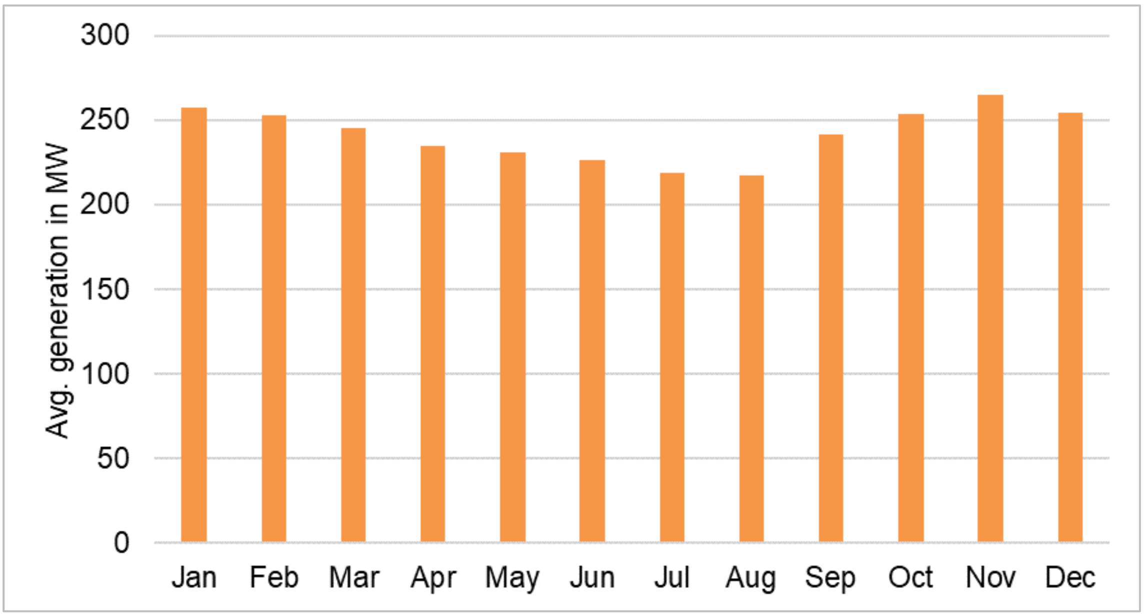

Figure 13 - Long-term average generation per month of all frontrunner projects

Table 14 - Long-term average per PV power plant

Month	Energy sent out in MWh/h											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AFRINERGIA POWER LTD	12	12	11	11	11	10	10	10	11	12	12	12
ANJEED KAFANCHAN LTD	24	23	23	22	21	21	20	20	22	24	25	24
CT COSMOS	17	16	16	15	15	15	14	14	16	16	17	16
EN AFRICA CONSULTING	12	12	11	11	11	10	10	10	11	12	12	12
KVK POWER	13	13	12	12	12	12	11	11	12	13	14	13
LR AARON POWER LTD	24	23	23	22	21	21	20	20	22	24	25	24
MIDDLE BAND SOLAR ONE LTD	24	23	23	22	21	21	20	20	22	24	25	24
MOTIR DUSABLE LTD	24	23	23	22	21	21	20	20	22	24	25	24
NIGERIAN SOLAR CAPITAL PARTNERS	24	23	23	22	21	21	20	20	22	24	25	24
NOVA SCOTIA POWER DEVELOPMENT LTD	19	19	18	17	17	17	16	16	18	19	20	19
NOVA SOLAR 5 FARM LTD	24	23	23	22	21	21	20	20	22	24	25	24
ORIENTAL RENEWABLE ENERGY RESOURCES	12	12	11	11	11	10	10	10	11	12	12	12
PAN AFRICA SOLAR	18	18	17	16	16	16	15	15	17	18	18	18
QUAINT POWER	12	12	11	11	11	10	10	10	11	12	12	12

4. Results (Base Case Scenario)

4.1. Generation Availability

4.1.1. Annual Development of ANE and RANGC

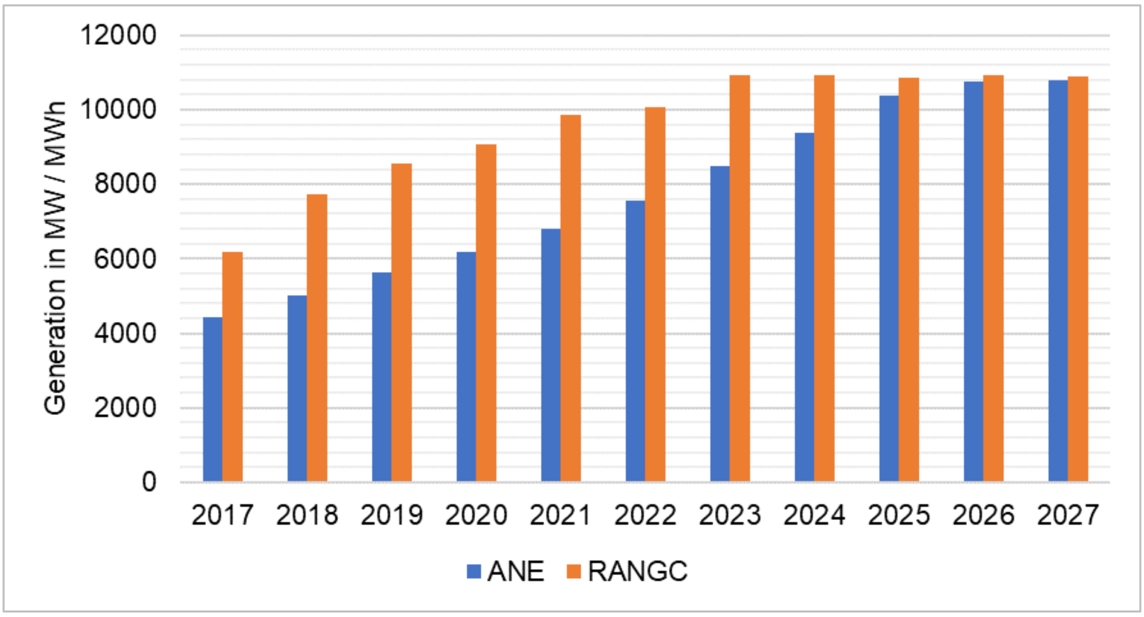

Figure 14 - Annual ANE and RANGC

As shown in Figure 14 the Available Net Energy (ANE) will increase almost constantly until 2025 and follows the availability of gas fuel. This is also confirmed by Figure 16 showing the predicted development of annual gas constraints in the analysed time frame. As shown by this figure, gas constraints will persist until 2026. In 2027, there is finally sufficient gas fuel available for fuelling all gas fired power stations in Nigeria up to their maximum level, which is defined by their technical availability.

Constraints caused by limited availability of water are conceptual constraints due to the seasonal variability of water. Figure 17 shows the development of annual water constraints, which is calculated as the difference between the average technically available capacity of hydro power plants and the average generation.

The Reliably Available Net Generation Capacity (RANGC) increases until 2023. From 2023 on, there are no new additions of gas fired power stations according to the generation expansion plan used for the Base Case (see also Figure 8) and therefore, RANGC remains constant after 2023.

Figure 15 shows the contribution of different primary energy sources to electricity supply in Nigeria in the time frame between 2017 and 2027. As the development of ANE according to Figure 14 shows, the available energy will predominantly increase with the addition of gas fired power station and the increased availability of gas for electricity use.

The contribution of hydro increases in 2018 with the addition of Zungeru power station and PV will contribute from 2019 on.

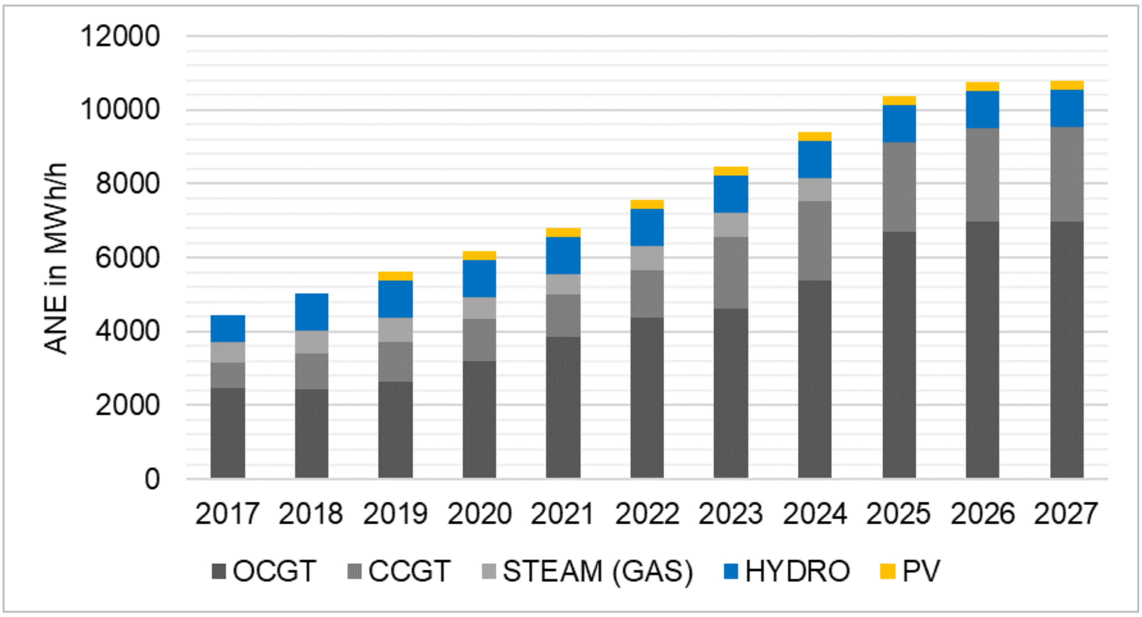

Figure 15 - ANE per type and year

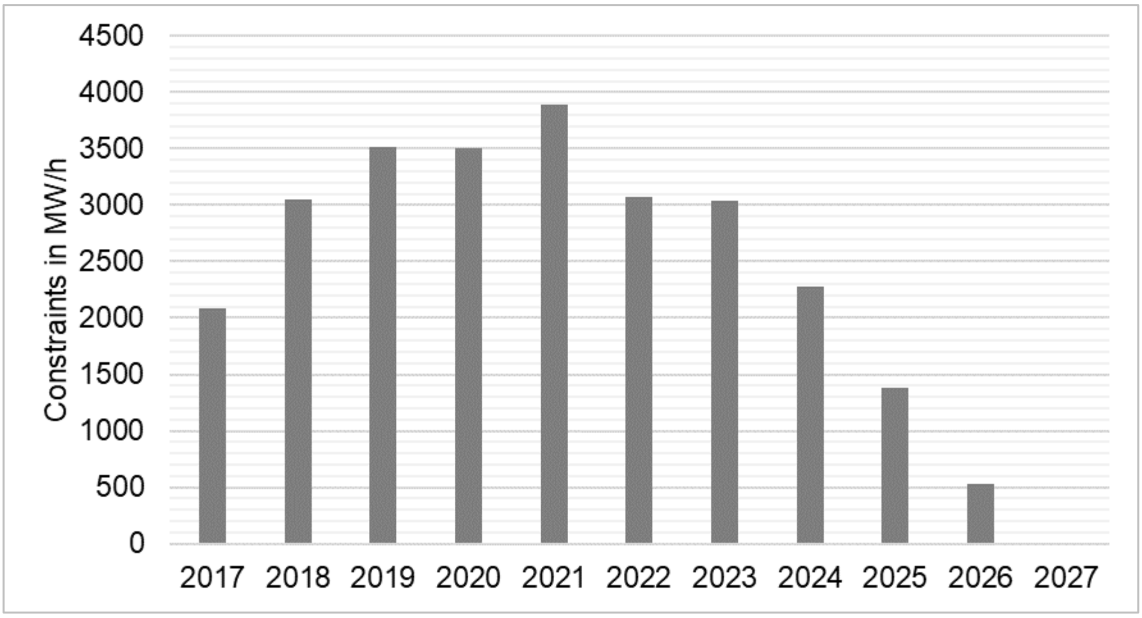

Figure 16 - Gas constraints

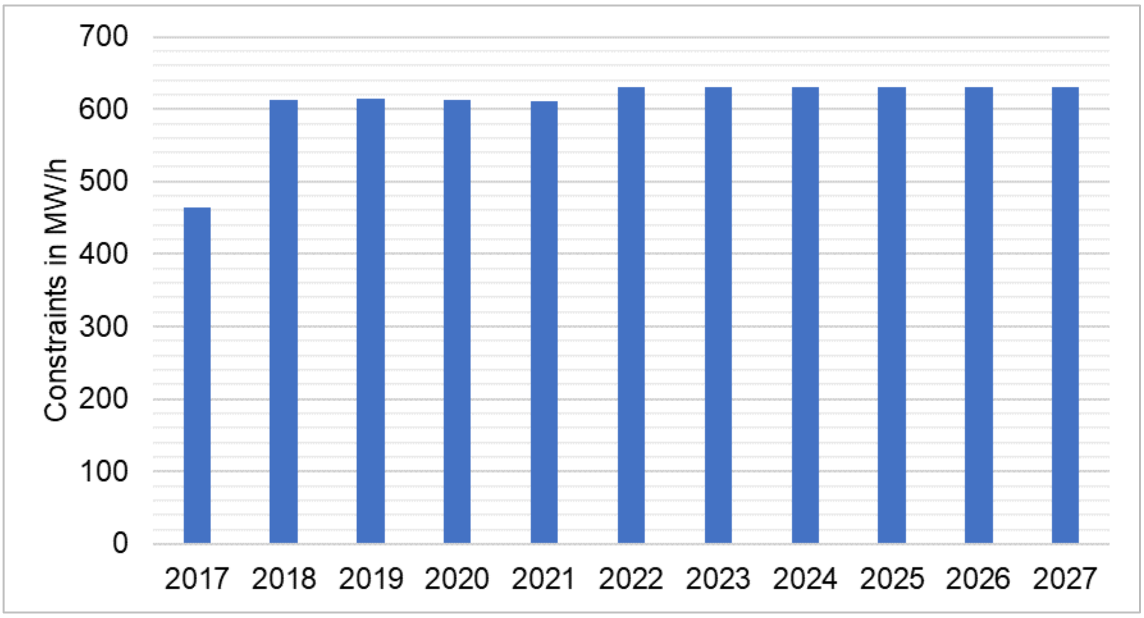

Figure 17 – Constraints due to water management

4.1.2. Monthly Variation of ANE and RANGC

When assessing the monthly variation of ANE and RANGC both values reach their maximum during the raining season (August to October). During the raining season, hydro generation is at its annual high because of high water inflow into the reservoirs. During this season more water can be used to generate and hence increases the ANE.

To use as much as possible water during the raining season the model considers that planned outages during this season are reduced to a minimum, which then also leads to a higher RANGC.

Figure 18 shows the monthly variation of the average predicted ANE and RANGC for the generators in 2017, and Figure 19 shows the corresponding figure for generators, which are considered to be available by end of 2018.

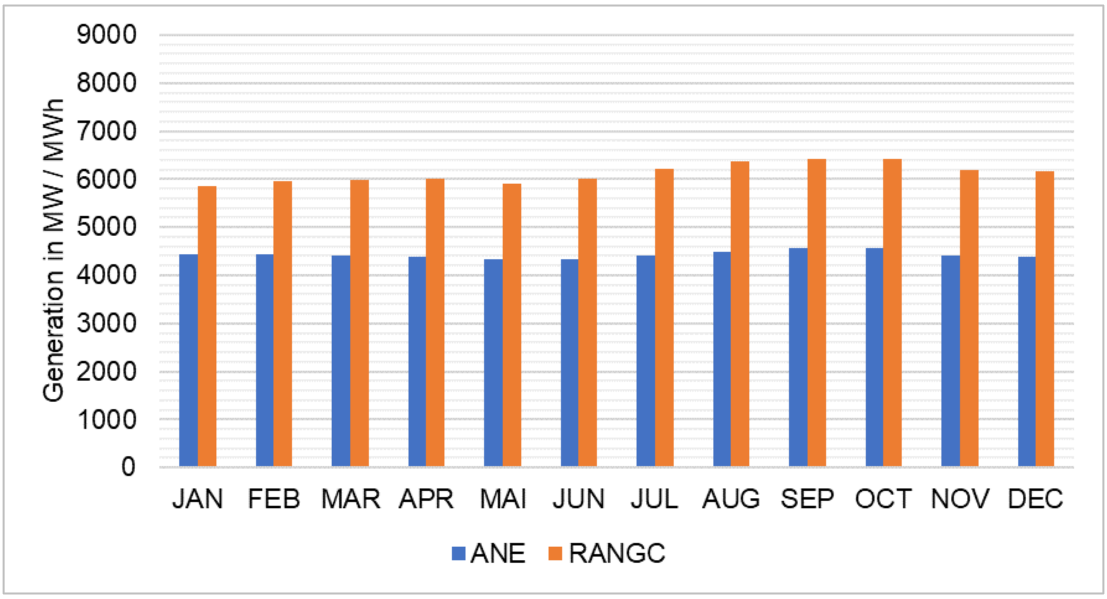

Figure 18 – Average monthly ANE and RANGC (hydro power stations as per 2017)

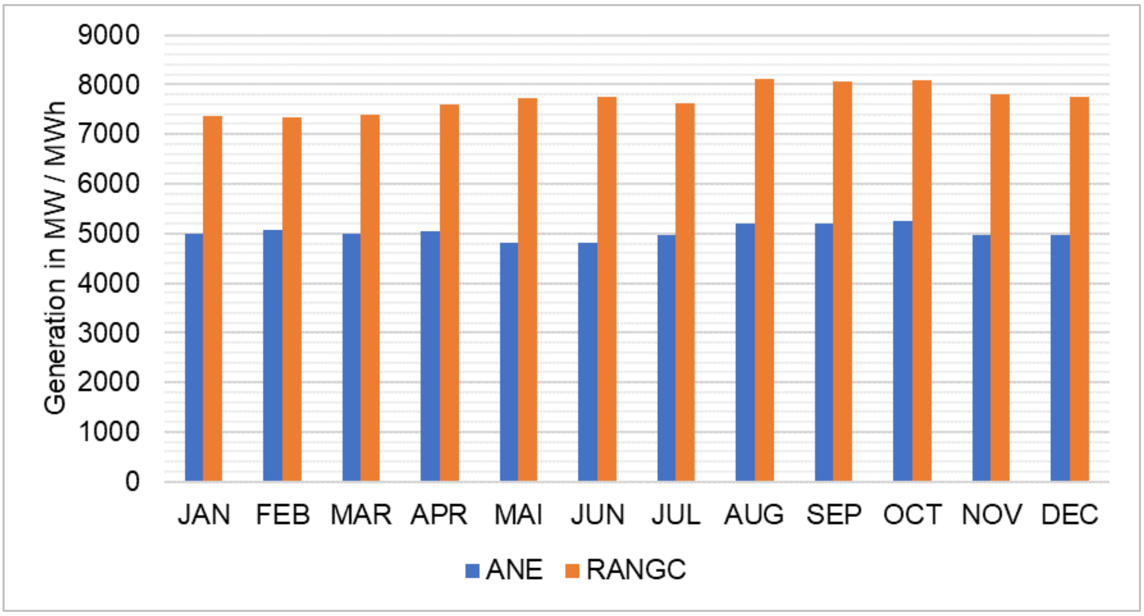

Figure 19 - Average monthly ANE and RANGC (hydro power stations as per 2018)

4.2. Remaining Energy Margin (REM)

To evaluate, if sufficient energy can be supplied to the power system to cover the energy demand, the Remaining Energy Margin (REM) was calculated for each year between 2017 and 2027.

$$REM = ANE - Demand \tag{4.1}$$

As per the definition according to (5.2), a positive REM means that more energy could be supplied to the transmission system as required and indicates adequate availability of electrical energy.

As shown by Figure 20, according to the assumptions of the Base Case, demand increases faster than the Available Net Energy (ANE) and therefore the energy deficit expressed by the Remaining Energy Margin (REM) increases as well.

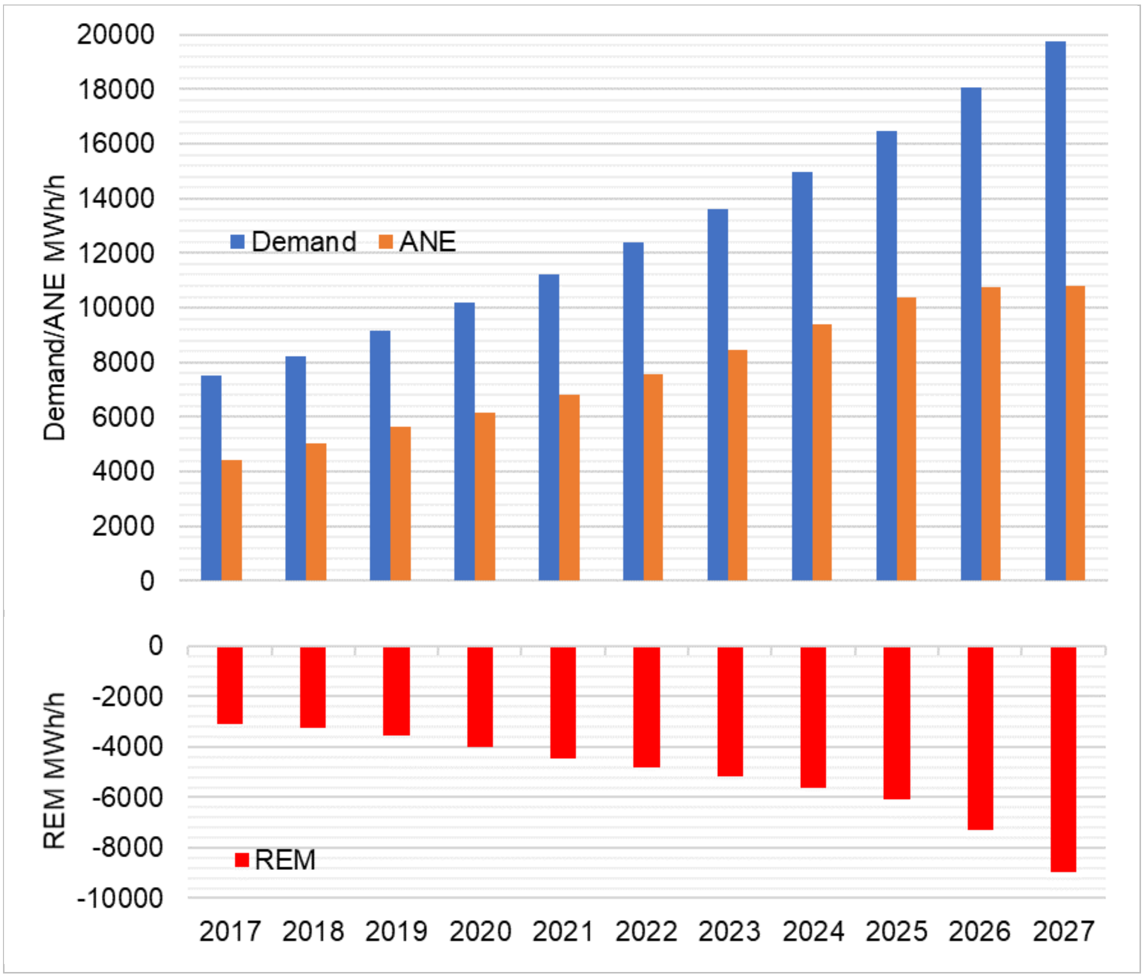

Figure 20 - Yearly REM

Table 15 - Yearly REM

YEAR	Demand in MWh/h	ANE in MWh/h	REM in MWh/h
2017	7537	4433	-3104
2018	8244	5024	-3220
2019	9171	5623	-3548
2020	10181	6178	-4002
2021	11234	6799	-4434
2022	12383	7559	-4824
2023	13633	8472	-5160
2024	14992	9391	-5601
2025	16466	10381	-6085
2026	18053	10762	-7291
2027	19755	10788	-8966

Figure 21 shows the REM as a percentage of Base Case demand. The relative REM remains close to 40% throughou the ten-year period.

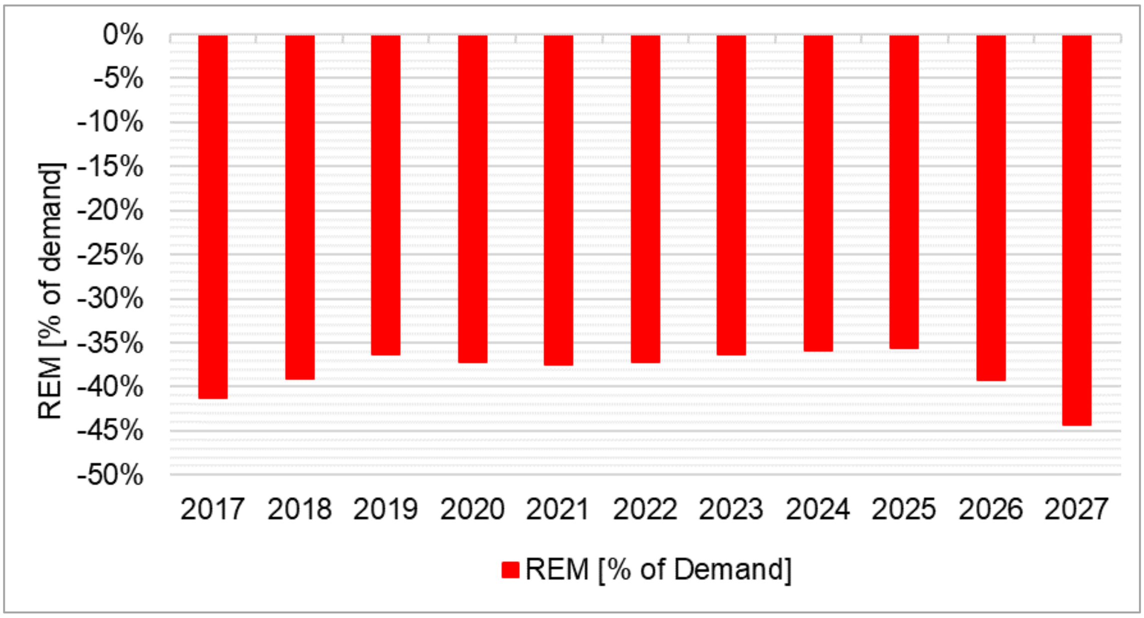

Figure 21 - relative yearly REM to Demand

The relative REM varies in the range from 35 to 45%. In the last three year a decreasing trend can be observed.

The monthly variation of REM for the years 2017 and 2018 is depicted in Figure 22. The diagram according to Figure 22 shows that the REM is negative throughout the complete year indicating a constant energy deficit even during raining season. Thus, there will still be an energy deficit in 2017 and 2018.

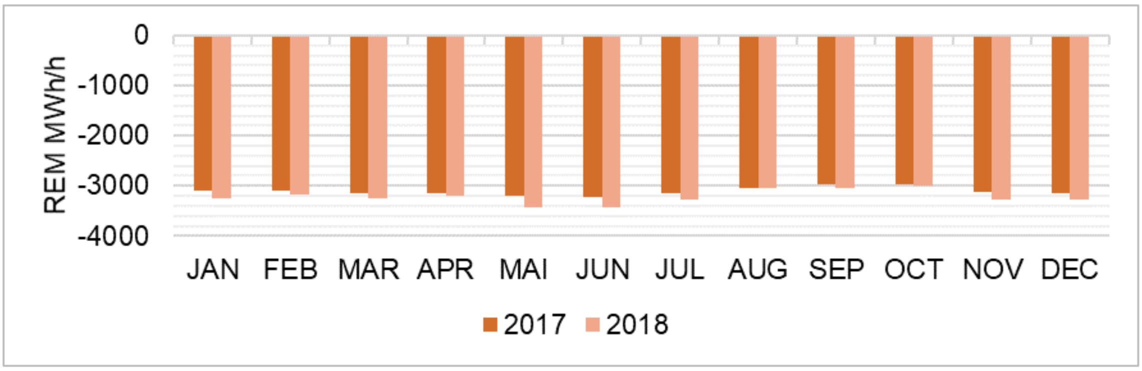

Figure 22 - Monthly variation of REM in 2017 and 2018

4.3. Remaining Capacity Margin

The development of the Remaining Capacity Margin (RM) in the analysed time frame between 2017 and 2027 is depicted in Figure 23. As shown by the diagrams of this figure, peak demand will grow much muster than the Reliably Available Net Generation Capacity (RANGC) and therefore, the capacity deficit will constantly increase until 2027. However, as stated in chapter 2, a capacity deficit has no real practical meaning as long as there will be an energy deficit in Nigeria.

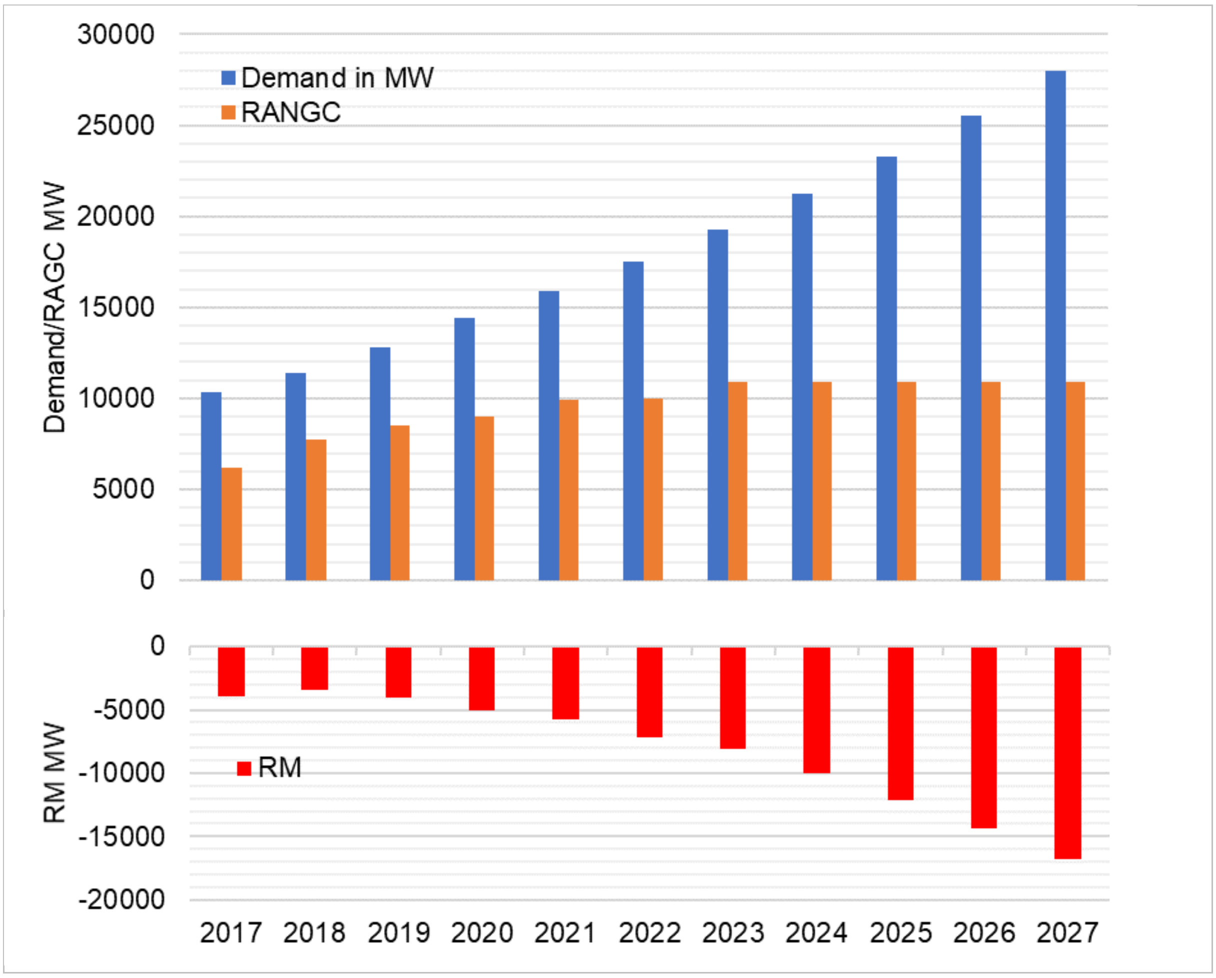

Figure 23 – Annual development of the Remaining Capacity Margin (RM)

Table 16 - Yearly RM

Year	Demand in MW	RANGC in MW	Operating Reserve in MW	RM in MW
2017	10364	6176	230	**-3957**
2018	11417	7757	275	**-3384**
2019	12792	8507	295	**-3989**
2020	14402	9025	295	**-5081**
2021	15894	9892	295	**-5706**
2022	17521	10026	295	**-7199**
2023	19294	10911	295	**-8087**
2024	21221	10926	295	**-9999**
2025	23311	10924	295	**-12091**
2026	25560	10880	295	**-14384**
2027	27972	10892	295	**-16784**

5. Sensitivity Studies

5.1. Introduction

In order to evaluate the impact of the various uncertainties of the assumptions made for defining the Base Case scenarios, the main parameters will be varied within a credible range and the sensitivity of the key adequacy indicator REM and RM in function of each parameter will be analysed. The parameters which will be subject to a sensitivity analysis are

- Demand (Energy and peak)
- Hydro generation (water availability)
- Generation expansion
- Technical availability/reliability of Nigeria's power plants.

5.2. Demand

This sensitivity analysis evaluates the impact of different demand forecast scenarios presented in the On-grid Demand Forecast [2] on the RM and REM, namely the "low case" driven by a GDP growth rate between 4.8% and 5.0% and the "high case" defined by a GDP growth rate between 7.3% and 8.0%. The resulting demand forecasts are depicted in Figure 24.

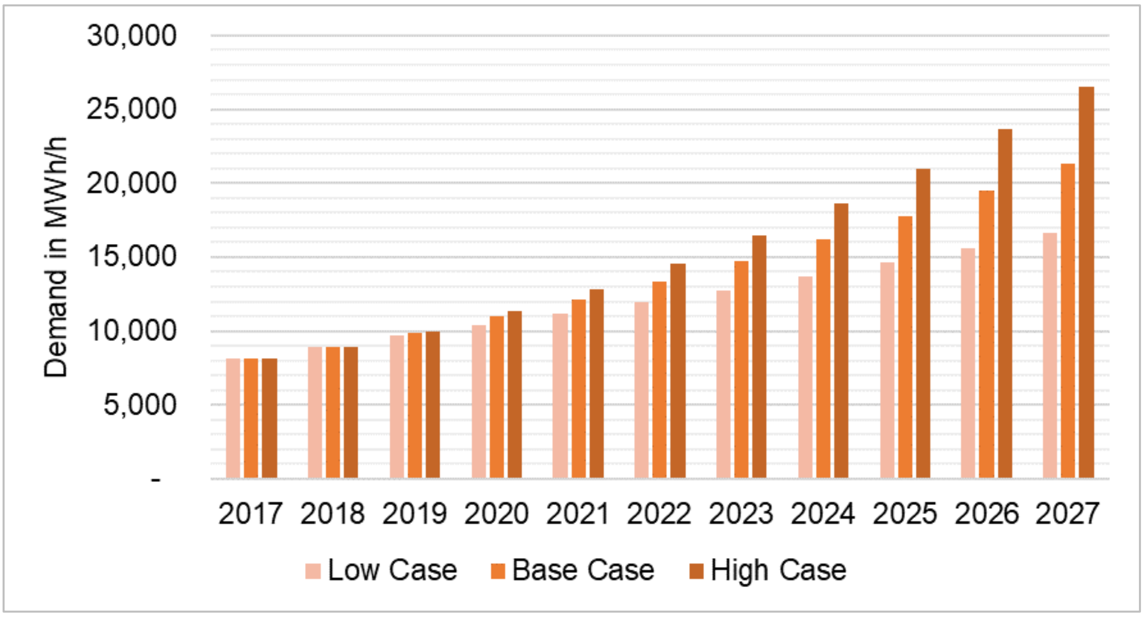

Figure 24 - Demand scenarios

The diagrams depicted in Figure 25 and Figure 26 show the corridor, in which REM and RM may be depending on future demand growth. In the best case scenario, when assuming low demand growth, the energy deficit will approximately remain at the same level as in 2017.

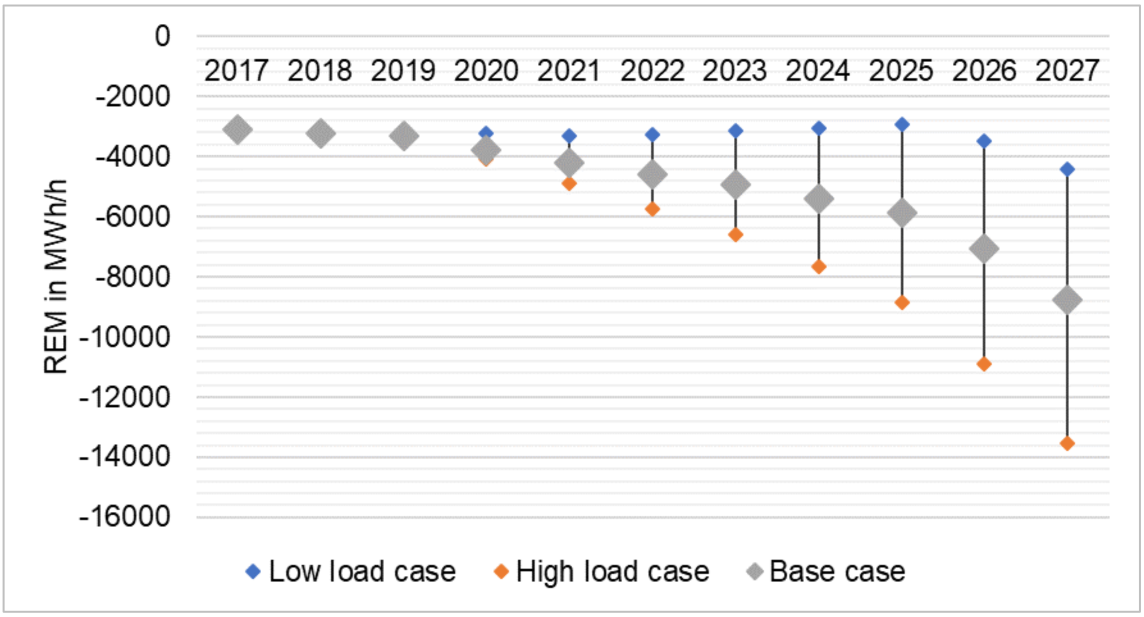

Figure 25 - Impact of demand sensitivity on REM

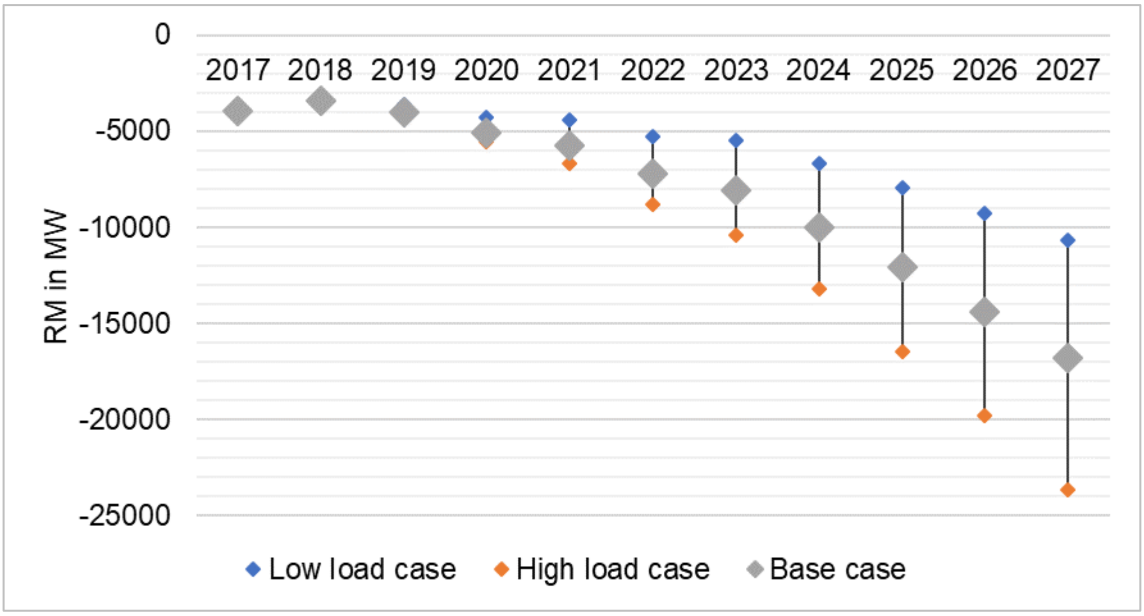

Figure 26 - Impact of demand sensitivity on RM

5.3. Hydro Generation

To assess the annual variation of hydro availability, the monthly standard deviation of the turbine discharge provided by the Hydro Power Dams Impact Assessment report [8] (see Annex 5 - Long-Term Hydro Power Station Discharge) was used to calculate the 90% confidence band of the monthly generated hydro energy. In the case of the planned Zungeru hydro power station, the standard deviation was unknown and therefore, the standard deviation as for Shiroro has been used for characterizing the annual variation of hydro energy generated by Zungeru.

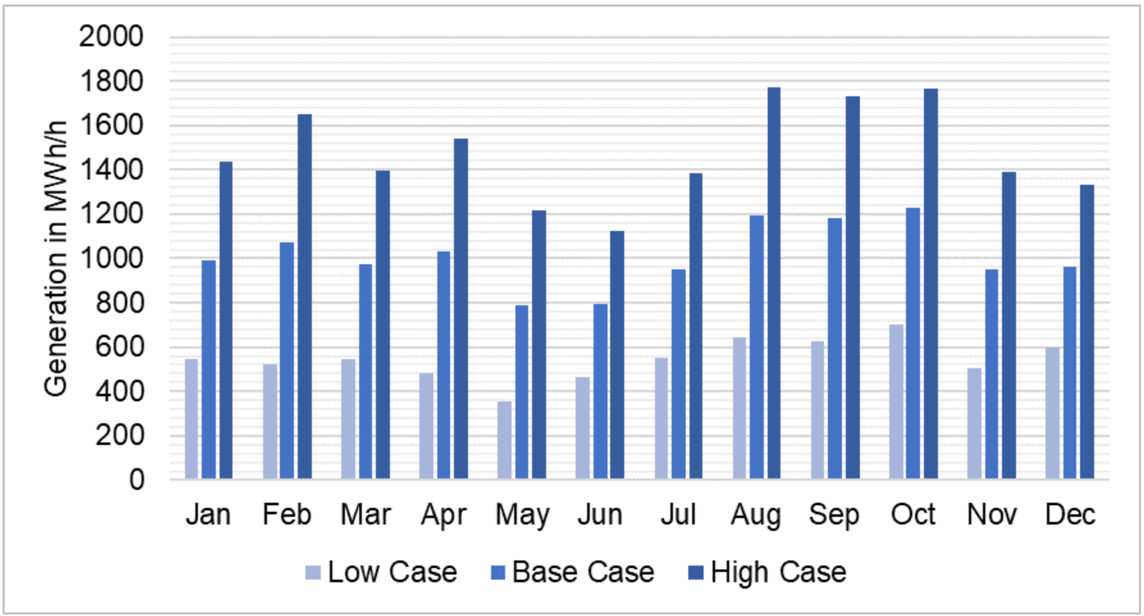

Figure 27 – 90%-confidence band of the annual hydro generation

Because different hydro availabilities have only an impact on the available energy (and not on the reliably available capacity), only the impact of the different hydro scenarios on REM has been calculated.

As shown by the diagram according to Figure 28, the impact of varying water availabilities is estimated to be in a range of +/- 400MWh/h around the Base Case value.

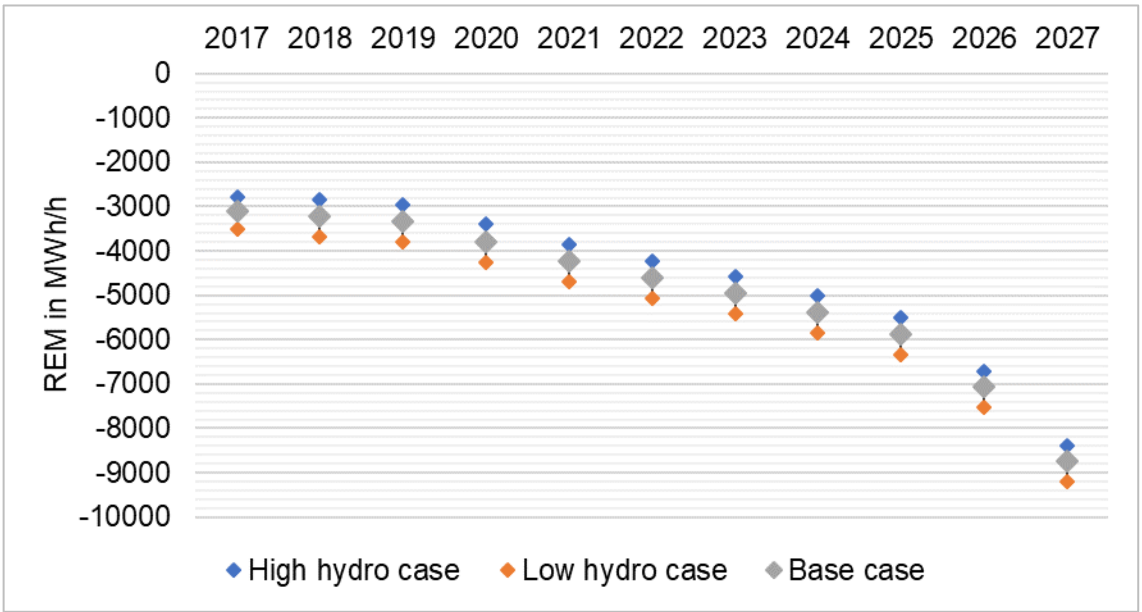

Figure 28 - Impact of hydro sensitivity on RM

5.4. Generation Expansion

To analyse the impact of delayed generation expansion on the key adequacy indices REM and RM the generation expansion plan according to section 3.3 has been modified according to the assumptions of Table 17. The resulting generation expansion plan is summarized in Figure 29 and Figure 30.

Table 17 - Delayed generation expansion

Status	Definition	Delay
O	Old generation and soon to be replaced	If on rehabilitation by 1 year
G	Existing generation in good condition and rather new	0 years
N	Existing generation of less than 7 years old	1 year
C1	Candidates of TCN list with advanced permitting status	0 - 3 years

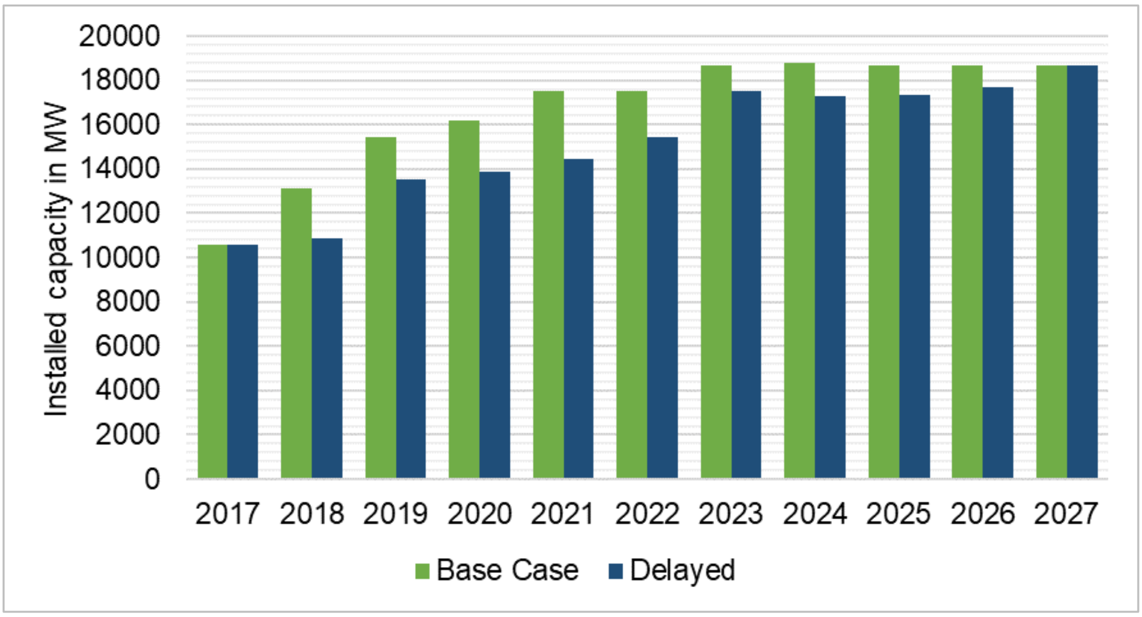

Figure 29 - Generation expansion sensitivities

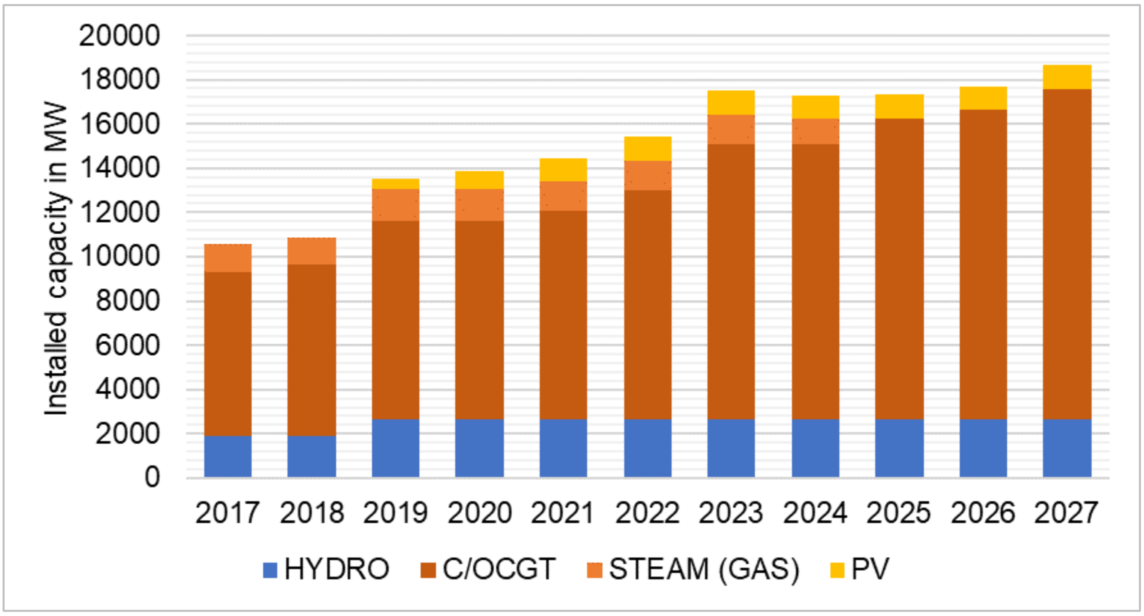

Figure 30 - Total installed capacity per generator type and year (delayed)

The impact of delayed generation expansion on the Remaining Energy Margin is only very minor because the REM is mainly defined by the availability of gas. In case of a delayed generation expansion the available gas is used in fewer power plants (operating at higher capacity factors), but the available gas can still be fully used.

The Remaining Capacity Margin (RM) is more influenced by delayed generation expansion because a lower installed capacity leads to lower the RANGC and consequently to a lower RM (higher capacity deficit, see Figure 32).

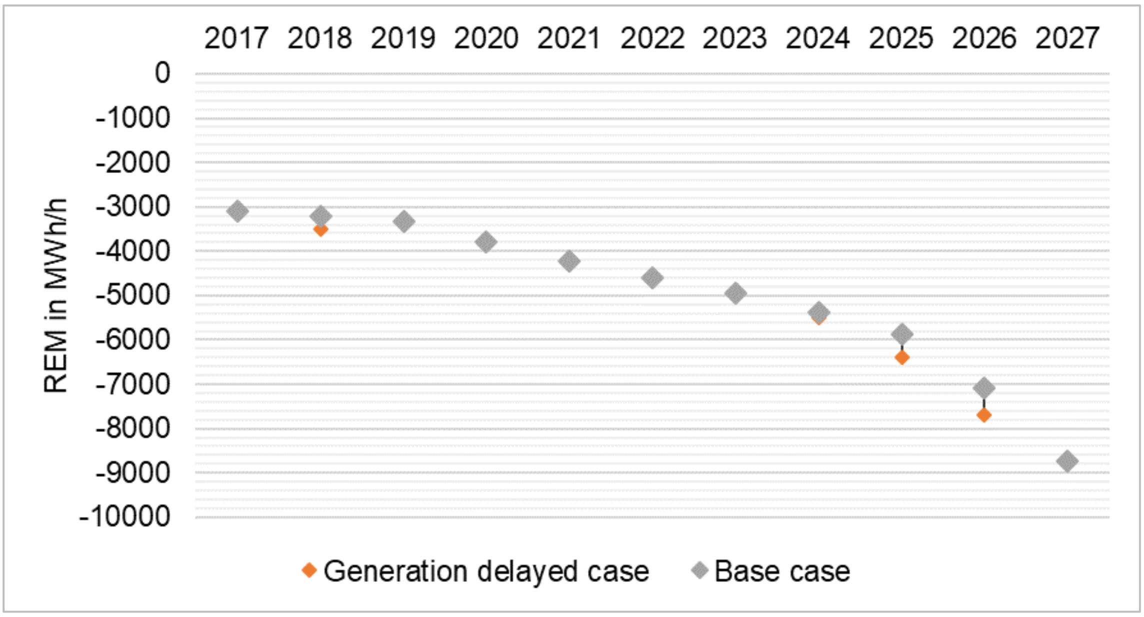

Figure 31 - Impact of the generation delayed sensitivity on REM

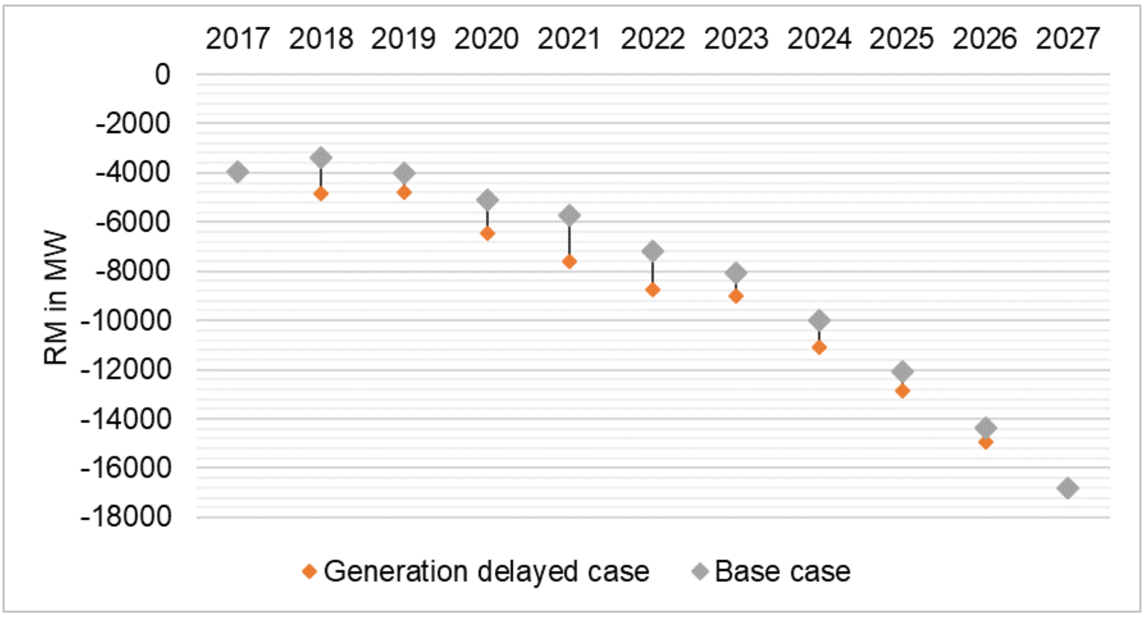

Figure 32 - Impact of the generation delayed sensitivity on RM

5.5. Improved Reliability

To evaluate the impact of plant reliability on the REM and the RM a scenario with improved generator reliability of “N” and “C1” generators has been developed (see Table 18 and Table 19).

As shown by the diagram according to Figure 33, until 2025, the REM will not improve with improved technical availability of the power plants, because until then, the REM will be limited by primary energy constraints. From 2026 on, the REM will be limited by the technical availability of Nigeria's power plants, and the REM improves with improved technical availability of the power plants.

Table 18 - Improved Planned Outage Factors

STATUS	GAS	HYDRO	STEAM	STEAM_CCGT
O	11%		24%	11%
G	16%	17%	3%	16%
N/C1	7%	5%	9%	7%

Table 19 - Improved Unplanned Outage Factors

STATUS	GAS	HYDRO	STEAM	STEAM_CCGT
O	35%		22%	35%
G	16%	22%	5%	16%
N/C1	5%	2%	6%	5%

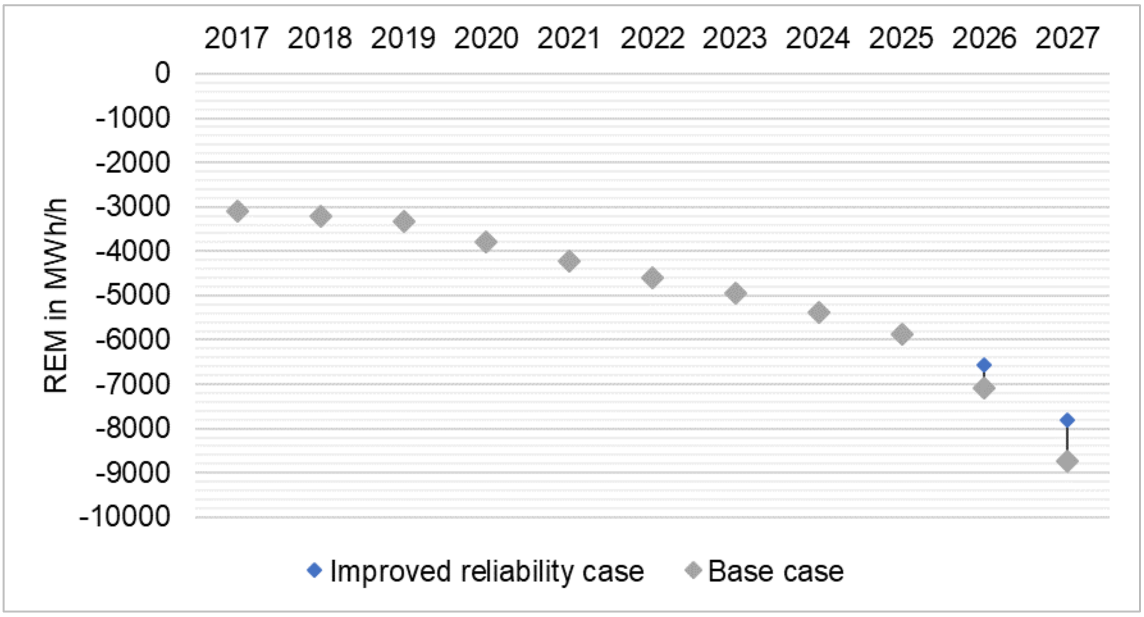

Figure 33 - Impact of the improved reliability sensitivity on REM

In contrast to the impact on the REM, an improved technical availability has always a positive impact on the Remaining Capacity Margin (RM), as shown by the diagram of Figure 34.

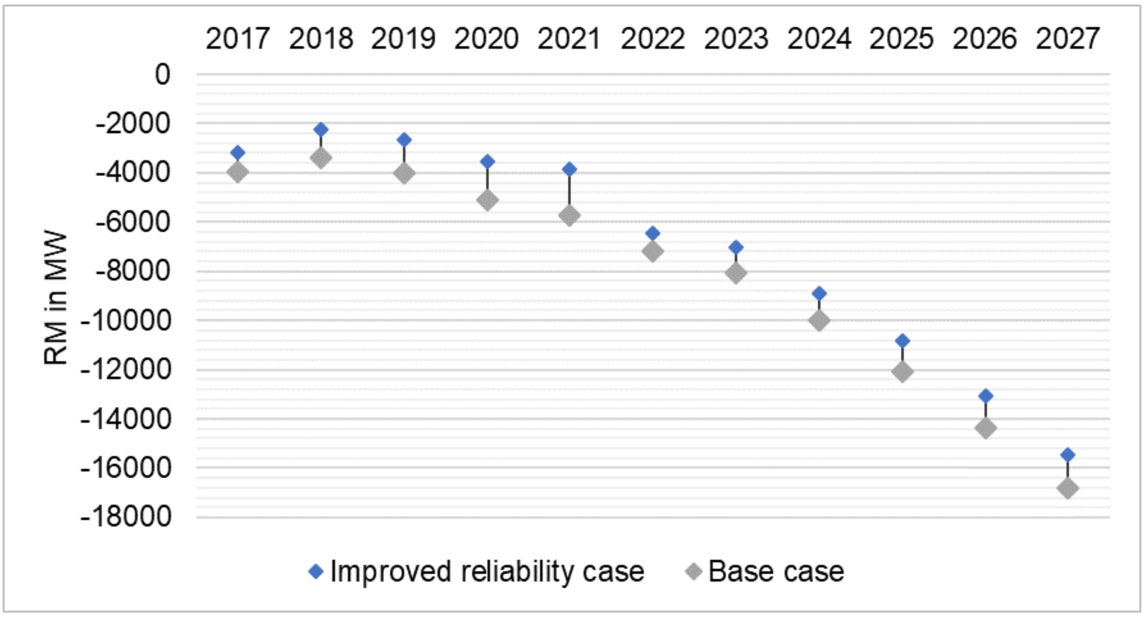

Figure 34 - Impact of the improved reliability sensitivity on RM

6. Summary

Under consideration of the results of the Base Case scenario and all sensitivities the development of Nigeria's electrical energy deficit can be predicted as shown by Figure 35.

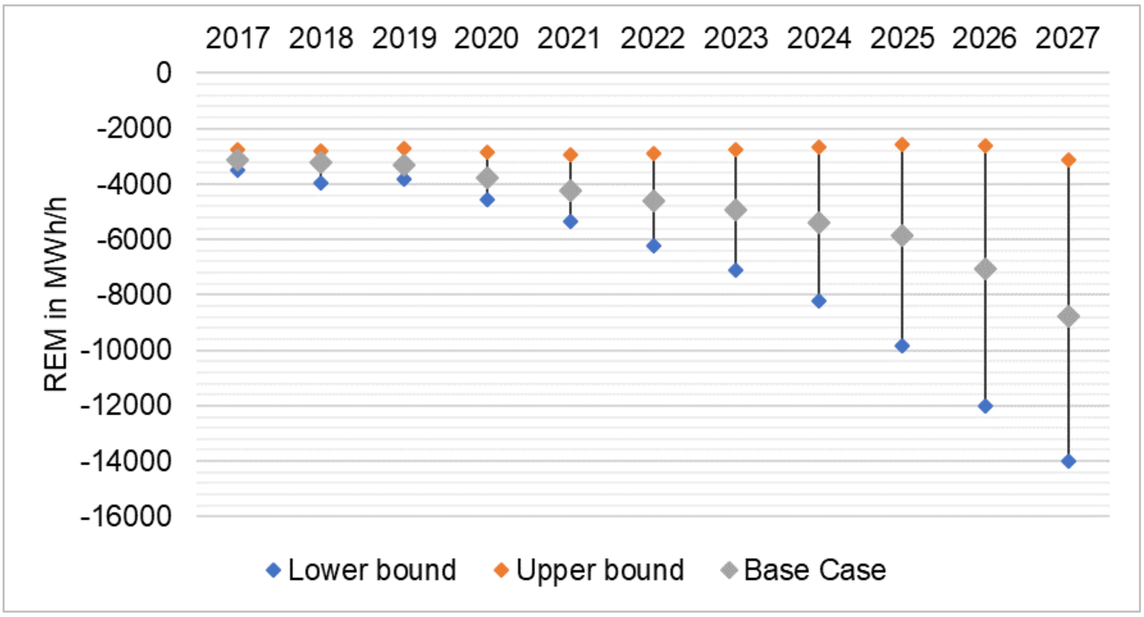

Figure 35 - Total range of REM

On basis of the considered generation expansion plan and demand forecast, the Nigerian power system will suffer from a severe energy deficit within the next 10 years. Even under most optimistic assumptions (high technical availability, high rainfalls, low demand growth), this energy deficit will remain at a level of around 3000MWh/h.

In the Base Case scenario of this outlook the energy deficit will even increase to around 9000MWh/h by 2027.

Based on the gas outlook report, which was used for this study, there will be gas fuel constraints until 2025.

The development of the Remaining Capacity Margin (RM), as depicted in Figure 36 shows that the capacity deficit will even be more severe than the energy deficit.

However, as long as the energy deficit prevails, a capacity deficit is far less relevant than the energy deficit, because its impact on the energy not supplied per annum is very low.

Under most optimistic assumptions the capacity deficit (negative of the RM) increases from a level of around 4.000 MW in 2017 to around 11.000 MW in 2027.

In the Base Case scenario, the capacity deficit (negative of the RM) will increase from around 5.000 MW to around 17.000 MW in 2027.

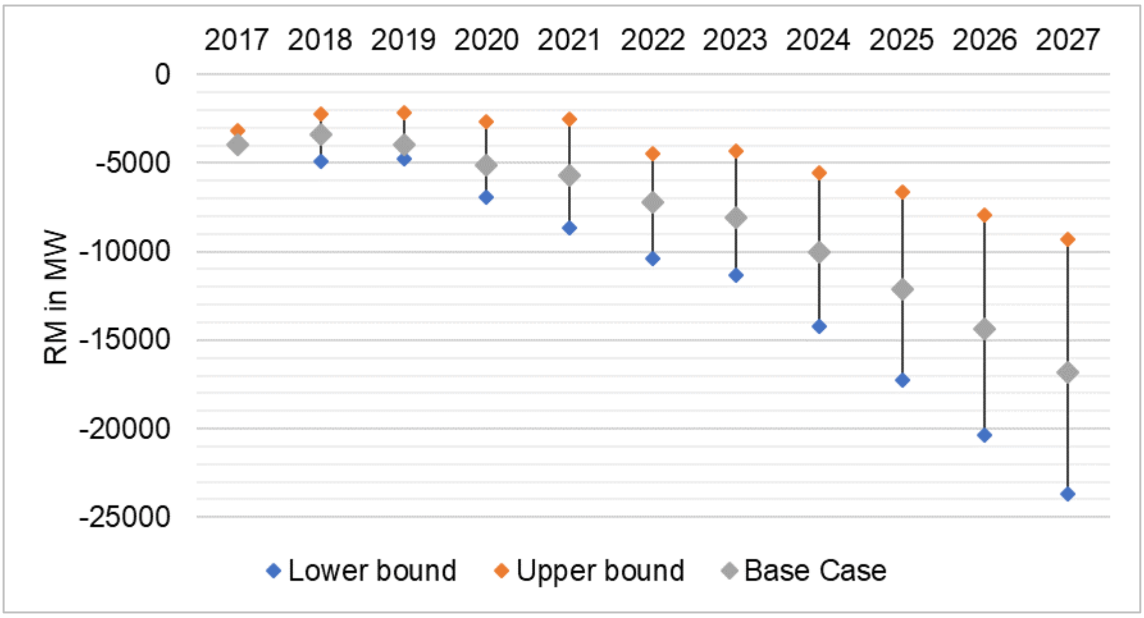

Figure 36 - Total range of RM

The energy deficit could only be resolved with a massive addition of more power plants as considered by the generation expansion plan of this study. However, this will be difficult to achieve within the analysed time frame because planning, permitting and construction of new power plants will take at least seven years (in case of OCGTs/CCGTs).

Adding more PV power plants, which can be realised in much shorter time frames than conventional power plants, could help mitigating the energy problem.

PV generation has no positive impact on the Remaining Capacity Margin because there is no PV production during full-load hours, which are assumed to be in the evening in Nigeria. However, as long as there is an energy deficit in the system, the energy deficit is much more relevant than the reported capacity deficit.

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Annex 1 – On-grid Demand Forecast

Table 20 - Cases of on-grid demand including exports (GWh) [2]

Year	On-grid demand including exports (GWh) - Low Case	On-grid demand including exports (GWh) - Base Case	On-grid demand including exports (GWh) - High Case
2015	63 787	63 787	63 787
2016	63 051	63 061	63 066
2017	65 963	66 028	66 056
2018	72 024	72 221	72 306
2019	78 344	80 345	80 522
2020	84 378	89 186	91 961
2021	90 403	98 413	104 367
2022	96 819	108 476	118 273
2023	103 646	119 430	133 820
2024	110 906	131 337	151 160
2025	118 617	144 248	170 441
2026	126 740	158 151	191 709
2027	135 254	173 055	215 068
2028	144 164	188 991	240 625
2029	153 469	205 977	268 473
2030	162 282	222 760	296 943
2031	169 113	237 100	322 817
2032	175 941	251 740	349 791
2033	182 739	266 620	377 773
2034	189 551	281 751	406 727
2035	196 196	296 914	436 385
2036	202 750	312 166	466 789
2037	209 185	327 447	497 831
2038	215 770	343 416	530 924
2039	222 498	360 085	566 175
2040	229 363	377 466	603 695

Table 21 - Cases of on-grid peak demand [2]

Year	Domestic on-grid peak demand with exports (MW) - Low Case	Domestic on-grid peak demand with exports (MW)) - Base Case	Domestic on-grid peak demand with exports (MW) - High Case
2015	9 499	9 499	9 499
2016	9 830	9 831	9 832
2017	10 354	10 364	10 368
2018	11 385	11 417	11 430
2019	12 470	12 792	12 820
2020	13 618	14 402	14 854
2021	14 587	15 894	16 865
2022	15 620	17 521	19 119
2023	16 720	19 294	21 641
2024	17 889	21 221	24 453
2025	19 131	23 311	27 583
2026	20 437	25 560	31 032
2027	21 808	27 972	34 824
2028	23 242	30 553	38 973
2029	24 740	33 303	43 495
2030	26 159	36 022	48 120
2031	27 258	38 346	52 324
2032	28 356	40 717	56 707
2033	29 451	43 130	61 256
2034	30 543	45 578	65 959
2035	31 612	48 037	70 782
2036	32 667	50 510	75 726
2037	33 703	52 989	80 775
2038	34 762	55 579	86 157
2039	35 845	58 283	91 892
2040	36 950	61 102	97 995

Annex 2 - Generation Expansion (without PV Projects)

			INSTALLED CAPACITY PER YEAR [MW]				
TYPE	STATE	PLANT ID	2017	2018	2019	2020	2021
GAS	C1	ABA					
		ABA_IPP					
		ALSCON					
		ANAMBRA					
		ASIP					500
		AZIKEL_IPP				467	467
		AZURA			295	295	295
		BRESSON			343	343	343
		CENTURY_IPP					480
		EGBIN_AES					144
		HUDSON				144	144
		IBOM					
		ICS_IPP					600
		LAFARAGE			47	47	254
		OMA_POWER			240	240	360
		PARAS				60	60
		QUATPOWER_ABA					
		SHIRORO				290	290
	G	AES	288	288	288	288	288
		AFAM	498	758	758	758	758
		DELTA	203	243	243	243	243
		GEREGU	405	405	405	405	405
		OKPAI	330	330	330	330	330
		OLORUNSOGO	320	320	320	320	320
		OMOKU	120	120	120	120	120
		OMOTOSHO	304	304	304	304	304
	N	ALAOJI	480	480	480	480	480
		EGBEMA		360	360	360	360
		ELEME		20	20	20	20
		GBARAIN		240	240	240	240
		GEREGU_NIPP	435	435	435	435	435
		IBOM		174	174	174	174
		IHOVBOR	480	480	480	480	480
		ODUKPANI	600	600	600	600	600
		OLORUNSOGO_NIPP	480	480	480	480	480
		OMOKU_NIPP		240	240	240	240
		OMOTOSHO_NIPP	480	480	480	480	480

		RIVERS		160	160	160	160
		SAPELE_NIPP	480	480	480	480	480
		TRANS-AMADI	80	80	80	80	80
	O	AFAM					
		DELTA	511.96	614.96	614.96	614.96	
HYDRO	C1	MABON					39
	G	JEBBA	570	570	570	570	570
		KAINJI	760	760	760	760	760
		SHIRORO	600	600	600	600	600
	N	ZUNGERU		700	700	700	700
STEAM	C1	ABA					
		AZURA			145	145	145
		OMA_POWER					
		QUATPOWER_ABA					
	G	AFAM	230	230	230	230	230
		OKPAI	140	140	140	140	140
	N	ALAOJI		275	275	275	275
		OLORUNSOGO_NIPP	120	240	240	240	240
	O	EGBIN	1100	1100	1320	1320	1320
		SAPELE	140	420	350	140	

			INSTALLED CAPACITY PER YEAR [MW]					
TYPE	STATE	PLANT ID	2022	2023	2024	2025	2026	2027
GAS	C1	ABA		240	240	240	240	240
		ABA_IPP		134	134	134	134	134
		ALSCON				340	340	340
		ANAMBRA				500	500	500
		ASIP	500	500	500	500	500	500
		AZIKEL_IPP	467	467	467	467	467	467
		AZURA	295	295	295	295	295	295
		BRESSON	343	343	343	343	343	343
		CENTURY_IPP	480	480	480	480	480	480
		EGBIN_AES	144	144	144	144	144	144
		HUDSON	144	144	144	144	144	144
		IBOM			360	480	480	480
		ICS_IPP	600	600	600	600	600	600
		LAFARAGE	254	254	254	254	254	254
		OMA_POWER	360	360	360	360	360	360
		PARAS	60	60	60	60	60	60
		QUATPOWER_ABA		268	268	268	268	268
		SHIRORO	290	290	290	290	290	290

	G	AES	288	288	288	288	288	288
		AFAM	758	758	758	758	758	758
		DELTA	243	243	243	243	243	243
		GEREGU	405	405	405	405	405	405
		OKPAI	330	330	330	330	330	330
		OLORUNSOGO	320	320	320	320	320	320
		OMOKU	120	120	120	120	120	120
		OMOTOSHO	304	304	304	304	304	304
	N	ALAOJI	480	480	480	480	480	480
		EGBEMA	360	360	360	360	360	360
		ELEME	20	20	20	20	20	20
		GBARAIN	240	240	240	240	240	240
		GEREGU_NIPP	435	435	435	435	435	435
		IBOM	174	174	174	174	174	174
		IHOVBOR	480	480	480	480	480	480
		ODUKPANI	600	600	600	600	600	600
		OLORUNSOGO_NIPP	480	480	480	480	480	480
		OMOKU_NIPP	240	240	240	240	240	240
		OMOTOSHO_NIPP	480	480	480	480	480	480
		RIVERS	160	160	160	160	160	160
		SAPELE_NIPP	480	480	480	480	480	480
		TRANS-AMADI	80	80	80	80	80	80
	O	AFAM						
		DELTA						
HYDRO	C1	MABON	39	39	39	39	39	39
	G	JEBBA	570	570	570	570	570	570
		KAINJI	760	760	760	760	760	760
		SHIRORO	600	600	600	600	600	600
	N	ZUNGERU	700	700	700	700	700	700
STEAM	C1	ABA		309	309	309	309	309
		AZURA	145	145	145	145	145	145
		OMA_POWER		103	103	103	103	103
		QUATPOWER_ABA		92	92	92	92	92
	G	AFAM	230	230	230	230	230	230
		OKPAI	140	140	140	140	140	140
	N	ALAOJI	275	275	275	275	275	275
		OLORUNSOGO_NIPP	240	240	240	240	240	240
	O	EGBIN	1320	1320	1100			
		SAPELE						

Annex 3 - Committed PV Projects

Table 22 - Committed solar projects (updated) [9]

S/N	Project Name	Capacity (MW)	Location	Expected COD
1	Pan Africa Solar	75	Kankiya, Katsina	20.07.2018
2	Nigerian Solar Capital Partners	100	Ganjuwa, Bauchi	20.07.2018
3	Nova Solar 5 Farm Ltd	100	Kankiya, Katsina	20.07.2018
4	Motir Dusable Ltd	100	Enugu	20.07.2018
5	LR Aaron Power Ltd	100	Abuja	08.08.2018
6	Middle Band Solar One Ltd	100	Kogi	20.07.2018
7	Afrinergia Power Ltd	50	Nasarawa	20.07.2018
8	Nova Scotia Power Development Ltd	80	Dutse, Jigawa	20.07.2018
9	Kvk Power	55	Yabo, Sokoto	20.07.2018
10	Quaint Power	50	Kaduna	12.08.2018
11	Anjeed Kafanchan Ltd	100	Kaduna	20.07.2018
12	CT Cosmos	70	Panyam, Plateau	08.08.2018
13	Oriental Renewable Energy Resources	50	Duste, Jigawa	20.07.2018
14	eN Africa Consulting	50	Igabi, Kaduna	20.07.2018

Annex 4 - Plant Outage Factors 2015/16

Table 23 – Average power station outage factors of 2015/16 [5, 6]

Plant	Type	POF in %	UOF in %
RIVERS	Gas-fired steam turbine	2%	3%
OMOTOSHO_GAS	Simple cycle gas turbine	6%	1%
OKPAI	Combined cycle gas turbine	6%	5%
GBARAIN	Gas-fired steam turbine	4%	8%
GEREGU_NIPP	Simple cycle gas turbine	7%	6%
AFAM_VI	Combined cycle gas turbine	7%	8%
OLORUNSOGO_GAS	Simple cycle gas turbine	3%	15%
OMOTOSHO_NIPP	Simple cycle gas turbine	4%	17%
OMOKU	Simple cycle gas turbine	18%	5%
TRANS_AMADI	Simple cycle gas turbine	4%	19%
EGBIN	Gas-fired steam turbine	6%	18%
SHIRORO	Hydro	22%	4%
JEBBA	Hydro	9%	19%
OLORUNSOGO_NIPP	Combined cycle gas turbine	13%	15%
DELTA	Simple cycle gas turbine	16%	20%
IHOVBOR	Simple cycle gas turbine	6%	30%
ODUKPANI	Gas-fired steam turbine	18%	27%
AFAM_IV-V	Simple cycle gas turbine	11%	35%
SAPELE_NIPP	Simple cycle gas turbine	19%	29%
ASCO	Gas-fired steam turbine	2%	50%
GEREGU_GAS	Simple cycle gas turbine	49%	6%
ALAOJI	Combined cycle gas turbine	40%	16%
KAINJI	Hydro	20%	43%
SAPELE_STEAM	Gas-fired steam turbine	41%	26%
IBOM	Combined cycle gas turbine	29%	40%
TOTAL AVERAGE		**15%**	**19%**

Annex 5 - Long-Term Hydro Power Station Discharge

Table 24 - Statistics of the turbine discharge at Kainji Hydropower dam (m^3/s) (1990-2010). [8]

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean	784	814	748	794	720	666	632	709	746	753	741	767
S.D	233	270	234	232	196	171	198	257	259	252	209	233
Skew	0.14	0.45	0.34	0.18	0.3	-0.1	0	0.45	0.69	0.52	-0.1	0.53
Max	1234	1432	1203	1345	1176	1027	1060	1445	1397	1289	1249	1402
Min	377	405	404	416	405	337	206	203	301	380	198	383

Table 25 - Statistics of the turbine discharge at Jebba Hydropower dam (m^3/s) (1990-2010). [8]

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean	1020	930	923	860	824	767	997	1319	1314	1038	1015	1020
S.D	352	306	312	237	250	288	407	391	433	336	279	352
Skew	-0.04	0.08	0.04	0.32	0.03	0.9	0.34	0.05	0.3	0.21	0.22	-0.04
Max	1643	1466	1672	1383	1340	1556	1927	2079	2143	1655	1606	1643
Min	376	425	232	451	362	328	366	633	685	479	514	376

Table 26 - Statistics of the turbine discharge at Shiroro Hydropower dam (m^3/s) (1990-2010). [8]

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean	237	261	255	238	214	231	338	359	339	346	245	226
S.D	81	71	72	85	79	84	85	140	149	119	121	87
Skew	0.11	-0.55	-0.3	0.68	0.12	2.41	0.33	1.3	-0.04	-0.26	-0.04	0.04
Max	417	390	382	445	407	526	494	792	605	575	505	436
Min	76	99	118	87	36	142	173	128	94	86	22	21

Annex 6 - Zungeru Hydro Power Station

Table 27 - Expected average turbine discharge per month (in m³/s) [10]

Month	2013	2012	2011
January	289	286	273
February	259	285	221
March	303	211	429
April	330	63	408
May	209	60	277
June	170	402	172
July	364	410	277
August	447	568	357
September	429	573	349
October	408	533	371
November	330	340	284
December	310	347	291

Table 28 - Operating Head (in m) [10]

Operating condition	Headwater El.	Tail water El.	Gross Head on Turbine in Reservoir
Maximum	231.0m	132.50m	98.50m
Normal maximum	230.0m	132.50m	97.50m
Normal minimum	223.0*	134.50m	88.50m
In flood conditions	231.90m	157.00m**	74.00m

Annex 7 - Gas Outlook

Generation adequacy depends on sufficient gas being reliably supplied to existing and planned gas powered thermal plants. Gas supplied to the power sector (thermal plants) hit a six-year low in 2016, with an average of 518 million standard cubic feet per day (mmcfd), the lowest since 2011 (see Figure 37) [11]. This meant that on average, 71 percent of the total gas thermal plant capacity in Nigeria, was idle throughout 2016.

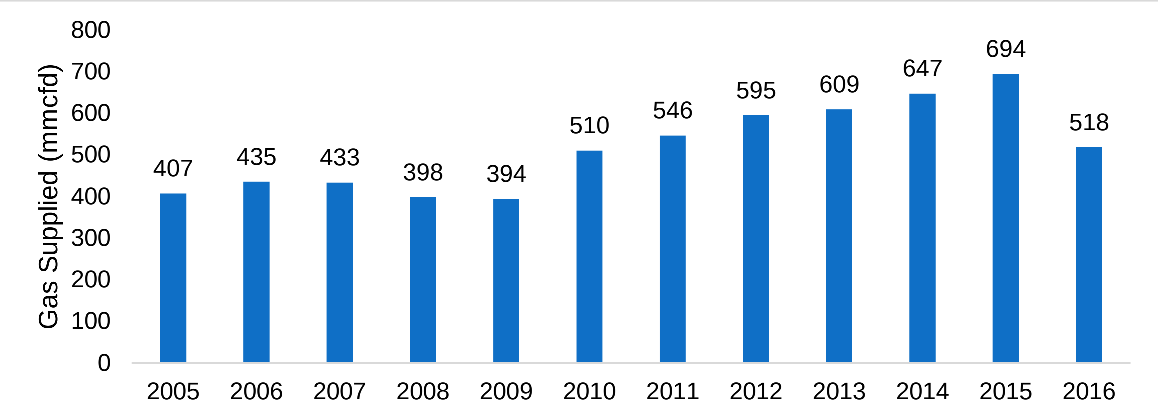

Figure 37 - Gas Supplied to Power Sector from 2005 to 2016 [11]

A baseline study by the Power Advisory team of the Vice President [12] estimated that the power sector required 1.4 billion standard cubic feet per day (bscfd) of gas supply to run the available gas thermal generation capacity of about 7,400MW as of 2015.

This Study projects how much gas is likely to be available for electricity generation in Nigeria, based on domestic production volumes, liquified natural gas (LNG) export capacity and prices, domestic pipeline infrastructure, vandalism events, and planned investments. Gas supplied to Nigeria's power sector is projected to grow steadily from its current levels (~700mmfcd/day) to about 2100mmcfd/day by 2030. These projections rely on analysis by OG Analysis, a leading publisher of global energy reports. OG Analysis provides insights and information on world oil and gas industries [13], conducting analysis for key players in the oil and gas sector, including the Nigerian National Petroleum Corporation and providing subscription based forecasts for the sector.

1.1 Results of Gas-to-Power Outlook Study by OG Analysis

Average daily gas supply to power infrastructure is expected to grow from 707mmcfd in 2017 to 2148mmcfd by 2030, as shown in Figure 38. The next subsection describes how these estimates were derived.

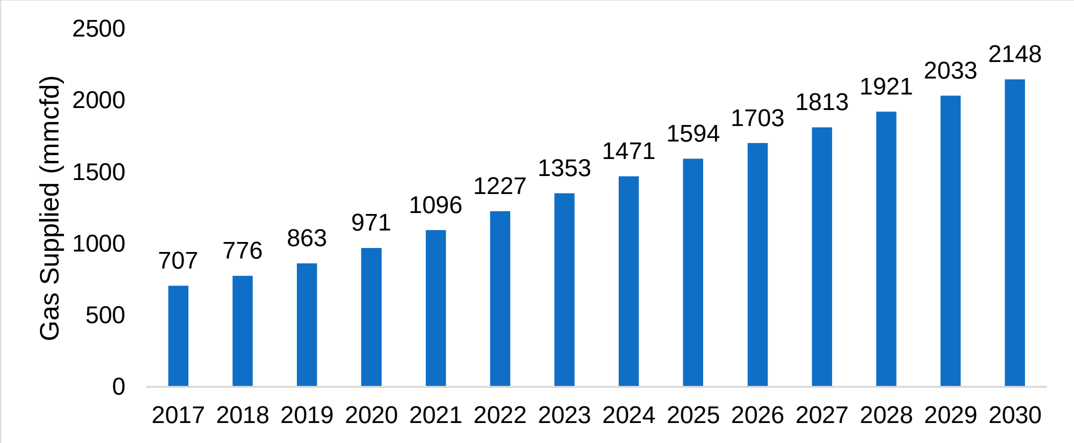

Figure 38 - Gas to Power Outlook in Base Case Scenario [11]

1.1.1 Methodology of Base Scenario

The gas outlook presented was determined based on the association of five variables with gas-to-power supply. These variables are:

- Present unmet gas demand in the power sector: This represents the shortfall between available gas generation capacity and gas supplied to the sector illustrated in Figure 37. Data are collected from NNPC.
- Marketed gas production: This represents the portion of gas produced domestically that is available for commercial purposes. The government forecasts that this production volume will increase dramatically based on gas flaring policy to be effective in the fourth quarter of 2017. Data are collected from various field sources.
- GDP: Data and forecasts are collected from the IMF
- Disposable income: Data and forecasts are collected from the IMF
- Government targets and planned power projects

The steps for arriving the gas forecast are outlined below:

- Step 1: Determined variables that drive gas-to-power supply
- Step 2: Collected historical data on variables and gas-to-power supply
- Step 3: Fit a linear trend to the historical values of each variable and gas-to-power supply. Obtain linear correlation model for each variable
- Step 4: Forecasted gas-to-power supply—the five variables were used to obtain five forecasts, one for each variable
- Step 5: Multiplied forecasts with weights for each variable Table 29 to calculate total gas-to-power supply for each year.

Table 29 - Weighting of Variables that Drive Gas-to-Power Supply [11]

Driver	Weight
Unmet demand	0.23
Marketed gas production	0.32
GDP	0.15
Disposable income	0.15
Government targets and planned power projects	0.15

Global gas prices were not considered in the model, because data were not sufficiently available to estimate their effect. Furthermore, the price of exporting gas has vastly reduced since the advent of shale gas and the difference between global LNG prices and domestic gas prices are no longer as wide as pre-2014 levels.

Figure 39 and Table 30 show the gas to power outlook based on the gas supply projection.

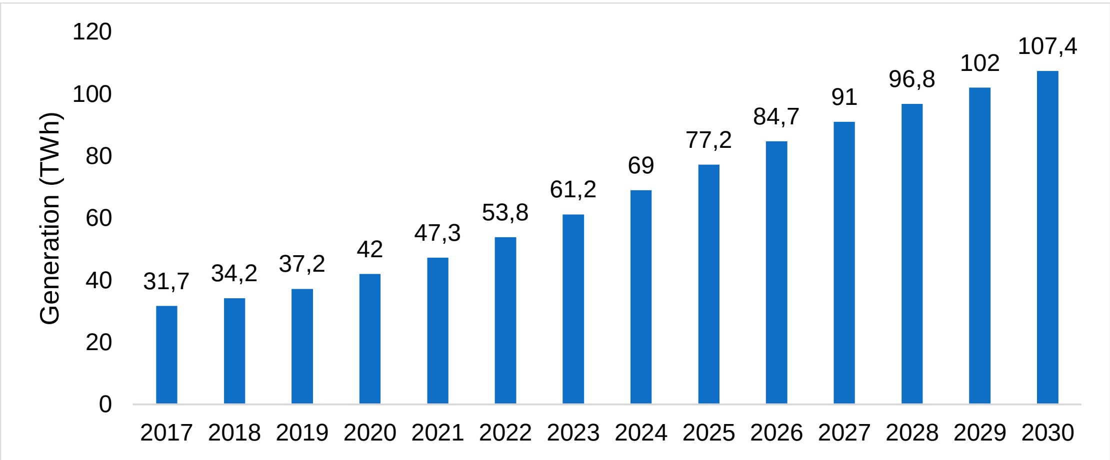

Figure 39 - Power Generation Outlook Based on Gas Supply for 2017-2030 (TWh) [11]

Table 30 - Gas-to-Power Outlook [11]

Year	Gas Supplied (mmcfd)	Generation (TWh)
2017	707	31.7
2018	776	34.2
2019	863	37.2
2020	971	42
2021	1,096	47.3
2022	1,227	53.8

2023	1,353	61.2
2024	1,471	69
2025	1,594	77.2
2026	1,703	84.7
2027	1,813	91
2028	1,921	96.8
2029	2,033	102
2030	2,148	107.4

1.2 Constraints to and Drivers of Gas-to-Power Supply Growth

The forecasts presented are motivated by expected shifts in the domestic gas market. These shifts include changes to current constraints to gas supply as well as known planned investments in the sector. The following sections discuss these constraints and investments.

1.2.1 Constraints to Gas-to-power Supply

Gas supply to Nigeria's power plants is constrained by frequent vandalism of gas pipelines and inadequate infrastructure investment.

Vandalism

The vandalism of gas pipelines has reduced gas availability and hence generation capacity, particularly in gas-fired power plants in Western Nigeria and the Middle Belt region such as Egbin, Omotosho, and Geregu (see Figure 40).

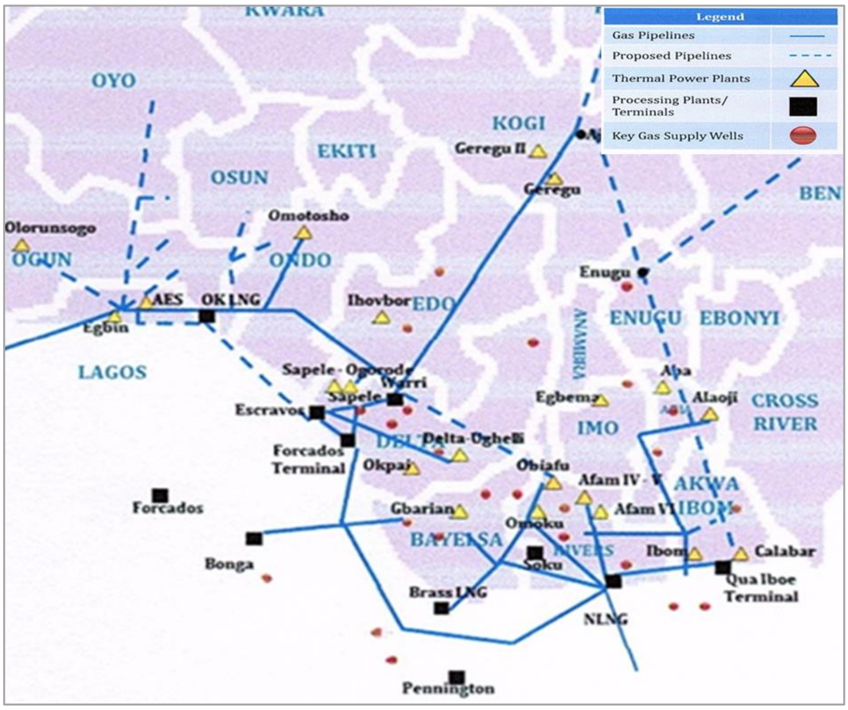

Figure 40 - Nigeria's Gas Network (2016) (source EMRC)

A total of 2,560 vandalism incidents occurred in 2016. Some of the major events included:

- Sabotage on the 14-inch Ogbainbir – Tebidaba pipeline serving the Brass Terminal in May 2016
- Incessant attacks on the Nigerian Petroleum Development Company, NPDC's Forcados trunk line is widely blamed for gas constraints to power supply in 2016 [14] and a loss of about 70 percent of NPDC's crude oil production capability. The company expects production to increase by 50 percent when repairs are completed.

Vandalism events however seem to be on the decline amid ongoing negotiations between parties and international support. Figure 41 shows the number of vandalism incidents in from January 2015- December 2016, which shows the lowest incidence of 18 in the month of December 2016.

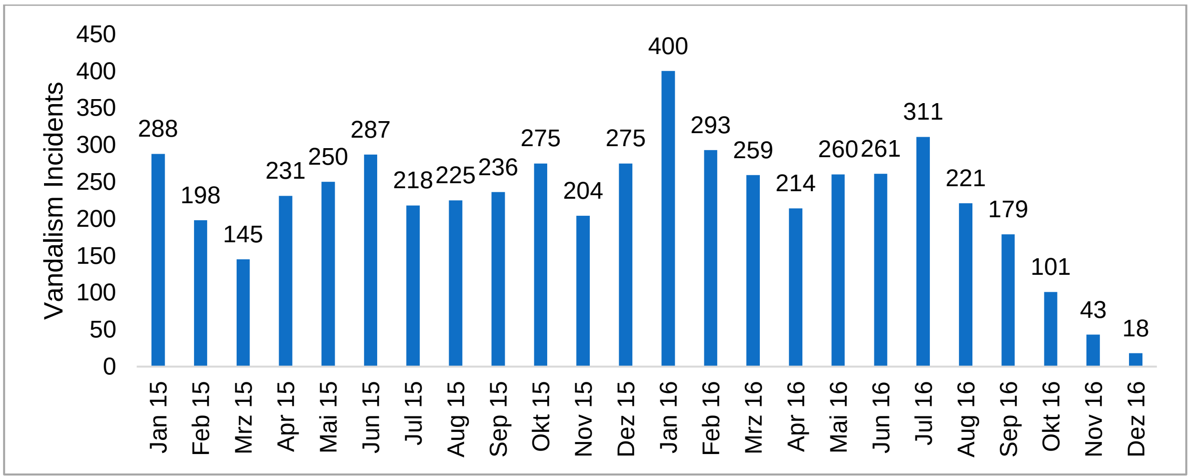

Figure 41 - Number of Recorded Vandalism Events

Inadequate investment

Producers are not incentivized to invest in developing the domestic market for several economic reasons. These include, low prices, exchange rate uncertainty, collection uncertainty and regulatory bottlenecks.

- **Prices:** NERC regulates domestic gas prices are regulated under the DSO. Prices were increased in late 2014 to $2.50/mmcfd plus pipeline transport costs of $0.80/mmscf in late 2014. However, producers [15] still insist prices are still below competitive market rates [16].
- **Exchange Rate Uncertainty:** High fluctuations in exchange rates since 2015 also exacerbates pricing in the sector. The Nigerian Gas Association claims that even though "gas investments and loans are largely denominated in US dollars and must be repaid in US dollars, however, the Central Bank recently enforced payments to gas suppliers, whose contracts are denominated in US dollars, to be paid in naira at the official exchange rate without making it possible for them to access US dollars at the official rates to repay their loans" [17].
- **Collection Uncertainty:** gas producers are not consistently paid for the gas they supply because the generation companies do not receive full remittances from NBET due to downstream collection issues. Therefore, the sector's debts to producers continue to accrue [18].
- **Regulatory Uncertainty:** Nigeria's oil and gas regulatory regime, specifically the Petroleum Industry Bill, has been under debate since 2008, causing investor uncertainty.

In addition to the poor economic incentives in the domestic gas market, the current state of infrastructure investment in the sector does not suggest a dramatic improvement in the domestic gas supply situation in the short to medium term. This is because of:

- **Limited joint venture funding.** The Nigerian National Petroleum Corporation (NNPC), the government counter-party to joint venture companies that supply oil and gas continues to under-invest in the sector. In the period 2010-2013, the gas industry received $6billion less than was required to fully implement its joint-venture business plans (on a yearly average basis). Resolving these funding challenges could increase gas production by ~2.8bscfd by 2020 under current fiscal terms.
- **Long-term under-investment and delays** in the delivery of planned gas infrastructure have resulted in a shortage of gas-processing and pipeline infrastructure. Lack of investment in gas-processing facilities and failure to complete already funded projects are key challenges.

1.2.2 Planned Investments and Actions to Mitigate Constraints

Conversely, there are a number ongoing activities which should mitigate the effects of the identified constraints. These activities include planned infrastructure projects and plans to end gas flaring. Some of the specific activities are illustrated below:

- NNPC is intensifying effort to drive the energy supply project to power industries by ensuring the completion of the Ajaokuta-Abuja-Kaduna-Kano (AKK) gas pipeline.
- NNPC is collaborating with the Republic of Niger in the area of sharing of geological data to further boost the ongoing exploratory activities in the Chad Basin and Benue Trough
- Nigeria is undertaking review of the existing production sharing contracts (PSC) arrangements with production partners with a view to improve Government share of revenue from the arrangement.
- Foreign companies like CNPC, Lukoil, Shell, Chevron, ENI and other companies continue to acquire stakes in Nigeria companies, largely because the government is open for investments from global integrated major companies as a part of its oil and gas development strategies.
- In addition to existing gas export infrastructure including WAGP pipeline and NLNG terminal, the country is planning to develop additional infrastructure including:
  - Brass LNG
  - Olokola LNG
  - NLNG Train 7
- New gas processing projects such as Oredo, Utorogu and Odidi are expected to increase gas supply by 220 mmscf/day.
- The Nigerian government has released a roadmap for curbing gas flaring envisages that investments will commence in the fourth quarter of 2017, the government expects the implementation will result in an additional 2.5GW of gas supply to the power sector [19].

This report was prepared by the Market Operator with support from the Nigerian Energy Support Programme (NESP).