LAGOS STATE **INTEGRATED RESOURCE PLAN**

POWER AFRICA

NIGERIA POWER SECTOR PROGRAM

THE LAGOS STATE INTEGRATED RESOURCE PLAN

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ACRONYMS

Acronym	Definition
AC	Alternating Current
BSCFD	Billion Standard Cubic Feet Per Day
BPE	Bureau of Public Enterprises
CC-G-250	Gas-Fired Combine Cycle Gas Turbine with 250 MW Generation Capacity
CC-L-250	LNG-Fired Combine Cycle Gas Turbine with 250 MW Generation Capacity
CC-O-250	LFO-Fueled Combine Cycle Gas Turbine with 250 MW Generation Capacity
CCGT	Combined Cycle Gas Turbines
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
COVID-19	Corona Virus Disease of 2019
CV	Current Value
Dangote	Dangote Industries Limited
DC	Double Circuit
DER	Distributed Energy Resource
DISCO	Distribution Company
DR	Demand Response
DSM	Demand Side Management
EC	Energy Conservation
ECN	Energy Commission of Nigeria
ECOWAS	Economic Community of West African States
EE	Energy Efficiency
EKEDC	Eko Electricity Distribution Company
EIA	U.S. Energy Information Administration
ELPS	Escravos-Lagos Pipeline System
EPC	Engineering, Procurement, and Construction
EUE	Expected Unsupplied Energy
EV	Electric Vehicle
EWOGGS	East-West Offshore Gas Gathering System
FGN	Federal Government of Nigeria
FSRU	Floating Storage Regasification Unit
GCS	Geographical Coordinate System
GenCo	Generation Company
GHG	Green-House-Gases
GT	Gas Turbine
GT-G-200	Gas-Fired Open Cycle Gas Turbine with 200 MW Generation Capacity
GT-O-200	LFO-Fueled Open Cycle Gas Turbine with 200 MW Generation Capacity
GW	Gigawatt, 1000 Megawatts or 1 Billion Watts, a Unit for Power
GWh	Gigawatt-Hour, 1000 Megawatt-Hours or 1 billion Watt-Hours, a Unit for Energy
HFO	Heavy Fuel Oil
Hg	Mercury
HHV	High Heating Value
IDC	Interest During Construction
IE	Ikeja Electric
IEA	International Energy Agency
IPP	Independent Power Producer
IRP	Integrated Resource Plan
km	Kilo meter or 1000 Meters
kV	Kilovolt or 1000 Volts

Acronym	Definition
kVA	Kilovolt Ampere
kW	Kilowatt or 1000 Watts, a Unit for Power
kWh	Kilowatt-Hour or 1000 Watt-Hours, a Unit for Energy
LAR	Local Administration Region
LASG	Lagos State Government
LCDA	Local Council Development Area
LCOE	Levelized Cost of Energy
LED	Light-Emitting Diode
LFO	Light Fuel Oil
LGA	Local Government Area
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LNG	Liquefied Natural Gas
M-US$	Million United State Dollar
MCR	Maximum Continuous Rating
MMBTU	Million British Thermal Unit
MSW	Municipal Solid Waste
mtpa	Million Tonnes Per Annum
MVA	Megavolt Ampere
MW	Megawatt or 1 million Watts, a Unit for Power
MWh	Megawatt-Hour or 1 Million Watt-Hours, a Unit for Energy
NAPTIN	National Power Training Institute of Nigeria
NDA	Non-Disclosure Agreement
NDPHC	Niger Delta Power Holding Company
NDPR	Niger Delta Petroleum Resources
NBET	Nigerian Bulk Electricity Trading Plc
NEEAP	National Energy Efficiency Implementation/Action Plan
NELMCO	Nigeria Electricity Liability Management Company
NEMSA	Nigerian Electricity Management Service Agency
NERC	Nigerian Electricity Regulatory Commission
NESI	Nigerian Electricity Supply Industry
NG	Natural Gas
NGC	Nigeria Gas Company
NGL	Natural Gas Liquid
NGMC	Nigeria Gas Marketing Company
NGTC	Nigeria Gas Transportation Company
NIPPs	National Integrated Power Projects
NLNG	Nigeria LNG Limited
NNPC	Nigerian National Petroleum Corporation
NNRA	Nigerian Nuclear Regulatory Authority
NO_x	Nitrogen Oxides
O&M	Operation & Maintenance
OPEC	Organization of the Petroleum Exporting Countries
PA-NPSP	Power Africa Nigeria Power Sector Program
Petcoke	Petroleum Coke
PHCN	Power Holding Company of Nigeria
PPA	Power Purchase Agreement
RDF	Refuse-Derived Fuel
PV	Present Value
REA	Rural Electrification Agency
RICE	Reciprocal Internal Combustion Engine
SC	Single Circuit

Acronym	Definition
SCADA	Supervisory Control and Data Acquisition
SE4ALL-AA	Sustainable Energy for All Action Agenda
SLD	Single Line Diagram
SMR	Small Module Reactor
SO_2	Sulphur Dioxide
SO_x	Sulphur Oxides
Solar PV	Solar Photovoltaic
SPV	Special Purpose Vehicle
ST	Steam Turbine
TCN	Transmission Company of Nigeria
TS	Transformation Station
UE	Unsupplied Energy
U.S. EPA	U.S. Environmental Protection Agency
US$	United State Dollar
USAID	U.S. Agency for International Development
UTM	Universal Transverse Mercator
WAGP	Western African Gas Pipeline
WTE	Waste to Energy

EXECUTIVE SUMMARY

ES.1 BACKGROUND

The Power Africa Nigeria Power Sector Program (PA-NPSP) is the U.S. Agency for International Development's (USAID) signature Power Africa program in Nigeria. PA-NPSP contributes to comprehensive reform within Nigeria's power sector, addressing gas-to-power challenges, competitive procurement of clean and conventional energy, regulatory and policy reforms to foster greater sector transparency and private investment, utility distribution sector reform, and off-grid electricity access. In line with Power Africa's broader goals, PA-NPSP's goal is to enable 10,000 MW of new/rehabilitated or unlocked electricity generation capacity and three million electricity connections, supporting reliable and affordable electricity access to millions of people for the first time.

PA-NPSP will increase electricity availability, access, and reliability throughout Nigeria, while measuring objective progress across four program outcomes:

- **Outcome 1 (OC1):** Increase Private Sector Investment Power Generation and Transmission
- **Outcome 2 (OC2):** Facilitate New Off-grid Connections to Cleaner Power Supply
- **Outcome 3 (OC3):** Improve the Enabling Environment for Private Sector Participation in the Power Sector
- **Outcome 4 (OC4):** Promote Improved Liquidity throughout the Energy Sector

PA-NPSP will achieve these outcomes by strategically aligning energy sector reform, increased generation, and electrification goals with new investment opportunities. This will include working to bring transactions to financial close, coordinating with local resources, and building human and institutional capacity at key Federal Government of Nigeria (FGN) entities. Critical to success will be the use of a results-oriented framework for decision-making that allows PA-NPSP to identify, prioritize, and select intervention activities and programming to increase and accelerate private sector investment and move transactions forward.

PA-NPSP and the Lagos State Government (LASG) have a common goal to increase electricity accessibility and reliability in Lagos State by promoting improved communication and decision-making in electricity supply, policy, and regulatory environment (enhanced sector planning, cost effective power supply, cost-reflective tariffs, and regulatory stability). LASG requested PA-NPSP to lead the development of an Integrated Resource Plan (IRP) for Lagos State, based on available data and complementary high-level assumptions and estimates.

The primary objective of the IRP, prepared based on a set of pre-established assumptions and criteria, is to provide guidance to stakeholders on the Lagos State power system development requirements, including federal/state government agencies, regulators, generators, transmitters, distributors, gas suppliers, investors, financial institutions, consumers, and others.

This integrated resource plan report includes the predicted load demand growth over the next 20 years, a least-cost generation development plan, the transmission development plan consistent with the least-cost generation development plan, and the distribution development plan.

ES.2 ELECTRICITY SUPPLY AND LOAD DEMAND IN LAGOS STATE

Lagos State is located in southwestern Nigeria. It is the smallest state among Nigeria's 36 states, in terms of area; however, the state is arguably the most economically important state of the country and a major financial center. Lagos State Ministry of Economic Planning and Budget estimated the state's population at 26.44 million in 2019.

Ikeja is the state capital and administrative center of the Lagos State Government. Lagos State is divided into five administrative divisions, which are further divided into 57 Local Administrative Regions (20 Local Government Areas (LGAs) and 37 Local Council Development Areas (LCDAs)).

In Nigeria, electricity supply is the concurrent responsibility of the Federal Government and State Governments as both parties are vested with powers under the Constitution of the Federal Republic of Nigeria 1999 (as amended) to make laws relating to the provision of electricity. The Nigerian Electricity Supply Industry has undergone fundamental changes over the past few years with the implementation of the Federal Government's reform program reputed to be one of the most ambitious privatization exercises in the global power industry. The key players of the industry include the Federal Ministry of Power, state ministries responsible for energy and power (such as Lagos State Ministry of Energy and Energy and Resources), Nigerian Electricity Regulatory Commission, Energy Commission of Nigeria, state electricity/energy boards (such as Lagos State Electricity Board), Electricity Generation Companies, Transmission Company of Nigeria, Electricity Distribution Companies, Nigerian Bulk Electricity Trading Plc, Nigeria Electricity Liability Management Company, Bureau of Public Enterprises, Gas Aggregation Company of Nigeria, Nigerian National Petroleum Corporation, Nigeria Gas Company, Rural Electrification Agency, Nigerian Electricity Management Service Agency, National Power Training Institute of Nigeria, FGN Power Company, and Advisory Power Team.

Two of the eleven (11) electricity distribution companies in Nigeria, Ikeja Electric and Eko Electricity Distribution Company, are located in Lagos State and supply the customers in the 20 LGAs and 37 LCDAs in the state. The electricity received by the two utilities is produced by Egbin power plant located in the state and power generation plants located in other states and then transmitted to transmission substations in the state through the national grid. The DISCOs have the ability and authority to negotiate power purchase agreements (PPAs) with the generators directly under the NERC Embedded Generation Regulation, 2012. In addition, there are several off-grid gas-fired captive generators in Lagos State, supplying power to government buildings and/or for personal use.

As of 31 December 2020, the national grid system in Lagos State (either located in Lagos State or located in Ogun State and supplying 33 kV feeders connected to customers in Lagos State) includes the Egbin 6x220 MW power plant, thirteen 330 kV and more than thirty 132 kV transmission lines (one line may include one to four circuits), seven 330 kV substations (four of which also directly supply power to 33 kV feeders), and twenty-one 132 kV substations (transformation stations) that directly supply power to 33 kV feeders.

The Load Forecast Report[1] presents the predicted load growth results for the state over the period from 2020 to 2040 as well as the methodology, key parameters, and assumptions used in preparation of the forecast. Table ES-1 presents the results, specifically the forecast annual system energy and peak demands at the generation bus for the three growth scenarios, i.e. most likely, high, and low. For a more intuitive comparison, peak demands are also graphically displayed in Figure ES-1.

The following can be noted from Table ES-1:

Most Likely Growth Scenario	High Growth Scenario	Low Growth Scenario
The peak demand will grow from 1,866 MW in 2020 to 6,924 MW in 2040, an increase of 271%.	The peak demand in 2040 will reach 9,380 MW, approximately a 400% increase from 2020.	The peak demand in 2040 will grow to 5,022 MW, around a 170% increase from 2020.
When compared with the forecast peak derived for 2040 under the most likely growth scenario, the forecasts under the high growth scenario will be approximately 35% higher. The forecasts under the low growth scenario would be 27% lower.		

[1] Power Africa Nigeria Power Sector Program: Long-Term Load Forecast – Lagos State, 12 February 2021

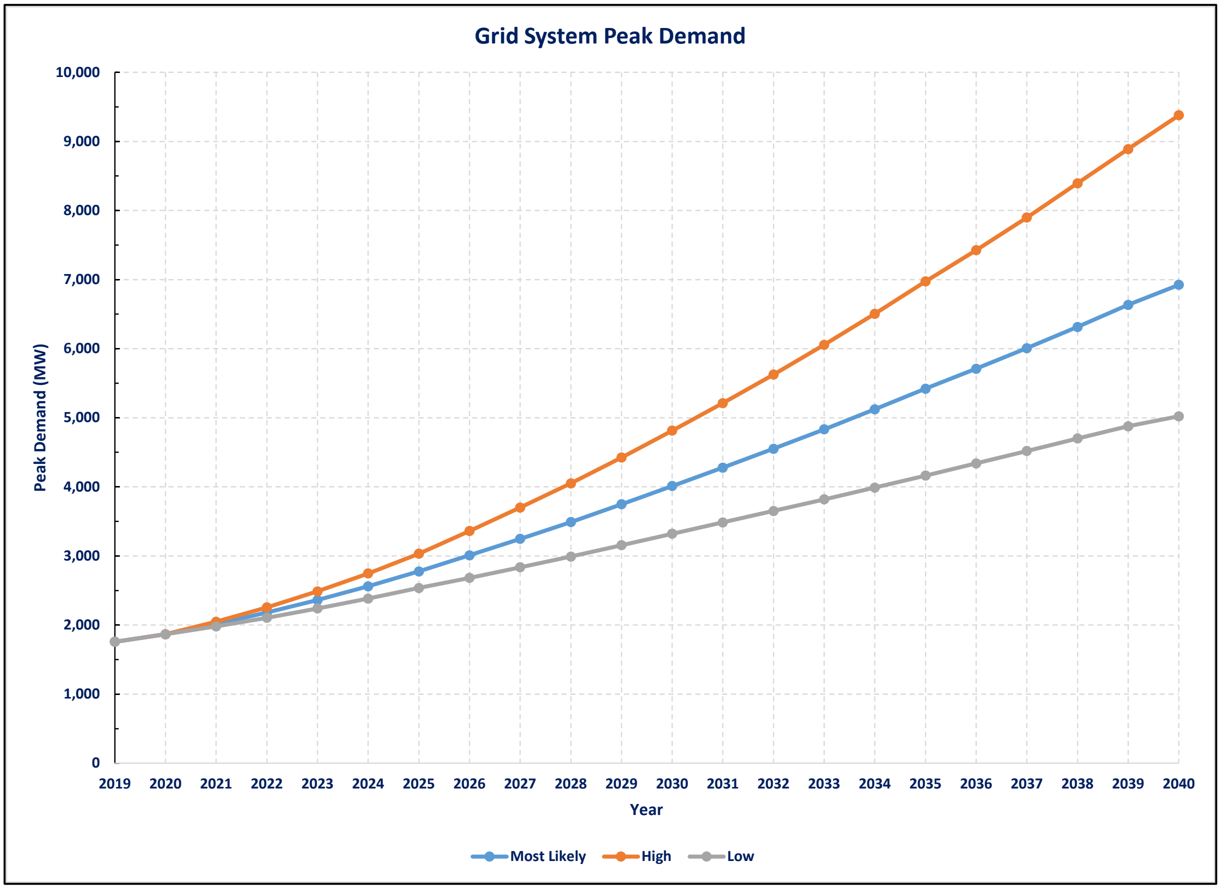
Table ES-1: Forecast System Energy and Peak Demands at Generation Bus

Year	Most Likely		High		Low	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
2019	10,008.84	1,757.79	10,008.84	1,757.79	10,008.84	1,757.79
2020	10,626.49	1,866.26	10,626.49	1,866.26	10,626.49	1,866.26
2021	11,469.03	2,014.23	11,660.56	2,047.87	11,278.72	1,980.81
2022	12,408.41	2,179.21	12,838.63	2,254.76	11,987.07	2,105.21
2023	13,444.72	2,361.21	14,163.31	2,487.41	12,750.77	2,239.33
2024	14,578.21	2,560.27	15,637.20	2,746.26	13,569.00	2,383.03
2025	15,809.34	2,776.49	17,263.35	3,031.85	14,441.26	2,536.22
2026	17,138.27	3,009.88	19,138.46	3,361.16	15,272.07	2,682.13
2027	18,490.91	3,247.44	21,069.84	3,700.36	16,148.14	2,835.99
2028	19,870.33	3,489.70	23,063.30	4,050.46	17,028.55	2,990.61
2029	21,338.22	3,747.49	25,194.07	4,424.67	17,964.71	3,155.02
2030	22,846.14	4,012.32	27,409.61	4,813.77	18,913.05	3,321.57
2031	24,360.69	4,278.31	29,674.39	5,211.52	19,843.80	3,485.04
2032	25,917.25	4,551.68	32,030.67	5,625.34	20,787.33	3,650.74
2033	27,518.00	4,832.81	34,483.96	6,056.19	21,744.53	3,818.85
2034	29,165.28	5,122.11	37,040.10	6,505.11	22,716.39	3,989.53
2035	30,861.42	5,419.99	39,705.10	6,973.15	23,703.69	4,162.92
2036	32,506.28	5,708.87	42,279.87	7,425.34	24,707.36	4,339.19
2037	34,204.51	6,007.11	44,976.00	7,898.84	25,728.12	4,518.46
2038	35,958.68	6,315.19	47,799.98	8,394.80	26,766.66	4,700.85
2039	37,771.07	6,633.49	50,613.49	8,888.92	27,770.88	4,877.22
2040	39,425.66	6,924.07	53,407.06	9,379.53	28,593.03	5,021.61
Times	**3.7101**	**3.7101**	**5.0258**	**5.0258**	**2.6907**	**2.6907**
Increase (%)	**271.01**	**271.01**	**402.58**	**402.58**	**169.07**	**169.07**
Comparing with the Forecasts in 2040 under Most Likely Scenario						
Times			**1.3546**	**1.3546**	**0.7252**	**0.7252**
Increase (%)			**35.46**	**35.46**	**-27.48**	**-27.48**

ES.3 GENERATION PLANNING APPROACH AND ASSUMPTIONS

Generation systems should be developed, operated, and maintained in accordance with the currently applicable acts, regulations, strategies, policies, rules, and guidelines. The Lagos State IRP Study Team has identified and collected many documents governing the development, operation, and maintenance of the generators and National Grid system in Nigeria. Four of them mainly govern the development of the generation system, including the (1) Draft Revised Edition of the National Energy Policy, (2) Sustainable Energy for All Action Agenda, (3) Grid Code for the Nigeria Electricity Transmission System, and (4) Market Rules for Transitional and Medium-Term Stages of the Nigeria Electricity Supply Industry. Each power plant must also meet the established environmental standards and the total annual pollutant emissions that are the intended targets for the country.

Figure ES-1: Grid System Peak Demands Under Three Scenarios



The basic approach used in the preparation of a least-cost generation development plan consists of comparing system costs of a number of scenarios that supply a given load demand, with comparable levels of reliability, over a study period (plus extended period for the impact of end-effect if necessary). These costs include annual capital charges (calculated according to the investments required for major improvement and reinforcement, refurbishment, and new facilities, economical life, and interest or discount rate), fuel expenses, O&M costs, power purchase costs, offset allowance for greenhouse gas (GHG) and other emissions, as well as costs of unsupplied energy, among others. The comparison is made on the basis of the cumulative present value of costs for a given scenario and predetermined simulation period at a predetermined discount rate.

Generation development scenarios are formulated based on the available and screened generation candidates. Every generation expansion scenario has a fixed part and a variable part. The fixed part includes the existing generating units with planned retirement schedule if available and those committed for installation. The committed projects include those under construction, with funds secured or construction contract executed (or at least awarded). The variable part consists of a number of generation candidates – either only one type (class) of generation candidates or several types depending on the study objectives.

In order to fairly assess the formulated generation development scenarios, it is necessary to establish a set of planning parameters and criteria prior to the development of the scenarios, which cover all aspects of power system planning work, such as technical, economic, financial, and environmental. Per the study team's experience, reliability criteria adopted in a study are usually the deciding factor in scheduling the addition of new generating plants. Considering that Lagos State has the highest electricity demand among the 36 states in Nigeria and it is located in the Southwest corner of the country, it is determined that in the generation expansion analysis, Lagos State would contribute approximately one third of the largest unit (250 MW) to the system primary, or spinning, reserve, namely 85 MW.

In today's practice, it is common when comparing different forms of generation to apply an economic levy (or offset allowance) on thermal plants, to take into account the societal cost of emissions that, while within the legal limits, do create costs that society as a whole must bear. This is normally done on the basis of the level of emissions, such as carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NOx), that are expected to be emitted by the relevant plant type. Some studies levy a cost in terms of US$ per tonne for the emissions to represent the societal cost for these emissions, and for the present study, an offset allowance, representing a cost to society, of US$10 per tonne of GHG emissions will be levied against thermal options.

ES.4 GENERATION RESOURCES AND TECHNOLOGIES

The study identified and conducted a high-level analysis of most energy resources, either available in Lagos State or imported from other states and countries, to determine which could be used in large-scale power plants in Lagos State. At present, the applicable resources include pipeline natural gas (NG), liquefied natural gas (LNG), compressed natural gas (CNG), light fuel oil, heavy fuel oil (HFO), petcoke, coal (in this study, it is used for analysis of coal power generation cost only), uranium, solar, municipal solid waste (MSW), and agricultural crop residues. However, it is assumed that the CNG price would be much higher than the regulated NG price and not economical for fuel grid connected power plants. The estimated fuel prices in US$/MMBTU are presented in Table ES-2.

Table ES-2: Fuel Price Estimate

Fuel Name	Natural Gas	LNG	LFO	HFO	Petcoke	Coal	MSW	Biomass	Uranium
Unit	MMBTU	MMBTU	BBL	BBL	Tonne	Tonne	Tonne	Tonne	MMBTU
Currency	US$								
Commodity Price (1)	2.50	3.00	50.00	50.00	50.00	30.00	5.00	15.00	1.50
Transportation	0.80	1.00				10.00	5.00	10.00	
Refining/Regasification		1.00	20.00	20.00					
Handling/Sorting						10.00	10.00		
Multiplier	1.00	1.00	1.30	0.50	1.00	1.00	1.00	1.00	1.00
Total Cost	3.30	5.00	91.00	35.00	50.00	50.00	20.00	25.00	1.50
High Heating Value	1.00	1.00	6.37	6.17	29.60	21.82	9.48	7.93	1.00
Unit Energy Price	3.30	5.00	14.30	5.67	1.69	2.29	2.11	3.15	1.50

Note: (1) The price for LFO and HFO is the crude oil price
The price for uranium is the delivered price

By using Google Earth maps, the study team identified 14 potential power plant sites which could use all fuels available to Lagos State. These sites are marked in the map presented in Figure ES-2 and summarized in Table ES-3. Each site location is defined by a pair of coordinates, i.e., latitude and longitude. The coordinates for each site indicated in the table are for the site proximity as its exact location might not have been measured during the study team's site visit due to its inaccessibility.

Based on the information available, the top three power plant sites selected for CCGT configurations are Sites 12 (Lekki Energy Center), 9 (Egbin II), and 6, and the top two power plant sites selected for GT configurations are Sites 5 and 2. It is important to note that Sites 12 and 9 might have already been studied extensively by two power plant developers (or independent power producers). The IRP has estimated the requirements to connect a power plant to the grid at a conceptual level, in terms of voltage, capacity, and cost. The detailed studies for each interconnection, such as a feasibility study and environmental impact assessment, must be carried out if the power plant is to be constructed.

Figure ES-2: Power Plant Sites

Table ES-3: Summary of the Identified Power Plant Sites

Site No.	Location Name	Local Administrative Region	Coordinates (Geographical Coordinate System)		Fuel	Technology	Maximum Capacity (MW)
1	Ahanve	Badagry West LCDA	6°26'13.59"N	2°46'25.25"E	NG	GT/CCGT	2,000
2	Oko Agbon Nla	Olorunda LCDA	6°26'42.76"N	3° 4'13.61"E	NG or Biomass	GT/CCGT/Steam	2,000
3	Navy Town	Oriade LCDA	6°26'13.29"N	3°17'41.34"E	LNG or Nuclear	GT/CCGT/Steam	2,000
4	Snake Island	Amuwo Odofin LGA	6°24'38.29"N	3°18'32.95"E	LNG or Nuclear	GT/CCGT/Steam	2,000
5	Ogudu Ori- Oke	Kosofe LGA	6°34'13.32"N	3°24'19.71"E	NG or MSW	GT/CCGT/Steam	2,000
6	Odo Ogun	Agboyi Ketu LCDA	6°35'48.04"N	3°27'18.45"E	NG or Biomass	GT/CCGT/Steam	2,000
7	Lagos Lagoon	Eti-Osa LGA	6°27'28.41"N	3°29'12.97"E	NG	GT/CCGT	2,000
8	Ijede	Ijede LCDA	6°33'46.64"N	3°37'11.53"E	NG	GT/CCGT	2,000
9	Ijede	Ijede LCDA	6°33'47.58"N	3°37'6.56"E	NG	GT/CCGT	2,000
10	Imota	Imota LCDA	6°40'10.58"N	3°39'27.19"E	NG or Biomass	GT/CCGT/Steam	2,000
11	Dangote Refinery	Ibeju Lekki LGA	6°28'15.70"N	4° 0'42.65"E	NG or HFO	GT/CCGT/RICE	1,000
12	Lekki Free Zone	Ibeju Lekki LGA	6°27'5.21"N	3°57'36.25"E	NG or LNG	GT/CCGT	2,000
13	Lekki Free Zone	Ibeju Lekki LGA	6°29'6.08"N	3°59'8.41"E	NG or Petcoke	GT/CCGT/Steam	1,000
14	Alaro City	Epe LGA	6°33'38.32"N	4° 0'1.02"E	NG	GT/CCGT	2,000

Table ES-4 shows the unit cost of energy in US$/MWh of the generation expansion candidates, which is calculated based on the assumed technical and economic parameters, excluding GHG offset allowance.

Table ES-4: Unit Cost of Energy (US$/MWh) of the Generation Expansion Candidates

Capacity Factor	CC-L-250	CC-G-250	Import	GT-G-200	PetCoke	Coal	CC-O-250	GT-O-200	RICE	SMR	SolarPV	MSW	Biomass
0.05	425.8	417.4	425.4	367.9	834.7	765.2	497.1	484.7	469.3	2,132.0	313.1	1,531.5	1,120.3
0.10	234.3	225.9	233.8	208.2	431.9	399.0	303.1	321.2	268.1	1,077.7	156.7	788.2	589.4
0.15	170.5	162.0	170.0	154.9	297.6	276.9	238.4	266.7	201.1	726.2	104.5	540.4	412.4
0.20	138.5	130.1	138.1	128.3	230.5	215.9	206.0	239.4	167.5	550.5	78.4	416.6	323.9
0.25	119.4	111.0	118.9	112.3	190.2	179.3	186.6	223.1	147.4	445.1	62.8	342.2	270.9
0.30	106.6	98.2	106.2	101.6	163.3	154.8	173.7	212.2	134.0	374.8	52.4	292.7	235.5
0.35	97.5	89.1	97.0	94.0	144.1	137.4	164.4	204.4	124.4	324.6	44.9	257.3	210.2
0.40	90.7	82.2	90.2	88.3	129.7	124.3	157.5	198.6	117.2	286.9	39.3	230.7	191.2
0.45	85.3	76.9	84.9	83.9	118.6	114.2	152.1	194.0	111.7	257.7	35.0	210.1	176.5
0.50	81.1	72.6	80.6	80.3	109.6	106.0	147.8	190.4	107.2	234.2	31.5	193.6	164.7
0.55	77.6	69.2	77.1	77.4	102.3	99.4	144.3	187.4	103.5	215.1	28.6	180.1	155.0
0.60	74.7	66.3	74.2	75.0	96.2	93.8	141.3	184.9	100.5	199.1	26.3	168.8	147.0
0.65	72.2	63.8	71.8	73.0	91.0	89.1	138.8	182.8	97.9	185.6	24.3	159.3	140.2
0.70	70.1	61.7	69.7	71.2	86.6	85.1	136.7	181.0	95.7	174.0	22.6	151.1	134.3
0.75	68.3	59.9	67.8	69.7	82.7	81.6	134.9	179.5	93.8	163.9	21.1	144.0	129.3
0.80	66.7	58.3	66.3	68.3	79.4	78.5	133.2	178.1	92.1	155.2	19.8	137.8	124.9
0.85	65.3	56.9	64.8	67.2	76.4	75.9	131.8	176.9	90.6	147.4	18.6	132.4	120.9
0.90	64.1	55.6	63.6	66.1	73.8	73.5	130.6	175.8	89.3	140.5	17.6	127.5	117.5
0.95	62.9	54.5	62.5	65.2	71.4	71.3	129.4	174.9	88.1	134.3	16.7	123.2	114.4

The following provides a summary on each of the generation expansion candidates:

Candidate	Type of Generation	Cost of Energy
CC-L-250	LNG CCGT – 250 MW generation	At an annual capacity factor of 85%, its unit cost of energy would be some US$65.3 per MWh.
CC-G-250	NG CCGT – 250 MW generation	At an annual capacity factor of 85%, its unit cost of energy would be some US$56.9 per MWh.
Import	Importing generation from other states	The unit cost of energy would be some US$64.8 per MWh when its annual capacity factor is 85%, which is slightly lower than the cost of CC-L-250.
GT-G-200	NG GT – 200 MW generation	When operated as a peaking load plant with an annual capacity factor of 20%, its unit cost of energy would be some US$128.3 per MWh.
PetCoke	Petcoke generation	With an annual capacity factor of 80%, its unit cost of energy would be approximately US$79.4 per MWh, which is even higher than that of GT-G-200.
Coal	Coal generation	At an annual capacity factor of 80%, its unit cost of energy would be about US$78.5 per MWh, at the similar level of petcoke generation.
CC-O-250	LFO CCGT – 250 MW generation	Unit cost of energy would be approximately US$133.2 per MWh when it has an annual capacity factor of 85%.
GT-O-200	LFO GT – 200 MW generation	As a peaking load plant with a capacity factor of 20%, its unit cost of energy would be approximately US$239.4 per MWh.
RICE	HFO generation	When operated as a base load plant at an annual capacity factor of 80%, its unit cost of energy would be about US$92.1 per MWh.
SMR	Nuclear Small Module Reactors generation	Its unit cost of energy would be US$140.5 per MWh even if operated at an annual capacity factor of 90%.
Solar PV	Solar PV generation	At an annual capacity factor of 20%, its cost could be approximately US$78.4 per MWh.
MSW	MSW generation	At an annual capacity factor of 85%, its unit cost of energy would be some US$132.4 per MWh.
Biomass	Biomass generation	At an annual capacity factor of 85%, its unit cost of energy would be some US$120.9 per MWh.

ES.5 FORMULATION AND EVALUATION OF GENERATION DEVELOPMENT SCENARIOS

Based on discussions on generation resources and technologies, commissioning any of the major generation projects prior to 2026 would be very difficult. Thus, from 2020 to 2025, the load would be supplied by Egbin power plant and power plants located in other states (except for the solar PV plants to be commissioned prior to 2026, as noted in the relevant scenarios). New power plants in the state could supply load starting from 1 January 2026. The study team accordingly formulated and evaluated 18 generation expansion scenarios for the most likely load forecast, which are presented in Table 5-3. The notes below are helpful to understand this table.

The scenarios are divided into the following three groups with different assumptions on the generation capacity required from 2020 to 2025 (the peak load in 2025 is the highest for the period from 2020 to 2025):

Scenarios under Group A – Generation capacity required from 2020 to 2025 will be carried forward to 2026 onwards:

1) Scenario 1 – Only NG-fired CCGT and GT power plants will be added to the system.
2) Scenario 2 – 3,000 MW of LNG-fueled CCGT power plants will be added to the system, and the balance of generation will be NG-fired CCGT and GT power plants.

Scenarios under Group B – All generation capacity required from 2020 to 2025 will be retired by the end of 2025 except for Egbin power plant, which is located within the state:

3) Scenario 3 – Only NG-fired CCGT and GT power plants will be added to the system.
4) Scenario 4 – In addition to NG-fired CCGT and GT power plants, one 400 MW RICE plant will also be added to the system.
5) Scenario 5 – 3,000 MW of LNG-fueled CCGT plants will be added to the system, and the balance of generation will be NG-fired CCGT and GT power plants.
6) Scenario 6 – In addition to NG-fired CCGT and GT power plants, one 900 MW petcoke power plant will also be added to the system.
7) Scenario 7 – In addition to NG-fired CCGT and GT power plants, one 1,200 MW coal power plant will also be added to the system.
8) Scenario 8 – 3,000 MW LNG CCGT and 900 MW petcoke power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.
9) Scenario 9 – 3,000 MW LNG CCGT and 1,200 MW coal power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.
10) Scenario 10 – 900 MW petcoke and 1,200 MW coal power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.
11) Scenario 11 – 3,000 MW LNG CCGT, 900 MW petcoke, and 1,200 MW coal power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.
12) Scenario 12 – 3,000 MW LNG CCGT, 1,200 MW coal, and 900 MW petcoke power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.
13) Scenario 13 – Only NG-fired CCGT and GT power plants and 500 MW new import will be added to the system.
14) Scenario 14 – Only NG-fired CCGT and GT power plants and 1,000 MW new import will be added to the system.
15) Scenario 15 – Only NG-fired CCGT and GT power plants and 1,500 MW new import will be added to the system.
16) Scenario 16 – Only NG-fired CCGT and GT power plants and 2,000 MW new import will be added to the system.

Scenarios under Group C – All generation capacity required from 2020 to 2025 will be retired by the end of 2025:

17) Scenario 17 – Only NG-fired CCGT and GT power plants will be added to the system.
18) Scenario 18 – 3,000 MW of LNG-fueled CCGT power plants will be added to the system, and the balance of generation will be NG-fired CCGT and GT power plants.

From these scenarios, a recommended IRP is detailed in ES.9 (Recommended Integrated Resource Plan).

ES.6 DETERMINATION OF THE LEAST-COST GENERATION DEVELOPMENT PLAN

Through the analysis of resources available to Lagos State for power generation, it is recognized that the most important issues are fuel availability, fuel supply security, and fuel price.

Fuel Availability

The main fuels available to power production in the state are NG supplied through pipelines and LNG transported through waterways or other means and then regasified through either a Floating Storage Regasification Unit (FSRU) or an on-land regasification plant.

There was only one operational pipeline (ELPS I) in 2020, and its capacity is almost completely utilized. Construction of ELPS II has been recently completed and it is operational now after ongoing an extended construction period. In addition, Dangote Industries Limited (Dangote) proposes to build the EWOGGS with two 36-inch, 550km pipelines.

LNG could be supplied by the Nigeria LNG plant located in Bonny Island of River State and/or imported from the international market. Depending on the economics and required term, either one FSRU could be leased for regasification of LNG or one on-land regasification plant could be constructed.

Solar PV power could be used to achieve the renewable energy target. However, solar PV power may not contribute any capacity credit to the Lagos system due to its intermittence, or very low to no availability during the high load demand period of weekdays, i.e. from 19:00 to 22:00. In addition, the cost of land could be prohibitive for grid-scale solar development in Lagos.

Other renewable resources, such as municipal solid waste and agricultural crop residues, could support achieving the renewable energy target and resource diversification while providing firm generation capacity but in a limited capacity due to its limited quantity.

Resources such as petcoke, HFO, coal, and uranium could be used to diversify the generation portfolio. However, these fuels should not be the primary generation fuels due to environmental, safety, and security concerns. It is also important to note that coal must be transported to the power plant in Lagos State from other states by railway from more than one thousand kilometers away, which might not make it a commercially viable option for power generation.

Fuel Supply Security

With the exception of NG pipelines, other fuels offer very high levels of supply security or reasonable storage options to ensure fuel availability in case of supply interruption. Fuel security is particularly important as the NG pipelines in Nigeria have encountered interruptions in the past due to various reasons, including vandalism, attacks, and necessary maintenance.

When there is only one NG pipeline, NG-fired power plants must be shut down if the gas supply is interrupted as large volumes of gas cannot be readily stored. The availability of pipelines and expansion plans should be assessed according to the number of pipelines available and their operating conditions.

For this IRP, it is recommended that all gas turbines (GTs) used in either combined cycle gas turbines (CCGT) or GT configurations should be designed for dual-fuel use without detailed analysis of the availability and security of pipeline NG; i.e., they could use either NG or light fuel oil (LFO) in order to overcome pipeline interruptions. In this case, each power plant could have a certain amount of storage of LFO to fuel the GTs. The actual storage capacity for each power plant needs to be assessed. It is strongly recommended that the availability and security of the pipeline NG be studied. The GTs could be designed as single-fuel facilities if the fuel supply can be maintained at an acceptable level.

It may also be possible that LNG is used to fuel CCGTs and GTs before the supply security of pipelines has reached the acceptable level and the fuel can be switched to pipeline NG.

Fuel Price

Based on the fuel price estimate presented in Table ES-2, it is very clear that NG-fired CCGT and GT power plants are much more cost-competitive than other fueled generation technologies, and the scenarios with them have a lower cost. In this case, the NG price is regulated at US$3.3/MMBTU, which is much lower than that supplied to other industries.

Compared with the price of NG supplied through a pipeline, the LNG price could be much higher as it includes two additional processes, liquefaction and regasification, for delivery and use. A favorable LNG price could be negotiated with Nigeria LNG Limited (NLNG), with the support of the federal and state governments.

Based on the analysis carried out, Scenario 3 (addition of NG-fired CCGT and GT power plants and solar PV power plants) is recommended as the least-cost generation development plan for the IRP and subsequent transmission analysis, which includes the following important assumptions:

1) Scenario 3 is prepared in accordance with the most likely load forecast.
2) Group B assumes that all generation capacity supplying load in 2025 will be retired in 2026 except for Egbin power plant, which is located in Lagos State. The plant was fully commissioned in September 1986 and is almost 35 years old. It is assumed that after retirement of the existing six units, the same amount of new generation capacity will be built, and the cost estimate covers all costs associated with bringing new generation online.
3) Only dual fuel (NG and LFO)-fired CCGT and GT power plants will be constructed to meet the load demand except for the solar PV power plants used to meet the 15% renewable energy target.

As presented in Table 5-7, the following table has a summary of the present and current value for costs over the planning period:

Cost Category	Present Value	Current Value
	US$ Million	US$ Million
Capital Repayment	3,516	13,458
Other Fixed Costs	3,300	7,521
Fuel	5,379	14,385
Other Variable Cost	1,925	4,567
GHG Offset Allowance	827	2,166
Total Generation Cost	**14,948**	**42,096**

The capacity balance table and capital expenditure cash flow of the least-cost generation development plan are presented in Table 5-8 and Table 5-9.

One may observe or calculate the following capacity additions from Table 5-8:

Capacity Additions			
Generation Technology	Number of Plants	MW of Capacity Added	Site #
CCGT	20 x 250 MW	2,000	12
		2,000	9
		1,000	6
GT	13 x 200 MW	1,600	5

		1,000	2
Solar PV	34 x 100 MW	3,400	Assumed that at least 50% of capacity would be through rooftop installations with the rest through large solar PV power plants.

The following capital investments may be seen from Table 5-9:

Capital Costs of Facilities	
Cost Category	**US$ Million**
Overnight Cost of a 250 MW CCGT Unit	275
Overnight Cost of a 200 MW GT Unit	200
Overnight Cost of a 100 MW Solar PV Unit	90
Total Capital Investment	
Time Period	**US$ Million**
2020 to 2025	3,690
2026 to 2030	3,195
2031 to 2035	2,605
2036 to 2040	1,671
Entire Study Period	**11,160**

ES.7 TRANSMISSION DEVELOPMENT PLAN

The transmission development plan is prepared for evacuating power from the power plants presented in the least-cost generation development plan and delivering it to the main load centers (transformation stations). The timing for the addition of a new facility or the upgrading of an existing facility is determined based on the allowable operation range of bus voltage defined in the Grid Code and the thermal loading limit of each equipment. The detailed additions and reinforcements of transformation stations and transmission lines are listed in Table 6-3, Table 6-4, Table 6-5, Table 6-6, Table 6-7, Table 6-8, Table 6-9, and Table 6-10.

The annual cost for operation of the transmission system is presented in Table 6-12 and includes three categories: the O&M cost for the existing system, amortized capital repayment, and O&M cost for operation of new facilities. The following total costs over the planning horizon may be seen from this table:

Cost Category	**Present Value**	**Current Value**
	US$ Million	**US$ Million**
O&M of Existing System	980	2,268
Capital Repayment	343	1,099
O&M of New Facilities	294	941
Total Transmission Cost	**1,616**[2]	**4,308**
The levelized cost energy of the transmission system would be US$9.93 per MWh		

[2] The difference in total is due to rounding.

Table 6-13 presents the capital expenditure cash flow for new transmission facilities installed over the planning horizon. The total investment over the planning horizon would be US$734 million, which can be broken into:

Time Period	Capital Investment (US$ Million)
2019 – 2025	400
2026 – 2030	113
2031 – 2035	127
2036 – 2040	94

For the facilities required in a year, it is assumed that they should be commissioned at the beginning of the year and their capital cost should be disbursed within two years before their commissioning.

ES.8 DISTRIBUTION DEVELOPMENT PLAN

The distribution development plan was prepared for two periods, one from 2021 to 2025 and the other from 2026 to 2040. During the first period, the requirements of distribution facilities – including 33 kV feeders, 33/11 kV substations, and associated 11 kV feeders – are analyzed by each 33 kV feeder, and the results are listed in Subsection 7.4.1 and Subsection 7.4.2.

For the second period, the requirement of 33 kV feeders (including the associated 33/11 kV substation and 11 kV feeders) is estimated based on the assumption that one new feeder would be required for every 10 MW of incremental system peak load demand. The study results are listed in Subsection 7.4.3.

Table 7-2 shows the annual cost by category, including three components, the O&M cost for the existing system, amortized capital repayment, and O&M cost for operation of new facilities. The following total costs over the planning horizon may be seen from this table:

Cost Category	Present Value	Current Value
	US$ Million	US$ Million
O&M of Existing System	2,766	6,402
Capital Repayment	1,125	3,812
O&M of New Facilities	963	3,264
Total Distribution Cost	**4,853**[3]	**13,478**
The levelized cost energy of the distribution system would be US$29.82 per MWh		

[3] The difference in total is due to rounding.

Table 7-3 presents the capital expenditure cash flow for new distribution facilities installed over the planning horizon. The total investment over the planning horizon would be US$3,181 million[4], which can be broken into:

Time Period	Capital Investment (US$ Million)
2019 – 2025	980
2026 – 2030	751
2031 – 2035	842
2036 – 2040	609

For the facilities required in a year, it is assumed that they should be commissioned at the beginning of the year and their capital cost should be disbursed within two years before their commissioning.

ES.9 RECOMMENDED INTEGRATED RESOURCE PLAN

The IRP is the combination of development plans for generation, transmission, and distribution. It is expected that the forecast load demand in terms of peak and energy would be supplied at the pre-defined reliability level with implementation of the IRP – namely, construction of the facilities identified and proposed. It is important to note that in order to supply the load reliably, the system needs to not only install the proposed new facilities and upgrade the existing facilities, but all facilities must also be operated and maintained in accordance with the best practices of reputable international utilities.

Regarding the operation cost of the entire electricity sector of the State, one may observe the following from Table 8-1:

Operational Cost in Individual Years		
Cost Category	**In 2030 (Current Value) (US$ Million)**	**In 2040 (Current Value) (US$ Million)**
Capital Repayment	951	1,807
Other Fixed Costs	921	1,209
Fuel	636	959
Other Variable Cost	185	254
GHG Offset Allowance	95	140
Annual System Cost	**2,788**	**4,369**
Broken Down by Power Sector		
Generation	1,946	3,107
Transmission	216	267
Distribution	626	994
System Operation Cost Over the Entire Planning Horizon		
Sector	**Present Value (US$ Million)**	**Current Value (US$ Million)**
Generation	14,948	42,096
Transmission	1,616	4,308

[4] The difference in total is due to rounding.

Distribution	4,853	13,478
Total System Cost	**21,417**	**59,882**
Other Key Insights		
When calculated based on the energy measured at generation bus, the levelized cost of energy would be US$125.03 per MWh, or US$0.12503 per kWh, which includes US$87.26, 9.44, and 28.33 per MWh for generation, transmission, and distribution, respectively.		
When calculated based on the energy measured at DISCOs' receiving bus, the levelized cost of energy would be US$131.61 per MWh, or US$0.13161 per kWh, which includes US$91.86, 9.93, and 29.82 per MWh for generation, transmission, and distribution, respectively. This should be understandable as 5% of transmission loss has been assumed in this study, which means that the energy received by DISCOs is 95% of energy measured at generation bus.		

Regarding the capital disbursement flow, one may see the following from Table 8-2:

1) Over the planning horizon, the system would need a total investment of US$15,075 million, which can be broken down in the following categories:

Facilities for Investment	Capital Investment (US$ Million)	Percent of Total Investment (%)
Generation	11,160	74.0
Transmission	734	4.9
Distribution	3,181	21.1

The funds would be used to build, construct, install, upgrade, and reinforce power plants, transformation stations, transmission lines, distribution feeders, distribution substations, distribution transformers, and customer energy meters.

2) The investment requirement for the four periods are described below.

Time Period	Capital Investment (US$ Million)
2019 – 2025	5,070
2026 – 2030	4,085
2031 – 2035	3,569
2036 – 2040	2,352

The first period would need a very large amount of investment, which is for construction of new power plants and addressing the challenges faced at present. It is also important to note that the capital disbursement presented in this table does not include that for the facilities to be commissioned from 2041 and onwards, whose construction may need to start prior to 2041.

3) Over the planning horizon, two years, 2024 and 2025, need an investment of US$1,820 million and US$1,631 million, respectively, which is much more than that in other years.

ES.10 FINDINGS AND SUGGESTIONS

The following summarizes our findings, suggestions, and recommendations on the load forecasting and generation planning work carried out.

1) **Preparation of an IRP –** In Nigeria, power sector master plans (also referred to as IRPs or other designations), generation plans, and transmission plans have normally been prepared at the national level. This IRP is the first one to be prepared by the Lagos State government for that state only. It is important to note that the IRP is prepared in accordance with technical aspects without inclusion of individual institutional responsibilities or mandates, which should be included in preparation of the IRP implementation plan. The IRP is therefore valid whether the Lagos State grid is considered a part of the national grid or as an independent system.

2) **Study Team –** For this undertaking, PA-NPSP, in collaboration with the Lagos State Government, has led and conducted the load forecast report with support from EKEDC, IE, and Rural Electrification Agency counterparts; the generation planning report with support from Egbin Power, Dangote, and Niger Delta Power Holding Company (NDPHC); and the transmission and distribution development plans with support from TCN, EKEDC, and IE. If Lagos State intends to carry out the IRP work on a regular basis, the state's Ministry of Energy and Mineral Resources should establish a small group of project managers, economists, analysts, and engineers who could manage, provide technical directions to, and/or perform the detailed analysis for, future IRP developments, either as an update or a completely new preparation.

3) **Load Forecast and Power System Planning Manuals –** The Nigeria Distribution Code requires each DISCO to prepare a 5-year load forecast for its service territory on an annual basis. The Grid Code requires the System Operator to create a new long-term (20 years) demand forecast for the Transmission Network at least once every three years. The Market Rules require the Market Operator to prepare a 10-year Generation Adequacy Report in November of each year. PA-NPSP has not been able to collect the load forecast and generation, transmission, and distribution planning manuals used by the DISCOs, System Operator, and/or Market Operator. It is suggested that the State Government prepare the four manuals if the development of the IRP will be routine in the future.

4) **Data Confidentiality –** PA-NPSA signed Non-Disclosure Agreements (NDAs) with several entities in order to collect the information required for preparation of the IRP. The preparation of the IRP has included a few key stakeholders and the IRP report could be a public document, providing the requirements/directions of the state power system development to all stakeholders, including consumers. In this case, the IRP report shall not include any confidential information but will only use general or normalized information.

5) **Data Availability –** During collection of system load consumption data and the information on energy resources available to large-scale power generation, it was found that the collection of some data (for example, the 33 kV feeders' hourly load) could take extra effort. It would be better if that data could be readily collected, for example, through the SCADA systems installed at each transformation station or the smart power meter measuring the power/energy flow to each 33 kV feeder. The two DISCOs at present receive power from a total of 24 TCN transformation stations and each transformation station has two to several 33 kV feeders connected to the DISCOs' 33/11 kV substations and/or HV connected customers. In addition to pipeline NG, the State Government may assess other resources available to power generation, including both quantity and cost, such as LNG, petroleum products, coal, uranium, hydro, solar, MSW, agricultural crop residues, other biomass, hydro, and wind. The State Government may also identify and evaluate DSM programs and implement those cost-competitive ones.

6) **Estimate of Population and Its Growth –** The last national Census was conducted in 2006, and the State Government has maintained that the population of the State in 2006 was much higher than that indicated in the census. As population and its expected growth in the future are very important factors in infrastructure planning and development, it is strongly suggested that Lagos State conduct a new state-wide census or work together with the federal government to conduct a national census. Accurate population data is important to both the state and federal governments for land use/zoning and the development of infrastructure, such as housing, roads/highways, electricity systems, water supply and waste disposal facilities, hospitals, schools, community centers, and shopping malls.

7) **Captive Generation Capacity –** Per NERC's Regulation NERC-R-0108, any entity that wishes to install a generator with a capacity exceeding 1 MW for its own use and not sold to a third party shall obtain a permit prior to its operation. The NERC website posts a list of captive power permit holders updated in 2013. The Lagos State Electricity Policy and Lagos Electric Power Sector Law 2018 also require the captive power permit holders to register with the State. For the future load forecasts, it is strongly suggested that the study team shall collect an updated list of captive power permit holders from the NERC and the State Registrar and then contact each permit holder to investigate (i) if the power plant has been built or when it could be set up, (ii) the generation capacity, (iii) fuel used, (iv) generation technology or make and model of the gen-set, (v) annual electricity production, and other parameters, which are very important in the analysis of switching from self-generation to a more energy-efficient and less polluting grid supply when the grid is reliable and tariffs are competitive.

8) **Accuracy Level of Technical and Economic Parameters and Assumptions –** Work on the IRP involves various parameters and assumptions, which are beyond the control and management of any persons, companies, and governments. Moreover, the operation and development of a power system are subject to various laws, regulations, policies, standards, human actions, funds availability, and other factors. It is therefore very difficult for the operational results of a power system to match their predicted values.

9) **Renewable Energy Target –** The least-cost generation development plan is prepared based on a presumed 15% renewable energy target from 2030 onwards, which results in solar PV power capacity would be approximately 50% of annual peak load demand. The study team discussed this penetration level in this report. However, it is strongly suggested that the State Government should discuss this with the Federal Government and ensure it meets the requirements established in Electricity Vision 30:30:30.

10) **Recommended Plan –** The recommended least-cost generation development plan includes only natural gas-fueled CCGT and GT power plants and solar PV power plants, in addition to the existing Egbin thermal power plant. In order to diversify supply mix, when cost-effective, environmentally friendly, socially responsible, and sustainable, any other resource-based power generation could be constructed, such as those using LNG, coal, petcoke, HFO, LFO, MSW, biomass, uranium, water, and wind.

11) **Waste to Energy Plants –** The development of Waste to Energy (WTE) plants would result in electricity production and other environmental and social benefits. It is therefore suggested that the State Government carry out an extensive WTE study to examine the costs and benefits. The cost of a WTE plant can be offset by the electricity produced and other environmental and social impacts reduced or avoided.

12) **Penetration of Renewable Energy –** When the renewable target (15% of energy) is met, the ratio of the installed solar PV power capacity to annual system peak would be approximately 50%, which is a very high-level penetration of renewable. The industrial practice suggests conducting a

comprehensive study to examine the impact of intermittent generation on system operation when its penetration level reaches 20% or above.

13) **GHG Emissions –** Due to lack of other energy resources in terms of quantity and cost, the least-cost generation development plan is prepared using NG-fueled CCGT and GT power plants and solar PV power plants. Although GHG emissions from NG-fired CCGTs is less than that from petcoke, coal, HFO and LFO-fueled generation, it is suggested that the State Government discuss with the Federal Government and ensure if the annual total GHG emissions are within the national annual limit if such limit is available.

14) **Fuel Supply Considerations –** One of the most important factors in power generation is fuel supply. Any large-scale new power generation projects in Lagos State would require NG transported through the recently commissioned ELPS II pipeline and/or the proposed EWOGGS or LNG (transported to Lagos State through waterways and then regasified locally). It is very important to consult with NGC on the available capacity of the ELPS II. Due to travel restrictions caused by COVID-19 conditions, the study team could not collect the required information although a few discussions were made with NGC and a list of the requested data was sent to them.

15) **Need for Visual Screening of Potential Sites–** Initial screening analysis of potential power plant sites and transmission line routes should be conducted based on the main technical, environmental, and social impact parameters. Due to travel restrictions resulting from COVID-19, the study team was not able to visit the potential sites and line routes to perform basic visual screening and instead relied on Google Earth to identify sites remotely. It is recommended that visual screening be conducted when possible and then updated in this analysis after completion.

16) **Preparation of an Implementation Plan for the IRP –** In order to prepare an implementation plan for the IRP, the state should conduct at least the following tasks:

    i) Consult with key stakeholders on the IRP and update it if necessary.

    ii) Approve the IRP for implementation.

    iii) Consult the Federal Ministry of Power, NERC, TCN, NBET, Gas Aggregation Company of Nigeria, NGC, IE, EKEDC, Dangote, IPPs, other generation companies and other key stakeholders to ensure that each stakeholder understands their responsibilities, address gaps, and establish the approach for the IRP implementation.

    iv) Address issues related to regulation, license, policy, and institutional framework.

    v) Establish the approach for coordination of domestic power plants and those located outside of Lagos State.

    vi) Establish the approaches for preparation of fuel supply agreements, generation interconnection agreements, competitive procurement processes, power purchase agreements, and other agreements/contracts.

17) **Next Update –** This IRP has been prepared with many assumptions that change continuously. It is therefore suggested that the IRP be updated if any combination of the main assumptions used changes significantly. For reference, it is typically understood that IRP reports need to be updated approximately every three to five years. As this is the first IRP for Lagos State and the continued implementation and development of the Lagos State electricity grid will bring many changes, it is recommended that in this case the next update should be started in approximately three years.

1 INTRODUCTION

1.1 BACKGROUND

The Power Africa Nigeria Power Sector Program (PA-NPSP) is the U.S. Agency for International Development's (USAID) signature Power Africa program in Nigeria. PA-NPSP contributes to comprehensive reform within Nigeria's power sector, addressing power generation and transmission challenges, competitive procurement of clean and conventional energy, regulatory and policy reforms to foster greater sector transparency and private investment, utility distribution sector reform, and off-grid electricity access. In line with Power Africa's broader goals, PA-NPSP's goal is to enable 10,000 MW of new/rehabilitated or unlocked electricity generation capacity and three million electricity connections, supporting reliable and affordable electricity access to millions of people for the first time.

PA-NPSP will increase electricity availability, access, and reliability throughout Nigeria, while measuring objective progress across four program outcomes:

- **Outcome 1 (OC1):** Increase Private Sector Investment in Power Generation, and Transmission
- **Outcome 2 (OC2):** Facilitate New Off-grid Connections to Cleaner Power Supply
- **Outcome 3 (OC3):** Improve the Enabling Environment for Private Sector Participation in the Power Sector
- **Outcome 4 (OC4):** Promote Improved Liquidity throughout the Energy Sector

PA-NPSP will achieve these outcomes by strategically aligning energy sector reform, increased generation, and electrification goals with new investment opportunities. This will include working to bring transactions to financial close, coordinating with local resources, and building human and institutional capacity at key Federal Government of Nigeria (FGN) entities. Critical to success will be the use of a results-oriented framework for decision-making that allows PA-NPSP to identify, prioritize, and select intervention activities and programming to increase and accelerate private sector investment and move transactions forward.

PA-NPSP and the Lagos State Government (LASG) have a common goal to increase electricity accessibility and reliability in Lagos State by promoting improved communication and decision-making in electricity supply, policy, and regulatory environment (enhanced sector planning, cost effective power supply, cost-reflective tariffs, and regulatory stability). In response to the request from the LASG, PA-NPSP decided to lead the development of an Integrated Resource Plan (IRP) for Lagos State, which will be based on high-level assumptions and estimates to complement available data.

The primary objective of the IRP is to provide guidance on the Lagos State power system development requirements on an annual basis to various stakeholders.

This IRP report includes the predicted load demand growth over the next 20 years, least-cost generation development plan, transmission development plan in accordance with the least-cost generation development plan, and distribution development plan.

1.2 INTEGRATED RESOURCE PLAN

Integrated resource planning is a process of planning to meet consumers' needs for electricity services in a way that satisfies multiple objectives for resource use, which, in general, includes the following:

1) To conform to federal, state, and local government laws, regulations, policies, guidelines, strategies, and development objectives
2) To ensure all households and businesses have access to electricity services at the pre-established reliability level

3) To minimize the economic cost of delivering electricity services
4) To minimize the environmental impacts of electricity supply and use
5) To diversify generation resources and portfolios, minimize the use of external resources, and increase penetration of renewable energy
6) To promote demand side management (DSM) programs, including energy efficiency, energy conservation, demand response, and distributed energy generation
7) To recognize climate change impacts and build potential mitigation measures into the planning process
8) To provide local economic benefits
9) To minimize foreign exchange rate risks

It is expected that the IRP will be subject to the following directives:

1) Federal/State Governance
2) Electricity Act
3) Electric Power Policy
4) Electric Power Sector Reform Act
5) Electricity Regulation Act
6) Electricity Market Rules
7) Grid Code
8) Distribution Code
9) Federal/State Government Energy Development Strategies/Policies
10) Environmental Protection Guidelines (including those on green-house-gas emissions)
11) Social Impact Guidelines

The essential objective of the IRP is to provide indications on the Lagos State power system development requirements on an annual basis to various stakeholders, including federal and state government agencies, regulators, generators, transmitters, distributors, gas suppliers, investors, financial institutions, consumers, and others, based on a set of pre-established assumptions and criteria. These indications could include the following information:

1) The level of load demand in terms of peak power and energy for the State and main load centers (transformation stations), taking into account elimination of suppressed demand, minimization of load shedding, and provision of electricity access to all
2) Detailed generation addition and retirement schedules (location, fuel, technology, size, etc.)
3) Detailed transmission addition and reinforcement schedules (route, technology, voltage, conductor size, etc.)
4) Detailed distribution addition and upgrade schedules (route, technology, voltage, conductor size, etc.) (for the first five study years only)
5) Potential achievements of DSM programs to be implemented (in terms of annual peak and energy reduction)

6) Costs, including capital investment, fuel, O&M (operation and maintenance), and EUE (expected unsupplied energy) or UE (unsupplied energy) cost as well as GHG (green-house-gases) offset allowance
7) Energy production from each generation unit/plant
8) Fuel consumption/requirement by each generation unit/plant
9) EUE or UE and capacity shortfall
10) GHG emissions

1.3 OUTLINE OF THE REPORT

This report, the fourth output of the IRP work, is a draft IRP report that includes the following sections and appendices:

Section 1	Introduction
Section 2	Electricity Supply and Load Demand in Lagos State
Section 3	Integrated Resource Planning Approach and Key Assumptions
Section 4	Generation Resources and Technologies
Section 5	Formulation of Generation Expansion Scenarios
Section 6	Transmission Development Plan
Section 7	Distribution Development Plan
Section 8	Recommended Integrated Resource Plan
Section 9	Next Update of the Integrated Resource Plan
Section 10	Findings and Suggestions

Appendix A: Analysis of the Identified Power Plant Sites

Appendix B: Technical and Economic Parameters of Generation Technologies

Appendix C: Cost Summary and Capacity Balance Tables

Appendix D: Tables and Figures for Transmission Development Plan

Appendix E: Tables and Figures for Distribution Development Plan

Appendix F: List of Most Relevant Documents Governing Electricity Supply Industry

Appendix G: Example Table of Contents for a Long-Term Load Forecast Manual

Appendix H: Example Table of Contents for a Generation Planning Manual

Appendix I: Example Table of Contents for a Transmission Planning Manual

Appendix J: Example Table of Contents for a Distribution Planning Manual

2 ELECTRICITY SUPPLY AND LOAD DEMAND IN LAGOS STATE

2.1 LAGOS STATE

Lagos State is located in southwestern Nigeria, as shown in Figure 2-1. It is the smallest state among Nigeria's 36 states, in terms of area. The state is arguably the most economically important state of the country and a major financial center.

Figure 2-1: Nigeria

Lagos State has the highest population density among Nigeria's 36 states. The actual population is disputed between the estimate of 26.44 million in 2019 from the Lagos State Ministry of Economic Planning and Budget and the National Population Estimates from the National Population Commission and National Bureau of Statistics.

Lagos State borders Ogun State on the north and east. In the west, it shares boundaries with the Republic of Benin. Behind its southern borders lies the Atlantic Ocean. Approximately 22% of its area of 3,577 km^2 is made up of lagoons and creeks.

Ikeja is the state capital and administrative center of the Lagos State Government. Lagos State is divided into five administrative divisions: Ikeja, Badagry, Ikorodu, Lagos (Eko), and Epe. These are further divided into 57 Local Administrative Regions, which include 20 local government areas, or LGAs – namely Agege, Ajeromi-Ifelodun, Alimosho, Amuwo-Odofin, Apapa, Badagry, Epe, Eti-Osa, Ibeju/Lekki, Ifak o-Ijaye, Ikeja, Ikorodu, Kosofe, Lagos Island, Lagos Mainland, Mushin, Ojo, Oshodi-Isolo, Shomolu and Surulere – and 37 Local Council Development Areas, or LCDAs.

2.2 THE NIGERIAN ELECTRICITY SUPPLY INDUSTRY

In Nigeria, electricity supply is a concurrent responsibility of the Federal Government and State Governments. The Nigerian Electricity Supply Industry (NESI) has undergone fundamental changes over the past few years with the implementation of the Federal Government's reform program reputed to be one of the most ambitious privatization exercises in the global power industry.

The NESI includes the following key industry players or participants:[5]

1) **The Federal Government of Nigeria, Federal Ministry of Power [6] –** Its main responsibilities include initiating and formulating broad policies and programs on the development of the power sector.

2) **Lagos State Government –** In line with the Constitution of the Federal Republic of Nigeria 1999 (as amended), Lagos State's House of Assembly may make laws with respect to (i) electricity and the establishment in the State of electric power stations; (ii) the generation, transmission, and distribution of electricity within the state; and (iii) the establishment within the state of any authority for the promotion and management of electric power stations established by the state.

    a. *Lagos State Ministry of Energy and Mineral Resources* – This ministerial arm of the Lagos State Government is responsible for the formulation and evaluation of policies relating to energy towards ensuring the availability of reliable energy for all residents in Lagos State. Specifically, the responsibilities of the Ministry include (i) development of sustainable policies for both conventional and renewable power solution, (ii) creation of an enabling environment for private investment in the state energy sector, (iii) coordination and supervision of independent power projects of the State Government, and (iv) continued engagement with the Federal Government of Nigeria's Ministry of Power and its agencies to align power reform policies and implementation.

    b. *Lagos State Electricity Board* – This is the implementing agency under the Lagos State Ministry of Energy and Mineral Resources responsible for energy development, independent power projects, and public lighting in Lagos State. It was established by law of the State House of Assembly in July 1980 to perform several functions, including (i) maximization of power supply to public facilities through independent power projects and improvement of public lighting for the citizens of Lagos state, and (ii) generation, transmission, and distribution of electricity to areas not covered by the national grid system within Lagos State.

3) **The Nigerian Electricity Regulatory Commission (NERC)[3] –** NERC is an independent regulatory agency which was inaugurated on 31 October 2005 as provided in the Electric Power Sector Reform Act 2005. Its main responsibility is to regulate standards of performance for all electricity licensees and monitor their performance to ensure that these standards are met and maintained or even exceeded. It is expected that NERC will regulate the electricity sector based on free market economic principles and thereby create a level playing field for all interested stakeholders/private sector, such as the independent power producers (IPPs), to participate in the electric power sector.

4) **Energy Commission of Nigeria (ECN)[7] –** ECN is responsible for promoting sustainable energy development in Nigeria through the production of strategic plans and the coordination of national policies in all their ramifications and without prejudice to the generality of the foregoing.

5) **Electricity Generation Companies (GenCos) –** These can be divided into three groups: (i) successor generation companies, (ii) IPPs, and (iii) National Integrated Power Projects (NIPPs). IPPs can be further split into private-owned and public-owned (various levels of government).

[5] https://nerc.gov.ng/index.php/home/nesi
[6] https://www.power.gov.ng/function-of-the-ministry/
[7] https://www.energy.gov.ng/mission_vision.php

6) **Transmission Company of Nigeria (TCN) –** TCN is responsible for the construction, operation, and maintenance of the national transmission grid, including high-voltage transmission lines and transformation stations.

7) **Electricity Distribution Companies (DISCOs) –** There are in total 11 electricity DISCOs covering various areas in Nigeria, which construct, operate, and maintain distribution facilities up to the 33 kV level.

8) **Nigerian Bulk Electricity Trading Plc (NBET) –** NBET is the manager and administrator of the electricity pool ("The Pool") in the NESI. NBET also manages existing PPAs and new procurement of power in the transition.

9) **Nigeria Electricity Liability Management Company (NELMCO)** [8] **–** NELMCO is responsible for all of the Power Holding Company of Nigeria (PHCN) liabilities leading up to the 1 November 2013 handover of the companies, as well as the management of their non-core assets prior to disposition of same.

10) **Bureau of Public Enterprises (BPE)**[9] **–** BPE drives the Federal Government's program of privatizing public enterprises, carries out sector reforms, and liberalizes key economic sectors, especially the infrastructure sector.

11) **Gas Aggregation Company of Nigeria –** This organization is responsible for ensuring an adequate supply of gas to the strategic sectors of the domestic market for the purpose of enhancing NG usage to achieve the much-desired industrialization in Nigeria.

12) **Nigerian National Petroleum Corporation (NNPC)**[10] **–** NNPC is an integrated oil and gas company, engaged in adding value to the nation's hydrocarbon resources for the benefit of all Nigerians and other stakeholders.

13) **Nigeria Gas Company (NGC)**[11] **–** A subsidiary of the NNPC, NGC recently split into NGTC (Nigeria Gas Transportation Company) and NGMC (Nigeria Gas Marketing Company). It is charged with the responsibility of developing an efficient gas industry to fully serve Nigeria's energy and industrial feedstock needs through an integrated gas pipeline network and also to export NG to the West African Sub-region.

14) **Rural Electrification Agency (REA)**[12] **–** REA provides access to reliable electric power supply for rural and unserved communities.

15) **Nigerian Electricity Management Service Agency (NEMSA)** [13] **–** NEMSA's functions include enforcement of technical standards and regulations, technical inspection, testing and certification of all categories of electrical installations, electricity meters and instruments; ensuring the efficient production and delivery of a safe, reliable, and sustainable supply of electrical power; and guaranteeing the safety of lives and property in the NESI and other allied industries/workplaces.

16) **The National Power Training Institute of Nigeria (NAPTIN)** [14] **–** NAPTIN's mandate is to provide a skilled workforce and professionals for the power sector through training, research, and development in partnership with national and international public and private entities. In pursuit of this, it took over the management of seven regional training centers of the Power

[8] http://nelmco.gov.ng/about-nelmco/background/
[9] https://bpe.gov.ng/about/
[10] https://www.nnpcgroup.com/About-NNPC/Pages/Mission-and-Vision.aspx
[11] https://ngc.nnpcgroup.com/pages/about-us.aspx
[12] https://rea.gov.ng/theagency/
[13] https://nemsa.gov.ng/mandate/
[14] http://www.naptin.gov.ng/about-us

Holding Company of Nigeria, which was unbundled into separate generation and distribution companies and the TCN.

17) **FGN Power Company –** This is the Special Purpose Vehicle (SPV) responsible for implementing the Presidential Power Initiative, a comprehensive transmission and distribution program to modernize and expand the national grid.
18) **Advisory Power Team (Vice President's Office) –** This provides the political direction necessary to encourage decision-making in the power sector and facilitate developments across the sector.

2.3 THE ELECTRICITY SUPPLY IN LAGOS STATE

2.3.1 DISCOS

Two of the 11 DISCOs in Nigeria, Ikeja Electric (IE) and Eko Electricity Distribution Company (EKEDC), are located in Lagos State to supply the customers in the 20 LGAs in the state. The electricity received by the two DISCOs is produced by generation plants located around the country and then transmitted to the transformation stations, or substations, in the state through the national grid. Among the large power plants, only Egbin's thermal power plant is located in Lagos State. The DISCOs may have, or will be negotiating, PPAs with generators. There are also several gas-fired captive (off-grid) generators in Lagos State, supplying power to government buildings and/or for personal use.

2.3.2 GRID SYSTEM

As of 31 December 2020, the national grid system in Lagos State includes the following main components (either located in Lagos State or located in Ogun State and supplying 33 kV feeders connected to customers in Lagos State):

1) One 6x220 MW power plant (Egbin)
2) Thirteen 330 kV and more than thirty 132 kV transmission lines (one line may include one to four circuits)
3) Seven 330 kV substations, four of which also directly supply power to 33 kV feeders
4) Twenty-one 132 kV substations (transformation stations) directly supply power to 33 kV feeders
5) IE receives power from 16 substations, four of which also supply power to EKEDC.
6) EKEDC receives power from 12 substations.

2.4 LOAD DEMAND PATTERNS IN LAGOS STATE

2.4.1 PEAK DAY HOURLY LOAD CURVE

Figure 2-2 shows the normalized hourly load curve in percentage of a system peak day, in which the load in each hour has been divided by the maximum load demand in the day and multiplied by 100.

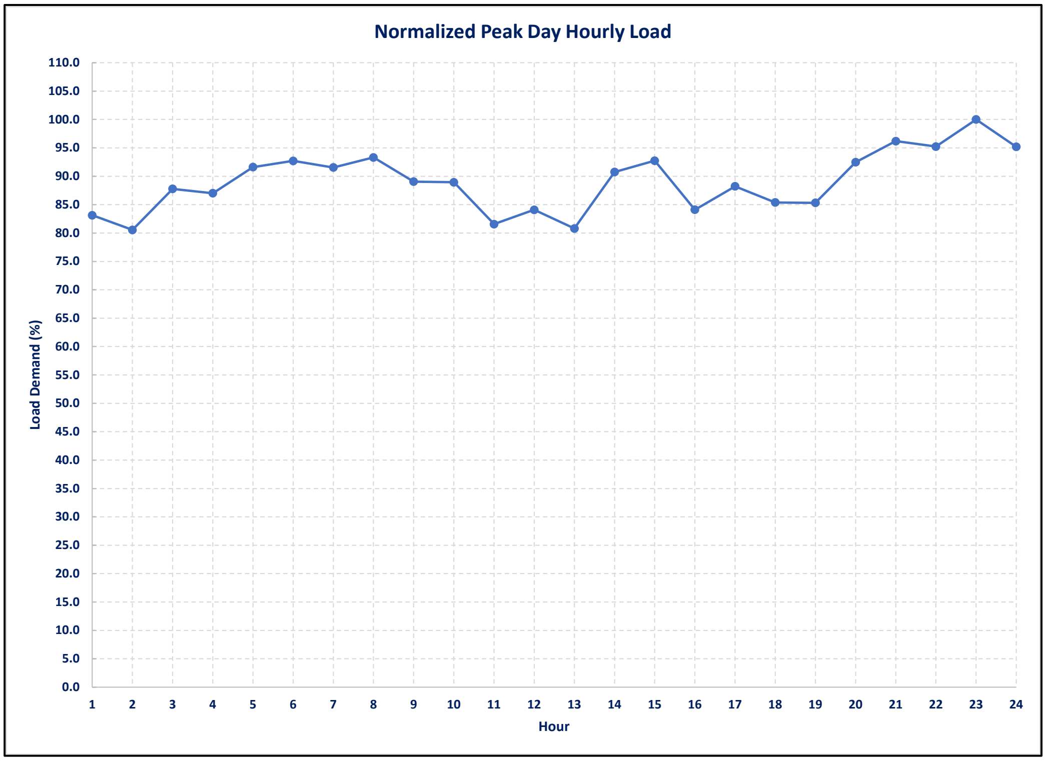
The following may be observed from Figure 2-2:

1) The hourly load in the peak day was very flat, varying between 80% and 100% of its highest hourly load demand. The lowest hourly load in the day was some 80% of its highest hourly load.
2) There were three peaks in the day, which occurred at Hours 8, 15, and 23. Due to various system conditions, the load in the day might have not been fully supplied or there were load curtailments. Most grid systems with a significant share of residential customers would experience two peak demands a day, one in the morning and the other in the evening. The morning peak is normally

lower than the evening peak, which could occur at Hour 19, Hour 20, or other time segments. Observing the daily peak at Hour 23 is very unusual.

3) The daily load factor is very high.

Figure 2-2: Peak Day Hourly Load



2.4.2 WEEKEND DAY HOURLY LOAD CURVE

One typical weekend day was selected to observe the hourly load variations as depicted in Figure 2-3, which also has a normalized load.

One may see the following from Figure 2-3:

1) The hourly load on the weekend day varied between 70% and 100% of its hourly peak load. The lowest hourly load in the day was some 70% of its highest hourly load.

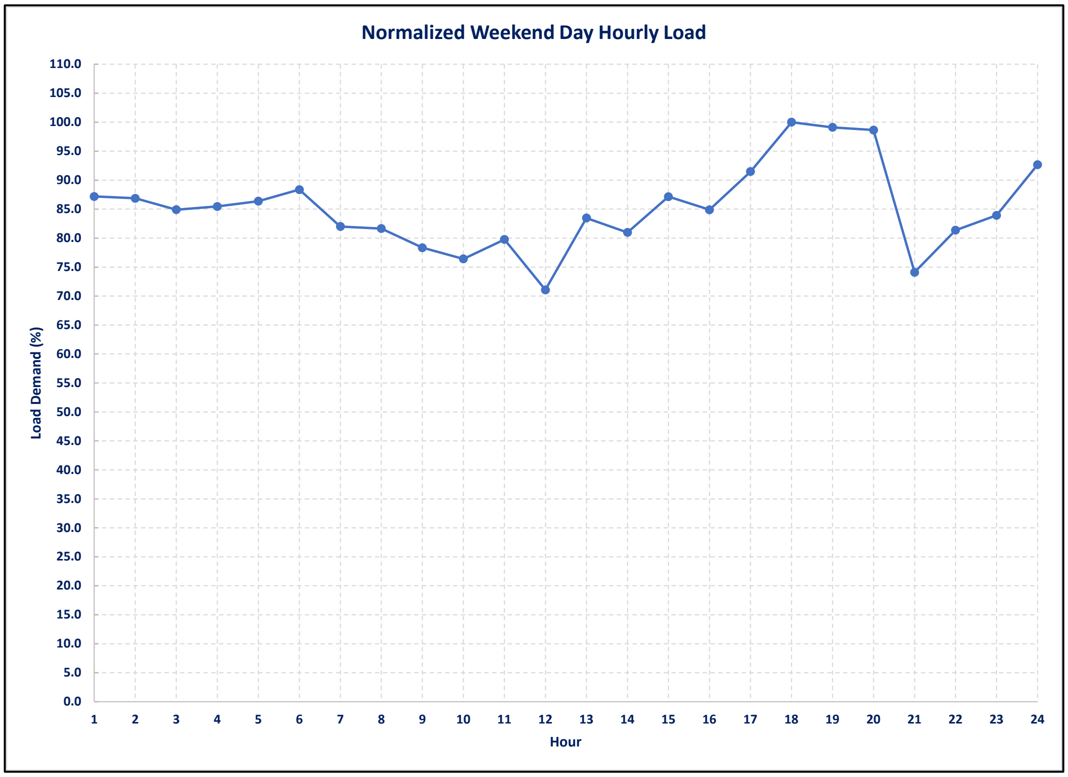
2) There were three peaks in the day although not very sharp, which occurred at Hours 6, 15, and 18. The system might have also experienced suppressed supply and/or load shedding.

3) Although the load factor on a weekend day could be relatively high, it could contribute much less to the annual load factor than the annual peak day due to the following:

   i) The highest demand experienced on a weekend day could be much less than that experienced in the annual peak day.

   ii) In calculation of the annual load factor, the highest demand in the period will be the annual peak demand.

Figure 2-3: Weekend Day Hourly Load



2.4.3 ANNUAL LOAD DURATION CURVE

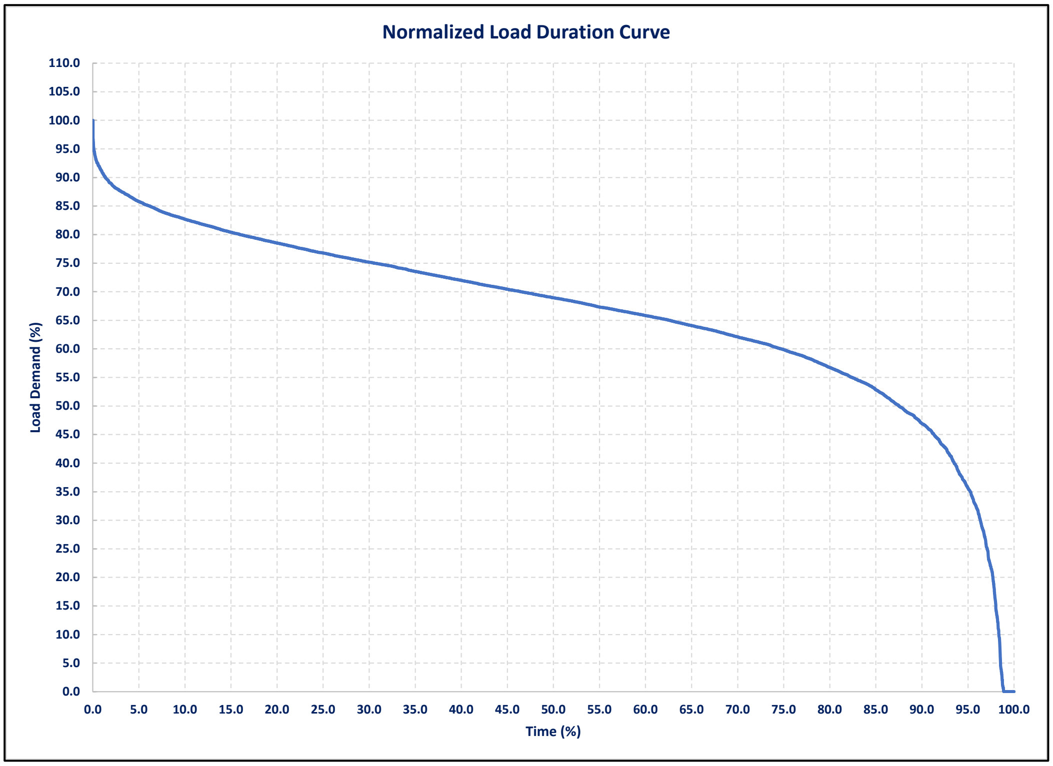
A normalized annual load duration curve of the Lagos State grid system (the grid system within the state) is displayed in Figure 2-4, which is derived through the following steps:

1) Collect 8,760 hourly loads within one year received by the two DISCOs at the TCN/DISCOs' transformation stations, which are directly connected to the DISCOs' 33 kV or 11 kV (including 13.8 kV) feeders.
2) Arrange the 8,760 hourly load values in descending order from the highest to lowest.
3) Divide each hourly load by the highest hourly load demand, i.e. the annual peak demand among the 8,760 hourly loads.
4) At the horizontal axis (time axis), each hour represents 1/8760-time segment (all time within one year is 1.0 or 100%).

It is important to note that the 8,760 hourly loads displayed in Figure 2-4 are the original and actual ones without any adjustment. The following may be observed from this figure:

1) The system experienced a load higher than 95% of its annual peak demand only for a very small percentage of time. The actual value shows the time is only approximately 0.1%, or 10 hours.
2) The system load exceeding 90% of its annual peak demand only occurred approximately less than 2% of the time.
3) The system experienced a load higher than 85% of its annual peak demand only for approximately 7% of the time.

4) Figure 2-4: Load Duration Curve



5) Almost 15% of the time, the system load is less than 50% of its annual peak demand.
6) Over approximately 70% of the time (from 15% to 85%), the system load varied between 80% and 55% of its annual peak demand.
7) Approximately 5% of time, the system load was less than 35% of its annual peak demand, or even zero, which could be caused by various system problems, such as equipment failure and system shutdown.
8) As load data collection is very tedious, human error would be unavoidable. More errors could be involved during the COVID-19 conditions. However, it is recognized that the characteristics of the load duration depicted in the figure are similar to those of other grid systems.

2.5 LOAD DEMAND FORECAST

The Load Forecast Report[15] has presented the predicted growth results for Lagos State over the period from 2020 to 2040 as well as the methodology, key parameters, and assumptions used in preparation of the forecast. The forecast annual system energy and peak demands at the generation bus (i.e. the metering/interconnection point between a generator and the transmission grid) for the three growth scenarios – namely most likely, high, and low – are presented in Table 2-1. For a more intuitive comparison, the energy and peak demands are also graphically displayed in Figure 2-5 and Figure 2-6, respectively.

[15] Power Africa Nigeria Power Sector Program: Long-Term Load Forecast – Lagos State, 12 February 2021

Table 2-1: Forecast System Energy and Peak Demands at Generation Bus

Year	Most Likely		High		Low	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
2019	10,008.84	1,757.79	10,008.84	1,757.79	10,008.84	1,757.79
2020	10,626.49	1,866.26	10,626.49	1,866.26	10,626.49	1,866.26
2021	11,469.03	2,014.23	11,660.56	2,047.87	11,278.72	1,980.81
2022	12,408.41	2,179.21	12,838.63	2,254.76	11,987.07	2,105.21
2023	13,444.72	2,361.21	14,163.31	2,487.41	12,750.77	2,239.33
2024	14,578.21	2,560.27	15,637.20	2,746.26	13,569.00	2,383.03
2025	15,809.34	2,776.49	17,263.35	3,031.85	14,441.26	2,536.22
2026	17,138.27	3,009.88	19,138.46	3,361.16	15,272.07	2,682.13
2027	18,490.91	3,247.44	21,069.84	3,700.36	16,148.14	2,835.99
2028	19,870.33	3,489.70	23,063.30	4,050.46	17,028.55	2,990.61
2029	21,338.22	3,747.49	25,194.07	4,424.67	17,964.71	3,155.02
2030	22,846.14	4,012.32	27,409.61	4,813.77	18,913.05	3,321.57
2031	24,360.69	4,278.31	29,674.39	5,211.52	19,843.80	3,485.04
2032	25,917.25	4,551.68	32,030.67	5,625.34	20,787.33	3,650.74
2033	27,518.00	4,832.81	34,483.96	6,056.19	21,744.53	3,818.85
2034	29,165.28	5,122.11	37,040.10	6,505.11	22,716.39	3,989.53
2035	30,861.42	5,419.99	39,705.10	6,973.15	23,703.69	4,162.92
2036	32,506.28	5,708.87	42,279.87	7,425.34	24,707.36	4,339.19
2037	34,204.51	6,007.11	44,976.00	7,898.84	25,728.12	4,518.46
2038	35,958.68	6,315.19	47,799.98	8,394.80	26,766.66	4,700.85
2039	37,771.07	6,633.49	50,613.49	8,888.92	27,770.88	4,877.22
2040	39,425.66	6,924.07	53,407.06	9,379.53	28,593.03	5,021.61
Increase (%)	**271.01**	**271.01**	**402.58**	**402.58**	**169.07**	**169.07**
Growth Rate (%)	**6.77**	**6.77**	**8.41**	**8.41**	**5.07**	**5.07**
Comparing with the Forecasts in 2040 under Most Likely Scenario						
Increase (%)			**35.46**	**35.46**	**-27.48**	**-27.48**

The following may be noted from Table 2-1:

1) Most likely growth scenario – The peak demand will grow from 1,866 MW in 2020 to 6,924 MW in 2040, an increase of some 270%.
2) High-growth scenario – The peak demand in 2040 will reach 9,380 MW, an increase of approximately 400% from 2020.
3) Low-growth scenario – The peak demand in 2040 will grow to 5,022 MW, an increase of approximately 170% from 2020.
4) When compared with the forecasts derived for 2040 under the most likely growth scenario, the forecasts under the high-growth scenario will be approximately 35% higher. The forecasts under the low-growth scenario would be only some 27% lower.

Figure 2-5: Grid System Energy Demands Under Three Scenarios

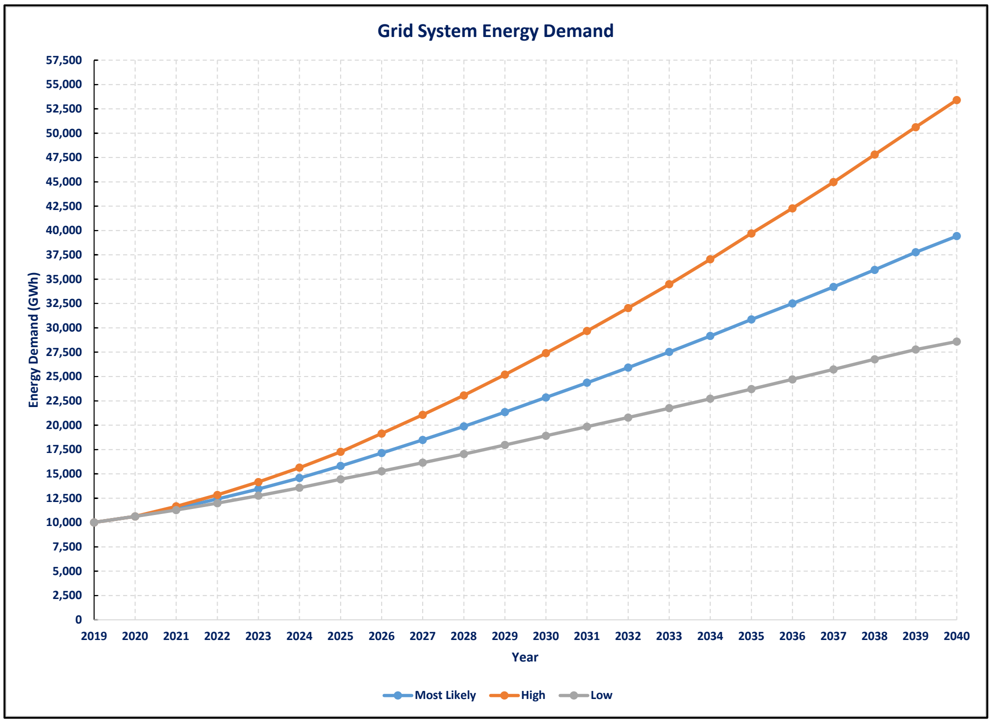
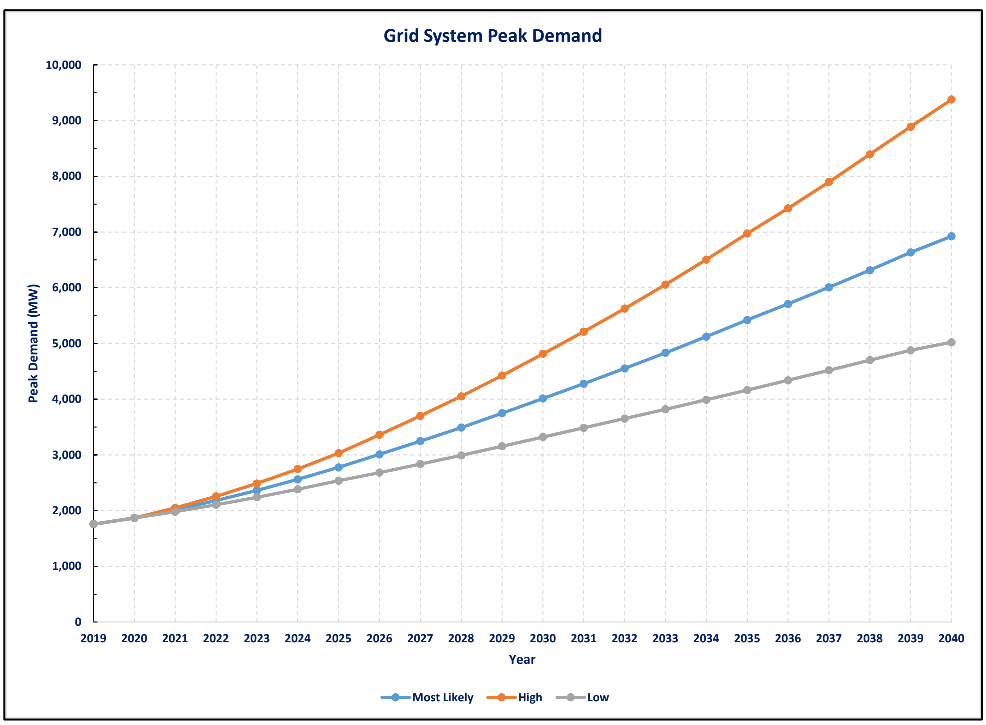


Figure 2-6: Grid System Peak Demands Under Three Scenarios



3 INTEGRATED RESOURCE PLANNING APPROACH AND KEY ASSUMPTIONS

The objective of integrated resource planning is to prepare a least-cost system development plan to supply the forecast load demand, taking into account the applicable and established government acts, regulations, policies, and guidelines as well as various assumptions and estimates.

3.1 DOCUMENTS GOVERNING ELECTRIC POWER SECTOR

The power system should be developed, operated, and maintained in accordance with consideration for the relevant acts, regulations, strategies, policies, rules, and guidelines. The Lagos State IRP Study Team has identified and collected the main documents governing the development, operation, and maintenance of the generators, national grid system, and distribution networks in Nigeria, which are listed in Appendix F; five of these documents are summarized below, including:

1) National Energy Policy, published in 2003, revised in 2018 (draft)
2) Sustainable Energy for All Action Agenda (SE4ALL-AA), Federal Republic of Nigeria, July 2016
3) The Grid Code for the Nigeria Electricity Transmission System – Version 03, NERC
4) Market Rules for Transitional and Medium-Term Stages of the Nigerian Electricity Supply Industry, December 2014
5) The Distribution Code for the Nigeria Electricity Distribution System – Version 02, NERC
6) The Lagos State Electricity Policy, December 2021

3.1.1 NATIONAL ENERGY POLICY – 2018

The Draft Revised Edition of the National Energy Policy prepared by the ECN in 2018 provides a comprehensive energy policy to ensure an optimal, adequate, reliable, and secure supply of energy and its efficient utilization in the country. The policy for each main primary energy resource is summarized as follows:

1) Petroleum

i) Crude oil – To increase the reserves and the production capacity and ensure an adequate and reliable supply and distribution of petroleum products.

ii) Natural gas – To intensify efforts in gas exploration and development and to put in place the necessary infrastructure and incentives for adequate geographical coverage of the gas transmission and distribution network.

iii) Shale hydrocarbon resources – To encourage coordinated baseline studies and research on, and the production, processing, and utilization of, shale hydrocarbon resources.

2) Coal and Tar Sands/Bitumen

i) Coal – To pursue vigorously a comprehensive program of resuscitation of the coal industry, explore the techno-economic feasibility of new coal technologies, support increased environmental monitoring for the existing and/or proposed mines and power stations, and reintroduce the use of coal for power generation.

ii) Tar sands/bitumen – To promote tar sands/bitumen exploration and exploitation and extract heavy oil from them for refineries.

3) Nuclear – To promote the development and peaceful use of nuclear energy and promote it as an important electricity component in the energy mix.

4) Renewable

i) Hydropower – To fully harness the hydropower potential for electricity generation.

ii) Solar – To aggressively pursue the integration of solar energy into the energy mix and encourage individuals and corporations to generate solar power and feed it into the grid.

iii) Wind – To commercially develop wind energy resources and integrate them with other energy resources into a balanced energy mix.

iv) Hydrogen – To integrate hydrogen as an energy source in the energy mix, which could be used in fuel cells for electricity generation.

v) Other renewables, including ocean waves, tidal energy, ocean thermal gradients, and geothermal energy – To encourage research and development in the technologies of the exploitation of these emerging energy resources.

5) Bio-Energy

i) Biomass, including wood, forage grasses and shrubs, animal wastes, and wastes arising from forestry, agricultural, municipal, and industrial activities as well as aquatic biomass – To effectively harness biomass energy resources, support the use of biomass for production of renewable energy, and promote electricity and heat generation from biomass waste.

ii) Fuelwood – To promote improved efficiency in use of fuelwood and de-emphasize the use of wood as a fuel in the energy mix.

iii) Biofuels – To promote the blending of biofuels as a component of fossil-based fuels for all automotive use.

6) Electricity – To ensure a steady, reliable, and competitive supply of electrical power at all times for industrial, commercial, and social activities, and make electricity available, accessible, affordable, and reliable 100% of the time to the population by the year 2030.

i) To ensure a strong and diversified and balanced energy mix.

ii) To broaden the energy options for generating electricity.

iii) To establish a viable cost-reflective tariff.

iv) To develop bankable feasibility studies for development of renewable, coal, nuclear, and large hydropower resources for power generation.

7) Energy Utilization

i) Industry – To ensure an adequate and reliable supply of energy, pursue the optimal utilization of the available energy types for various activities in an environmentally sustainable manner, and ensure energy efficiency and conservation in industry.

ii) Agriculture – To ensure an adequate and reliable supply of energy, ensure that appropriate sources of energy are utilized judiciously and efficiently, and emphasize the use of affordable, adaptable, reliable, and sustainable agricultural technologies.

iii) Transportation – To vigorously pursue the development of an optimal energy mix with particular attention to gas, ensure regular and adequate availability of all commercially viable fuel types, ensure the use of energy efficient and environmentally friendly technologies, and vigorously promote the development of mass transit systems.

iv) Households – To vigorously pursue the development of an optimal energy mix, ensure regular and adequate availability of all fuel types, ensure the use of energy-efficient and environmentally friendly technologies, and ensure the improved energy performance of building components and systems.

v) Commercial/Services – To vigorously pursue the development of an optimal energy mix and to ensure the regular and adequate availability of all fuel types.

8) **Energy Efficiency and Conservation**

i) To adopt and promote energy efficiency and conservation best practices in the exploration and utilization of energy resources.

ii) To mainstream energy efficiency and conservation best practice into all sectors of economy.

iii) To adopt appropriate energy pricing, metering, and building mechanisms.

iv) To integrate energy efficiency and conservation studies into the curricula of educational institutions.

v) To adopt, promote, and enforce standardization of energy appliances standards and code for energy efficiency and conservation technologies.

9) **Environment and Climate Change –** The major environmental problems related to energy production, distribution, and consumption are mainly deforestation and pollution. Energy resources should be exploited, distributed, and utilized in an environmentally friendly and sustainable manner.

3.1.2 SUSTAINABLE ENERGY FOR ALL ACTION AGENDA

The SE4ALL-AA agenda adopted by the Inter-Ministerial Committee on Renewable Energy and Energy Efficiency and approved by the National Council on Power was published by the Federal Republic of Nigeria in July 2016. It established the Electricity Vision 30:30:30, namely to deliver 30 GW of electricity with a 30% renewable energy mix by 2030. The Electricity Vision 30:30:30 Energy Delivery Projections shows that 30% of renewable energy consists of large hydropower plants and other renewables, such as small and medium hydro, solar PV, solar thermal, wind, biomass, and geothermal power plants. It was also estimated that each of the large hydropower plants and other renewables will contribute to 15% of the total energy.[16]

3.1.3 THE GRID CODE – VERSION 03

The Grid Code for the Nigeria Electricity Transmission System, Version 03, was published by the NERC. The Grid Code contains the day-to-day operating procedures and principles governing the development, maintenance, and operation of an effective, well-coordinated, and economic transmission system for the NESI. This Transmission Development Plan Report only summarizes the operating reserve and transmission system operation requirements.

3.1.3.1 Operating Reserve

In order to achieve system operation within acceptable frequency limits at all times, the system operator shall operate the system with an adequate operating reserve. Operating reserve is additional active power output provided by generating units, or a reduction in consumers' demand, which must be realizable in real-time operation to contain and correct any potential power system frequency deviation to an acceptable level.

[16] https://www.seforall.org/sites/default/files/NIGERIA_SE4ALL_ACTION_AGENDA_FINAL.pdf

Clause 15.4.2 of the Grid Code states that the Nigerian power system requires a minimum primary reserve that is sufficient to cover the largest credible trip in order to secure the network. The "largest credible trip" is the largest loss of power inflow that could be caused by a single trip, which will normally be the largest generating unit synchronized to the system; however, it could be an inflow from an exporting area that flows through a double circuit. In addition, the Grid Code also indicates that the level of secondary reserve should at least be equal to the allocated primary reserve. The level of tertiary reserve should at least be equal to the allocated secondary reserve plus that required for managing load and power park module forecast errors.

Although the Grid Code requires the transmission system to have a minimum primary reserve at all times, the system operator, TCN at present, is unable to meet this requirement. It is believed that TCN would meet the requirement in the near future.

3.1.3.2 Transmission System Operation

The main requirements on transmission system operation are listed below:

1) Frequency in Clause 10.1.2
    - Normal – +/- 0.5%, i.e. from 49.75 to 50.25 Hz
    - System Stress – +/- 2.5%, from 48.75 to 51.25 Hz
2) Voltage in Clause 10.1.5
    - Normal

Voltage Level (kV)	Minimum Voltage kV (pu)	Maximum Voltage kV (pu)
330	280.5 (0.85)	346.5 (1.05)
132	112.2 (0.85)	145.2 (1.10)
66	62.04 (0.94)	69.96 (1.06)
33	31.02 (0.94)	34.98 (1.06)
11	10.45 (0.95)	11.55 (1.05)

    - System Stress – A further deviation of +/- 5% (assuming based on the base values) per those for normal operation conditions
3) Basic insulation level (BIL) in Clause 10.1.8
    - 1,050 kV for 330 kV system
    - 650 kV for 132 kV system
4) Typical fault clearing times in Clause 12.5.5
    - 60 ms for faults cleared by busbar protection at 330 kV and 132 kV
    - 80 ms for faults cleared by distance protection on 330 kV and 132 kV overhead lines
    - 60 ms for faults cleared by transformer protection on HV transformers
5) Generator in Clause 12.6.1
    - Power factor
        - 0.85 power factor lagging (inductive load)
        - 0.95 power factor leading (capacitive load)
    - Voltage variation – +/- 10% of normal voltage
    - Ramping up (loading) – 3% of registered capacity per minute
    - Ramping down (de-loading) – 3% of registered capacity per minute

6) Generator speed droop in Clause 12.6.2 – between 4% and 6%

3.1.4 THE MARKET RULES

The Market Rules for Transitional and Medium-Term Stages of the Nigeria Electricity Supply Industry prepared in December 2014 is aimed to establish and govern an efficient, competitive, transparent, and reliable market for the sale and purchase of wholesale electricity and ancillary services in Nigeria and to ensure that the Grid Code and the Market Rules work together to secure efficient co-ordination and adequate participation. This subsection only summarizes the important rules relevant to generation system adequacy.

Clause 21.1.1 requires the system operator to prepare a load projection report prior to the end of October in each year, which provides the monthly energy and system peak load forecast for the next 10 years.

Clause 21.1.5 indicates that the system operator must define the reserve requirement in MW that will ensure adequacy of generation in the wholesale electricity market.

Clause 21.2 requires that prior to the end of November in each year, the market operator shall prepare a generation adequacy report, which provides the forecast monthly generation capacity requirement for each DISCO and for the entire system.

3.1.5 THE DISTRIBUTION CODE – VERSION 02

Per Clause 1.2.2 in Part 1 – General Conditions of the Distribution Code, the operational voltages of DISCOs in Nigeria are from 230V to up to 33 kV.

Clause 4.3 in Part 2 – Distribution Planning and Connection Code of the Distribution Code defines the nominal and operational voltages under the normal conditions as follows:

Nominal	**Operation Voltage**	
	Minimum	**Maximum**
Voltage	**kV-V (pu)**	**kV-V (pu)**
33 kV	31 kV (0.94)	34.98 kV (1.06)
16 kV	15.2 kV (0.95)	16.8 kV (1.05)
11 kV	10.45 kV (0.95)	11.55 kV (1.05)
400 V	376 V (0.94)	424 V (1.06)
230 V	216.2 V (0.94)	243.8 V (1.06)

3.1.6 THE LAGOS STATE ELECTRICITY POLICY

The Lagos State Ministry of Energy and Mineral Resources prepared the Lagos State Electricity Policy and submitted it to the state legislation for enactment in December 2021. The Policy outlines the following critical requirements to implement a historic solution that delivers a clean, adequate, and reliable electricity supply to the consumers in the state:

1) An enabling constitutional and legal framework
2) Collaborative Federal and State Government support for market growth and customer satisfaction
3) An autonomous and credible regulatory body
4) An Integrated Resource Plan (IRP)
5) Competitive and transparent procurement of generation resources
6) A bankable commercial framework

7) Well-funded, well-managed generation, transmission, and distribution players
8) An Independent System Operator (ISO)

The Policy articulates the vision of LASG on the necessary constitutional, legal, engineering, and commercial foundations for creating a viable sub-national electricity sector that caters fully to the needs of its citizens, while enabling significant socio-economic growth and development both for Lagos State and the country at large.

It is expected that LASG will consult with the Federal Ministry of Power, NERC, TCN, and Nigeria Bulk Electricity Trade Plc. for independent operation (or transit to independent operation gradually) of the Lagos State electricity system, which also implies independent planning and design of the state electricity system, and will address issues related to regulation, license, policy, and institutional framework.

3.2 PLANNING APPROACH

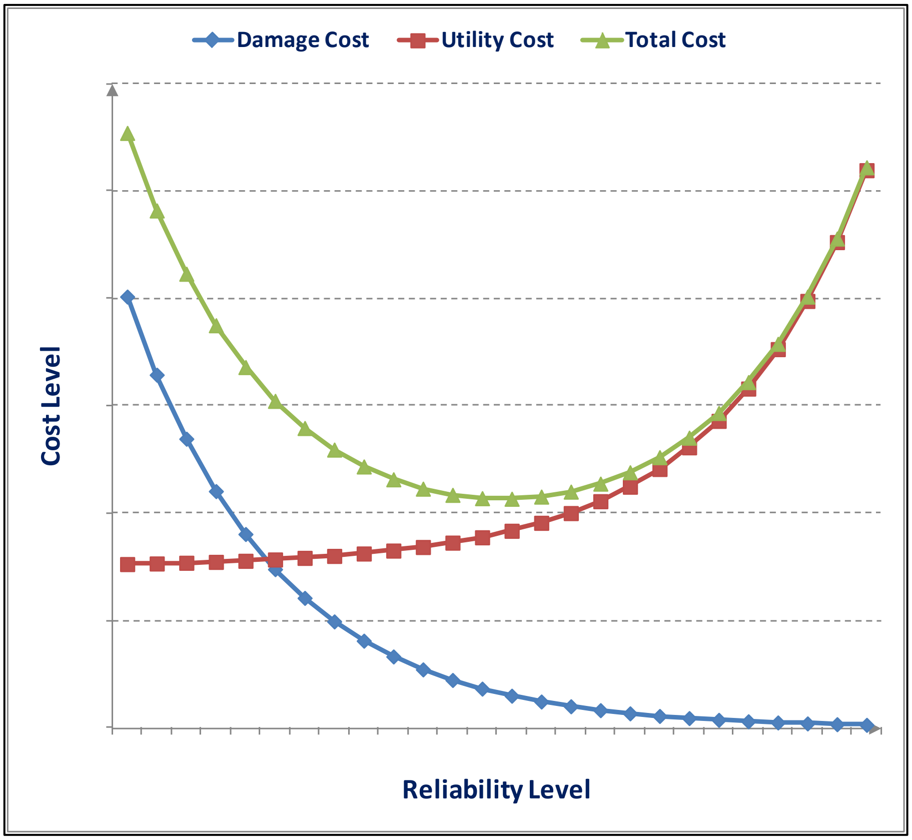
3.2.1 SYSTEM RELIABILITY AND COST

The total cost to electricity consumers includes not only the utility-related cost but also consumer damage cost (unsupplied energy cost in deterministic analysis and expected unsupplied energy cost in probabilistic analysis). This concept is illustrated using Figure 3-1.

The first part of the total cost includes capital investment, fuel, and operations and maintenance (O&M) costs of power supply facilities, operation profits, and emissions offset allowance, which is relatively easy to evaluate. The second part is associated with cost and loss caused by supply interruption, which could be difficult to assess. The consumer damage cost can be divided into the direct cost resulting directly from cessation of power supply or provision of backup generation and the indirect cost resulting from a response to an interruption. The direct cost includes such impacts as lost production, idle but paid for resources, backup generation cost, process restart costs, spoilage or raw material and equipment damage, and the direct cost associated with human health and safety. Examples of indirect cost are civil disobedience and looting during an extended blackout, or failure of an industry safety device in an industrial plant, necessitating neighboring residential evacuation. It is important to recognize that consumers are ultimate payers of both the utility cost and consumer damage cost.

The essential objective of power system planning is to find out the optimal point with the least total cost to customers at acceptable reliability levels.

Figure 3-1: Electricity Cost to Customers



3.2.2 GENERATION DEVELOPMENT PLAN

The basic approach used in the preparation of a least-cost generation development plan consists of comparing system costs of a number of scenarios that supply a given load demand, with a comparable level of reliability, over a study period (plus an extended period for the impact of the end-effect if necessary). These costs include, among others, annual capital charges (calculated according to the investments required for major improvement/reinforcement, refurbishment and new facilities, economical life, and interest/discount rate), fuel expenses, O&M costs, power purchase costs, offset allowance for GHG and other emissions, and costs of unsupplied energy. The comparison is made on the basis of the cumulative present value of costs for a given scenario and a predetermined simulation period at a predetermined discount rate.

Generation development scenarios are formulated based on the available and screened generation candidates. Every generation expansion scenario has a fixed part and a variable part. The fixed part includes the existing generating units with planned retirement schedule if available and those committed for installation. The committed projects include those under construction, with funds secured or construction contract executed (at least awarded). The variable part consists of a number of generation candidates and may include either only one type (class) of generation candidates or several types depending on the study objectives.

Each of the formulated generation development scenarios has been evaluated using the Generation Analysis Model developed for this project. Based on the evaluation results from scenario simulation, the study team analyzed and ranked the generation development scenarios according to their total costs in present value. The top-ranked generation development sequence, taking into various factors (with a lower total cost), has been selected and passed on for analysis of the required transmission additions. The result of the generation development sequence, along with those of the respective transmission sequence and distribution plans, has been taken into account in selection of the IRP.

3.2.3 TRANSMISSION DEVELOPMENT PLAN

Requirements for the transmission system over the study horizon are determined based on the least-cost generation development plan and forecasted load centers. The transmission system development plan is developed to meet the planning and operation criteria for the study horizon. The plan takes into account transmission requirements to incorporate new generation into the system and connect new load centers to the system.

3.2.4 DISTRIBUTION DEVELOPMENT PLAN

Requirements for the distribution system over the first five years, namely from 2021 to 2025, are studied for each 33 kV feeder based on the predicted load growth, which connects a transformation station and a 33/11 kV substation. The requirements for its downstream system 11 kV feeders are estimated.

For the period from 2026 onwards, the requirements for the distribution system are estimated based on the peak demand predicted at the delivery points of transformation stations, namely the metering points between TCN transformation stations and the DISCOs' 33 kV feeders (or DISCOs' 11 kV feeders if they are transformed from 132 kV level).

3.3 ASSUMPTIONS

In order to fairly assess the formulated generation development scenarios, it is necessary to establish a set of planning parameters and criteria prior to the development of the scenarios. It is expected that these parameters and criteria cover all aspects of power system planning work, such as technical, economic, financial, and environmental.

The assumptions and criteria presented in this subsection were developed from several sources, including previous planning reports, in-house criteria used in previous similar assignments, and international best practices.

3.3.1 TECHNICAL AND ECONOMIC PARAMETERS

The main parameters and assumptions used in preparation of the IRP include the following:

1) Study Area – Only the grid supply areas in Lagos State, namely the service territories covered by the two DISCOs (or more DISCOs in the future) which receive power supply from transformation stations of the main grid.
2) Reference Year – 2019. All data are collected for the period up to 2019.
3) Base Year – 2020
4) Planning Horizon – From 2020 to 2040
5) Power factor at transformation station delivery point – 90%
6) MVA base for per unit value calculation – 100 MVA
7) A 350 mm^2 aluminum conductor is selected for new 132 kV and 330 kV transmission lines, and a 150 mm^2 aluminum conductor for new 11 kV and 33 kV feeders. Each phase of a 330 kV circuit could consist of either twin conductors or quad conductors. Selection of the type of conductors should be studied during the design stage, based on local environmental conditions. Certain types of conductors may not be suitable to humid and hot weather conditions due to the high degree of erosion they undergo.

8) Penetration of renewable energy – As Lagos State does not have a potential site for large hydropower plant development, it is determined that the IRP will maintain at least 15% renewable energy, particularly from solar, from 2030 onwards.

9) Accuracy level of estimated costs and other information – The system development plans are prepared based on the costs and other information estimated at the conceptual study level, which has a lower accuracy level than that derived from a preliminary or full feasibility study.

10) Cost and Present Value datum – All costs are expressed at January 2020 prices. All present value and discounting calculations would also use January 2020 as their reference point.

11) Escalation – The economic analysis is proposed to be based on real costs expressed at January 2020 price levels, omitting projections for general price inflation during the planning period.

12) Currency – All monetary values are expressed in constant U.S. dollars. All economic costs and benefits exclude all federal and state taxes, levies, duties, and royalties when applicable and possible.

13) Duties, levies, royalties, and federal/state taxes are not included in this economic study. Property tax may be taken into account if it is levied by the local government.

14) Foreign currency exchange rate – When necessary, the monetary values in local currency are converted to U.S. dollars at the exchange rate of one U.S. dollar to 360 Naira (the approximate exchange rate in January 2020).

15) All cash flows occur at the middle of a year.

16) Discount rate – 10% is selected in the IRP preparation.

17) Cost of unsupplied energy – US$1/kWh is used in this study. It is important to note that as the deterministic dispatch method is used in analysis of each scenario, there would be no unsupplied energy when the total effective generation capacity in a year is larger than or equal to the system peak load demand.

18) Cost of wheeling and transmission losses – An average cost of US$12/MWh is calculated and determined to add to the imported energy from other states to cover wheeling and transmission losses encountered by the transmission system outside of Lagos State.

19) Interest During Construction (IDC) – Interest is a financial cost and as such is excluded from the economic evaluations. The impact of construction periods of different lengths will be taken into account by distributing the capital over the entire construction period. In order to align the capital disbursement flow and present value calculation, the interest rate used will be equal to the discount rate applied in calculation of present value.

20) Heating value of fuels and heat rate of generators are expressed in high heating value (HHV) if not explicitly noted.

3.3.2 GENERATION PLANNING CRITERIA

The primary objective of the generation development planning is to find the least-cost long-term expansion scenario that supplies the forecast demand at an acceptable or pre-specified level of reliability. In any given year, it is essential to verify that the generation capacity reserve is sufficient so that the system can meet the load demand even if one or more units are out of service and/or, for systems with significant hydroelectric capacity, unexpected hydrological conditions are encountered. The reliability criteria are usually the deciding factor in scheduling the addition of new generating plants. There are usually two types of reliability criteria used in generation development planning: deterministic and probabilistic.

3.3.2.1 Deterministic Criteria

There are a number of ways to define deterministic reliability criteria. The core part of these criteria is, however, generation capacity. Depending on the application, these criteria could be measured using the values calculated using generator gross MCR (maximum continuous rating) or gross capacity; net MCR (gross MCR less station services) or net capacity; or seasonal MCR (MCR less seasonal derating and/or energy limitation) or seasonal capacity. Some utilities or systems apply the deterministic criteria prior to allowing for generating unit planned maintenance outage while others apply them after.

The deterministic reliability criteria are normally expressed in three different ways: (1) a fixed amount of capacity in MW to account for the random (could also include the planned) outage of one, two, or more largest units, (2) a percentage of annual peak demand, or (3) a percentage of annual peak demand plus a fixed amount of capacity.

The following describes the reliability criterion selected in this study:

1) As mentioned in Subsection 3.1.3, TCN at present is unable to meet the primary reserve requirement (at least the largest generating unit), but it is believed that it would meet the requirement in the near future.
2) At present, the largest generating unit in the TCN system has an installed capacity of 220 MW at Egbin power plant (all six units in the plant have the same size) in Lagos State.
3) In the Lagos State IRP study, combined cycle gas turbine (CCGT) plants fueled by NG, LNG, and/or light fuel oil (LFO) would be the most economical generation candidate. Each CCGT is to have an installed capacity of 500 MW, with a configuration of two gas turbines (GTs) and one steam turbine (ST), which means failure of one GT would result in loss of 250 MW (approximately 167 MW from GT and 83 MW from ST).
4) Taking into account that Lagos State has the highest electricity demands among the 36 Nigerian states and it is located in the southwestern corner of the country, it is determined that in the generation expansion analysis, Lagos State would contribute approximately one third of the largest unit to the system primary reserve, namely 85 MW.
5) The Generation Analysis Model was developed to perform generation dispatch based on generators' effective capacity, i.e. the installed capacity minus station services, and then discounted by the maintenance rate and forced outage rate. After taking into account these factors, a reserve capacity of 65 MW is applied in the model.

3.3.2.2 Probabilistic Criteria

The commonly adopted probabilistic reliability criteria include both the loss of load probability (LOLP) or loss of load expectation (LOLE) and the expected unsupplied energy (EUE), which are obtained from the probabilistic convolution of the load demand and available generation.

LOLP is used to measure the risk associated with having insufficient generation capacity to meet the forecast load demand, which is normally expressed in days per year or hours per year, or as a percentage. For example, a 1% LOLP indicates that the installed generation will not be able to meet the forecast demand in a given year for 3.65 days or approximately 87.6 hours. It is important to understand that a simple LOLP value may have different implications as it could be calculated based on either a daily peak load duration curve or an hourly load duration curve. In the case of the daily peak load duration curve, each day is represented by one point, the highest hourly demand during the day.

EUE is the quantity of expected energy that a system would not be able to serve with the planned generation system in a given year. It is expressed either in MWh or as a percentage, in which case it is equal to the expected unsupplied energy divided by the energy demand and multiplied by 100.

The probabilistic criteria are not applied in the Lagos State IRP development.

3.3.3 TRANSMISSION PLANNING CRITERIA

Due to various constraints, the transmission development plan will be prepared based on power flow (normal condition) and N-1 contingency (stress conditions) studies only. The transmission system performance is therefore examined in accordance with the following criteria:

1) Bus voltage variation range, as listed in Subsection 3.1.3.2
2) Equipment thermal loading limit
3) Reactive compensation

3.3.4 DISTRIBUTION PLANNING CRITERIA

A detailed technical analysis for each feeder could not be carried out in this study, which could be used to examine the bus voltage, loading level, reactive compensation, etc. The feeder performance is therefore examined in accordance with its approximate maximum thermal loading limit such as:

1) 20 MW for a 33 kV feeder
2) 5 MW for a 11 kV feeder

3.3.5 EMISSIONS CRITERIA

The development of any power plant would need to take full account of the environmental impact of the chosen plant type irrespective of its location. Due consideration should be taken of both the direct and indirect environmental effects, and where appropriate, suitable mitigation measures should be put in place. The capital estimate and O&M costs of a power plant should include these mitigation measures.

One of the environmental considerations for the thermal plants is the likely emissions from the stacks of those plants. These include sulphur dioxide (SO_2), nitrous oxides (and NO_x), carbon dioxide (CO_2) and other greenhouse gases (GHG), and particulate matter.

In today's practice, it is common when comparing different forms of generation to apply an economic levy on thermal plants (or offset allowance) to take into account the cost to society of emissions that, while within the legal limits, do create costs that society as a whole must bear. This is normally done on the basis of the level of emissions, such as CO_2, SO_2, and NO_x, expected to be emitted by the relevant plant type. Some studies levy a cost in terms of US$ per tonne for the emissions to represent the societal cost for these emissions. For the present study an offset allowance of US$10 per tonne of GHG emissions, representing a cost to society, is levied against thermal options.

4 GENERATION RESOURCES AND TECHNOLOGIES

This section briefly describes the energy resources available to electric power generation to meet the electricity demand in Lagos State, including both domestic and imported fuels as well as fuel price estimates and generation technologies suitable to Lagos State. The main technical and economic parameters of the suitable technologies are also presented.

4.1 RESOURCES AND TECHNOLOGIES

4.1.1 NATURAL GAS RESERVE AND PRODUCTION AND PIPELINE SYSTEMS

NG has been a primary energy resource for electric power generation in Nigeria for many years. NG is produced at gas/oil wells and then transported to power plants through a gas pipeline system.

The OPEC (Organization of the Petroleum Exporting Countries) website[17] indicates that Nigeria has a proven NG reserve of 5,761 billion cubic meters. 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. In order to build new NG-fired power plants in Lagos State, the NG produced in the Niger Delta must be transported to the power plants in Lagos State using the gas pipeline system or in the form of LNG.

The Aje offshore oil and gas field (OML 113) in Lagos State commenced its Phase I oil production in May 2016. Its Phase II will focus on increasing its oil production, and Phase III will target the development of the Turonian gas condensate reservoir. After implementation of Phase III, it is expected that the NG supply availability and security to Lagos State will be significantly improved.

The estimate provided in Table 4-1 indicates that the proven gas reserve could supply approximately 70,000 MW power generation for a period of 40 years if all gas is used for power production.

Table 4-1: Natural Gas Available for Power Generation

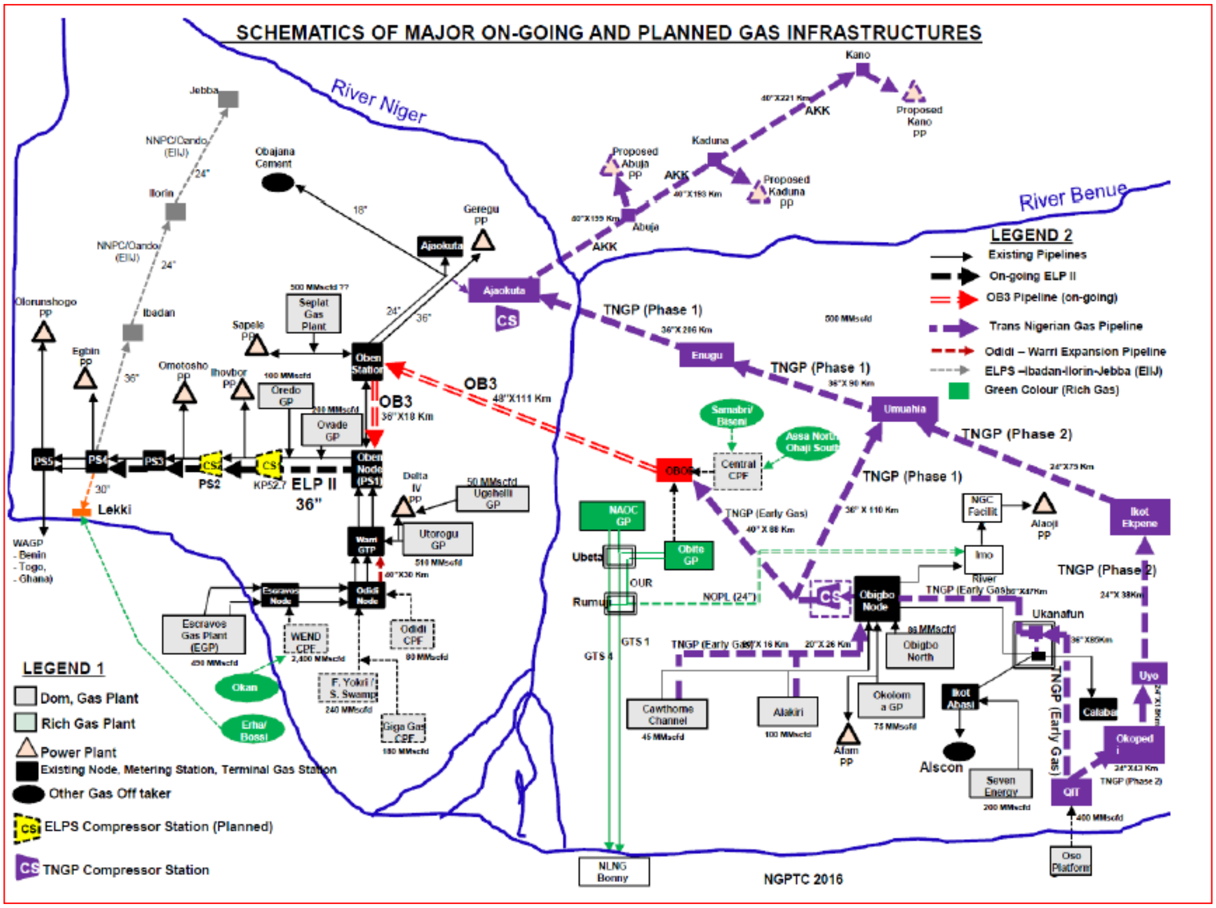
Proven Natural Gas Reserve	5.761E+12	Cubic Meter
Heating Value (HHV)	0.038481	MMBTU/Cubic Meter
Total Energy	2.217E+11	MMBTU
Consumption Life	40	Year
Energy Available	5.542E+09	MMBTU/Year
Operation at Full Capacity	7,884.0	Hour/Year
Energy Available	702,978	MMBTU/Hour
Generator Heat Rate	10	MMBTU/MWh
Potential Generation Capacity	70,298	MW

Figure 4-1 shows the schematic map of major existing and planned gas infrastructure facilities in Nigeria. The following may be observed/understood from the map:

1) The existing gas pipeline network in Nigeria, which is operated and maintained by NGC, consists of three separate systems, namely the Western, Eastern, and Northern network systems.
2) Lagos State is at present supplied by the Western network system through the 36-inch ELPS 1 (Escravos-Lagos Pipeline System No.1).

[17] https://www.opec.org/opec_web/en/about_us/167.htm

Figure 4-1: Nigeria Gas Infrastructure Blueprint



3) The news on 26 February 2021 reported that the 36-inch ELPS II pipeline construction work has been completed and it is now commissioned for operation.

4) The news reported that the 48-inch, 127 km, Obiafu-Obrikom-Oben (OB3) pipeline, whose construction started in 2013, would soon be operational, which will improve the NG supply availability and security to Lagos State.

It is estimated that each of the two 36-inch pipelines could be operated at the capacity of 1.1 billion standard cubic feet per day (bscfd), i.e. approximately 1.2 million MMBTU per day, which could supply fuel to a 7,000 to 8,000 MW gas-fueled base load generation capacity. The capacity of the existing ELPS I pipeline has been almost fully utilized by the existing power plants, industrial users, and export to West African countries through the WAGP (Western African Gas Pipeline).

It was reported by Africa Oil+Gas Report that Dangote Industries Limited (Dangote) proposes to build the East-West Offshore Gas Gathering System (EWOGGS) to transport NG from the Niger Delta to Lagos State[18]. The system consists of two 36-inch, 550km pipelines, each with a capacity of 1.5 bscfd, which would be constructed in two phases.

Based on the forecast load demand level, it is determined that in this study, NG-fired generation could be developed in either CCGT (combined cycle gas turbine) 500 MW and/or GT (gas turbine) 200 MW, subject to their economic scale. The configuration of each CCGT would include two GTs and one ST

[18] EWOGGS Pipeline

(steam turbine) although other configurations could also be possible, feasible, and/or economical. The failure of one GT in a CCGT set would result in a generation loss of 250 MW. It is suggested that in order to increase the power supply reliability, the GTs (in both CCGT and GT configurations) should be designed as dual fuels, which would allow the GTs to burn light fuel oil (LFO) in case the gas pipeline(s) is interrupted due to various reasons such as maintenance, damage, or vandalism.

The modern technologies would allow a CCGT to be synchronized to a system and operated at its full capacity within approximately 30 minutes from a cold state. One GT would take up to approximately 10 minutes to achieve the same operation goal. When economical, CCGTs may be used to replace GTs for the peaking purpose when more economical.

4.1.2 LIQUEFIED NATURAL GAS

Nigeria's LNG (liquefied natural gas) plant located in Bonny Island of River State started its commercial operation in 1999. With six trains currently operational, the entire complex is capable of producing 22 million tonnes per annum (mtpa) of LNG and 5 mtpa of NGLs (natural gas liquids) from 3.5 bscfd of NG intake. After completion of a current expansion to add a seventh LNG processing unit, its production capability would be increased to 30 mtpa.

LNG-fueled power plant(s) in Lagos State could use either Nigeria LNG or imported LNG, subject to the total cost delivered to the power plants. A comprehensive study should be conducted to examine the feasibility and economy of a floating storage regasification unit (FSRU) against an on-land regasification plant if a long term (10 years and longer) of LNG generation is expected.

For the LNG-fueled power plant, CCGTs at 500 MW each are selected in this study. LNG could be transported to Lagos State through waterways.

4.1.3 COMPRESSED NATURAL GAS

Compressed natural gas (CNG) could be used to fuel power plants when pipeline NG is not available or has a low level of availability and security. However, when it is used for a large power plant such as 50 MW or larger, there could be serious concerns on its transportation and on-site storage due to the difficult logistics of moving such a large volume or quantity from the processing plant to power plant sites.

Several captive generators in Lagos State at present use CNG as back-up fuel for their power production. According to the current practice, grid-connected NG-fired power plants receive pipeline NG at a regulated price, which is much lower than that of NG sold to other customers; therefore, it is expected that the CNG price would be much higher than that of the regulated NG.

Based on this assumption for pricing and the difficult transportation and storage of large quantities of CNG, it is determined that this study will not take CNG as a separate generation resource. If such plants are constructed and connected to the grid, the capacity required by other generation types, such as NG and LNG-fueled generation, could be reduced accordingly.

4.1.4 PETROLEUM OIL AND ITS PRODUCTS

Nigeria has a proven oil reserve of 36,890 million barrels[17], ranked as the largest oil producer in Africa and the 11th largest in the world, averaging production for more than 1.946 million barrels per day[19].

There are currently five refineries in Nigeria. Four are owned by the Nigerian Government through the Nigerian National Petroleum Corporation (NNPC), while the fifth is owned and operated by Niger Delta Petroleum Resources (NDPR). All are located outside of Lagos State.

Dangote is currently building one refinery with a daily processing capacity of 650,000 barrels crude oil in Lagos State although its final products have not been finalized.

[19] https://en.wikipedia.org/wiki/List_of_countries_by_oil_production

The web site of the U.S. EIA (Energy Information Administration) lists the petroleum products produced from one 42-gallon barrel of oil input at U.S. refineries in 2019[20], which is summarized in Table 4-2.

Table 4-2: Petroleum Oil Products at Refineries

Refineray Product	Gallon	Percentage
Finished motor gasoline	19.40	43.46%
Distilate fuel oil	12.47	27.93%
Kerosene-type jet fuel	4.41	9.88%
Petroleum coke	2.06	4.61%
Still gas	1.64	3.67%
Hydrocarbon gas liquids	1.47	3.29%
Residual fuel oil	0.88	1.97%
Asphalt and road oil	0.80	1.79%
Naphtha for feedstocks	0.46	1.03%
Lubricants	0.42	0.94%
Other oils for feedstocks	0.25	0.56%
Miscellaneous products	0.21	0.47%
Special naphthas	0.08	0.18%
Finished aviation gasoline	0.04	0.09%
Kerosene	0.04	0.09%
Waxes	0.01	0.02%
Total	**44.64**	100.00%
Processing again	2.65	

One may observe and/or calculate the following from Table 4-2:

1) Three of the oil products are commonly used to fuel power plants: (1) distillate fuel oil (or light fuel oil – LFO, which is very expensive and it is mostly used for peaking power generation) for GTs and high-speed diesel; (2) petroleum coke (or petcoke) for STs; and (3) residual fuel oil (or heavy fuel oil – HFO) for reciprocal internal combustion engines (RICE), medium-speed diesels, and low-speed diesels.

2) In this IRP, LFO would only be studied as the backup fuel of the GTs in CCGT configuration and GTs for peaking power generation. LFO could be transported to the power plants in Lagos State from the refineries located in other Nigeria states if domestic LFO is not available or inadequate.

3) The final list of the products of the Dangote refinery currently under construction could not be collected for this study. Petcoke and LFO could be two fuel resources for power generation if they are produced locally. These two resources could, of course, be imported from other Nigeria states for power production if they are more cost-effective, environmentally acceptable, and sustainable.

4) With a production volume of 2.06 gallons of petcoke from the refining of one barrel petroleum oil, it is estimated that the available fuel could be burned for more than 900 MW power generation capacity.

[20] https://www.eia.gov/energyexplained/oil-and-petroleum-products/refining-crude-oil-inputs-and-outputs.php

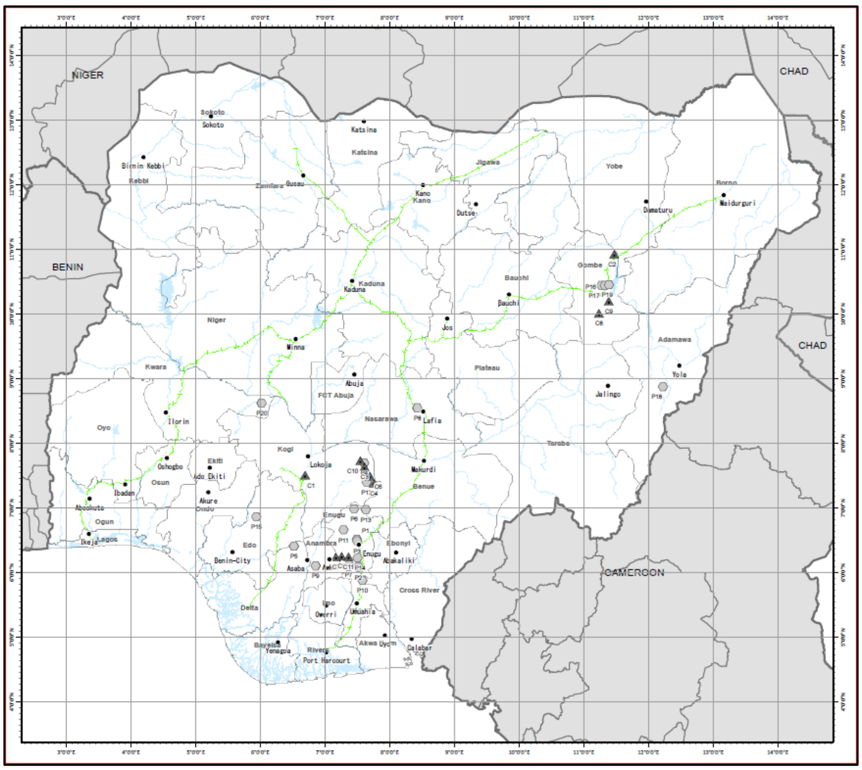
5) With a production volume of 0.88 gallons of HFO from the refining of one barrel petroleum oil, it is estimated that the available fuel could be used for more than 400 MW power generation capacity.

6) Petcoke and HFO are analyzed together with other fuels to examine their cost-competitiveness.

4.1.5 COAL

Nigeria has major unexploited coal resources. Available data show that coal (mainly sub-bituminous stream coals except for the lafia-Obi bituminous coking coal) is available in more than 22 coalfields spread over 13 states in the country. The proven coal reserves are approximately 639 million metric tonnes while the inferred reserves are about 2.75 billion metric tonnes. Three of the 13 states – Kogi, Benue, and Enugu – have been explored to a greater degree than others. Figure 4-2 shows the location of main coal resources.

Figure 4-2: Location of Main Coal Resources



Many national and local governments have established high standards on coal-fired power generation due to its pollutant emissions. As summarized in Subsection 3.1.1, the 2018 National Energy Policy supports increased environmental monitoring for the existing and proposed coal-fired power stations and reintroduces the use of coal for power generation.

It could be cost-effective to transport coal by rail from its production state(s) to Lagos State. Figure 4-3 shows the railway transportation systems in Nigeria. Additional railway and loading and unloading stations would be required if coal-fired power plants are to be built in the state.

It is estimated that up to 1,200 MW coal-fired power generation capacity would be installed in the study (for analysis of coal power generation cost only) if it is cost competitive.

Figure 4-3: Railway Transportation Systems

4.1.6 URANIUM

It was reported that as of 2017, identified uranium reserves recoverable at US$130/kg were 6.14 million metric tonnes, which are sufficient for over 130 years of supply at the consumption rate in 2017[21].

Uranium ore is mined in several ways: open pit, underground, in-situ leaching, and borehole mining. Commercial-grade uranium can be produced through the reduction of uranium halides with alkali or alkaline earth metals. Uranium metal can also be prepared through electrolysis of KU5 or UF4, dissolved in molten calcium chloride (CaCl2) and sodium chloride (NaCl) solution. Very pure uranium is produced through the thermal decomposition of uranium halides on a hot filament.

As nuclear power generation has become established since the 1950s, the size of reactor units has grown from 60 MW to some 1,600 MW, with corresponding economies of scale in operation. At the same time, there have been many smaller power reactors built both for naval use and as neutron sources, yielding enormous expertise in the engineering of small units.

Due partly to the high capital cost of large nuclear reactors generating electricity via the steam cycle and partly to the need to service small electricity grids under about 4,000 MW, there is a move to develop smaller nuclear power units. These may be built independently or as modules in a larger complex, with capacity added incrementally as required. Small units are seen as a much more manageable investment than big ones, whose cost rivals the capitalization of the utilities concerned. It was reported that NuScale has designed a small module reactor (SMR) that would take up 1% of the space of a conventional reactor. Each NuScale SMR would generate at 60 MW. For a total of US$3 billion, NuScale would erect up to 12 SMRs side by side, like beer cans in a six-pack, to form a power plant[22].

Per international practice, nuclear power generation is relatively expensive and requires a good national technological base and well-trained human resources to operate and maintain such power plants. In

[21] https://en.wikipedia.org/wiki - Uranium Reserves
[22] NuScale small modular reactor

deciding if and when a nuclear power plant should be constructed in Nigeria or Lagos State, a number of factors such as those listed below must first be taken into account:

1) Grid load demand including export to other states and/or countries. From both economic and technical aspects, nuclear power units should be dispatched to supply base load although advanced technologies could adapt a nuclear power unit with relatively flexible output. The appropriate time to build a nuclear power unit is when the system off-peak load could consume all the unit output.
2) The Nigerian Nuclear Regulatory Authority (NNRA) is a government entity responsible for nuclear safety and radiological protection regulation in Nigeria. It was established pursuant to the Nuclear Act 1995. In order to install a nuclear power plant(s) in the country, the NNRA should formulate policies and develop regulations governing nuclear reactors and nuclear material safety, issues orders to licensees, and adjudicates legal matters.
3) Selection of potential power plant site(s) and conduct of site environmental and social impact assessment.
4) Financing has to be obtained regardless of the intended ownership, private, public, or private public partnership.
5) Maintenance and operation of a nuclear power plant requires considerable technical expertise and a technology base in order to be able to supply the specialist skills and products to a nuclear power station.
6) In most jurisdictions, the nuclear power generation option requires considerable government interventions with regards to stipulations contained in international conventions, safety regulations, funding and technical facilitations, identification of countries from where safe and proven technologies and initial human expertise can be sourced, as well as establishment of a plan to train more Nigerians in nuclear physics and nuclear engineering.
7) Consideration and/or programs for radioactive waste handling and final disposition, including spent fuel considerations.

After analysis of the information available, it was concluded that the conventional nuclear technologies would be much more expensive than the SMRs, and it was then determined that only SMRs would be used in the analysis of generation expansion candidates.

4.1.7 NON-HYDRO RENEWABLE

4.1.7.1 Solar

Nigeria has one of the highest solar radiation regimes in Africa and the world, which is ranged between 4.0 and 6.5 kWh/m^2/day and the highest intensity is found in the northern areas, while it is lower in the southern areas.

There are a number of different solar PV power technologies on the market, but they operate on the same principle that involves the utilization of irradiance from the sun for producing electricity using solar panels. Due to the low voltage of an individual solar cell, several cells are wired in series in the manufacture of a "laminate". The laminate is assembled into a protective weatherproof enclosure, thus making a photovoltaic module or solar panel. Modules are then strung together into a photovoltaic array. Most solar PV arrays use an inverter to convert the direct current power produced by the modules into AC power that can be transmitted via transmission or distribution systems to load centers to meet electricity demands.

The most common solar panel technologies on the market today are crystalline silicon modules and thin-film modules. Sun-tracking technology is available and can be implemented to improve the overall energy conversion efficiencies of a solar PV project. Trackers and sensors that optimize the performance are often seen as optional, even though tracking systems can increase output by up to 50%.

Solar PV power projects can produce significant amounts of electricity ranging from a few kW to several MW and the technology is mature. Within the Lagos State context, solar PV power projects can be effectively integrated into the power portfolio. The energy from the solar resource is available and free. Typically, power production is higher at mid-day than the morning and afternoon, with no production at night.

A relatively high initial capital investment and sizeable areas for the installation of solar PV projects are required. The cost of land itself could be the most prohibitive in terms of Lagos grid-scale solar development. However, the direct costs of generation using this technology are currently very competitive to the conventional generation options, and there has been a proliferation of rooftop solar solutions in Lagos over the last several years. Lagos State has an excellent resource and environment for a large amount of rooftop solar PV power.

The size of solar PV power plants could change very significantly, from a few kW (such as household rooftop solar PV installation) to a few hundred MW (such as a large solar PV farm). The size of solar PV plants selected in this assignment is 100 MW. For solar PV installations less than 100 MW, one 100 MW capacity would be an aggregation or a cluster of a few or many of them. For solar PV farms larger than 100 MW, each of them could be represented using more than one 100 MW power plants.

4.1.7.2 Municipal Solid Waste

With an estimated population over 26 million in 2019, Lagos State produces a very large amount of MSW. It is strongly suggested that the state government should undertake a comprehensive study to assess the MSW potential for power generation as well as its cost and benefit if there are no adequate resources to meet the federal government's renewable energy target. In addition to electricity, utilization of MSW would also result in various social benefits.

Electricity can be produced by burning MSW as a fuel. MSW power plants, also called waste to energy (WTE) plants, are designed to dispose of MSW and to produce electricity as a byproduct of the incinerator operation. The term MSW describes the stream of solid waste generated by households and apartments, commercial establishments, industries, and institutions. MSW consists of everyday items such as product packaging, grass clippings, furniture, clothing, bottles, food scraps, newspapers, appliances, paint, and batteries. It does not include medical, commercial, and industrial hazardous or radioactive wastes, which must be treated separately.

MSW is managed by a combination of disposal in landfill sites, recycling, and incineration. MSW incinerators often produce electricity in WTE plants. The U.S. EPA (Environmental Protection Agency) recommends, "The most environmentally sound management of MSW is achieved when these approaches are implemented according to EPA's preferred order: source reduction first, recycling and composting second, and disposal in landfills or waste combustors last."

In the United States, there are currently two main WTE facility designs:

1) Mass burn is the most common waste-to-energy technology, in which MSW is combusted directly in much the same way as fossil fuels are used in other direct combustion technologies. Burning MSW converts water to steam to drive a turbine connected to an electricity generator.
2) Refuse-derived fuel (RDF) facilities process the MSW prior to direct combustion. The level of pre-combustion processing varies among facilities, but generally involves shredding of the MSW and removal of metals and other bulky items. The shredded MSW is then used as fuel in the same manner as at mass burn plants.

In addition to the two main WTE facilities designs mentioned above, there are also two other technologies, pyrolysis and thermal gasification, under development with a limited number of units in operation. Pyrolysis and thermal gasification are related technologies. Pyrolysis is the thermal decomposition of organic material at elevated temperatures in the absence of gases such as air or oxygen. The process, which requires heat, produces a mixture of combustible gases (primarily methane, complex hydrocarbons, hydrogen, and carbon monoxide), liquids, and solid residues.

Thermal gasification of MSW is different from pyrolysis in that the thermal decomposition takes place in the presence of a limited amount of oxygen or air. The producer gas which is generated can then be used in either boilers or cleaned up and used in combustion turbine/generators. The primary area of research for this technology is the scrubbing of the producer gas of tars and particulates at high temperatures in order to protect combustion equipment downstream of the gasifier and still maintain high thermal efficiency.

A plant size of 40 MW is selected to examine its cost-competitiveness in this project.

4.1.7.3 Agricultural Crop Residues

Agricultural crop residues are relevant types of biomass for bioenergy and other bioproducts as they are by-products of agricultural crop production and do not require additional land for harvest. Estimates of the potential available for bioenergy and other uses vary significantly. While the theoretical potential is high, the economic availability can vary greatly. It depends on numerous factors including the yield and site-specific parameters, the type of crop rotation, slope and soil type, length of the harvest window, the presence of a local processor or aggregator, and whether the agriculture producer sees value in collecting a portion of the crop residue.

Agricultural residues in Lagos State could be very limited due to its small size in terms of area and state-wide urbanization, commercialization, and industrialization. If necessary, Lagos State may build a biomass power plant using agricultural residues from the state and other states.

A plant size of 40 MW is selected to examine its cost competitiveness in this project.

4.1.8 HYDRO AND OTHER NON-HYDRO RENEWABLES

Due to a lack of analysis of their potential for commercial and grid-scale power generation, the following resources are not taken into account in analysis of the generation expansion candidates for preparation of the Lagos State IRP. For example, there has been increasing interest in using hydrogen for grid-scale power generation; however, due to a lack of technological and economic maturity, grid-scale hydrogen generation could not be analyzed at a reasonably accurate level for this iteration of the IRP and should be reassessed in preparation for the next IRP.

1) Hydropower, all sizes
2) Ocean waves, tidal energy, and ocean thermal gradients
3) Wind
4) Geothermal
5) Hydrogen
6) Wood waste and forestry residues
7) Fuelwood
8) Biofuels, including bioethanol and biodiesel

4.1.9 DEMAND SIDE MANAGEMENT PROGRAMS

The term "demand side management" (DSM) refers to the activities and approaches utilized by governments and energy utility companies to encourage customers to modify their energy consumption patterns in order to reduce electricity usage and pattern. The International Energy Agency (IEA) identifies DSM as a major contributor to efficiency and sustainability in global power sector development.

DSM programs could be grouped into the following four categories:

1) Energy Efficiency (EE) programs, designed to deliver equivalent electricity services using less energy, such as upgrading to light-emitting diode (LED) lightbulbs
2) Demand Response (DR) programs designed to encourage consumers to adjust the time of their energy use based on price or availability of supply
3) Energy Conservation (EC) programs designed to encourage consumers to reduce their energy consumption. Examples include turning off unused lighting, increasing room temperature for cooling, and decreasing room temperature for heating.
4) Distributed Energy Resource (DER) programs designed to manipulate the demand or supply of electricity at the customer's location or on the network which serves them. Examples include rooftop solar panels, electric vehicles (EV), and smart EV chargers, as well as battery storage, fuel cells, microgrids, and domestic combined heat and power (CHP) systems.

Nigeria developed and adopted its own National Energy Efficiency Implementation/Action Plan (NEEAP) for 2015-2030, setting the following targets for renewable energy and energy efficiency for 2030:

1) As described in Subsection 3.1.2, in 2016 the Nigerian government approved the SE4ALL Action Agenda with Electricity Vision 30:30:30 to achieve 30GW of electricity generation by 2030 with 30% renewable energy.
2) Energy efficiency in lighting: Phase-out 40% of inefficient incandescent bulbs by 2020, and 100% by 2030.
3) High-performance distribution of electricity: Reduce losses in electricity distribution to 15-20% by 2020; and below 10% by 2030.
4) Clean cooking fuels and stoves: Achieve universal access to safe, clean, affordable, efficient, and sustainable cooking for the entire population of the Economic Community of West African States (ECOWAS) by 2030.
5) Energy efficiency standards and labelling: N/A (targets not set).
6) Energy efficiency in buildings: 30% of new large private buildings and 40% new public buildings that implement energy efficient building designs and methods to be achieved by 2030.
7) Energy efficiency in industry: N/A (targets not set).
8) Energy efficiency in transportation: N/A (targets not set).
9) Finance: N/A (targets not set).

DSM is at an early stage of development in Nigeria and Lagos State. The potential DSM programs which could significantly reduce the electricity demand in Lagos State have not been identified. Therefore, this IRP will not take into account any DSM programs. In order to include DSM programs in the preparation of the next IRP, the following is recommended to identify the implementable DSM programs:

1) Conduct an assessment of the energy savings potential in an applicable sector, such as surveys to determine appliance ownership and saturation in the household sector, and/or electricity use

patterns, sources, and costs. The results of the surveys will allow the development of scenario-based demand projections and estimations of how much energy can be saved with a different level of penetration of energy-efficient appliances.

2) Conduct a cost-benefit analysis and estimate the overall impact on the power system as well as on the state economy.
3) Identify the gaps between current and target levels, and develop an action plan on how, when, and by whom the gaps will be addressed.
4) Establish DSM program targets and incentives for short-, medium-, and long-term periods.
5) Develop the required legislative frameworks, regulations, and standards.
6) Develop DSM program monitoring systems that will help collect data and track impact.
7) Develop a system and legislation to facilitate the specification, collection, storage, maintenance, and supply of energy-related data, according to the requirements of integrated energy plan and international standards.
8) Develop an annual implementation plan.

4.2 FUEL PRICE ESTIMATE

The estimated fuel prices in US$/MMBTU are shown in Table 4-3, based on the information collected, in-house data, and assumptions.

Table 4-3: Fuel Price Estimate

Fuel Name	Natural Gas	LNG	LFO	HFO	Petcoke	Coal	MSW	Biomass	Uranium
Unit	MMBTU	MMBTU	BBL	BBL	Tonne	Tonne	Tonne	Tonne	MMBTU
Currency	US$								
Commodity Price [1]	2.50	3.00	50.00	50.00	50.00	30.00	5.00	15.00	1.50
Transportation	0.80	1.00				10.00	5.00	10.00	
Refining/Regasification		1.00	20.00	20.00					
Handling/Sorting						10.00	10.00		
Multiplier	1.00	1.00	1.30	0.50	1.00	1.00	1.00	1.00	1.00
Total Cost	3.30	5.00	91.00	35.00	50.00	50.00	20.00	25.00	1.50
High Heating Value	1.00	1.00	6.37	6.17	29.60	21.82	9.48	7.93	1.00
Unit Energy Price	3.30	5.00	14.30	5.67	1.69	2.29	2.11	3.15	1.50

Note: (1) The price for LFO and HFO is the crude oil price
The price for uranium is the delivered price

The notes below would be helpful to understand the price estimates in Table 4-3:

1) The NG price for power production is currently regulated and includes US$2.5/MMBTU for commodity and US$0.8/MMBTU for transportation/delivery.
2) Compared with NG prices to other Nigerian industries, the price of gas used for power generation is much lower (a few times). It is expected that the Federal government could also provide a lower than market price for LNG used for power generation. The estimated LNG price includes US$3/MMBTU for commodity and US$1/MMBTU for transportation and US$1/MMBTU for regasification.
3) The LFO price in US$/BBL is estimated at 1.3 times of the sum of crude oil and refining costs.
4) Due to its relatively low market demand, the HFO price in US$/BBL is estimated at 0.5 times of the sum of crude oil and refining costs.

5) It is assumed that petcoke would be from the Dangote refinery located in Lagos State, US$50/tonne is the total price of the fuel delivered to power plant. Due to its low market demand, the price could be lower.

6) The total price of US$50/tonne for coal includes US$30 for the commodity delivered to nearby railway station(s), US$10 for railway transportation, and US$10 for handling (unloading and delivery to the power plant).

7) The total price of US$20/tonne for MSW includes US$5 for the waste, US$5 for transportation (within Lagos State), and US$10 for sorting. As MSW is a burden to governments, it could be free to power producers.

8) The total price of US$25/tonne for biomass (agricultural crop residues) includes US$15 for the commodity and US$10 for transportation.

9) The price of uranium is estimated at US$1.5/MMBTU.

4.3 POWER PLANT SITES

4.3.1 KEY FACTORS CONSIDERED IN SELECTION OF A POWER PLANT SITE

Five key factors figure in the selection of a power plant site: the availability of the required resources, economic impacts on the plant development and operation, accessibility to the required services, concerns on the environmental impacts, and concerns on the social impacts. The details on these five factors are summarized in Appendix A.

4.3.2 IDENTIFICATION OF POWER PLANT SITES

By using Google Earth maps, the study team identified 14 potential power plant sites which could use all fuels available to Lagos State. These sites are marked in the map presented in Figure 4-4 and summarized in Table 4-4. Each site location is defined by a pair of coordinates, latitude (North as positive, from -90° to 90°) and longitude (East as positive, from -180° to 180°) using the Geographical Coordinate System (GCS), expressed using degree, minute, and second, such as 41°24'12.2"N and 2°10'26.5"E. The coordinates for each site indicated in Table 4-4 are for the site proximity as its exact location might not have been measured during our site visit due to its inaccessibility. It is important to note that Sites 9 (Egbin II) and 12 (Lekki Energy Center) might already have been studied extensively by two power plant developers (or independent power producers).

Table 4-4 includes the following information for each site:

1) Site No.

2) Location Name – The name of the village or town where the site/land is located

3) Local Administration Region (LGA or LCDA) – The pollical boundary/administration in which the site is located, which could be either a Local Government Area (LGA) or a Local Council Development Area (LCDA)

4) Coordinates (Geographical Coordinate System) – The approximate coordinates (latitude and longitude) of the site

5) Fuel – The primary fuel type to be used by the potential power plant

6) Technology – Power generation technologies to be applied to the site

7) Maximum Generation Capacity (MW) – The maximum installed generation capacity, in MW, of the power plant

Figure 4-4: Power Plant Sites

Table 4-4: Summary of the Identified Power Plant Sites

Site No.	Location Name	Local Administrative Region	Coordinates (Geographical Coordinate System)		Fuel	Technology	Maximum Capacity (MW)
1	Ahanve	Badagry West LCDA	6°26'13.59"N	2°46'25.25"E	NG	GT/CCGT	2,000
2	Oko Agbon Nla	Olorunda LCDA	6°26'42.76"N	3° 4'13.61"E	NG or Biomass	GT/CCGT/Steam	2,000
3	Navy Town	Oriade LCDA	6°26'13.29"N	3°17'41.34"E	LNG or Nuclear	GT/CCGT/Steam	2,000
4	Snake Island	Amuwo Odofin LGA	6°24'38.29"N	3°18'32.95"E	LNG or Nuclear	GT/CCGT/Steam	2,000
5	Ogudu Ori- Oke	Kosofe LGA	6°34'13.32"N	3°24'19.71"E	NG or MSW	GT/CCGT/Steam	2,000
6	Odo Ogun	Agboyi Ketu LCDA	6°35'48.04"N	3°27'18.45"E	NG or Biomass	GT/CCGT/Steam	2,000
7	Lagos Lagoon	Eti-Osa LGA	6°27'28.41"N	3°29'12.97"E	NG	GT/CCGT	2,000
8	Ijede	Ijede LCDA	6°33'46.64"N	3°37'11.53"E	NG	GT/CCGT	2,000
9	Ijede	Ijede LCDA	6°33'47.58"N	3°37'6.56"E	NG	GT/CCGT	2,000
10	Imota	Imota LCDA	6°40'10.58"N	3°39'27.19"E	NG or Biomass	GT/CCGT/Steam	2,000
11	Dangote Refinery	Ibeju Lekki LGA	6°28'15.70"N	4° 0'42.65"E	NG or HFO	GT/CCGT/RICE	1,000
12	Lekki Free Zone	Ibeju Lekki LGA	6°27'5.21"N	3°57'36.25"E	NG or LNG	GT/CCGT	2,000
13	Lekki Free Zone	Ibeju Lekki LGA	6°29'6.08"N	3°59'8.41"E	NG or Petcoke	GT/CCGT/Steam	1,000
14	Alaro City	Epe LGA	6°33'38.32"N	4° 0'1.02"E	NG	GT/CCGT	2,000

4.3.3 SCREENING ANALYSIS OF THE POWER PLANT SITES

The detailed study for a power plant site is normally carried out by the power plant developer at the feasibility study stage. As these types of studies are not available for preparation of the Lagos State IRP (or it has not been prepared), it was decided that only a high-level screening analysis of these identified sites is performed in the preparation of this IRP.

The study team conducted visual field surveys for 10 of the 14 identified power plant sites and collected the essential information required for the screening analysis. Site 2 could not be reached due to its inaccessibility from road (isolated by water and riverbanks), and Site 11 is located inside the Dangote Industrial compound and is not accessible to the public. Sites 8 and 9 were also inaccessible to the study team, and they collected some basic information from nearby. A summary of the collected information is presented in Appendix A.

4.3.4 THE POWER PLANT SITES SELECTED IN THE IRP

Based on the information available, the top three power plant sites selected for CCGT configurations are Sites 12 (Lekki Energy Center), 9 (Egbin II), and 6, and the top two power plant sites selected for GT configurations are Sites 5 and 2. The IRP has estimated the requirements to connect a power plant to the grid at conceptual level, in terms of voltage, capacity, and cost. The detailed studies for each interconnection, such as a feasibility study and an environmental impact assessment, must be carried out if the power plant is to be constructed.

4.4 TECHNICAL AND ECONOMIC PARAMETERS OF CANDIDATE POWER PLANTS

Based on the data collected from publicly available sources, plus the study team's in-house data and experience, the team estimated the technical and economic parameters for each of the power generation technologies using the fuels described in Subsection 4.1. These parameters include the following:

1) Gross capacity
2) Station services
3) Net capacity (installed capacity less station services)
4) Economic life
5) Lead time (the total time required for study, design, financing, and construction)
6) Earliest on-line year (the first full operation year)
7) Equivalent forced outage rate
8) Planned outage rate (maintenance rate)
9) Equivalent availability –> (1.0-equivalent forced outage rate) *(1.0-maintenance rate)
10) Net heat rate
11) Fuel cost
12) Overall capitalized cost, including overnight EPC cost, owner's cost, and interest during construction (per the description in Subsection 3.3.1)
13) Fixed O&M cost
14) Variable O&M cost
15) CO_2 emission intensity
16) NO_x emission intensity
17) SO_2 emission intensity
18) Particular matter emission intensity

The detailed estimate of technical and economic parameters for a few selected generation technologies is presented in Appendix B, which includes the following tables:

1) Table B-1: Technical and Economical Parameters – LNG and NG Fueled Generation Technologies
2) Table B-2: Technical and Economical Parameters – Solar PV Generation Technology

3) Table B-3: Technical and Economical Parameters – MSW and Agricultural Residues Fueled Generation Technologies

The cost estimate presented in these tables excludes land cost, taxes, and import duties. The insurance premium and property tax if applicable are included in the fixed O&M category.

4.5 SCREENING CURVE ANALYSIS OF GENERATION EXPANSION CANDIDATES

4.5.1 ANALYSIS OF GENERATION COST

Table 4-5 shows the unit cost of energy in US$/MWh, and Table 4-6 shows the annual unit cost of capacity in US$/MW. These costs are calculated based on the presumed technical and economic parameters, excluding GHG offset allowance. The two sets of values are the functions of annual capacity factor. The following provides a summary on each of the generation expansion candidates:

1) CC-L-250 (LNG CCGT – 250 MW) generation – When operated as a base load plant, it would have an annual capacity factor of approximately 85%. At this production level, its unit cost of energy would be some US$65.3 per MWh.
2) CC-G-250 (NG CCGT – 250 MW) generation – At an annual capacity factor of 85%, its unit cost of energy would be some US$56.9 per MWh
3) Import – The unit cost of energy would be some US$64.8 per MWh when its annual capacity factor is 85%, which is slightly lower than the cost of CC-L-250. However, the import may not be as reliable as CC-L-250 as it is located outside of Lagos State and could be interrupted due to various reasons such as a vandalism attack on NG pipeline(s). A dual fuel supply to a power plant has not been taken into account in cost calculation of import power.
4) GT-G-200 (NG GT – 200 MW) Generation – When operated as a peaking load plant with an annual capacity factor of 20%, its unit cost of energy would be some US$128.3 per MWh. Its cost could be reduced to US$67.2 per MWh when its annual capacity factor reaches 85%. However, it is much more expensive than CC-G-250 and more expensive that CC-L-250.
5) Petcoke Generation – With an annual capacity factor of 80%, its unit cost of energy would be approximately US$79.4 per MWh, which is even higher than that of GT-G-200.
6) Coal Generation – At an annual capacity factor of 80%, its unit cost of energy would be some US$78.5 per MWh, at a similar level to petcoke generation.
7) CC-O-250 (LFO CCGT – 250 MW) Generation – Its unit cost of energy would be some US$133.2/MWh when it has an annual capacity factor of 85%, which is very expensive.
8) GT-O-200 (LFO GT – 200 MW) Generation – Operated as a peaking load plant with an annual capacity factor of 20%, its unit cost of energy would be some US$239.4 per MWh, which is extremely expensive.
9) RICE (HFO) Generation – RICE could be operated as a peaking, intermediate, or base load plant. When operated as a base load plant at annual capacity factor of 80%, its unit cost of energy would be some US$92.1 per MWh.

Table 4-5: Unit Cost of Energy (US$/MWh) of the Generation Expansion Candidates

Capacity Factor	CC-L-250	CC-G-250	Import	GT-G-200	PetCoke	Coal	CC-O-250	GT-O-200	RICE	SMR	SolarPV	MSW	Biomass
0.05	425.8	417.4	425.4	367.9	834.7	765.2	497.1	484.7	469.3	2,132.0	313.1	1,531.5	1,120.3
0.10	234.3	225.9	233.8	208.2	431.9	399.0	303.1	321.2	268.1	1,077.7	156.7	788.2	589.4
0.15	170.5	162.0	170.0	154.9	297.6	276.9	238.4	266.7	201.1	726.2	104.5	540.4	412.4
0.20	138.5	130.1	138.1	128.3	230.5	215.9	206.0	239.4	167.5	550.5	78.4	416.6	323.9
0.25	119.4	111.0	118.9	112.3	190.2	179.3	186.6	223.1	147.4	445.1	62.8	342.2	270.9
0.30	106.6	98.2	106.2	101.6	163.3	154.8	173.7	212.2	134.0	374.8	52.4	292.7	235.5
0.35	97.5	89.1	97.0	94.0	144.1	137.4	164.4	204.4	124.4	324.6	44.9	257.3	210.2
0.40	90.7	82.2	90.2	88.3	129.7	124.3	157.5	198.6	117.2	286.9	39.3	230.7	191.2
0.45	85.3	76.9	84.9	83.9	118.6	114.2	152.1	194.0	111.7	257.7	35.0	210.1	176.5
0.50	81.1	72.6	80.6	80.3	109.6	106.0	147.8	190.4	107.2	234.2	31.5	193.6	164.7
0.55	77.6	69.2	77.1	77.4	102.3	99.4	144.3	187.4	103.5	215.1	28.6	180.1	155.0
0.60	74.7	66.3	74.2	75.0	96.2	93.8	141.3	184.9	100.5	199.1	26.3	168.8	147.0
0.65	72.2	63.8	71.8	73.0	91.0	89.1	138.8	182.8	97.9	185.6	24.3	159.3	140.2
0.70	70.1	61.7	69.7	71.2	86.6	85.1	136.7	181.0	95.7	174.0	22.6	151.1	134.3
0.75	68.3	59.9	67.8	69.7	82.7	81.6	134.9	179.5	93.8	163.9	21.1	144.0	129.3
0.80	66.7	58.3	66.3	68.3	79.4	78.5	133.2	178.1	92.1	155.2	19.8	137.8	124.9
0.85	65.3	56.9	64.8	67.2	76.4	75.9	131.8	176.9	90.6	147.4	18.6	132.4	120.9
0.90	64.1	55.6	63.6	66.1	73.8	73.5	130.6	175.8	89.3	140.5	17.6	127.5	117.5
0.95	62.9	54.5	62.5	65.2	71.4	71.3	129.4	174.9	88.1	134.3	16.7	123.2	114.4

Table 4-6: Annual Unit Cost of Capacity (US$/MW) of the Generation Expansion Candidates

Capacity Factor	CC-L-250	CC-G-250	Import	GT-G-200	PetCoke	Coal	CC-O-250	GT-O-200	RICE	SMR	SolarPV	MSW	Biomass
0.05	186,515	182,821	186,311	161,162	365,612	335,169	217,738	212,301	205,558	933,802	137,144	670,785	490,693
0.10	205,252	197,864	204,843	182,348	378,328	349,522	265,475	281,364	234,883	944,038	137,232	690,465	516,311
0.15	223,988	212,907	223,375	203,534	391,044	363,876	313,212	350,428	264,209	954,274	137,319	710,145	541,929
0.20	242,725	227,950	241,907	224,720	403,760	378,230	360,949	419,491	293,534	964,510	137,407	729,826	567,547
0.25	261,462	242,993	260,440	245,906	416,476	392,584	408,686	488,555	322,860	974,746	137,494	749,506	593,165
0.30	280,198	258,035	278,972	267,091	429,192	406,938	456,423	557,618	352,185	984,981	137,582	769,186	618,783
0.35	298,935	273,078	297,504	288,277	441,908	421,292	504,160	626,682	381,511	995,217	137,670	788,866	644,401
0.40	317,672	288,121	316,036	309,463	454,624	435,646	551,898	695,746	410,837	1,005,453	137,757	808,546	670,019
0.45	336,408	303,164	334,569	330,649	467,339	450,000	599,635	764,809	440,162	1,015,689	137,845	828,226	695,637
0.50	355,145	318,207	353,101	351,835	480,055	464,354	647,372	833,873	469,488	1,025,925	137,932	847,906	721,255
0.55	373,882	333,250	371,633	373,021	492,771	478,708	695,109	902,936	498,813	1,036,161	138,020	867,587	746,873
0.60	392,618	348,293	390,165	394,207	505,487	493,062	742,846	972,000	528,139	1,046,397	138,108	887,267	772,491
0.65	411,355	363,336	408,698	415,393	518,203	507,416	790,583	1,041,063	557,464	1,056,633	138,195	906,947	798,109
0.70	430,092	378,378	427,230	436,578	530,919	521,770	838,320	1,110,127	586,790	1,066,868	138,283	926,627	823,727
0.75	448,828	393,421	445,762	457,764	543,635	536,124	886,057	1,179,190	616,115	1,077,104	138,370	946,307	849,345
0.80	467,565	408,464	464,295	478,950	556,351	550,478	933,795	1,248,254	645,441	1,087,340	138,458	965,987	874,963
0.85	486,302	423,507	482,827	500,136	569,067	564,832	981,532	1,317,318	674,766	1,097,576	138,546	985,667	900,581
0.90	505,038	438,550	501,359	521,322	581,783	579,186	1,029,269	1,386,381	704,092	1,107,812	138,633	1,005,347	926,199
0.95	523,775	453,593	519,891	542,508	594,499	593,540	1,077,006	1,455,445	733,417	1,118,048	138,721	1,025,028	951,817

10) SMR Generation – Its unit cost of energy would be US$140.5 per MWh even if operated at an annual capacity factor of 90%, which is very expensive.
11) Solar PV Generation – Its unit cost of energy is presented at various capacity factor levels. Due to the limitation of its resource, its annual capacity factor could be in the range of 15 to 25%. In this study, an annual capacity factor of 20% is assumed. At this output level, its cost could be some $78.4 per MWh. The energy output of solar PV modules degrades from 0.5 to 0.75% per annum from its initial output.
12) MSW Generation – At an annual capacity factor of 85%, its unit cost of energy would be some US$132.4 per MWh, which is very expensive.
13) Biomass Generation – At an annual capacity factor of 85%, its unit cost of energy would be some US$120.9 per MWh, which is very expensive.

Based on the summary above, one may conclude the following:

1) LFO CCGT, LFO GT, and SMR should not be taken into account in the subsequent analysis of generation options and generation expansion scenarios.
2) Solar PV generation should be used to meet the renewable target although it is intermittent.
3) The resources for MSW and biomass generation are very limited in the state, and they are, at present far less than the established renewable target unless more resources could be identified.
4) The retained generation expansion candidates would include LNG CCGT, NG CCGT, natural GT, import, petcoke, coal, RICE, solar PV, MSW, and biomass.

4.5.2 SCREENING CURVE ANALYSIS

Figure 4-5 and Figure 4-6 present screening curve analyses for the retained generation candidates, LNG CCGT, NG CCGT, natural GT, import, petcoke, coal, RICE, and biomass. The former is for the unit cost of energy in US$/kWh, while the latter is for the annual unit cost of capacity in US$/kW.

Figure 4-5: Unit Cost of Energy

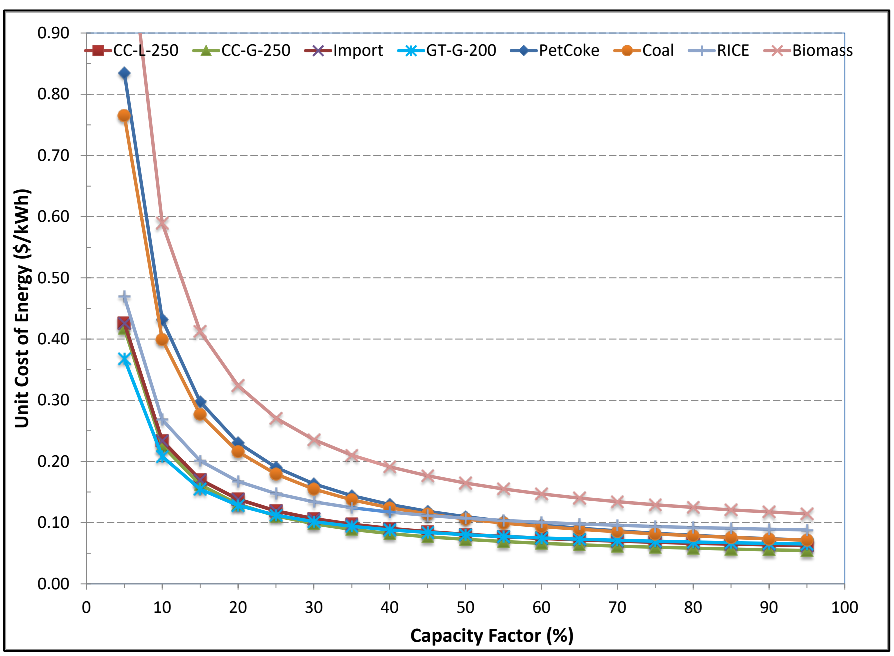
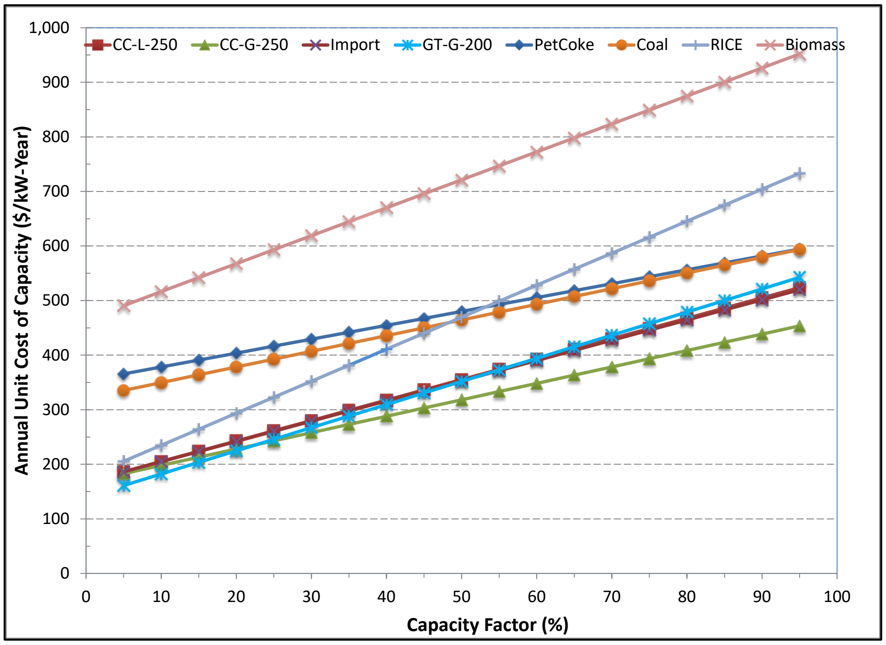


Figure 4-6: Annual Unit Cost of Capacity



According to the information presented in Tables 4-5 and 4-6 and in Figures 4-5 and 4-6, one may conclude that the generation cost of the selected candidates should be ranked as follows (from low to high):

1) NG CCGT
2) Import
3) LNG CCGT
4) NG GT (the cost break-even point between NG CCGT and NG gas GT is at approximately 25% capacity factor)
5) Coal
6) Petcoke
7) Solar PV
8) RICE
9) Biomass (with very limited resources if any)
10) MSW (with limited resources)

5 FORMULATION OF GENERATION EXPANSION SCENARIOS AND DETERMINATION OF LEAST-COST GENERATION PLAN

This section summarizes the generation expansion scenarios formulated and assessed, and the least-cost generation development plan recommended.

5.1 FORMULATION OF SCENARIOS

Based on the discussions on generation resources and technologies described in Section 4, the commissioning of any major generation projects prior to 2026 would be very difficult. It is determined that from 2020 to 2025, the load would be supplied by Egbin power plant and power plants located in other states (except for the solar PV plants to be commissioned prior to 2026, as noted to the relevant scenarios). New power plants in the state could supply load starting from 1 January 2026. The study team accordingly formulated 18 generation expansion scenarios as provided in Table 5-1. In these scenarios, solar PV power plants will be developed to meet the 15% renewable energy requirement.

Table 5-1: Generation Expansion Scenarios

Scenario		Generation Expansion Candidate						
		Technology						
		CCGT	CCGT	CFB	CFB	RICE	Solar PV	Import
No.	Description	Fuel						
		Natural Gas	LNG	Petcoke	Coal	HFO	Sunlight	Natural Gas
A. Carry forward all generation capacity in 2025								
1	CCGT-NG only	X					O	
2	3000MW LNG	X	X				O	
B. Starting from 2026, all power plants (except for Egbin) are new additions								
3	CCGT-NG only	X					O	
4	400MW RICE	X				X	O	
5	3000MW LNG	X	X				O	
6	900MW Petcoke	X		X			O	
7	1200MW Coal	X			X		O	
8	3000MW LNG+900MW Petcoke	X	X	X			O	
9	3000MW LNG+1200MW Coal	X	X		X		O	
10	900MW Petcoke+1200MW Coal	X		X	X		O	
11	3000MW LNG+900MW Petcoke+1200MW Coal	X	X	X	X		O	
12	3000MW LNG+1200MW Coal+900MW Petcoke	X	X	X	X		O	
13	500MW Import	X					O	X
14	1000MW Import	X					O	X
15	1500MW Import	X					O	X
16	2000MW Import	X					O	X
C. Starting from 2026, all power plants are new additions								
17	CCGT-NG only	X					O	
18	3000MW LNG	X	X				O	

Note: (1) X - Main resource
(2) O - Support resource

The notes below may be helpful to understand the generation expansion scenarios presented in Table 5-1:

1) The scenarios are divided into following three groups with different assumptions on the generation capacity required from 2020 to 2025 (the peak load in 2025 is the highest for the period from 2020 to 2025):

A) The generation capacity required from 2020 to 2025 will be carried forward to 2026 onwards.

B) All generation capacity required from 2020 to 2025 will be retired by the end of 2025 except for Egbin power plant, which is located within the state.

C) All generation capacity required from 2020 to 2025 will be retired by the end of 2025.

Scenarios under Group A

2) Scenario 1 – Only NG-fired CCGT and GT power plants will be added to the system.

3) Scenario 2 – 3,000 MW of LNG-fueled CCGT power plants will be added to the system, and the balance of generation will be NG-fired CCGT and GT power plants.

Scenarios under Group B

4) Scenario 3 – Only NG-fired CCGT and GT power plants will be added to the system.

5) Scenario 4 – In addition to the NG-fired CCGT and GT power plants, one 400 MW RICE plant will also be added to the system.

6) Scenario 5 – 3,000 MW of the LNG-fueled CCGT plants will be added to the system, and the balance of generation will be NG-fired CCGT and GT power plants.

7) Scenario 6 – In addition to the NG-fired CCGT and GT power plants, one 900 MW petcoke power plant will also be added to the system.

8) Scenario 7 – In addition to the NG-fired CCGT and GT power plants, one 1,200 MW coal power plant will also be added to the system.

9) Scenario 8 – 3,000 MW LNG CCGT and 900 MW petcoke power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.

10) Scenario 9 – 3,000 MW LNG CCGT and 1,200 MW coal power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.

11) Scenario 10 – 900 MW petcoke and 1,200 MW coal power plants will be added to the system, and the balance will be NG-fired CCGT and GT power plants.

12) Scenario 11 – 3,000 MW LNG CCGT, 900 MW petcoke, and 1,200 MW coal power plants will be added to the system. and the balance will be NG-fired CCGT and GT power plants.

13) Scenario 12 – 3,000 MW LNG CCGT, 1,200 MW coal, and 900 MW petcoke power plants will be added to the system. and the balance will be NG-fired CCGT and GT power plants.

14) Scenario 13 – Only NG-fired CCGT and GT power plants and 500 MW of new import will be added to the system.

15) Scenario 14 – Only NG-fired CCGT and GT power plants and 1,000 MW of new import will be added to the system.

16) Scenario 15 – Only NG-fired CCGT and GT power plants and 1,500 MW of new import will be added to the system.

17) Scenario 16 – Only NG-fired CCGT and GT power plants and 2,000 MW of new import will be added to the system.

Scenarios under Group C

18) Scenario 17 – Only NG-fired CCGT and GT power plants will be added to the system.

19) Scenario 18 – 3,000 MW of LNG-fueled CCGT power plants will be added to the system, and the balance of generation will be NG-fired CCGT and GT power plants.

As described in Subsection 3.3.1, this IRP will maintain at least 15% renewable energy from 2030 onwards to assist the federal government to achieve its renewable energy target established in Electricity Vision 30:30:30 as summarized in Subsection 3.1.2. Due to a lack of information on other large-scale renewable energy resources in terms of quantity, price, and accuracy level, solar PV plants in a size of 100 MW are used in the study to meet the renewable energy requirement. Other renewable resources could be used to produce power and achieve the renewable target if they are available and cost-competitive. Table 5-2 shows the annual renewable energy requirement and addition of solar PV power plants for the most likely load forecast.

Table 5-2: Installation Schedule of Solar PV Power Plants

Most Likely Load Forecast

Renewable Requirements =	15.0%
Solar PV Power Plant Size (MW) =	100.0
Solar PV Capacity Factor =	20.0%
Solar PV Annual Energy Production (GWh) =	175.2

Year	Peak Demand (MW)	Forecast Demand (GWh)	Renewable Required (GWh)	Total Number of Solar PV Plants Required	Annual Addition (Plant)	Total Addition (Plant)	Solar PV Penetration to Peak
2019	1,757.8	10,008.8					
2020	1,866.3	10,626.5					
2021	2,014.2	11,469.0					
2022	2,179.2	12,408.4					
2023	2,361.2	13,444.7					
2024	2,560.3	14,578.2					
2025	2,776.5	15,809.3			2	2	
2026	3,009.9	17,138.3			2	4	
2027	3,247.4	18,490.9			4	8	
2028	3,489.7	19,870.3			4	12	
2029	3,747.5	21,338.2			4	16	
2030	4,012.3	22,846.1	3,426.9	20	4	20	49.8%
2031	4,278.3	24,360.7	3,654.1	21	1	21	49.1%
2032	4,551.7	25,917.3	3,887.6	23	2	23	50.5%
2033	4,832.8	27,518.0	4,127.7	24	1	24	49.7%
2034	5,122.1	29,165.3	4,374.8	25	1	25	48.8%
2035	5,420.0	30,861.4	4,629.2	27	2	27	49.8%
2036	5,708.9	32,506.3	4,875.9	28	1	28	49.0%
2037	6,007.1	34,204.5	5,130.7	30	2	30	49.9%
2038	6,315.2	35,958.7	5,393.8	31	1	31	49.1%
2039	6,633.5	37,771.1	5,665.7	33	2	33	49.7%
2040	6,924.1	39,425.7	5,913.8	34	1	34	49.1%

One may observe the following from Table 5-2:

1) Each solar PV power plan is assumed at a size of 100 MW.
2) The annual capacity factor of a solar PV plant is assumed at 20%. Less generation capacity would be required if the actual capacity factor is higher than 20%, vice versa.

3) One 100 MW solar PV power plant would produce approximately 175 GWh per annum. Solar PV modules have an annual degradation of 0.5-0.75% of their initial production. However, the degradation has not been taken into account in the analysis. More solar PV power plants could be added if the operational ones produce less energy than expected.
4) The system would need 2,000 (20x100) MW solar PV power plants by 2030. In order to achieve this goal, it is decided to commission solar PV power plants from 2025 (for those to be operational by 1 January 2025, their construction would need to commence from 2023 based on the assumption of a two-year construction period).
5) By 2040, the system would need a total of 3,400 (34x100) MW of solar PV power generation.
6) When the renewable target (15% of energy) is met, the ratio of the installed solar PV power capacity to annual system peak would be approximately 50%, which is a very high-level penetration of renewable. The industrial practice suggests that a comprehensive study should be conducted to examine the impact of intermittent generation on system operation when its penetration level reaches 20% or above.
7) As the solar PV power plants would not produce any energy during the system on-peak period, from 19:00 to 22:00 of weekdays, the system peak would need to be met by non-intermittent generation, which implies that the capacity factor of the non-intermittent power plants could be much less.

5.2 EVALUATION OF SCENARIOS FOR THE MOST LIKELY LOAD FORECAST

Eighteen scenarios were constructed based on the information presented in Table 5-1 and Table 5-2 and evaluated using the Generation Analysis Model developed for the IRP project. The summary of total cost in present value (PV) of the scenarios and their ranking are presented in Table 5-3.

Table 5-3 includes the following information:

1) Scenario number
2) Short description of the scenario
3) Capacity additions from 2026 to 2040
4) Cost in PV, which is divided into five categories:
    i) Amortized capital repayment
    ii) Other fixed cost (fixed O&M, insurance premium, and property tax)
    iii) Fuel cost
    iv) Other variable cost (variable O&M)
    v) GHG offset allowance
5) It also shows the difference between the cost of the scenario under study and that of Scenario 3. A negative value means the scenario under study results in lower total cost than Scenario 3.
6) Levelized cost of energy (LCOE) over the entire study horizon, i.e. from 2020 to 2040
7) Ranking

Table 5-3: Cost Evaluation and Ranking of Scenarios

Scenario		Main Capacity	Cost in Present Value (Million US$, 2020) From 2020 to 2040							LCOE	Rank
No.	Description	Additions from 2026 to 2040	Capital	Other Fix	Fuel	Other Var	GHG	Total	Diff	($/MWh)	
A. Carry forward all generation capacity in 2025											
1	CCGT-NG Only	15x250MW CCGT-NG, 8x200MW GT-NG and 34x100MW Solar PV	2,255	4,401	5,632	2,501	887	**15,676**	**728**	91.51	**15**
2	3000MW LNG	12x250MW CCGT-LNG, 3x250MW CCGT-NG 8x200MW GT-NG and 34x100MW Solar PV	2,305	4,412	5,881	2,489	886	**15,974**	**1,026**	93.25	**18**
B. Starting from 2026, all power plants (except for Egbin) are new additions											
3	CCGT-NG Only	20x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,516	3,300	5,379	1,925	827	**14,948**	--	87.26	**3**
4	400MW RICE	4x100MW RICE, 18x250MW CCGT-NG, 14x200MW GT-NG and 34x100MW Solar PV	3,520	3,305	5,721	1,978	867	**15,392**	**445**	89.86	**9**
5	3000MW LNG	12x250MW CCGT-LNG, 8x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,527	3,303	5,830	1,925	826	**15,410**	**463**	89.96	**10**
6	900MW Petcoke	4x225MW Petcoke, 14x250MW CCGT-NG, 16x200MW GT-NG and 34x100MW Solar PV	3,946	3,383	5,163	2,013	951	**15,456**	**508**	90.23	**11**
7	1200MW Coal	4x300MW Coal, 17x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,774	3,352	5,304	1,959	904	**15,293**	**345**	89.28	**7**
8	3000MW LNG+900MW Petcoke	12x250MW CCGT-LNG, 4x225MW Petcoke, 4x250MW CCGT-NG, 14x200MW GT-NG and 34x100MW Solar PV	3,749	3,347	5,685	1,967	883	**15,632**	**684**	91.26	**13**
9	3000MW LNG+1200MW Coal	12x250MW CCGT-LNG, 4x300MW Coal, 2x250MW CCGT-NG, 15x200MW GT-NG and 34x100MW Solar PV	3,693	3,337	5,750	1,946	872	**15,598**	**651**	91.06	**12**
10	900MW Petcoke+1200MW Coal	4x225MW Petcoke, 4x300MW Coal, 12x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	4,200	3,434	5,076	2,038	1,023	**15,771**	**824**	92.07	**17**
11	3000MW LNG+900MW Petcoke+1200MW Coal	12x250MW CCGT-LNG, 4x225MW Petcoke, 4x300MW Coal, 13x200MW GT-NG and 34x100MW Solar PV	3,832	3,364	5,636	1,976	906	**15,715**	**767**	91.74	**16**
12	3000MW LNG+1200MW Coal+900MW Petcoke	12x250MW CCGT-LNG, 4x300MW Coal, 4x225MW Petcoke, 13x200MW GT-NG and 34x100MW Solar PV	3,750	3,348	5,710	1,956	886	**15,650**	**703**	91.36	**14**
13	500MW Import	500MW Import, 18x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,516	3,300	5,321	2,097	827	**15,062**	**114**	87.93	**4**
14	1000MW Import	1000MW Import, 16x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,516	3,300	5,269	2,253	827	**15,165**	**218**	88.53	**5**
15	1500MW Import	1500MW Import, 14x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,516	3,300	5,226	2,381	827	**15,250**	**303**	89.03	**6**
16	2000MW Import	2000MW Import, 12x250MW CCGT-NG, 13x200MW GT-NG and 34x100MW Solar PV	3,544	3,305	5,190	2,474	826	**15,339**	**391**	89.55	**8**
C. Starting from 2026, all power plants are new additions											
17	CCGT-NG Only	23x250MW CCGT-NG, 16x200 GT-NG and 34x100MW Solar PV	4,222	2,495	5,055	1,630	748	**14,149**	**-798**	82.60	**1**
18	3000MW LNG	12x250MW CCGT-LNG, 11x250MW CCGT-NG, 16x200MW GT-NG and 34x100MW Solar PV	4,222	2,495	5,718	1,630	748	**14,813**	**-135**	86.48	**2**

The formulation and construction of scenarios were started with scenarios under Group B assumptions. After examination of the results, it was recognized that one of Scenarios 3 and 5 would possibly be recommended as the least-cost plan. Two similar scenarios were then constructed for each of Group A assumptions and Group C assumptions, namely Scenarios 1 and 2 for Group A assumptions and Scenarios 17 and 18 for Group C assumptions. More detailed annual cost, total cost, LCOE, and annual capacity balance table for Scenario 3 are presented in Appendix C, including the following:

1) Table C-1: Cost Summary – Scenario 03
2) Table C-2: Capacity Balance Table – Scenario 03

The information presented in the tables in Appendix C is self-explanatory. However, it is assumed that the system could tolerate a 30 MW deficit of net effective capacity (after taking into account peak demand and 65 MW operating reserve). Power plant sites are also presented in the capacity balance tables.

By examining the information presented in Table 5-3, one may conclude the following:

1) The following information would be helpful to understand the impacts of the existing generation on the evaluated cost:
    i) Without adequate generation capacity in the state, the power to be supplied to the state would come from Egbin and power plants located in other states, some of which could be at least a few hundred kilometers away.
    ii) All grid-connected power plants in Nigeria could be divided into three groups; hydro, NG-fueled thermal, and NG-fired open/combined cycle gas turbine (GT/CCGT). The Alaoji and Olorunsogo II power plants were designed as CCGTs, but only GTs have been commissioned and STs have not been commissioned. At present, there is no CCGT power plant in operation.
    iii) The thermal and GT power plants have a much higher heat rate than CCGT power plants, which results in higher fuel cost in US$/MWh.
    iv) Due to the low availability of the existing thermal and GT power plants and their fixed cost including capital repayment, O&M, insurance premium, and others, the fixed cost allocated to each unit of energy produced would be high.
    v) In this study, the generation supplying Lagos State load is a mix of the entire generation fleet, the cost of which is estimated.
    vi) Existing power plants may have PPAs that specify a generation tariff, but the study team was unable to collect them. The generation tariff in the PPAs could be single price in US$/MWh, two-component prices (one for capacity in US$/kW-year and the other for energy in US$/MWh), or other forms. In case of a two-component tariff, the one for capacity is to cover the capital repayment, fixed O&M, land lease, insurance premium, property tax, and others, while the one for energy is to cover fuel, lubricant, variable O&M, etc.
    vii) The unit cost of energy from the existing generation fleet would be higher than the planned CCGT power plants.
2) The total generation cost of the two scenarios under Group A assumptions is between US$15,676 and US$15,974 million. For the 14 scenarios developed under Group B assumptions, the generation cost varies from US$14,948 to US$15,771 million. The generation cost of the two scenarios under Group C assumptions is between US$14,149 and US$14,813 million.
3) Among the scenarios within each of the three groups, the scenario with all generation from NG CCGT and GT power plants has the lowest cost, namely Scenario 1 in Group A, Scenario 3 in

Group B, and Scenario 17 in Group C. Among these three scenarios, the scenario with all new power plants from 2026 onwards has the lowest cost, and that is Scenario 17.

4) Scenario 17 has the lowest cost of US$14,149 million. The one with the second lowest cost among all scenarios is Scenario 18. The difference between the two scenarios is that Scenario 18 has 3,000 MW of LNG CCGT added.
5) Scenario 3 is ranked third with a total cost of US$14,948 million.
6) Except for NG and LNG, no other major resources could provide a large amount of cost-competitive power generation. The study also examines the system cost with 400 MW RICE, 900 MW petcoke, and/or 1,200 MW coal, and finds them not very cost-competitive, in addition to the concerns noted below:
   i) HFO could be supplied from either the Dangote refinery currently being constructed or operational refineries located in other states. The price of the HFO is a serious concern.
   ii) It is not clear if the by-products of the Dangote refinery would include petcoke. In addition to its availability, other concerns about a petcoke power plant include capital cost, fuel price, GHG emissions, and SO_x emissions.
   iii) Coal would need to be transported from other states by rail. Similar to petcoke, the main concerns about a coal power plant include capital cost, fuel price, fuel supply security, GHG emissions, and SO_x emissions (a CFB boiler could be used for low-sulphur coal to reduce SO_x emissions by approximately 80%). Taking into account the high density of population of Lagos State, only one coal power plant with up to 1,200 MW could be constructed if all concerns could be properly addressed and the final cost is lower than that of NG CCGT.
7) The assumptions for new import are same as those for domestic NG CCGT except for the following two:
   i) The NG cost for the new import is the regulated price, while the fuel cost for the domestic CCGT is the weighted average of 95% of regulated NG price and 5% of LFO price.
   ii) Each unit of energy (MWh) of the new import would cost US$12 for wheeling, which is for transmission losses and transmission usage fee.

5.3 GENERATION DEVELOPMENT SCENARIOS FOR THE HIGH AND LOW LOAD FORECAST

Similar to that for the most likely load forecast, the study team also calculated the renewable energy requirements for the high and low load forecasts, which are presented in Table 5-4 and Table 5-5.

For the high load growth case, the following may be observed from Table 5-4:

1) 2,400 (24X100) MW solar PV power plants would need be constructed prior to 2030 in order to meet the 15% renewable energy target. It is suggested that four power plant be added each year over the period from 2025 to 2030.
2) By 2040, the system would need a total of 4,600 (46x100) MW solar PV power plants.
3) Over the period from 2030 to 2040, the penetration level of renewable is approximately 50%, which is at a very high level. Comprehensive studies should be carried out to examine the impact of the high-level renewable penetration on system operation.

Table 5-4: Installation Schedule of Solar PV Power Plants – High Load Forecast

High Load Forecast

Renewable Requirements =	15.0%
Solar PV Power Plant Size (MW) =	100.0
Solar PV Capacity Factor =	20.0%
Solar PV Annual Energy Production (GWh) =	175.2

Year	Peak Demand (MW)	Forecast Demand (GWh)	Renewable Required (GWh)	Total Number of Solar PV Plants Required	Annual Addition (Plant)	Total Addition (Plant)	Solar PV Penetration to Peak
2019	1,757.8	10,008.8					
2020	1,866.3	10,626.5					
2021	2,047.9	11,660.6					
2022	2,254.8	12,838.6					
2023	2,487.4	14,163.3					
2024	2,746.3	15,637.2					
2025	3,031.8	17,263.3			4	4	
2026	3,361.2	19,138.5			4	8	
2027	3,700.4	21,069.8			4	12	
2028	4,050.5	23,063.3			4	16	
2029	4,424.7	25,194.1			4	20	
2030	4,813.8	27,409.6	4,111.4	24	4	24	49.9%
2031	5,211.5	29,674.4	4,451.2	26	2	26	49.9%
2032	5,625.3	32,030.7	4,804.6	28	2	28	49.8%
2033	6,056.2	34,484.0	5,172.6	30	2	30	49.5%
2034	6,505.1	37,040.1	5,556.0	32	2	32	49.2%
2035	6,973.1	39,705.1	5,955.8	34	2	34	48.8%
2036	7,425.3	42,279.9	6,342.0	37	3	37	49.8%
2037	7,898.8	44,976.0	6,746.4	39	2	39	49.4%
2038	8,394.8	47,800.0	7,170.0	41	2	41	48.8%
2039	8,888.9	50,613.5	7,592.0	44	3	44	49.5%
2040	9,379.5	53,407.1	8,011.1	46	2	46	49.0%

For the low load growth case, we may see the following from Table 5-5:

1) 1,700 (17X100) MW solar PV power plants would be required by 2030 in order to meet the 15% renewable energy target. The suggested addition schedule is 2x100 MW for each of 2025 to 2027, 3x100 MW for 2028, and 4x100 MW for each of 2029 and 2030.
2) By 2040, a total of 2,500 (25x100) MW solar PV power would be required.
3) Over the period from 2030 to 2040, the penetration level of renewable is approximately 50%, which is at a very high level. Comprehensive studies should be carried out to examine the impact of the high-level renewable penetration on system operation.

Table 5-5: Installation Schedule of Solar PV Power Plants – Low Load Forecast

Low Load Forecast	
Renewable Requirements =	15.0%
Solar PV Power Plant Size (MW) =	100.0
Solar PV Capacity Factor =	20.0%
Solar PV Annual Energy Production (GWh) =	175.2

Year	Peak Demand (MW)	Forecast Demand (GWh)	Renewable Required (GWh)	Total Number of Solar PV Plants Required	Annual Addition (Plant)	Total Addition (Plant)	Solar PV Penetration to Peak
2019	1,757.8	10,008.8					
2020	1,866.3	10,626.5					
2021	1,980.8	11,278.7					
2022	2,105.2	11,987.1					
2023	2,239.3	12,750.8					
2024	2,383.0	13,569.0					
2025	2,536.2	14,441.3			2	2	
2026	2,682.1	15,272.1			2	4	
2027	2,836.0	16,148.1			2	6	
2028	2,990.6	17,028.6			3	9	
2029	3,155.0	17,964.7			4	13	
2030	3,321.6	18,913.0	2,837.0	17	4	17	51.2%
2031	3,485.0	19,843.8	2,976.6	17	0	17	48.8%
2032	3,650.7	20,787.3	3,118.1	18	1	18	49.3%
2033	3,818.8	21,744.5	3,261.7	19	1	19	49.8%
2034	3,989.5	22,716.4	3,407.5	20	1	20	50.1%
2035	4,162.9	23,703.7	3,555.6	21	1	21	50.4%
2036	4,339.2	24,707.4	3,706.1	22	1	22	50.7%
2037	4,518.5	25,728.1	3,859.2	23	1	23	50.9%
2038	4,700.9	26,766.7	4,015.0	23	0	23	48.9%
2039	4,877.2	27,770.9	4,165.6	24	1	24	49.2%
2040	5,021.6	28,593.0	4,289.0	25	1	25	49.8%

For each of the high and low load forecast cases, three generation expansion plans have been formulated and developed. Each of the three expansion plans under one set of load forecast conditions corresponds to one of the three sets of group assumptions on the generation capacity supplying load in 2025. These six expansion plans are developed using NG-fired CCGT and GT only, without any generation from other resources.

Table 5-6 shows the total generation cost of the six scenarios for the high and low load forecasts. Similar to the conclusions derived for the most likely load forecast, no matter the high or low load forecast, the generation expansion plan under Group C assumptions results in lowest cost.

One may see from Table 5-6 that under the high load forecast conditions, the total generation cost of the three scenarios varies from US$16,419 to US$17,925 million. Under the low load forecast, the total generation cost varies from US$12,250 to US$13,737 million.

Table 5-6: Cost of Scenarios for High and Low Load Forecasts

Scenario No.	Scenario Description	Main Capacity Additions from 2026 to 2040	Cost in Present Value (Million US$, 2020) From 2020 to 2040: Capital	Other Fix	Fuel	Other Var	GHG	Total	LCOE ($/MWh)
A. Carry forward all generation capacity in 2025 - high load forecast									
21	CCGT-NG Only	22x250MW CCGT-NG, 13x200MW GT-NG and 46x100MW Solar PV	3,082	4,724	6,366	2,759	993	**17,925**	89.41
B. Starting from 2026, all power plants (except for Egbin) are new additions - high load forecast									
22	CCGT-NG Only	26x250MW CCGT-NG, 21x200MW GT-NG and 46x100MW Solar PV	4,560	3,509	6,131	2,117	933	**17,250**	86.04
C. Starting from 2026, all power plants are new additions - high load forecast									
23	CCGT-NG Only	33x250MW CCGT-NG, 19x200 GT-NG and 46x100MW Solar PV	5,276	2,712	5,764	1,820	848	**16,419**	81.90
A. Carry forward all generation capacity in 2025 - low load forecast									
31	CCGT-NG Only	7x250MW CCGT-NG, 8x200MW GT-NG and 25x100MW Solar PV	1,573	4,109	4,987	2,275	794	**13,737**	93.57
B. Starting from 2026, all power plants (except for Egbin) are new additions - low load forecast									
32	CCGT-NG Only	12x250MW CCGT-NG, 11x200MW GT-NG and 25x100MW Solar PV	2,686	3,124	4,753	1,749	738	**13,051**	88.90
C. Starting from 2026, all power plants are new additions - low load forecast									
33	CCGT-NG Only	17x250MW CCGT-NG, 11x200 GT-NG and 25x100MW Solar PV	3,438	2,333	4,373	1,455	652	**12,250**	83.45

5.4 DETERMINATION OF THE LEAST-COST GENERATION DEVELOPMENT PLAN

Through the analysis of resources available to Lagos State for power generation, it is recognized that the most important issues are fuel availability, fuel supply security, and fuel price.

5.4.1 FUEL AVAILABILITY

The main fuels available to power production in the state are NG supplied through pipelines and LNG transported through waterways or other means and then regasified through either a FSRU or an on-land regasification plant.

As described in Subsection 4.1.1, there was only one operational pipeline (ELPS I) in 2020, and its capacity has been almost used up. Construction of ELPS II has been recently completed and it is operational now after undergoing an extended construction period. In addition, Dangote proposes to build the EWOGGS with two 36-inch, 550km pipelines.

LNG could be supplied by the Nigeria LNG plant located in Bonny Island of River State and/or imported from the international market. Depending on the economics and required term, either one FSRU could be leased for regasification of LNG or one on-land regasification plant could be constructed.

Solar PV power could be used to achieve the renewable energy target. However, solar PV power may not contribute any capacity credit to the Lagos system due to its intermittence, very low or no availability during the high load demand period of weekdays, namely from 19:00 to 22:00.

Other renewable resources, such as municipal solid waste and agricultural crop residues, could support achieving the renewable energy target and resource diversification while providing firm generation capacity but in a limited capacity due to its limited quantity.

Resources such as petcoke, HFO, coal, and uranium could be used to diversify the generation portfolio. However, these fuels should not be the majority of generation resources due to environmental, safety, and security concerns. It is also important to note that coal must be transported to the power plant in Lagos State from other states by rail, which would be more than one thousand kilometers away, which might not make it a commercially viable option for power generation.

5.4.2 FUEL SUPPLY SECURITY

Except for NG pipelines, other fuels could have a very high level of supply security, or power plants could have reasonable storage to store the fuel for later use in case of supply interruption. The NG pipelines in Nigeria have encountered interruptions due to various reasons such as vandalism and maintenance.

When there is only one NG pipeline, NG-fired power plants must be shut down if the gas supply is interrupted as a large volume of gas cannot be readily stored. It is important to note that the availability of pipelines could be studied according to the number of pipelines available and their operating conditions.

For this IRP, it is recommended that, absent a detailed analysis of the availability and security of pipeline NG, all GTs used in either CCGT or GT configurations should be designed for dual fuel use; that is, they could use either NG or LFO in order to overcome pipeline interruptions. In this case, each power plant could have a certain amount of storage of LFO to fuel the GTs. The actual storage capacity for each power plant needs to be studied. It is strongly recommended that the availability and security of the pipeline NG be studied. The GTs could be designed as single fuel if the fuel supply could be maintained at an acceptable level.

It could also be possible that LNG is used to fuel CCGTs and GTs before the supply security of NG pipelines has reached the acceptable level and a switch from LNG to pipeline NG can be affected.

5.4.3 FUEL PRICE

The fuel price estimate has been summarized in Subsection 4.2 and presented in Table 4-3. Based on the analysis described in previous sections, it is very clear that NG-fired CCGT and GT power plants are much more cost-competitive than other fueled generation technologies and the scenarios with them have lower cost. In this case, the NG price is the regulated one, namely a total of US$3.3/MMBTU (including US$2.5/MMBTU and US$0.8/MMBTU for transportation or delivery), which is much lower than that supplied to other industries.

Compared with the supply of NG through pipeline, the price of LNG could be much higher as it includes other two important processes, liquefaction and regasification. Perhaps a favorable LNG price could be negotiated with Nigeria LNG Limited (NLNG) with the support of the federal and state governments.

5.5 LEAST-COST GENERATION DEVELOPMENT PLAN

5.5.1 ANNUAL COST AND DEVELOPMENT SEQUENCE

Based on the descriptions provided in the previous section and analysis carried out, it is concluded that Scenario 3 should be selected as the least-cost generation development plan for the IRP and subsequent transmission analysis, which includes the following important assumptions:

1) It is for the most likely load forecast.
2) Group B assumptions: that is, all generation capacity supplying load in 2025 will be retired except for Egbin power plant, which is located in Lagos State. The plant was fully commissioned in September 1986, and so it is almost 35 years old. It is assumed that after retirement of the existing six units, the same amount of new generation capacity will be built, and the cost estimate covers all cost of the new generation facility.
3) Only dual-fuel (NG and LFO) CCGT and GT power plants will be constructed to meet the load demand except for the solar PV power plants used to meet the 15% renewable energy target.

The annual cost by category and capacity balance table of the least-cost generation development plan are presented in Table 5-7 and Table 5-8, which are same as Table C-1 and Table C-2 in Appendix C. The following may be observed from Table 5-7:

Table 5-7: Annual Cost by Category – Generation Development Plan

Present Value Reference Year: 2020
Discount Rate: 10.0%
GHG Emission Offset Allowance: 10 $/Tonne

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Peak	1,866.3	2,014.2	2,179.2	2,361.2	2,560.3	2,776.5	3,009.9	3,247.4	3,489.7	3,747.5	4,012.3	4,278.3	4,551.7	4,832.8	5,122.1	5,420.0	5,708.9	6,007.1	6,315.2	6,633.5	6,924.1
Energy	10,626.5	11,469.0	12,408.4	13,444.7	14,578.2	15,809.3	17,138.3	18,490.9	19,870.3	21,338.2	22,846.1	24,360.7	25,917.3	27,518.0	29,165.3	30,861.4	32,506.3	34,204.5	35,958.7	37,771.1	39,425.7
Cost in Current Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	22.4	394.4	462.5	540.6	642.0	720.1	787.9	843.6	911.4	955.8	1,034.9	1,102.7	1,158.3	1,226.1	1,305.2	1,349.6
Other Fixed Cost (Excluding Capital Repayment)	366.8	383.0	402.0	422.9	448.9	481.4	251.5	263.9	278.4	295.3	309.8	319.2	328.7	338.1	345.1	357.0	366.4	375.9	385.3	397.2	404.2
Fuel Cost	406.8	439.0	474.8	514.0	550.4	575.6	552.8	574.4	592.4	613.5	635.9	674.3	708.7	749.7	792.0	830.7	872.9	911.6	957.2	999.6	959.2
Other Variable Cost (Excluding Fuel Cost)	174.3	195.1	218.4	243.3	269.1	287.8	166.8	170.9	175.1	179.7	184.7	193.1	200.6	209.5	218.7	227.0	236.1	244.4	254.2	263.2	254.5
GHG Offset Allowance	65.5	70.7	76.4	82.7	88.6	92.6	83.8	86.8	89.3	92.2	95.2	100.5	105.3	111.0	116.8	122.2	128.0	133.3	139.6	145.5	139.8
Total	**1,013.3**	**1,087.7**	**1,171.6**	**1,262.8**	**1,356.9**	**1,459.8**	**1,449.4**	**1,558.5**	**1,675.8**	**1,822.7**	**1,945.7**	**2,075.0**	**2,186.9**	**2,319.7**	**2,428.5**	**2,571.8**	**2,706.1**	**2,823.6**	**2,962.5**	**3,110.6**	**3,107.3**
Cumulative Cost in Current Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	22.4	416.8	879.3	1,419.9	2,061.9	2,782.0	3,569.9	4,413.5	5,324.9	6,280.8	7,315.6	8,418.3	9,576.6	10,802.8	12,107.9	13,457.5
Other Fixed Cost (Excluding Capital Repayment)	366.8	749.7	1,151.7	1,574.5	2,023.4	2,504.7	2,756.2	3,020.1	3,298.5	3,593.8	3,903.6	4,222.8	4,551.5	4,889.6	5,234.7	5,591.7	5,958.1	6,334.0	6,719.3	7,116.5	7,520.7
Fuel Cost	406.8	845.8	1,320.6	1,834.6	2,384.9	2,960.5	3,513.3	4,087.7	4,680.1	5,293.6	5,929.5	6,603.8	7,312.4	8,062.1	8,854.1	9,684.8	10,557.7	11,469.4	12,426.6	13,426.2	14,385.3
Other Variable Cost (Excluding Fuel Cost)	174.3	369.4	587.8	831.1	1,100.2	1,388.0	1,554.9	1,725.8	1,900.9	2,080.6	2,265.3	2,458.4	2,659.0	2,868.5	3,087.2	3,314.2	3,550.3	3,794.8	4,048.9	4,312.1	4,566.6
GHG Offset Allowance	65.5	136.1	212.5	295.2	383.8	476.4	560.3	647.1	736.3	828.5	923.7	1,024.2	1,129.5	1,240.5	1,357.3	1,479.5	1,607.5	1,740.8	1,880.5	2,025.9	2,165.7
Total	**1,013.3**	**2,101.0**	**3,272.6**	**4,535.4**	**5,892.3**	**7,352.1**	**8,801.4**	**10,360.0**	**12,035.7**	**13,858.4**	**15,804.1**	**17,879.1**	**20,066.0**	**22,385.6**	**24,814.1**	**27,385.9**	**30,092.0**	**32,915.6**	**35,878.1**	**38,988.6**	**42,095.9**
Discount Factor	0.9535	0.8668	0.7880	0.7164	0.6512	0.5920	0.5382	0.4893	0.4448	0.4044	0.3676	0.3342	0.3038	0.2762	0.2511	0.2283	0.2075	0.1886	0.1715	0.1559	0.1417
Cost in Present Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	13.3	212.2	226.3	240.5	259.6	264.7	263.3	256.3	251.7	240.0	236.2	228.8	218.5	210.3	203.5	191.3
Other Fixed Cost (Excluding Capital Repayment)	349.7	331.9	316.7	302.9	292.3	285.0	135.4	129.1	123.8	119.4	113.9	106.7	99.9	93.4	86.6	81.5	76.0	70.9	66.1	61.9	57.3
Fuel Cost	387.9	380.5	374.1	368.2	358.4	340.7	297.5	281.0	263.5	248.1	233.7	225.3	215.3	207.0	198.9	189.6	181.1	172.0	164.2	155.8	135.9
Other Variable Cost (Excluding Fuel Cost)	166.2	169.1	172.1	174.3	175.2	170.4	89.8	83.6	77.9	72.7	67.9	64.5	60.9	57.9	54.9	51.8	49.0	46.1	43.6	41.0	36.1
GHG Offset Allowance	62.4	61.2	60.2	59.3	57.7	54.8	45.1	42.5	39.7	37.3	35.0	33.6	32.0	30.6	29.3	27.9	26.6	25.2	23.9	22.7	19.8
Total	**966.1**	**942.8**	**923.2**	**904.6**	**883.6**	**864.2**	**780.1**	**762.5**	**745.4**	**737.0**	**715.2**	**693.4**	**664.4**	**640.7**	**609.7**	**587.0**	**561.5**	**532.6**	**508.0**	**484.9**	**440.4**
Cumulative Cost in Present Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	13.3	225.5	451.8	692.3	951.9	1,216.6	1,479.9	1,736.2	1,987.9	2,227.9	2,464.1	2,692.9	2,911.4	3,121.7	3,325.1	3,516.4
Other Fixed Cost (Excluding Capital Repayment)	349.7	681.6	998.3	1,301.3	1,593.6	1,878.5	2,013.9	2,143.0	2,266.8	2,386.3	2,500.1	2,606.8	2,706.7	2,800.0	2,886.7	2,968.2	3,044.2	3,115.1	3,181.2	3,243.1	3,300.4
Fuel Cost	387.9	768.4	1,142.5	1,510.7	1,869.1	2,209.9	2,507.4	2,788.4	3,051.9	3,300.0	3,533.8	3,759.1	3,974.4	4,181.4	4,380.3	4,569.9	4,751.0	4,923.0	5,087.2	5,243.0	5,378.9
Other Variable Cost (Excluding Fuel Cost)	166.2	335.3	507.4	681.7	856.9	1,027.3	1,117.1	1,200.8	1,278.6	1,351.3	1,419.2	1,483.7	1,544.7	1,602.5	1,657.4	1,709.3	1,758.3	1,804.4	1,847.9	1,889.0	1,925.0
GHG Offset Allowance	62.4	123.7	183.9	243.1	300.8	355.6	400.8	443.2	482.9	520.2	555.2	588.8	620.8	651.4	680.8	708.6	735.2	760.4	784.3	807.0	826.8
Total	**966.1**	**1,908.9**	**2,832.1**	**3,736.8**	**4,620.4**	**5,484.6**	**6,264.7**	**7,027.2**	**7,772.6**	**8,509.6**	**9,224.9**	**9,918.3**	**10,582.7**	**11,223.3**	**11,833.1**	**12,420.1**	**12,981.6**	**13,514.2**	**14,022.3**	**14,507.2**	**14,947.6**

Levelized Cost of Energy (US$/MWh) = 87.26 Total Cost in PV (M-US$) = 14,947.6 Total Energy in PV (GWh) = 171,292.7

Table 5-8: Capacity Balance Table

Year	Addition/Retirement								Total		Annual	Reserve		
		Capacity (MW)							Net	Effective	Peak	Net Capacity		Effective
	Location	Network	CC-NG	GT-NG	Solar	Total	Net	Effective	Capacity	Capacity	(MW)	(MW)	(%)	Capacity
2019											1,758			
2020	Egbin	1,320				1,320	1,188	984	2,248	1,869	1,866	382	20	3
	External	1,175				1,175	1,060	885						
2021	External	180				180	166	148	2,414	2,017	2,014	399	20	2
2022	External	200				200	184	164	2,598	2,181	2,179	418	19	2
2023	External	220				220	202	181	2,800	2,362	2,361	439	19	0
2024	External	260				260	234	202	3,034	2,564	2,560	474	19	4
2025	External	275				275	248	214	3,282	2,778	2,776	505	18	2
					200	200	0	0						
2026	External	-2,310				-2,310	-2,094	-1,794	3,683	3,167	3,010	673	22	158
	Site12		1,750			1,750	1,575	1,362						
	Site05			1,000		1,000	920	822						
					200	200	0	0						
2027	Site05			200		200	184	164	3,867	3,332	3,247	620	19	84
					400	400	0	0						
2028	Site12		250			250	225	195	4,092	3,526	3,490	602	17	37
					400	400	0	0						
2029	Site09		250			250	225	195	4,501	3,885	3,747	754	20	138
	Site05			200		200	184	164						
					400	400	0	0						
2030	Site09		250			250	225	195	4,726	4,080	4,012	714	18	67
					400	400	0	0						
2031	Site09		250			250	225	195	5,135	4,439	4,278	857	20	160
	Site05			200		200	184	164						
					100	100	0	0						
2032	Site09		250			250	225	195	5,360	4,633	4,552	808	18	82
					200	200	0	0						
2033	Site09		250			250	225	195	5,769	4,992	4,833	936	19	159
	Site02			200		200	184	164						
					100	100	0	0						
2034	Site09		250			250	225	195	5,994	5,187	5,122	872	17	65
					100	100	0	0						
2035	Site09		250			250	225	195	6,403	5,546	5,420	983	18	126
	Site02			200		200	184	164						
					200	200	0	0						
2036	Site09		250			250	225	195	6,812	5,905	5,709	1,103	19	196
	Site02			200		200	184	164						
					100	100	0	0						
2037	Site06		250			250	225	195	7,037	6,099	6,007	1,030	17	92
					200	200	0	0						
2038	Site06		250			250	225	195	7,446	6,458	6,315	1,131	18	143
	Site02			200		200	184	164						
					100	100	0	0						
2039	Site06		250			250	225	195	7,855	6,817	6,633	1,222	18	184
	Site02			200		200	184	164						
					200	200	0	0						
2040	Site06		250			250	225	195	8,080	7,012	6,924	1,156	17	88
					100	100	0	0						
Total		**1,320**	**5,000**	**2,600**	**3,400**	**12,320**	**8,080**	**7,012**						

1) The peak demand and energy demand by 2040 will reach approximately 6,924 MW and 39,426 GWh, respectively.

2) The total generation cost (in current value) over the planning period from 2020 to 2040 will be US$42,096 million, including US$13,458 million for capital repayment, US$7,521 million for other fixed costs, US$14,385 million for fuel, US$4,567 million for other variable cost, and US$2,166 million for GHG offset allowance.

3) The total generation cost (in present value) over the planning period will be US$14,948 million, including US$3,516 million for capital repayment, US$3,300 million for other fixed costs, US$5,379 million for fuel, US$1,925 million for other variable cost, and US$827 million for GHG offset allowance.
4) The LCOE over the planning period will be US$87.26 per MWh.

One may observe or calculate the following from Table 5-8:

1) From 2026 to 2040, there would be 5,000 (20x250) MW CCGT power plants added to the system: 2,000 MW at Site 12, 2,000 MW at Site 9, and 1,000 MW at Site 6.
2) A total of 2,600 (13x200) MW GT power plants would be added to the system, including 1,600 MW at Site 5 and 1,000 MW at Site 2.
3) A total of 3,400 (34x100) MW of solar PV power plants will be added to the system. It is assumed that at least 50% of the solar PV capacity would be contributed by rooftop installations. The rest could be installed at large solar PV power plants.

The selected least-cost generation development plan includes only NG-fueled CCGT and GT power plants and solar PV power plants, which is determined according to the presumed technical and economic parameters of generation technologies. Other renewable generation technologies could be used to replace some of the solar power plants and/or NG-fueled CCGT and GT power plants when they are cost-competitive and/or diversification of resources is required. It is important to note that development of Waste to Energy (WTE) plants would result in electricity production and other environmental and social benefits. It is therefore suggested that the State Government carry out an extensive WTE study to examine the costs and benefits. The cost of a WTE plant can be offset by the electricity produced and other environmental and social impacts reduced or avoided. Similarly, LNG, coal, petcoke, HFO, and uranium-fueled generation technologies as well as import from other states could be used to replace some of the NG-fueled CCGT and GT power plants when they are cost-competitive, environmentally friendly, socially responsible, and sustainable and/or diversification of resources/supplies is necessary.

5.5.2 ANNUAL CAPITAL INVESTMENT CASH FLOW

In evaluating the generation cost for each scenario, the capitalized cost (overnight cost-plus IDC) of a power plant is amortized to annual repayments over its economic life, i.e the product of the capitalized cost and capital recovery factor. However, during construction of a power plant, its overnight cost will be distributed per the presumed capital expenditure cash flow prior to completion of construction. Table 5-9 shows the annual capital investment cash flow for the least-cost generation development plan, including the following:

1) Addition number
2) Technology added
3) Capacity added in MW
4) Unit/Plant operational year
5) Total overnight cost of the generation unit/power plant
6) Annual capital disbursement flow

The presumed capital expenditure (or disbursement) cash flow for each selected generation technology is presented in the corresponding table presented in Appendix B. For easy reference, the following lists the capital expenditure cash flow for CCGT, GT, and solar PV power plant:

1) CCGT – 25%, 45%, and 30% over the three-year construction period
2) GT – 60% and 40% over the two-year construction period

3) Solar PV – 60% and 40% over the two-year construction period

One may understand the following from Table 5-9:

1) The capital cash flow presented in the table does not include that required for the generation projects to be commissioned after 2040 although their construction may start prior to 2041.
2) The overnight cost of one 250 MW CCGT unit will be US$275 million, US$200 million for one 200 MW GT unit, and US$90 million for one 100 MW solar PV power plant.
3) The total capital investment over the study period will be US$11,160 million.
4) The total capital investment over every five years will be as follows:
    i) US$3,690 million from 2020 to 2025
    ii) US$3,195 million from 2026 to 2030
    iii) US$2,605 million from 2031 to 2035
    iv) US$1,671 million from 2036 to 2040

Table 5-9: Capital Expenditure Cash Flow – Generation Development Plan

Addition				Total	Year																				
No.	**Technology**	**(MW)**	**On-Line**	**(M-US$)**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
2	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
3	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
4	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
5	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
6	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
7	**CCGT-NG**	**250**	**2026**	**275.0**				68.8	123.8	82.5															
8	**CCGT-NG**	**250**	**2028**	**275.0**						68.8	123.8	82.5													
9	**CCGT-NG**	**250**	**2029**	**275.0**							68.8	123.8	82.5												
10	**CCGT-NG**	**250**	**2030**	**275.0**								68.8	123.8	82.5											
11	**CCGT-NG**	**250**	**2031**	**275.0**									68.8	123.8	82.5										
12	**CCGT-NG**	**250**	**2032**	**275.0**										68.8	123.8	82.5									
13	**CCGT-NG**	**250**	**2033**	**275.0**											68.8	123.8	82.5								
14	**CCGT-NG**	**250**	**2034**	**275.0**												68.8	123.8	82.5							
15	**CCGT-NG**	**250**	**2035**	**275.0**													68.8	123.8	82.5						
16	**CCGT-NG**	**250**	**2036**	**275.0**														68.8	123.8	82.5					
17	**CCGT-NG**	**250**	**2037**	**275.0**															68.8	123.8	82.5				
18	**CCGT-NG**	**250**	**2038**	**275.0**																68.8	123.8	82.5			
19	**CCGT-NG**	**250**	**2039**	**275.0**																	68.8	123.8	82.5		
20	**CCGT-NG**	**250**	**2040**	**275.0**																		68.8	123.8	82.5	
21	**GT-NG**	**200**	**2026**	**200.0**					120.0	80.0															
22	**GT-NG**	**200**	**2026**	**200.0**					120.0	80.0															
23	**GT-NG**	**200**	**2026**	**200.0**					120.0	80.0															
24	**GT-NG**	**200**	**2026**	**200.0**					120.0	80.0															
25	**GT-NG**	**200**	**2026**	**200.0**					120.0	80.0															
26	**GT-NG**	**200**	**2027**	**200.0**						120.0	80.0														
27	**GT-NG**	**200**	**2029**	**200.0**								120.0	80.0												
28	**GT-NG**	**200**	**2031**	**200.0**										120.0	80.0										
29	**GT-NG**	**200**	**2033**	**200.0**												120.0	80.0								
30	**GT-NG**	**200**	**2035**	**200.0**														120.0	80.0						
31	**GT-NG**	**200**	**2036**	**200.0**															120.0	80.0					
32	**GT-NG**	**200**	**2038**	**200.0**																	120.0	80.0			
33	**GT-NG**	**200**	**2039**	**200.0**																		120.0	80.0		
34	**Solar PV**	**100**	**2025**	**90.0**				54.0	36.0																
35	**Solar PV**	**100**	**2025**	**90.0**				54.0	36.0																
36	**Solar PV**	**100**	**2026**	**90.0**					54.0	36.0															
37	**Solar PV**	**100**	**2026**	**90.0**					54.0	36.0															

(Table 5-9 Continued)

Addition				Total	Year																				
No.	**Technology**	**(MW)**	**On-Line**	**(M-US$)**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
38	Solar PV	100	2027	90.0						54.0	36.0														
39	Solar PV	100	2027	90.0						54.0	36.0														
40	Solar PV	100	2027	90.0						54.0	36.0														
41	Solar PV	100	2027	90.0						54.0	36.0														
42	Solar PV	100	2028	90.0							54.0	36.0													
43	Solar PV	100	2028	90.0							54.0	36.0													
44	Solar PV	100	2028	90.0							54.0	36.0													
45	Solar PV	100	2028	90.0							54.0	36.0													
46	Solar PV	100	2029	90.0								54.0	36.0												
47	Solar PV	100	2029	90.0								54.0	36.0												
48	Solar PV	100	2029	90.0								54.0	36.0												
49	Solar PV	100	2029	90.0								54.0	36.0												
50	Solar PV	100	2030	90.0									54.0	36.0											
51	Solar PV	100	2030	90.0									54.0	36.0											
52	Solar PV	100	2030	90.0									54.0	36.0											
53	Solar PV	100	2030	90.0									54.0	36.0											
54	Solar PV	100	2031	90.0										54.0	36.0										
55	Solar PV	100	2032	90.0											54.0	36.0									
56	Solar PV	100	2032	90.0											54.0	36.0									
57	Solar PV	100	2033	90.0												54.0	36.0								
58	Solar PV	100	2034	90.0													54.0	36.0							
59	Solar PV	100	2035	90.0														54.0	36.0						
60	Solar PV	100	2035	90.0														54.0	36.0						
61	Solar PV	100	2036	90.0															54.0	36.0					
62	Solar PV	100	2037	90.0																54.0	36.0				
63	Solar PV	100	2037	90.0																54.0	36.0				
64	Solar PV	100	2038	90.0																	54.0	36.0			
65	Solar PV	100	2039	90.0																		54.0	36.0		
66	Solar PV	100	2039	90.0																		54.0	36.0		
67	Solar PV	100	2040	90.0																			54.0	36.0	
Total				**11,160**	**0**	**0**	**0**	**589**	**1,646**	**1,454**	**633**	**755**	**715**	**593**	**499**	**521**	**445**	**539**	**601**	**499**	**521**	**619**	**412**	**119**	**0**
Total for Every Five Years					**3,690**						**3,195**					**2,605**					**1,671**				
Cumulative					**0**	**0**	**0**	**589**	**2,236**	**3,690**	**4,322**	**5,077**	**5,792**	**6,385**	**6,884**	**7,405**	**7,850**	**8,389**	**8,990**	**9,489**	**10,010**	**10,629**	**11,042**	**11,160**	**11,160**

6 TRANSMISSION DEVELOPMENT PLAN

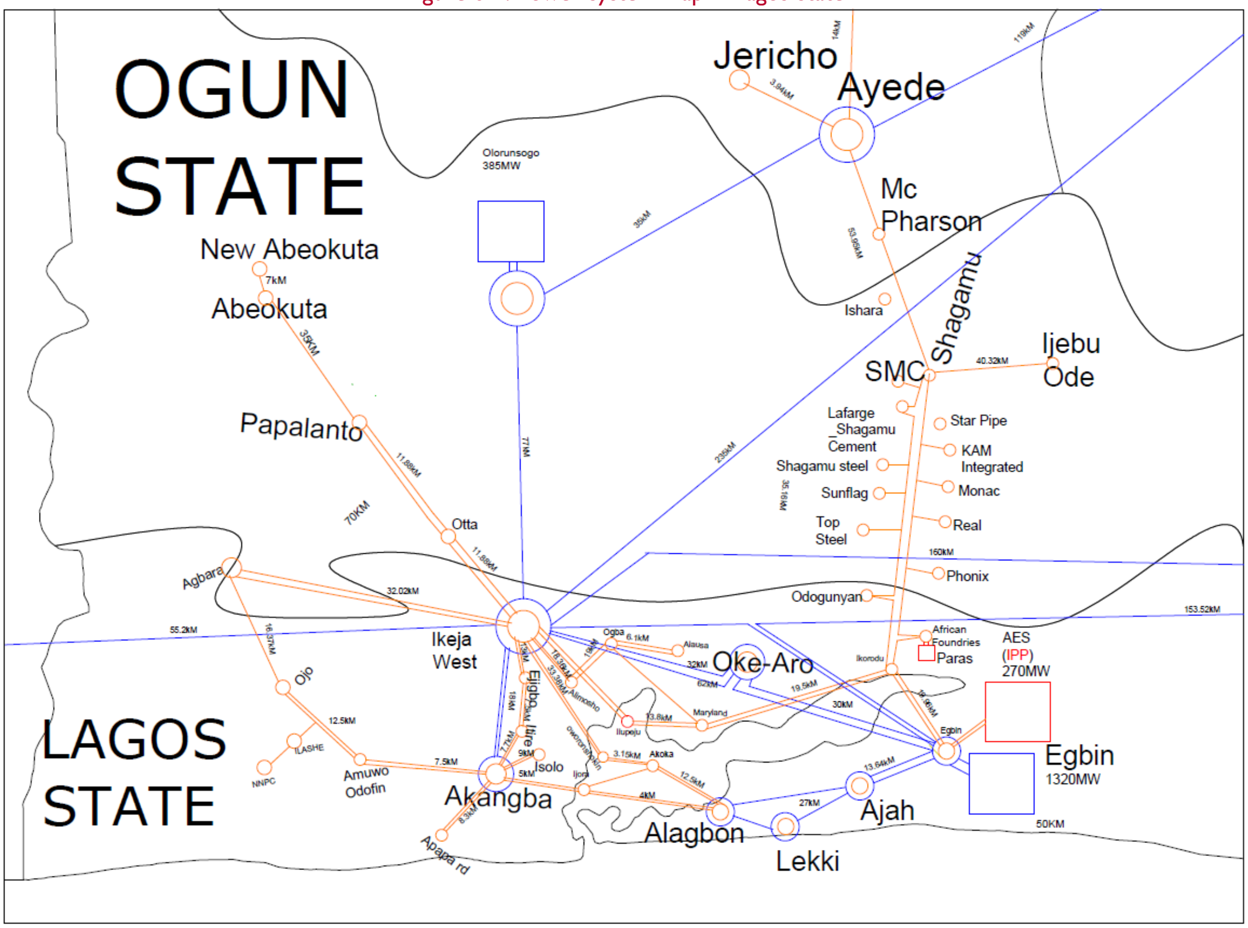
This section summarizes the existing transmission system in Lagos State and additional requirements over the planning horizon in order to evacuate power from power plants and deliver it to DISCOs, as well as the annual cost and capital investment cash flow.

6.1 THE EXISTING POWER GRID AND COMMITTED ADDITIONS

6.1.1 THE EXISTING POWER GRID

Figure 6-1 shows the current grid system map in Lagos State and a partial network in Ogun State.

Figure 6-1: Power System Map in Lagos State



As of 31 December 2020, the power system in Lagos State includes the following main components (either located in Lagos State or located in Ogun State and supplying 33 kV feeders connected to customers in Lagos State):

1) One 6x220 MW power plant (Egbin)
2) Thirteen 330 kV and more than thirty 132 kV transmission lines (one line may include one or more circuits)
3) Seven 330 kV substations, four of which also directly supply power to DISCOs 33 kV feeders

4) Twenty-one 132 kV substations (transformation stations) directly supply power to DISCOs 33 kV feeders (Ilashe was recently constructed and there was no 33 kV feeder connected to it yet). In addition, there are also several privately owned 132 kV substations in the state.

5) The location of the transformation stations/substations supplying Lagos State is geographically displayed in Figure 6-2.

Figure 6-2: Geographical Location of Transformation Stations Supply Lagos State

Table 6-1 and Table 6-2 present the basic information of the existing 330 kV and main 132 kV transmission lines respectively, which connect the substations shown in Figure 6-2. Basic information about the substations is presented in Table D-1 in Appendix D.

Table 6-1: The Existing 330 kV Transmission Lines

Line			length	Circuit Type
Number	From	To	(km)	(SC or DC)
1	Ajah	Alagbon	25.8	SC
2	Ajah	Lekki	9.4	SC
3	Benin	Egbin	269.3	SC
4	Egbin	Ajah	14.1	DC
5	Egbin	Oke Aro	41.8	DC
6	Ikeja West	Akangba	16.7	DC
7	Ikeja West	Egbin	44.6	SC
8	Ikeja West	Olorunsogo	41.3	SC
9	Ikeja West	Omotosho	173.3	SC
10	Ikeja West	Osogbo	238.7	SC
11	Ikeja West	Sakete (Benin)	71.7	SC
12	Lekki	Alagbon	16.6	SC
13	Oke Aro	Ikeja West	15.2	DC

Table 6-2: The Existing 132 kV Transmission Lines

Line			Length (km)	Circuit Type (SC or DC)
Number	From	To		
1	Agbara	Ojo	16.0	DC
2	Akangba	Amuwo Odofin	4.7	DC
3	Akangba	Apapa Road	5.0	SC
4	Akangba	Ijora	5.0	DC
5	Akangba	Isolo	4.8	DC
6	Akangba	Itire	3.4	DC
7	Akoka	Alagbon	6.0	SC
8	Alimosho	Ogba	8.3	DC
9	Ejigbo	Itire	4.1	DC
10	Ijora	Akoka	6.6	SC
11	Ijora	Alagbon	5.4	SC
12	Ikeja West	Agbara	24.2	DC
13	Ikeja West	Alimosho	5.7	DC
14	Ikeja West	Ayobo	1.0	DC
15	Ikeja West	Ejigbo	10.6	DC
16	Ikeja West	Ilupeju	16.8	DC
17	Ikeja West	Otta	8.5	DC
18	Ikeja West	Oworonshoki	33.0	DC
19	Ikorodu	Egbin	20.0	DC
20	Ikorodu	Odogunyan	28.1	SC
21	Ikorodu	Paras	9.0	SC
22	Ilashe	NNPC	16.3	SC
23	Ilupeju	Isolo	7.0	SC
24	Ilupeju	Maryland	2.4	DC
25	Maryland	Ikorodu	18.3	DC
26	NNPC Junction	Amuwo Odofin	7.9	SC
27	NNPC Junction	Ilashe	8.0	SC
28	Odogunyan	Sagamu	40.0	SC
29	Ogba	Alausa	2.0	SC
30	Ojo	Amuwo Odofin	12.5	SC
31	Ojo	NNPC Junction	1.0	SC
32	Otta	Ogba	44.3	SC
33	Oworonshoki	Akoka	3.4	DC
34	Paras	Sagamu	30.0	SC

6.1.2 COMMITTED ADDITIONS

Based on the information collected from TCN and the study team's analysis, there are quite a few committed, or planned, transmission line and substation projects in Lagos State and Ogun State in order to meet the fast-growing load demand in Lagos State. The committed additions include the following:

1) Construction of one 330 kV double-circuit line from Ajah transformation station (TS) to Epe TS with an expected online time of between 2024 and 2025

2) Construction of one 330 kV double-circuit line from Epe TS to Omotosho TS with an expected online time between 2023 and 2024
3) Construction of one 330 kV double-circuit line from Lekki TS to Eko Atlantic TS with an expected online time of 2023 (the line would be operated at 132 kV over its first several operation years)
4) Upgrade of the two existing 132/33 kV 45 MVA transformers to two 100 MVA transformers at Agbara TS in 2022
5) Addition of one 132/33 kV 100 MVA transformer to Ajah TS in 2023
6) Upgrade of the two existing 132/33 kV transformers, one from 45 MVA to 60 MVA and the other from 40 MVA to 60 MVA at Akoka TS in 2022
7) Upgrade of the existing 132/33 kV 45 MVA transformer to 100 MVA, and addition of one 132/33 kV 60 MVA transformer at Alausa TS in 2022
8) Addition of one 132/33 kV 60 MVA transformer to Amuwo TS before 2025
9) Return of the removed 132/33 kV 45 MVA transformer to Apapa-Road TS in 2023
10) Construction of two 132/33 kV 60 MVA transformers at Eko Atlantic TS in 2023
11) Upgrade of the two existing 132/33 kV 30 MVA transformers to two 100 MVA transformers at Ijora TS 2023
12) Repairing the damaged 132/33 kV 60 MVA transformer and upgrading the existing 132/33 kV 45 MVA transformer to 60 MVA at Isolo TS in 2022
13) Upgrading the three existing 132/33 kV transformers (one is damaged) to two 100 MVA and one 60 MVA at Itire TS in 2022
14) Addition of one 132/33 kV 60 MVA transformer to Lekki TS in 2022
15) Upgrade of the two existing 132/33 kV 30 MVA transformers to one 100 MVA and one 60 MVA at Maryland TS in 2022
16) Addition of one 132/33 kV 100 MVA transformer to Oke-Aro TS in 2022
17) Upgrade of the existing 132/33 kV 30 MVA transformers to 60MAV at Oworonshokin TS in 2022

6.2 LOAD FORECAST BY SUBSTATION

Based on the generation expansion sequence presented in the recommended least-cost generation development plan, the requirements of transmission system evacuating power from power plants and delivering it to the transformation stations are studied in detail for Years 2021, 2026, 2030, 2035, and 2040. The transmission requirements for remaining years are interpolated.

The peak demand by substation is predicted for two different times based on the forecast energy demand, one at the system peak time and the other at each individual substation station peak time.

Table D-2 and Table D-3 in Appendix D present the two forecast peaks by substation for the selected study years. The transformation capacity at each substation should meet its individual peak demand and transmission lines should be capable of transporting power to the load demand centers at all times.

One may see the following from Table D-2 and Table D-3:

1) The substation coincident peak for the selected five years presented in Table D-2 is 1,914, 2,859, 3,812, 5,149, and 6,578 MW, respectively, which are slightly lower than the corresponding forecast peak demands presented in Table 2-1. The difference between any one pair of these peak demands is the transmission (including line and substation transformer) losses. The peak loads in

the former table are measured at the interconnection points between transformation stations and the DISCOs' receiving points, while the peak loads in the latter table are measured at the interconnection points between generators and transmission grid.

2) The coincident peak at each substation is calculated based on the forecast energy demand for the substation and the system load factor.

3) The substation non-coincident peak for the selected five years presented in Table D-3 is 3,735, 5,532, 7,294, 9,775, and 12,417 MW, respectively, which is almost twice the corresponding value presented in Table D-2. This also means that each substation may experience its peak demand at a time different from other substations.

4) The non-coincident peak at each substation is calculated based on the forecast energy demand for the substation and its own load factor.

6.3 TECHNICAL AND ECONOMIC ASSUMPTIONS ON TRANSMISSION FACILITIES

The following lists the technical and economic assumptions on transmission facilities:

1) Construction Duration – 2 years
2) Capital Expenditure Disbursement Flow – 60% in the first construction year and 40% in the second construction year
3) IDC Addition Factor to Capitalize the EPC cost – 11.174%, calculated based on the discount rate of 10% and the cash disbursement flow
4) Economic Life – 25 years
5) Capital Recovery Factor – 10.504%, calculated based on the discount rate of 10% and the economic life
6) O&M Cost of the new transmission facilities – 10.0% of the EPC cost
7) O&M Cost of the existing transmission system – US$0.0107/kWh, estimated based on the NERC's reports for 2018 and 2019
8) 132 kV SC Line – US$0.17 million per km
9) 330 kV SC Line – US$0.30 million per km
10) 132 kV DC Line – US$0.28 million per km
11) 330 kV DC Line – US$0.45 million per km
12) 132 kV SC Line Reconductoring – US$0.05 million per km
13) 132 kV SC Line Reconductoring (RAIL equivalent) – US$0.05 million per km
14) 132 kV SC Line Reconductoring (ACCC 1000amp) – US$0.10 million per km
15) 132 kV Line Bay – US$0.80 million per set/installation
16) 330 kV Line Bay – US$1.70 million per set/installation
17) 132/33 kV 145 MVA Transformer – US$2.71 million per set/installation
18) 330/132 kV 300 MVA Transformer – US$4.60 million per set/installation
19) 132/33 kV 145 MVA Transformer – US$1.96 million per upgrade
20) 330/132 kV 300 MVA Transformer – US$3.6 million per upgrade

21) 132/33 kV 60 MVA Transformer – US$1.35 million per set/installation

22) 132/33 kV 100 MVA Transformer – US$2.1 million per set/installation

23) 132/33 kV 60 MVA Transformer – US$0.85 million per upgrade

24) 132/33 kV 100 MVA Transformer – US$1.6 million per upgrade

6.4 NETWORK STUDY AND UPGRADES OR ADDITIONS REQUIRED

6.4.1 YEAR 2021

Based on the information collected (generation capacity and peak load demand in 2019 in Lagos State), almost one half of the state's peak demand was supplied from the import of power from other states in Nigeria through the 330 kV transmission network. The electric system in Lagos State is connected to Ogun State via two 330 kV lines from Osogbo and Olorunsogo transformation stations (TS) to Ikeja West TS and two 330 kV lines from Benin TS station in Edo State to Egbin and Omotosho/Ikeja West transformation stations. Ikeja West TS is also connected to Sakete TS in the Republic of Benin. Egbin is the only generation station of 1,320 MW in the state which interconnects to two 330 kV lines to Ajah TS and three 330 kV lines towards Ikeja West TS, two of which are connected to Oke-Aro TS along the way.

The existing 132 kV transmission network in the state interconnects the existing seven (7) 330 kV transformation stations and provide limited intertransfer capability among these stations in case of contingencies of transmission system elements. Figure 6-3 provides a schematic diagram of the existing 330 kV and 132 kV network supplying power to various load centers in Lagos State.

Load flow studies and contingency analysis were performed to assess the adequacy of the existing transmission system. The results, under the normal system operation conditions, are depicted in Figure D-1 and Figure D-2 for 330 kV and 132 kV transmission networks, respectively. The results show that all transmission elements are operating within their loading capabilities and the voltage profile across the entire network is close to 90% of the nominal values. This low voltage range is primarily due to heavy reliance on the imported power from distant power plants and not having the support of local reactive power resources that could boost the voltage profiles of the 330 kV and 132 kV networks close to their nominal values.

The N-1 contingency analysis reveal than many of the transmission elements get overloaded after one element (a transformer or a transmission circuit) is out of service. Table D-4 shows the loading of the monitored elements, and Table D-5 shows the monitored buses with low voltage problem. In Table D-4, the overloaded elements are highlighted. A significant number of transmission system reinforcements and expansions will have to be implemented in the next two to five years to adequately meet the forecasted demand and to avoid violations of planning criteria in 2026. Accordingly, the proposed reinforcements for the system are presented in the next subsection.

6.4.2 YEAR 2026

Becoming self-sufficient in generation capacity within the state's geographical boundaries brings a major shift in the transmission system power flow and expansion plan. This emphasis not only reduces the reliance on the imported power from other states but also reduces transmission expansion requirements for the 330 kV network, which may have already been committed or planned by TCN. At the same time, generation interconnection facilities to the existing transmission network will need to be developed for the evacuation of power from the proposed two new power generation facilities to be implemented by 2026. The generation facility at Site 12 will be a CCGT power plant of 2,000 MW, and the generation facility at Site 5 will be a GT power plant of 1,600 MW. The CCGT power plant will be interconnected to Ajah, Lekki, and Alagbon 330 kV TS via two 330 kV double circuit lines. One 330 kV double-circuit, 50-km-long line from the CCGT power plant will be interconnected between Alagbon TS and Ajah TS. The second 330 kV double-circuit, 45-km-long line will be interconnected between Ajah TS and Lekki TS. The GT power plant is in the heart of the load center and will have multiple interconnections with the existing 132 kV transmission network, and multiple new 132 kV lines will be built to at least two new 132/33 kV transformation stations. The proposed interconnection schemes of both power plants are shown in the schematic diagram presented in Figure 6-4. Further, a few transformation stations will be reinforced with additional transformation capacities, and quite a few transmission lines need to be reconductored or expanded. Table 6-3 and Table 6-4 provide the proposed expansion plans for transformation stations and transmission lines respectively.

Table 6-3: Proposed Substation Additions/Upgrades – 2026

Sr. No.	Transformation Station	Voltage Rating (kV)	Capacity (MVA)
1	Aja	330/132	300
2	Lekki	132/33	170
3	Alagbon	330/132	300
4	Akangba	330/132	210
5	Egbin	330/132	300
6	New Ijora	330/132	600
7	Aja	132/33	255
8	Alagbon	132/33	85
9	Alagbon 2	132/33	290
10	Akangba	132/33	85
11	Isolo	132/33	85
12	Ejigbo	132/33	175
13	Maryland	132/33	115
14	Ikorodu	132/33	215
15	Ikorodu 2	132/33	145
16	Agbara	132/33	100
17	Akoka	132/33	115
18	Alausa	132/33	230
19	Alimosho	132/33	115
20	Amuwo	132/33	85
21	Apapa Road	132/33	115
22	Ayobo	132/33	85
23	New Ijora	132/33	145
24	Ijora	132/33	115
25	Illupeju	132/33	115
26	Odogunyan	132/33	85
27	Ojo	132/33	115
28	Ogba	132/33	85
29	Oke Aro	132/33	85
30	Oworo	132/33	115
31	Itire	132/33	115
32	TS1	132/33	290
33	TS2	132/33	290

Table 6-4: Proposed Transmission Line Additions/Reinforcements – 2026

Sr. No.	Node		Voltage (kV)	Length (km)	Circuit Type (SC or DC)
	From	To			
1	SITE 12	Alagbon-Ajah Line	330	50.0	DC
2	SITE 12	Lekki-Ajah Line	330	45.0	DC
3	Alagbon	Ajah	330	27.0	DC
4	Alagbon	New Ijora	330	4.0	DC
5	New Ijora	Akangba	330	8.3	DC
6	Alagbon	Alagbon-2	132	2.2	DC
7	Alagbon 2	New Ijora	132	3.5	DC
8	New Ijora	Ijora-Alagbon Line	132	1.3	DC
9	New Ijora	Amuwo	132	7.9	DC
10	TS2	Itire-Ejigbo Line	132	1.6	DC
11	TS2	Illupeju-Isolo Line	132	2.0	DC
12	TS2	Ikeja west-Illupeju Line	132	1.5	DC
13	Illupeju	Isolo	132	7.0	SC
14	TS1	Alimosho-Ogba Line	132	4.0	DC
15	Egbin	Ikorodu-2	132	7.5	DC
16	Ikorodu-2	Egbin-Ikorodu Line	132	4.5	DC
17	Site 05	Oworo-Ikeja Line	132	1.8	DC
18	Site 05	Oworo-Ikeja Line	132	1.8	DC
19	Site 05	Maryland-Ikorodu Line	132	3.3	DC
20	Site 05	Maryland-Ikorodu Line	132	3.3	DC
21	Site -05	Illupeju-Isolo line	132	10.0	DC
22	Site 05	TS1	132	9.0	DC
23	Alausa	Oworo-Ikeja Line	132	4.2	DC
24	Ayobo	Oke-Aro	132	13.0	DC
25	Oke-Aro	Ikeja west-Oworo Line	132	2.0	DC

Figure D-3 and Figure D-4 show the power flow under normal system operation conditions for 330 kV and 132 kV transmission networks, respectively. The results show that all transmission elements would be operating within their loading capabilities and the voltage profile across the entire network is significantly improved and bus voltages are near the nominal values. Local generation resources have boosted the Lagos state voltage profile to a great extent.

The N-1 contingency analysis reveals that no transmission element gets overloaded after one element (a transformer or a transmission circuit) goes out of service. This is the result of implementing a significant number of transmission system reinforcements and expansions during the last five years. Now, the integrated power system is adequate to meet the forecasted demand in 2026 and comply with the operating criteria.

6.4.3 YEAR 2030

Over the period from 2029 to 2036, Site 9 will be developed as a CCGT generation facility with a 2,000 MW capacity. The power plant will be interconnected to Egbin – Ajah 330 kV double circuit in an in-and-out arrangement. This will connect the CCGT power plant to Egbin TS with a 330 kV double-circuit line and also interconnect Ajah TS through a 330 kV double-circuit line. The proposed interconnection scheme is shown in the schematic diagram presented in Figure 6-5. Further, a few transformation stations will be reinforced with additional transformation capacities, and a few transmission lines need to be reconductored or expanded. Table 6-5 and Table 6-6 present expansion plans for transformation stations and transmission lines, respectively.

Table 6-5: Proposed Substation Additions/Upgrades – 2030

Sr. No.	Transformation Station	Voltage Rating (kV)	Capacity (MVA)
1	Aja	330/132	450
2	Lekki	330/132	300
3	Alagbon	330/132	300
4	New Ijora	330/132	300
5	Oke Aro	330/132	300
6	Egbin	330/132	150
7	TS5	132/33	290
8	Aja 2	132/33	290
9	Lekki	132/33	145
10	Akangba 2	132/33	290
11	Isolo	132/33	85
12	Isolo 2	132/33	145
13	Ejigbo 2	132/33	145
14	Maryland	132/33	115
15	Ikorodu 2	132/33	145
16	Agbara 2	132/33	290
17	Alimosho	132/33	45
18	Amuwo	132/33	115
19	Ayobo	132/33	85
20	Ilupeju	132/33	115
21	Ojo	132/33	85
22	Ogba 2	132/33	145
23	Oke Aro	132/33	85
24	Oworo	132/33	85
25	Itire	132/33	105
26	TS1	132/33	145

Table 6-6: Proposed Transmission Line Additions/Reinforcements – 2030

Sr. No.	Node		Voltage (kV)	Length (km)	Circuit Type (SC or DC)
	From	To			
1	Site 09	Egbin-Ajah line	330	0.5	DC
2	Site 09	Egbin-Ajah line	330	0.5	DC
3	Site 05	TS5	132	5.0	DC
4	Site 05	TS5	132	5.0	DC
5	TS5	Oworo-Akoka Line	132	3.5	DC
6	TS5	Illupeju Line	132	7.5	DC
7	TS1	Alimosho	132	4.0	DC

Figure D-5 and Figure D-6 show the power flow results under normal system operation conditions for 330 kV and 132 kV transmission networks, respectively. The results show that all transmission elements would be operating within their loading capabilities and bus voltages across the entire network are near the nominal values. For the purpose of power flow analysis, additional demands between 2026 and 2030 are added to 132 kV buses of 330/132 kV transformation stations since 132 kV lines and transformation stations cannot be optimized at this stage due to the uncertainty of future load locations. However, the expected transmission reinforcement and expansion requirements have been identified, and their cost estimates have been prepared accordingly.

The N-1 contingency analysis reveals that no transmission element gets overloaded after one element (a transformer or a transmission circuit) goes out of service. This shows that the integrated power system can adequately supply the forecasted demand in 2030 and comply with the operating criteria.

6.4.4 YEAR 2035

The proposed generation facility at Site 2 will be located on the west side of Lagos State and will have a capacity of 1,000 MW, which consists of simple-cycle GTs. The facility will be interconnected at the 132 kV level and will have multiple interconnections with the existing 132 kV transmission network besides having multiple new 132 kV lines that will be built to at least two new 132/33 kV transformation stations. The proposed interconnection scheme for the GT power plant is shown in the schematic diagram presented in Figure 6-6. Further, a few transformation stations will be reinforced with additional transformation capacities, and a few more transmission lines need to be added. Table 6-7 and Table 6-8 present the proposed expansion plans for transformation stations and transmission lines respectively.

Table 6-7: Proposed Substation Additions/Upgrades – 2035

Sr. No.	Transformation Station	Voltage Rating (kV)	Capacity (MVA)
1	Aja	330/132	150
2	Alagbon	330/132	300
3	Lekki	330/132	300
4	Akangba	330/132	210
5	Aja-3	132/33	435
6	Lekki-2	132/33	145
7	Alagbon-3	132/33	290
8	Isolo-2	132/33	145
9	Ejigbo-2	132/33	145
10	Maryland-2	132/33	145
11	Ikorodu-2	132/33	145
12	Ikorodu-3	132/33	145
13	Agbara	132/33	100
14	Akoka	132/33	145
15	Alausa-2	132/33	145
16	Alimosho 2	132/33	145
17	Amuwo	132/33	115
18	Apapa Road	132/33	85
19	Ayobo	132/33	145
20	Ijora	132/33	100
21	Odugunyan	132/33	85
22	Ojo	132/33	85
23	Oke Aro	132/33	145
24	Oworo	132/33	85
25	TS2	132/33	145
26	TS3	132/33	145
27	TS4	132/33	290

Table 6-8: Proposed Transmission Line Additions/Reinforcements – 2035

Sr. No.	Node		Voltage (kV)	Length (km)	Circuit Type (SC or DC)
	From	To			
1	Site -09	Egbin	330	4.00	SC
2	Site -02	Ikeja West-Agbara Line	132	2.0	DC
3	Site -02	TS4	132	15.0	DC
4	TS 4	Ejigbo-Itire Line	132	7.5	DC
5	Site-02	TS3	132	12.0	DC
6	TS3	Ikeja West-Ejigbo	132	9.0	DC
7	TS3	TS4	132	6.0	SC
8	TS4	Ojo-Amuwo Line	132	4.0	DC
9	Site -02	Ikeja West-Agbara Line	132	2.0	DC

Figure D-7 and Figure D-8 show the power flow results under normal system operating conditions for 330 kV and 132 kV transmission networks, respectively. The results show that all transmission elements would be operating within their loading capabilities and bus voltages across the entire network are near the nominal values. For the purpose of power flow analysis, additional demands between 2030 and 2035 are added to 132 kV buses of 330/132 kV transformation stations, plus a few new 132 kV transformation stations since all the required 132 kV lines and transformation stations cannot be planned and optimized at this stage due to the uncertainty of future load centers. However, the expected transmission reinforcement and expansion requirements have been identified and their cost estimates have been prepared accordingly.

The N-1 contingency analysis reveals that no transmission element gets overloaded after one element (a transformer or a transmission circuit) goes out of service. This shows that the integrated power system can adequately supply the forecasted demand in 2035 and comply with the system operating criteria.

6.4.5 YEAR 2040

The proposed generation facility at Site 6, a CCGT power plant, is located about 6 km northeast of Site 5 and has a capacity of 1,000 MW. This facility will be interconnected at the 330 kV level through a double-circuit line using quad bundle conductor. This generation interconnection line will be terminated at TS-01 by converting it to a 330 kV transformation station. Also, the 330 kV line between Ikeja West and Akangba transformation stations will be made in an in-and-out arrangement at the new 330 kV TS-01. In addition, multiple 132 kV lines will emanate from this new 330 kV TS-01 to supply demand in neighboring areas with an adequate number of new 132/33 kV transformation stations and sufficient transformation capacities. The proposed interconnection arrangement for the power plant at Site 6 is shown in the schematic diagram presented in Figure 6-7. Further, a few more transformation stations will be reinforced with additional transformation capacities in other areas. Table 6-9 and Table 6-10 present the proposed expansion plans for transformation stations and transmission lines, respectively.

Figure D-9 and Figure D-10 show the power flow results under normal system operating conditions for the 330 kV and 132 kV transmission networks, respectively. The results show that all transmission elements would be operating within their loading capabilities and bus voltages across the entire network are near the nominal values. For the purpose of power flow analysis, additional demands between 2035 and 2040 are added to 132 kV buses of 330/132 kV transformation stations and a few new 132/33 kV transformation stations since all the required 132 kV lines and transformation stations cannot be planned and optimized at this stage due to the uncertainty of the future load locations. However, the expected transmission reinforcement and expansion requirements have been identified and their cost estimates have been prepared accordingly.

Table 6-9: Proposed Substation Additions/Upgrades – 2040

Sr. No.	Transformation Station	Voltage Rating (kV)	Capacity (MVA)
1	TS1	330/132	900
2	Egbin	330/132	150
3	Aja-2	132/33	145
4	Lekki-2	132/33	145
5	Alagbon-3	132/33	145
6	Akangba	132/33	85
7	Isolo-2	132/33	145
8	Ejigbo-2	132/33	145
9	Maryland-2	132/33	145
10	Ikorodu-3	132/33	145
11	Agbara	132/33	85
12	Alausa-2	132/33	145
13	Alimosho-2	132/33	145
14	Amuwo	132/33	60
15	Ijora	132/33	115
16	Ojo-2	132/33	145
17	Ogba-2	132/33	145
18	TS1	132/33	145
19	TS3	132/33	145
20	TS5	132/33	145
21	TS6	132/33	145

Table 6-10: Proposed Transmission Line Additions/Reinforcements – 2040

Sr. No.	Node		Voltage (kV)	Length (km)	Circuit Type (SC or DC)
	From	To			
1	Site 06	OkeAro-Egbin Line	330	12.0	DC
2	Site 06	TS1 330KV	330	15.5	DC
3	TS1-330KV	Ikeja-Akangba Line	330	7.0	DC
4	TS6	Isolo-Akangba Line	132	4.00	DC
5	TS6	TS5	132	2.2	SC
6	TS6	Akoka-Ijora Line	132	3.00	DC

The N-1 contingency analysis reveals that no transmission element gets overloaded after one element (a transformer or a transmission circuit) goes out of service. This shows that the integrated power system in Lagos State can adequately supply the forecasted demand in 2040 and comply with the system operating criteria.

6.4.6 ADDITIONAL NOTES

Due to the nature of solar PV power generation, it is assumed that it would have very little or no power output during the system evening on-peak hours, and it is therefore not included in the power flow studies. It is also assumed that its capital cost estimate would include the cost required to interconnect it to the power grid.

As listed in Subsection 6.1.2, it is assumed that the two 330 kV lines – one between Ajah and Epe transformation stations and the other between Epe and Omotosho transformation stations – are committed projects, which could be determined based on TCN's assumption that most load in Lagos State would be supplied by generators located outside of the state, i.e. import power from outside. In this case these two lines may be necessary.

In this IRP study, all load in the state would be supplied by domestic generators starting from 2026; i.e. there would be no or very little import of power from outside under the normal operating conditions. Import could only be required under system stress conditions and/or economic trade. In this case, the two committed lines could be redundant.

Taking into account the economic scale of substation transformers and the space requirement of them at each substation, it is wise to use all transformers at a standard size of 145 MVA at 132/33 kV for either new additions or upgrade of the existing ones. This size of transformers has been popularly used in several countries, and its standard designs are available from several main transformer manufacturers. In this case, the following numbers of smaller transformers could be removed from the existing substations (which could be used for the low load demand areas) and the standard size transformer could be installed:

1) Sixteen 132/33 kV 30 MVA
2) Two 132/33 kV 40 MVA
3) Three 45 132/33 kV MVA
4) Twenty-seven 132/33 kV 60 MVA
5) Two 330/132/33 kV 90 MVA
6) Four 132/33 kV 100 MVA
7) Five 330/132/33 kV 150 MVA

6.5 ANNUAL COST

The overnight EPC cost for the committed additions listed in Subsection 6.1.2, and new additions and reinforcements of substations and transmission lines listed in Subsection 6.4, is presented in Table 6-11. As explained before, transmission analysis was only performed for five study years over the planning horizon, i.e. 2021, 2026, 2030, 2035, and 2040. One may see from this table that the total EPC cost required over the planning horizon would be US$734.1 million, which will be used to calculate the annual operation cost of the new facilities as well as the annual capital expenditure cash flow.

Table 6-12 shows the annual cost by category, including three components: the O&M cost for the existing system, amortized capital repayment, and O&M cost for operation of new facilities. The following may be seen from this table:

1) The total operation cost in CV over the planning horizon would be US$4,308 million, including US$2,268 million for operation of the existing transmission system, US$1,099 million for capital repayment, and US$941 million for operation of the new facilities.

2) The total operation cost in PV over the planning horizon would be US$1,616 million, including US$980 million for operation of the existing transmission system, US$343 million for capital repayment, and US$294 million for operation of the new facilities.
3) The levelized cost of energy of the transmission system would be US$9.93 per MWh.

6.6 ANNUAL CAPITAL INVESTMENT CASH FLOW

Table 6-13 presents the capital expenditure cash flow for new transmission facilities installed over the planning horizon. One may see the following from this table:

1) The transmission system would need an investment of US$400 million prior to 2026 (it is assumed that the facilities required in a year should be commissioned at the beginning of the year).
2) A total of US$113 million would be invested prior to 2030.
3) An investment of US$127 million would be required prior to 2035.
4) The system would need an investment of US$94 million prior to 2040.
5) The total investment over the planning horizon would be US$734 million.

Figure 6-3: Schematic Diagram of the Transmission System in 2021

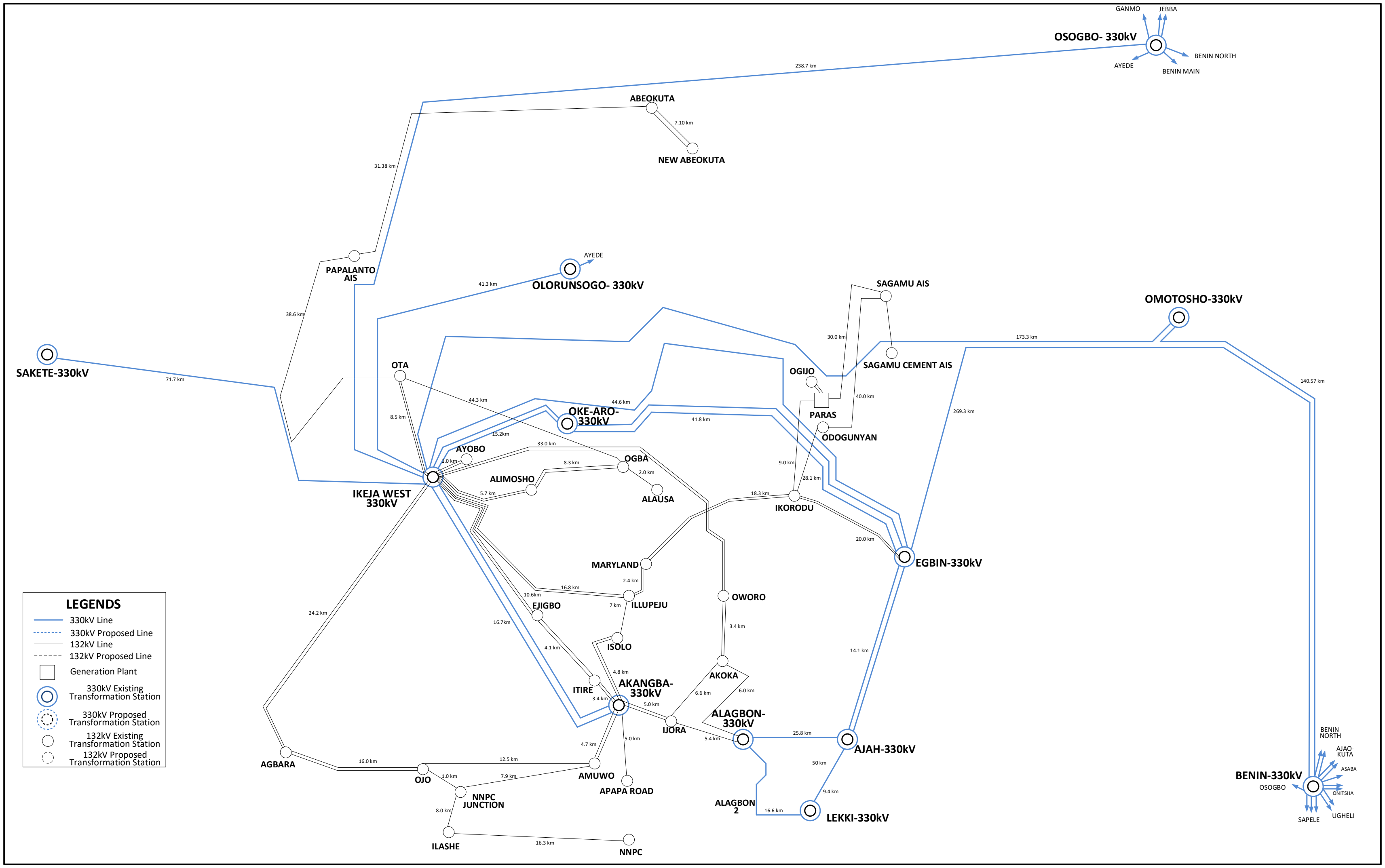


Figure 6-4: Schematic Diagram of the Transmission System in 2026

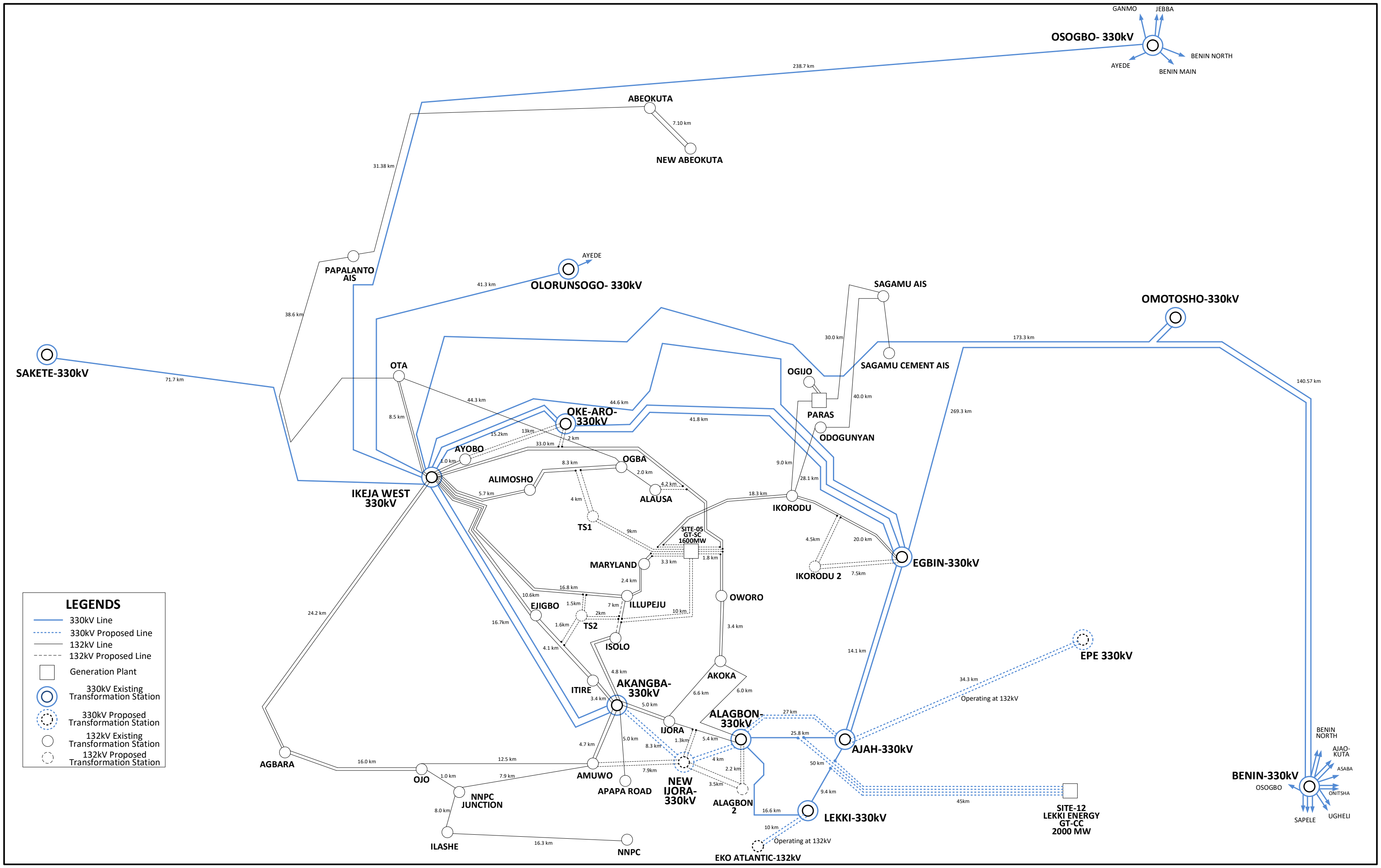


Figure 6-5: Schematic Diagram of the Transmission System in 2030

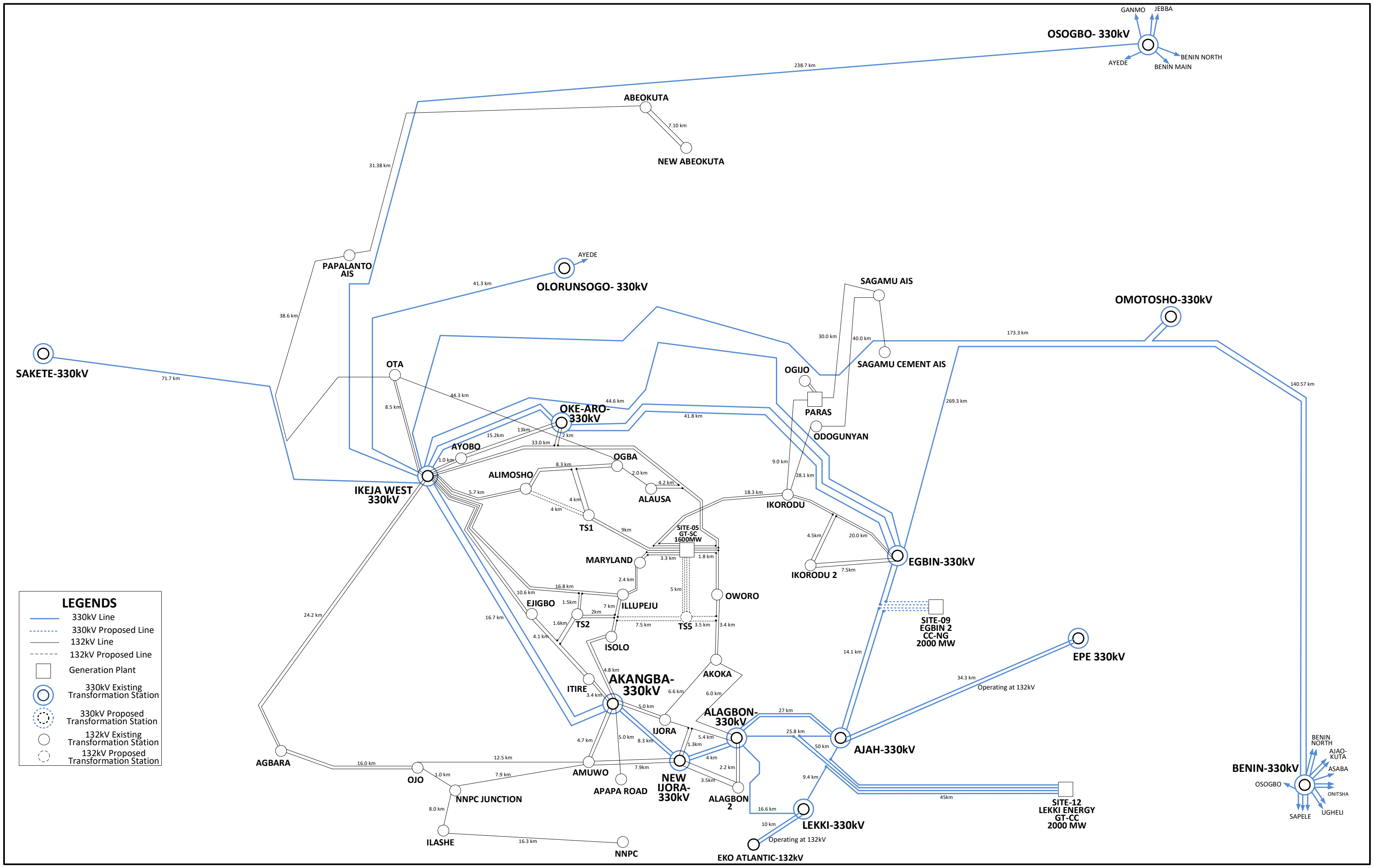


Figure 6-6: Schematic Diagram of the Transmission System in 2035

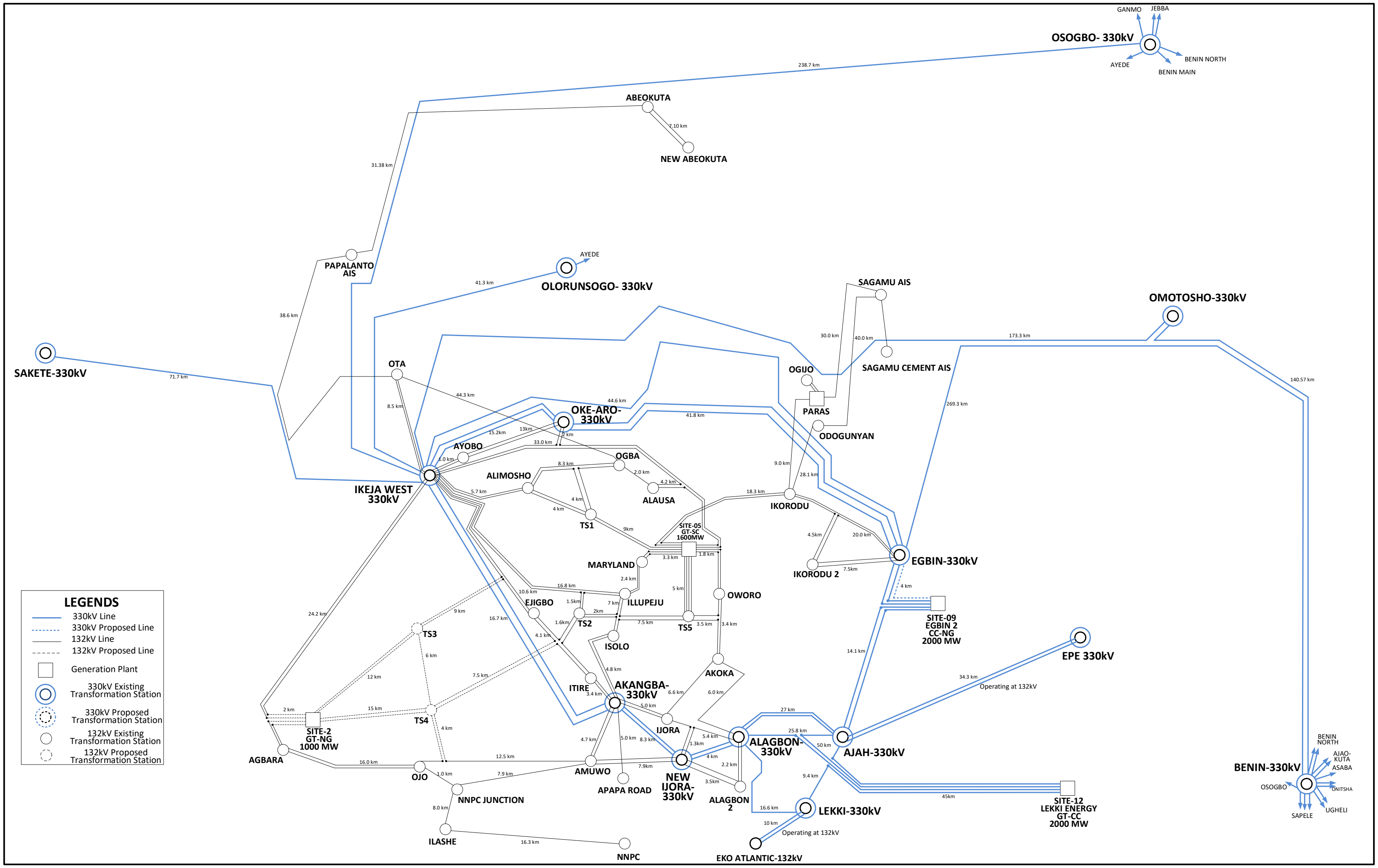


Figure 6-7: Schematic Diagram of the Transmission System in 2040

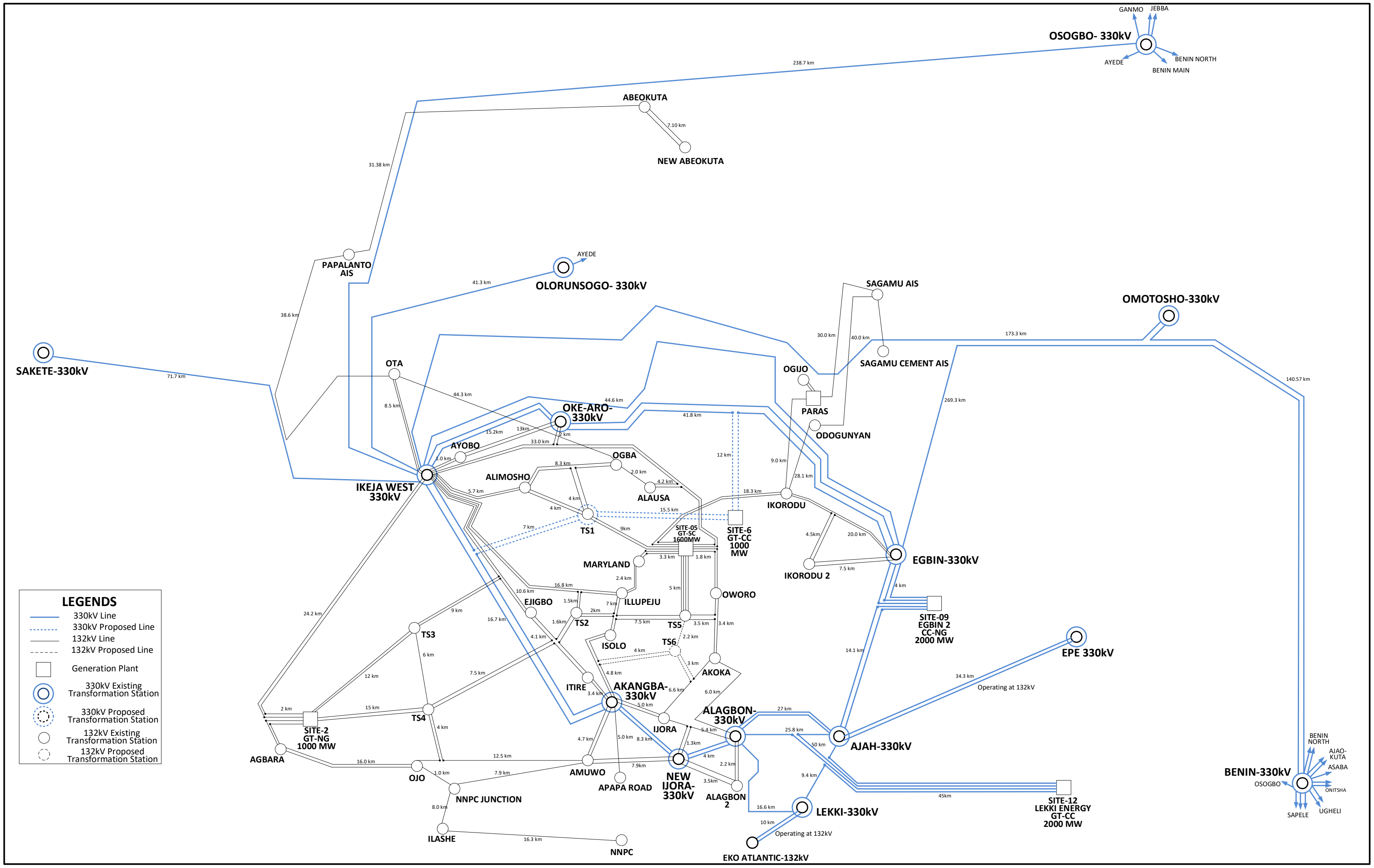


Table 6-11: Overnight EPC Cost for New Additions and Reinforcements – Transmission Development Plan

Project		Quantity	Online	Year																					
No.	Name	(km or Set)	Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	Committed Projects	Subtotal	2022				19.5																		
2	Committed Projects	Subtotal	2023					64.4																	
3	Committed Projects	Subtotal	2024						22.2																
4	Committed Projects	Subtotal	2025							1.4															
5	132 kV SC Line	7	2026								1.2														
6	132 kV DC Line	84.40	2026								23.6														
7	330 kV DC Line	134.3	2026								60.4														
4	132 kV Line Bay	54	2026								43.2														
5	330 kV Line Bay	16	2026								27.2														
6	145 MVA Transformer 132/33 kV	8	2026								21.7														
7	300 MVA Transformer 330/132 kV	4	2026								18.4														
8	132 kV SC Line Reconductoring (ACCC 1000amp)	119.6	2026								12.0														
9	145 MVA Transformer 132/33 kV (Augment)	31	2026								60.8														
10	300 MVA Transformer 330/132 kV (Augment)	2	2026								7.2														
11	132 kV DC Line	25	2030												7.0										
12	330 kV DC Line	1	2030												0.5										
13	132 kV Line Bay	16	2030												12.8										
14	330 kV Line Bay	4	2030												6.8										
15	145 MVA Transformer 132/33 kV	14	2030												37.9										
16	300 MVA Transformer 330/132 kV	5	2030												23.0										
17	132 kV SC Line Reconductoring (ACCC 1000amp)	1	2030												0.1										
18	145 MVA Transformer 132/33 kV (Augment)	10	2030												19.6										
19	300 MVA Transformer 330/132 kV (Augment)	2	2030												7.2										
20	132 kV SC Line	6	2035																	1.0					
21	132 kV DC Line	79	2035																	22.1					
22	132 kV Line Bay	22	2035																	17.6					
23	330 kV Line Bay	2	2035																	3.4					
24	145 MVA Transformer 132/33 kV	20	2035																	54.2					
25	300 MVA Transformer 330/132 kV	2	2035																	9.2					
26	132 kV SC Line Reconductoring (ACCC 1000amp)	13.3	2035																	1.3					
27	145 MVA Transformer 132/33 kV (Augment)	7	2035																	13.7					
28	300 MVA Transformer 330/132 kV (Augment)	2	2035																	7.2					
29	132 kV SC Line	2.2	2040																						0.4
30	330 kV SC Line	4	2040																						1.2
31	132 kV DC Line	12	2040																						3.4
32	330 kV DC Line	34.5	2040																						15.5
33	132 kV Line Bay	8	2040																						6.4
34	330 kV Line Bay	8	2040																						13.6
35	145 MVA Transformer 132/33 kV	15	2040																						40.7
36	300 MVA Transformer 330/132 kV	3	2040																						13.8
37	145 MVA Transformer 132/33 kV (Augment)	4	2040																						7.8
38	300 MVA Transformer 330/132 kV (Augment)	1	2040																						3.6
	Total			**0.0**	**0.0**	**0.0**	**19.5**	**64.4**	**22.2**	**1.4**	**275.7**	**0.0**	**0.0**	**0.0**	**114.9**	**0.0**	**0.0**	**0.0**	**0.0**	**129.8**	**0.0**	**0.0**	**0.0**	**0.0**	**106.3**
	Cumulative Total			**0.0**	**0.0**	**0.0**	**19.5**	**83.9**	**106.1**	**107.4**	**383.1**	**383.1**	**383.1**	**383.1**	**498.0**	**498.0**	**498.0**	**498.0**	**498.0**	**627.8**	**627.8**	**627.8**	**627.8**	**627.8**	**734.1**

Table 6-12: Annual Cost by Category – Transmission Development Plan

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Load Forecast																					
Energy to DISCOs (GWh)	10,095.2	10,895.6	11,788.0	12,772.5	13,849.3	15,018.9	16,281.4	17,566.4	18,876.8	20,271.3	21,703.8	23,142.7	24,621.4	26,142.1	27,707.0	29,318.3	30,881.0	32,494.3	34,160.7	35,882.5	37,454.4
Peak Demand at DISCOs Metering (MW)	1,772.9	1,913.5	2,070.2	2,243.1	2,432.3	2,637.7	2,859.4	3,085.1	3,315.2	3,560.1	3,811.7	4,064.4	4,324.1	4,591.2	4,866.0	5,149.0	5,423.4	5,706.8	5,999.4	6,301.8	6,577.9
Cost in Current Value (M-US$)																					
Existing System O&M Cost	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0	108.0
Amortized Capital Repayment	0.0	0.0	8.7	22.7	31.7	38.3	44.7	48.1	51.4	54.8	58.2	61.2	64.2	67.2	70.3	73.3	75.8	78.3	80.8	83.2	85.7
O&M Cost (Excluding Capital Repayment)	0.0	0.0	7.5	19.4	27.1	32.8	38.3	41.2	44.1	46.9	49.8	52.4	55.0	57.6	60.2	62.8	64.9	67.0	69.2	71.3	73.4
Total	**108.0**	**108.0**	**124.2**	**150.1**	**166.9**	**179.1**	**191.1**	**197.3**	**203.5**	**209.7**	**216.0**	**221.6**	**227.2**	**232.9**	**238.5**	**244.1**	**248.7**	**253.3**	**257.9**	**262.5**	**267.2**
Cumulative Cost in Current Value (M-US$)																					
Existing System O&M Cost	108.0	216.0	324.1	432.1	540.1	648.1	756.1	864.1	972.2	1,080.2	1,188.2	1,296.2	1,404.2	1,512.3	1,620.3	1,728.3	1,836.3	1,944.3	2,052.3	2,160.4	2,268.4
Amortized Capital Repayment	0.0	0.0	8.7	31.4	63.1	101.4	146.1	194.2	245.7	300.5	358.6	419.8	484.0	551.3	621.5	694.8	770.6	848.9	929.7	1,012.9	1,098.7
O&M Cost (Excluding Capital Repayment)	0.0	0.0	7.5	26.9	54.0	86.8	125.1	166.3	210.4	257.3	307.1	359.5	414.5	472.1	532.2	595.0	659.9	727.0	796.1	867.4	940.8
Total	**108.0**	**216.0**	**340.2**	**490.3**	**657.2**	**836.3**	**1,027.4**	**1,224.7**	**1,428.2**	**1,637.9**	**1,853.9**	**2,075.5**	**2,302.7**	**2,535.6**	**2,774.0**	**3,018.2**	**3,266.9**	**3,520.2**	**3,778.1**	**4,040.7**	**4,307.8**
Discount Factor	0.9535	0.8668	0.7880	0.7164	0.6512	0.5920	0.5382	0.4893	0.4448	0.4044	0.3676	0.3342	0.3038	0.2762	0.2511	0.2283	0.2075	0.1886	0.1715	0.1559	0.1417
Cost in Present Value (M-US$)																					
Existing System O&M Cost	103.0	93.6	85.1	77.4	70.3	63.9	58.1	52.9	48.0	43.7	39.7	36.1	32.8	29.8	27.1	24.7	22.4	20.4	18.5	16.8	15.3
Amortized Capital Repayment	0.0	0.0	6.9	16.2	20.6	22.7	24.1	23.5	22.9	22.2	21.4	20.4	19.5	18.6	17.6	16.7	15.7	14.8	13.8	13.0	12.2
O&M Cost (Excluding Capital Repayment)	0.0	0.0	5.9	13.9	17.7	19.4	20.6	20.1	19.6	19.0	18.3	17.5	16.7	15.9	15.1	14.3	13.5	12.6	11.9	11.1	10.4
Total	**103.0**	**93.6**	**97.9**	**107.5**	**108.7**	**106.0**	**102.8**	**96.5**	**90.5**	**84.8**	**79.4**	**74.1**	**69.0**	**64.3**	**59.9**	**55.7**	**51.6**	**47.8**	**44.2**	**40.9**	**37.9**
Cumulative Cost in Present Value (M-US$)																					
Existing System O&M Cost	103.0	196.6	281.7	359.1	429.5	493.4	551.5	604.4	652.4	696.1	735.8	771.9	804.7	834.6	861.7	886.4	908.8	929.1	947.7	964.5	979.8
Amortized Capital Repayment	0.0	0.0	6.9	23.1	43.8	66.4	90.5	114.0	136.9	159.1	180.5	200.9	220.4	239.0	256.6	273.4	289.1	303.9	317.7	330.7	342.8
O&M Cost (Excluding Capital Repayment)	0.0	0.0	5.9	19.8	37.5	56.9	77.5	97.6	117.2	136.2	154.5	172.0	188.7	204.6	219.8	234.1	247.6	260.2	272.1	283.2	293.6
Total	**103.0**	**196.6**	**294.5**	**402.0**	**510.7**	**616.7**	**719.5**	**816.1**	**906.6**	**991.4**	**1,070.8**	**1,144.9**	**1,213.9**	**1,278.2**	**1,338.1**	**1,393.8**	**1,445.4**	**1,493.2**	**1,537.4**	**1,578.4**	**1,616.2**

Levelized Cost of Energy (US$/MWh) = 9.93 **Total Cost in PV (M-US$) = 1,616.2** **Total Energy in PV (GWh) = 162,728.0**

Table 6-13: Capital Expenditure Cash Flow – Transmission Development Plan

	Project	Quantity	Online	Year																					
No.	Name	(km or Set)	Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	Committed Projects	Subtotal	2022		11.7	7.8																			
2	Committed Projects	Subtotal	2023			38.6	25.7																		
3	Committed Projects	Subtotal	2024				13.3	8.9																	
4	Committed Projects	Subtotal	2025					0.81	0.5																
5	132 kV SC Line	7	2026		0.1	0.2	0.2	0.2	0.2	0.1															
6	132 kV DC Line	84.40	2026		2.8	4.7	4.7	4.7	4.7	1.9															
7	330 kV DC Line	134.3	2026		7.3	12.1	12.1	12.1	12.1	4.8															
4	132 kV Line Bay	54	2026		5.2	8.6	8.6	8.6	8.6	3.5															
5	330 kV Line Bay	16	2026		3.3	5.4	5.4	5.4	5.4	2.2															
6	145 MVA Transformer 132/33 kV	8	2026		2.6	4.3	4.3	4.3	4.3	1.7															
7	300 MVA Transformer 330/132 kV	4	2026		2.2	3.7	3.7	3.7	3.7	1.5															
8	132 kV SC Line Reconductoring (ACCC 1000amp)	119.6	2026		1.4	2.4	2.4	2.4	2.4	1.0															
9	145 MVA Transformer 132/33 kV (Augment)	31	2026		7.3	12.2	12.2	12.2	12.2	4.9															
10	300 MVA Transformer 330/132 kV (Augment)	2	2026		0.9	1.4	1.4	1.4	1.4	0.6															
11	132 kV DC Line	25	2030							1.1	1.8	1.8	1.8	0.7											
12	330 kV DC Line	1	2030							0.1	0.1	0.1	0.1	0.0											
13	132 kV Line Bay	16	2030							1.9	3.2	3.2	3.2	1.3											
14	330 kV Line Bay	4	2030							1.0	1.7	1.7	1.7	0.7											
15	145 MVA Transformer 132/33 kV	14	2030							5.7	9.5	9.5	9.5	3.8											
16	300 MVA Transformer 330/132 kV	5	2030							3.5	5.8	5.8	5.8	2.3											
17	132 kV SC Line Reconductoring (ACCC 1000amp)	1	2030							0.0	0.0	0.0	0.0	0.0											
18	145 MVA Transformer 132/33 kV (Augment)	10	2030							2.9	4.9	4.9	4.9	2.0											
19	300 MVA Transformer 330/132 kV (Augment)	2	2030							1.1	1.8	1.8	1.8	0.7											
20	132 kV SC Line	6	2035											0.1	0.2	0.2	0.2	0.2	0.1						
21	132 kV DC Line	79	2035											2.7	4.4	4.4	4.4	4.4	1.8						
22	132 kV Line Bay	22	2035											2.1	3.5	3.5	3.5	3.5	1.4						
23	330 kV Line Bay	2	2035											0.4	0.7	0.7	0.7	0.7	0.3						
24	145 MVA Transformer 132/33 kV	20	2035											6.5	10.8	10.8	10.8	10.8	4.3						
25	300 MVA Transformer 330/132 kV	2	2035											1.1	1.8	1.8	1.8	1.8	0.7						
26	132 kV SC Line Reconductoring (ACCC 1000amp)	13.3	2035											0.2	0.3	0.3	0.3	0.3	0.1						
27	145 MVA Transformer 132/33 kV (Augment)	7	2035											1.6	2.7	2.7	2.7	2.7	1.1						
28	300 MVA Transformer 330/132 kV (Augment)	2	2035											0.9	1.4	1.4	1.4	1.4	0.6						
29	132 kV SC Line	2.2	2040																0.0	0.1	0.1	0.1	0.1	0.0	
30	330 kV SC Line	4	2040																0.1	0.2	0.2	0.2	0.2	0.1	
31	132 kV DC Line	12	2040																0.4	0.7	0.7	0.7	0.7	0.3	
32	330 kV DC Line	34.5	2040																1.9	3.1	3.1	3.1	3.1	1.2	
33	132 kV Line Bay	8	2040																0.8	1.3	1.3	1.3	1.3	0.5	
34	330 kV Line Bay	8	2040																1.6	2.7	2.7	2.7	2.7	1.1	
35	145 MVA Transformer 132/33 kV	15	2040																4.9	8.1	8.1	8.1	8.1	3.3	
36	300 MVA Transformer 330/132 kV	3	2040																1.7	2.8	2.8	2.8	2.8	1.1	
37	145 MVA Transformer 132/33 kV (Augment)	4	2040																0.9	1.6	1.6	1.6	1.6	0.6	
38	300 MVA Transformer 330/132 kV (Augment)	1	2040																0.4	0.7	0.7	0.7	0.7	0.3	
	Total			**0.0**	**44.8**	**101.5**	**94.2**	**64.8**	**55.7**	**39.3**	**28.7**	**28.7**	**28.7**	**27.1**	**26.0**	**26.0**	**26.0**	**26.0**	**23.1**	**21.3**	**21.3**	**21.3**	**21.3**	**8.5**	**0.0**
							400.3					**113.2**					**127.0**					**93.6**			
	Cumulative Total			**0.0**	**44.8**	**146.3**	**240.5**	**305.4**	**361.0**	**400.3**	**429.0**	**457.8**	**486.5**	**513.6**	**539.5**	**565.5**	**591.4**	**617.4**	**640.5**	**661.8**	**683.1**	**704.3**	**725.6**	**734.1**	**734.1**

7 DISTRIBUTION DEVELOPMENT PLAN

This section summarizes the existing distribution system in Lagos State and additional requirements over the planning horizon in order to deliver power to customers from transformation stations as well as annual cost and capital investment cash flow.

7.1 THE EXISTING DISTRIBUTION

As mentioned in previous sections, EKEDC and IE are the two DISCOs responsible for electricity distribution in Lagos State, which are supplied by a total of 25 TCN transformation stations (including the recently constructed Ilashe TS). The DISCOs' load centers are connected to the transformation stations through 178 (86 for EKEDC and 92 for IE) 33 kV or 11 kV (only a few are connected to TCN 132/11 kV transformers) feeders. In addition, there are also several privately owned 132kV substations in the state.

Several transformation stations of the two DISCOs are either overloaded or are operating at their maximum capability. Moreover, transformers installed at these stations are either very old or have low transformation capabilities. At present, the transformers used at 132/33 kV level have low transformation capacities, such as 30, 40, 45, 60, on up to a maximum of 100 MVA. In order to have more feeders at 33 kV and 11 kV connected to a transformation station, there is a need to strengthen the system at 132/33 kV substations. In this report, the study team has proposed augmentation of the already installed low-rating transformers with the 132/33 kV 145 MVA transformers. This is done due to the high load density in the state. It is a better guideline to adopt higher-rating transformers to utilize the existing substations and serve the increasing load demand.

Load shedding is prevalent across the Lagos distribution network. It needs immediate reinforcements to be able to supply the load demand at an acceptable reliability level.

7.2 LOAD FORECAST BY 33 KV FEEDER

The load forecast results for Lagos State are presented in Table 2-1, which includes three scenarios, most likely, high, and low. The distribution development plan has been prepared for the most likely load forecast.

The load forecast by feeder for the period from 2020 to 2025 is presented in Table E-1 (for EKEDC feeders) and Table E-2 (for IE feeders). One may see from the two tables that the EKEDC non-coincident feeder peak will grow from 1,850 MW in 2021 to 2,482 MW in 2025. The IE non-coincident feeder peak will reach 2,604 MW in 2025 from 1,857 MW in 2021.

7.3 TECHNICAL AND ECONOMIC ASSUMPTIONS ON DISTRIBUTON FACILITIES

The following lists the technical and economic assumptions on distribution facilities:

1) Construction Duration – 2 years
2) Capital Expenditure Disbursement Flow – 60% in the first construction year and 40% in the second construction year
3) IDC Addition Factor to Capitalize the EPC cost – 11.174%, calculated based on the discount rate of 10% and the cash disbursement flow
4) Economic Life – 25 years
5) Capital Recovery Factor – 10.504%, calculated based on the discount rate of 10% and the economic life
6) O&M Cost of the new distribution facilities – 10.0% of the EPC cost

7) One new 33 kV feeder (including 33/11 kV transformers and 11 kV feeders) for every 10 MW peak load, from 2026 onwards

8) The Operation and Maintenance Cost of the existing distribution system – US$0.0302/kWh, estimated based on the NERC's reports for 2018 and 2019

9) 33 kV Overhead Line with Single Feeder – US$0.033 million per km

10) 33 kV Overhead Line with Double Feeder – US$0.04 million per km

11) 33 kV Overhead Line with Quad Feeder – US$0.05 million per km

12) 33 kV Underground Cable – US$0.235 million per km

13) 33 kV Outdoor Bay – US$0.12 million per set/installation

14) 33/11 kV 1x15 MVA Transformation Substation – US$0.75 million per set/installation

15) 33/11 kV 2x15 MVA Transformation Substation – US$1.40 million per set/installation

16) 33/11 kV 1x30 MVA Transformation Substation – US$1.30 million per set/installation

17) 11 kV Feeder – US$0.756 million per set/installation. It is assumed that each new 11 kV feeder would have 40 three-phase consumer meters and 1,300 single-phase consumer meters. The total capital cost for the 1,340 meters will be more than US$0.171 million.

18) 33 kV Feeder – US$6.135 million per set/installation. It is assumed that each new 33 kV feeder will supply six 11 kV feeders. The total capital cost of the consumer meters for one 33 kV feeder is estimated at more than US$1.026 million.

7.4 DETAILED PLAN/UPGRADATION BY STATION

This subsection summarizes the annual addition of 33 kV feeders in the transformation stations for EKEDC and IE. For every year from 2021 to 2025, new 33 kV feeders are proposed for those transformation stations with overloaded 33 kV feeders. For 2021 and 2022, 33 kV feeders having a peak load of approximately 25 MW have been targeted for an upgrade with a parallel feeder at the same route to serve the high load density area. After 2022, a new 33 kV feeder would be added if the peak load of the existing feeder is over the 20 MW allowed. The following three subsections present the proposed additions over the period from 2021 to 2025 for each of the two DISCOs, plus those over the period from 2026 to 2040 for both DISCOS.

7.4.1 EKEDC

A total of 26 new 33 kV feeders would be added in 2021 with a total length of approximately 376 km, which is listed below:

1) One new 33 kV feeder at Agbara, to share the load of BADAGRY EXPRESS (25.1 MW)

2) Three new 33 kV feeders at Akangba, to share the load of NEW YABA (25.1 MW), LUTH (29 MW), and ADELABU 1 (29 MW)

3) Five new 33 kV feeders at Ajah, to share the load of ELEMORO (26.2 MW), ILASAN (26.1 MW), IBEJU (30.3 MW), MAROKO (37 MW), and OKE-IRA (26 MW)

4) Three new 33 kV feeders at Ojo, to share the load of FESTAC 1 (OJO) (34.4 MW), FESTAC 11 (OJO) (29 MW), and VOLKSWAGEN (38.6 MW)

5) One new 33 kV feeder at Apapa Road, to share the load of TINCAN (27 MW)

6) One new 33 kV feeder at Isolo, to share the load of PTC (26 MW)

7) One new 33 kV feeder at Itire, to share the load of IJESHA (26.1 MW)
8) Seven new 33 kV feeder at Alagbon, to share the load of ADEMOLA 11 (26 MW), FOWLER 2 (25.2 MW), ANIFOWOSHE 2 (26.6 MW), FOWLER 1 (27.7 MW), FOWLER 3 (27.6 MW), ADEMOLA I (27 MW), and ANIFOWOSHE (27 MW)
9) Four new 33 kV feeders at Lekki, to share the load of ELEGUSHI (31.7 MW), LEKKI (31.6 MW), AGUNGI (34.4 MW), and WATERFRONT (29 MW)

The system would need 17 new 33 kV feeders with a total length of approximately 526 km in 2022, including the following:

1) Three new 33 kV feeders at Agbara, to share the load of AGBARA LOCAL (22 MW), BADAGRY (21.2 MW), and OKO AFO (22.6 MW)
2) Two new 33 kV feeders at Akangba, to share the load of SANYA (25.9 MW) and AKANGBA NRC (23 MW)
3) Two new 33 kV feeders at Akoka, to share the load of AKOKA LOCAL (23.8 MW) and AKOKA NEW YABA (23 MW)
4) Three new 33 kV feeders at Ijora, to share the load of AJELE 1 (25.7 MW), AJELE 11(25.6 MW), and BADIA (23 MW)
5) One new 33 kV feeder at Ajah, to share the load of ELEKO (24.5 MW)
6) One new 33 kV feeder at Ojo, to share the load of VOLKSWAGEN (40.4 MW)
7) One new 33 kV feeder at Amuwo, to share the load of KIRIKIRI EXPRESS (23 MW)
8) One new 33 kV feeder at Isolo, feeder to share the load of NITEL (21.6 MW)
9) Two new 33 kV feeders at Alagbon, to share the load of A/BERKLEY EXPRESS (24.7 MW) and A/FED SEC BERKLEY (25.4 MW)
10) One new 33 kV feeder at Lekki, to share the load of IGBO EFON (26 MW)

Twelve new 33 kV feeders with a total length of approximately 101 km would be installed in 2023, which are as follows:

1) One new 33 kV feeder at Agbara, to share the load of AGBARA (21 MW)
2) Two new 33 kV feeders at Ijora, to share the load of CUSTOM 1 (21.6 MW) and IJORA C/WAY 1 (21 MW)
3) Three new 33 kV feeders at Ajah, to share the load of IKATE EXPRESS (21 MW), MAIN ONE (22.6 MW), and MAROKO (40.4 MW)
4) Three new 33 kV feeders at Ojo, to share the load of T1 15 MVA OJO LOCAL (22.4 MW), T2 15 MVA OJO LOCAL (22.2W), and T3 15 MVA OJO LOCAL (21.6 MW)
5) One new 33 kV feeder at Amuwo, to share the load of SATELLITE 1(21 MW)
6) Two new 33 kV feeders at Alagbon, to share the load of TI ALAGBON LOCAL (21 MW) and T2 ALAGBON LOCAL (21 MW)

The DISCO needs only one new 33 kV feeder at Akangba, to share the load of IGANMU (20.02 MW) in 2024, which has a length of 2.2 km.

EKEDC would need five new 33 kV feeders with a total length of approximately 20 km in 2025, which include the following:

1) Two new 33 kV feeders at Akangba, to share the load of ADELABU 11 (20.2 MW) and AMUWO (20.1 MW)
2) One new 33 kV feeder at Ijora, to share the load of IJORA C/WAY 11(20.1 MW)
3) One new 33 kV feeder at Amuwo, to share the load of FESTAC 1 (AMUWO) (20.1 MW)
4) One new 33 kV feeder at Apapa Road, to share the load of APAPA MAINS 1 (20.2 MW)

7.4.2 IE

IE would need 27 new 33 kV feeder with a total length of approximately 429 km in 2021 to supply its load, which are listed below:

1) Two new 33 kV feeders at Alausa, to share the load of ALAUSA (27.03 MW) and OJODU (25.3 MW)
2) Two new 33 kV feeders at Alimosho, to share the load of AGEGE (33.97 MW) and IPAJA EKORO (26.9 MW)
3) Two new 33 kV feeders at Ayobo, to share the load of AIYETORO (27.1 MW) and ABESAN (28.7 MW)
4) Four new 33 kV feeders at Ejigbo, to share the load of IGANDO (24.8 MW), EGBE (32.2 MW), IJEGUN (24.7 MW), and BOLORUNPELU (25.3 MW)
5) Six new 33 kV feeders at Ikorodu, to share the load of IJEDE (40.8 MW), INDUSTRIAL (27 MW), OWUTU (27 MW), AGBOWA (38 MW), IGBOGBO (26 MW), and SPINTEX (24 MW)
6) One new 33 kV feeder at Isolo, to share the load of AJAO (29 MW)
7) Two new 33 kV feeders at Maryland, to share the load of PTC (31 MW) and ALAUSA (25.6 MW)
8) One new 33 kV feeder at Odugunyan, to share the load of Odogunyan (27 MW)
9) Three new 33 kV feeders at Ogba, to share the load of ABOKUTA EXP. (27 MW), FEEDER 8 (28 MW), and CISCO (27 MW)
10) Two new 33 kV feeders at Oke-Aro, to share the load of NEW IJU W/WC (26 MW) and YIDI (27 MW)
11) One new 33 kV feeder at Otta, to share the load of AMJE (32 MW)
12) Two new 33 kV feeders at Oworo, to share the load of OGUDU 1 (27.5 MW)

In 2022, the DISCO would need 14 new 33 kV feeders to meet the growing load demand, with a total length of approximately 245 km. These new feeders are:

1) One new 33 kV feeder at Oworo, to share the load of TOWER ALUMINIUM (21 MW)
2) One new 33 kV feeder at Amuwo, to share the load of HONGXING 2 (24 MW)
3) Three new 33 kV feeders at Ejigbo, to share the load of AIRPORT (24 MW), OKEAFA 2 (24.4 MW), and AGODO EGBE (23 MW)
4) Two new 33 kV feeders at Ikorodu, to share the load of IJEDE (48 MW) and IBESHE (25 MW)
5) One new 33 kV feeder at Ilupeju, to share the load of ILUPEJU IGBOBI (26.7 MW)
6) One new 33 kV feeder at Isolo, to share the load of PTC (25.6 MW)
7) Two new 33 kV feeders at Itire, to share the load of ITIRE 1 (26.4 MW) and AGO 1 (27.6 MW)
8) One new 33 kV feeder at Maryland, to share the load of AJGUNLE (26.8 MW)

9) One new 33 kV feeder at Odogunyan, to share the load of Agbede (25.2 MW)
10) Two new 33 kV feeders at Oke-Aro, to share the load of AKUTE (26 MW)

The system would need 20 new 33 kV feeders in 2023, with a total length of approximately 318 km, which are listed below:

1) Two new 33 kV feeders at Alausa, to share the load of OPIC (23 MW) and MAGODO (20 MW)
2) Two new 33 kV feeders at Alimosho, to share the load of T4 (20 MW) and AGEGE (43.3 MW)
3) Two new 33 kV feeders at Amuwo, feeder to share the load of AMUKOKO (23 MW) and HONGXING 1 (20.1 MW)
4) Two new 33 kV feeders at Ayobo, to share the load of ABULE TAYLOR (22.2 MW) and AMIKANLE (21.8 MW)
5) One new 33 kV feeder at Ejigbo, feeder to share the load of OKEAFA 1 (22.3 MW)
6) Three new 33 kV feeders at Ikorodu, to share the load of FAKALE Source (25.6 MW), PULKIT (24.6 MW), and AGBOWA (48.4 MW)
7) One new 33 kV feeder at Isolo, to share the load of AIRPORT (23.5 MW)
8) One new 33 kV feeder at Itire, to share the load of AGO II (22.2 MW)
9) One new 33 kV feeder at Odugunyan, to share the load of Mega Steel (26.5 MW)
10) Two new 33 kV feeders at Ogba, to share the load of PTC EXP. (23 MW) and FEEDER 2 (21.1 MW)
11) One new 33 kV feeder at Otta, to share the load of AMJE (41 MW)
12) Two new 33 kV feeder at Oworo, to share the load of CHEVRON/T3A (22.7 MW) and IGBOBI (25.3 MW)

A total of 11 new 33 kV feeders would be required in 2024, with a total length of approximately 41 km. These new feeders include the following:

1) One new 33 kV feeder at Alausa, to share the load of OPEBI (21.5 MW)
2) Two new 33 kV feeders at Alimosho, feeder to share the load of T5 (21 MW) and NEW GOWON (21 MW)
3) One new 33 kV feeder at Ejigbo, to share the load of EGBE (44.5 MW)
4) One new 33 kV feeder at Ikorodu, to share the load of T2A (20.2 MW)
5) One new 33 kV feeder at Ilupeju, to share the load of ILUPEJU BY-PASS (20.5 MW)
6) Three new 33 kV feeders at Maryland, to share the load of T1A (21 MW), PTC (43 MW) and T2A (20.1 MW)
7) Two new 33 kV feeders at Oworo, to share the load of OWORO 1/T1A (20.5 MW) and OWORO 2/T2A (20.1 MW)

IE would need 11 new 33 kV feeders, with a total length of approximately 78 km, to meet its load demand in 2025, which are listed as follows:

1) One new 33 kV feeder at Alausa, to share the load of ALAUSA (41 MW)
2) One new 33 kV feeder at Alimosho, to share the load of ALIMOSHO (21 MW)
3) One new 33 kV feeder at Ayobo, to share the load of ABESAN (43.1 MW)

4) Two new 33 kV feeders at Ikorodu, to share the load of IJEDE (61 MW) and T1A (21.5 MW)
5) One new 33 kV feeder at Isolo, to share the load of AJAO (44 MW)
6) One new 33 kV feeder at Maryland, to share the load of T3A (21 MW)
7) One new 33 kV feeder at Odugunyan, to share the load of Odogunyan (41 MW)
8) One new 33 kV feeder at Ogba, to share the load of FEEDER 8 (41.5 MW)
9) One new 33 kV feeder at Oke-Aro, to share the load of LAMBE (21 MW)
10) One new 33 kV feeder at Oworo, to share the load of OGUDU 1 (41.3 MW)

7.4.3 OVER THE PERIOD FROM 2026 TO 2040

For every year from 2026 onwards, an estimated number of 33 kV feeders would be added, which is based on the assessment that one new feeder would be required for every 10 MW of incremental system peak load demand. In this case, it is assumed that each 33 kV feeder would include the following components:

1) A length of 5 km
2) One 33/11 kV substation with 2x15 MVA transformers
3) Four 11 kV feeders

The estimated number of new 33 kV feeders in each year of the period from 2026 to 2040 is listed below:

1) 23 feeders in 2026
2) 22 feeders in 2027
3) 23 feeders in 2028
4) 25 feeders in 2029
5) 25 feeders in 2030
6) 25 feeders in 2031
7) 26 feeders in 2032
8) 27 feeders in 2033
9) 27 feeders in 2034
10) 29 feeders in 2035
11) 27 feeders in 2036
12) 28 feeders in 2037
13) 30 feeders in 2038
14) 30 feeders in 2039
15) 28 feeders in 2040

7.5 ANNUAL COST

The overnight EPC cost for the new additions and reinforcements of 33 kV and 33/11 kV substations listed in Subsection 7.4 is presented in Table 7-1. As may be seen from this table, the annual cost for the period from 2021 to 2025 has been calculated in detail with respect to the unit cost estimates of the distribution facilities. The addition of new 33 kV feeders is deemed to be the highest in 2021 to relieve the over loaded existing system. This reflects the highest annual cost of the distribution development plan in 2021. The annual cost subsequently decreases afterwards till 2025. Keeping a cost-effective and practical approach towards the outlay of new 33 kV feeder from its feeding station, the following evacuation has been decided:

1) 35% of the total length will be the 33 kV feeder poles with quad circuit.
2) 35% of the total length will be the 33 kV feeder poles with double circuit.
3) 30% of the total length will be the 33 kV feeder poles with single circuit.

One may see from Table 7-1 that the total EPC cost required over the planning horizon would be US$3,181 million, which will be used to calculate the annual operation cost of the new facilities as well as the annual capital expenditure cash flow.

Table 7-2 shows the annual cost by category, including three components: the O&M cost for the existing system, amortized capital repayment, and O&M cost for operation of new facilities. The following may be seen from this table:

1) The total operation cost in CV over the planning horizon would be US$13,478 million, including US$6,402 million for operation of the existing transmission system, US$3,812 million for capital repayment, and US$3,264 million for operation of the new facilities.
2) The total operation cost in PV over the planning horizon would be US$4,853 million, including US$2,766 million for operation of the existing transmission system, US$1,125 million for capital repayment, and US$963 million for operation of the new facilities.
3) The levelized cost of energy of the distribution system would be US$29.82 per MWh.

7.6 ANNUAL CAPITAL INVESTMENT CASH FLOW

Table 7-3 presents the capital expenditure cash flow for new distribution facilities installed over the planning horizon. One may see the following from this table:

1) The distribution system would need an investment of US$980 million prior to 2026, i.e. between 2019 and 2025. (For the facilities required in a year, it is assumed that they should be commissioned at the beginning of the year. Their capital cost should be disbursed within two years before their commissioning.)
2) A total of US$751 million would be invested between 2026 and 2030.
3) An investment of US$842 million would be required between 2031 and 2035.
4) The system would need an investment of US$609 million between 2036 and 2040.
5) The total investment over the planning horizon would be US$3,181 million.

7.7 CAPITAL COST OF THE CONSUMER METERS

It is estimated that the total capital cost required for the consumer meters (three-phase and single-phase) of the new 11/33 kV feeders would amount to over US$505.4 million over the planning horizon. The breakdown for every five years is provided as follows:

1) US$99.4 million for the period from 2021 to 2025
2) US$121.3 million for the period from 2026 to 2030
3) US$137.7 million for the period from 2031 to 2035
4) US$147 million for the period from 2031 to 2035

Table 7-1: Overnight EPC Cost – Distribution Development Plan

	Project	Quantity	Online	Year																				
No.	Name	(km or Set)	Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	33kV Overhead Line-Single Feeder	241.3	2021		8.0																			
2	33kV Overhead Line-Double Feeder	281.5	2021		11.3																			
3	33kV Overhead Line-Quad Feeder	281.5	2021		14.1																			
4	33kV Underground Cable	15.9	2021		3.7																			
5	33kV Outdoor Bay	53	2021		6.4																			
6	33/11kV 2*15MVA Substation	53	2021		74.2																			
7	11kV Feeder	212	2021		160.3																			
8	33kV Overhead Line-Single Feeder	231.4	2022			7.6																		
9	33kV Overhead Line-Double Feeder	269.9	2022			10.8																		
10	33kV Overhead Line-Quad Feeder	269.9	2022			13.5																		
11	33kV Underground Cable	9.3	2022			2.2																		
12	33kV Outdoor Bay	31	2022			3.7																		
13	33/11kV 2*15MVA Substation	31	2022			43.4																		
14	11kV Feeder	124	2022			93.7																		
15	33kV Overhead Line-Single Feeder	125.8	2023				4.2																	
16	33kV Overhead Line-Double Feeder	146.8	2023				5.9																	
17	33kV Overhead Line-Quad Feeder	146.8	2023				7.3																	
18	33kV Underground Cable	9.6	2023				2.3																	
19	33kV Outdoor Bay	32	2023				3.8																	
20	33/11kV 2*15MVA Substation	32	2023				44.8																	
21	11kV Feeder	128	2023				96.8																	
22	33kV Overhead Line-Single Feeder	13	2024					0.4																
23	33kV Overhead Line-Double Feeder	15.2	2024					0.6																
24	33kV Overhead Line-Quad Feeder	15.2	2024					0.8																
25	33kV Underground Cable	3.6	2024					0.8																
26	33kV Outdoor Bay	12	2024					1.4																
27	33/11kV 2*15MVA Substation	12	2024					16.8																
28	11kV Feeder	48	2024					36.3																
29	33kV Overhead Line-Single Feeder	29.29	2025						1.0															
30	33kV Overhead Line-Double Feeder	34.2	2025						1.4															
31	33kV Overhead Line-Quad Feeder	34.2	2025						1.7															
32	33kV Underground Cable	5.1	2025						1.2															
33	33kV Outdoor Bay	17	2025						2.0															
34	33/11kV 2*15MVA Substation	17	2025						23.8															
35	11kV Feeder	68	2025						51.4															
36	33kV Feeder All	23	2026							141.1														
37	33kV Feeder All	22	2027								135.0													
38	33kV Feeder All	23	2028									141.1												
39	33kV Feeder All	25	2029										153.4											
40	33kV Feeder All	25	2030											153.4										
41	33kV Feeder All	25	2031												153.4									
42	33kV Feeder All	26	2032													159.5								
43	33kV Feeder All	27	2033														165.6							
44	33kV Feeder All	27	2034															165.6						
45	33kV Feeder All	29	2035																177.9					
46	33kV Feeder All	27	2036																	165.6				
47	33kV Feeder All	28	2037																		171.8			
48	33kV Feeder All	30	2038																			184.1		
49	33kV Feeder All	30	2039																				184.1	
50	33kV Feeder All	28	2040																					171.8
	Total			**0.0**	**277.9**	**175.0**	**165.0**	**57.2**	**82.5**	**141.1**	**135.0**	**141.1**	**153.4**	**153.4**	**153.4**	**159.5**	**165.6**	**165.6**	**177.9**	**165.6**	**171.8**	**184.1**	**184.1**	**171.8**
	Cumulative Total			**0.0**	**277.9**	**452.8**	**617.9**	**675.0**	**757.5**	**898.6**	**1033.6**	**1174.7**	**1328.1**	**1481.5**	**1634.8**	**1794.3**	**1960.0**	**2125.6**	**2303.6**	**2469.2**	**2641.0**	**2825.0**	**3009.1**	**3180.9**

Table 7-2: Annual Cost by Category – Distribution Development Plan

Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Load Forecast																					
Energy to DISCOs (GWh)	10,095.2	10,895.6	11,788.0	12,772.5	13,849.3	15,018.9	16,281.4	17,566.4	18,876.8	20,271.3	21,703.8	23,142.7	24,621.4	26,142.1	27,707.0	29,318.3	30,881.0	32,494.3	34,160.7	35,882.5	37,454.4
Peak Demand at DISCOs Metering (MW)	1,772.9	1,913.5	2,070.2	2,243.1	2,432.3	2,637.7	2,859.4	3,085.1	3,315.2	3,560.1	3,811.7	4,064.4	4,324.1	4,591.2	4,866.0	5,149.0	5,423.4	5,706.8	5,999.4	6,301.8	6,577.9
Cost in Current Value (M-US$)																					
Existing System O&M Cost	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9	304.9
Amortized Capital Repayment	0.0	32.4	52.9	72.2	78.8	88.5	104.9	120.7	137.2	155.1	173.0	190.9	209.5	228.9	248.2	269.0	288.3	308.4	329.9	351.4	371.5
O&M Cost (Excluding Capital Repayment)	0.0	27.8	45.3	61.8	67.5	75.8	89.9	103.4	117.5	132.8	148.1	163.5	179.4	196.0	212.6	230.4	246.9	264.1	282.5	300.9	318.1
Total	**304.9**	**365.1**	**403.0**	**438.8**	**451.2**	**469.1**	**499.7**	**528.9**	**559.5**	**592.8**	**626.0**	**659.3**	**693.8**	**729.8**	**765.7**	**804.2**	**840.1**	**877.4**	**917.3**	**957.2**	**994.4**
Cumulative Cost in Current Value (M-US$)																					
Existing System O&M Cost	304.9	609.7	914.6	1,219.5	1,524.4	1,829.2	2,134.1	2,439.0	2,743.9	3,048.7	3,353.6	3,658.5	3,963.4	4,268.2	4,573.1	4,878.0	5,182.9	5,487.7	5,792.6	6,097.5	6,402.4
Amortized Capital Repayment	0.0	32.4	85.3	157.5	236.3	324.8	429.7	550.4	687.6	842.7	1,015.7	1,206.6	1,416.2	1,645.0	1,893.3	2,162.3	2,450.6	2,759.0	3,088.9	3,440.3	3,811.8
O&M Cost (Excluding Capital Repayment)	0.0	27.8	73.1	134.9	202.4	278.1	368.0	471.3	588.8	721.6	869.8	1,033.2	1,212.7	1,408.7	1,621.2	1,851.6	2,098.5	2,362.6	2,645.1	2,946.0	3,264.1
Total	**304.9**	**670.0**	**1,073.0**	**1,511.8**	**1,963.0**	**2,432.1**	**2,931.8**	**3,460.8**	**4,020.3**	**4,613.1**	**5,239.1**	**5,898.3**	**6,592.2**	**7,322.0**	**8,087.6**	**8,891.9**	**9,732.0**	**10,609.4**	**11,526.7**	**12,483.8**	**13,478.2**
Discount Factor	0.9535	0.8668	0.7880	0.7164	0.6512	0.5920	0.5382	0.4893	0.4448	0.4044	0.3676	0.3342	0.3038	0.2762	0.2511	0.2283	0.2075	0.1886	0.1715	0.1559	0.1417
Cost in Present Value (M-US$)																					
Existing System O&M Cost	290.7	264.3	240.2	218.4	198.5	180.5	164.1	149.2	135.6	123.3	112.1	101.9	92.6	84.2	76.5	69.6	63.3	57.5	52.3	47.5	43.2
Amortized Capital Repayment	0.0	28.1	41.7	51.7	51.3	52.4	56.5	59.1	61.0	62.7	63.6	63.8	63.7	63.2	62.3	61.4	59.8	58.2	56.6	54.8	52.6
O&M Cost (Excluding Capital Repayment)	0.0	24.1	35.7	44.3	44.0	44.8	48.4	50.6	52.3	53.7	54.5	54.6	54.5	54.1	53.4	52.6	51.2	49.8	48.4	46.9	45.1
Total	**290.7**	**316.5**	**317.6**	**314.3**	**293.8**	**277.7**	**268.9**	**258.8**	**248.9**	**239.7**	**230.1**	**220.3**	**210.8**	**201.5**	**192.2**	**183.6**	**174.3**	**165.5**	**157.3**	**149.2**	**140.9**
Cumulative Cost in Present Value (M-US$)																					
Existing System O&M Cost	290.7	554.9	795.2	1,013.6	1,212.1	1,392.6	1,556.7	1,705.9	1,841.5	1,964.8	2,076.8	2,178.7	2,271.3	2,355.5	2,432.1	2,501.7	2,564.9	2,622.4	2,674.7	2,722.3	2,765.5
Amortized Capital Repayment	0.0	28.1	69.8	121.5	172.8	225.2	281.7	340.7	401.7	464.5	528.1	591.9	655.5	718.7	781.1	842.5	902.3	960.5	1,017.0	1,071.8	1,124.5
O&M Cost (Excluding Capital Repayment)	0.0	24.1	59.8	104.0	148.0	192.8	241.2	291.8	344.0	397.7	452.2	506.8	561.3	615.5	668.8	721.4	772.7	822.5	870.9	917.8	962.9
Total	**290.7**	**607.2**	**924.7**	**1,239.1**	**1,532.9**	**1,810.6**	**2,079.6**	**2,338.4**	**2,587.2**	**2,826.9**	**3,057.1**	**3,277.4**	**3,488.2**	**3,689.7**	**3,882.0**	**4,065.5**	**4,239.9**	**4,405.4**	**4,562.7**	**4,711.9**	**4,852.8**
Levelized Cost of Energy (US$/MWh) =	**29.82**				**Total Cost in PV (M-US$) =**	**4,852.8**				**Total Energy in PV (GWh) =**	**162,728.0**										

Table 7-3: Capital Expenditure Cash Flow – Distribution Development Plan

No.	Project Name	Quantity (km or Set)	Online Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	33kV Overhead Line-Single Feeder	241.3	2021	4.8	3.2																				
2	33kV Overhead Line-Double Feeder	281.5	2021	6.8	4.5																				
3	33kV Overhead Line-Quad Feeder	281.5	2021	8.4	5.6																				
4	33kV Underground Cable	15.9	2021	2.2	1.5																				
5	33kV Outdoor Bay	53	2021	3.8	2.5																				
6	33/11kV 2*15MVA Substation	53	2021	44.5	29.7																				
7	11kV Feeder	212	2021	96.2	64.1																				
8	33kV Overhead Line-Single Feeder	231.4	2022		4.6	3.1																			
9	33kV Overhead Line-Double Feeder	269.9	2022		6.5	4.3																			
10	33kV Overhead Line-Quad Feeder	269.9	2022		8.1	5.4																			
11	33kV Underground Cable	9.3	2022		1.3	0.9																			
12	33kV Outdoor Bay	31	2022		2.2	1.5																			
13	33/11kV 2*15MVA Substation	31	2022		26.0	17.4																			
14	11kV Feeder	124	2022		56.2	37.5																			
15	33kV Overhead Line-Single Feeder	125.8	2023			2.5	1.7																		
16	33kV Overhead Line-Double Feeder	146.8	2023			3.5	2.3																		
17	33kV Overhead Line-Quad Feeder	146.8	2023			4.4	2.9																		
18	33kV Underground Cable	9.6	2023			1.4	0.9																		
19	33kV Outdoor Bay	32	2023			2.3	1.5																		
20	33/11kV 2*15MVA Substation	32	2023			26.9	17.9																		
21	11kV Feeder	128	2023			58.1	38.7																		
22	33kV Overhead Line-Single Feeder	13	2024				0.3	0.2																	
23	33kV Overhead Line-Double Feeder	15.2	2024				0.4	0.2																	
24	33kV Overhead Line-Quad Feeder	15.2	2024				0.5	0.3																	
25	33kV Underground Cable	3.6	2024				0.5	0.3																	
26	33kV Outdoor Bay	12	2024				0.9	0.6																	
27	33/11kV 2*15MVA Substation	12	2024				10.1	6.7																	
28	11kV Feeder	48	2024				21.8	14.5																	
29	33kV Overhead Line-Single Feeder	29.29	2025					0.6	0.4																
30	33kV Overhead Line-Double Feeder	34.2	2025					0.8	0.5																
31	33kV Overhead Line-Quad Feeder	34.2	2025					1.0	0.7																
32	33kV Underground Cable	5.1	2025					0.7	0.5																
33	33kV Outdoor Bay	17	2025					1.2	0.8																
34	33/11kV 2*15MVA Substation	17	2025					14.3	9.5																
35	11kV Feeder	68	2025					30.8	20.6																
36	33kV Feeder All	23	2026						84.7	56.4															
37	33kV Feeder All	22	2027							81.0	54.0														
38	33kV Feeder All	23	2028								84.7	56.4													
39	33kV Feeder All	25	2029									92.0	61.4												
40	33kV Feeder All	25	2030										92.0	61.4											
41	33kV Feeder All	25	2031											92.0	61.4										
42	33kV Feeder All	26	2032												95.7	63.8									
43	33kV Feeder All	27	2033													99.4	66.3								
44	33kV Feeder All	27	2034														99.4	66.3							
45	33kV Feeder All	29	2035															106.7	71.2						
46	33kV Feeder All	27	2036																99.4	66.3					
47	33kV Feeder All	28	2037																	103.1	68.7				
48	33kV Feeder All	30	2038																		110.4	73.6			
49	33kV Feeder All	30	2039																			110.4	73.6		
50	33kV Feeder All	28	2040																				103.1	68.7	
	Total			**166.7**	**216.1**	**169.0**	**100.3**	**72.4**	**117.7**	**137.4**	**138.7**	**148.5**	**153.4**	**153.4**	**157.1**	**163.2**	**165.6**	**173.0**	**170.6**	**169.3**	**179.1**	**184.1**	**176.7**	**68.7**	**0.0**
	Total			**979.6**							**750.9**					**841.7**					**608.6**				
	Cumulative Total			**166.7**	**382.9**	**551.9**	**652.2**	**724.5**	**842.2**	**979.6**	**1118.3**	**1266.7**	**1420.1**	**1573.5**	**1730.5**	**1893.7**	**2059.4**	**2232.4**	**2402.9**	**2572.3**	**2751.4**	**2935.5**	**3112.1**	**3180.9**	**3180.9**

8 RECOMMENDED INTEGRATED RESOURCE PLAN

This section summarizes the system development plan and cost of the Lagos State IRP.

8.1 ADDITIONS AND REINFORCEMENTS OF SYSTEM FACILITIES

The IRP is the combination of the following three system development plans:

1) Generation Development Plan – The generation resource addition and retirement plan presented in Table 5-8 shows the annual requirement on generation capacity as well as the capacity balance between generation capacity and peak load demand.
2) Transmission Development Plan – The new additions and reinforcements of transformation stations and transmission lines are listed in Tables 6-3, 6-4, 6-5, 6-6, 6-7, 6-8, 6-9, and 6-10.
3) Distribution Development Plan – The new additions and upgrades of distribution feeders are listed in Subsection 7.4.1 (for EKEDC from 2021 to 2025), Subsection 7.4.2 (for IE from 2021 to 2025), and Subsection 7.4.3 (for entire state from 2026 to 2040).

It is expected that the forecast load demand in terms of peak and energy would be supplied at the pre-defined reliability level with implementation of the IRP, i.e. construction of the facilities identified and proposed. In order to supply the load reliably, the system needs to not only have the proposed new facilities installed and the existing facilities upgraded, but all its facilities also need to be operated and maintained in accordance with the best practice of reputable international utilities.

8.2 SYSTEM OPERATION COST

Table 8-1 shows the annual operation cost of entire electricity sector of the state, which includes the generation cost as presented in Table 5-7, transmission cost as shown in Table 6-12, and distribution cost as exhibited in Table 7-2. As indicated in Table 8-1, the total system cost includes the following five components:

1) Amortized Capital Repayment – Annual total repayment for the capital investment used in addition/reinforcement/upgrading of generation, transmission, and distribution facilities.
2) Other Fixed Cost – The sum of the fixed cost (excluding capital repayment) of generation, O&M cost of the existing transmission (estimated based on the current transmission tariff), O&M cost of the new transmission, O&M cost of the existing distribution (estimated based on the current distribution tariff), and O&M cost of the new distribution.
3) Fuel Cost – The total fuel cost for both existing and new generating units (power plants)
4) Other Variable Cost – The total variable cost for both existing and new generating units (power plants)
5) GHG Offset Allowance – The total GHG emission penalty imposed to both existing and new generating units (power plants)

In order to understand the annual operation cost intuitively, Figure 8-1 illustrates the contribution of generation, transmission, and distribution components to the annual total cost, and Figure 8-2 shows the contribution of these components to cumulative cost.

Table 8-1: System Operation Cost

	Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Cost in Current Value (M-US$)																						
G	Amortized Capital Repayment	0	0	0	0	0	22	394	463	541	642	720	788	844	911	956	1,035	1,103	1,158	1,226	1,305	1,350
	Other Fixed Cost	367	383	402	423	449	481	252	264	278	295	310	319	329	338	345	357	366	376	385	397	404
	Fuel Cost	407	439	475	514	550	576	553	574	592	613	636	674	709	750	792	831	873	912	957	1,000	959
	Other Variable Cost	174	195	218	243	269	288	167	171	175	180	185	193	201	210	219	227	236	244	254	263	254
	GHG Offset Allowance	65	71	76	83	89	93	84	87	89	92	95	101	105	111	117	122	128	133	140	145	140
	Subtotal	**1,013**	**1,088**	**1,172**	**1,263**	**1,357**	**1,460**	**1,449**	**1,559**	**1,676**	**1,823**	**1,946**	**2,075**	**2,187**	**2,320**	**2,428**	**2,572**	**2,706**	**2,824**	**2,962**	**3,111**	**3,107**
T	Existing System O&M Cost	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108
	Amortized Capital Repayment	0	0	9	23	32	38	45	48	51	55	58	61	64	67	70	73	76	78	81	83	86
	O&M Cost	0	0	7	19	27	33	38	41	44	47	50	52	55	58	60	63	65	67	69	71	73
	Subtotal	**108**	**108**	**124**	**150**	**167**	**179**	**191**	**197**	**204**	**210**	**216**	**222**	**227**	**233**	**238**	**244**	**249**	**253**	**258**	**263**	**267**
D	Existing System O&M Cost	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305	305
	Amortized Capital Repayment	0	32	53	72	79	88	105	121	137	155	173	191	210	229	248	269	288	308	330	351	371
	O&M Cost	0	28	45	62	68	76	90	103	117	133	148	163	179	196	213	230	247	264	283	301	318
	Subtotal	**305**	**365**	**403**	**439**	**451**	**469**	**500**	**529**	**560**	**593**	**626**	**659**	**694**	**730**	**766**	**804**	**840**	**877**	**917**	**957**	**994**
System	Amortized Capital Repayment	0	32	62	95	111	149	544	631	729	852	951	1,040	1,117	1,208	1,274	1,377	1,467	1,545	1,637	1,740	1,807
	Other Fixed Cost	780	824	868	917	956	1,003	793	821	853	888	921	948	976	1,005	1,031	1,063	1,091	1,120	1,150	1,182	1,209
	Fuel Cost	407	439	475	514	550	576	553	574	592	613	636	674	709	750	792	831	873	912	957	1,000	959
	Other Variable Cost	174	195	218	243	269	288	167	171	175	180	185	193	201	210	219	227	236	244	254	263	254
	GHG Offset Allowance	65	71	76	83	89	93	84	87	89	92	95	101	105	111	117	122	128	133	140	145	140
	Total	**1,426**	**1,561**	**1,699**	**1,852**	**1,975**	**2,108**	**2,140**	**2,285**	**2,439**	**2,625**	**2,788**	**2,956**	**3,108**	**3,282**	**3,433**	**3,620**	**3,795**	**3,954**	**4,138**	**4,330**	**4,369**
Cost Composition																						
	Generation	71.0%	69.7%	69.0%	68.2%	68.7%	69.2%	67.7%	68.2%	68.7%	69.4%	69.8%	70.2%	70.4%	70.7%	70.7%	71.0%	71.3%	71.4%	71.6%	71.8%	71.1%
	Transmission	7.6%	6.9%	7.3%	8.1%	8.4%	8.5%	8.9%	8.6%	8.3%	8.0%	7.7%	7.5%	7.3%	7.1%	6.9%	6.7%	6.6%	6.4%	6.2%	6.1%	6.1%
	Distribution	21.4%	23.4%	23.7%	23.7%	22.8%	22.3%	23.3%	23.2%	22.9%	22.6%	22.5%	22.3%	22.3%	22.2%	22.3%	22.2%	22.1%	22.2%	22.2%	22.1%	22.8%
	Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
Cumulative Cost in Current Value (M-US$)																						
	Generation	1,013	2,101	3,273	4,535	5,892	7,352	8,801	10,360	12,036	13,858	15,804	17,879	20,066	22,386	24,814	27,386	30,092	32,916	35,878	38,989	42,096
	Transmission	108	216	340	490	657	836	1,027	1,225	1,428	1,638	1,854	2,075	2,303	2,536	2,774	3,018	3,267	3,520	3,778	4,041	4,308
	Distribution	305	670	1,073	1,512	1,963	2,432	2,932	3,461	4,020	4,613	5,239	5,898	6,592	7,322	8,088	8,892	9,732	10,609	11,527	12,484	13,478
	Total	**1,426**	**2,987**	**4,686**	**6,538**	**8,513**	**10,621**	**12,761**	**15,045**	**17,484**	**20,109**	**22,897**	**25,853**	**28,961**	**32,243**	**35,676**	**39,296**	**43,091**	**47,045**	**51,183**	**55,513**	**59,882**
Discount Factor		0.9535	0.8668	0.7880	0.7164	0.6512	0.5920	0.5382	0.4893	0.4448	0.4044	0.3676	0.3342	0.3038	0.2762	0.2511	0.2283	0.2075	0.1886	0.1715	0.1559	0.1417
Cost in Present Value (M-US$)																						
	Generation	966	943	923	905	884	864	780	763	745	737	715	693	664	641	610	587	562	533	508	485	440
	Transmission	103	94	98	108	109	106	103	97	91	85	79	74	69	64	60	56	52	48	44	41	38
	Distribution	291	316	318	314	294	278	269	259	249	240	230	220	211	202	192	184	174	166	157	149	141
	Total	**1,360**	**1,353**	**1,339**	**1,326**	**1,286**	**1,248**	**1,152**	**1,118**	**1,085**	**1,062**	**1,025**	**988**	**944**	**907**	**862**	**826**	**787**	**746**	**710**	**675**	**619**
Cumulative Cost in Present Value (M-US$)																						
	Generation	966	1,909	2,832	3,737	4,620	5,485	6,265	7,027	7,773	8,510	9,225	9,918	10,583	11,223	11,833	12,420	12,982	13,514	14,022	14,507	14,948
	Transmission	103	197	294	402	511	617	720	816	907	991	1,071	1,145	1,214	1,278	1,338	1,394	1,445	1,493	1,537	1,578	1,616
	Distribution	291	607	925	1,239	1,533	1,811	2,080	2,338	2,587	2,827	3,057	3,277	3,488	3,690	3,882	4,066	4,240	4,405	4,563	4,712	4,853
	Total	**1,360**	**2,713**	**4,051**	**5,378**	**6,664**	**7,912**	**9,064**	**10,182**	**11,266**	**12,328**	**13,353**	**14,341**	**15,285**	**16,191**	**17,053**	**17,879**	**18,667**	**19,413**	**20,122**	**20,797**	**21,417**
Load at Generation Bus																						
	Peak (MW)	1,866	2,014	2,179	2,361	2,560	2,776	3,010	3,247	3,490	3,747	4,012	4,278	4,552	4,833	5,122	5,420	5,709	6,007	6,315	6,633	6,924
	Energy (GWh)	10,626	11,469	12,408	13,445	14,578	15,809	17,138	18,491	19,870	21,338	22,846	24,361	25,917	27,518	29,165	30,861	32,506	34,205	35,959	37,771	39,426
Load at DISCOs Receiving Bus																						
	Peak (MW)	1,773	1,914	2,070	2,243	2,432	2,638	2,859	3,085	3,315	3,560	3,812	4,064	4,324	4,591	4,866	5,149	5,423	5,707	5,999	6,302	6,578
	Energy (GWh)	10,095	10,896	11,788	12,772	13,849	15,019	16,281	17,566	18,877	20,271	21,704	23,143	24,621	26,142	27,707	29,318	30,881	32,494	34,161	35,883	37,454
Levelized Cost of Energy (US$/MWh)																						
	Load at Generation Bus	**Total =**		**125.03**		**Generation =**		**87.26**		**Transmission =**		**9.44**		**Distribution =**		**28.33**						
	Load at DISCOs Receiving Bus	**Total =**		**131.61**		**Generation =**		**91.86**		**Transmission =**		**9.93**		**Distribution =**		**29.82**						

Figure 8-1: Contribution of Generation, Transmission and Distribution to Annual Total Cost

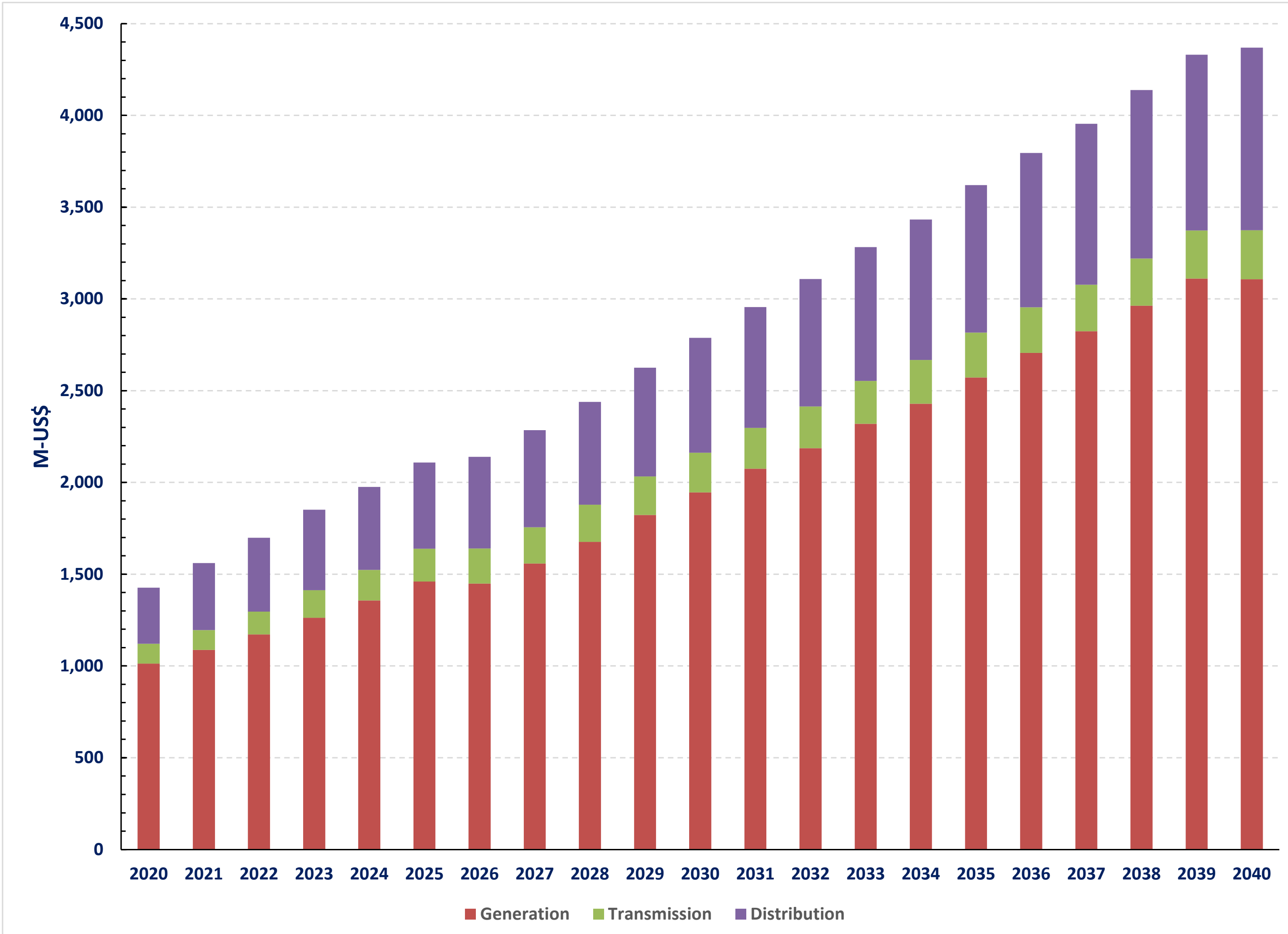
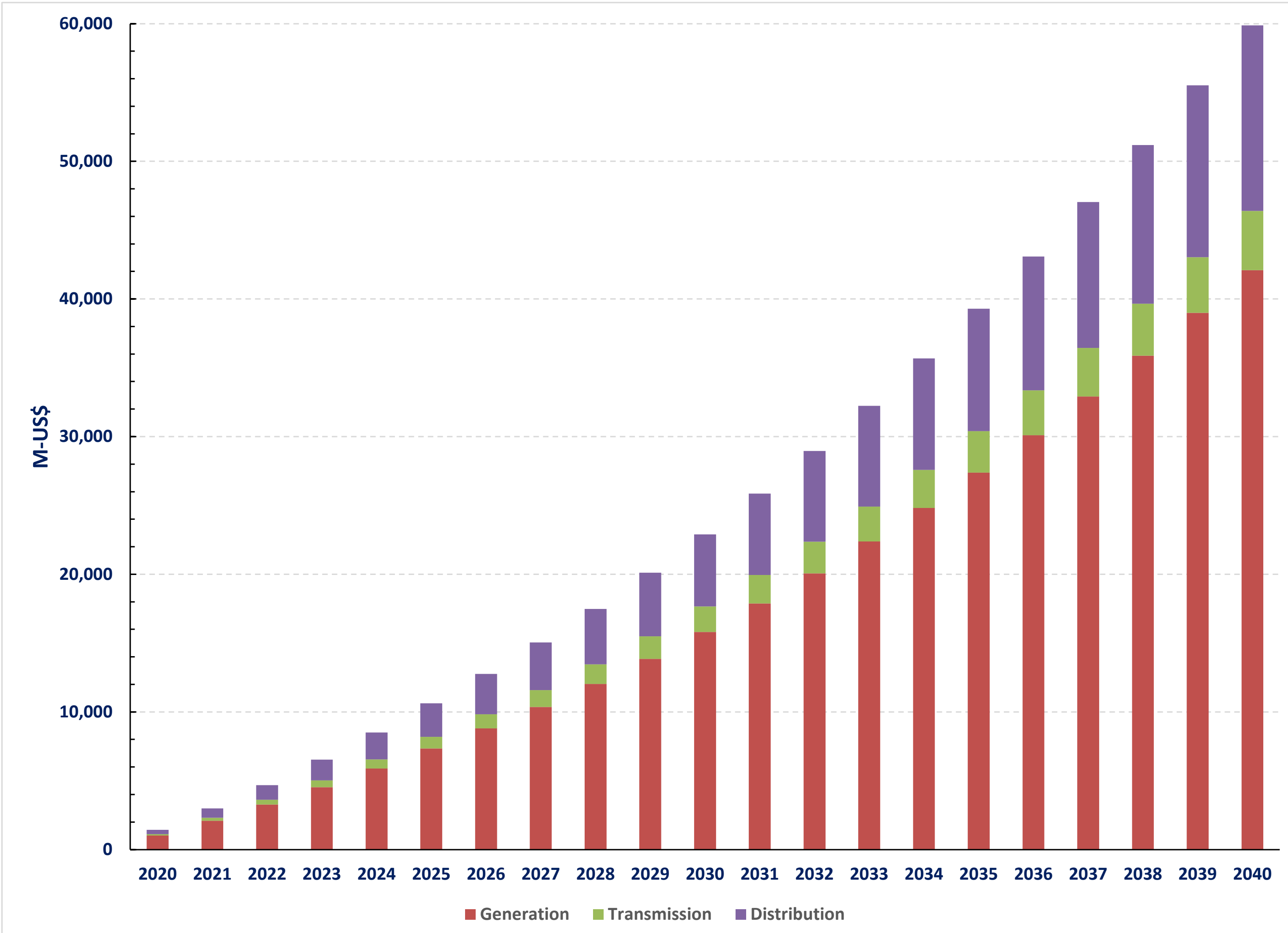


Figure 8-2: Contribution of Generation, Transmission and Distribution to Cumulative Cost



The following may be observed from Table 8-1, Figure 8-1, and Figure 8-2:

1) The annual system operation cost in 2030 would reach US$2,788 million in CV, including US$1,946 million from generation, US$216 million from transmission, and US$626 million from distribution. In terms of cost category, it includes US$951 million for capital repayment, US$921 million for other fixed cost, US$636 million for fuel cost, US$185 for other variable cost, and US$95 million for GHG offset allowance.
2) The annual system operation cost in 2040 would amount to US$4,369 million in CV, including US$3,107 million from generation, US$267 million from transmission, and US$994 million from distribution. In terms of cost category, it includes US$1,807 million for capital repayment, US$1,209 million for other fixed cost, US$959 million for fuel cost, US$254 for other variable cost, and US$140 million for GHG offset allowance.
3) In terms of CV, over the entire planning horizon, the system operation cost would be US$59,882 million, including US$42,096 million for generation, US$4,308 million for transmission, and US$13,478 million for distribution.
4) In terms of PV, over the entire planning horizon, the system operation cost would be US$21,417 million, including US$14,948 million for generation, US$1,616 million for transmission, and US$4,853 million for distribution.
5) When calculated based on the energy measured at generation bus, the levelized cost of energy would be US$125.03 per MWh, or US$0.12503 per kWh, which includes US$87.26, 9.44, and 28.33 per MWh for generation, transmission, and distribution, respectively.
6) When calculated based on the energy measured at the DISCOs' receiving bus, the levelized cost of energy would be US$131.61 per MWh, or US$0.13161 per kWh, which includes US$91.86, 9.93, and 29.82 per MWh for generation, transmission, and distribution, respectively. This should be understandable as 5% of transmission loss has been assumed in this study, which means that the energy received by DISCOs is 95% of energy measured at generation bus.

8.3 CAPITAL INVESTMENT CASH FLOW

Table 8-2 summarizes the annual capital disbursement flow, including the contribution from generation as shown in Table 5-9, transmission as provided in Table 6-13, and distribution as presented in Table 7-3. In order to understand the capital expenditure flow intuitively, Figure 8-3 illustrates the contribution of generation, transmission, and distribution components to the annual capital disbursement flow, and Figure 8-4 presents the contribution of these components to cumulative capital disbursement flow.

Table 8-2: Annual Capital Disbursement Flow

Capital Disbursement Flow (M-US$)						
Year	**Generation**	**Transmission**	**Distribution**	**Subtotal**	**Subtotal**	**Cumulative**
2019		0.0	166.7	**166.7**		**166.7**
2020	0.0	44.8	216.1	**260.9**		**427.6**
2021	0.0	101.5	169.0	**270.5**		**698.2**
2022	0.0	94.2	100.3	**194.5**	**5,069.7**	**892.7**
2023	589.3	64.8	72.4	**726.4**		**1,619.2**
2024	1,646.3	55.7	117.7	**1,819.6**		**3,438.7**
2025	1,454.3	39.3	137.4	**1,631.0**		**5,069.7**
2026	632.5	28.7	138.7	**799.9**		**5,869.6**
2027	755.0	28.7	148.5	**932.2**		**6,801.8**
2028	715.0	28.7	153.4	**897.1**	**4,084.6**	**7,698.9**
2029	593.0	27.1	153.4	**773.4**		**8,472.3**
2030	499.0	26.0	157.1	**682.0**		**9,154.3**
2031	521.0	26.0	163.2	**710.1**		**9,864.5**
2032	445.0	26.0	165.6	**636.6**		**10,501.1**
2033	539.0	26.0	173.0	**738.0**	**3,569.0**	**11,239.0**
2034	601.0	23.1	170.6	**794.7**		**12,033.7**
2035	499.0	21.3	169.3	**689.6**		**12,723.3**
2036	521.0	21.3	179.1	**721.4**		**13,444.7**
2037	619.0	21.3	184.1	**824.3**		**14,269.1**
2038	412.3	21.3	176.7	**610.2**	**2,351.7**	**14,879.3**
2039	118.5	8.5	68.7	**195.7**		**15,075.0**
2040	0.0	0.0	0.0	**0.0**		**15,075.0**
Total	**11,160.0**	**734.1**	**3,180.9**	**15,075.0**		
Ratio	**74.0%**	**4.9%**	**21.1%**	**100.0%**		

One may see the following from Table 8-2, Figure 8-3, and Figure 8-4:

1) Over the planning horizon, the system would need a total investment of US$15,075 million, including US$11,160 million (74.0% of the total) for generation facilities, US$734 million (4.9% of the total) for transmission facilities, and US$3,181 million (21.1% of the total) for distribution facilities. The funds would be used to build, construct, install, upgrade, and reinforce power plants, transformation stations, transmission lines, distribution feeders, distribution substations, distribution transformers, and customer energy meters.

2) The investment requirement for the four periods – from 2019 to 2025, 2026 to 2030, 2031 to 2035, and 2036 to 2040 – would be US$5,070, 4,085, 3,569, and 2,351 million, respectively. The first period would need a very large amount of investment, which is for construction of new power plants and addressing the challenges faced at present. The capital disbursement presented in this table does not include that for the facilities to be commissioned from 2041 and onwards, of which the construction may have to start prior to 2041.

3) Over the planning horizon, two years, 2024 and 2025, need an investment of US$1,820 million and 1,631 million, respectively, which is much more than that in other years.

Figure 8-3: Contribution of Generation, Transmission and Distribution to Annual Capital Disbursement Flow

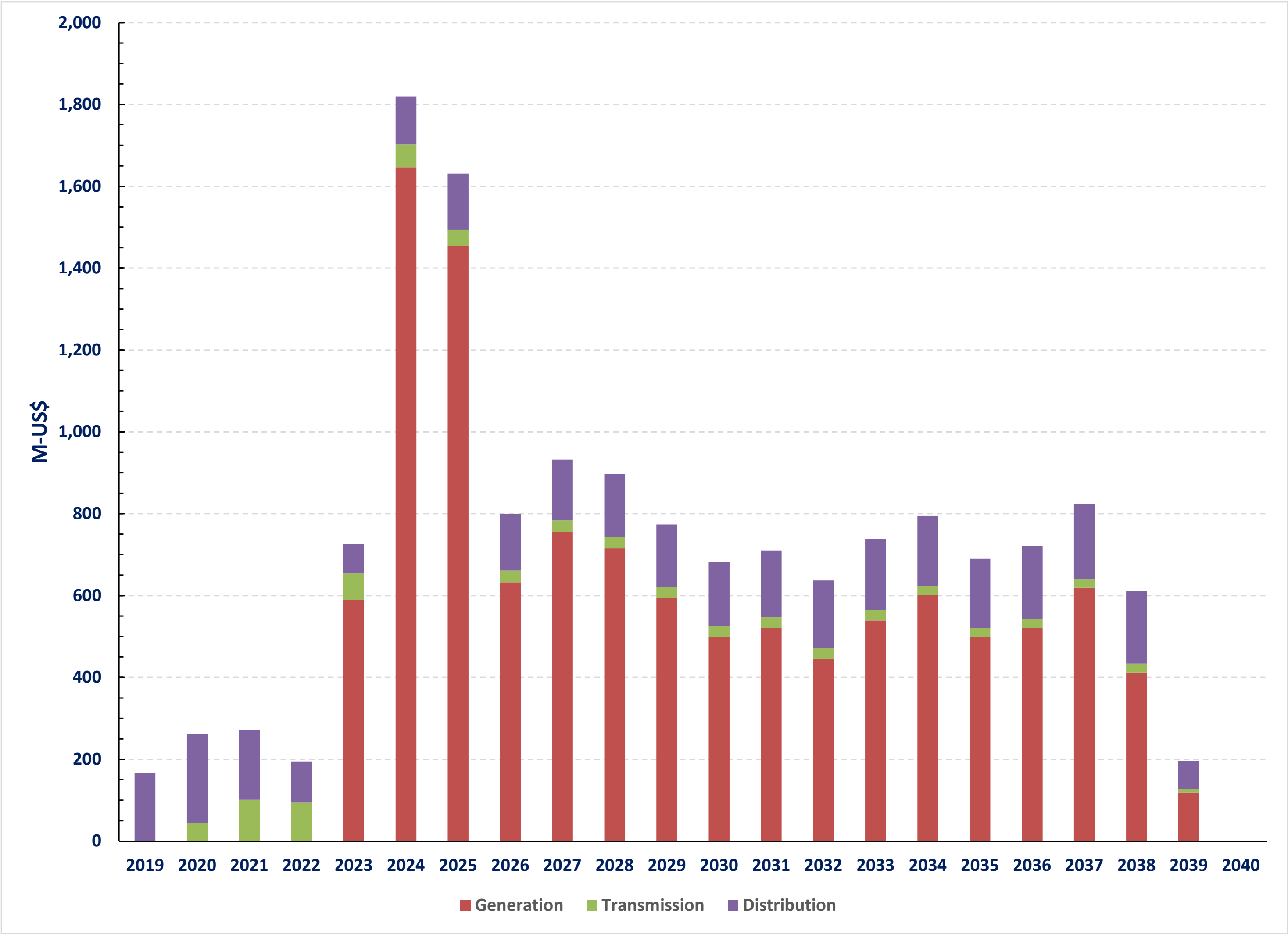
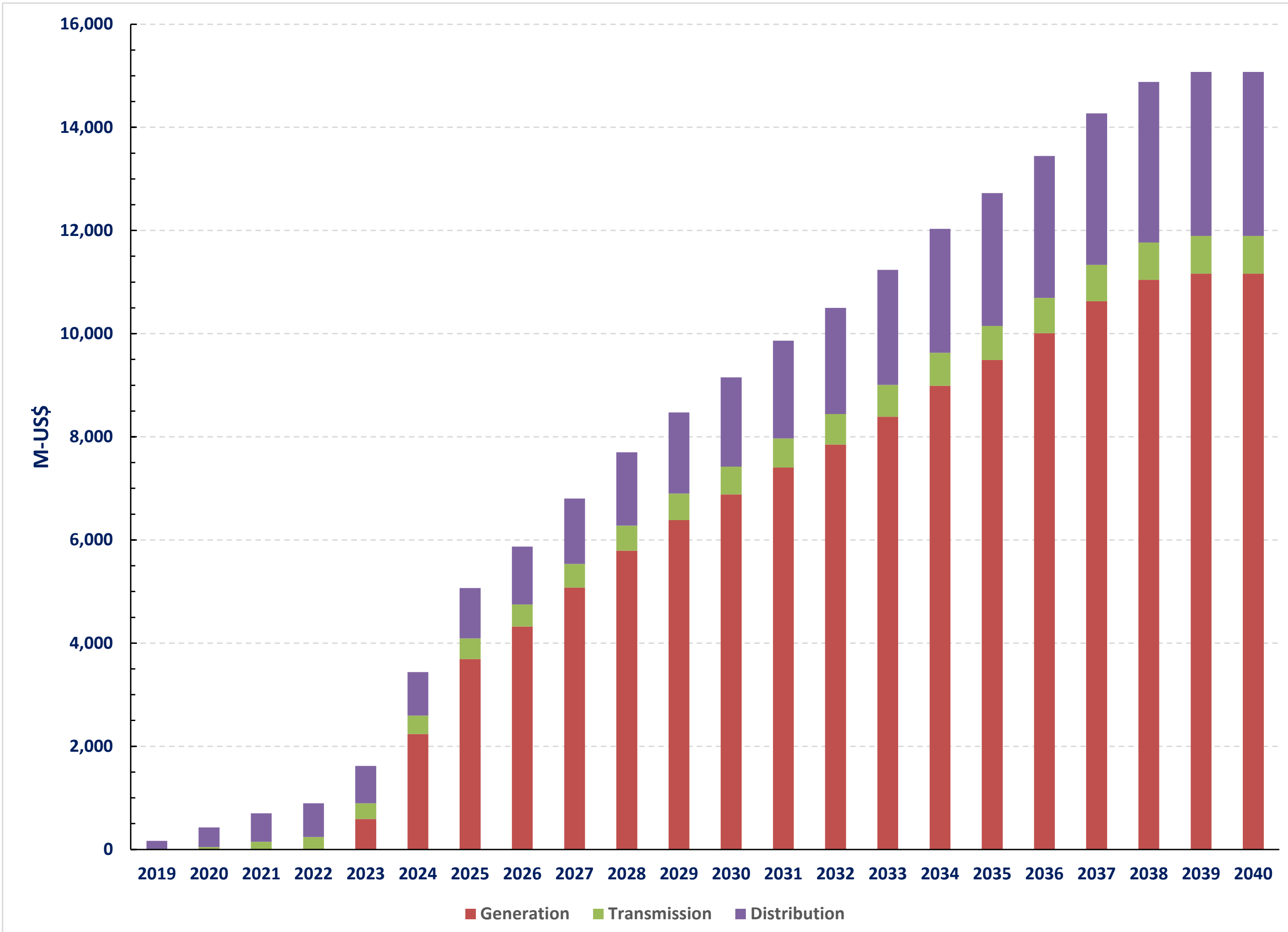


Figure 8-4: Contribution of Generation, Transmission and Distribution to Cumulative Capital Disbursement Flow



9 NEXT UPDATE OF THE INTEGRATED RESOURCE PLAN

This is the first IRP for Lagos State and the available information for the IRP preparation is very limited due to the COVID-19 conditions and other reasons. It is therefore suggested to initiate an update of the IRP if any of the main assumptions change significantly. These could include the following:

1) Government policies on the power sector, such as:
    i) Sector laws, regulations, and industrial structure
    ii) Timeframe compliance with Sustainable Development Goals and funding to achieve
    iii) Penetration of renewable energy
    iv) Implementation of DSM programs
    v) Fuel diversification
    vi) Environmental and social impacts
    vii) Implementation of the Presidential Power Initiative or other intervention projects
2) The total energy and peak demand, including energy sales, distribution losses, transmission losses, massive grid connection, and load factor
3) Capital costs of main power facilities, including all generation, transmission, and distribution
4) Operation and maintenance costs of power facilities
5) Fuel costs
6) Discount rate in calculation of costs in present value and for comparison of different scenarios
7) Operation and other risks
8) Funds available to power sector
9) Others

For reference, IRP reports will typically need to be updated approximately every three to five years. As this is the first IRP for Lagos State, and the continued implementation and development of the Lagos State electricity grid will bring many changes, it is recommended that in this case the next update should be started in approximately three years.

10 FINDINGS AND SUGGESTIONS

This section summarizes the study team's findings, suggestions, and recommendations on the IRP work carried out:

1) Preparation of an IRP – In Nigeria, power sector master plans (also referred to as IRPs or other designations), generation plans, and transmission plans have normally been prepared at the national level. This IRP, the first prepared by the Lagos State government for the state only, was prepared in accordance with technical aspects without inclusion of any individual institutional responsibilities or mandates that might be included in preparation of an IRP implementation plan. The IRP is therefore valid whether the Lagos State grid is maintained as part of the national grid or as an independent system.

2) Study Team – For this undertaking, PA-NPSP, in collaboration with the Lagos State Government, has led and conducted the load forecast report with support from EKEDC, IE, and Rural Electrification Agency counterparts; the generation planning report with support from Egbin Power, Dangote, and Niger Delta Power Holding Company (NDPHC); and the transmission and distribution development plans with support from TCN, EKEDC, and IE. If Lagos State intends to carry out the IRP work on a regular basis, then its Ministry of Energy and Mineral Resources should establish a small group of project managers, economists, analysts, and engineers to manage, provide technical directions to, and/or perform the detailed analysis for future IRP developments, either as an update or as a completely new preparation.

3) Load Forecast and Power System Planning Manuals – The Nigeria Distribution Code[23] requires each DISCO to prepare a 5-year load forecast for its service territory on an annual basis. The Grid Code requires the System Operator to create a new long-term (20 years) demand forecast for the Transmission Network at least once every three years. The Market Rules[24] require the Market Operator to prepare a 10-year Generation Adequacy Report in November of each year. PA-NPSP has not been able to collect the load forecast and generation, transmission, and distribution planning manuals used by the DISCOs, System Operator, and/or Market Operator. It is suggested that the State Government shall prepare the four manuals if the development of IRPs it to be a routine task in the future, which shall include the main topics, such as service coverage area, study time horizon, process, approach, model, assumptions, and expected outputs. As this will be an iterative process in the future, it is also suggested that this work be institutionalized by successive administrations in Lagos State to ensure the continued expansion and development of electricity and energy resources for the state. The example tables of contents of a long-term load forecast manual and generation, transmission, and distribution planning manuals are presented in Appendices G, H, I, and J, respectively.

4) Data Confidentiality – PA-NPSA signed Non-Disclosure Agreements (NDAs) with several entities in order to collect the information required for preparation of the IRP. Its preparation has included a few key stakeholders, and the IRP report itself will probably be a public document, which will provide the requirements and directions of the state power system development to all stakeholders including consumers. In that case, the IRP report shall not include any confidential information, and it shall only use general or normalized information.

5) Data Availability – During collection of system load consumption data and the information on energy resources available to large-scale power generation, it was found that some data, for example, the 33 kV feeders' hourly load, could take extra effort to collect. It would be better if the data could be readily collected, for example, through the SCADA system installed at each

[23] The Distribution Code for the Nigeria Electricity Distribution System – Version 02, NERC

[24] Market Rules for Transitional and Medium-Term Stages of Nigeria Electricity Supply Industry, December 2014

transformation station or the smart power meter measuring the power/energy flow to each 33 kV feeder. The two DISCOs at present receive power from a total of 24 TCN transformation stations, each station having two to several 33 kV feeders connected to the DISCOs' 33/11 kV substations and/or HV connected customers. In addition to pipeline NG, the State Government may assess other resources available to power generation including both quantity and cost, such as LNG, petroleum products, coal, uranium, hydro, solar, MSW, agricultural crop residues, other biomass, hydro, and wind. The State Government may also identify and evaluate DSM programs and implement cost-competitive ones.

6) Estimate of Population and Its Growth – The last national Census was conducted in 2006. The State Government has maintained that the population of the State in 2006 was much higher than that indicated in the census. As population and its expected future growth are very important factors in infrastructure planning and development, it is strongly suggested that the state conduct a new state-wise census or work together with the federal government to conduct a national census. Accurate population data is important to both the state and federal governments for land use/zoning and the development of infrastructure such as housing, road/highway, electricity system, water supply, waste disposal, hospitals, schools, community centers, and shopping malls.

7) Captive Generation Capacity – NERC's Regulation NERC-R-0108[25] stipulates that any entity that wishes to install a generator with a capacity exceeding 1 MW for its own use and not sold to a third party shall obtain a permit prior to its operation. The NERC website posts a list of captive power permit holders updated in 2013. The Lagos State Electricity Policy and Lagos Electric Power Sector Law 2018 also require the captive power permit holders to register with the state. For the future load forecasts, it is strongly suggested that the study team collect an updated list of captive power permit holders from the NERC and the State Registrar, and then contact each permit holder to investigate (i) if the power plant has been built or when it could be set up, (ii) the generation capacity, (iii) fuel used, (iv) generation technology or make and model of the gen-set, (v) annual electricity production, etc. These are very important in the analysis of switching self-generation to what should be a more energy-efficient and less polluting grid supply when the grid is reliable and tariffs are competitive.

8) Accuracy Level of Technical and Economic Parameters and Assumption – The IRP work involves various parameters and assumptions that are beyond the control and management of any persons, companies, and governments, and the operation and development of a power system are subject to various laws, regulations, policies, standards, human actions, funds availability, etc. It is therefore very difficult for the operation results of a power system to match their predicted values.

9) Renewable Energy Target – The least-cost generation development plan is prepared based on a presumed 15% renewable energy target from 2030 onwards, which means that solar PV power capacity would be approximately 50% of annual peak load demand. We have discussed this penetration level in this report. However, it is strongly suggested that the State Government should discuss this with the Federal Government and ensure it meets the requirements established in Electricity Vision 30:30:30.

10) The recommended least-cost generation development plan includes only natural gas-fueled CCGT and GT and solar PV power plants in addition to the existing Egbin thermal power plant. In order to diversify the supply mix, when cost-effective, environmentally friendly, socially responsible and sustainable, any other resource-based power generation could be constructed such as those using LNG, coal, petcoke, HFO, LFO, MSW, biomass, uranium, water, and wind.

11) The development of Waste to Energy (WTE) plants would result in electricity production and other environmental and social benefits. It is therefore suggested that the State Government carry

[25] Permits for Captive Power Generation Regulations, 2008, NERC

out an extensive WTE study to examine the costs and benefits. The cost of a WTE plant can be offset by the electricity produced and other environmental and social impacts reduced or avoided.

12) Penetration of Renewable Energy – When the renewable target (15% of energy) is met, the ratio of the installed solar PV power capacity to annual system peak would be approximately 50%, which is a very high-level penetration of renewable. When its penetration level reaches 20% or above, the industrial practice suggests that a comprehensive study be conducted to examine the impact of intermittent generation on system operation.

13) GHG Emissions – Due to a lack of other energy resources in terms of quantity and cost, the least-cost generation development plan is prepared using NG-fueled CCGT and GT power plants and solar PV power plants. Although GHG emissions from NG-fired CCGTs are less than those from petcoke, coal, HFO, and LFO-fueled generation, it is suggested that the State Government discuss emission levels with the Federal Government to ensure that the annual total of GHG emissions is within the national annual limit if such a limit is available.

14) One of the most important factors in power generation is fuel supply. Any large-scale new power generation projects in Lagos State would require NG transported through the recently commissioned ELPS II pipeline and/or the proposed EWOGGS or LNG (transported to Lagos State through waterways and then regasified locally). It is very important to consult with NGC on the available capacity of the ELPS II pipeline. Due to travel restrictions caused by COVID-19 conditions, the study team could not collect the required information although a few discussions were held with NGC and a list of the requested data was sent to them.

    An initial screening analysis of potential power plant sites and transmission line routes should be conducted based on the main technical, environmental, and social impact parameters. Due to travel restrictions resulting from COVID-19, the study team was not able to visit the potential sites and line routes to perform basic visual screening and instead relied on Google Earth to identify sites remotely. It is recommended that visual screening be conducted when possible and then updated in this analysis after completion.

15) Preparation of an Implementation Plan for the IRP – In order to prepare an implementation plan for the IRP, the state should conduct at least the following tasks:

    i) Consult with key stakeholders on the IRP and update this report, if necessary.
    ii) Approve the IRP for implementation.
    iii) Consult the Federal Ministry of Power, NERC, TCN, NBET, Gas Aggregation Company of Nigeria, NGC, IE, EKEDC, Dangote, IPPs, other generation companies and other key stakeholders; ensure that each stakeholder understands their responsibilities; address gaps; and establish the approach for the IRP implementation.
    iv) Address issues related to regulation, license, policy, and institutional framework.
    v) Establish an approach for the coordination of domestic power plants and those located outside of the state.
    vi) Establish approaches for the preparation of fuel supply agreements, generation interconnection agreements, competitive procurement processes, power purchase agreements, and other agreements/contracts.

16) Next Update – This IRP has been prepared with many continuously changing assumptions. It is therefore suggested that an update of the IRP be initiated if any one, or several, of the main assumptions used change significantly. For reference, it must be understood that IRP reports will typically need to be updated approximately every three to five years. As this is the first IRP for Lagos State and the continued implementation and development of the Lagos State electricity grid will bring many changes, it is recommended that in this case the next update should be started in approximately three years.

APPENDIX A: ANALYSIS OF THE IDENTIFIED POWER PLANT SITES

This appendix summarizes the analyzed results of the identified power plant sites.

A.1 Key Factors Considered in Selection of a Power Plant Site

There are five key factors in selection of a power plant site: the availability of the required resources, economic impacts on the plant's development and operation, accessibility to the required services, concerns on the environmental impacts, and concerns on the social impacts.

A.1.1 Availability of the Required Resources

The resources required for a power plant site include the (i) land space used for plant construction, operation and maintenance, fuel storage, waste storage and disposal, etc., (ii) fuel, (iii) water, and (iv) skilled labor.

1) Land – The suitability of a piece of land to the construction and operation of a power plant could be studied in terms of (i) topographic features, (ii) meteorologic conditions, (iii) geographic features, and (iv) geological conditions.

   A hydro power plant site could be studied in terms of (i) topographic features, (ii) rainfall during the year, (iii) catchment area, (iv) land space for civil engineering construction works (including powerhouse, dam, etc.) as well as plant operation and maintenance, (v) suitable site for storing water behind the dam, (vi) quantity of water at sufficient head and cost of civil engineering works, and (vii) others.

   In case of nuclear power plants, the disposal of products (radioactive in nature) could be a big and serious problem. They have either to be disposed of in a deep trench or in a site away from the seashore.

2) Fuel – The fuel used by a power plant could be locally produced or transported to the site from other locations in the country or other countries. The critical issue is that the fuel be supplied/delivered to the power plant in the required amount, at a reasonable cost, and with the expected reliability (including security). Possible interruptions of the fuel supply due to vandalism and other causes may also need to be considered in selecting a power plant site. The cost of fuel (including delivery cost) is an important factor in selecting the type of power plant technology for a particular location.

3) Water – In case of a hydro power plant, the flowing water will fuel the plant.

   When required, water could be used for cooling and other purposes at thermal (i.e. CCGT, coal, biomass, MSW, petcoke, etc.) and nuclear power plants. A steam power plant needs larger quantities of cooling water than diesel and gas turbine power plants. Water is circulated through condenser tubes to condense the steam and to maintain a high vacuum in the turbine condenser for high efficiency.

   Many power plant technologies use water from lakes, rivers, municipal water utilities, or ground water. In general, surface water is used for plant cooling and ground water is used for plant processes. The presence of adequate and usable water resources at or near a site is preferred over sites with remote, inadequate, or low-quality water resources. Sites with noncompeting water uses are generally preferred to sites with many uses.

4) Skilled Manpower – The construction, operation, and maintenance of a power plant require executive officers, managers, engineers, analysts, technicians, and skilled labor force. In accordance

with best industry practice and economic concerns, it is expected that most of the required skilled manpower could be recruited locally or domestically. In this case, local communities can benefit from these employment opportunities. Generally, sites that can make use of local labor are more desirable. These sites would have a larger skilled work force within a short distance from the power plant site.

A.1.2 Economic Impacts

The following factors also play key roles in the selection of a power plant site:

1) Land acquisition/lease cost – The cost of land in some areas could be extremely high, which would be a barrier to the development of a power plant.
2) Additional investment cost – One power plant would need to be interconnected to a grid system, and to be connected to the fuel and water supplies as well as other services. If a site is not appropriately selected, the required interconnection and services may result in additional costs to the power plant's construction, operation, and maintenance.
3) O&M cost – High transportation costs, living costs, insurance premiums, and property taxes will increase the plant's O&M cost,
4) Payback period
5) Future development limitations – The space available in the power plant may be used for future development.
6) Possibility for site expansion – The sites next to the power plant may be available for site expansion in the future.

A.1.3 Accessibility to the Required Services

In order to evacuate power and/or get the required services, a power plant must be accessible to the following:

1) Transmission grid – Capable of evacuating the power from the power plant (with interconnection and/or transmission reinforcement)
2) Transportation infrastructure, such as roads, a railway, an airport, and waterways, which are required to transport heavy machinery for installation at the power plant or fuel and materials required for operation and maintenance
3) Major electricity load centers, such as large industrial facilities, commercial centers, government compounds, and educational institutions. A power plant should be located as near to the load centers as possible to minimize transmission line costs and transmission losses.
4) Urban areas – To provide the supplies and services required by the power plant and its labor force

A.1.4 Environmental Impact Concerns

The following environmental factors need to be considered in the selection of a power plant site and its generation technologies:

1) Degradation of local air quality
2) Air pollutant emissions, including SOx, NOx, Hg, particular matters, etc. – A site for power plant near residential areas may be objectionable from the point of view of pollution and noise.
3) Solid waste

4) Liquid waste
5) Radioactive contamination – Radioactivity may be present in the atmosphere near a nuclear power plant. To prevent this, a dome is normally used in the plant which does not allow the radioactivity to spread by wind or underground waterways.
6) Ecological diversity
7) Land use impacts
8) Dust
9) Noise and vibration – Noise is objectionable but may be reduced to some extent by means of silencers.
10) Effect on water bodies
11) Greenhouse gases
12) Others

A.1.5 Social Impact Concerns

The impacts of a power plant on society may be studied from the following five aspects:

1) The total number of direct and indirect jobs that would be created.
2) Public acceptance – There have been cases when power plants have had to be relocated to or resited on different locations due to the public's objection, resulting in a significant amount of additional construction cost. It is strongly suggested that public consultation be conducted during the site selection process.
3) Need for a significant amount of resettlement, which could be one of the barriers to power plant development
4) Distance from the public areas
5) Safety and public health

A.2 Identification of Power Plant Sites

Using Google Earth maps, the study team identified 14 potential power plant sites that could use all fuels available to Lagos State. These sites are marked on the map presented in Figure A-1 and summarized in Table A-1. Each site location is defined by a pair of coordinates, latitude (north as positive, from -90° to 90°) and longitude (east as positive, from -180° to 180°) using the Geographical Coordinate System (GCS), expressed using degrees, minutes, and seconds, such as 41°24'12.2"N and 2°10'26.5"E. The coordinates for each site indicated in Table A-1 are for the site proximity as its exact location might not be measured during the study team's site visit due to its inaccessibility. It is important to note that Sites 9 (Egbin II) and 12 (Lekki Energy Center) might have been studied extensively by two power plant developers (or independent power producers).

Figure A-1: Identified Power Plant Sites

Table A-1: Summary of the Identified Power Plant Sites

Site No.	Location Name	Local Administrative Region	Coordinates (Geographical Coordinate System)		Fuel	Technology	Maximum Capacity (MW)
1	Ahanve	Badagry West LCDA	6°26'13.59"N	2°46'25.25"E	NG	GT/CCGT	2,000
2	Oko Agbon Nla	Olorunda LCDA	6°26'42.76"N	3° 4'13.61"E	NG or Biomass	GT/CCGT/Steam	2,000
3	Navy Town	Oriade LCDA	6°26'13.29"N	3°17'41.34"E	LNG or Nuclear	GT/CCGT/Steam	2,000
4	Snake Island	Amuwo Odofin LGA	6°24'38.29"N	3°18'32.95"E	LNG or Nuclear	GT/CCGT/Steam	2,000
5	Ogudu Ori- Oke	Kosofe LGA	6°34'13.32"N	3°24'19.71"E	NG or MSW	GT/CCGT/Steam	2,000
6	Odo Ogun	Agboyi Ketu LCDA	6°35'48.04"N	3°27'18.45"E	NG or Biomass	GT/CCGT/Steam	2,000
7	Lagos Lagoon	Eti-Osa LGA	6°27'28.41"N	3°29'12.97"E	NG	GT/CCGT	2,000
8	Ijede	Ijede LCDA	6°33'46.64"N	3°37'11.53"E	NG	GT/CCGT	2,000
9	Ijede	Ijede LCDA	6°33'47.58"N	3°37'6.56"E	NG	GT/CCGT	2,000
10	Imota	Imota LCDA	6°40'10.58"N	3°39'27.19"E	NG or Biomass	GT/CCGT/Steam	2,000
11	Dangote Refinery	Ibeju Lekki LGA	6°28'15.70"N	4° 0'42.65"E	NG or HFO	GT/CCGT/RICE	1,000
12	Lekki Free Zone	Ibeju Lekki LGA	6°27'5.21"N	3°57'36.25"E	NG or LNG	GT/CCGT	2,000
13	Lekki Free Zone	Ibeju Lekki LGA	6°29'6.08"N	3°59'8.41"E	NG or Petcoke	GT/CCGT/Steam	1,000
14	Alaro City	Epe LGA	6°33'38.32"N	4° 0'1.02"E	NG	GT/CCGT	2,000

Table A-1 includes the following information:

1) Site No. – The numbering of a power plant site
2) Location Name – The name of the village or town where the site/land is located
3) Local Administration Region (LAR) – The political boundary/administration which the site is located in, which could be either a Local Government Area (LGA) or a Local Council Development Area (LCDA). Lagos State includes a total of 57 LARs, 20 LGAs, and 37 LCDAs.

4) Coordinates (Geographical Coordinate System) – The approximate coordinates (latitude and longitude) of the site defined using the Geographical Coordinate System
5) Fuel – The primary fuel type to be used by the potential power plant, such as NG, LNG, biomass, nuclear, MSW, heavy fuel oil (HFO), or petcoke
6) Technology – Power generation technologies such as GT, CCGT, and steam turbine (for the technologies using boiler and steam turbine)
7) Maximum Generation Capacity (MW) – The maximum installed generation capacity in MW of the power plant. It is assumed that each set of CCGT (combined cycle gas turbines) in a CCGT plant would have an installed capacity of 500 MW (the most suitable configuration could be two approximately 170 MW gas turbines and one approximately 170 MW steam turbine), and each GT in a GT plant would have an installed capacity of 200 MW.

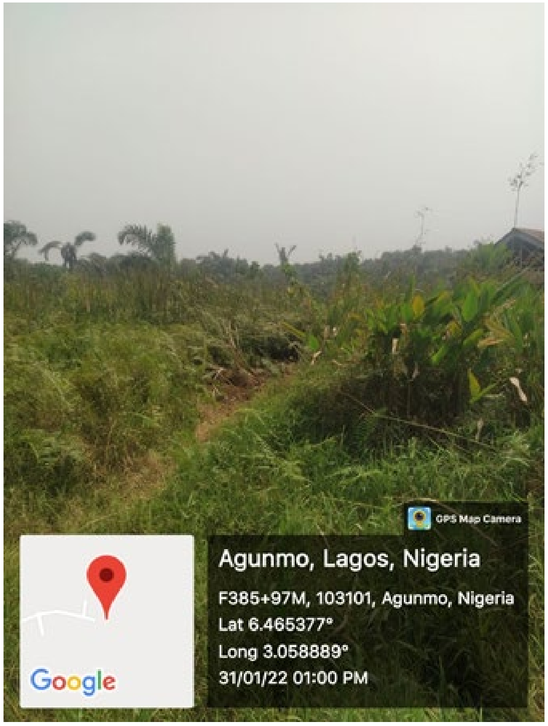
A.3 Screening Analysis of the Power Plant Sites

A detailed study for a power plant site is normally carried out by the power plant developer at the feasibility study stage. As these types of studies are not available for preparation of the Lagos State IRP, it was decided that only a high-level screening analysis of these identified sites would be performed in the preparation of this IRP.

The study team conducted visual field surveys of 10 of the 14 identified power plant sites and collected the essential information required for the screening analysis. Site 2 could not be reached due to its inaccessibility from road (isolated by water and riverbanks), and Site 11 is located inside Dangote Industrial compound and is not accessible to the public. Sites 8 and 9 were also inaccessible to the study team, who collected some basic information from nearby. Figure A-2 to Figure A-11 show the photos taken for the 10 sites visually surveyed.

Figure A-2: Pictures of Site 1

Figure A-3: Pictures of Site 2



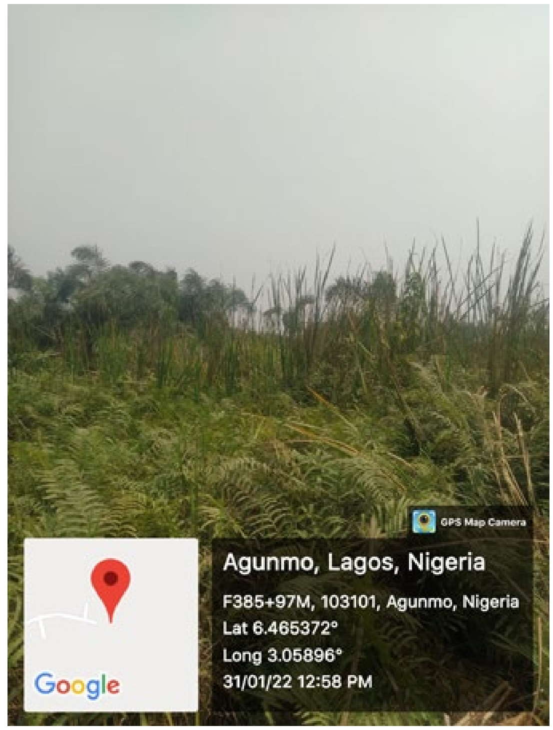


Figure A-4: Pictures of Site 3

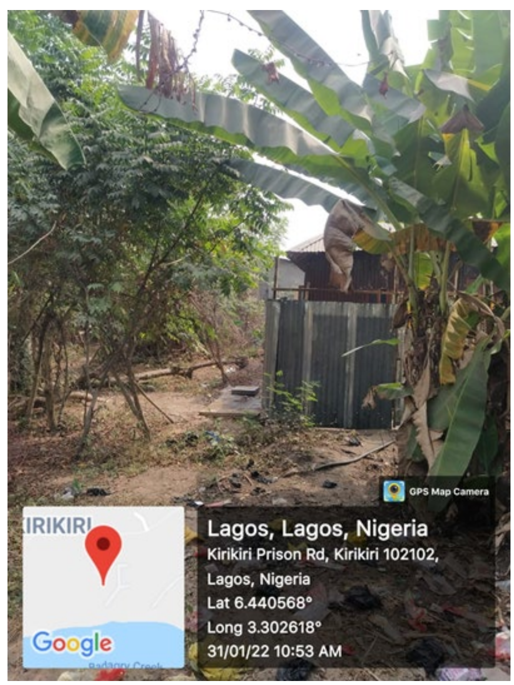
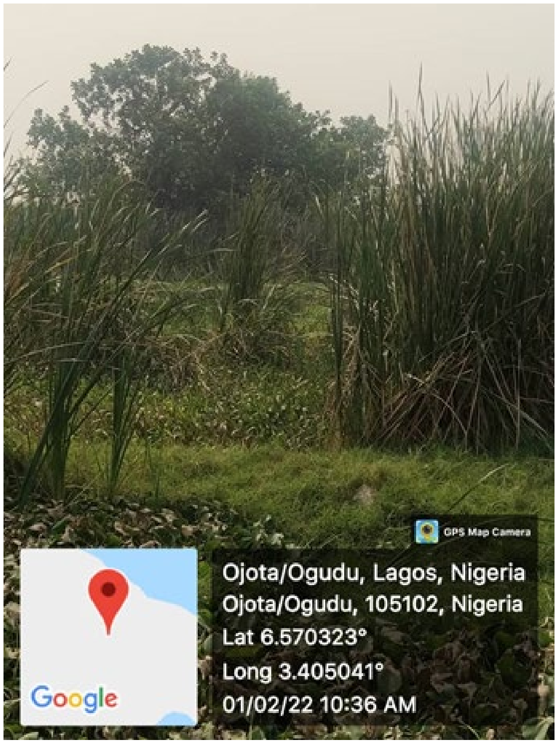


Figure A-5: Pictures of Site 5



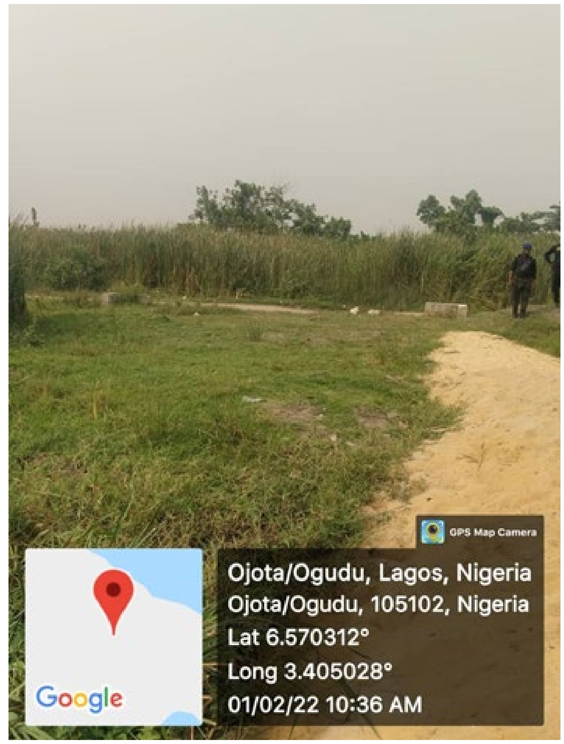
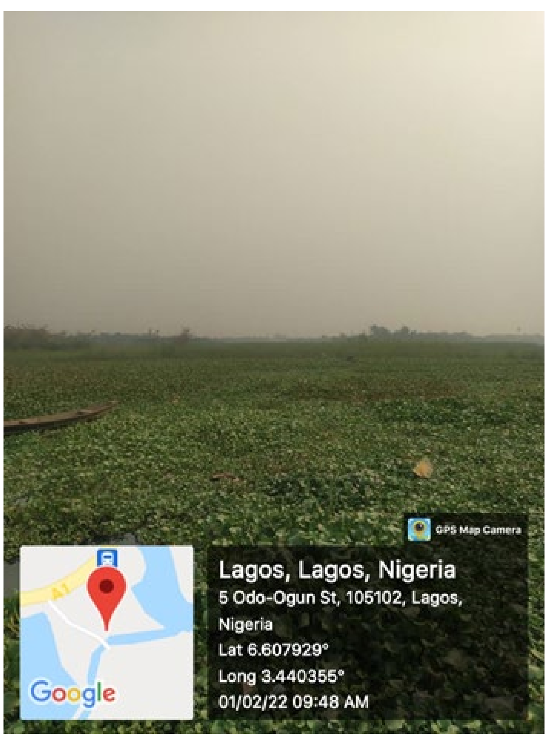


Figure A-6: Pictures of Site 6



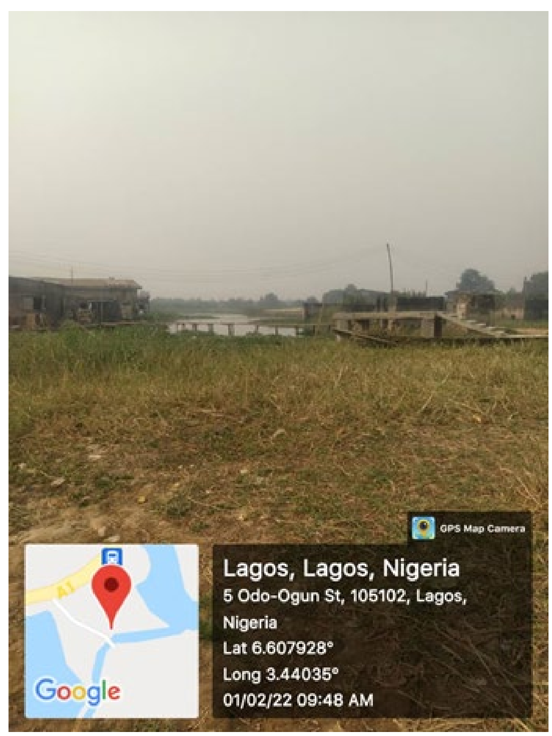


Figure A-7: Pictures of Site 7

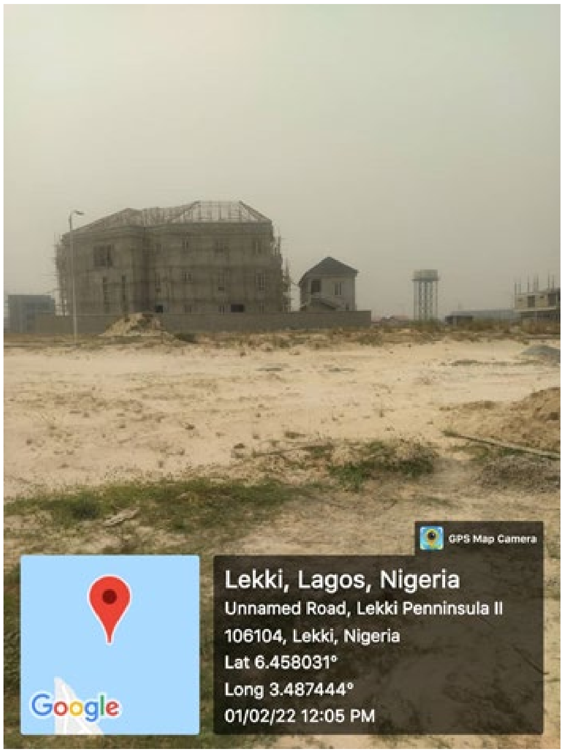
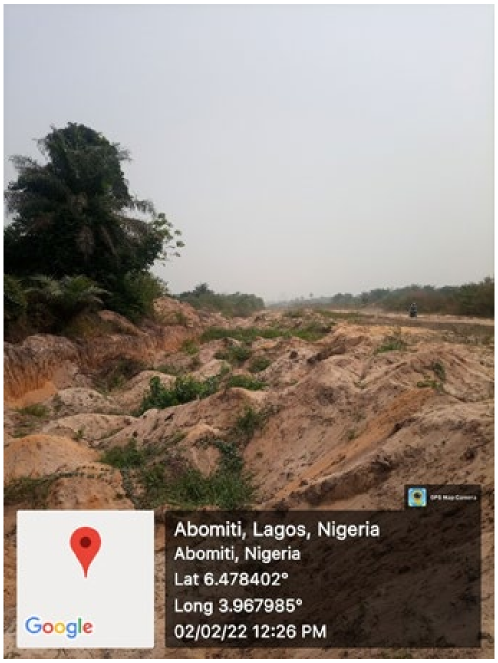


Figure A-8: Pictures of Site 10

Figure A-9: Pictures of Site 12



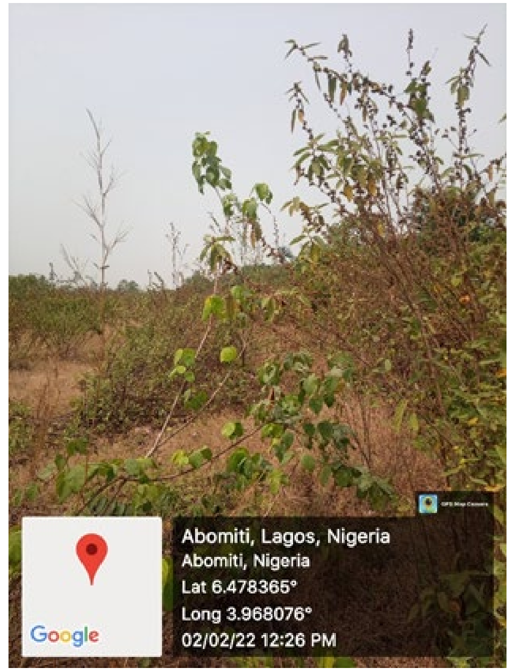


Figure A-10: Pictures of Site 13

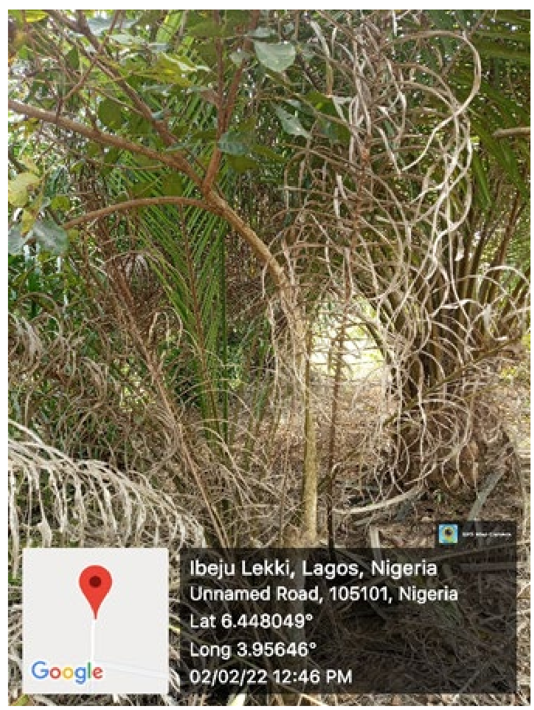


Figure A-11: Pictures of Site 14

A summary of the collected site information is presented in Table A-2. The notes below may be helpful in understanding the information summarized in the table:

1) Land Name – The name of the identified potential site for the development of a power plant
2) Location Name – Same as that for Table A-1
3) Local Administration Region (LAR) – The lower level of the political boundary/administration in which the site is located, which could be either a Local Government Area (LGA) or a Local Council Development Area (LCDA)
4) Administration Division – The higher level of the political boundary/administration which the site belongs to. Lagos State is divided into five Administration Divisions.
5) Fuel Type – Same as that for Table A-1
6) Maximum Generation Capacity (MW) – Same as that for Table A-1
7) Estimated Land Size Requirement (Acre) – An estimated range of land requirement, in acres, was estimated for each power plant site. One acre is approximately equal to 4,047 m^2. For illustration and simplicity, assume one acre as 4,000 m^2.

   60 acres ≈ 4,000x60 = 240,000 m^2. For a rectangle, it could be approximately 600 meter long and 400 meters wide.

   80 acres ≈ 4,000x80 = 320,000 m^2. For a rectangle, it could be approximately 800 meter long and 400 meters wide.

   100 acres ≈ 4,000x100 = 400,000 m^2. For a rectangle, it could be approximately 800 meters long and 500 meters wide.

8) Latitude and Longitude – The approximate coordinates of the site defined using the Geographical Coordinate System
9) Zone, Easting and Northing – It was learned that Lagos State Land Registration Office uses the Universal Transverse Mercator (UTM) system to define a site/land or location.

   UTM is a map projection system for assigning coordinates to locations on the surface of the earth. Like the traditional method of latitude and longitude, it is a horizontal position representation, which means it ignores altitude and treats the earth as a perfect ellipsoid.

However, it differs from global latitude/longitude in that it divides earth into 60 zones and projects each to the plane as a basis for its coordinates.

The UTM zones in Africa are illustrated in Figure A-12.

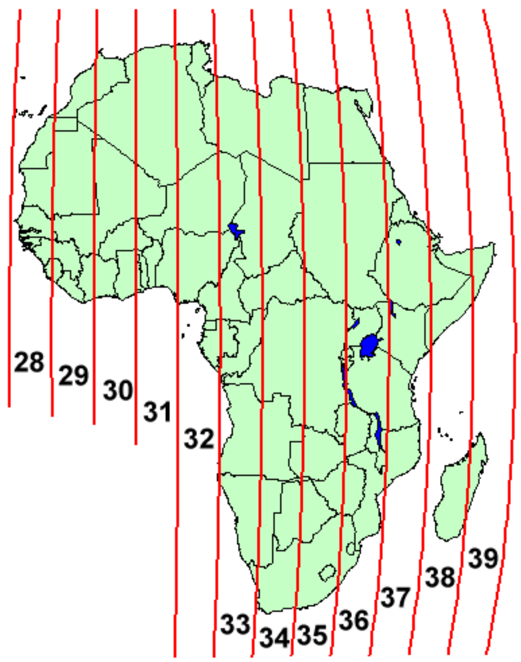
For example, Egbin Power Plant in Lagos State, Nigeria is at approximately 6°33'48.00"N and 3°36'56.78"E in the GCS format, which is in UTM zone 31, and the grid position is approximately 568001m east, 725554m north.

10) Estimated Land Available (Acre) – The minimum land available estimated based on the information collected from the visual survey

11) Land Type (Composition) – For example, soil, swamp, stone, gravel, sand, etc.

12) Current Usage – For example, agriculture, forest, water, vacant, riverbank, etc.

Figure A-12: UTM Zones in Africa



13) Conservation Area Nearby (Within ? km) (Yes/No) – Are there any conservation or ecological sensitive areas (such as tropical forest, biosphere reserve, important lake and coastal areas rich in coral formation, etc.) nearby? How far in km are they from the site if any?

14) Park Nearby (Within ? km) (Yes/No) – Are there any important parks nearby? How far in km are they from the site if any?

15) Residence Area Nearby (With ? km) (Yes/No) – Are there any residential areas nearby? How far in km are they from the site if any?

16) Other Important Places Nearby (Within ? km) (Yes/No) – Are there are any other important places (such as archaeological, historical, cultural/religious/tourist importance, and defense installations, etc.) nearby? How far in km are they from the site if any?

17) Railway Access – Is the site accessible to the railway (to deliver construction materials, power plant equipment, and fuels)?

18) Road Access – Is the site accessible to a highway or high-quality road (for trucks to deliver construction materials, power plant equipment, and fuels)?

19) Waterway Access – Is there a body of water nearby which is deep enough for construction of a harbor (for ships to deliver construction materials, power plant equipment, and fuels)?

A.4 Findings

Based on the information collected and analyzed, the following is the high-level conclusion for each of the identified power plant sites. The sites in bold type are selected for the power plants recommended in the least-cost generation expansion plan.

1) Site 1 – The site is available for the development of a power plant with up to 2,000 MW NG-fueled GTs and/or CCGTs.

2) **Site 2** – The site is available for the development of a power plant with up to 2,000 MW NG-fueled GTs and/or CCGTs, or biomass-fueled steam turbines.

3) Site 3 – The site is available for the development of a power plant with up to 2,000 MW LNG-fired GTs and/or CCGTs, or uranium-fueled steam turbines.

4) Site 4 – Although the study team could not conduct visual survey for the site due to its inaccessibility (no road and ferry), it is believed that the site is available for the development of a power plant with up to 2,000 MW LNG-fired GTs and/or CCGTs, or uranium-fueled steam turbines.

5) **Site 5** – It was estimated through the visual survey that only approximately 42 acres of land are available for the development of a power plant. It was observed from the Google Earth map that there is open space available near the site. It is believed that the site/area is available for the development of a power plant with up to 2,000 MW MSW-fueled steam turbines or NG-fired GTs and/or CCGTs.

6) **Site 6** – The site is available for the development of a power plant with up to 2,000 MW NG-fired GTs and/or CCGTs, or biomass-fueled steam turbines.

7) Site 7 – Although there is open space available at the site, it appears that the land has been zoned for residential and/or business development. It is therefore concluded that the site is not available for power plant development.

8) Site 8 – The study team was not available to access the site and take photos of it. However, the Google Earth map shows that there is open space available at the site. It appears that the site is available for the development of a power plant with up to 2,000 MW NG-fired GTs and/or CCGTs.

9) **Site 9** – Egbin II power plant site. It is believed that the site has been extensively studied for Egbin II power project in the past and it is available for the development of a power plant with up to 2,000 MW NG-fueled GTs and/or CCGTs.

10) Site 10 – The site is available for the development of a power plant with up to 2,000 MW NG-fired GTs and/or CCGTs, or biomass-fueled steam turbines.

11) Site 11 – The site is located inside Dangote Industrial compound and is not accessible to the public, including the study team for the visual survey. Based on previous discussions with Dangote staff, it may be assumed that the site is available for the development of a power plant with up to 1,000 HFO-fueled RICEs or NG-fired GTs and/or CCGTs. The HFO would be the by-product of

the Dangote refinery (if the refinery is designed with such by-product), supplemented by other refineries in Nigeria.

12) **Site 12** – It is believed that the site has been extensively studied by an IPP for the development of a power plant with up to 2,000 MW LNG-fueled CCGTs. If NG is available and more cost-attractive than LNG to the site, the plant could also be fueled using NG.

13) Site 13 – The site is available for the development of a power plant with up to 1,000 MW petcoke-fueled steam turbines or NG-fired GTs and/or CCGTs.

14) Site 14 – The site is available for the development of a power plant with up to 2,000 MW NG-fired GTs and/or CCGTs.

A.5 Potential Sites Recommended

In the least-cost plan prepared for the Lagos State IRP, the following sites are selected for power plant construction over the planning horizon:

1) Site 12 – 2,000 MW NG-fueled CCGTs
2) Site 5 – 1,600 MW NG-fueled GTs
3) Site 9 – 2,000 MW NG-fired CCGTs
4) Site 2 – 1,000 MW NG-fired GTs
5) Site 6 – 1,000 MW NG-fueled CCGTs

The IRP has estimated the requirements to connect a power plant to the grid at a conceptual level, in terms of voltage, capacity, and cost. The detailed studies for each interconnection, such as a feasibility study and environmental impact assessment, must be carried out if the power plant is to be constructed.

Table A-2: Summary of Identified Power Plants

Item		Unit	Site No.						
No.	**Description**		**1**	**2**	**3**	**4**	**5**	**6**	**7**
1	Land Name		Toyon and Oshadare Family	Oko Agbon Nla	Navy Town	Snake Island	Sand Fill	Odo Ogun	Private Estate
2	Location Name		Ahanve	Oko Agbon Nla	Navy Town	Snake Island	Ogudu Ori- Oke	Odo Ogun	Lagos Lagoon
3	Local Administrative Region		Badagry West LCDA	Olorunda LCDA	Oriade LCDA	Amuwo Odofin LGA	Kosofe LGA	Agboyi Ketu LCDA	Eti-Osa LGA
4	Administrative Division		Badagry	Badagry	Badagry	Badagry	Ikeja	Ikeja	Lagos (Eko)
5	Fuel Type		NG	NG or Biomass	LNG or Nuclear	LNG or Nuclear	MSW or NG	NG or Biomass	NG
6	Maximum Generation Capacity	(MW)	2,000	2,000	2,000	2,000	2,000	2,000	2,000
7	Estimated Land Size Requirement	(Acre)	60-80	60-100	60-100	60-100	60-100	60-100	60-80
8	Latitude		6°26'13.59"N	6°26'42.76"N	6°26'13.29"N	6°24'38.29"N	6°34'13.32"N	6°35'48.04"N	6°27'28.41"N
	Longitude		2°46'25.25"E	3° 4'13.61"E	3°17'41.34"E	3°18'32.95"E	3°24'19.71"E	3°27'18.45"E	3°29'12.97"E
9	Zone		31	31	31	31	31	31	31
	Easting	(m)	475579.00mE	507794.28mE	532006.33mE	NA	544921.71mE	549665.19mE	553576.28mE
	Northing	(m)	710584.00mN	712389.62mN	711569.34mN	NA	726080.72mN	728861.49mN	713900.80mN
10	Estimated Available Land	(Acre)	66	80	100		42	97	94
11	Land Type (Composition)		Swamp	Swamp	Swamp/Lake		Water	Water	Sand Filled Land
12	Current Usage		Foresty	Forest	Forest		Forest/Water	Forest/Water	Residential Estate
13	Conservation Area Nearby (Within ? Km)	(Yes/No)	No	No	No		No	No	No
14	Park Nearby (Within ? km)	(Yes/No)	No	No	No		No	No	No
15	Residence Areas Nearby (Within ? km)	(Yes/No)	Yes (10km)	No	Yes (1km)		Yes (0.3km)	Yes (2km)	Yes
16	Other Important Places Nearby (Within ? km)	(Yes/No)	No	No	Navy Barracks (2km)		No	Mile 12 Market (5km)	No
17	Railway Access	(Yes/No)	No	No	No		No	No	No
18	Road Access	(Yes/No)	No	No	Yes		Yes	Yes (2km)	Yes
19	Waterway Access	(Yes/No)	No	Yes	Yes		Yes	Yes	Yes

(Table A-2 Continued)

Item		Unit	Site No.						
No.	Description		8	9	10	11	12	13	14
1	Land Name		Ijede	Egbin II	Imota Scheme	Dangote Refinery	Lekki Free Zone	Lekki Free Zone	Alaro City
2	Location Name		Ijede	Ijede	Imota	Dangote Refinery	Lekki Free Zone	Lekki Free Zone	Alaro City
3	Local Administrative Region		Ijede LCDA	Ijede LCDA	Imota LCDA	Ibeju Lekki LGA	Ibeju Lekki LGA	Ibeju Lekki LGA	Epe LGA
4	Administrative Division		Ikorodu	Ikorodu	Ikorodu	Epe	Epe	Epe	Epe
5	Fuel Type		NG	NG	NG or Biomass	HFO or NG	NG or LNG	Petcoke or NG	NG
6	Maximum Generation Capacity	(MW)	2,000	2,000	2,000	1,000	2,000	1,000	2,000
7	Estimated Land Size Requirement	(Acre)	60-80	60-80	60-100	30-40	60-80	30-50	60-80
8	Latitude		6°33'46.64"N	6°33'47.58"N	6°40'10.58"N	6°28'15.70"N	6°27'5.21"N	6°29'6.08"N	6°33'38.32"N
	Longitude		3°37'11.53"E	3°37'6.56"E	3°39'27.19"E	4° 0'42.65"E	3°57'36.25"E	3°59'8.41"E	4° 0'1.02"E
9	Zone		31	31	31	31	31	31	31
	Easting	(m)	568289.00mE		572113.75mE	NA	608613.93mE	605969.66mE	610082.68mE
	Northing	(m)	725249.57mN		736986.14mN	NA	716678.83mN	713001.56mN	725082.92mN
10	Estimated Available Land	(Acre)	41		98		76	46	96
11	Land Type (Composition)		Sand	Sand	Sand		Land Filled	Land Filled	Swamp
12	Current Usage		Forest/Vacant	Forest	Forest		Forest	Forest	Forest
13	Conservation Area Nearby (Within ? Km)	(Yes/No)	No	No	No		No	No	No
14	Park Nearby (Within ? km)	(Yes/No)	No	No	No		No	No	No
15	Residence Areas Nearby (Within ? km)	(Yes/No)	No	No	Yes		No	No	No
16	Other Important Places Nearby (Within ? km)	(Yes/No)	Yes (Egbin Plant)	Yes (Egbin Plant)	No		Dangote Refinery (8 km)	Dangote Refinery (8 km)	No
17	Railway Access	(Yes/No)	No	No	No		No	No	No
18	Road Access	(Yes/No)	Yes	Yes	Yes		Yes	Yes	Yes
19	Waterway Access	(Yes/No)	No	No	No		Yes	Yes	Yes

APPENDIX B: TECHNICAL AND ECONOMIC PARAMETERS OF GENERATION TECHNOLOGIES

Table B-1: Technical and Economical Parameters – LNG and NG-Fueled Generation Technologies

Generation Technology	CCGT	CCGT	Import	GT	Comment
Fuel	LNG	NG	NG	NG	
Plant Gross Capacity (MW)	250	250	250	200	
Station Services (MW)	25	25	25	16	
Plant Net Capacity (MW)	225	225	225	184	
Number of Units	1	2	1	2	
Economic Life (Year)	25	25	25	25	
Lead Time (Year)	4	4	4	3	
Earliest On-Line Year (Full Operation Year)	2026	2026	2026	2025	
Equivalent Forced Outage Rate (%)	6.0	6.0	6.0	5.0	
Planned Outage Rate (%)	8.0	8.0	8.0	6.0	
Equivalent Availability (%)	86.5	86.5	86.5	89.3	
Net Heat Rate (MMBTU/MWh, HHV)	7.333	7.333	7.333	10.870	
Primary Fuel Cost ($/MMBTU)	5.00	3.85	3.30	3.85	
Overall Capitalized Cost ($M)	316.5	316.5	316.5	222.3	
Plant EPC (US$/kW)	1,100.0	1,100.0	1,100.0	1,000.0	
Plant EPC ($M)	275.0	275.0	275.0	200.0	Based on gross capacity
Owner's Cost ($M)	0.0	0.0	0.0	0.0	
Plant CAPEX Disbursement Flow (%)	25%, 45%, 30%	25%, 45%, 30%	25%, 45%, 30%	60%, 40%	
Plant IDC ($M)	41.5	41.5	41.5	22.3	
Grid Integration EPC ($M)	0.0	0.0	0.0	0.0	
Owner's Cost for Grid Integration ($M)	0.0	0.0	0.0	0.0	
Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	60%, 40%	60%, 40%	60%, 40%	
Grid Integration IDC ($M)	0.0	0.0	0.0	0.0	
Overall Plant Capital Unit Capacity Cost ($/kW-Net)	1,407	1,407	1,407	1,208	
Fixed O&M Cost ($/kW-Year, Gross)	18.00	18.00	18.00	12.00	
Total Fixed O&M Cost ($M)	4.50	4.50	4.50	2.40	
Variable O&M Cost ($/MWh)	6.11	6.11	18.11	6.52	
CO2 Emission Rate (kg/MMBTU)	53.107	53.107	53.107	53.107	Uncontrolled factors calculated as per the parameters from the US EIA and EPA. About 90% of NOx could be reduced by GT. SO2 emission factor was calculated based on 1% sulphur content.
NOx Emission Rate (kg/MMBTU)	0.148780	0.148780	0.148780	0.148780	
SO2 Emission Rate (kg/MMBTU)	0.000027	0.000027	0.000027	0.000027	
Particulate Matter Emission Rate (kg/MMBTU)	0.002990	0.002990	0.002990	0.002990	

Note: (1) For domestic CCGT and GT, the fuel price is a mix of 95% of NG price and 5% of LFO price.

(2) For import, the fuel price is the NG price.

(3) For import, the variable O&M cost includes a wheeling charge of US$12/MWh.

Table B-2: Technical and Economical Parameters – Solar PV Generation Technology

Generation Technology		Solar PV	Comment
Fuel		Sun Light	
Plant Gross Capacity (MW)		100	
Station Services (MW)		0	
Plant Net Capacity (MW)		100	
Number of Units		1	
Economic Life (Year)		20	
Lead Time (Year)		3	
Earliest On-Line Year (Full Operation Year)		2025	
Equivalent Forced Outage Rate (%)		0.0	
Planned Outage Rate (%)		0.0	
Equivalent Availability (%)		100.0	
Net Heat Rate (MMBTU/MWh, HHV)		0.000	
Primary Fuel Cost ($/MMBTU)		0.00	
Overall Capitalized Cost ($M)		100.1	
	Plant EPC (US$/kW)	900.0	
	Plant EPC ($M)	90.0	Based on gross capacity
	Owner's Cost ($M)	0.0	
	Plant CAPEX Disbursement Flow (%)	60%, 40%	
	Plant IDC ($M)	10.1	
	Grid Integration EPC ($M)	0.0	
	Owner's Cost for Grid Integration ($M)	0.0	
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	
	Grid Integration IDC ($M)	0.0	
Overall Plant Capital Unit Capacity Cost ($/kW-Net)		1,001	
Fixed O&M Cost ($/kW-Year, Gross)		25.00	
Total Fixed O&M Cost ($M)		2.50	
Variable O&M Cost ($/MWh)		0.20	
CO2 Emission Rate (kg/MMBTU)			Not applicable
NOx Emission Rate (kg/MMBTU)			
SO2 Emission Rate (kg/MMBTU)			
Particulate Matter Emission Rate (kg/MMBTU)			

Table B-3: Technical and Economical Parameters – MSW and Agricultural Residues Fueled Generation Technologies

Generation Technology		RDF	CFB	Comment
Fuel		MSW	Ag-Residues	
Plant Gross Capacity (MW)		40	40	
Station Services (MW)		4.8	4.8	
Plant Net Capacity (MW)		35.2	35.2	
Number of Units		1	1	
Economic Life (Year)		30	30	
Lead Time (Year)		4	4	
Earliest On-Line Year (Full Operation Year)		2026	2026	
Equivalent Forced Outage Rate (%)		10.0	9.0	
Planned Outage Rate (%)		8.0	8.0	
Equivalent Availability (%)		82.8	83.7	
Net Heat Rate (MMBTU/MWh, HHV)		15.909	15.682	
Primary Fuel Cost ($/MMBTU)		2.11	3.15	
Overall Capitalized Cost ($M)		193.4	138.1	
	Plant EPC (US$/kW)	4,200.0	3,000.0	
	Plant EPC ($M)	168.0	120.0	Based on gross capacity
	Owner's Cost ($M)	0.0	0.0	
	Plant CAPEX Disbursement Flow (%)	25%, 45%, 30%	25%, 45%, 30%	
	Plant IDC ($M)	25.4	18.1	
	Grid Integration EPC ($M)	0.0	0.0	
	Owner's Cost for Grid Integration ($M)	0.0	0.0	
	Grid Integration CAPEX Disbursement Flow (%)	60%, 40%	60%, 40%	
	Grid Integration IDC ($M)	0.0	0.0	
Overall Plant Capital Unit Capacity Cost ($/kW-Net)		5,494	3,924	
Fixed O&M Cost ($/kW-Year, Gross)		84.00	60.00	
Total Fixed O&M Cost ($M)		3.36	2.40	
Variable O&M Cost ($/MWh)		11.36	9.09	
CO2 Emission Rate (kg/MMBTU)				Not applicable
NOx Emission Rate (kg/MMBTU)				
SO2 Emission Rate (kg/MMBTU)				
Particulate Matter Emission Rate (kg/MMBTU)				

APPENDIX C: COST SUMMARY AND CAPACITY BALANCE TABLES

Table C-1: Cost Summary – Scenario 03

Present Value Reference Year:	2020																				
Discount Rate:	10.0%																				
GHG Emission Offset Allowance:	10 $/Tonne																				
Year	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Peak	1,866.3	2,014.2	2,179.2	2,361.2	2,560.3	2,776.5	3,009.9	3,247.4	3,489.7	3,747.5	4,012.3	4,278.3	4,551.7	4,832.8	5,122.1	5,420.0	5,708.9	6,007.1	6,315.2	6,633.5	6,924.1
Energy	10,626.5	11,469.0	12,408.4	13,444.7	14,578.2	15,809.3	17,138.3	18,490.9	19,870.3	21,338.2	22,846.1	24,360.7	25,917.3	27,518.0	29,165.3	30,861.4	32,506.3	34,204.5	35,958.7	37,771.1	39,425.7
Cost in Current Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	22.4	394.4	462.5	540.6	642.0	720.1	787.9	843.6	911.4	955.8	1,034.9	1,102.7	1,158.3	1,226.1	1,305.2	1,349.6
Other Fixed Cost (Excluding Capital Repayment)	366.8	383.0	402.0	422.9	448.9	481.4	251.5	263.9	278.4	295.3	309.8	319.2	328.7	338.1	345.1	357.0	366.4	375.9	385.3	397.2	404.2
Fuel Cost	406.8	439.0	474.8	514.0	550.4	575.6	552.8	574.4	592.4	613.5	635.9	674.3	708.7	749.7	792.0	830.7	872.9	911.6	957.2	999.6	959.2
Other Variable Cost (Excluding Fuel Cost)	174.3	195.1	218.4	243.3	269.1	287.8	166.8	170.9	175.1	179.7	184.7	193.1	200.6	209.5	218.7	227.0	236.1	244.4	254.2	263.2	254.5
GHG Offset Allowance	65.5	70.7	76.4	82.7	88.6	92.6	83.8	86.8	89.3	92.2	95.2	100.5	105.3	111.0	116.8	122.2	128.0	133.3	139.6	145.5	139.8
Total	**1,013.3**	**1,087.7**	**1,171.6**	**1,262.8**	**1,356.9**	**1,459.8**	**1,449.4**	**1,558.5**	**1,675.8**	**1,822.7**	**1,945.7**	**2,075.0**	**2,186.9**	**2,319.7**	**2,428.5**	**2,571.8**	**2,706.1**	**2,823.6**	**2,962.5**	**3,110.6**	**3,107.3**
Cumulative Cost in Current Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	22.4	416.8	879.3	1,419.9	2,061.9	2,782.0	3,569.9	4,413.5	5,324.9	6,280.8	7,315.6	8,418.3	9,576.6	10,802.8	12,107.9	13,457.5
Other Fixed Cost (Excluding Capital Repayment)	366.8	749.7	1,151.7	1,574.5	2,023.4	2,504.7	2,756.2	3,020.1	3,298.5	3,593.8	3,903.6	4,222.8	4,551.5	4,889.6	5,234.7	5,591.7	5,958.1	6,334.0	6,719.3	7,116.5	7,520.7
Fuel Cost	406.8	845.8	1,320.6	1,834.6	2,384.9	2,960.5	3,513.3	4,087.7	4,680.1	5,293.6	5,929.5	6,603.8	7,312.4	8,062.1	8,854.1	9,684.8	10,557.7	11,469.4	12,426.6	13,426.2	14,385.3
Other Variable Cost (Excluding Fuel Cost)	174.3	369.4	587.8	831.1	1,100.2	1,388.0	1,554.9	1,725.8	1,900.9	2,080.6	2,265.3	2,458.4	2,659.0	2,868.5	3,087.2	3,314.2	3,550.3	3,794.8	4,048.9	4,312.1	4,566.6
GHG Offset Allowance	65.5	136.1	212.5	295.2	383.8	476.4	560.3	647.1	736.3	828.5	923.7	1,024.2	1,129.5	1,240.5	1,357.3	1,479.5	1,607.5	1,740.8	1,880.5	2,025.9	2,165.7
Total	**1,013.3**	**2,101.0**	**3,272.6**	**4,535.4**	**5,892.3**	**7,352.1**	**8,801.4**	**10,360.0**	**12,035.7**	**13,858.4**	**15,804.1**	**17,879.1**	**20,066.0**	**22,385.6**	**24,814.1**	**27,385.9**	**30,092.0**	**32,915.6**	**35,878.1**	**38,988.6**	**42,095.9**
Discount Factor	0.9535	0.8668	0.7880	0.7164	0.6512	0.5920	0.5382	0.4893	0.4448	0.4044	0.3676	0.3342	0.3038	0.2762	0.2511	0.2283	0.2075	0.1886	0.1715	0.1559	0.1417
Cost in Present Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	13.3	212.2	226.3	240.5	259.6	264.7	263.3	256.3	251.7	240.0	236.2	228.8	218.5	210.3	203.5	191.3
Other Fixed Cost (Excluding Capital Repayment)	349.7	331.9	316.7	302.9	292.3	285.0	135.4	129.1	123.8	119.4	113.9	106.7	99.9	93.4	86.6	81.5	76.0	70.9	66.1	61.9	57.3
Fuel Cost	387.9	380.5	374.1	368.2	358.4	340.7	297.5	281.0	263.5	248.1	233.7	225.3	215.3	207.0	198.9	189.6	181.1	172.0	164.2	155.8	135.9
Other Variable Cost (Excluding Fuel Cost)	166.2	169.1	172.1	174.3	175.2	170.4	89.8	83.6	77.9	72.7	67.9	64.5	60.9	57.9	54.9	51.8	49.0	46.1	43.6	41.0	36.1
GHG Offset Allowance	62.4	61.2	60.2	59.3	57.7	54.8	45.1	42.5	39.7	37.3	35.0	33.6	32.0	30.6	29.3	27.9	26.6	25.2	23.9	22.7	19.8
Total	**966.1**	**942.8**	**923.2**	**904.6**	**883.6**	**864.2**	**780.1**	**762.5**	**745.4**	**737.0**	**715.2**	**693.4**	**664.4**	**640.7**	**609.7**	**587.0**	**561.5**	**532.6**	**508.0**	**484.9**	**440.4**
Cumulative Cost in Present Value (M-US$)																					
Amortized Capital Payment	0.0	0.0	0.0	0.0	0.0	13.3	225.5	451.8	692.3	951.9	1,216.6	1,479.9	1,736.2	1,987.9	2,227.9	2,464.1	2,692.9	2,911.4	3,121.7	3,325.1	3,516.4
Other Fixed Cost (Excluding Capital Repayment)	349.7	681.6	998.3	1,301.3	1,593.6	1,878.5	2,013.9	2,143.0	2,266.8	2,386.3	2,500.1	2,606.8	2,706.7	2,800.0	2,886.7	2,968.2	3,044.2	3,115.1	3,181.2	3,243.1	3,300.4
Fuel Cost	387.9	768.4	1,142.5	1,510.7	1,869.1	2,209.9	2,507.4	2,788.4	3,051.9	3,300.0	3,533.8	3,759.1	3,974.4	4,181.4	4,380.3	4,569.9	4,751.0	4,923.0	5,087.2	5,243.0	5,378.9
Other Variable Cost (Excluding Fuel Cost)	166.2	335.3	507.4	681.7	856.9	1,027.3	1,117.1	1,200.8	1,278.6	1,351.3	1,419.2	1,483.7	1,544.7	1,602.5	1,657.4	1,709.3	1,758.3	1,804.4	1,847.9	1,889.0	1,925.0
GHG Offset Allowance	62.4	123.7	183.9	243.1	300.8	355.6	400.8	443.2	482.9	520.2	555.2	588.8	620.8	651.4	680.8	708.6	735.2	760.4	784.3	807.0	826.8
Total	**966.1**	**1,908.9**	**2,832.1**	**3,736.8**	**4,620.4**	**5,484.6**	**6,264.7**	**7,027.2**	**7,772.6**	**8,509.6**	**9,224.9**	**9,918.3**	**10,582.7**	**11,223.3**	**11,833.1**	**12,420.1**	**12,981.6**	**13,514.2**	**14,022.3**	**14,507.2**	**14,947.6**
Levelized Cost of Energy (US$/MWh) =	**87.26**		**Total Cost in PV (M-US$) =**		**14,947.6**			**Total Energy in PV (GWh) =**		**171,292.7**											

Table C-2: Capacity Balance Table – Scenario 03

Year	Addition/Retirement								Total		Annual	Reserve		
		Capacity (MW)							Net	Effective	Peak	Net Capacity		Effective
	Location	Network	CC-NG	GT-NG	Solar	Total	Net	Effective	Capacity	Capacity	(MW)	(MW)	(%)	Capacity
2019											1,758			
2020	Egbin	1,320				1,320	1,188	984	2,248	1,869	1,866	382	20	3
	External	1,175				1,175	1,060	885						
2021	External	180				180	166	148	2,414	2,017	2,014	399	20	2
2022	External	200				200	184	164	2,598	2,181	2,179	418	19	2
2023	External	220				220	202	181	2,800	2,362	2,361	439	19	0
2024	External	260				260	234	202	3,034	2,564	2,560	474	19	4
2025	External	275				275	248	214	3,282	2,778	2,776	505	18	2
					200	200	0	0						
2026	External	-2,310				-2,310	-2,094	-1,794	3,683	3,167	3,010	673	22	158
	Site12		1,750			1,750	1,575	1,362						
	Site05			1,000		1,000	920	822						
					200	200	0	0						
2027	Site05			200		200	184	164	3,867	3,332	3,247	620	19	84
					400	400	0	0						
2028	Site12		250			250	225	195	4,092	3,526	3,490	602	17	37
					400	400	0	0						
2029	Site09		250			250	225	195	4,501	3,885	3,747	754	20	138
	Site05			200		200	184	164						
					400	400	0	0						
2030	Site09		250			250	225	195	4,726	4,080	4,012	714	18	67
					400	400	0	0						
2031	Site09		250			250	225	195	5,135	4,439	4,278	857	20	160
	Site05			200		200	184	164						
					100	100	0	0						
2032	Site09		250			250	225	195	5,360	4,633	4,552	808	18	82
					200	200	0	0						
2033	Site09		250			250	225	195	5,769	4,992	4,833	936	19	159
	Site02			200		200	184	164						
					100	100	0	0						
2034	Site09		250			250	225	195	5,994	5,187	5,122	872	17	65
					100	100	0	0						
2035	Site09		250			250	225	195	6,403	5,546	5,420	983	18	126
	Site02			200		200	184	164						
					200	200	0	0						
2036	Site09		250			250	225	195	6,812	5,905	5,709	1,103	19	196
	Site02			200		200	184	164						
					100	100	0	0						
2037	Site06		250			250	225	195	7,037	6,099	6,007	1,030	17	92
					200	200	0	0						
2038	Site06		250			250	225	195	7,446	6,458	6,315	1,131	18	143
	Site02			200		200	184	164						
					100	100	0	0						
2039	Site06		250			250	225	195	7,855	6,817	6,633	1,222	18	184
	Site02			200		200	184	164						
					200	200	0	0						
2040	Site06		250			250	225	195	8,080	7,012	6,924	1,156	17	88
					100	100	0	0						
Total		**1,320**	**5,000**	**2,600**	**3,400**	**12,320**	**8,080**	**7,012**						

APPENDIX D: TABLES AND FIGURES FOR TRANSMISSION DEVELOPMENT PLAN

Table D-1: The Existing Substations

Substation		Transformer			
Number	Name	ID	Rating (MVA)	Available (MVA)	Voltage (kV)
1	Agbara	T1	`45/30/15	45	132/33
		T2	`45/30/15	45	132/33
		T3	60	60	132/33
2	Ajah	T4	150	150	330/132/33
		T5	150	150	330/132/33
		TR1	60	60	132/33
		TR2	60	60	132/33
		TR8	60	60	132/33
		T7	100	100	132/33
3	Akangba	5T1B	109/90/30	90	330/132/13.8
		5T2A	109/90/30	90	330/132/13.8
		5T2B	109/90/30	90	330/132/13.8
		5T4A	162/150/50	150	330/132/33
		5T4B	162/150/50	150	330/132/33
		5T5A	300	300	330/132/22
		10T1A	60	60	132/33
		10T1B	60	60	132/33
		10T2A	60	60	132/33
		10T2B	60	60	132/33
		10T3A	60	60	132/33
4	Akoka	T1	`45/30/15	30	132/33
		T3	40	40	132/33
5	Alagbon	TR1	300	300	330/132/33
		T1	100	100	132/33
		T2	60	60	132/33
		TR11	60	60	132/33
		TR12	60	60	132/33
		MOB-60	60	60	132/33
6	Alausa	T1	`45/30/15	30	132/33
		T2	30	30	132/33
		T3	60	60	132/33
7	Alimosho	T1	30	30	132/33
		T2	100	100	132/33
		T3	100	100	132/33

(Table D-1 Continued)

Substation		Transformer			
Number	Name	ID	Rating (MVA)	Available (MVA)	Voltage (kV)
8	Amuwo	T1	60	60	132/33
		T2	30	30	132/33
		T3	30	30	132/33
		T4	40	40	132/33
9	Apapa-Road	T1	45/30/15	0	132/33
		TR2	60	60	132/33
10	Ayobo	T1	60	60	132/33
		T2	60	60	132/33
11	Egbin	IBTR1	150	150	330/132/33
		IBTR2	150	150	330/132/33
		T1	30	30	132/33
			270	270	330/16
			270	270	330/16
			270	270	330/16
			270	270	330/16
			270	270	330/16
			270	270	330/16
12	Ejigbo	T1	100	100	132/33
		T2	100	100	132/33
		T3	60	60	132/33
13	Ijora	T1A	30	30	132/33
		T2A	`45/30/15	45	132/33
		T2B	30	30	132/33
14	Ikeja West	T1A	150	150	330/132/33
		T1B	150	150	330/132/33
		T2A	150	150	330/132/33
		T2B	150	150	330/132/33
		T3A	150	150	330/132/33
		T4A	300	300	330/132/33
		Reactor		75	330
		Reactor		75	330
15	Ikorodu	T1	60	60	132/33
		T2	60	60	132/33
		T3	100	100	132/33
		T4	60	60	132/33/11
16	Ilashe	T1	30	30	132/33

(Table D-1 Continued)

Substation		Transformer			
Number	**Name**	**ID**	**Rating (MVA)**	**Available (MVA)**	**Voltage (kV)**
17	Illupeju	T2	`45/30/15	30	132/33/11
		T4	30	30	132/33
		T3	15	15	132/11
		T1	15	15	132/11
18	Isolo	T1	60	60	132/33
		T2	60	0	132/33
		T3	`45/30/15	30	132/33
19	Itire	T1	30	30	132/33
		T2	60	0	132/33
		T3	40	40	132/33
20	Lekki	TR1	300	300	330/132/33
		TR1	60	60	132/33
		TR2	60	60	132/34
21	Maryland	T1	`30/22.5	30	132/33
		T2	60	60	132/33
		T3	30	30	132/33
22	Odogunyan	T1	60	60	132/33/11
		T2	60	60	132/33/11
23	Ojo	T3	60	60	132/33
		T4	60	60	132/33
24	Ogba	T1	60	60	132/33
		T2	60	60	132/33
		T3	60	60	132/33
		T4	100	100	132/33
		MOB	45	30	132/33
25	Oke-Aro	T1	300	300	330/132/33
		T5	60	60	132/33
		T6	60	60	132/33
26	Otta	T1	40	40	132/33
		T2	60	60	132/33
		T4	60	60	132/33
		MOB	40/30/20	40	132/33
27	Oworonshokin	T1	60	60	132/33
		T2	60	60	132/33
		T3	30	30	132/33

Table D-2: Substation Load Demand – Coincident Peak

Transformation Station		2021		2026		2030		2035		2040	
		Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
No.	Name										
Total		**10,896**	**1,914**	**16,281**	**2,859**	**21,704**	**3,812**	**29,318**	**5,149**	**37,454**	**6,578**
1	AGBARA	343.1	60.3	510.5	89.7	633.9	111.3	811.4	142.5	995.8	174.9
2	AJAH	698.1	122.6	1,085.6	190.7	1,347.9	236.7	1,725.3	303.0	2,117.5	371.9
3	AKANGBA	604.6	106.2	764.0	134.2	948.6	166.6	1,214.2	213.2	1,490.2	261.7
4	AKOKA	127.8	22.4	165.7	29.1	205.7	36.1	263.3	46.2	323.2	56.8
5	ALAGBON	845.7	148.5	1,290.1	226.6	1,601.7	281.3	2,050.3	360.1	2,516.3	441.9
6	ALAUSA	597.2	104.9	897.0	157.5	1,113.7	195.6	1,425.6	250.4	1,749.6	307.3
7	ALIMOSHO	523.9	92.0	786.9	138.2	977.0	171.6	1,250.6	219.6	1,534.9	269.6
8	AMUWO	433.0	76.1	562.8	98.8	698.8	122.7	894.5	157.1	1,097.8	192.8
9	APAPA ROAD	182.9	32.1	232.8	40.9	289.1	50.8	370.0	65.0	454.1	79.8
10	AYOBO	352.5	61.9	529.5	93.0	657.4	115.5	841.5	147.8	1,032.8	181.4
11	EJIGBO	834.8	146.6	1,230.5	216.1	1,527.7	268.3	1,955.5	343.4	2,399.9	421.5
12	IJORA	349.2	61.3	444.6	78.1	552.0	96.9	706.6	124.1	867.1	152.3
13	IKORODU	901.7	158.4	1,339.2	235.2	1,662.6	292.0	2,128.3	373.8	2,611.9	458.7
14	ILUPEJU	224.3	39.4	336.9	59.2	418.2	73.4	535.4	94.0	657.0	115.4
15	ISOLO	572.7	100.6	916.6	161.0	1,138.0	199.9	1,456.7	255.8	1,787.8	314.0
16	ITIRE	338.7	59.5	492.3	86.5	611.3	107.4	782.4	137.4	960.3	168.6
17	LEKKI	444.6	78.1	695.1	122.1	862.9	151.6	1,104.6	194.0	1,355.7	238.1
18	MARYLAND	501.1	88.0	809.2	142.1	1,004.7	176.4	1,286.0	225.9	1,578.3	277.2
19	ODOGUNYAN	127.8	22.4	171.7	30.2	213.2	37.4	272.9	47.9	335.0	58.8
20	OGBA	500.6	87.9	794.7	139.6	986.6	173.3	1,262.9	221.8	1,549.9	272.2
21	OJO	456.7	80.2	584.2	102.6	725.3	127.4	928.5	163.1	1,139.5	200.1
22	OKE ARO	373.4	65.6	560.8	98.5	696.2	122.3	891.2	156.5	1,093.8	192.1
23	OTTA	138.9	24.4	208.7	36.6	259.1	45.5	331.6	58.2	407.0	71.5
24	OWORO	422.2	74.2	634.2	111.4	787.4	138.3	1,007.9	177.0	1,236.9	217.2
25	EKO ATLANTIC			106.8	18.8	132.6	23.3	169.7	29.8	208.3	36.6
26	ILASHE			38.9	6.8	48.3	8.5	61.9	10.9	75.9	13.3
27	EPE			92.0	16.2	114.2	20.1	146.2	25.7	179.4	31.5
28	NEW AGBARA					372.5	65.4	476.8	83.7	585.1	102.8
29	BADAGRY					124.2	21.8	158.9	27.9	195.0	34.3
30	EK-TF-A							256.0	45.0	314.2	55.2
31	EK-TF-B							256.0	45.0	314.2	55.2
32	EK-TF-C							256.0	45.0	314.2	55.2
33	EK-TF-D									245.5	43.1
34	EK-TF-E									245.5	43.1
35	EK-TF-F									245.5	43.1
36	EK-TF-G										
37	EK-TF-H										
38	EK-TF-I										
39	EK-TF-J										
40	OGIJO					124.2	21.8	158.9	27.9	195.0	34.3
41	REDEEM					124.2	21.8	158.9	27.9	195.0	34.3
42	MFM					372.5	65.4	476.8	83.7	585.1	102.8
43	ARIGBAJO					372.5	65.4	476.8	83.7	585.1	102.8
44	IE-TF-A							256.0	45.0	314.2	55.2
45	IE-TF-B							256.0	45.0	314.2	55.2
46	IE-TF-C							256.0	45.0	314.2	55.2
47	IE-TF-D									245.5	43.1
48	IE-TF-E									245.5	43.1
49	IE-TF-F									245.5	43.1
50	IE-TF-G										
51	IE-TF-H										
52	IE-TF-I										
53	IE-TF-J										
54	IE-TF-K										
55	IE-TF-L										

Table D-3: Substation Load Demand – Non-coincident Peak

Transformation Station		2021		2026		2030		2035		2040	
		Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
No.	Name										
	Total	**10,896**	**3,735**	**16,281**	**5,532**	**21,704**	**7,294**	**29,318**	**9,775**	**37,454**	**12,417**
1	AGBARA	343.1	166.0	510.5	247.0	633.9	306.6	811.4	392.5	995.8	481.7
2	AJAH	698.1	318.8	1,085.6	495.7	1,347.9	615.5	1,725.3	787.8	2,117.5	966.9
3	AKANGBA	604.6	213.7	764.0	270.0	948.6	335.2	1,214.2	429.1	1,490.2	526.7
4	AKOKA	127.8	100.6	165.7	130.4	205.7	161.9	263.3	207.3	323.2	254.4
5	ALAGBON	845.7	321.8	1,290.1	490.9	1,601.7	609.5	2,050.3	780.2	2,516.3	957.5
6	ALAUSA	597.2	153.6	897.0	230.6	1,113.7	286.3	1,425.6	366.5	1,749.6	449.8
7	ALIMOSHO	523.9	152.6	786.9	229.2	977.0	284.5	1,250.6	364.2	1,534.9	447.0
8	AMUWO	433.0	144.5	562.8	187.9	698.8	233.2	894.5	298.6	1,097.8	366.4
9	APAPA ROAD	182.9	86.6	232.8	110.3	289.1	136.9	370.0	175.3	454.1	215.1
10	AYOBO	352.5	99.4	529.5	149.3	657.4	185.3	841.5	237.2	1,032.8	291.1
11	EJIGBO	834.8	207.2	1,230.5	305.4	1,527.7	379.1	1,955.5	485.3	2,399.9	595.6
12	IJORA	349.2	160.1	444.6	203.8	552.0	253.1	706.6	323.9	867.1	397.5
13	IKORODU	901.7	305.4	1,339.2	453.6	1,662.6	563.2	2,128.3	720.9	2,611.9	884.8
14	ILUPEJU	224.3	82.3	336.9	123.6	418.2	153.5	535.4	196.5	657.0	241.2
15	ISOLO	572.7	170.7	916.6	273.2	1,138.0	339.2	1,456.7	434.2	1,787.8	532.9
16	ITIRE	338.7	111.1	492.3	161.5	611.3	200.5	782.4	256.7	960.3	315.0
17	LEKKI	444.6	155.2	695.1	242.6	862.9	301.3	1,104.6	385.6	1,355.7	473.3
18	MARYLAND	501.1	135.5	809.2	218.9	1,004.7	271.8	1,286.0	347.9	1,578.3	427.0
19	ODOGUNYAN	127.8	71.5	171.7	96.1	213.2	119.3	272.9	152.7	335.0	187.4
20	OGBA	500.6	160.1	794.7	254.1	986.6	315.5	1,262.9	403.8	1,549.9	495.6
21	OJO	456.7	170.4	584.2	217.9	725.3	270.6	928.5	346.4	1,139.5	425.1
22	OKE ARO	373.4	97.5	560.8	146.5	696.2	181.9	891.2	232.8	1,093.8	285.7
23	OTTA	138.9	35.4	208.7	53.2	259.1	66.0	331.6	84.5	407.0	103.7
24	OWORO	422.2	115.0	634.2	172.8	787.4	214.5	1,007.9	274.6	1,236.9	337.0
25	EKO ATLANTIC			106.8	30.5	132.6	37.8	169.7	48.4	208.3	59.4
26	ILASHE			38.9	11.1	48.3	13.8	61.9	17.7	75.9	21.7
27	EPE			92.0	26.2	114.2	32.6	146.2	41.7	179.4	51.2
28	NEW AGBARA					372.5	106.3	476.8	136.1	585.1	167.0
29	BADAGRY					124.2	35.4	158.9	45.4	195.0	55.7
30	EK-TF-A							256.0	73.1	314.2	89.7
31	EK-TF-B							256.0	73.1	314.2	89.7
32	EK-TF-C							256.0	73.1	314.2	89.7
33	EK-TF-D									245.5	70.0
34	EK-TF-E									245.5	70.0
35	EK-TF-F									245.5	70.0
36	EK-TF-G										
37	EK-TF-H										
38	EK-TF-I										
39	EK-TF-J										
40	OGIJO					124.2	35.4	158.9	45.4	195.0	55.7
41	REDEEM					124.2	35.4	158.9	45.4	195.0	55.7
42	MFM					372.5	106.3	476.8	136.1	585.1	167.0
43	ARIGBAJO					372.5	106.3	476.8	136.1	585.1	167.0
44	IE-TF-A							256.0	73.1	314.2	89.7
45	IE-TF-B							256.0	73.1	314.2	89.7
46	IE-TF-C							256.0	73.1	314.2	89.7
47	IE-TF-D									245.5	70.0
48	IE-TF-E									245.5	70.0
49	IE-TF-F									245.5	70.0
50	IE-TF-G										
51	IE-TF-H										
52	IE-TF-I										
53	IE-TF-J										
54	IE-TF-K										
55	IE-TF-L										

Figure D-1: 330 kV Network Power Flow in 2021

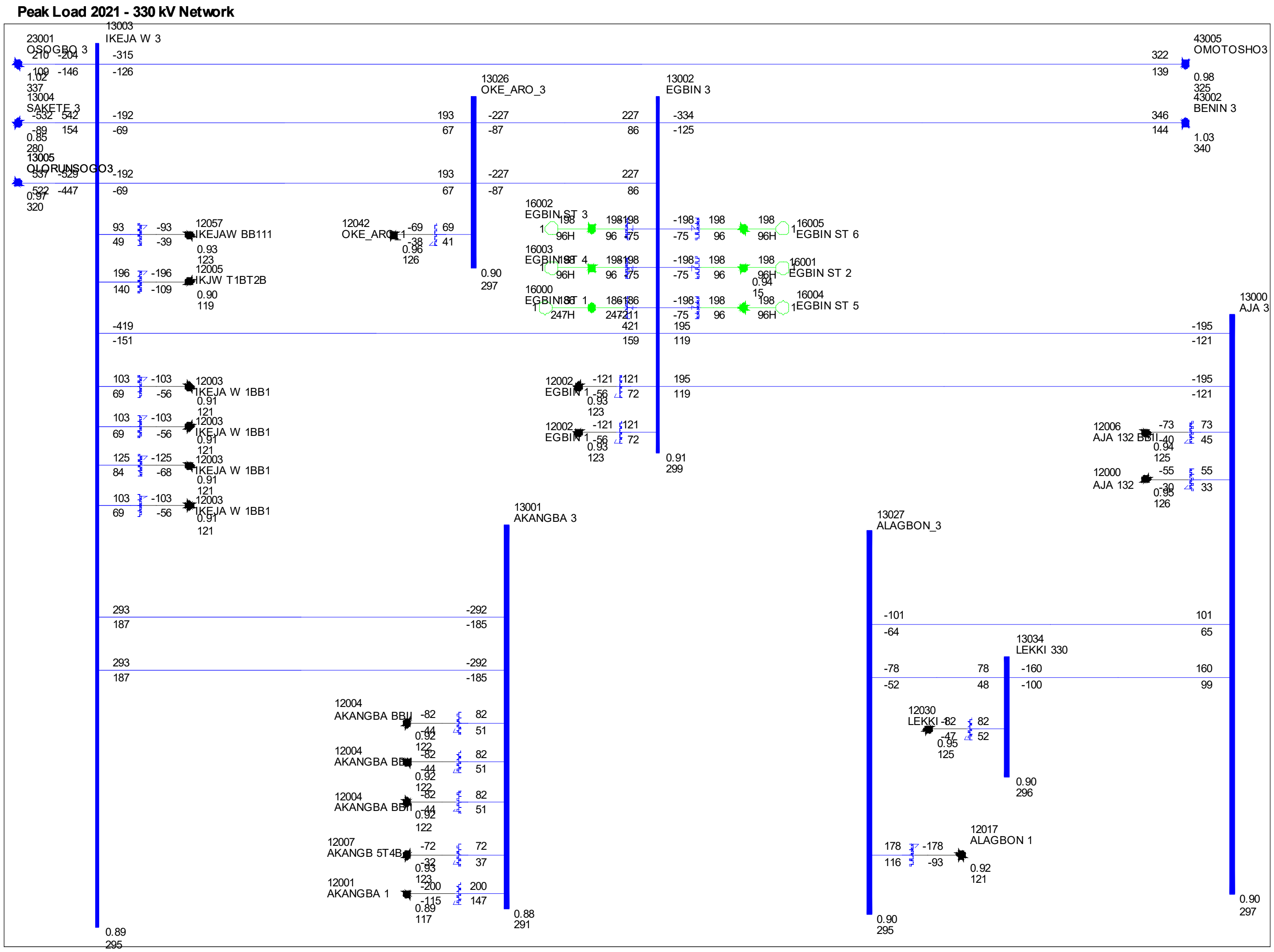


Figure D-2: 132 kV Network Power Flow in 2021

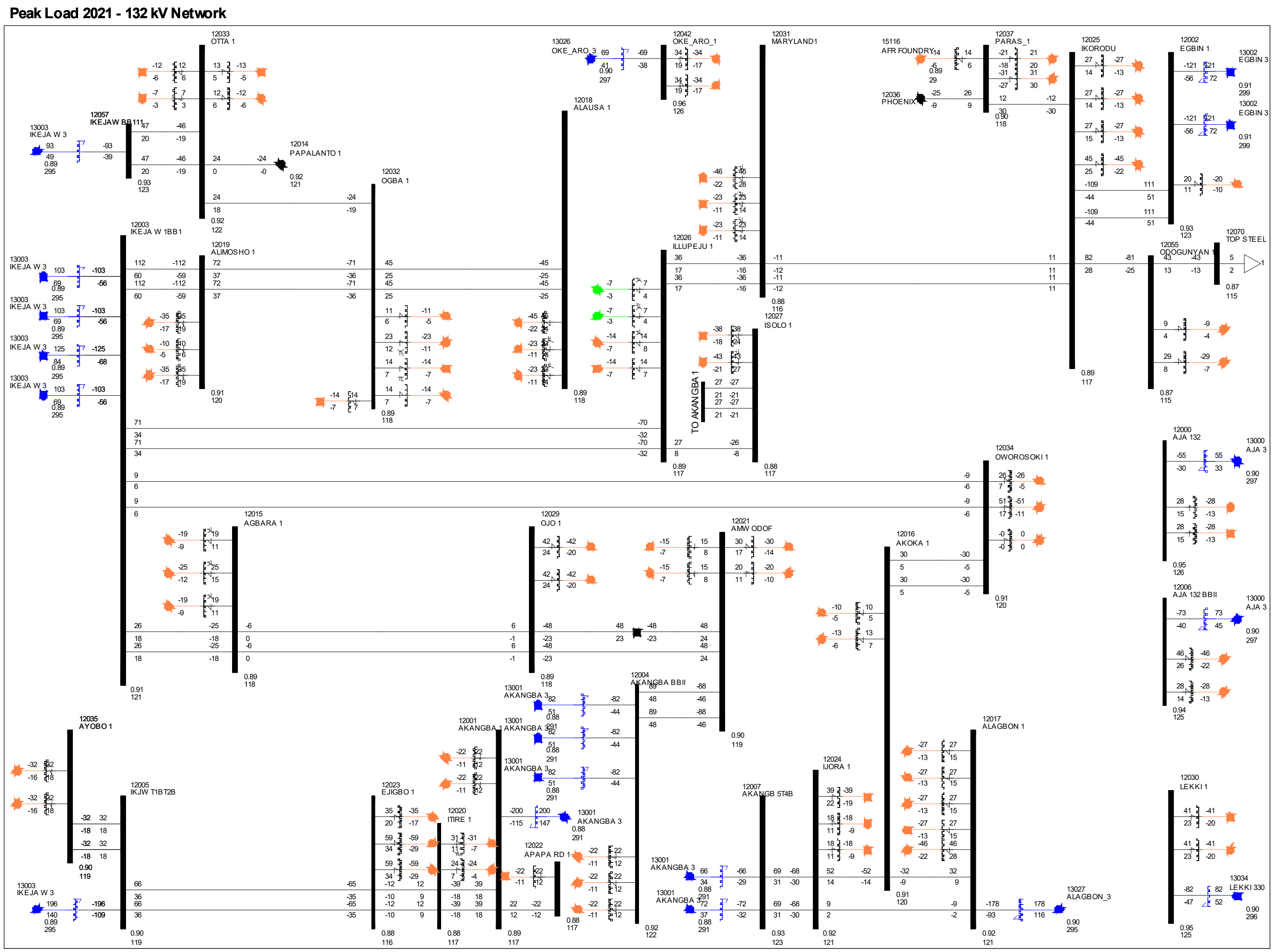


Table D-4: Element Loading – Contingency Analysis Results – 2021

Monitored Transmission Elements						N-1 Contingency	Pre Contingency Loading (MVA)	Maximum Flow (MVA)	Rating (MVA)	Post Contingency Loading (%)
From			To							
Bus No	Bus Name	Voltage (kV)	Bus No	Bus Name	Voltage (kV)					
12000	AJA 132	330	13000	AJA 3	330	12005-13003(1)	64.02	64.25	150	42.83
12001	AKANGBA 1	132	12020	ITIRE 1	132	12005-13003(1)	43.4	161.72	125.7	166.95
12001	AKANGBA 1	132	12020	ITIRE 1	132	12005-13003(1)	43.4	161.72	125.7	166.95
12001	AKANGBA 1	132	12022	APAPA RD 1	132	12001-13001(1)	25.54	25.74	90	36.75
12001	AKANGBA 1	132	12027	ISOLO 1	132	12001-12027(2)	34.39	64.36	90	81.21
12001	AKANGBA 1	132	12027	ISOLO 1	132	12001-12027(1)	34.39	64.36	90	81.21
12001	AKANGBA 1	132	13001	AKANGBA 3	330	12005-13003(1)	248.53	405.69	300	135.23
12002	EGBIN 1	132	12025	IKORODU	132	12002-12025(2)	117.27	192.98	125.7	177.43
12002	EGBIN 1	132	12025	IKORODU	132	12002-12025(1)	117.27	192.98	125.7	177.43
12002	EGBIN 1	132	13002	EGBIN 3	330	12002-13002(2)	140.96	216.96	150	144.64
12002	EGBIN 1	132	13002	EGBIN 3	330	12002-13002(1)	140.96	216.96	150	144.64
12003	IKEJA W 1BB1	132	12015	AGBARA 1	132	12003-12015(2)	31.44	47.61	125.7	42.9
12003	IKEJA W 1BB1	132	12015	AGBARA 1	132	12003-12015(1)	31.44	47.61	125.7	42.9
12003	IKEJA W 1BB1	132	12019	ALIMOSHO 1	132	12003-12019(2)	126.07	247.83	125.7	219.76
12003	IKEJA W 1BB1	132	12019	ALIMOSHO 1	132	12003-12019(1)	126.07	247.83	125.7	219.76
12003	IKEJA W 1BB1	132	12026	ILLUPEJU 1	132	12001-13001(1)	76.48	135.2	125.7	131.29
12003	IKEJA W 1BB1	132	12026	ILLUPEJU 1	132	12001-13001(1)	76.48	135.2	125.7	131.29
12003	IKEJA W 1BB1	132	12034	OWOROSOKI 1	132	12017-13027(1)	10.94	60.02	125.7	55.97
12003	IKEJA W 1BB1	132	12034	OWOROSOKI 1	132	12017-13027(1)	10.94	60.02	125.7	55.97
12003	IKEJA W 1BB1	132	13003	IKEJA W 3	330	12003-13003(4)	124.27	149.16	150	99.44
12003	IKEJA W 1BB1	132	13003	IKEJA W 3	330	12003-13003(4)	124.27	149.16	150	99.44
12003	IKEJA W 1BB1	132	13003	IKEJA W 3	330	12003-13003(4)	124.27	149.16	150	99.44
12003	IKEJA W 1BB1	132	13003	IKEJA W 3	330	12005-13003(1)	150.95	178.6	150	119.07
12004	AKANGBA BBII	132	12021	AMW ODOF	132	12004-12021(2)	99.44	179.46	125.7	160.87
12004	AKANGBA BBII	132	12021	AMW ODOF	132	12004-12021(1)	99.44	179.46	125.7	160.87
12004	AKANGBA BBII	132	13001	AKANGBA 3	330	12004-13001(2)	96.14	133.3	90	148.11

(Table D-4 **Continued)**

Monitored Transmission Elements						N-1 Contingency	Pre Contingency (MVA)	Maximum Flow (MVA)	Rating (MVA)	Post Contingency (%)
From			To							
Bus No	Bus Name	Voltage (kV)	Bus No	Bus Name	Voltage (kV)					
12004	AKANGBA BBII	132	13001	AKANGBA 3	330	12004-13001(1)	96.14	133.3	90	148.11
12004	AKANGBA BBII	132	13001	AKANGBA 3	330	12004-13001(1)	96.14	133.3	90	148.11
12005	IKJW T1BT2B	132	12023	EJIGBO 1	132	12001-13001(1)	73.61	116.99	125.7	118.26
12005	IKJW T1BT2B	132	12023	EJIGBO 1	132	12001-13001(1)	73.61	116.99	125.7	118.26
12005	IKJW T1BT2B	132	12035	AYOBO 1	132	12005-12035(2)	37.33	74.69	125.7	66.07
12005	IKJW T1BT2B	132	12035	AYOBO 1	132	12005-12035(1)	37.33	74.69	125.7	66.07
12005	IKJW T1BT2B	132	13003	IKEJA W 3	330	12001-13001(1)	241.08	366.15	300	122.05
12006	AJA 132 BBII	132	13000	AJA 3	330	12005-13003(1)	86.24	86.63	150	57.76
12007	AKANGB 5T4B	132	12024	IJORA 1	132	12017-13027(1)	74.57	127.81	90	166.54
12007	AKANGB 5T4B	132	12024	IJORA 1	132	12017-13027(1)	74.57	127.81	90	166.54
12007	AKANGB 5T4B	132	13001	AKANGBA 3	330	12017-13027(1)	80.63	145.5	150	97
12007	AKANGB 5T4B	132	13001	AKANGBA 3	330	12017-13027(1)	74.46	134.37	150	89.58
12015	AGBARA 1	132	12029	OJO 1	132	12001-13001(1)	6.23	16.14	125.7	14.93
12015	AGBARA 1	132	12029	OJO 1	132	12001-13001(1)	6.23	16.14	125.7	14.93
12016	AKOKA 1	132	12017	ALAGBON 1	132	12016-12024(1)	32.73	69.74	125.7	61.4
12016	AKOKA 1	132	12024	IJORA 1	132	12016-12017(1)	53.57	78.55	125.7	68.93
12016	AKOKA 1	132	12034	OWOROSOKI 1	132	12016-12034(2)	30.26	57.09	125.7	50.08
12016	AKOKA 1	132	12034	OWOROSOKI 1	132	12016-12034(1)	30.26	57.09	125.7	50.08
12017	ALAGBON 1	132	12024	IJORA 1	132	12017-13027(1)	9.15	144.86	125.7	137.02
12017	ALAGBON 1	132	13027	ALAGBON_3	330	13002-13003(1)	212.95	241.81	300	80.6
12018	ALAUSA 1	132	12032	OGBA 1	132	12018-12032(2)	51.96	103.97	125.7	93.14
12018	ALAUSA 1	132	12032	OGBA 1	132	12018-12032(1)	51.96	103.97	125.7	93.14
12019	ALIMOSHO 1	132	12032	OGBA 1	132	12019-12032(2)	79.9	152.63	125.7	138.31
12019	ALIMOSHO 1	132	12032	OGBA 1	132	12019-12032(1)	79.9	152.63	125.7	138.31
12020	ITIRE 1	132	12023	EJIGBO 1	132	12005-13003(1)	15.32	128.92	125.7	137.55
12020	ITIRE 1	132	12023	EJIGBO 1	132	12005-13003(1)	15.32	128.92	125.7	137.55

(Table D-4 **Continued)**

Monitored Transmission Elements						N-1 Contingency	Pre Contingency (MVA)	Maximum Flow (MVA)	Rating (MVA)	Post Contingency (%)
From			To							
Bus No	Bus Name	Voltage (kV)	Bus No	Bus Name	Voltage (kV)					
12021	AMW ODOF	132	12029	OJO 1	132	12029-12120(1)	53.43	97.86	125.7	87.64
12021	AMW ODOF	132	12120	NNPC JUNCTIO	132	12021-12029(1)	53.46	97.94	125.7	87.54
12025	IKORODU	132	12031	MARYLAND1	132	12001-13001(1)	15.85	36.08	125.7	35.14
12025	IKORODU	132	12031	MARYLAND1	132	12001-13001(1)	15.85	36.08	125.7	35.14
12025	IKORODU	132	12037	PARAS_1	132	12005-13003(1)	32.43	33.23	125.7	31.95
12025	IKORODU	132	12055	ODOGUNYAN 1	132	12005-13003(1)	85.24	85.42	125.7	84.04
12026	ILLUPEJU 1	132	12027	ISOLO 1	132	12001-13001(1)	27.68	177.62	90	251.25
12026	ILLUPEJU 1	132	12031	MARYLAND1	132	12026-12031(2)	39.09	73.87	90	93.46
12026	ILLUPEJU 1	132	12031	MARYLAND1	132	12026-12031(1)	39.09	73.87	90	93.46
12029	OJO 1	132	12120	NNPC JUNCTIO	132	12021-12029(1)	53.48	97.81	125.7	87.61
12030	LEKKI 1	132	13034	LEKKI 330	330	12005-13003(1)	96.8	97.32	300	32.44
12042	OKE_ARO_1	132	13026	OKE_ARO_3	330	12005-13003(1)	80.11	80.42	300	26.81
12057	IKEJAW BB111	132	13003	IKEJA W 3	330	12003-13003(4)	105.07	115.05	150	76.7
12120	NNPC JUNCTIO	132	12122	ILASHE	132	12025-12055(1)	0.14	0.14	125.7	0.12
12122	ILASHE	132	12123	NNPC	132	12025-12055(1)	0.09	0.09	125.7	0.08
13000	AJA 3	330	13002	EGBIN 3	330	13000-13002(2)	228.94	444.58	777.3	64.12
13000	AJA 3	330	13002	EGBIN 3	330	13000-13002(1)	228.94	444.58	777.3	64.12
13000	AJA 3	330	13027	ALAGBON_3	330	13000-13034(1)	119.1	291.27	777.3	42.3
13000	AJA 3	330	13034	LEKKI 330	330	13000-13027(1)	188.4	298.68	777.3	42.9
13001	AKANGBA 3	330	13003	IKEJA W 3	330	13001-13003(2)	345.4	638.05	777.3	94.58
13001	AKANGBA 3	330	13003	IKEJA W 3	330	13001-13003(1)	345.4	638.05	777.3	94.58
13002	EGBIN 3	330	13003	IKEJA W 3	330	12017-13027(1)	445.27	547.51	777.3	80.03
13002	EGBIN 3	330	13026	OKE_ARO_3	330	13002-13003(1)	243.26	435.63	777.3	62.65
13002	EGBIN 3	330	13026	OKE_ARO_3	330	13002-13003(1)	243.26	435.63	777.3	62.65
13003	IKEJA W 3	330	13026	OKE_ARO_3	330	13002-13003(1)	204.48	393.48	777.3	57.25
13003	IKEJA W 3	330	13026	OKE_ARO_3	330	13002-13003(1)	204.48	393.48	777.3	57.25
13027	ALAGBON_3	330	13034	LEKKI 330	330	13000-13027(1)	93.87	203.06	777.3	29.35

Table D-5: Bus Voltage – Contingency Analysis Results – 2021

System	N-1 Contingency	Bus No	Bus Name	Voltage (kV)	V-Cont	V-Init	V-Max	V-Min
330&132kV	12001-13001(1)	12001	AKANGBA 1	132	0.78121	0.88710	1.10	0.85
330&132kV	12001-13001(1)	12005	IKJW T1BT2B	132	0.82315	0.90082	1.10	0.85
330&132kV	12001-13001(1)	12020	ITIRE 1	132	0.78163	0.88477	1.10	0.85
330&132kV	12001-13001(1)	12022	APAPA RD 1	132	0.77836	0.88465	1.10	0.85
330&132kV	12001-13001(1)	12023	EJIGBO 1	132	0.78699	0.88206	1.10	0.85
330&132kV	12001-13001(1)	12025	IKORODU	132	0.83378	0.88927	1.10	0.85
330&132kV	12001-13001(1)	12026	ILLUPEJU 1	132	0.81920	0.88698	1.10	0.85
330&132kV	12001-13001(1)	12027	ISOLO 1	132	0.78552	0.88295	1.10	0.85
330&132kV	12001-13001(1)	12031	MARYLAND1	132	0.81661	0.88176	1.10	0.85
330&132kV	12001-13001(1)	12035	AYOBO 1	132	0.82235	0.90011	1.10	0.85
330&132kV	12001-13001(1)	12037	PARAS_1	132	0.84221	0.89693	1.10	0.85
330&132kV	12001-13001(1)	12055	ODOGUNYAN 1	132	0.81502	0.87196	1.10	0.85
330&132kV	12002-12025(1)	12055	ODOGUNYAN 1	132	0.84736	0.87196	1.10	0.85
330&132kV	12002-12025(2)	12055	ODOGUNYAN 1	132	0.84736	0.87196	1.10	0.85
330&132kV	12002-13002(1)	12055	ODOGUNYAN 1	132	0.83880	0.87196	1.10	0.85
330&132kV	12002-13002(2)	12055	ODOGUNYAN 1	132	0.83880	0.87196	1.10	0.85
330&132kV	12005-13003(1)	12001	AKANGBA 1	132	0.78178	0.88710	1.10	0.85
330&132kV	12005-13003(1)	12005	IKJW T1BT2B	132	0.73328	0.90082	1.10	0.85
330&132kV	12005-13003(1)	12015	AGBARA 1	132	0.84700	0.89357	1.10	0.85
330&132kV	12005-13003(1)	12018	ALAUSA 1	132	0.84149	0.89028	1.10	0.85
330&132kV	12005-13003(1)	12020	ITIRE 1	132	0.77062	0.88477	1.10	0.85
330&132kV	12005-13003(1)	12022	APAPA RD 1	132	0.77893	0.88465	1.10	0.85
330&132kV	12005-13003(1)	12023	EJIGBO 1	132	0.74564	0.88206	1.10	0.85
330&132kV	12005-13003(1)	12025	IKORODU	132	0.82751	0.88927	1.10	0.85
330&132kV	12005-13003(1)	12026	ILLUPEJU 1	132	0.81425	0.88698	1.10	0.85
330&132kV	12005-13003(1)	12027	ISOLO 1	132	0.78476	0.88295	1.10	0.85
330&132kV	12005-13003(1)	12029	OJO 1	132	0.84901	0.89405	1.10	0.85
330&132kV	12005-13003(1)	12031	MARYLAND1	132	0.81127	0.88176	1.10	0.85
330&132kV	12005-13003(1)	12032	OGBA 1	132	0.84363	0.89228	1.10	0.85
330&132kV	12005-13003(1)	12035	AYOBO 1	132	0.73234	0.90011	1.10	0.85
330&132kV	12005-13003(1)	12037	PARAS_1	132	0.83596	0.89693	1.10	0.85
330&132kV	12005-13003(1)	12055	ODOGUNYAN 1	132	0.80858	0.87196	1.10	0.85
330&132kV	12005-13003(1)	13001	AKANGBA 3	330	0.84813	0.88284	1.05	0.85
330&132kV	12017-13027(1)	12017	ALAGBON 1	132	0.84107	0.91507	1.10	0.85
330&132kV	12025-12037(1)	12055	ODOGUNYAN 1	132	0.84870	0.87196	1.10	0.85
330&132kV	12057-13003(1)	12057	IKEJAW BB111	132	0.80173	0.93068	1.10	0.85

Figure D-3: 330 kV Network Power Flow in 2026

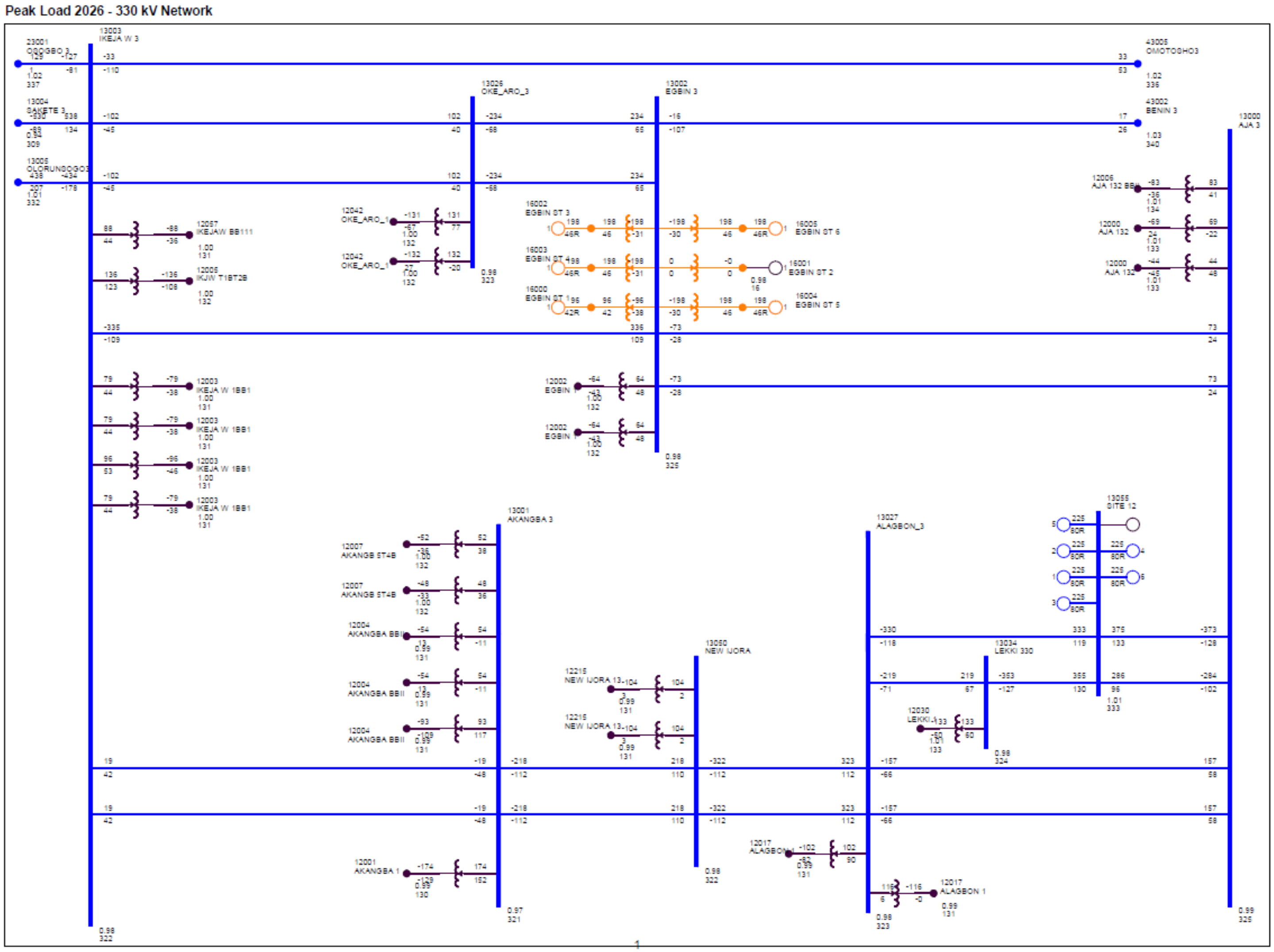


Figure D-4: 132 kV Network Power Flow in 2026

Peak Load 2026 - 132 kV Network

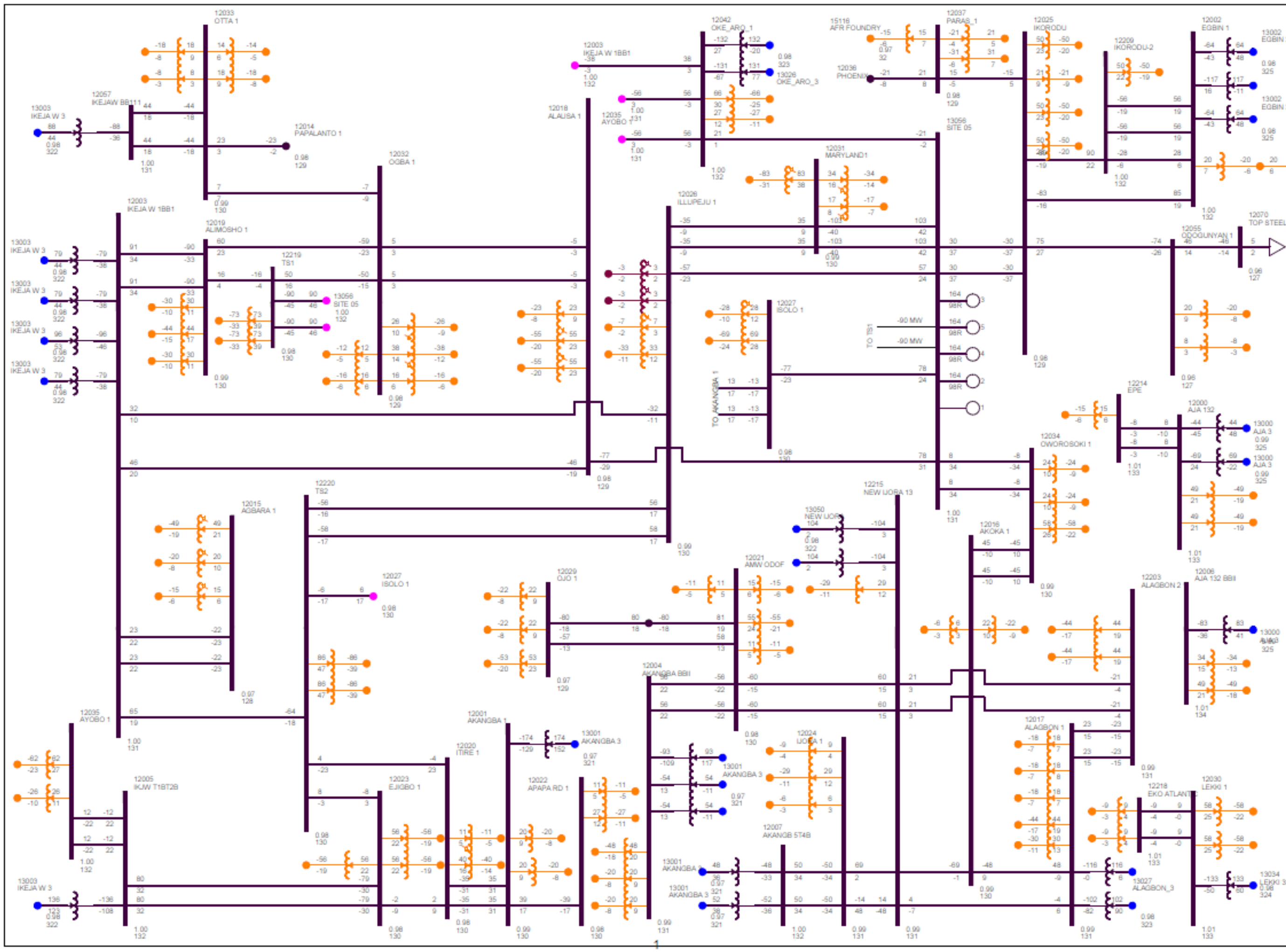


Figure D-5: 330 kV Network Power Flow in 2030

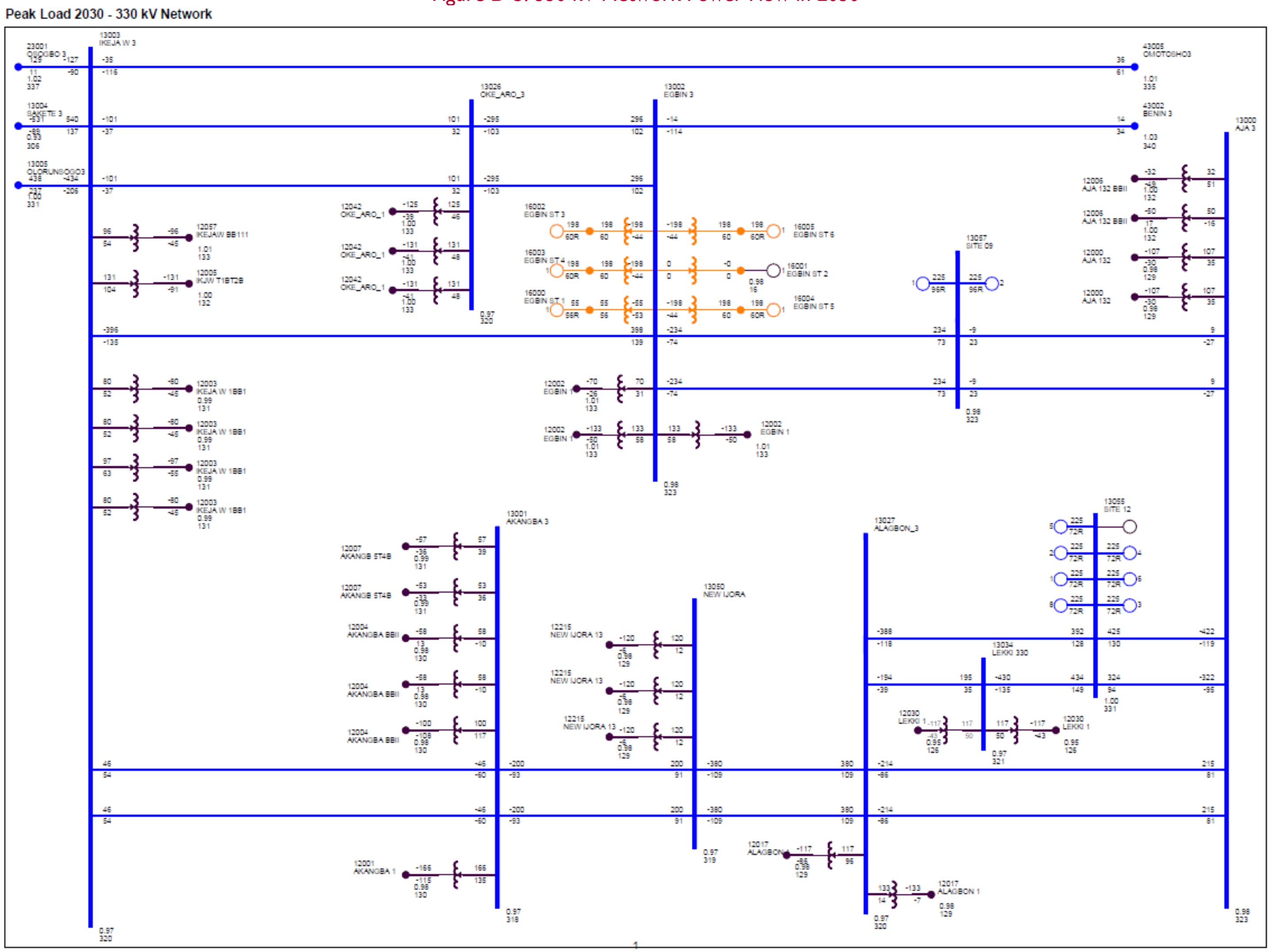


Figure D-6: 132 kV Network Power Flow in 2030

Peak Load 2030 - 132 kV Network

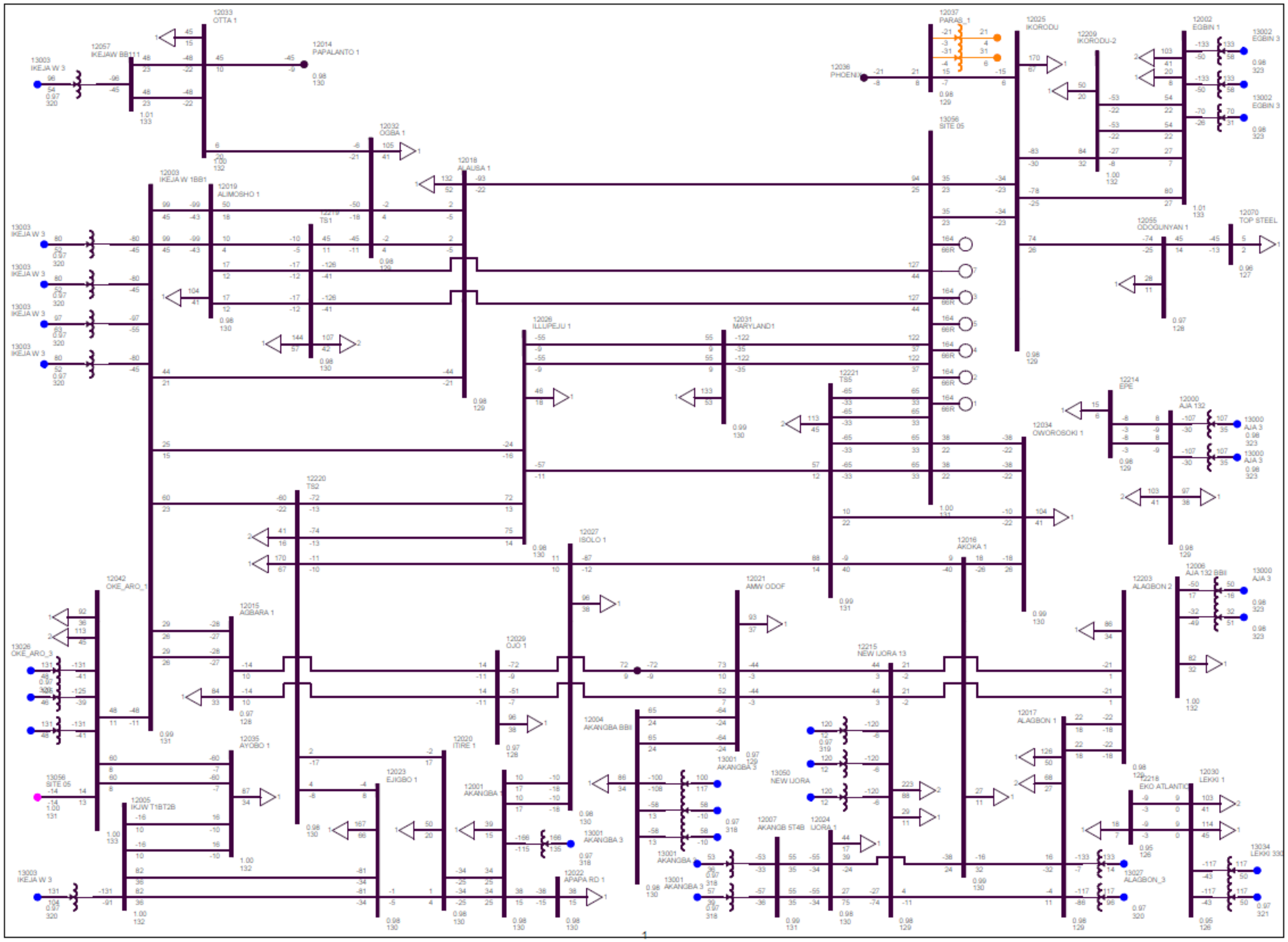


Figure D-7: 330 kV Network Power Flow in 2035

Peak Load 2035 - 330 kV Network

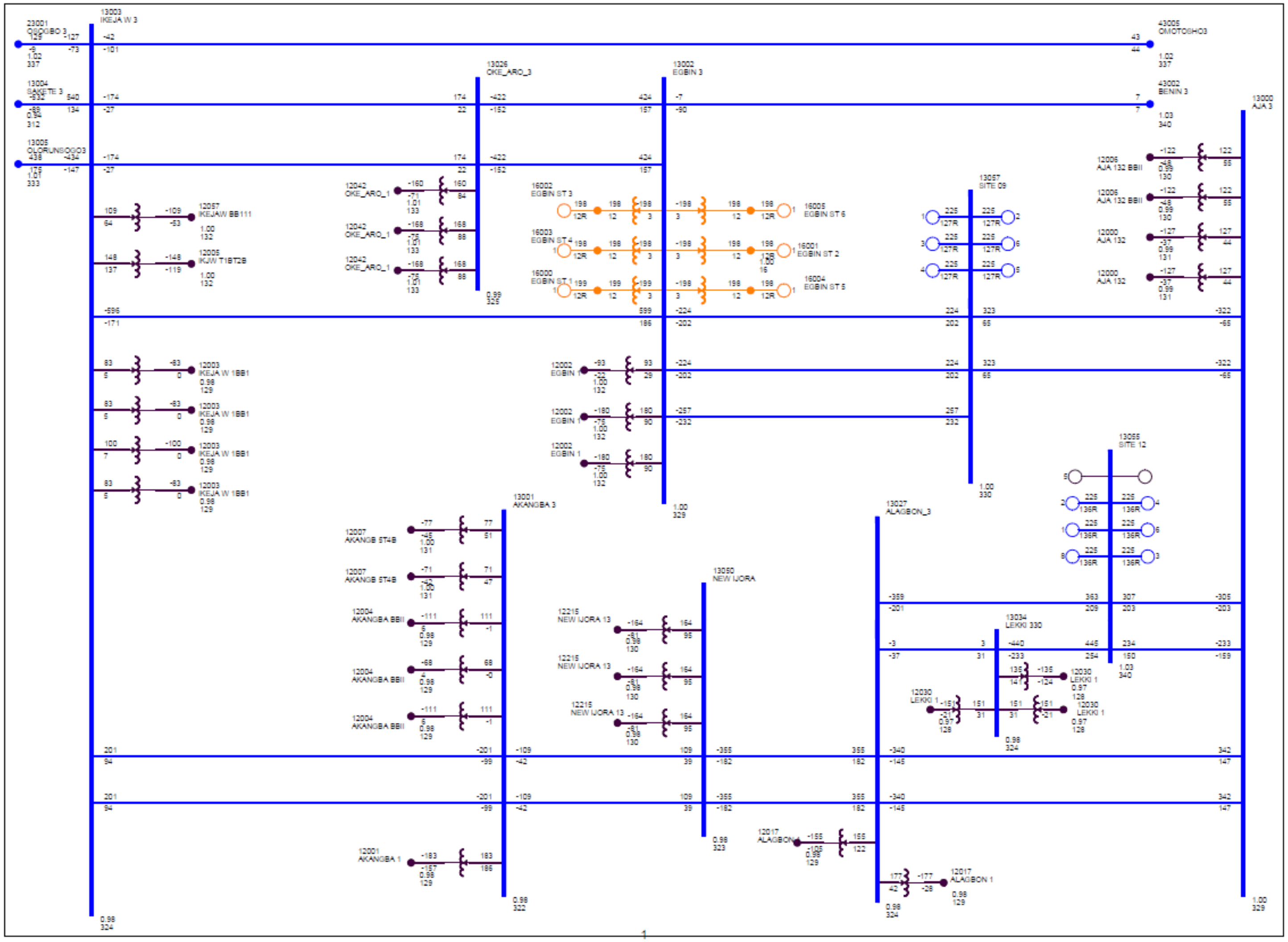


Figure D-8: 132 kV Network Power Flow in 2035

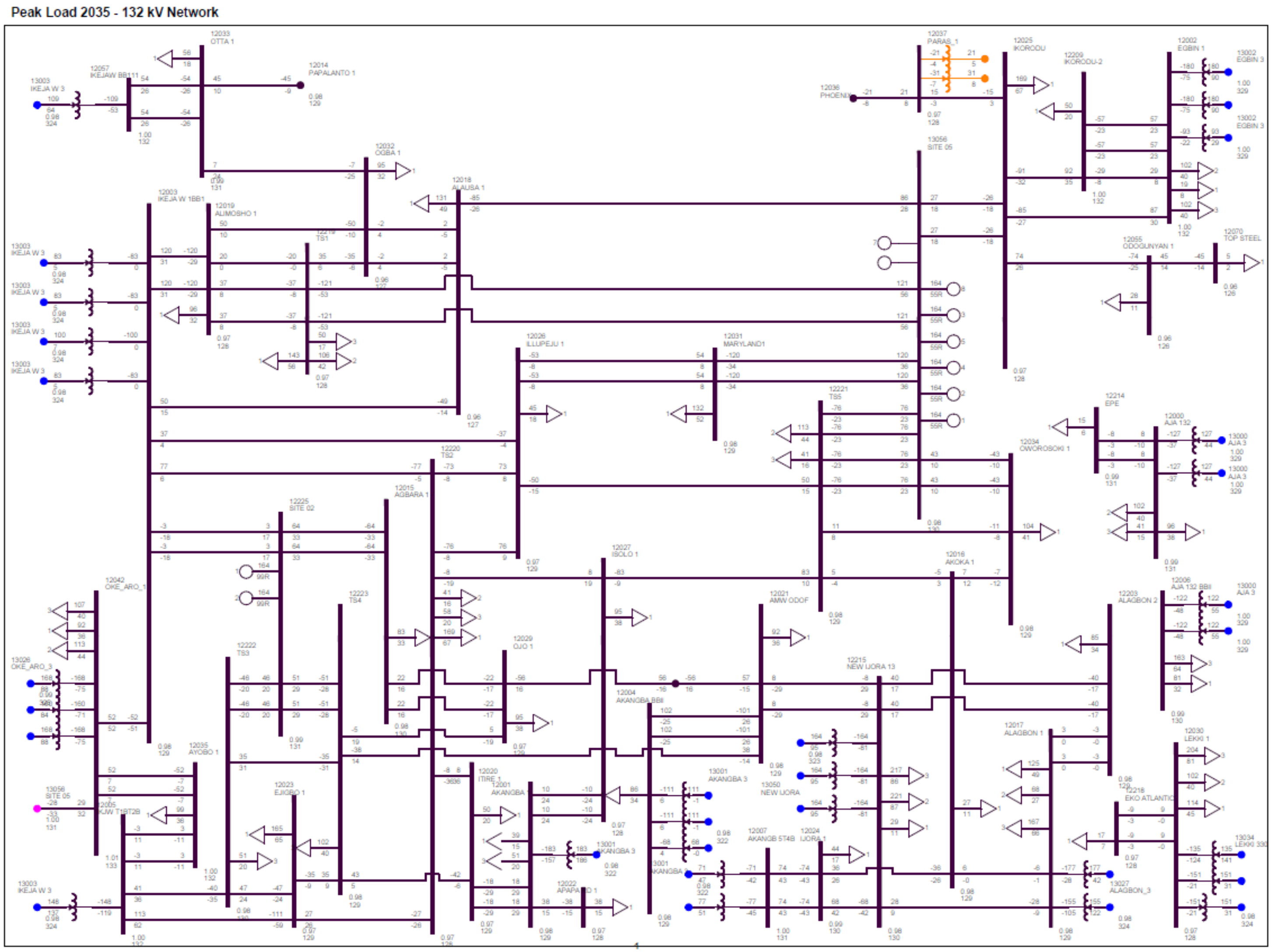


Figure D-9: 330 kV Network Power Flow in 2040

Peak Load 2040 - 330 kV Network

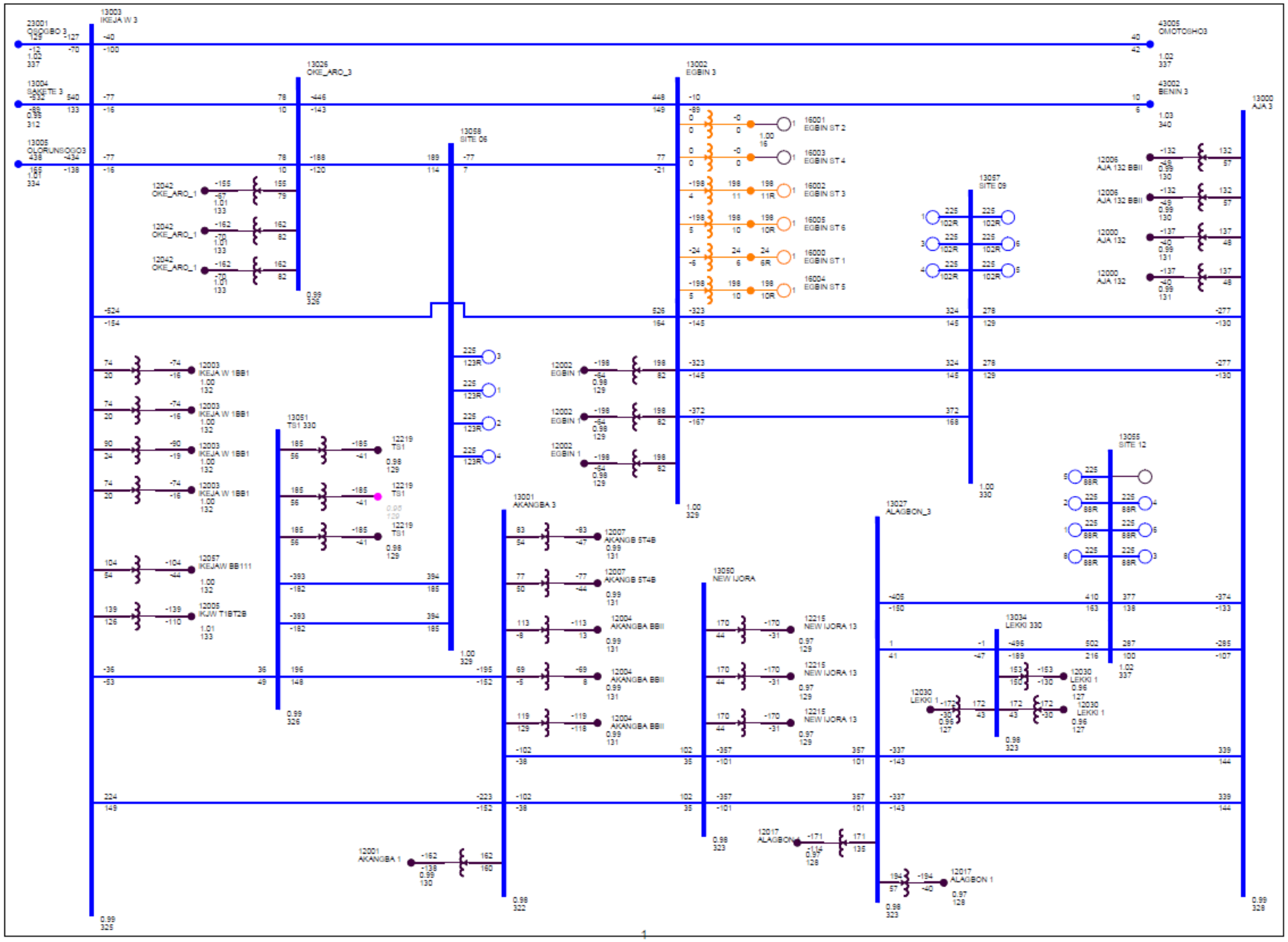
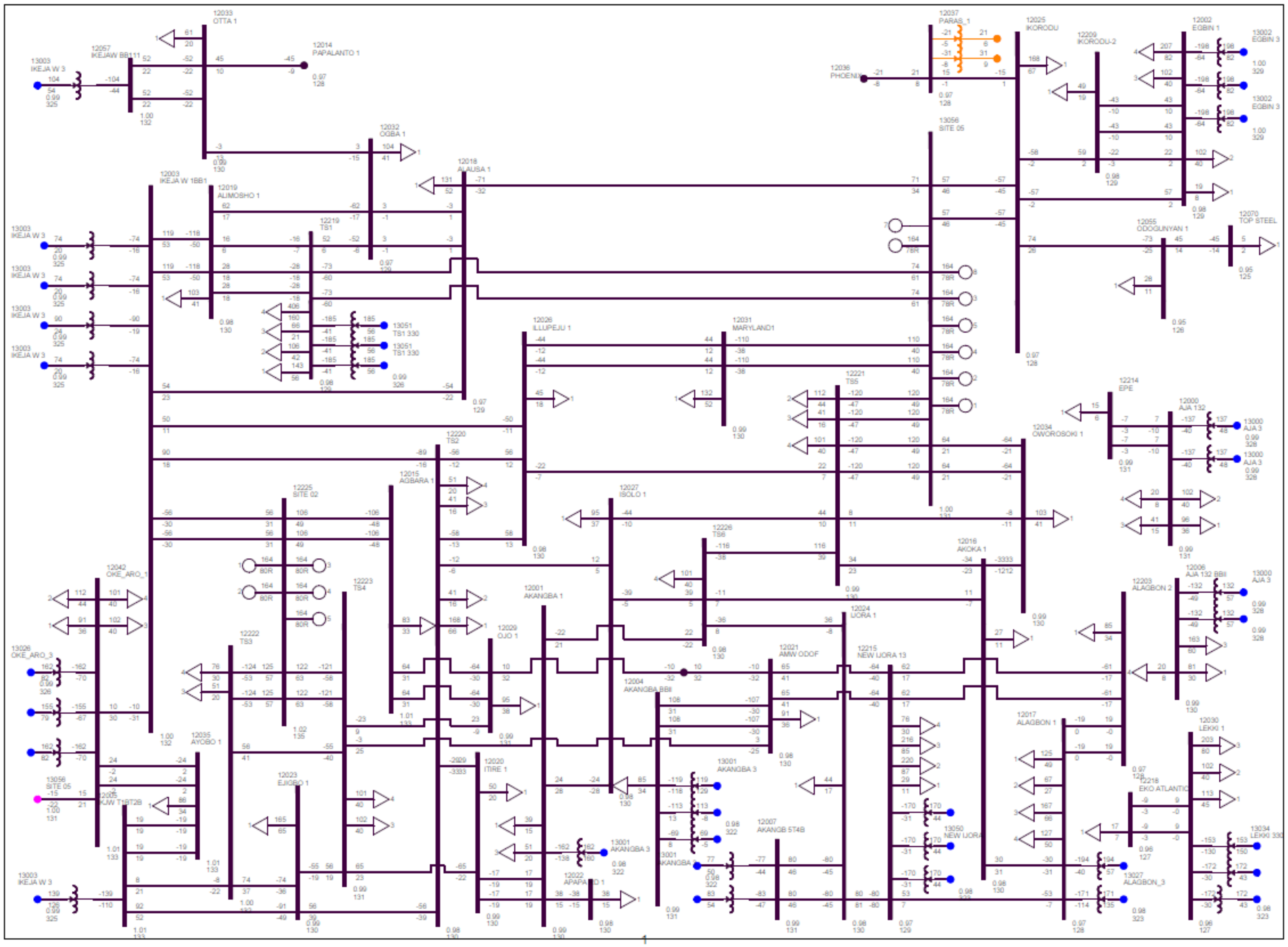


Figure D-10: 132 kV Network Power Flow in 2040

Peak Load 2040 - 132 kV Network



APPENDIX E: TABLES AND FIGURES FOR DISTRIBUTION DEVELOPMENT PLAN

Table E-1: Load Forecast By Feeder – EKEDC

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020		2021		2022		2023		2024		2025	
					Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
Total					**4,432.5**	**1,725.8**	**4,756.6**	**1,850.1**	**5,116.8**	**1,988.2**	**5,512.2**	**2,139.8**	**5,942.3**	**2,304.5**	**6,406.6**	**2,482.2**
1	EKEDC	AGBARA	AGBARA	46.2	77.30	19.1	79.84	19.7	83.78	20.7	88.05	21.8	91.38	22.6	93.76	23.2
2	EKEDC	AGBARA	BADAGRY	31.7	55.81	20.1	57.64	20.8	60.48	21.8	63.56	22.9	65.97	23.8	67.69	24.4
3	EKEDC	AGBARA	BADAGRY EXPRESS	1.9	3.03	18.2	3.09	18.6	3.16	19.0	3.22	19.3	3.28	19.7	3.35	20.1
4	EKEDC	AGBARA	BETA GLASS	15.9	15.11	10.8	15.41	11.1	15.72	11.3	16.04	11.5	16.36	11.7	16.68	12.0
5	EKEDC	AGBARA	OKO AFO	38.6	72.55	21.5	74.94	22.2	78.63	23.3	82.63	24.4	85.76	25.4	88.00	26.0
6	EKEDC	AGBARA	RIDER GLASS	8.9	10.73	13.8	11.08	14.2	11.63	14.9	12.22	15.7	12.68	16.3	13.01	16.7
7	EKEDC	AGBARA	T4 15MVA AGBARA LOCAL	38.2	41.62	12.4	42.99	12.8	45.11	13.5	47.41	14.2	49.20	14.7	50.48	15.1
8	EKEDC	AGBARA	T5 15MVA AGBARA LOCAL	33.6	49.84	16.9	51.47	17.5	54.01	18.4	56.76	19.3	58.91	20.0	60.44	20.5
9	EKEDC	AGBARA	T6 15MVA AGBARA LOCAL	3.5	6.41	20.9	6.62	21.6	6.94	22.6	7.30	23.8	7.57	24.7	7.77	25.3
10	EKEDC	AJAH	AJAH LOCAL	33.5	48.09	16.4	49.67	16.9	52.12	17.8	54.78	18.7	56.85	19.4	58.33	19.9
11	EKEDC	AJAH	CHEVRON	49.0	41.04	9.6	42.38	9.9	44.48	10.4	46.74	10.9	48.51	11.3	49.77	11.6
12	EKEDC	AJAH	ELEKO	21.7	44.09	23.2	45.54	24.0	47.78	25.1	50.21	26.4	52.11	27.4	53.47	28.1
13	EKEDC	AJAH	ELEMORO	17.3	39.34	26.0	40.63	26.8	42.64	28.1	44.81	29.6	46.51	30.7	47.72	31.5
14	EKEDC	AJAH	IBEJU	26.5	69.88	30.1	72.17	31.1	75.73	32.6	79.59	34.3	82.60	35.6	84.75	36.5
15	EKEDC	AJAH	IKATE EXPRESS	40.0	66.97	19.1	69.17	19.7	72.58	20.7	76.28	21.8	79.16	22.6	81.22	23.2
16	EKEDC	AJAH	ILASAN	17.4	39.53	25.9	40.83	26.8	42.85	28.1	45.03	29.5	46.73	30.7	47.95	31.5
17	EKEDC	AJAH	MAIN ONE	6.4	8.46	15.1	8.63	15.4	8.81	15.7	8.98	16.0	9.16	16.3	9.35	16.7
18	EKEDC	AJAH	MAROKO	49.9	161.25	36.9	166.55	38.1	174.77	40.0	183.67	42.0	190.61	43.6	195.58	44.7
19	EKEDC	AJAH	OKE- IRA	30.6	69.50	25.9	71.78	26.8	75.32	28.1	79.16	29.5	82.15	30.6	84.29	31.4
20	EKEDC	AJAH	ROYAL GARDEN CITY	7.3	9.70	15.2	10.02	15.7	10.51	16.4	11.05	17.3	11.47	17.9	11.77	18.4
21	EKEDC	AJAH	TWINLAKE	1.0	0.16	1.8	0.17	1.9	0.17	2.0	0.18	2.1	0.19	2.2	0.20	2.2
22	EKEDC	AKANGBA	ADELABU 1	42.2	106.04	28.7	109.52	29.6	114.92	31.1	120.78	32.7	125.34	33.9	128.61	34.8
23	EKEDC	AKANGBA	ADELABU 11	31.2	48.57	17.8	50.16	18.4	52.64	19.3	55.32	20.2	57.41	21.0	58.91	21.6
24	EKEDC	AKANGBA	AKANGBA NEW YABA	28.8	69.05	27.4	71.32	28.3	74.83	29.7	78.65	31.2	81.62	32.4	83.75	33.2
25	EKEDC	AKANGBA	AKANGBA NRC	24.1	46.21	21.9	47.73	22.6	50.09	23.7	52.64	24.9	54.63	25.9	56.05	26.6
26	EKEDC	AKANGBA	AMUWO	48.4	55.18	13.0	56.28	13.3	57.41	13.5	58.56	13.8	59.73	14.1	60.92	14.4
27	EKEDC	AKANGBA	IDI ARABA	7.1	8.52	13.7	8.80	14.1	9.23	14.8	9.70	15.6	10.07	16.2	10.33	16.6
28	EKEDC	AKANGBA	IGANMU	9.8	15.31	17.8	15.81	18.4	16.59	19.3	17.43	20.3	18.09	21.1	18.56	21.6
29	EKEDC	AKANGBA	IGANMU 2	38.4	55.12	16.4	56.93	16.9	59.74	17.8	62.78	18.7	65.16	19.4	66.86	19.9
30	EKEDC	AKANGBA	LUTH	40.4	101.40	28.7	104.73	29.6	109.89	31.1	115.49	32.6	119.86	33.9	122.98	34.8
31	EKEDC	AKANGBA	SANYA	37.4	80.63	24.6	83.28	25.4	87.39	26.7	91.84	28.0	95.31	29.1	97.80	29.9
32	EKEDC	AKOKA	AKOKA LOCAL	0.3	0.59	22.6	0.61	23.4	0.64	24.5	0.68	25.8	0.70	26.8	0.72	27.5
33	EKEDC	AKOKA	AKOKA NEW YABA	34.2	65.46	21.9	67.61	22.6	70.95	23.7	74.56	24.9	77.38	25.8	79.40	26.5
34	EKEDC	AKOKA	AKOKA NRC	0.2	0.15	8.3	0.15	8.6	0.16	9.0	0.17	9.5	0.17	9.8	0.18	10.1
35	EKEDC	AKOKA	SABO	31.1	44.61	16.4	46.08	16.9	48.35	17.7	50.81	18.7	52.73	19.4	54.11	19.9
36	EKEDC	AKOKA	UNILAG	0.2	0.03	1.9	0.03	2.0	0.04	2.1	0.04	2.2	0.04	2.3	0.04	2.3

(Table E-1 Continued)

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020		2021		2022		2023		2024		2025	
					Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
37	EKEDC	ALAGBON	A/BERKLEY EXPRESS	7.4	15.17	23.4	15.67	24.2	16.44	25.4	17.28	26.6	17.93	27.7	18.40	28.4
38	EKEDC	ALAGBON	A/FED,SEC,BERKLEY	22.9	48.34	24.1	49.93	24.9	52.39	26.1	55.06	27.4	57.14	28.5	58.63	29.2
39	EKEDC	ALAGBON	ADEMOLA 11	37.3	83.54	25.6	86.29	26.4	90.54	27.7	95.15	29.1	98.75	30.2	101.33	31.0
40	EKEDC	ALAGBON	ADEMOLA I	52.1	123.29	27.0	127.34	27.9	133.62	29.3	140.43	30.8	145.74	31.9	149.54	32.8
41	EKEDC	ALAGBON	ANIFOWOSHE	33.5	79.28	27.0	81.88	27.9	85.92	29.3	90.30	30.8	93.71	31.9	96.16	32.8
42	EKEDC	ALAGBON	ANIFOWOSHE 2	23.0	53.15	26.4	54.89	27.2	57.60	28.6	60.53	30.0	62.82	31.2	64.46	32.0
43	EKEDC	ALAGBON	BANANA ISLAND 1	16.4	15.76	11.0	16.28	11.3	17.08	11.9	17.95	12.5	18.63	13.0	19.11	13.3
44	EKEDC	ALAGBON	BANANA ISLAND 11	47.1	39.42	9.6	40.72	9.9	42.73	10.4	44.90	10.9	46.60	11.3	47.82	11.6
45	EKEDC	ALAGBON	FOWLER 1	53.1	127.76	27.5	131.96	28.4	138.47	29.8	145.52	31.3	151.02	32.5	154.96	33.3
46	EKEDC	ALAGBON	FOWLER 2	24.0	52.50	25.0	54.22	25.8	56.90	27.1	59.79	28.4	62.06	29.5	63.67	30.3
47	EKEDC	ALAGBON	FOWLER 3	12.3	29.56	27.4	30.53	28.3	32.04	29.7	33.67	31.2	34.94	32.4	35.86	33.3
48	EKEDC	ALAGBON	NEW IDUMAGBO	22.7	34.84	17.5	35.99	18.1	37.76	19.0	39.69	20.0	41.19	20.7	42.26	21.3
49	EKEDC	ALAGBON	T2 ALAGBON LOCAL	26.1	43.82	19.2	45.26	19.8	47.49	20.8	49.91	21.8	51.80	22.7	53.15	23.2
50	EKEDC	ALAGBON	TI ALAGBON LOCAL	39.0	72.34	21.2	74.71	21.9	78.40	22.9	82.39	24.1	85.51	25.0	87.74	25.7
51	EKEDC	AMUWO	FESTAC 1 (AMUWO)	60.0	93.28	17.7	96.35	18.3	101.10	19.2	106.25	20.2	110.27	21.0	113.14	21.5
52	EKEDC	AMUWO	KIRIKIRI EXPRESS	41.0	78.55	21.9	81.13	22.6	85.13	23.7	89.47	24.9	92.85	25.9	95.27	26.5
53	EKEDC	AMUWO	SATELLITE 1	29.8	49.89	19.1	51.53	19.7	54.07	20.7	56.82	21.8	58.97	22.6	60.51	23.2
54	EKEDC	AMUWO	SATELLITE 2	0.1	0.05	6.2	0.06	6.4	0.06	6.7	0.06	7.1	0.06	7.3	0.07	7.5
55	EKEDC	AMUWO	SNAKE ISLAND	16.3	10.04	7.0	10.24	7.2	10.45	7.3	10.65	7.5	10.87	7.6	11.08	7.8
56	EKEDC	AMUWO	T3 15MVA AMUWO LOCAL	62.2	74.43	13.7	76.88	14.1	80.67	14.8	84.78	15.6	87.99	16.1	90.28	16.6
57	EKEDC	APAPA ROAD	APAPA MAINS 1	24.1	37.56	17.8	38.79	18.4	40.70	19.3	42.78	20.3	44.39	21.0	45.55	21.6
58	EKEDC	APAPA ROAD	APAPA MAINS 11	23.1	33.14	16.4	34.23	16.9	35.91	17.7	37.74	18.7	39.17	19.4	40.19	19.9
59	EKEDC	APAPA ROAD	FLOUR MILLS	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
60	EKEDC	APAPA ROAD	NAVAL BASE	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
61	EKEDC	APAPA ROAD	T1 15MVA APAPA ROAD LOCAL	46.7	56.47	13.8	58.33	14.3	61.21	15.0	64.32	15.7	66.76	16.3	68.50	16.7
62	EKEDC	APAPA ROAD	T2 15MVA APAPA ROAD LOCAL	32.9	49.67	17.2	51.30	17.8	53.83	18.7	56.57	19.6	58.71	20.4	60.24	20.9
63	EKEDC	APAPA ROAD	TINCAN	0.1	0.23	26.6	0.24	27.5	0.25	28.9	0.27	30.3	0.28	31.5	0.28	32.3
64	EKEDC	IJORA	AJELE 1	23.5	50.10	24.3	51.75	25.1	54.30	26.4	57.06	27.7	59.22	28.8	60.77	29.5
65	EKEDC	IJORA	AJELE 11	14.5	30.88	24.3	31.90	25.1	33.47	26.3	35.17	27.7	36.50	28.7	37.45	29.5
66	EKEDC	IJORA	BADIA	47.4	90.82	21.9	93.80	22.6	98.43	23.7	103.44	24.9	107.35	25.9	110.15	26.5
67	EKEDC	IJORA	CUSTOM 1	22.2	38.33	19.7	39.59	20.4	41.55	21.4	43.66	22.5	45.31	23.3	46.50	23.9
68	EKEDC	IJORA	CUSTOM 11	2.2	3.19	16.6	3.29	17.1	3.46	17.9	3.63	18.9	3.77	19.6	3.87	20.1
69	EKEDC	IJORA	IJORA C/WAY 1	12.4	20.84	19.2	21.52	19.8	22.58	20.8	23.73	21.8	24.63	22.7	25.27	23.3
70	EKEDC	IJORA	IJORA C/WAY 11	40.6	63.18	17.8	65.26	18.3	68.47	19.3	71.96	20.2	74.68	21.0	76.63	21.5
71	EKEDC	IJORA	UBA/UBN	40.1	40.79	11.6	42.13	12.0	44.21	12.6	46.46	13.2	48.21	13.7	49.47	14.1
72	EKEDC	ISOLO	ISOLO LOCAL	40.0	59.80	17.1	61.77	17.6	64.81	18.5	68.11	19.4	70.69	20.2	72.53	20.7

(Table E-1 Continued)

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020 Energy (GWh)	2020 Peak (MW)	2021 Energy (GWh)	2021 Peak (MW)	2022 Energy (GWh)	2022 Peak (MW)	2023 Energy (GWh)	2023 Peak (MW)	2024 Energy (GWh)	2024 Peak (MW)	2025 Energy (GWh)	2025 Peak (MW)
73	EKEDC	ISOLO	NITEL	51.0	91.47	20.5	94.48	21.1	99.14	22.2	104.18	23.3	108.13	24.2	110.95	24.8
74	EKEDC	ISOLO	PTC	36.7	83.49	26.0	86.24	26.8	90.49	28.1	95.10	29.6	98.69	30.7	101.27	31.5
75	EKEDC	ITIRE	IJESHA	30.5	69.27	25.9	71.55	26.8	75.07	28.1	78.90	29.5	81.88	30.6	84.02	31.4
76	EKEDC	LEKKI	AGUNGI	26.4	79.02	34.2	81.62	35.3	85.64	37.0	90.00	38.9	93.41	40.4	95.85	41.4
77	EKEDC	LEKKI	ELEGUSHI	11.7	32.23	31.4	33.29	32.5	34.93	34.1	36.71	35.8	38.10	37.2	39.10	38.1
78	EKEDC	LEKKI	IGBO EFON	35.7	76.99	24.6	79.52	25.4	83.44	26.7	87.69	28.0	91.00	29.1	93.38	29.9
79	EKEDC	LEKKI	LEKKI	60.2	165.61	31.4	171.05	32.4	179.48	34.0	188.62	35.8	195.76	37.1	200.86	38.1
80	EKEDC	LEKKI	WATER FRONT	30.5	76.64	28.7	79.16	29.6	83.06	31.1	87.29	32.7	90.59	33.9	92.96	34.8
81	EKEDC	OJO	FESTAC 1 (OJO)	40.4	120.94	34.2	124.92	35.3	131.08	37.0	137.75	38.9	142.96	40.4	146.69	41.4
82	EKEDC	OJO	FESTAC 11 (OJO)	31.4	78.91	28.7	81.50	29.6	85.52	31.1	89.87	32.7	93.27	33.9	95.71	34.8
83	EKEDC	OJO	T1 15MVA OJO LOCAL	41.3	74.06	20.5	76.49	21.1	80.27	22.2	84.35	23.3	87.54	24.2	89.83	24.8
84	EKEDC	OJO	T2 15MVA OJO LOCAL	19.9	35.32	20.3	36.48	20.9	38.28	22.0	40.23	23.1	41.75	23.9	42.84	24.6
85	EKEDC	OJO	T3 15MVA OJO LOCAL	22.4	38.70	19.7	39.98	20.4	41.95	21.4	44.08	22.5	45.75	23.3	46.94	23.9
86	EKEDC	OJO	VOLKSWAGEN	24.6	82.51	38.3	85.22	39.5	89.43	41.5	93.98	43.6	97.54	45.3	100.08	46.4
87	EKEDC	AGBARA	New-01	30.0	0.00	0.0	0.00	0.0	20.99	8.0	42.04	16.0	49.82	19.0	49.25	18.7
88	EKEDC	AGBARA	New-02	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	20.52	7.8
89	EKEDC	AJAH	New-01	30.0	0.00	0.0	49.58	18.9	50.37	19.2	50.44	19.2	49.82	19.0	49.25	18.7
90	EKEDC	AJAH	New-02	30.0	0.00	0.0	30.99	11.8	50.37	19.2	50.44	19.2	49.82	19.0	49.25	18.7
91	EKEDC	AJAH	New-03	30.0	0.00	0.0	0.00	0.0	26.23	10.0	50.44	19.2	49.82	19.0	49.25	18.7
92	EKEDC	AJAH	New-04	30.0	0.00	0.0	0.00	0.0	0.00	0.0	31.53	12.0	49.82	19.0	49.25	18.7
93	EKEDC	AJAH	New-05	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	31.13	11.8	49.25	18.7
94	EKEDC	AJAH	New-06	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	30.78	11.7
95	EKEDC	ALAGBON	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	49.82	19.0	49.25	18.7
96	EKEDC	ALAGBON	New-02	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	20.76	7.9	49.25	18.7
97	EKEDC	ALAGBON	New-03	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	49.25	18.7
98	EKEDC	ALAGBON	New-04	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	49.25	18.7
99	EKEDC	LEKKI	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	47.29	18.0	49.82	19.0	49.25	18.7
100	EKEDC	LEKKI	New-02	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	31.13	11.8	49.25	18.7
101	EKEDC	LEKKI	New-03	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	20.52	7.8
102	EKEDC	ISOLO	New-01	30.0	0.00	0.0	49.58	18.9	50.37	19.2	50.44	19.2	49.82	19.0	49.25	18.7
103	EKEDC	ISOLO	New-02	30.0	0.00	0.0	49.58	18.9	50.37	19.2	50.44	19.2	49.82	19.0	49.25	18.7
104	EKEDC	ISOLO	New-03	30.0	0.00	0.0	0.00	0.0	47.22	18.0	50.44	19.2	49.82	19.0	49.25	18.7
105	EKEDC	ISOLO	New-04	30.0	0.00	0.0	0.00	0.0	0.00	0.0	21.02	8.0	49.82	19.0	49.25	18.7
106	EKEDC	ISOLO	New-05	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	46.17	17.6
107	EKEDC	ILASHE	New-01	30.0	0.00	0.0	0.00	0.0	20.99	8.0	26.27	10.0	31.13	11.8	35.91	13.7
108	EKEDC	EKO Atlantic	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	49.82	19.0	49.25	18.7
109	EKEDC	EKO Atlantic	New-02	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	49.25	18.7

Table E-2: Load Forecast by Feeder – IE

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020 Energy (GWh)	2020 Peak (MW)	2021 Energy (GWh)	2021 Peak (MW)	2022 Energy (GWh)	2022 Peak (MW)	2023 Energy (GWh)	2023 Peak (MW)	2024 Energy (GWh)	2024 Peak (MW)	2025 Energy (GWh)	2025 Peak (MW)
Total					**5,662.7**	**1,715.8**	**6,138.9**	**1,856.9**	**6,671.2**	**2,014.5**	**7,260.3**	**2,194.9**	**7,907.0**	**2,392.1**	**8,612.3**	**2,604.3**
1	IE	AKOKA	33-AkokaTCN-New Yaba	2.7	3.08	13.0	3.35	14.2	3.65	15.4	3.94	16.7	4.27	18.0	4.64	19.6
2	IE	AKOKA	33-AkokaTCN-T3	5.5	9.13	18.9	9.92	20.6	10.81	22.4	11.67	24.2	12.64	26.2	13.74	28.5
3	IE	ALAUSA	33-AlausaTCN-ALAUSA	45.0	107.88	27.4	117.25	29.7	127.74	32.4	137.97	35.0	149.37	37.9	162.46	41.2
4	IE	ALAUSA	33-AlausaTCN-MAGODO	47.8	66.86	16.0	72.68	17.4	79.18	18.9	85.52	20.4	92.58	22.1	100.70	24.0
5	IE	ALAUSA	33-AlausaTCN-OJODU	35.8	80.30	25.6	87.28	27.8	95.09	30.3	102.70	32.7	111.19	35.5	120.93	38.6
6	IE	ALAUSA	33-AlausaTCN-OPEBI	56.2	77.59	15.8	84.34	17.1	91.89	18.7	99.24	20.2	107.44	21.8	116.86	23.7
7	IE	ALAUSA	33-AlausaTCN-OPIC	47.6	76.24	18.3	82.86	19.9	90.28	21.7	97.50	23.4	105.56	25.3	114.81	27.5
8	IE	ALAUSA	33-AlausaTCN-T4	47.7	56.12	13.4	61.00	14.6	66.46	15.9	71.78	17.2	77.71	18.6	84.52	20.2
9	IE	ALAUSA	33-AlausaTCN-T5	39.5	42.42	12.3	46.11	13.3	50.23	14.5	54.25	15.7	58.74	17.0	63.89	18.5
10	IE	ALAUSA	33-AlausaTCN-T6	38.1	42.05	12.6	45.70	13.7	49.79	14.9	53.78	16.1	58.22	17.4	63.32	19.0
11	IE	ALIMOSHO	33-AlimoshoTCN-ADIYAN	38.7	51.22	15.1	55.67	16.4	60.66	17.9	65.51	19.3	70.92	20.9	77.14	22.8
12	IE	ALIMOSHO	33-AlimoshoTCN-AGEGE	36.0	108.44	34.4	117.87	37.4	128.41	40.7	138.69	44.0	150.15	47.6	163.31	51.8
13	IE	ALIMOSHO	33-AlimoshoTCN-IPAJA EKORO	46.1	110.09	27.3	119.66	29.6	130.36	32.3	140.80	34.9	152.43	37.7	165.79	41.1
14	IE	ALIMOSHO	33-AlimoshoTCN-T4	44.3	62.75	16.2	68.20	17.6	74.30	19.1	80.25	20.7	86.88	22.4	94.49	24.4
15	IE	ALIMOSHO	33-AlimoshoTCN-T6	33.5	44.61	15.2	48.49	16.5	52.83	18.0	57.05	19.4	61.77	21.0	67.18	22.9
16	IE	ALIMOSHO	33-AlimoshoTCN-T8	42.7	52.37	14.0	56.92	15.2	62.01	16.6	66.98	17.9	72.51	19.4	78.87	21.1
17	IE	ALIMOSHO	33-AlimoshoTCN-TOWER ALUMINIUM	33.1	52.54	18.1	57.10	19.7	62.21	21.5	67.19	23.2	72.74	25.1	79.12	27.3
18	IE	AMUWO	33-AmuwoTCN-AMUKOKO	41.2	65.69	18.2	71.40	19.8	77.79	21.6	84.02	23.3	90.96	25.2	98.93	27.4
19	IE	AMUWO	33-AmuwoTCN-FESTAC1	6.9	2.13	3.5	2.32	3.8	2.52	4.2	2.73	4.5	2.95	4.9	3.21	5.3
20	IE	AMUWO	33-AmuwoTCN-HONGXING 1	17.5	17.52	11.4	17.87	11.7	18.23	11.9	18.59	12.1	18.96	12.4	19.34	12.6
21	IE	AMUWO	33-AmuwoTCN-HONGXING 2	19.4	24.77	14.6	25.26	14.9	25.77	15.2	26.28	15.5	26.81	15.8	27.34	16.1
22	IE	AYOBO	33-AyoboTCN-ABESAN	43.3	110.23	29.1	119.82	31.6	130.54	34.4	140.98	37.2	152.63	40.2	166.01	43.8
23	IE	AYOBO	33-AyoboTCN-ABULE TAYLOR	36.6	56.65	17.7	61.58	19.2	67.09	20.9	72.46	22.6	78.45	24.5	85.32	26.6
24	IE	AYOBO	33-AyoboTCN-AIYETORO	39.2	94.07	27.4	102.25	29.8	111.39	32.4	120.31	35.0	130.25	37.9	141.67	41.3
25	IE	AYOBO	33-AyoboTCN-AMIKANLE	41.7	63.38	17.4	68.89	18.9	75.06	20.5	81.06	22.2	87.76	24.0	95.45	26.1
26	IE	EJIGBO	33-EjigboTCN-AGODO EGBE	48.8	85.64	20.0	93.09	21.8	101.42	23.7	109.53	25.6	118.58	27.7	128.98	30.2
27	IE	EJIGBO	33-EjigboTCN-AIRPORT	53.7	70.10	14.9	71.50	15.2	72.93	15.5	74.39	15.8	75.88	16.1	77.40	16.5
28	IE	EJIGBO	33-EjigboTCN-BOLORUNPELU	49.7	111.66	25.6	121.37	27.9	132.23	30.4	142.81	32.8	154.61	35.5	168.16	38.6
29	IE	EJIGBO	33-EjigboTCN-EGBE	47.8	136.37	32.6	148.22	35.4	161.49	38.6	174.41	41.7	188.82	45.1	205.37	49.0
30	IE	EJIGBO	33-EjigboTCN-OKEAFA 1	51.0	79.09	17.7	85.96	19.2	93.66	21.0	101.15	22.6	109.51	24.5	119.11	26.7

(Table E-2 Continued)

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020 Energy (GWh)	2020 Peak (MW)	2021 Energy (GWh)	2021 Peak (MW)	2022 Energy (GWh)	2022 Peak (MW)	2023 Energy (GWh)	2023 Peak (MW)	2024 Energy (GWh)	2024 Peak (MW)	2025 Energy (GWh)	2025 Peak (MW)
31	IE	EJIGBO	33-EjigboTCN-OKEAFA 2	33.2	61.12	21.0	66.43	22.8	72.38	24.9	78.17	26.9	84.63	29.1	92.05	31.7
32	IE	EJIGBO	33-EjigboTCN-SHASHA	31.9	37.00	13.2	40.22	14.4	43.82	15.7	47.32	16.9	51.24	18.3	55.73	19.9
33	IE	EJIGBO	33-EjigboTCN-IGANDO	47.3	103.86	25.1	112.89	27.2	122.99	29.7	132.83	32.1	143.81	34.7	156.42	37.8
34	IE	EJIGBO	33-EjigboTCN-IJEGUN	39.9	87.54	25.0	95.15	27.2	103.66	29.7	111.96	32.0	121.21	34.7	131.83	37.7
35	IE	IKORODU	33-IkoroduTCN-AGBOWA	30.8	103.92	38.5	112.95	41.9	123.06	45.6	132.90	49.3	143.89	53.3	156.50	58.0
36	IE	IKORODU	33-IkoroduTCN-DANGOTE	21.5	8.50	4.5	8.67	4.6	8.84	4.7	9.02	4.8	9.20	4.9	9.38	5.0
37	IE	IKORODU	33-IkoroduTCN-FAKALE Source	17.3	30.87	20.4	33.55	22.1	36.56	24.1	39.48	26.1	42.75	28.2	46.49	30.7
38	IE	IKORODU	33-IkoroduTCN-IBESHE	47.0	89.36	21.7	97.13	23.6	105.82	25.7	114.29	27.8	123.73	30.1	134.58	32.7
39	IE	IKORODU	33-IkoroduTCN-IGBOGBO	35.0	81.59	26.6	88.68	28.9	96.61	31.5	104.35	34.0	112.97	36.8	122.87	40.1
40	IE	IKORODU	33-IkoroduTCN-IJEDE	36.4	131.73	41.3	143.18	44.9	155.99	48.9	168.47	52.8	182.39	57.2	198.38	62.2
41	IE	IKORODU	33-IkoroduTCN-INDUSTRIAL	36.6	87.56	27.3	95.17	29.7	103.69	32.3	111.98	34.9	121.24	37.8	131.86	41.1
42	IE	IKORODU	33-IkoroduTCN-OWUTU	38.7	92.53	27.3	100.57	29.7	109.57	32.3	118.34	34.9	128.12	37.8	139.34	41.1
43	IE	IKORODU	33-IkoroduTCN-PULKIT	9.3	11.43	14.0	11.66	14.3	11.90	14.6	12.13	14.9	12.38	15.2	12.62	15.5
44	IE	IKORODU	33-IkoroduTCN-SPINTEX	13.3	20.41	17.5	20.82	17.9	21.23	18.2	21.66	18.6	22.09	19.0	22.53	19.3
45	IE	IKORODU	33-IkoroduTCN-T1A	61.4	78.33	14.6	85.14	15.8	92.76	17.2	100.18	18.6	108.46	20.2	117.97	21.9
46	IE	IKORODU	33-IkoroduTCN-T2A	70.4	91.14	14.8	99.07	16.1	107.93	17.5	116.57	18.9	126.20	20.5	137.26	22.3
47	IE	IKORODU	33-IkoroduTCN-UNTL	16.3	5.00	3.5	5.10	3.6	5.20	3.6	5.30	3.7	5.41	3.8	5.52	3.9
48	IE	ILUPEJU	33-IlupejuTCN-ILUPEJU BY-PASS	46.4	60.90	15.0	66.19	16.3	72.11	17.7	77.88	19.2	84.32	20.7	91.71	22.6
49	IE	ILUPEJU	33-IlupejuTCN-ILUPEJU IGBOBI	40.4	81.20	22.9	88.26	24.9	96.16	27.2	103.85	29.3	112.43	31.8	122.29	34.6
50	IE	ILUPEJU	33-IlupejuTCN-T4A	17.5	18.07	11.8	19.64	12.8	21.40	14.0	23.11	15.1	25.02	16.3	27.21	17.8
51	IE	ILUPEJU	T1 ILUPEJU	20.3	21.68	12.2	23.57	13.3	25.68	14.4	27.73	15.6	30.02	16.9	32.66	18.4
52	IE	ILUPEJU	T3 ILUPEJU	20.1	24.48	13.9	26.61	15.1	28.99	16.5	31.31	17.8	33.90	19.3	36.87	20.9
53	IE	ISOLO	33-IsoloTCN- AJAO	45.3	117.63	29.6	127.86	32.2	139.30	35.1	150.44	37.9	162.88	41.0	177.15	44.6
54	IE	ISOLO	33-IsoloTCN-AFPRINT	36.8	2.10	0.7	2.14	0.7	2.18	0.7	2.23	0.7	2.27	0.7	2.32	0.7
55	IE	ISOLO	33-IsoloTCN-AIRPORT	5.3	6.21	13.4	6.34	13.6	6.46	13.9	6.59	14.2	6.72	14.5	6.86	14.8
56	IE	ISOLO	33-IsoloTCN-PTC	45.1	87.18	22.1	94.75	24.0	103.23	26.1	111.49	28.2	120.71	30.6	131.29	33.2
57	IE	ISOLO	33-IsoloTCN-ASWANI	40.0	0.00	0.0	0.01	0.0	0.01	0.0	0.01	0.0	0.01	0.0	0.01	0.0
58	IE	ITIRE	33-ItireTCN-AGO I	42.1	87.56	23.7	95.17	25.8	103.69	28.1	111.98	30.4	121.24	32.9	131.87	35.8
59	IE	ITIRE	33-ItireTCN-AGO II	23.4	36.19	17.7	39.34	19.2	42.86	20.9	46.29	22.6	50.12	24.4	54.51	26.6
60	IE	ITIRE	33-ItireTCN-ITIRE 1	41.4	82.48	22.7	89.65	24.7	97.67	26.9	105.48	29.1	114.20	31.5	124.21	34.2

(Table E-2 Continued)

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020 Energy (GWh)	2020 Peak (MW)	2021 Energy (GWh)	2021 Peak (MW)	2022 Energy (GWh)	2022 Peak (MW)	2023 Energy (GWh)	2023 Peak (MW)	2024 Energy (GWh)	2024 Peak (MW)	2025 Energy (GWh)	2025 Peak (MW)
61	IE	ITIRE	33-ItireTCN-T3A	34.7	39.55	13.0	42.99	14.1	46.83	15.4	50.58	16.6	54.76	18.0	59.56	19.6
62	IE	MARYLAND	33-MarylandTCN-AJEGUNLE	25.3	51.16	23.1	55.61	25.1	60.59	27.3	65.43	29.5	70.84	32.0	77.05	34.8
63	IE	MARYLAND	33-MARYLANDTCN-ALAUSA	43.4	98.43	25.9	106.98	28.1	116.55	30.7	125.88	33.1	136.29	35.8	148.23	39.0
64	IE	MARYLAND	33-MarylandTCN-PTC	52.3	144.33	31.5	156.88	34.2	170.92	37.3	184.59	40.3	199.85	43.6	217.36	47.4
65	IE	MARYLAND	33-MarylandTCN-T1A	48.2	65.04	15.4	70.69	16.7	77.02	18.2	83.18	19.7	90.05	21.3	97.95	23.2
66	IE	MARYLAND	33-MarylandTCN-T2A	48.8	62.84	14.7	68.31	16.0	74.42	17.4	80.37	18.8	87.02	20.4	94.64	22.1
67	IE	MARYLAND	33-MarylandTCN-T3A	31.6	39.20	14.2	42.60	15.4	46.41	16.8	50.13	18.1	54.27	19.6	59.03	21.3
68	IE	ODOGUNYAN	33-OdogunyanTCN-Agbede	28.4	53.96	21.7	58.65	23.6	63.90	25.7	69.01	27.7	74.71	30.0	81.26	32.7
69	IE	ODOGUNYAN	33-OdogunyanTCN-Chiki Chiki	3.7	3.53	10.9	3.83	11.8	4.17	12.9	4.51	13.9	4.88	15.1	5.31	16.4
70	IE	ODOGUNYAN	33-OdogunyanTCN-Mega Steel	1.9	3.51	21.1	3.82	22.9	4.16	25.0	4.49	27.0	4.86	29.2	5.29	31.8
71	IE	ODOGUNYAN	33-OdogunyanTCN-Odogunyan	34.8	60.29	19.8	61.50	20.2	62.73	20.6	63.98	21.0	65.26	21.4	66.57	21.8
72	IE	OGBA	33-OgbaTCN-ABEOKUTA EXP.	45.8	109.62	27.3	119.15	29.7	129.81	32.4	140.20	34.9	151.78	37.8	165.08	41.1
73	IE	OGBA	33-OgbaTCN-CISCO	46.3	110.85	27.3	120.48	29.7	131.26	32.4	141.76	35.0	153.48	37.8	166.93	41.2
74	IE	OGBA	33-OgbaTCN-FEEDER 2	26.1	38.41	16.8	41.75	18.3	45.49	19.9	49.13	21.5	53.19	23.3	57.85	25.3
75	IE	OGBA	33-OgbaTCN-FEEDER 8	42.2	103.63	28.0	112.63	30.5	122.71	33.2	132.53	35.9	143.48	38.8	156.06	42.2
76	IE	OGBA	33-OgbaTCN-IJU WATER WORKS	21.1	7.78	4.2	8.45	4.6	9.21	5.0	9.95	5.4	10.77	5.8	11.71	6.3
77	IE	OGBA	33-OgbaTCN-PTC DUNLOP	36.7	40.10	12.5	43.58	13.6	47.48	14.8	51.28	16.0	55.52	17.3	60.38	18.8
78	IE	OGBA	33-OgbaTCN-PTC EXP.	20.6	32.91	18.2	35.77	19.8	38.97	21.6	42.09	23.3	45.57	25.3	49.56	27.5
79	IE	OGBA	33-OgbaTCN-SANKYO	24.8	13.04	6.0	13.30	6.1	13.57	6.2	13.84	6.4	14.12	6.5	14.40	6.6
80	IE	OGBA	33-OgbaTCN-UNIVERSAL STEEL	13.6	5.01	4.2	5.44	4.6	5.93	5.0	6.41	5.4	6.94	5.8	7.54	6.3
81	IE	OJO	33-OjoTCN-FESTAC II INTERFACE	40.5	11.18	3.2	12.15	3.4	13.24	3.7	14.30	4.0	15.48	4.4	16.84	4.7
82	IE	OKE ARO	33-Oke-AroTCN-AKUTE	42.9	84.27	22.4	91.60	24.4	99.79	26.6	107.78	28.7	116.68	31.0	126.91	33.8
83	IE	OKE ARO	33-Oke-AroTCN-LAMBE	36.4	44.68	14.0	48.57	15.2	52.91	16.6	57.14	17.9	61.87	19.4	67.29	21.1
84	IE	OKE ARO	33-Oke-AroTCN-NEW IJU W/WORKS	54.1	122.78	25.9	133.45	28.2	145.39	30.7	157.03	33.1	170.01	35.9	184.91	39.0
85	IE	OKE ARO	33-Oke-AroTCN-YIDI	38.4	91.76	27.3	99.74	29.7	108.66	32.3	117.36	34.9	127.06	37.8	138.20	41.1
86	IE	OTTA	33-OtaTCN-AMJE	44.8	127.82	32.6	138.93	35.4	151.36	38.6	163.48	41.7	176.99	45.1	192.50	49.1
87	IE	OWORO	33-OworonshokiTCN-CHEVRON	50.0	79.16	18.1	86.04	19.6	93.73	21.4	101.24	23.1	109.60	25.0	119.21	27.2
88	IE	OWORO	33-OworonshokiTCN-IGBOBI	38.2	67.51	20.2	73.38	21.9	79.94	23.9	86.34	25.8	93.47	27.9	101.67	30.4
89	IE	OWORO	33-OworonshokiTCN-OGUDU 1	54.8	133.72	27.9	145.35	30.3	158.35	33.0	171.02	35.6	185.16	38.6	201.38	42.0
90	IE	OWORO	33-OworonshokiTCN-OWORO 1	48.2	63.29	15.0	68.79	16.3	74.94	17.7	80.94	19.2	87.63	20.8	95.31	22.6

(Table E-2 Continued)

No	DISCO	Transformation Station	Feeder	Presumed LF (%)	2020 Energy (GWh)	2020 Peak (MW)	2021 Energy (GWh)	2021 Peak (MW)	2022 Energy (GWh)	2022 Peak (MW)	2023 Energy (GWh)	2023 Peak (MW)	2024 Energy (GWh)	2024 Peak (MW)	2025 Energy (GWh)	2025 Peak (MW)
91	IE	OWORO	33-OworonshokiTCN-OWORO 2	14.5	18.66	14.7	20.28	16.0	22.10	17.4	23.87	18.8	25.84	20.3	28.10	22.1
92	IE	OWORO	33-OworonshokiTCN-NEW OWORO	22.6	26.12	13.2	28.39	14.3	30.93	15.6	33.40	16.9	36.16	18.3	39.33	19.9
93	IE	MARYLAND	33-IPAKODO	30.0	0.00	0.0	0.00	0.0	0.00	0.0	27.00	10.3	51.97	19.8	52.21	19.9
94	IE	MARYLAND	New-02	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
95	IE	MARYLAND	New-03	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
96	IE	OGBA	DANGOTE	30.0	0.00	0.0	0.00	0.0	0.00	0.0	43.20	16.4	43.31	16.5	43.51	16.6
97	IE	EPE	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	43.31	16.5	52.21	19.9
98	IE	EPE	New-02	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	32.63	12.4
99	IE	IE-TF-D	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
100	IE	IE-TF-D	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
101	IE	IE-TF-E	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
102	IE	IE-TF-F	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
103	IE	IE-TF-G	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
104	IE	IE-TF-H	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
105	IE	IE-TF-I	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
106	IE	IE-TF-J	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
107	IE	IE-TF-K	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
108	IE	IE-TF-L	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
109	IE	IE-TF-M	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
110	IE	IE-TF-N	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
111	IE	IE-TF-O	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
112	IE	IE-TF-P	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
113	IE	IE-TF-Q	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
114	IE	IE-TF-R	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
115	IE	IE-TF-S	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
116	IE	IE-TF-T	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
117	IE	IE-TF-U	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
118	IE	IE-TF-V	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
119	IE	IE-TF-W	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
120	IE	IE-TF-X	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0
121	IE	IE-TF-Y	New-01	30.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0	0.00	0.0

APPENDIX F: LIST OF MOST RELEVANT DOCUMENTS GOVERNING ELECTRICITY SUPPLY INDUSTRY

1) National Energy Policy, published in 2003, revised in 2018 (draft)
2) Sustainable Energy for All Action Agenda (SE4ALL-AA), Federal Republic of Nigeria, July 2016
3) The Grid Code for the Nigeria Electricity Transmission System – Version 03, NERC
4) Market Rules for Transitional and Medium-Term Stages of the Nigerian Electricity Supply Industry, December 2014
5) The Distribution Code for the Nigeria Electricity Distribution System – Version 02, NERC
6) CAP. E10 – Energy Commission of Nigeria Act
7) National Electric Power Policy 2001
8) National Energy Policy, published in 2003, revised in 2018 (draft)
9) Electric Power Sector Reform Act, 2005, including legislation regarding Electricity (Private Licenses), Electricity (Annual Returns), and Electricity Installation
10) Guidelines for Obtaining Clearance Certificate for the Importation of Generating Sets and Related Matters, 2011, NERC
11) Permits for Captive Power Generation Regulations, 2008, NERC
12) NERC (Embedded generation) Regulations, 2012
13) NERC (Acquisition of Land and Access Rights for Electricity Projects) Regulations, 2012
14) Guidelines on National Content Development for NESI, 2013, NERC or newer version
15) Regulations on National Content Development for the Power Sector, 2014, NERC
16) Electricity Industry Enforcement Regulation, 2014, NERC
17) Nigeria Electricity Supply and Installation Standards Regulations, 2015, NERC
18) Generation Procurement Guidelines, 2014, NERC
19) Regulations for Investment in Electricity Network in Nigeria, 2015, NERC
20) Feed in Tariff for Renewable Energy Sourced Electricity in Nigeria, 2015, NERC
21) Market Rules for Transitional and Medium-Term Stages of the Nigerian Electricity Supply Industry, December 2014
22) Environmental Protection Act/Regulations

APPENDIX G: EXAMPLE TABLE OF CONTENTS FOR A LONG-TERM LOAD FORECAST MANUAL

The Table of Contents of a long-term load forecast manual might include the following contents:

1 Introduction
2 Long-term load forecasting process
3 Service area and study time horizon
4 Customer data
5 Forecasting approaches and concepts
    i Top-down approach
    ii Bottom-up approach
    iii Scenario writing
    iv Scenario generation
    v Aggregated approach
    vi Disaggregated approach
6 Selection of methods/models of energy demand forecast
    i Time series method
    ii Econometric method
    iii Regression method
    iv End-use method
    v Survey-based method
7 Collection of external data
8 Other important factors, which may not be included in the model (including import/export contracts, step load, switch from self-generation, distributed generation, DSM programs)
9 Preparation of long-term load forecast
    i Levels for load forecasting
        - Nation/state/region
        - Substation/area/zone
        - Feeder/township/municipality
    ii Forecast scenarios
        - Most likely
        - Low growth
        - High growth
10 Conclusions

APPENDIX H: EXAMPLE TABLE OF CONTENTS FOR A GENERATION PLANNING MANUAL

The Table of Contents of a generation planning manual might include the following contents:

1) Introduction
2) Definition for key terms
3) Roles and responsibilities
4) Establishment of key parameters and assumptions – study area, study horizon, base year for cost estimate and present value calculation, discount rate, etc.
5) Generation planning criteria and values to be used, including technical, economic, and environmental
6) Generation planning software tools to be used
7) Gap analysis between the existing and committed generation system and the future requirements on generation capacity
8) Formulation of generation development themes/cases/scenarios taking into account regulations, government policies, energy development strategy/directives, resources availability and delivery, renewable energy requirement, rural electrification, etc.
9) Evaluation of generation development themes/cases/scenarios and ranking them according to the total cost expressed in present value
10) Sensitivity and risk analysis when necessary
11) Determination of generation least-cost plan taking into account financial constraints when necessary
12) Capital investment cash flow of the least-cost generation development plan
13) Implementation plan
14) Conclusions

APPENDIX I: EXAMPLE TABLE OF CONTENTS FOR A TRANSMISSION PLANNING MANUAL

The Table of Contents of a transmission planning manual might include the following contents:

1) Introduction
2) Definition for key terms
3) Roles and responsibilities
4) Establishment of key parameters and assumptions – study area, study horizon, base year for cost estimate and present value calculation, discount rate, etc.
5) Criteria and standards (such as frequency and/or voltage variation range under normal and/or stress system operation conditions, power factor of load, etc.) for technical studies, taking into account load representation, modeling, voltage limits, and line/transformer loading limits
    i) Criteria for analysis – Different criteria may be required for different generation technologies, such as wind, solar, hydro, coal, nuclear, geothermal, biomass, gas turbine, gas turbine combined cycle, RICE (reciprocal internal combustion engine), and for different transmission line types (AC and DC)
        a) Steady-state stability, including N-1 and other contingencies
        b) Dynamic stability
        c) Short circuit
        d) Voltage stability
        e) Frequency stability
        f) Power quality
        g) Harmonics
    ii) Criteria for substation planning
    iii) Reliability standards
    iv) Remedial actions
    v) Reactive power compensation
    vi) Load shedding
6) Simulation tools to be used and system modeling
7) Identification of transmission system expansion alternatives
8) Cost estimate of transmission line and substation options
9) Approach/methodology for evaluation of transmission system expansion alternatives
10) Determination of the best transmission system expansion plan

APPENDIX J: EXAMPLE TABLE OF CONTENTS FOR A DISTRIBUTION PLANNING MANUAL

The Table of Contents of a distribution planning manual might include the following contents:

1) Introduction
2) Definition for key terms
3) Roles and responsibilities
4) Establishment of key parameters and assumptions – study area, study horizon, base year for cost estimate and present value calculation, discount rate, etc.
5) Criteria and standards (such as voltage variation range under normal and/or stress system operation conditions, power factor of load, etc.) for technical studies, taking into account load representation, modeling, voltage limits, and feeder/transformer loading limits, which could include:
    i) Power flow analysis
    ii) Power quality analysis
    iii) Fault analysis
    iv) Dynamic analysis
6) Simulation tools to be used and system modeling
7) Identification of feeder/substation reinforcement/upgrade/addition
8) Cost estimate of feeder and substation options
9) Approach/methodology for evaluation of feeder/substation reinforcement/upgrade/addition
10) Determination of the best distribution system expansion plan