Republic of Angola
Ministry of Energy and
Water Affairs

The Project for Power Development Master Plan in the Republic of Angola

Final Report

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Japan International Cooperation Agency (JICA)

Tokyo Electric Power Services Co., Ltd.(TEPSCO)

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【Table of Contents】

【List of Figures】

【List of Tables】

【Abbreviations】

Abbreviation	Word
ACCC	All Aluminium Alloy Conductor
AC	Alternating Current
ACSR	Aluminum Conductors Steel Reinforced
AGC	Automatic Generation Control
AOA	Angolan Kwanza
ARAP	Abbreviated Resettlement Action Plan
ATP	Alternative Transient Program
AfDB	African Development Bank
BAU	Business as Usual
bbl	Barrel
BOD	Biochemical Oxygen Demand
BOT	Build-Operate-Transfer
BP	British Petroleum
bp	Base Point
bpd	barrel per day
B/S	Balance Sheet
C/C	Combined Cycle
C/P	Counterpart
CCGT	Combined Cycle Gas Turbine
CCPP	Combined Cycle Power Plant
CIRR	Commercial Interest Reference Rates
CMEC	China Machinary Engineering Corporation
CO_2	Carbon Dioxide
COP	Conference of the Parties
CR	Critically Endangered
CRF	Capital Recovery Factor
DAC	Development Assistance Committee
DC	Direct Current
DES	Debt Equity Swap
DFR	Draft Final Report
DG	Diesel Generator
DNA	National Directorate of Water
DNEE	National Directorate of Electric Energy
DNER	National Directorate of Renewable Energies
DNERL	National Directorate of Rural and Local Electrification
DNPAIA	National Deirectorate for Prevention and Environmental Impact Assessment
DR Congo	Democratic Republic of the Congo
ECA	Export Credit Agency
EDEL	Empresa de Electricidade de Luanda
EFL	Environmental Framework Law
EIA	Environmental Impact Assessment
EIRR	Economic Internal Rate of Return
EMMP	Environmental Monitoring Plan
EMP	Environmental Management Plan
EMTP	Electromagnetic Transient Program
EN	Endangered
ENDE	National Electricity Distribution Company
ENE	Empresa Nacional de Electricidade

Abbreviation	Word
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
EU	European Union
EUR	Euro
F/S	Feasibility Study
FIRR	Financial Internal Rate of Return
FR	Final Report
GABHIC	Gabinete Para a Administração da Bacia Hidroeléctrica do Cunene
GAMEK	Gabinete de Abinete de Aproveintamento do Médio Kwanza
GDP	Gross Domestic Product
GE	General Electric Company
GHG	Green House Gas
GIB	Gas Insulated Busbars
GIS	Gas Insulated Switchgear
GIS	Geographic Information System
GIT	Gas Insulated Transformer
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt hour
HFO	Heavy Fuel Oil
HPP	Hydropower Plant
HPS	Hydropower Station
HQ	Headquarters
HRSG	Heat Recovery Steam Generator
HV	High Voltage
IDC	Interest during Construction
IEA	International Energy Agency
IMF	International Monetary Fund
INDC	Intended Nationally Determined Contribution
INE	Instituto Nacional de Estatística
I/P	Implementation Report
IPP	Independent Power Producer
IRR	Internal Rate of Return
IRSEA	Instituto Regulador dos Servicos de Electricidate e Agua
IUCN	International Union for Conservation of Nature
Ic/R	Inception Report
It/R	Interim Report
JBIC	Japan Bank for International Corporation
JCC	Joint Coordination Committee
JICA	Japan International Cooperation Agency
JOGMEC	Japan Oil, Gas and Metals National Corporation
JPY	Japanese Yen
JV	Joint Venture
km	Kilometer
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
kt-CO2e	Kiloton of Carbon Dioxide Equivalent
L/A	Loan Agreement
LFO	Light Fuel Oil
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas
LOLE	loss of load expectation

Abbreviation	Word
LOLP	Loss of Load Probability
LPG	liquefied petroleum gas
LRMC	Long-run Marginal Cost
LV	Low Voltage
Mcal	Mega clorie
MINEA	Ministry of Energy and Water Resources
MMBTU	Million British Thermal Unit
MOEF	Ministry of Environment and Forestry
MOU	Memorandum of Understanding
MScfpd	Million Standard cubic feet per day
MUS$	Million U.S. dollar
MVA	Mega volt ampere
MW	Megawatt
NDP	National Development Plan
NESSP	National Power Security Strategy and Policy
NEXI	Nippon Export and Investment
NG	Natural Gas
NGO	Non-Governmental Organization
NLDC	National Load Dispatch Center
O&M	Operation and Maintenance
ODA	Official Development Assistance
OECD	Organisation for Economic Co-operation and Development
OJT	On-the-Job Training
OPGW	Optical Fiber Ground Wire
OVPS	Overvoltage Protectors
PAP	Project Affected People
PDMP	Power Development Master Plan
PDPAT	Power Development Planning Assist Tool
PIL	Private Investment Law
P/L	Profit and Loss Statement
PPP	Public Plivate Partnership
PRODEL	Public Electricity Production Company
PSRSP	Power Sector Reform Suport Program
PSS/E	Power System Simulator for Engineering
PTSE	Electricity Sector Transformation Program
p.u.	per unit
PV	Photovoltaic Power Generation
RETICS	Reliability Evaluation Tool for Inter-conneted System
RNT	National Electricity Transportation Company
ROA	Return on Assets
ROW	Right of Way
SAPP	Southern African Power Pool
SAF	Special Assistance Facility
SAPI	Special Assistance for Project Implementation
SAPROF	Special Assistance for Project Formation
SAPS	Special Assistance for Project Sustainability
SCADA	Supervisory Control and Data Acquisition
SEA	Strategic Environmental Assessment
SGL	Sovereign Guarantee Loan
SHM	Stakeholder Meeting
SS	Substation
ST	Steam Turbine
T/L	Transmission Line

Abbreviation	Word
TEPCO	Tokyo Electric Power Company
TEPSCO	Tokyo Electric Power Service Company
TOR	Terms of Reference
TPP	Thermal Power Plant
TWh	Terawatt Hour
UNDP	United Nation Development Programme
UNFCC	United Nations Framework Convention on Climate Change
USD	U.S. Dollar
UXO	Unexploded Ordenance
VU	Vulnerable
WB	World Bank

Summary

1. Purpose of the Survey

The purpose of this Survey is to produce a master plan for the generation and transmission development of the whole of Angola up to the year 2040, and thereby contribute to the smooth implementation of power development to enable a stable power supply for the country. In the course of the survey, the Survey Team will seek to:

- Formulate a comprehensive power development master plan (2018-2040) encompassing nationwide generation development plans and transmission development plans.
- Promote a sufficient understanding of the master plan by related organizations (MINEA, RNT, PRODEL, ENDE) and build up the capacity of personnel in related organizations to formulate and revise power development master plans.

2. Activities

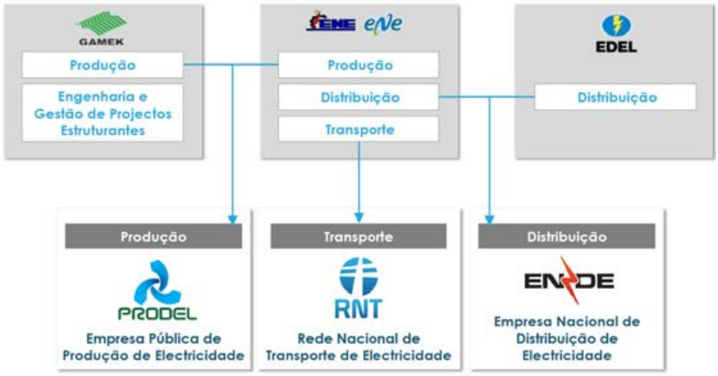
- Preparations at home and Discussion and Consultation on the Inception Report
- Review of the current situation in the power sector
- Power demand forecast
- Analysis on primary energy sources for generation development
- Formulation of a generation development plan based on an optimal power generation mix
- Study on optimization of the transmission system development plan
- Review of the framework and implementation of private investment
- Formulation of a long-term investment plan
- Economic and financial analysis
- Environmental and social considerations
- Drafting of the Master Plan
- Capacity building

3. Review of the Current Situation in the Power Sector

3.1 Social & Economic Situation

Item	Number
Occupied Area	1,246,700km^2
Population	25,900,000 (year 2014, source: MINEA）
GDP	103 Billion USD (WB ： year 2015)

3.2 Current Status of the Power Sector



(Sources: The Transformation Program for the Electricity Sector-PTSE)

The Angola Electricity Sector is undergoing organizational reforms under the Electricity Sector Transformation Program (PTSE).

MINEA has reorganized GAMEK, ENE and EDEL into three new public companies, i.e., the power generation company PRODEL, the power transmission company RNT, and the electricity distribution company ENDE.

A PTSE roadmap on sector reform recommends the following based on a study the PTSE performed on an optimum model for the electricity market: a restructuring of the market into a classic single-buyer model, an unbundling of the power utilities into Generation, Transmission, and Distribution core activities, the establishment of commercial contracts among market participants, and amendments to the laws to improve the regulations and attract PPP. The study further proposed four (4) reform phases, each with specific deliverables:

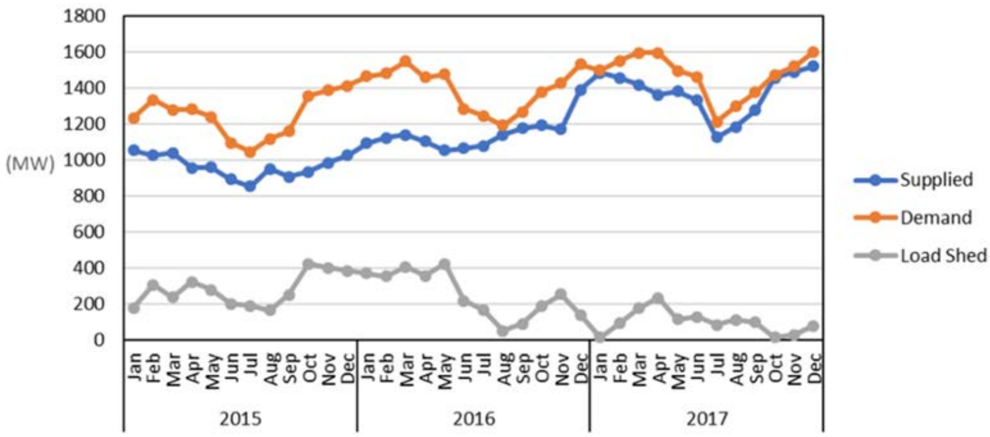
(i) Preparation Phase (2010-2013) for the design of a new market structure;

(ii) Phase I (2014- 2017), a stabilization phase following the sector restructuring and unbundling of the power utilities;

(iii) Phase II (2018-2021), transition to efficient operation with limited use of IPPs, mainly in RE using RE Feed-In tariffs;

(iv) Phase III (2021-2025), partial liberalization of the power market with the introduction of the PPP and IPPs and limited concessions for the distribution system.

3.3 Record of Power Demand & Supply



(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Figure Monthly Maximum Demand and Load-shedding Results (North System)

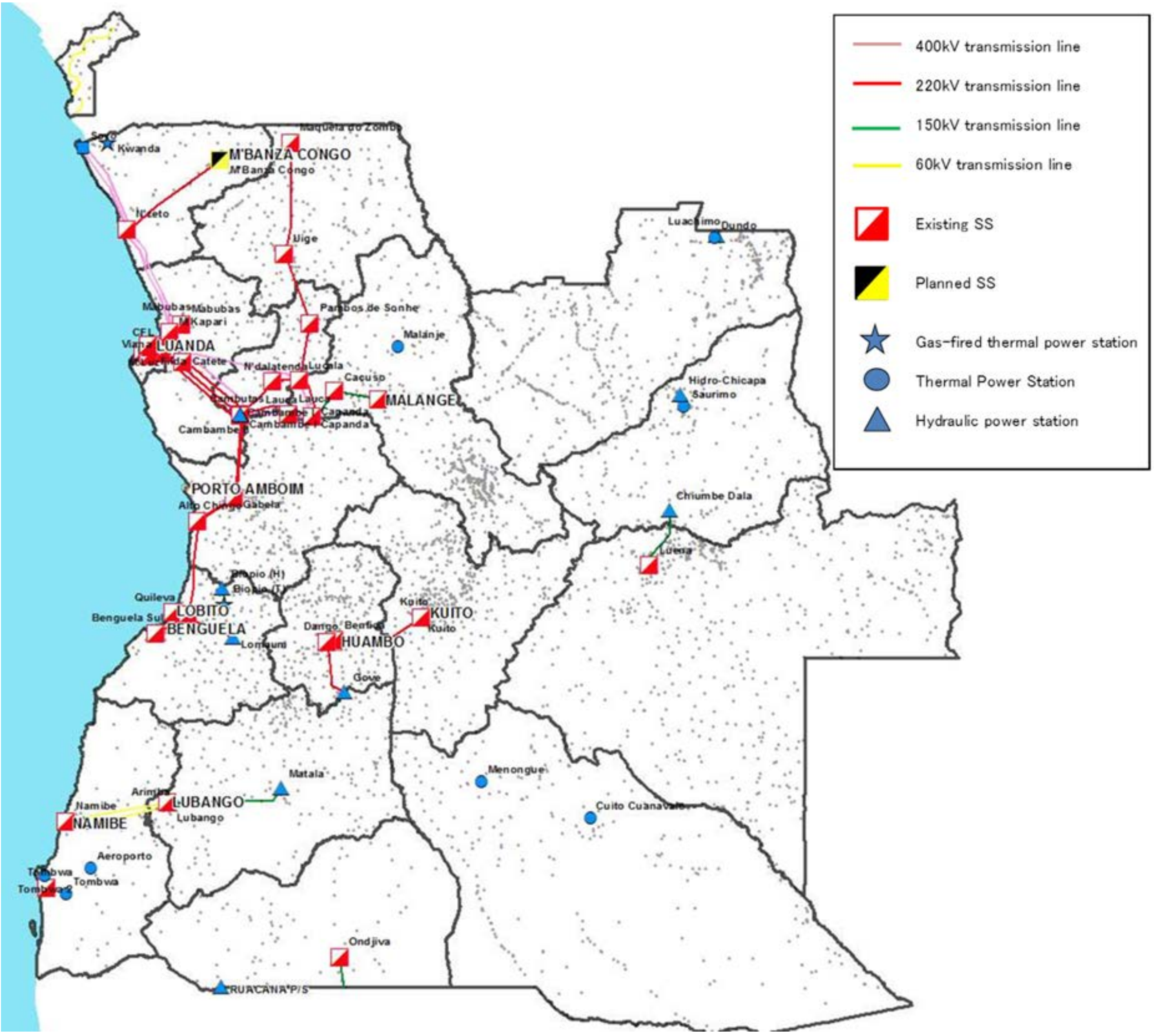
3.4 Existing power plants

Table Major power generation plants by region and type (MW)

Region	Total	Hydropower (except small)	Thermal Power		Renewable		
			GT	Diesel	Biomass	Wind	Solar PV
Whole Country	**4,339**	**2,365**	**1,181**	**743**	**50**	**0**	**0**
North Region	3,527	2,172	899	407	50	0	0
Central Region	492	125	254	113	0	0	0
South Region	221	41	28	152	0	0	0
East Region	99	28	0	71	0	0	0

(Source: Prepared by the JICA Survey Team based on Data from PRODEL, MINEA)

3.5 Current power system in Angola

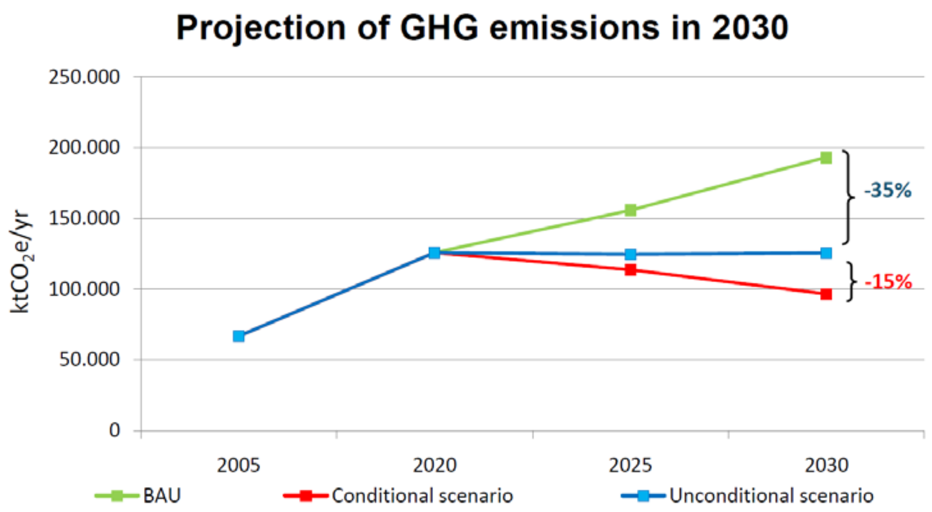


(Source: RNT)

Figure Transmission system map of Angola (July 2017)

3.6 Angolan Policy on Climate Change Measures (INDC etc.)

The country is committed to stabilizing its emissions by reducing GHG emissions by up to 50% below the BAU emission levels by 2030 through unconditional and conditional actions.



<table>
<tr><th></th><th>2005</th><th>2020</th><th>2030</th></tr>
<tr><td>Emissions-BAU scenario ($ktCO_2e$)</td><td rowspan="3">66,812</td><td rowspan="3">125,778</td><td>193,250</td></tr>
<tr><td>Emissions-Unconditional scenario ($ktCO_2e$)</td><td>125,612 (-35%)</td></tr>
<tr><td>Emissions-Conditional scenario ($ktCO_2e$)</td><td>96,625 (-50%)</td></tr>
</table>

(source：DRAFT INDC of the Republic of Angola)

Figure Baseline scenario and projections of unconditional and conditional mitigation scenarios in Angola

4. Primary Energy Analysis for Power Development

4.1 The potential of primary energy

Primary energy	Potential
Crude oil	Confirmed crude oil reserves: 12.7 billion barrels (BP statistics at the end of 2014)
Natural gas	Confirmed natural gas reserves in Angola: total 9.7 trillion cubic feet (2014, Cedigaz)
Hydropower	Hydropower Potential: 18GW (Atras and National Strategy for the new Renewable Energies)
Solar energy	17.3GW (Atras and National Strategy for the new Renewable Energies)
Wind energy	3.9GW (Angola Energia 2025)
Biomass	4GW (Angola Energia 2025)

4.2 Status of energy supply facilities

(1) LNG Production Facilities

The Angola LNG plant located in Soyo of Zair State is the only LNG production facility in Angola. Petroleum-associated gas obtained as a result of oil extraction is sent to this facility in a pipeline and processed within the facility to LNG. The Angola LNG production facility has a capacity to produce 34 MSm33/d.

(2) Oil Refinery

The only oil refinery currently established in Angola is the Luanda Refinery in the capital city Luanda. Angola's oil refining capacity is therefore insufficient relative to the national consumption of petroleum products. Currently, more than 80% of the consumption is covered by imported products.

Sonangol has formulated a plan to build new refineries in Lobito in central Angola, in Soyo and Cabinda in northern Angola, and in Namibe in southern Angola. The refinery plan at Lobito was scheduled to commence in 2018, but construction was halted in August 2016 due to a lack of funds. The Soyo refinery plan was launched but never reached the construction phase. Construction for the Namibe refinery was commenced in July 2017 and is currently proceeding.

In February 2018, Sonangol announced new oil refinery development plans in Lobito and Cabinda and expansion plans for the existing Luanda Refinery. Under the Lobito plan, a facility with a 200,000 bpd/day capacity (unchanged from the previous plan) will be completed by 2022. Under the Cabinda plan, a smaller refinery than that in Lobito will be completed by 2020. The expansion plan for the existing Luanda Refinery aims to expand production from the current 57,000 bpd/day to 65,000 bpd/day by 2020.

4.3 Fuel Price

Studies for long-term power development planning require that future fuel prices be set for thermal power. For this purpose, we adopt future fuel prices based on the current international price and IEA's long-term forecast under the New Policy Scenario (see the Table below).

Table Fuel prices for development planning

unit: UScents/Mcal

Year	CrudeOil	LFO	HFO	LPG	NG	LNG
2015	3.281	3.948	3.919	4.041	1.036	4.087
2020	5.082	6.116	6.071	6.259	1.633	3.810
2025	6.111	7.354	7.300	7.527	1.892	4.266
2030	7.140	8.593	8.529	8.795	2.151	4.722
2035	7.558	9.096	9.029	9.310	2.450	4.822
2040	7.977	9.599	9.528	9.825	2.749	4.921

(Source: JICA Study Team, based on the international price in 2015 and IEA data)

5. Procedure for Formulating a Power Master Plan based on the Optimal Generation Mix (“The Best Mix”)

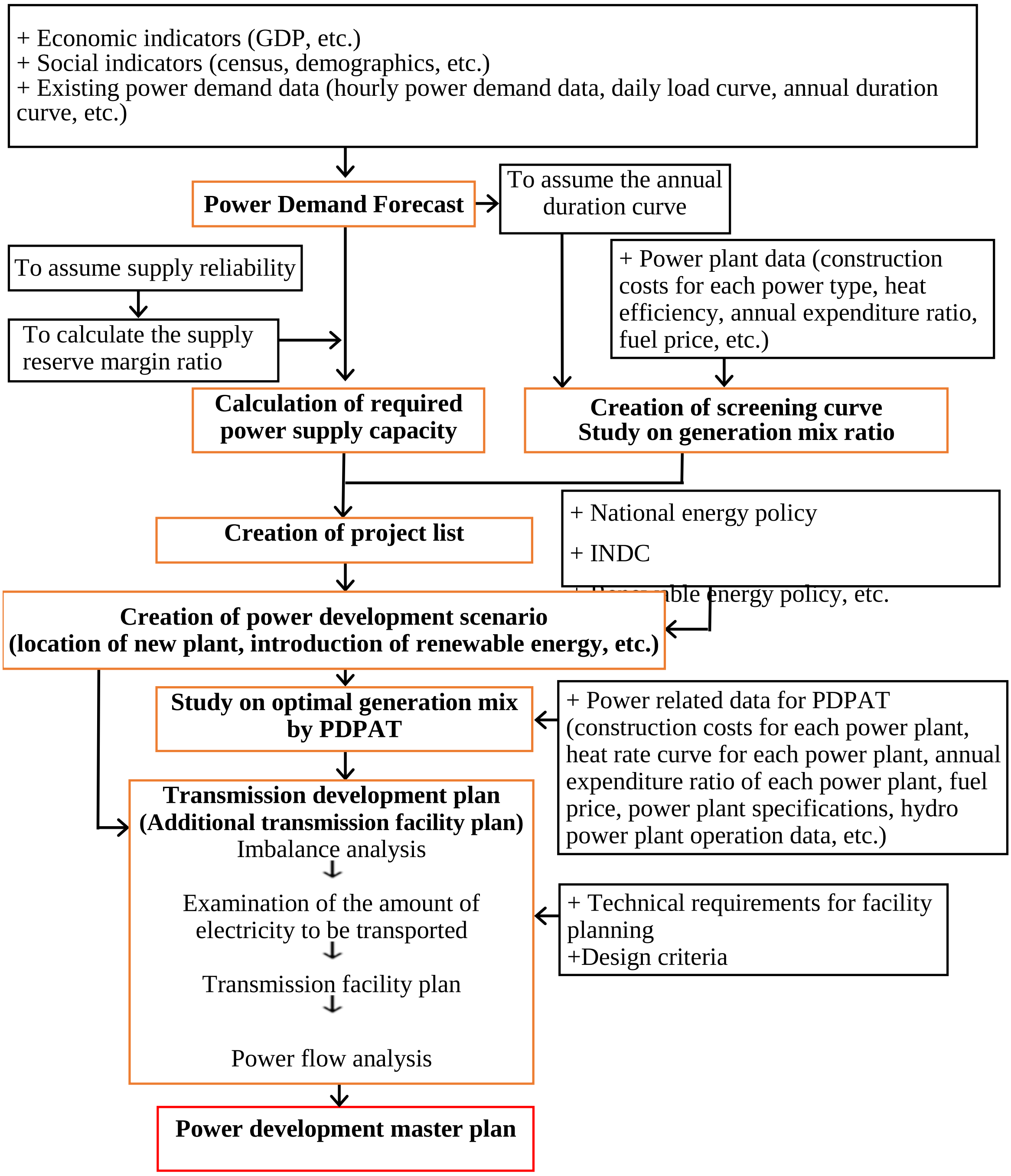


Figure Flow for Formulating a Power Development Master Plan

6. Power Demand Forecast

6.1 Power demand forecasting methodology

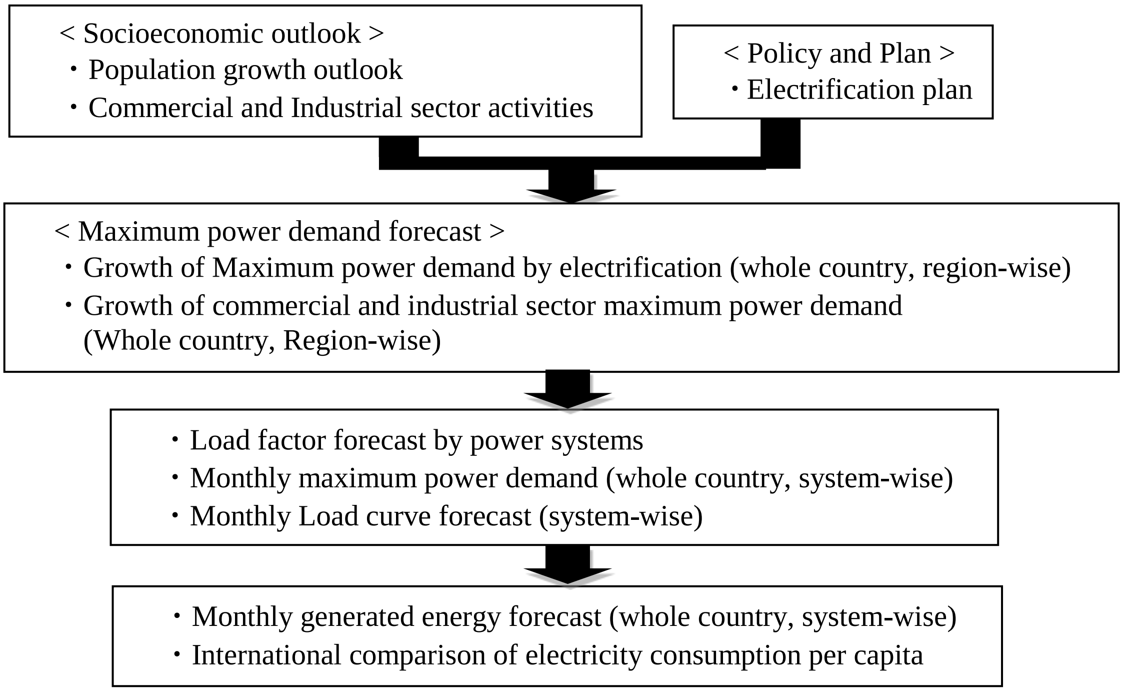
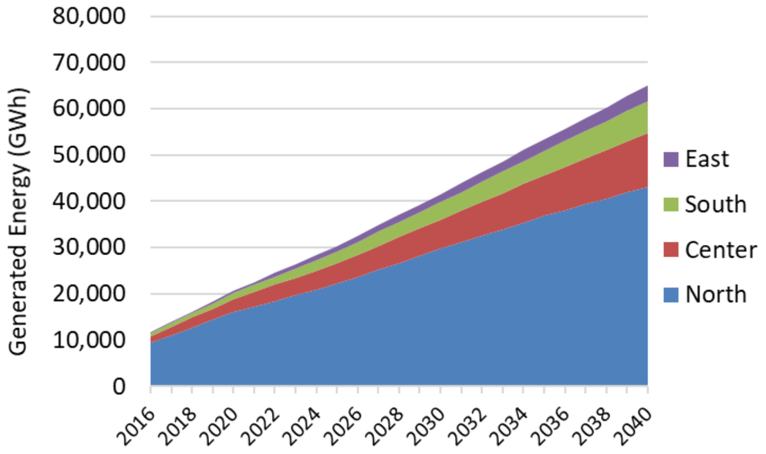


Figure Power Demand Forecasting Flow in Angola

6.2 Annual maximum power demand forecast

Annual maximum demand in the residential consumer sector was calculated based on the electrification rate, population, mean population per customer, maximum power demand per contract. The annual maximum power demand up to 2040 was then assumed by adding the annual maximum power demand forecast for commercial and industrial customers. The results are shown in the table and figure below. As a result of the calculations, the maximum power demand forecast for 2040 was 11,226 MW.



(unit: MW)

	2016	2020	2025	2030	2035	2040
North	1,546	2,584	3,570	4,753	5,864	6,839
Central	266	574	877	1,275	1,765	2,313
South	135	267	499	758	1,060	1,409
East	42	91	249	346	490	665
Total	1,989	3,516	5,195	7,132	9,180	11,226

(Source: JICA Survey Team)

Figure Annual Maximum Power Demand Forecast

6.3 Annual generated energy demand forecast

Generation energy demand is calculated by the following formula.

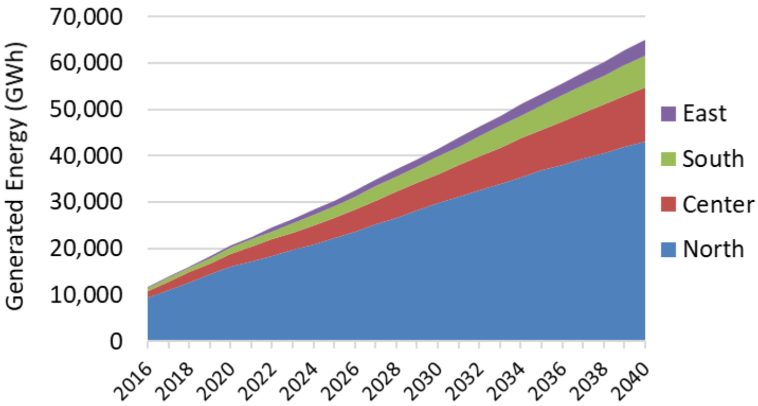
Generation energy demand (kWh) = annual maximum power demand (kW) × 8,760 hours × annual load factor

Table Annual Generated Energy Demand Forecast by System

(Unit: GWh)

	North	Center	South	East	Whole
2016	9,522	1,325	673	208	11,728
2020	15,977	2,860	1,329	453	20,619
2025	22,183	4,366	2,485	1,241	30,275
2030	29,685	6,347	3,774	1,723	41,529
2035	36,805	8,790	5,279	2,442	53,316
2040	43,136	11,518	7,015	3,309	64,979

(Source: JICA Survey Team)



(Source: JICA Survey Team)

Figure Generated Energy Demand Forecast

7. Optimization of the Generation Development Plan

7.1 Relationship between LOLE and Reserve Capacity

The reserve margin ratio corresponding to 24 hours of LOLE was formulated by PDPAT and RETICS. The examination results are shown in the figures below. The required reserve margin gradually decreases over time, reaching about 11% after 2030. This level, 11%, is therefore set as the target value.

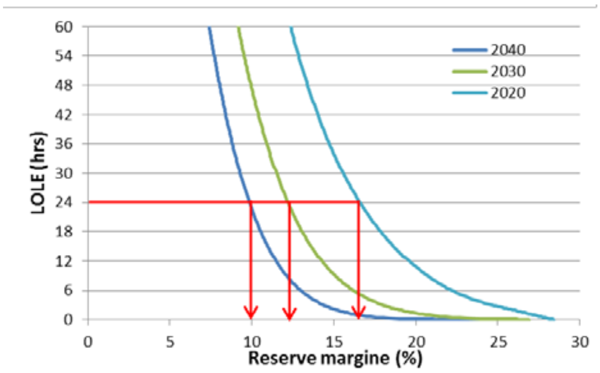


Figure Relationship between LOLE and reserve margin rate

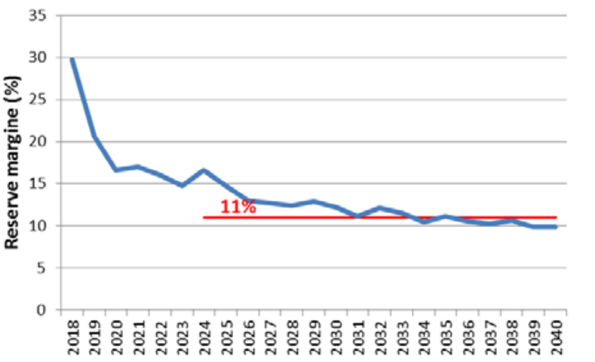


Figure Necessary reserve margin rate equivalent to LOLE of 24hrs

7.2 The Most economical power supply composition ratio by using PDPAT

Here we consider the power supply composition that minimizes the total cost in the year 2040, the final year of the power master plan. We examine the most economical configuration in 2040 among large hydropower, combined cycle (CCGT), and gas turbine (GT).

The following assumptions are adopted for the calculation using PDPAT:

- The target year is 2040.
- The reserve margin rate is set at 11%, is the value selected in 6.4.2. GT shares the capacity for the reserve margin, as it has a lower fixed cost.
- The supply configuration ratio is calculated in the month with the lowest reserve margin for the year and is defined as the ratio of the available supply (excluding the capacity corresponding to the reserve margin) of each power source to the peak demand of the month.

The figure below shows the relation between the total cost per year and the configuration ratio of GT, calculated using PDPAT. The annual cost is lowest when the configuration ratio of GT is 12%.

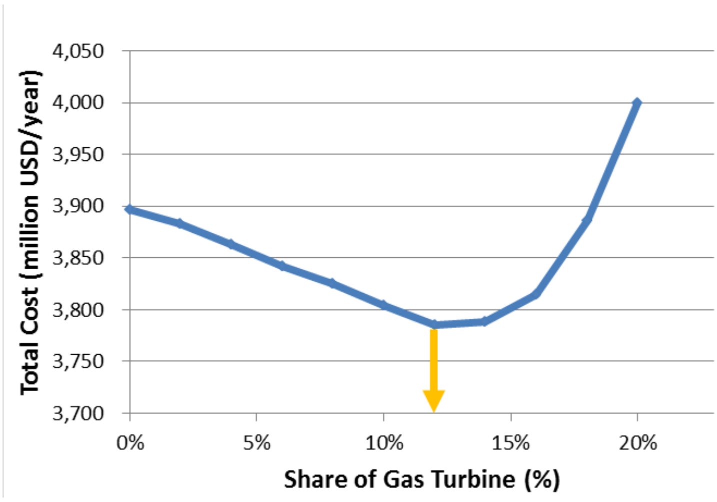


Figure Configuration ratio of GT and total annual cost (year 2040)

Peak demand in the year 2040 appears in December. Meanwhile, the most severe month of the year in terms of the supply-demand balance is November, since supply capacity of hydropower declines during the drought period. The figure below shows the power configuration ratio when the ratio of GT is set to 12% in the November 2040 section. This configuration ratio corresponds to the future target value. The final power development plan formulated for each year up to 2040 needs to approach this power configuration ratio.

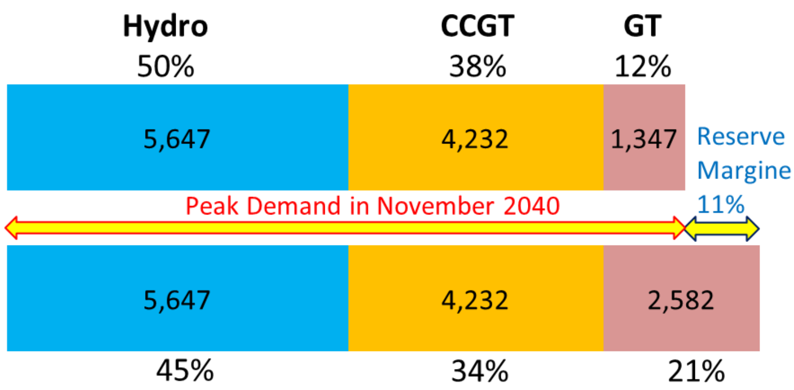


Figure Cost minimum power supply configuration in the year 2040 (November balance)

7.3 List of Generation Development Plan Projects

The table below shows recommended power development projects.

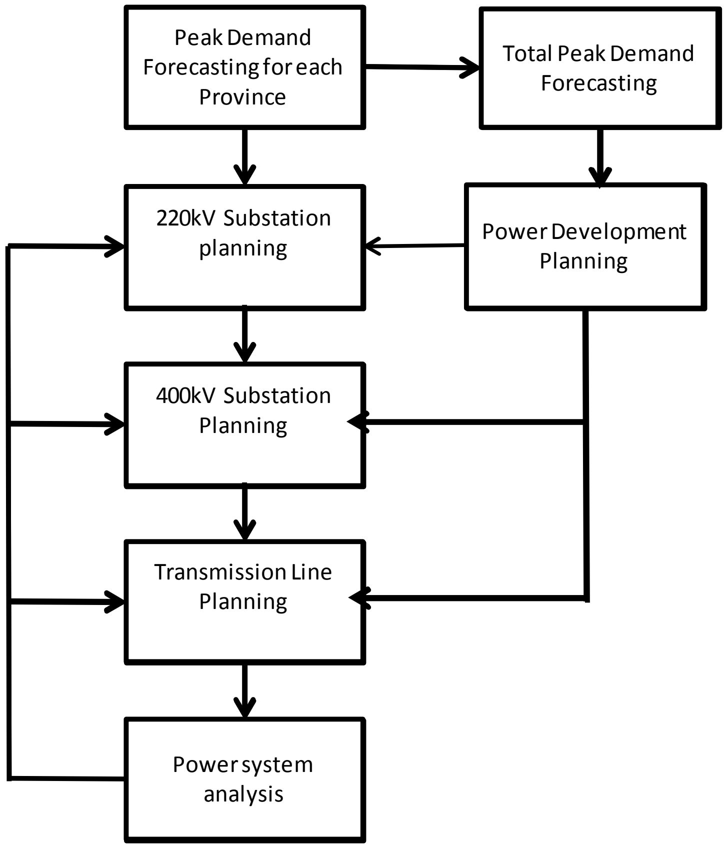
Table Long-term power development plan

Year	Long-term Power Development Plan				
	Hydropower	CCGT	GT	Wind power	Solar power
2017		Soyo1-1 (250)			
2018	Lauca (2070) Lomaun ext.(65)	Soyo1-2 (500)			
2019					
2020	Luachimo ext.(34)				
2021		Soyo2-1 (375)			
2022		Soyo2-2 (375)	Cacuaco No.1 (125)		
2023					
2024	Caculo Cabaça(2172)		Cacuaco No.2 (125)		
2025			Sambizanga No.1 (125)		
2026	Baynes (300)				
2027		Lobito1-1 (375)	Quileva No.1 (125)		
2028	Quilengue (210)		Quileva No.2 (125)	Beniamin (52)	Benguela (10)
2029		Lobito1-2 (375)		Cacula (88)	Cambongue (10)
2030			Quileva No.3 (125) Soyo-SS No.1 (125)	Chibia (78)	Caraculo (10)
2031		Lobito2-1 (375)		Calenga (84)	Catumbera (10)
2032	Zenzo (950)		Cacuaco No.3 (125) Cacuaco No.4 (125)	Gasto (30)	Lobito (10)
2033			Sambizanga No.2 (125) Quileva No.4 (125) Quileva No.5 (125) Quileva No.6 (125)	Kiwaba Nzoji I (62)	Lubango (10)
2034		Lobito2-2 (375)		Kiwaba Nzoji II (42)	Matala (10)
2035	Genga (900)		Soyo-SS No.2 (125) Cacuaco No.5 (125)	Mussede I (36)	Quipungo (10)
2036		Namibe1-1 (375)		Mussede II (44) Nharea (36)	Techamutete (10)
2037			Cacuaco No.6 (125) Sambizanga No.3 (125) Soyo-SS No.3 (125)	Tombwa (100)	Namacunde (10)
2038	Túmulo Caçador(453)	Namibe1-2 (375)			
2039					
2040	Jamba Ya Oma (79) Jamba Ya Mina (205)	Lobito3-1 (375)			
Total	7,438 MW	4,125 MW	2,250 MW	652 MW	100 MW

8. Study on Optimization of the Transmission System Development Plan

8.1 Transmission Development Planning Procedure

The development planning procedure is shown in the flowchart of the figure below.

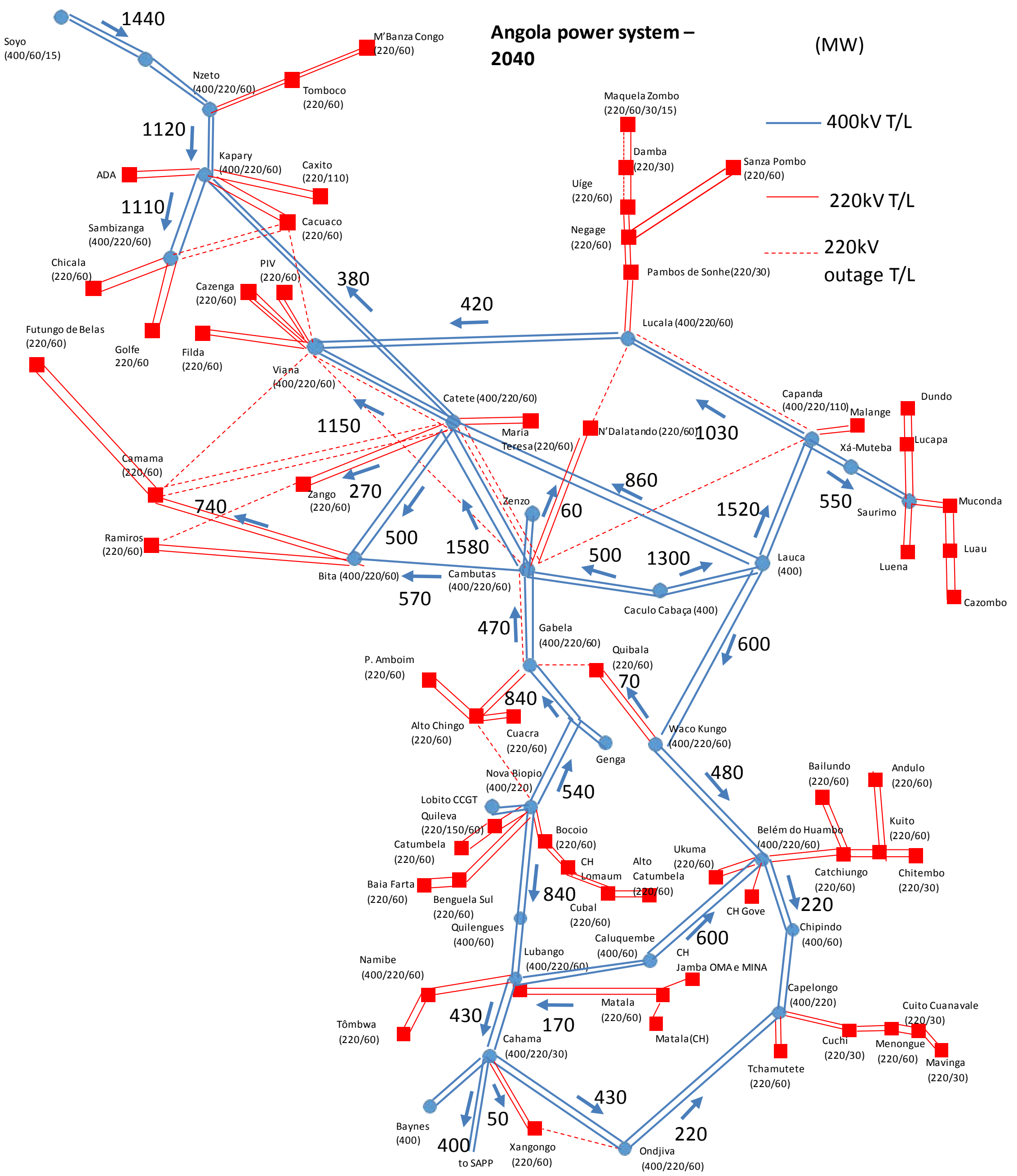


(Source: JICA Survey Team)

Figure Flowchart of the Transmission Network Development Plan

8.2 The Transmission Development Plan for 2040

The results of the analysis using PSSE confirmed that there was no overload based on the n-1 standard for any of the transmission lines or S/Ss with voltages of 220 kV or more.



(Source: JICA Survey Team)

Figure Main power system in 2040（400 kV, 220 kV）

8.3 Lists of Transmission Development Plan Projects

The tables below show recommended transmission development projects.

Table List of 400 kV Substation Projects

Project#	Year of operation	Area	Voltage (kV)	Substation Name	Capacity (MVA)	Cost (MUS$)	Remarks
1	2020	**Cuanza Sul**	400	**Waco kungo**	450	40.5	450 x 1, under construction(China)
2	2020	**Huambo**	400	**Belem do Huambo**	900	51.3	450 x 2, under construction(China)
3	2022	**Luanda**	400	**Bita**	900	51.3	450 x 2, under construction(Brazil)
4	2025	**Cuanza Sul**	400	**Waco kungo**	450	40.5	upgrade 450 x 1
5	2025	**Luanda**	400	**Bita**	450	40.5	upgrade 450 x 1
6	2025	**Zaire**	400	**N'Zeto**	450	40.5	upgrade 450 x 1
7	2025	**Luanda**	400	**Viana**	2,790	96.6	upgrade 930 x 3
8	2025	**Bengo**	400	**Kapary**	450	40.5	upgrade 450 x 1
9	2025	**Huila**	400	**Lubango2**	900	51.3	450 x 2, Pre-FS implemented*
10	2025	**Huila**	400	**Capelongo**	900	51.3	450 x 2
11	2025	**Huila**	400	**Calukembe**	120	32.6	60 x 2
12	2025	**Benguera**	400	**Nova Biopio**	900	51.3	450 x 2
13	2025	**Southern**	400	**Cahama**	900	51.3	450 x 2
14	2025	**Eastern**	400	**Saurimo**	900	51.3	450 x 2, under Pre-FS
15	2025	**Lunda Norte**	400	**Xa-Muteba**	360	38.3	180 x 2, under Pre-FS
16	2025	**Huila**	400	**Quilengues**	120	32.6	60 x 2
17	2025	**Cuanza Sul**	400	**Gabela**	900	51.3	450 x 2
18	2025	**Luanda**	400	**Sambizanga**	2,790	96.6	930 x 3
19	2025	**Malanje**	400	**Lucala**	900	51.3	450 x 2
20	2025	**Chipindo**	400	**Chipindo**	360	38.3	180 x 2
21	2030	**Bengo**	400	**Kapary**	450	40.5	upgrade 450 x 1
22	2030	**Luanda**	400	**Catete**	450	40.5	upgrade 450 x 1
23	2035	**Cunene**	400	**Ondjiva**	900	51.3	450 x 2, Pre-FS implemented*
24	2035	**Luanda**	400	**Bita**	450	40.5	upgrade 450 x 1
25	2035	**Malanje**	400	**Lucala**	450	40.5	upgrade 450 x 1
Total					19,590	1,171.4	

Pre-FS implemented*:Candidate site were selected by USTDA and DBSA.

Table List of 400 kV Transmission Line Projects

Project#	Year of operation	Area	Voltage (kV)	Starting point	End point	number of circuit	Power Flow (MVA)	Line Length (km)	Cost (MUS$)	Remarks
1	2020	**Central**	400	**Lauca**	**Waco kungo**	1	307	177	138.1	under construction(China)
2	2020	**Central**	400	**Waco kungo**	**Belem do Huambo**	1	242	174	135.7	under construction(China)
3	2020	**Northern**	400	**Cambutas**	**Bita**	1	580	172	134.2	under construction(Brazil)
4	2022	**Northern**	400	**Catete**	**Bita**	2	504	54	52.9	under construction(Brazil)
5	2025	**Northern**	400	**Cambutas**	**Catete**	1	791	123	95.9	Dualization
6	2025	**Northern**	400	**Catete**	**Viana**	1	579	36	28.1	Dualization
7	2025	**Northern**	400	**Lauca**	**Capanda elev.**	1	518	41	32.0	Dualization
8	2025	**Northern**	400	**Kapary**	**Sambizanga**	2	1130	45	44.1	For New Substation
9	2025	**Northern**	400	**Lauca**	**Catete**	2	868	190	186.2	Changing Connection Plan
10	2025	**Central**	400	**Lauca**	**Waco kungo**	1	307	177	138.1	Dualization
11	2025	**Central**	400	**Waco kungo**	**Belem do Huambo**	1	242	174	135.7	Dualization
12	2025	**Central**	400	**Cambutas**	**Gabela**	2	484	131	128.4	Pre-FS implemented*
13	2025	**Central**	400	**Gabela**	**Benga**	2	848	25	24.5	Pre-FS implemented*
14	2025	**Central**	400	**Benga**	**Nova Biopio**	2	550	200	196.0	Pre-FS implemented*
15	2025	**Southern**	400	**Belem do Huambo**	**Caluquembe**	2	606	175	171.5	Pre-FS implemented*
16	2025	**Southern**	400	**Caluquembe**	**Lubango2**	2	666	168	164.6	Pre-FS implemented*
17	2025	**Southern**	400	**Belem do Huambo**	**Chipindo**	2	264	114	111.7	
18	2025	**Southern**	400	**Chipindo**	**Capelongo**	2	190	109	106.8	
19	2025	**Southern**	400	**Nova Biopio**	**Quilengues**	2	840	117	114.7	Pre-FS implemented*
20	2025	**Southern**	400	**Quilengues**	**Lubango2**	2	772	143	140.1	Pre-FS implemented*
21	2025	**Southern**	400	**Lubango2**	**Cahama**	2	450	190	186.2	Pre-FS implemented*
22	2025	**Eastern**	400	**Capanda_elev**	**Xa-Muteba**	2	590	266	260.7	
23	2025	**Eastern**	400	**Xa-Muteba**	**Saurimo**	2	510	335	328.3	under Pre-FS
24	2027	**Southern**	400	**Capelongo**	**Ondjiva**	2	292	312	305.8	
25	2027	**Southern**	400	**Cahama**	**Ondjiva**	2	442	175	171.5	
26	2027	**Southern**	400	**Cahama**	**Ruacana**	2	409	125	122.5	International Interconnection
Total								3,948	3,654.2	

Pre-FS implemented*:Candidate route were selected by USTDA and DBSA.

9. Long-term Investment Plan

9.1 Investment in terms of the Commissioning Year

The following table lists investment plans by commissioning year. The total investment comes to 32,449 million USD: hydropower (19,849 million USD), thermal power (6,413 million USD), renewable energy (0 million USD), transmission line (4,551 million USD) and sub-station (1,636 million USD).

Table Long-term Investment Planed up to 2040 (commissioning Year)

(unit: mil. $)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Hydro	0	0	5,589	34	0	0	0	0	5,864	810	0	567	0	0
TPP	300	0	0	0	1,050	531	0	531	81	0	81	450	81	163
Renewable	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Transmission	208	0	2	414	0	878	556	2	1,614	0	785	0	0	18
Sub-station	0	25	0	225	0	444	51	0	196	0	426	0	0	18
total	508	25	5,591	673	1,050	1,854	607	533	7,756	810	1,293	1,017	82	199

(unit: mil. $)

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	total
Hydro	0	2,603	77	115	2,583	153	115	1,300	38	0	**19,849**
TPP	450	163	325	450	163	450	244	450	0	450	**6,413**
Renewable	0	0	0	0	0	0	0	0	0	0	**0**
Transmission	34	0	0	8	6	0	6	0	18	2	**4,551**
Sub-station	129	0	0	0	103	0	0	0	18	0	**1,636**
total	613	2,766	402	573	2,855	603	365	1,750	74	452	**32,449**

9.2 Long-Run Marginal Cost (LRMC)

Following is the long run marginal cost (LRMC) calculated by the JICA Survey Team in accordance with the '*Internal Rate of Return (IRR) Manual for Yen Loan Projects'* (JBIC):

Long Run Marginal Cost (LRMC）＝ total project cost ✕ capital recovery factor ＋ O&M expenses

capital recovery factor＝ $r \,／\, (1-(1+r)^{-n})$

r：10%

n：durable year (hydropower, 40 years; thermal power, 25 years (CCGT) and 20 years (GT)

O&M expenses = O&M expenses + fuel cost (thermal)

O&M expense: calculated to a certain percent of the total construction cost

Fuel cost: annual fuel cost for thermal power plants

The results indicate that the unit price for generation will reach 8.5 cents USD at maximum, while the unit price for transmission and substation will reach 2 cents USD.

Table Annual Unit Incremental Cost for Generation (hydro and thermal)

($ /kWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
incremental cost $/kWh	0.031	0.024	0.014	0.057	0.063	0.066	0.065	0.059	0.085	0.084	0.081	0.082	0.080	0.079

($ /kWh)

type	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	total
incremental cost $/kWh	0.079	0.083	0.083	0.084	0.085	0.085	0.085	0.084	0.083	0.082	–

Table Annual Unit Incremental Cost for Transmission and Sub-station

($ /kWh)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
incremental cost $/kWh	0.002	0.003	0.003	0.006	0.006	0.013	0.016	0.015	0.019	0.018	0.022	0.021	0.020	0.019

($ /kWh)

type	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	total
incremental cost /kWh	0.018	0.018	0.017	0.016	0.015	0.014	0.014	0.013	0.013	0.012	–

These figures indicate that the unit cost of PRODEL needs to increase by 15 AOA, starting from the current 23.11 AOA. Likewise, the unit cost price of RNT needs to increase by 3.59 AOA, starting from the current 8.86 AOA.

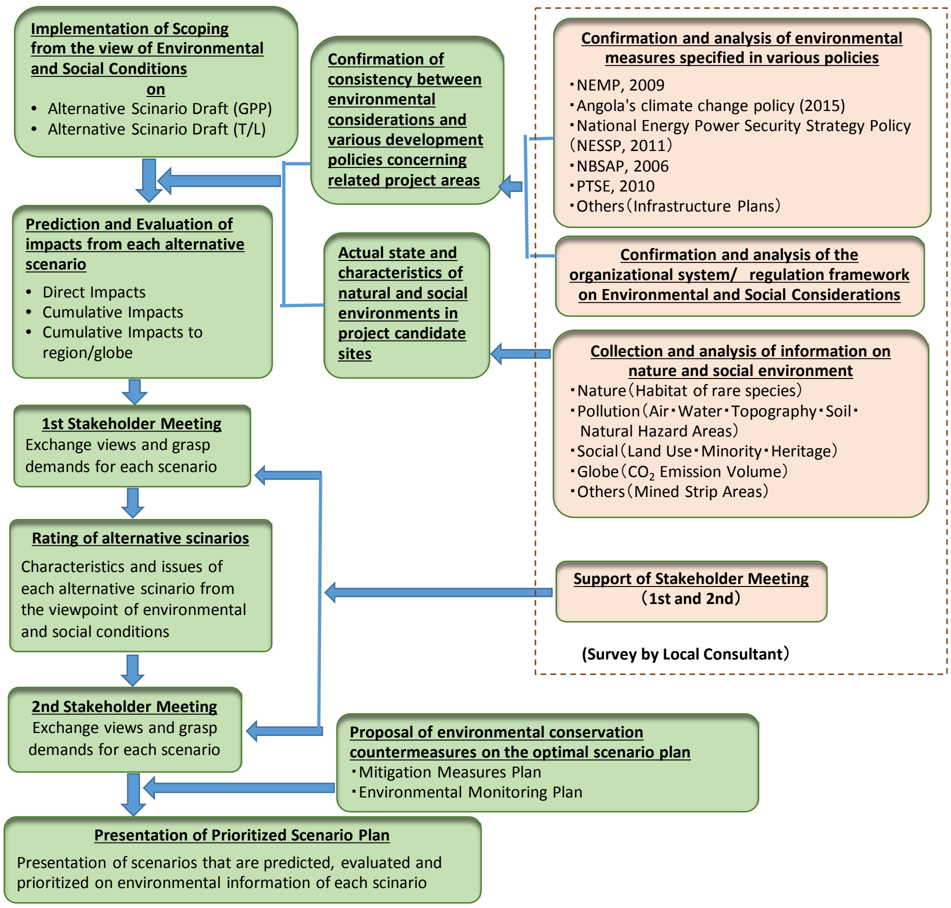
Table Unit Prices and the Unit Incremental Costs

	PRODEL	RNT
1. unit revenue price in 2016	@0.09 $ /kWh (=@20.17 AOA/kWh)	@0.043 $ /kWh (=@9.34 AOA/kWh)
2. unit cost price in 2016	@0.09$ /kWh (=@19.74 AOA/kwh)	@0.039 $ / kWh (=@8.45 AOA/kWh)
3. incremental cost based on the long-term investment	@0.085$/ kWh (=@18.3 AOA/kWh)	@0.02$/ kWh (=@4.3 AOA/kWh)
4. total cost (2+3)	@0.175 $/kWh (=@38.04AOA/kWh)	@ 0.059 $/kWh (=@12.75 AOA/kWh)
5. increase of tariff (unit cost of investment／current unit cost)	17.9 AOA (1.92)	3.41 AOA (1.51)

※USD is converted using the official exchange rate of Nacional Banco de Angola as of March 12, 2018 ($1=215.064 AOA (T.T.M))

10. Environmental and Social Considerations

10.1 Outline of the Strategic Environmental Assessment (SEA) Approach for the Power Development Master Plan



(Source: JICA Survey Team)

Figure Workflow for the SEA

10.2 Environmental Evaluation

The table below presents the results of SEA-based evaluations of the environmental and social considerations linked to power development, rated by indicator (degree of environmental impact).

The power sources ranked from lower negative impacts on the natural and social environment are as follows: (i). Biomass, (ii). Hydropower, (iii). Solar, (iv). Wind, (v). Thermal (LNG/Heavy Oil).

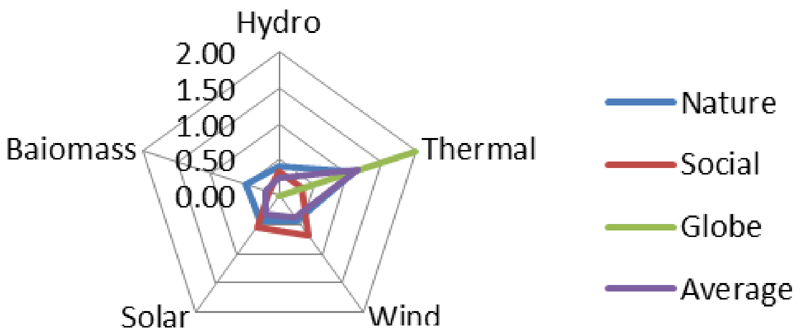
The relatively high total environmental impact assessed for wind power and solar power generation stems from the large negative impact on the local landscape caused by the appearance of huge artificial structures in the vast plains (mainly savanna, shrub vegetation) of the continent of Africa.

Table Environmental Indicators for the Different Types of Power Generation Plants

Type	HYPP		THPP	Wind PP								Solar PP										Bio. PP
Name	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22
MW	960	40.8	212	52	88	84	30	62	36	36	100	10	10	10	10	10	10	10	10	10	10	3
Topography & Geology	−1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Soil	−1.0	0.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0	−1.0	−1.0	−1.0	−1.0	−1.0	0.0	0.0	0.0	0.0
Quality of Water	−1.0	−1.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0	−1.0	−1.0	−1.0
Quality of Air	0.0	0.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0
Noise/Vibration	0.0	0.0	−1.0	−1.0	−1.0	0.0	0.0	−2.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0
Waste	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−2.0	−2.0	−2.0	−2.0	−2.0	−2.0	−2.0	−2.0	−2.0	−2.0	−2.0
Subsidence	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Flora	−2.0	−1.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0	−1.0	−2.0	−2.0	−2.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fauna/Fish/Coral	−1.0	0.0	−2.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−1.0	−1.0	−2.0	−1.0	0.0	−1.0	−1.0	0.0	0.0	0.0	0.0
Nature Protected Areas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(Natural Environment)	−0.60	−0.20	−1.10	−0.40	−0.40	−0.30	−0.30	−0.50	−0.50	−0.40	−0.70	0.50	−0.60	−0.70	−0.60	−0.30	−0.40	−0.40	−0.30	−0.30	−0.30	−0.50
(Aberage)	−0.40		−1.10	−0.43								−0.44										−0.50
Resettlement	−1.0	−1.0	−1.0	0.0	−1.0	−1.0	0.0	−2.0	−2.0	0.0	0.0	−1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ethnic /Indigenous pec	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Land use	0.0	0.0	0.0	−1.0	−1.0	−1.0	0.0	0.0	0.0	−1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0	0.0	0.0	0.0
Water Use	−1.0	−1.0	−1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−1.0
Landscape	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	−3.0	0.0
Historical Heritage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(Social Environment)	−0.33	−0.33	−0.33	−0.66	−0.83	−0.66	−0.50	−0.83	−0.83	−0.66	−0.50	−0.66	−0.50	−0.50	−0.50	−0.50	−0.50	−0.50	−0.66	−0.50	−0.50	−0.15
(Average)	−0.33		−0.33	−0.68								−0.53										−0.15
een House Gas	0.0	0.0	−2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(Globale Environment)	0.00	0.00	−2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
(Average)	0.00		−2.00	0.00								0.00										0.00
Comprehensive Environmental Indexes	−0.31	−0.17	−1.14	−0.35	−0.41	−0.32	−0.26	−0.44	−0.44	−0.35	−0.40	−0.38	−0.36	−0.40	−0.36	−0.26	−0.30	−0.30	−0.32	−0.26	−0.26	−0.21
Comprehensive Environmental Indexes (Average)	−0.24		−1.14	−0.31								−0.32										−0.21
Comprehensive Environmental Indexes/per MW (each Plant)*	−0.32	−4.16	−5.37	−6.73	−4.65	−3.80	−8.66	−7.08	−12.22	−9.72	−4.00	−38.00	−36.00	−40.00	−36.00	−26.00	−36.00	−30.00	−32.00	−26.00	−26.00	−70.00
Comprehensive Environmental Indexes/per MW (Type of Generation)	−2.24		−5.37	−7.11								−32.00										−70.00

*: For convenience sake, it is 1,000 times for comparison.

(Source: JICA Survey Team)



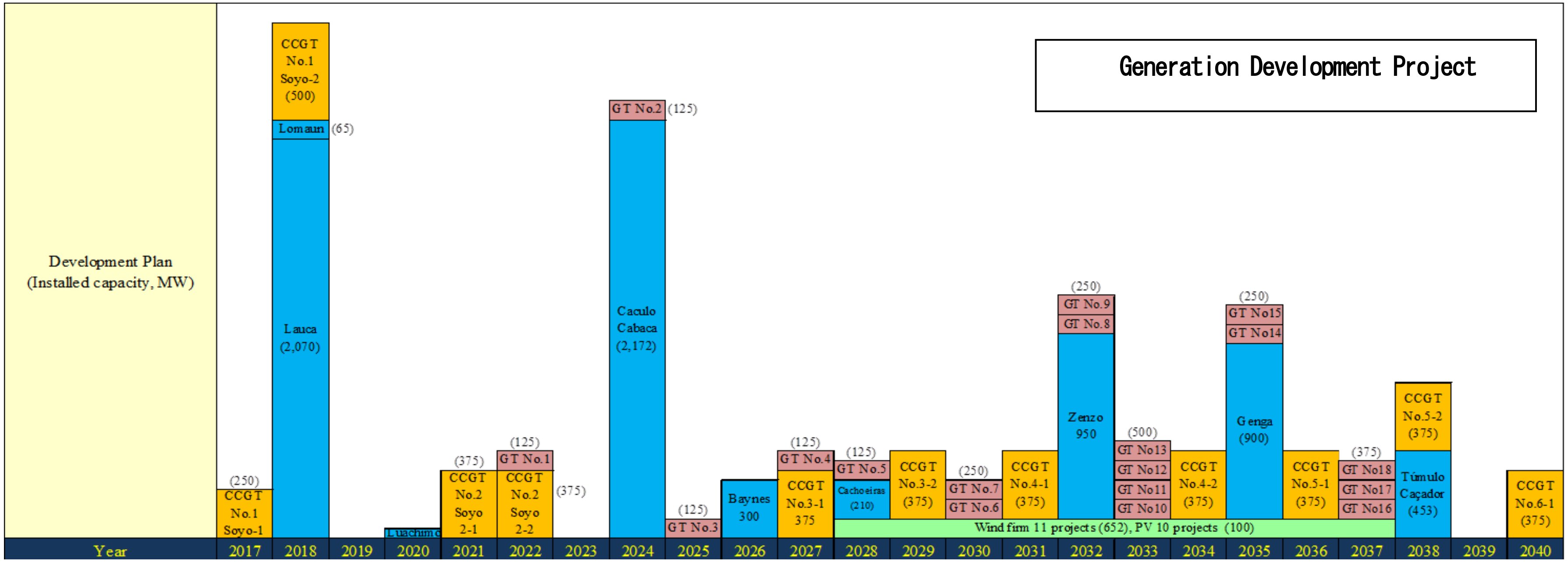
(0: means the lowest impact)

(Source: JICA Survey Team)

Figure Environmental Impact Analysis Diagram of Power Generation Type (Overall)

11. Drafting PDMP

The generation development plans and transmission development plans are summarized in the figure below.



Transmission Dev. Plan	Year 2018-20	Year 2021-25	Year 2026-30	Year 2031-35	Year 2036-40
Trans. For Power Plant	Implementation of projects to connect the new hydropower plants and the new gas-fired thermal power plants in the central and south to the main & regional system.				
Construction of 400 kV Main System	Lauca – Waco Kungo – Belem do Huambo	– Lubango			
	Cambutasu - Gabela – Nova Biopio – Lubango				
		Lubango – Cahama			
Enhancement of 220 kV System	To enhance the 220 kV regional system, mainly in Luanda, Benguela region				
Two circuits of the backbone line to secure N-1 criteria	The following steps will be necessary to eliminate operational restrictions, improve reliability, and avoid overload during an accident of an existing circuit of a transmission line: add one transmission line in parallel for the backbone line to make two circuits.				

Figure Summary of Generation Development Plans & Transmission Development Plans

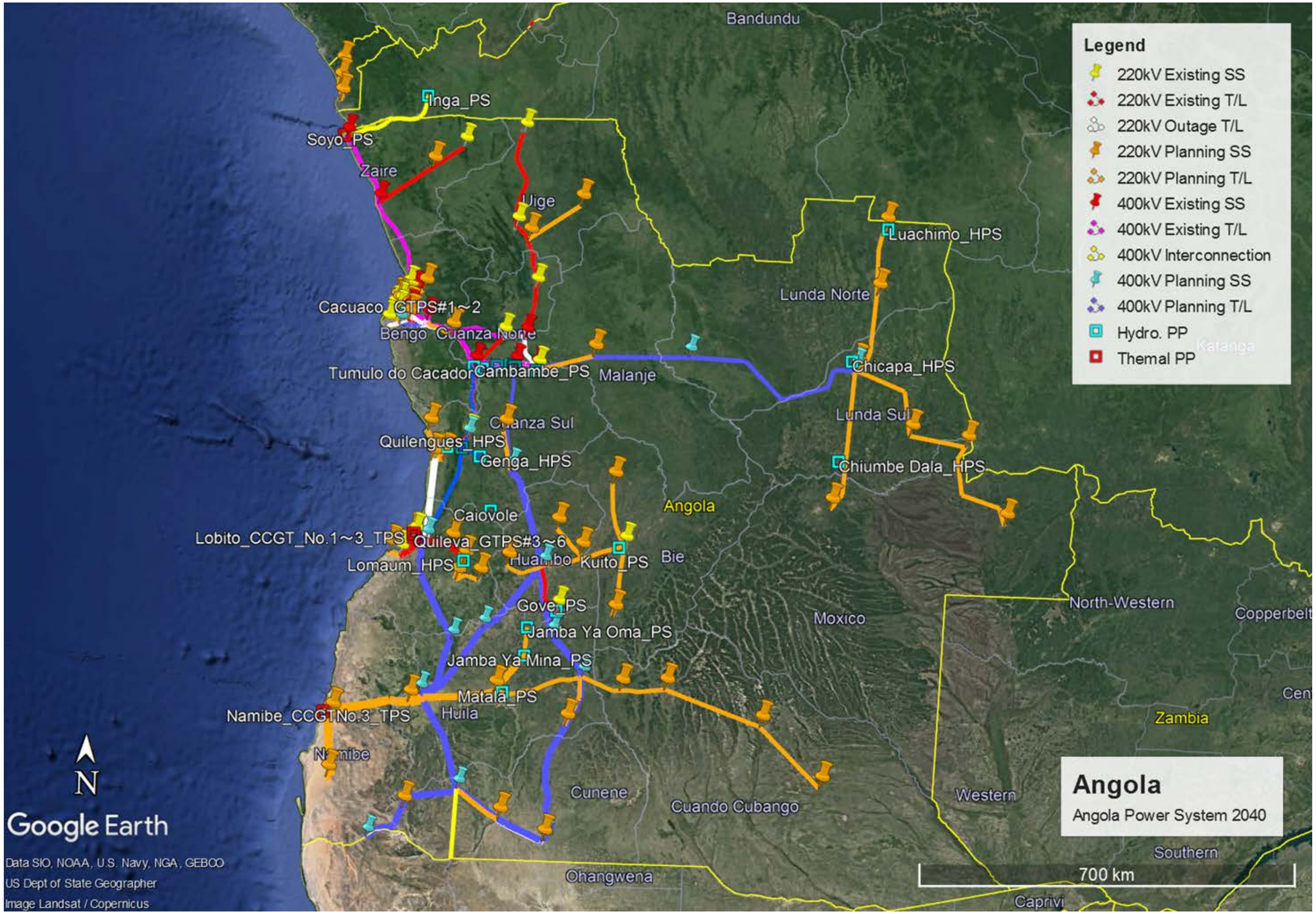


Figure　Project Map toward 2040

12. Advice to MINEA, RNT, PRODEL, ENDE and IRSEA on their Action Plans for the Power Development Master Plan

The following table summarizes Angolan action plans for the Power Development Master Plan.

Table Action Plans for the Power Development Master Plan

Target	Item	Action Plan in Detail
Action plans related to maintenance of the Power Master Plan	Establishment of an organization to formulate the PDMP	➢ Establishment of the Institute of Power Development Planning (IPDP) <tentative name>
	Revising the PDMP on an ongoing basis	Ongoing revision of the Power Demand Forecast ➢ Collection of necessary data such as economic indicators ➢ Collection of demand data and improve accumulation methods ➢ Sounding out customers
		Ongoing revision of the Generation Development Plans ➢ Review of fuel procurement plans ➢ Collection of the latest technical information on hydropower & thermal power ➢ Ongoing study on occupancy hydropower potential ➢ Maintaining the Best Generation Mix
		Ongoing revision of the Transmission Development Plan ➢ Ongoing analysis of the power supply-and-demand imbalance by region ➢ Review of transmission facility specifications ➢ Review of power flow analyses
Action plans related to the execution of development projects	Company Operation & Project management	➢ Deployment and reflection of the PDMP in the medium-term plans of different entities
	Management and reform of fund procurement	➢ Improvement of the tariff system ➢ Study on how to use foreign loans ➢ Study on how to introduce private sector funds
Others	Reform of dispatching organization	➢ Introduction of SCADA ➢ Reform of central and regional dispatching organizations

Table Schedule of Action Plans for the PDMP

		2018-'20	2021-'25	2026-'30	2031-'35	2036-'40
Establishment of Organization to Formulate PDPM	MINEA RNT PRODEL ENDE	Establishment of IPDP →				
Revision of PDPM	MINEA/IPDP		▼	▼	▼	▼
➢ Acton on improve accuracy of Power Demand Forecast ✧ Organizing and accumulating information ✧ Hearing to customers	RNT ENDE	Design &introduction of SCADA → Enhancement of customer hearing system; Continuation of hearing →	Efficient accumulation and analysis of data →			
➢ Revision of study on occupancy hydropower potential			▼	▼	▼	▼
Formulation of mid-term plan	RNT PRODEL ENDE	Review of the mid-term plan year by year →				
Design of electricity tariff structure	IRSEA	Tariff structure design →	until the start of liberalization at the latest			
Institution design for IPP entry ➢ Concession system, PPA system etc.	IRSEA	Institution design for IPP entry →	until the start of liberalization at the latest			
Renovation of load dispatching organization ➢ Reform of load dispatching offices ➢ Introduction of SCADA	RNT PRODEL	Reform of load dispatching offices → Introduction of SCADA →				

Chapter 1 Outline of the Survey

1.1 Background of Survey

The economy of the Republic of Angola (hereinafter “Angola”) has grown steadily since the end of the civil war in 2002, achieving an average economic growth rate of 10.7% from 2002 to 2013. Under a long-term development policy (Vision 2025) and a development plan spanning from 2013 to 2017 ("National Development Plan”; NDP 2013-2017) formulated by the Government of Angola, the country seeks to achieve sustainable economic growth by diversifying its industries and reducing its excessive dependence on oil revenues.

NDP 2013-2017 designates the power sector as one of seven important sectors in Angola. Though power infrastructure destroyed during the civil war is rapidly being restored, progress is impeded by the following problems: a low electricity rate of about 5 kW/kWh versus a supply cost of about 40 kWh/kWh; a vulnerable power system dependent on hydropower generation with seasonal fluctuation (caused by drought), a system accounting for about 60% of total electricity generation; a low electrification rate of about 30% nationwide on average; transmission and distribution loss of 55% or higher (technical losses: 15%; non-technical losses 40%); and a low fee collection rate due to a lack of electric meters installed.

The Ministry of Energy and Water Affairs (hereinafter MINEA), the responsible policymaking body for the power sector, has formulated a "National Power Security Strategy and Policy” (NESSP 2011) and assigned top priority to formulating frameworks and policies for power sector reform, introducing PPP, and promoting power development (including gas-combined cycle power plant, hydropower plant), grid development, and renewable energy development. In order to realize these reforms, MINEA has formulated an "Electricity Sector Transformation Program” (PTSE) that clarifies the actions to be tackled in four phases from 2010 to 2025 step by step. PTSE targets an increase in the electricity access rate from 30% to 60% and the development of power facility capacity from 2,120 MW to 8,742 MW by 2025.

In order to promote PTSE, MINEA plays a role in encompassing the individual plans made by each public company, namely, the National Electricity Transportation Company (hereinafter “RNT”), Public Electricity Production Company (hereinafter “PRODEL”), and National Electricity Distribution Company (hereinafter “ENDE”), into a series of power development master plans. MINEA, however, has never formulated a comprehensive power development master plan based on highly accurate demand forecasts or Long Run Marginal Cost (LRMC) forecasts factoring in various conditions such as long-term production facilities. For stable power supply in Angola, it will be necessary to develop a power supply and grid system in line with power development master plans based on statistical data and scientific analysis. The formulation of such a master plan is an urgent issue.

Under these circumstances, the Angolan side asked the Japanese side to cooperate in the formulation of a long-term power development master plan up to the year 2040, in the expectation of benefiting from Japan's experience, knowledge, and technology in the power sector.

1.2 Purpose of the Survey

1.2.1 Purpose

The purpose of this Survey is to produce a master plan for the generation and transmission development of the whole of Angola up to the year 2040, and thereby contribute to the smooth implementation of power development to enable a stable power supply for the country. The outcomes of this survey are as follows:

- To formulate a comprehensive power development master plan (2018-2040) encompassing nationwide generation development plans and transmission development plans.
- To promote sufficient understanding of the master plan by related organizations (MINEA, RNT, PRODEL, ENDE) and build up the capacity of related organization staffs to formulate and revise power development master plans.

1.2.2 Implementing Organizations of the Partner Country

Competent Authority: The Ministry of Energy and Water Affairs (MINEA)

Department: National Directorate of Electricity Energy (hereinafter "DNEE")

Implementing Organizations: National Electricity Transportation Company (RNT), Public Electricity Production Company (PRODEL), National Electricity Distribution Company, (ENDE), Instituto Regulador dos Serviços de Electricidade e Água (hereinafter "IRSEA")

1.3 Activities

(1) **Preparations at home and Discussion and Consultation on the Inception Report**

- To collect relevant data and information and examine them
- To make the Inception Report
- To discuss and consult on the content of the Inception Report with the Government of Angola and the relevant organizations. And to confirm the demarcation of responsibility among the government, the implementing organization and JICA missions

(2) **Review of the current situation in the power sector**

- To review the current situation in the power sector (policy and strategy, legal and regulatory framework, power sector structure, and national development plans)
- To review the recent power sector development
- To review the current power demand and supply
- To review cooperation by development partners, including donors, and commercial activity by private sector partners
- To review the Intended Nationally Determined Contributions (INDC) relating to the power sector in Angola

(3) **Power demand forecast**

- To formulate power demand forecasts toward the year 2040 with sensitivity analysis, including the following:
- demand forecast at the national level (and regional level if data are available)
- sector-wise forecasts and impacts by major development projects/plans
- daily load curves and load profiles

(4) **Analysis on primary energy sources for generation development**

- To analyze the potential of primary energy sources in Angola such as hydro, renewable, natural gas and oil
- To organize information on the primary energy facilities to be developed to promote generation development

(5) **Formulation of a generation development plan based on an optimal power generation mix**

- To analyze the current generation facilities
- To analyze the existing power development projects
- To formulate a long-term optimal generation development plan toward the year 2040 with sensitivity analysis, including the following:
  - ✓ To analyze the generation planning database, including latest technical and cost data
  - ✓ To prepare several development scenarios such as a base demand case, high demand case, etc.
  - ✓ To conduct sensitivity analysis
  - ✓ To estimate the amounts of GHG (Greenhouse Gas) emission for the respective development scenarios

(6) **Study on optimization of the transmission system development plan**

- To analyze the existing transmission facilities

- To analyze the latest system development strategies and plans prepared by MINEA, including the following:
  - ✓ To analyze the existing development strategies and projects
  - ✓ To analyze the update cost and technical data for the existing facilities
  - ✓ To analyze the transmission interconnection corridors with neighboring countries such as the Democratic Republic of the Congo (hereinafter "DR Congo"), Namibia, Zambia
- To conduct power flow analysis
- To select appropriate software for power system analysis
- To examine the reduction of transmission loss
- To formulate transmission development plans toward the year 2040

(7) **Review of the framework and implementation of private investment**

- To review the policy/strategy, legal and regulatory framework, and procedures for private investment in the power sector
- To review the current status of private investment and identify bottlenecks

(8) **Formulation of a long-term investment plan**

- To undertake an economic and financial analysis of the implementation of the proposed development plans
- To review and update the existing investment plan up to the year 2025
- To formulate a long-term investment plan up to the year 2040 integrated with generation development plans and transmission development plans

(9) **Economic and financial analysis**

- To analyze the financial aspects of RNT, PRODEL, ENDE, including the present tariff levels, cost structures, and borrowing capacities of RNT, PRODEL, and ENDE
- To formulate financial strategies
- To analyze the financial sustainability of RNT, PRODEL, and ENDE
- To recommend an optimal financial strategy

(10) **Environmental and social considerations**

- To analyze the legal and regulatory frameworks for environmental and social considerations
- To identify the potential impacts associated with environmental and social issues in the updated plan and propose the possible mitigation measures based on Strategic Environmental Assessment (SEA)

(11) **Drafting the Master Plan**

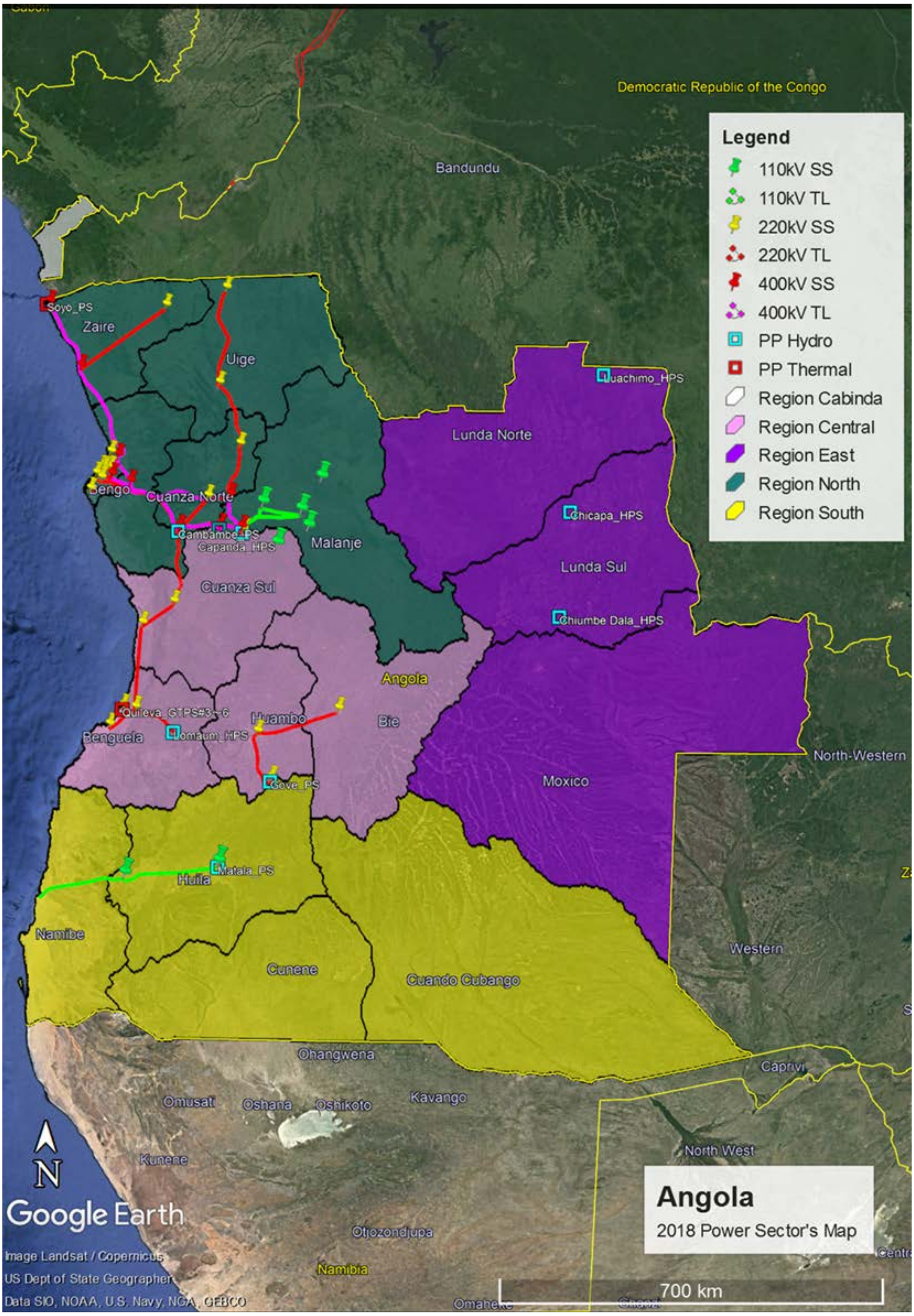
- To draft comprehensive master plans toward the year 2040 integrating the above analysis
- To advise the action plans of MINEA, RNT, PRODEL, ENDE, and IRSEA

(12) **Capacity building**

- To conduct technical transfer to MINEA, RNT, PRODEL, ENDE, and IRSEA via workshops and on-the-job training
- To conduct relevant training in Japan

Chapter 2 Review of the Current Situation in the Power Sector

2.1 Location of Angola



2.2 Country overview

2.2.1 Social situation

Angola occupies an area of 1,246,700 km2 (approximately triple the area of Japan) in the Western region of southern Africa with a coastline extending more than 1,600 km along the Atlantic Ocean. The country has land borders to the East with the Democratic Republic of Congo and Republic of Zambia, to the North with the Democratic Republic of the Congo, and to the South with the Republic of Namibia.

Although Angola is located in a tropical zone in the southern hemisphere, a confluence of three factors results in a climate uncharacteristic of the region: the orography in the countryside, the cold Benguela current along the South coast, and the Namib desert to the southeast of the territory.

The climate in Angola essentially contrasts between dry, hot conditions characterized by low precipitation along the coast from May to August and humid conditions characterized by milder temperatures with more abundant rainfall in the interior from October to April.

Angola has a total population of about 25,900,000 living in 18 provinces. Luanda is the most densely occupied province, accounting for 27% of the national population, followed by Huila (10%), Benguela and Huambo (8% each), Cuanza Sul (7%), and Bié and Uige (6% each). The populations of these seven provinces account for 72% of the total population of the country.

Provinces of Angola	
1. Bengo	10. Huíla
2. Benguela	11. Luanda
3. Bié	12. Lunda-Norte
4. Cabinda	13. Lunda-Sul
5. Cuando Cubango	14. Malange
6. Kwanza-Norte	15. Moxico
7. Kwanza-Sul	16. Namibe
8. Cunene	17. Uige
9. Huambo	18. Zaire

2.2.2 Economic condition

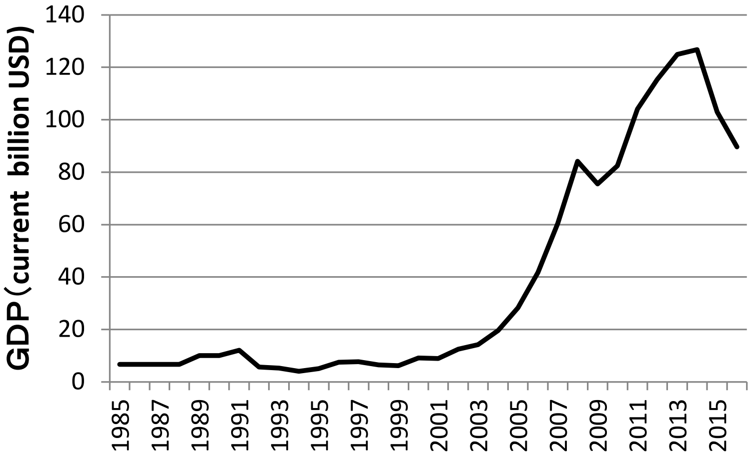
Figure 2-1 and 2-2 respectively show the historical records of Angola's GDP and GDP growth rate.

Angola's long-standing civil war from the independence of 1975 severely exhausted the country. From the end of the civil war in 2002, however, abundant mineral resources such as oil and diamonds helped Angola achieve high economic growth, especially from 2004 to 2008, mainly through the development of export industries of these resources. The country's GDP had reached 103 Billion USD as of 2015.

In recent years, however, declining oil prices have hit the Angolan economy severely. Economic growth has been stagnant and the GDP growth rate dropped to almost zero in 2016.

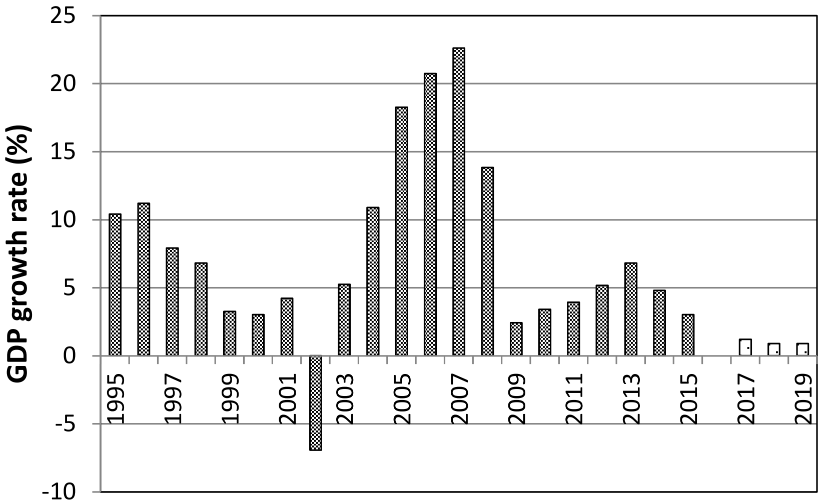
Figure 2-3 shows the sectoral GDP. As seen, the economy is largely made up of mining industries including that for oil, a factor that leaves the economic structure vulnerable to shifts in prices for international resources such as oil.

Encouraged by Angola's high potential for agriculture and fishery, the government has formulated a national development plan to curb the economic downturn by reducing its reliance on the oil industry while promoting other industries and diversifying their industry structure. The government is promoting the power sector under the development plan and struggling to achieve power sector reforms. Activities to liberalize the power generation sector and power distribution are ongoing.



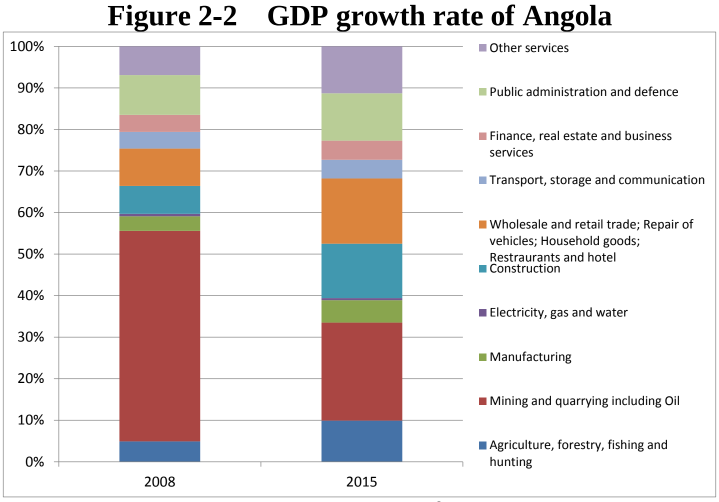
(Sources: World Bank)

Figure 2-1 GDP of Angola



(Source: World Bank）

Figure 2-2 GDP growth rate of Angola



(Source: African Economic Outlook 2017; AfDB, OECD, UNDP)

Figure 2-3 GDP of Angola by sector

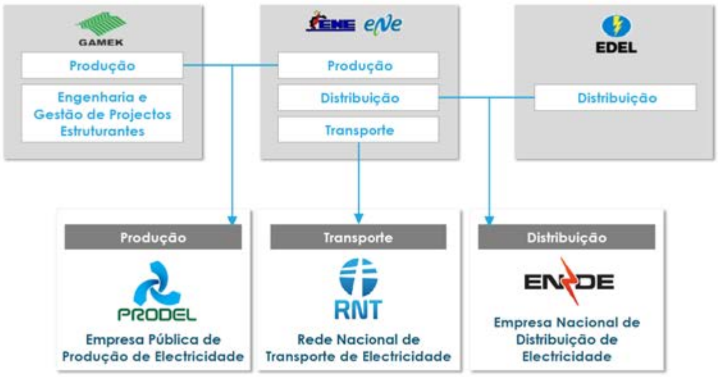
2.3 Review of the current status of the power sector structure

The following chapters will describe the current status of the public companies involved in Angola’s power sector. Prior to that, this chapter will outline the overall power sector, including the public power companies.

2.3.1 Electricity Sector Transformation Program (PTSE)

PTSE is a component of the Power Reform Support Program (PSRSP) conducted mainly by JICA and the African Development Bank (AfDB).

A PTSE roadmap on sector reform recommends the following based on a study the PTSE performed on an optimum model for the electricity market: a restructuring of the market into a classic single-buyer model, an unbundling of the power utilities into Generation, Transmission and Distribution core activities, the establishment of commercial contracts among market participants, and amendments to the laws to improve the regulations and attract PPP. The study further proposed four (4) reform phases, each with specific deliverables:



(Sources: The Transformation Program for the Electricity

Figure 2-4 Restructuring of the Electric Sector

- (i) Preparation Phase (2010-2013) for the design of a new market structure;
- (ii) Phase I (2014- 2017), a stabilization phase following the sector restructuring and unbundling of the power utilities;
- (iii) Phase II (2018-2021), transition to efficient operation with limited use of IPPs, mainly in RE using RE Feed-In tariffs;
- (iv) Phase III (2021-2025), partial liberalization of the power market with the introduction of the PPP and IPPs and limited concessions for the distribution system.

The transmission system, a natural monopoly, will remain a public sector entity. To improve rural access to electricity services and efficiency, the distribution system will be further unbundled into a total of 18 business units in 5 geographic regions.

2.3.2 Power sector organization after sector reform

(1) **MINEA**

Figure 2-5 shows the organization chart of MINEA, the administrative agency handling Angola's electric power business. MINEA basically consists of four divisions: National Directorate of Water (DNA), National Directorate of Electric Energy (DNEE), National Directorate of Renewable Energies (DNER), and National Directorate of Rural and Local Electrification (DNERL). According to an interview with MINEA, its members also include the Gabinete de Abinete de Aproveintamento do Médio Kwanza (GAMEK), Gabinete Para a Administração da Bacia Hidroeléctrica do Cunene (GABHIC), and Instituto Regulador dos Seviços de e de Água (IRSEA).

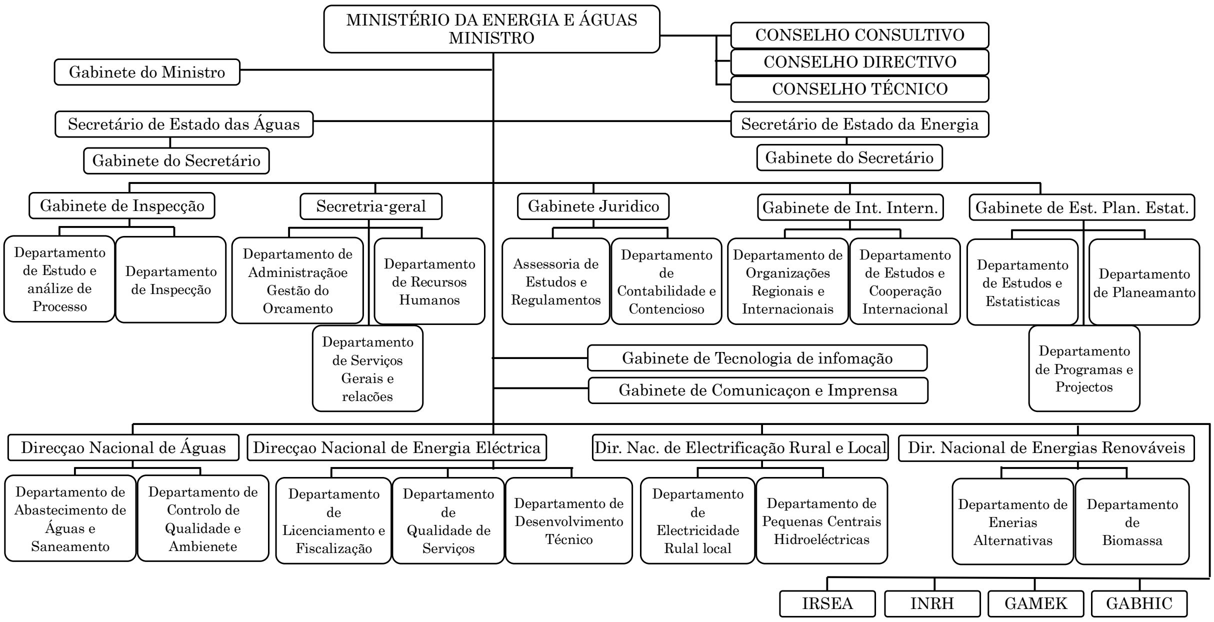
MINEA is charged with the tasks of proposing, formulating, managing, executing, and controlling the Government’s policy in the areas of energy, water, and sanitation. Amongst its responsibilities, the Ministry must propose and promote the execution of the following Energy and Water policies: establish clear strategies to exploit all energy resources in reasonable ways that ensure their sustainable development; plan and promote the national policy on electrification; foster research in its domains; create the necessary legislation to rule the sector’s activities, etc.

DNEE occupies an important position among MINEA's organizations as the department in charge of electricity policy. DNEE is a planning department that summarizes the electric power development plan submitted by the planning departments of ENDE, RNT, and PRODEL every year, examines the plan, and prepares a budget proposal based on it.

GAMEK, a putative division of MINEA, is responsible for the planning of large projects related to power supply and power transmission up to the start of their operations. Once the power generation facilities and transmission facilities are commissioned, they are respectively transferred to PRODEL and RNT and operated and maintained by the two public companies.

While DNEE indicates that the public companies prepare the development plans up to the point of completion, GAMEK is the organization that actually carries out the large development projects. As the definitions for large-scale projects are themselves unclear, it can be difficult for third parties to discern which departments conduct the power development plans at their own initiative.

Apart from GAMEK, GABHIC, the organization in charge of hydropower plant development of the Cunene River in the south, also exists as an MINEA member.



(Source: Survey Team)

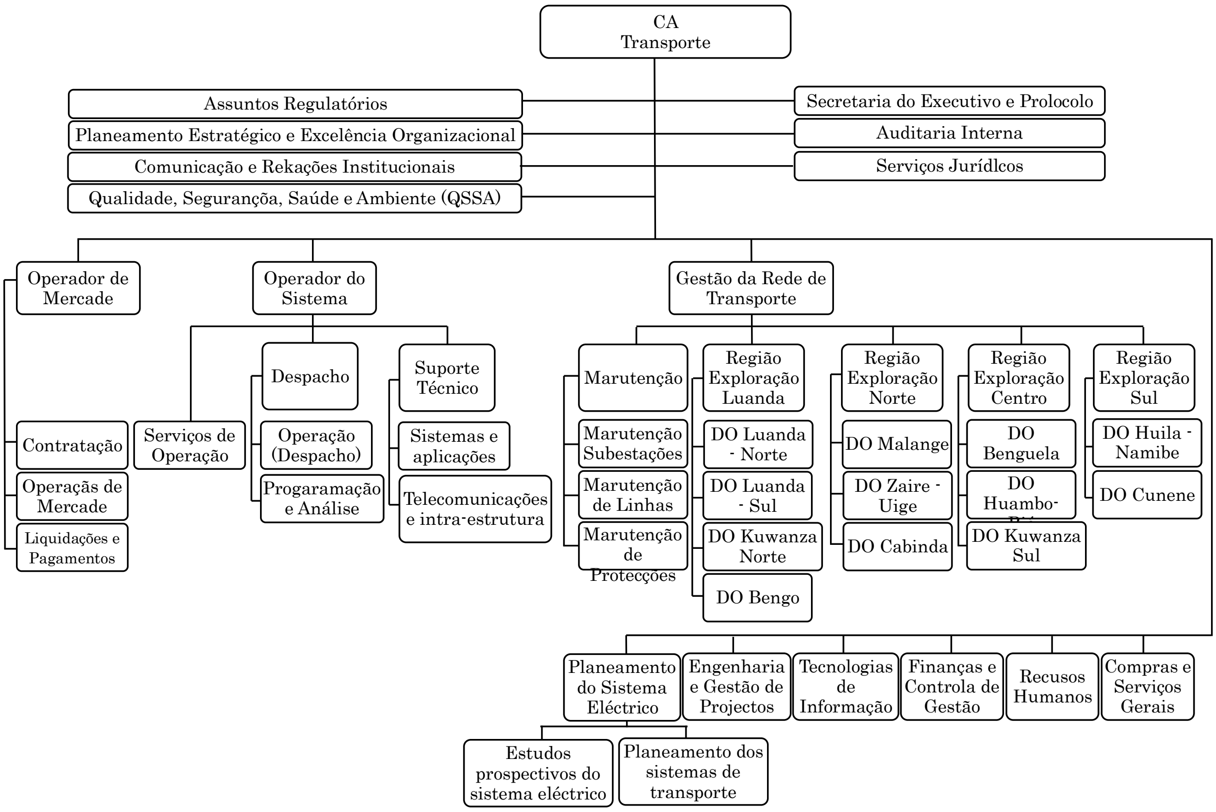
Figure 2-5   MINEA's Organization Chart

(2) IRSEA

IRSEA was created by Presidential decree nº 4/2002 on the 12th of March. One of IRSEA's responsibilities is to establish rules for the functioning of the electric sector through regulations such as the following: Tariff Regulation, Access to Network and Interconnections Regulation, Quality of Service Regulation, Commercial Relationship Regulation, and Dispatching Regulation. The main objectives of IRSEA's mission are to guarantee energy supply, protect consumers, promote conditions favorable to the economic and financial balance of the public companies managing the electric system, foster competition, and ensure a non-discriminatory commercial environment. IRSEA functions as an advisor to MINEA on all matters related to the energy industry. All of the sector's public companies are subject to its regulations.

(3) **RNT**

RNT is a new public company charged with managing and planning the transmission network for the whole country, integrating all of the Very-High-Voltage Transmission assets of the former ENE. Figure 2-6 shows the organization chart of RNT as of July 2017.



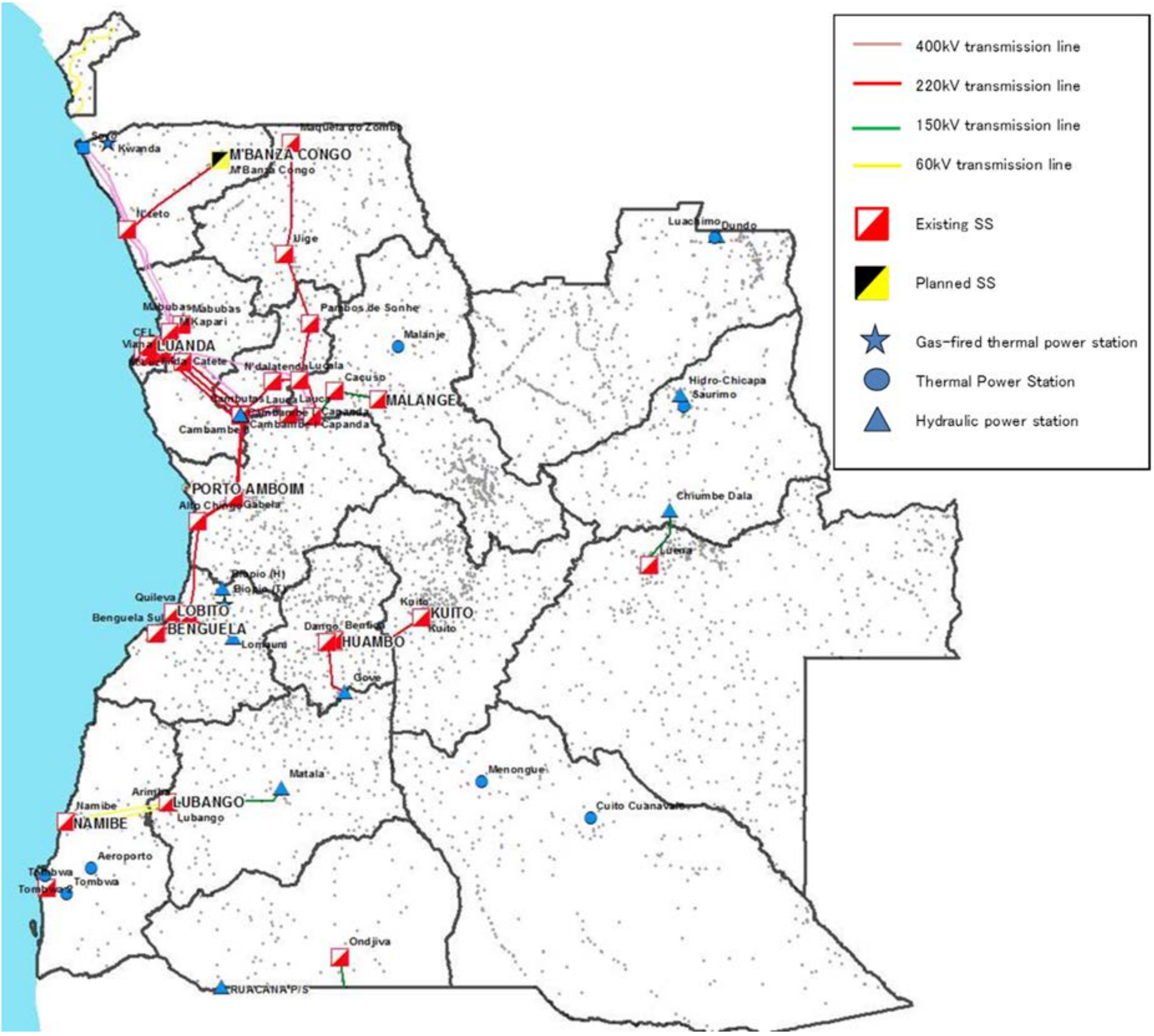
(Source: Survey Team)

Figure 2-6 RNT organization chart

The diagram in Figure 2-7 outlines the transmission system of the RNT as of July 2017. The power grid consists of transmission facilities of 400 kV, 220 kV, 150 kV, 132 kV, 110 kV, and 60 kV.

The Angolan power grid is divided into three parts, namely, the northern grid, the central grid, and the southern grid. Among them, the northern grid supplies electricity to Bengo, Malanje, Cuanza Norte, Cuanza Sul, Uige, etc. centered on the capital city Luanda, a major demand area. This grid covers 80% of Angola's power supply utilizing large hydropower plants such as Capanda HPP and Cambambe HPP.

The construction work for interconnection between Alto Chingo of the northern grid and Nova Biopio-Quileva of the central grid was completed as of July 2017, effectively uniting the facility bases of the northern and central grids. The transmission system between Alto Chingo and Nova Biopio-Quileva has yet to be activated, however, as the Cambambe-Gabela line transmitting electricity from the northern hydropower plants to Alto Chingo is aging and functionally impaired. Cambambe-Gabela, a new 220 kV line, is currently under construction toward a planned commissioning in 2017. The northern-central system will be substantially united when this new line is completed.



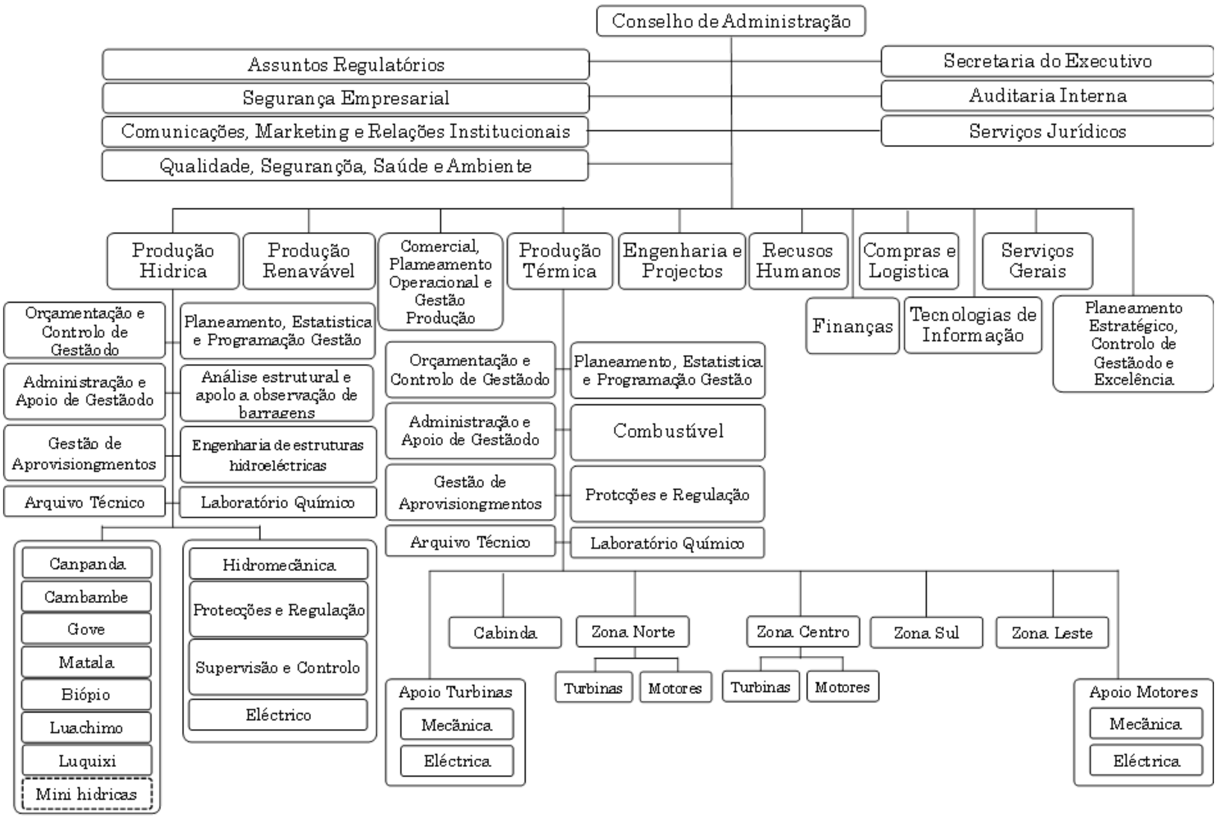
(Source: PNT)

Figure 2-7 RNT grid map (as of July 2017)

(4) PRODEL

PRODEL, the Public Company for Electricity Production, is a new entity responsible for operating and maintaining the generation facilities belonging to the state. PRODEL integrates Capanda Hydropower plant, a facility previously under the responsibility of GAMEK, and the generation assets of ENE, the former National Company of Electricity.

The PRODEL organization chart is shown in Figure 2-8.



(Source: Survey Team)

Figure 2-8 PRODEL organization chart

According to interviews with the public power companies, the installed capacity of the power plants in Angola as of June 2017 is as shown in Table 2-1. The total capacity of all plants combined is 3,055 MW, of which 2,560 MW is on grid. The public companies also indicate, however, that many of the thermal power plants are aging and some of them are suspending or reducing their outputs. Hence, the total plant output is surely smaller than the total nominal installed capacity.

By type of power source, hydropower plants and thermal power plants account for 56% and 42% of the installed capacity, respectively.

All of the thermal power plants are internal combustion engine power plants or GTs. Most of the fuel is diesel oil, and jet fuel is also used in part. On the other hand, large HPPs such as Capanda, Cambambe, and Cambambe-2 account for about 90% of the installed hydropower capacity.

Table2-1 Installed capacity of power plants in Angola (as of the end of June 2017)

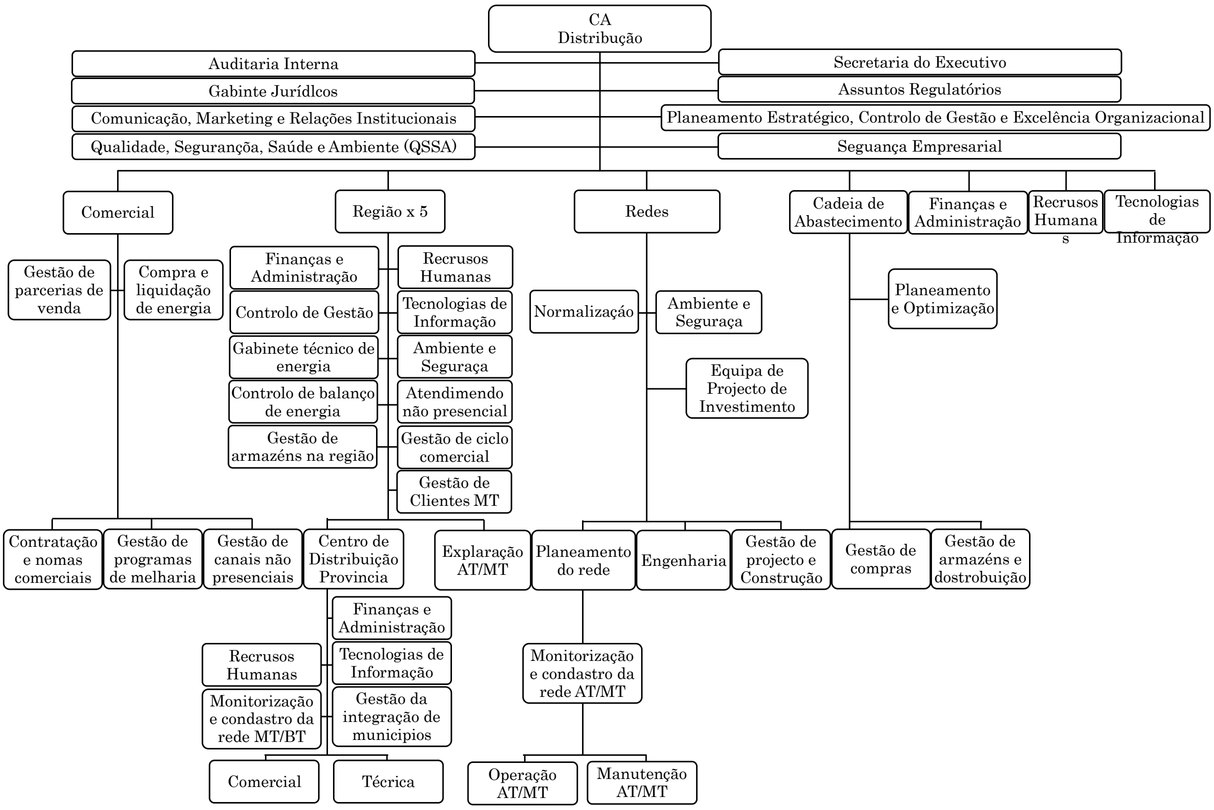
Type	On grid (MW)	Off grid (MW)	Total (MW)	Composition (%)
Hydropower	**1,671.00**	**36.40**	**1,707.40**	**55.9%**
Thermal	**839.30**	**457.40**	**1,296.70**	**42.4%**
Biomass	**50.00**	**0.00**	**50.00**	**1.6%**
Mini hydro	**0.00**	**0.94**	**0.94**	**0.0%**
Total	**2,560.30**	**494.74**	**3,055.04**	**100.0%**

(Source: Created by the Survey Team based on interviews with the public companies)

(5) ENDE

ENDE, the National Company for Electricity Distribution, is a new public company responsible for distributing electricity. ENDE integrates all of the activities and assets of the former EDEL and distributes the assets of the former ENE.

Figure 2-9 and Table 2-2 show the ENDE organization chart and a profile of the company, respectively.



(Source: Survey Team)

Figure 2-9 ENDE organization chart

Table2-2 ENDE company profile

Number of employees	4,652 (as of July 2017)
Number of contracts	1,297,609 (as of July 2017)
Peak demand	1,252 MW (in December 2016)
Supplying Electricity	9,348 GWh (in 2016)
Electricity sales	49,495Million Kz (in 2016, including commercial losses)

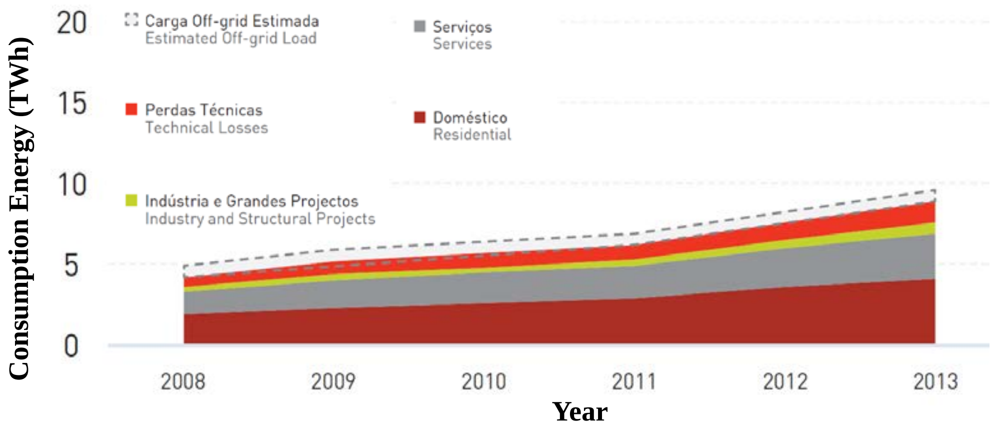
(Source: ENDE RELATÓ DE BALANÇO DAS ACTIVIDADES)

2.4 Review of the current power demand and supply

2.4.1 Demand status

(1) **Energy consumption**

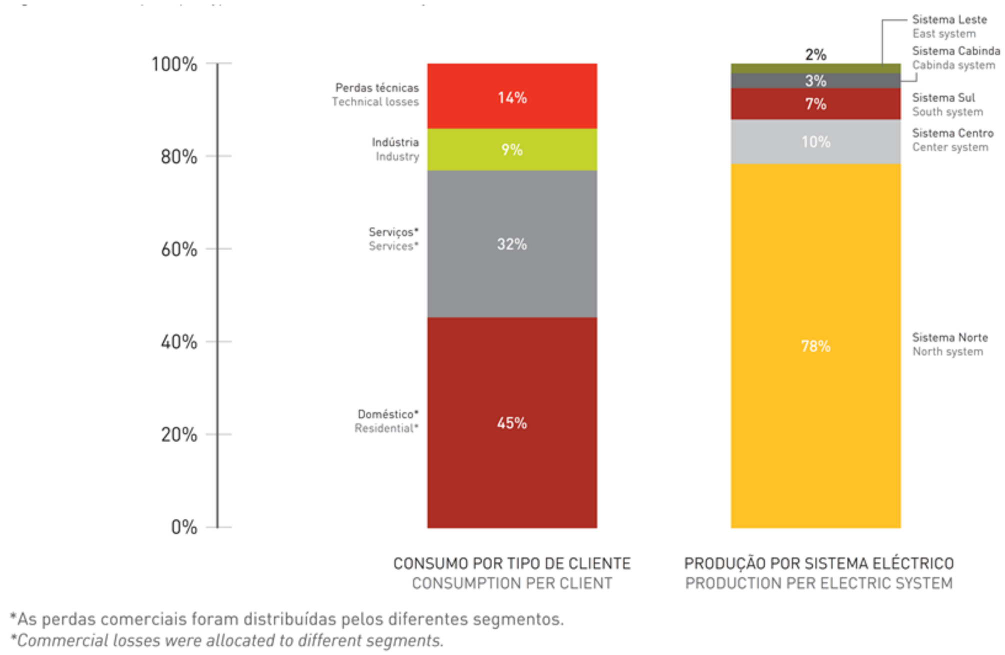
Energy consumption rose at an annual average growth rate of 15.5% between 2008 and 2014. As a result, Angolan energy consumption attributed to production reached an estimated 9.48 TWh in 2014, when disregarding suppressed demand and self-generation in the calculation.



(Source: Long-Term Vision for the Angolan Power Sector: Angola Energia 2025)

Figure 2-10 Consumption energy

Energy consumption in Angola is mostly urban and residential. The residential sector demand accounts for an estimated 45% of total generation, followed by services (ca. 32%) and industry (ca. 9%).



(Source: Long-Term Vision for the Angolan Power Sector: Angola Energia 2025)

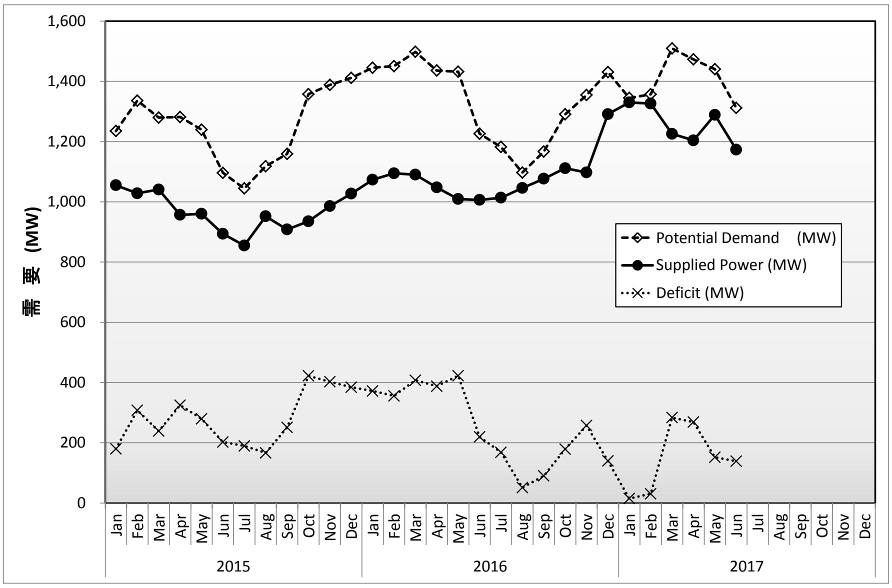
Figure 2-11 Consumption energy by sector and system

(2) **Max. power demand**

Figure 2-12 shows a record of the maximum power demand by month, where ◇ indicates the potential demand taking into account load shedding, ● indicates the demand for which power was actually supplied, and × indicates the supply deficit

The annual growth rate of the potential demand in the past two years was about 6% and that of the actual demand was about 12%.

As the potential demand has been steadily growing, the power supply capacity has been strengthened from 2016 to 2017. And shortages in supply are being resolved, so the actual demand growth has increased substantially.



（Source: Created by the Survey Team based on data provided by RNT）

Figure 2-12 Power demand in Angola

2.4.2 Power supply status

As mentioned earlier, the total installed capacity on grid is 2,560.30 MW as of June 2017.

However, the remaining shortage in the power supply (shown in Figure 2-12) leads to suspensions and reductions in output stemming from the aging of the power plants. At the same time, the power output of the hydropower plants is presumed to be decreasing due to shortages of river water.

Nonetheless, the commissioning of new power plants has been ongoing from 2016 to 2017 and the power supply is being steadily strengthened.

Table2-3 Power plants commissioned in 2016 & 2017

Plant Name	Type	Installed Cap. (MW)	Commissioning Date
Cambambe 2	Hydropower	700	2016
Lauca unit 1	Hydropower	340	Jul 21,2017
Soyo CCGT (partially)	CCGT	125	Aug, 2017

2.5 Review of cooperation by donors and activities by the private sector

2.5.1 Cooperation by donors

(1) **African Development Bank**

The donor most actively engaged in power sector activities in Angola is the African Development Bank. The bank also played a leading role in the power sector reform implemented in 2014.

The bank is currently focusing on technical assistance related to the power distribution sector and promoting the implementation of the following four FS.

- ✓ Fixed Asset Register Project
- ✓ Technical Loss Reduction Program
- ✓ Non-technical Loss Reduction Program
- ✓ Transmission Lines Program

(2) **US Embassy**

Under the direction of the Bureau of Energy Resources in the US Department of State, the US government is implementing technical assistance mainly for RNT from 2016 to 2017. The assistance focuses on the formulation of an interconnected transmission line plan encompassing the northern, central and southern grids, which as of now have yet to be interconnected.

Other than that, the US government is advancing a GT introduction program to establish emergency power supplies mainly in the central and south power system.

2.5.2 Activity by the private sector

(1) **IPP**

As mentioned earlier, the Angolan government announced that full-fledged IPP entry and the introduction of PPP will be implemented after 2021. IPPs operating small-scale diesel power plants as off-grid power plants are in place even now, but they are limited in number.

(2) **PPP**

The Angolan PPP law of 02/2011 was published on the 14th of March with the goal of attracting private sector investment in Angola. The law seeks to achieve its goal by defining general rules for the overall operation of public-private partnerships from the initial stages to adjudication and subsequent follow-up of the implemented projects.

The PPP law was to have been complemented by a set of regulations to make it function properly. This never came to be, however, and the law has never been effectively applied to this date. With the new General Electricity Act and Private Participation in the Electric Sector Program coming into action, it will be important for Angola to have all of the necessary mechanisms to successfully implement PPPs.

(3) **Others**

Currently, the major private activities in Angola are engineering, procurement, and construction (EPC). Following are several examples:

- ✓ Cambambe HPP：Odebrecht, Alstom, Voith, Semence
- ✓ LaucaHPP：Odebrecht
- ✓ Laúca-Huambo transmission line：CMEC (China Machinery Engineering Corporation）
- ✓ Soyo：CMEC (China Machinery Engineering Corporation), GE
- ✓ Soyo 2 lotto：AE energy, GE

As a Japanese participant, Sumitomo Corporation has signed an MOU with the Angolan government to build a diesel power plant utilizing diesel generators produced by a Japanese manufacturer.

2.6 Review of the Intended Nationally Determined Contributions (INDCs) relating to the power sector in Angola

A draft of Angola's Intended Nationally Determined Contribution (INDC) was published in December 2015. The contents can be outlined as follows:

(1) Reduction target

Angola plans to reduce GHG emissions by up to 35% unconditionally by 2030 as compared to the Business As Usual (BAU) scenario (base year 2005). And in a conditional mitigation scenario, the country is expected to be capable of reducing emissions by an additional 15% below the BAU emission levels by 2030. In achieving its unconditional and conditional targets, Angola expects to reduce its emissions trajectory by nearly 50% below the BAU scenario by 2030 at an overall cost of over 14.7billion USD.

In light of Angola's extreme vulnerability to Climate Change impacts in key economic sectors, the Angolan INDC also includes priority adaptation actions that will enable a strengthening of the resilience of the country towards the attainment of the Long-Term Strategy for the Development of Angola (2025).

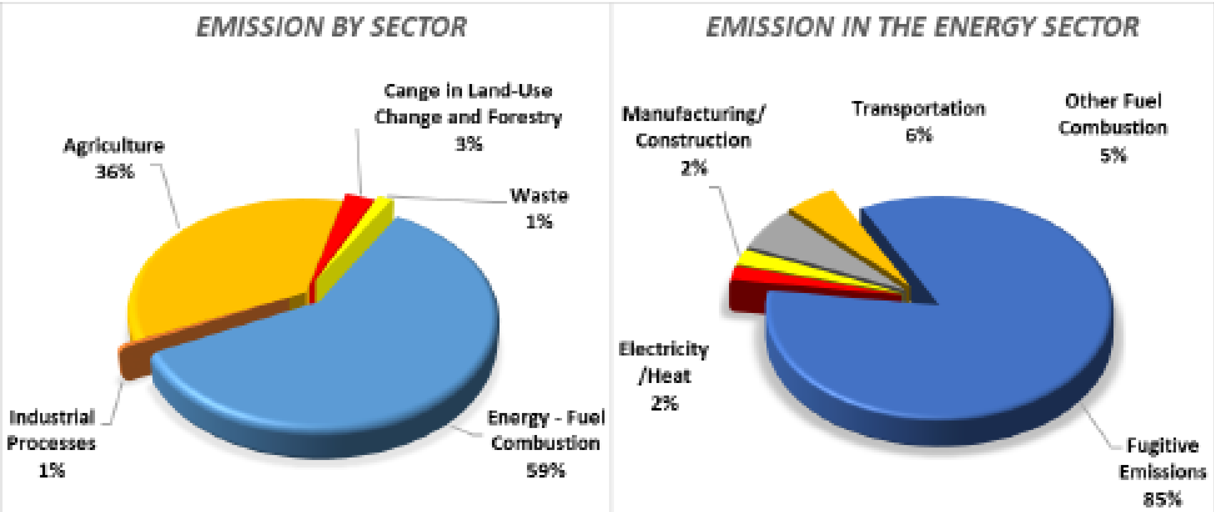
(2) Base year period and baseline data

The year 2005 is used as the reference year.

Figure 2-13 shows GHG emissions by sector in Angola for the year 2005. According to this, GHG emissions from the fuel combustion of the energy sector accounted for the majority of the total (occupancy rate: 59%).

The next largest contributors were emissions from agriculture, from change in land-use, and from forestry sectors.

The figure also shows the emission amount in the energy sector. The contribution of fugitive emissions in the energy sector is very hitgh, accounting for 85% of the total.



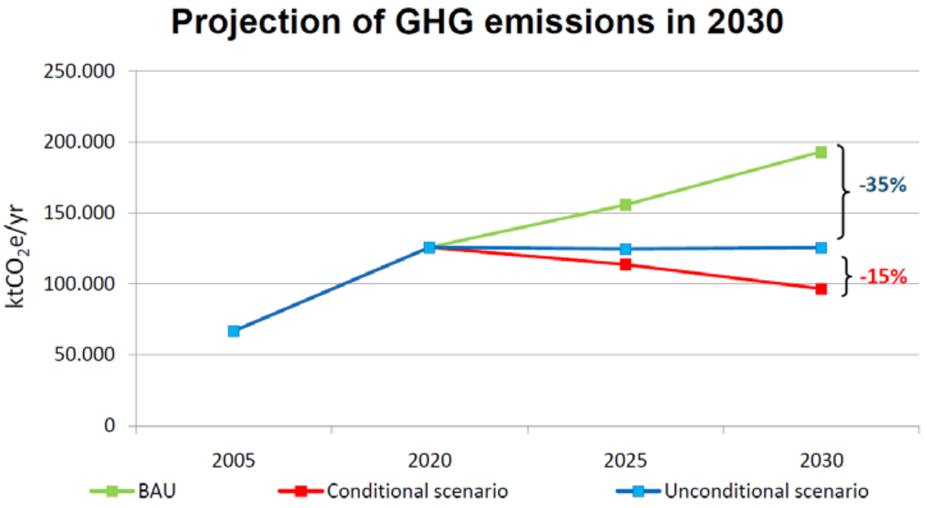
(source：DRAFT INDC of the Republic of Angola)

Figure 2-13 Baseline structure (2005) of GHG emissions in Angola by sector and emissions in the energy sector

(3) Reference scenario without mitigation policies

Therefore, the country is committed to stabilizing its emissions by reducing GHG emissions by up to 50% below the BAU emission levels by 2030 through unconditional and conditional actions targeting the following sectors:

- ✓ Power generation from renewable sources
- ✓ Reforestation.



	2005	2020	2030
Emissions-BAU scenario ($ktCO_2e$)			193,250
Emissions-Unconditional scenario ($ktCO_2e$)	66,812	125,778	125,612 (-35%)
Emissions-Conditional scenario ($ktCO_2e$)			96,625 (-50%)

(source：DRAFT INDC of the Republic of Angola)

Figure 2-14 Baseline scenario and projections of unconditional and conditional mitigation scenarios in Angola

(4) Outline of mitigation

An unconditional countermeasure is an ongoing project in which funding has been fully identified. The following three projects are specified as efforts in the power sector.

- ➢ Repowering of Cambambe I Hydroelectric Power Plant
- ➢ Cambambe Hydroelectric Second Power Plant
- ➢ Tombwa Wind Farm

A conditional countermeasure is a project that will be implemented after its performance is analyzed. MINEA has summarized the list of potential countermeasure project candidates in the power sector. The outline is as follows

- ➢ 681 MW for wind energy projects,
- ➢ 438 MWfor solar energy projects
- ➢ 640 MW for biomass projects, and
- ➢ 6,732 MW hydroelectric projects

2.7 Some issues faced by the Angola power sector

Based on the review of the current status, the Survey Team will point out a number of issues facing the Angolan power sector.

2.7.1 Issues in term of the organization

(1) **Entity in charge of the generation development plan**

As plans stand, MINEA is to proceed with the power development plan in the following stages:

- ✓ First, ENDE implements the power demand assumption.
- ✓ Based on that, PRODEL formulates a generation development plan.
- ✓ Based on the above assumption and plan, the RNT formulates a transmission development plan.
- ✓ DNEE summarizes the foregoing plans in a draft budget plan for the country.

It seems, however, that PRODEL, the company responsible for the generation development plan, does not share this recognition. PRODEL's view of the process may stem from GAMEK's role as the organization actually in charge of large-scale power development and PRODEL's inability to actually become a responsible company.

After the Survey Team formulates the power development master plan in this work, the Angolan entities need to roll up the plan every year.

Hence, the technology for formulating the master plan in this study will also be transferred. This is a major problem with the organization, as it remains unclear whether the technology should be transferred to GAMEK or PRODEL.

(2) **Insufficient accumulation of data**

As the state-run power utilities were integrated and horizontally separated into three (3) public power companies only fairly recently, in 2015, none of them have accumulated or integrated extensive data as of this year, 2017.

While the data predating the reorganization has been handed over to the three public companies, much of the data was found to be inconsistent at the stage of compiling.

In the future, the Survey Team strongly recommends that MINEA and the headquarters of each public company clearly decide data collection policies and concentrate the following data mainly in their headquarters.

- ✓ Nationwide hourly demand data
- ✓ Operational records for all power plants
- ✓ Hydraulic data (river flow data, reservoir operation data, discharge data, etc.)
- ✓ Fuel usage records, etc.

2.7.2 Issues related to electric power system

(1) **Excessive introduction of diesel & GT generators**

Many diesel and GT generators are introduced in the Angolan power system, mainly in local substations. Ostensibly they have been installed to stabilize the system voltage at peak demand times, but they seem to be mainly operated to compensate for supply shortages. They tend to be operated in a high load factor as a result.

As described later, diesel or GT generation has economic merit if the power is generated in a low load factor. The operation of plants of these types for such long periods is likely to result in high generation costs.

(2) **Dispatching center**

The dispatching center office of Angolan power system is attached to the Camama substation. Currently, this office might have failed to make detailed dispatch for the power plants because the power output of each power station cannot be monitored. For that reason, it is particularly problematic that dispatching the peak power plants for peak demand have not been made smoothly. In order to improve the reliability of the electric power system in the future, it is necessary to change the operating policy of power system and to innovate on facilities in the dispatching systems.

(3) **Toll collection system**

It is said that the current transmission and distribution loss of Angola is about 55% and the technical loss is presumed to be about 15%. That is, about 40% is non-technical loss. According to AfDB the vast majority of nontechnical losses are nonpayment of fees. It seems that the collecting rate of condominium, multi-tenant buildings is low in particular. In the future, measures to introduce prepaid cards system such as South Africa will be promoted.

2.7.3 Issues in terms of power policy

(1) **Barriers to private entry**

As mentioned above, PTSE is to promote private entry into the power sector from 2021, but detailed supplementary provisions are not planned. For that reason, IPP entrants are currently negotiating with the government individually, and seem to be developing according to the judgment of government respondents. Preparation for an early legal system is needed for the first year of entry into the private sector in 2021.

Chapter 3 Primary Energy Analysis for Power Development

3.1 General energy condition in Angola

3.1.1 Primary energy flow analysis

Angola is the second largest oil-producing country in Africa, after Nigeria. The confirmed crude oil reserves of Angola total 12.7 billion barrels (2014, BP statistics) and the production volume totals 177.2 million barrels/day (2015, JOGMEC). The confirmed natural gas reserve totals 9.7 trillion cubic feet (2014, Cedigaz) and commercial production totals 29.7 billion cubic feet (2014, OECD / IEA).

Figure 3-1 shows most of the primary energy flow. Most of the oil produced in the country is exported. Most of the natural gas produced (oil-associated natural gas), meanwhile, is reintroduced into oil fields or incinerated, as the country lacks liquefaction plants and equipment for transporting natural gas. As such, only a small amount of the natural gas is effectively used.

As the flow shows, none of the benefits of oil and natural gas reach the general public.

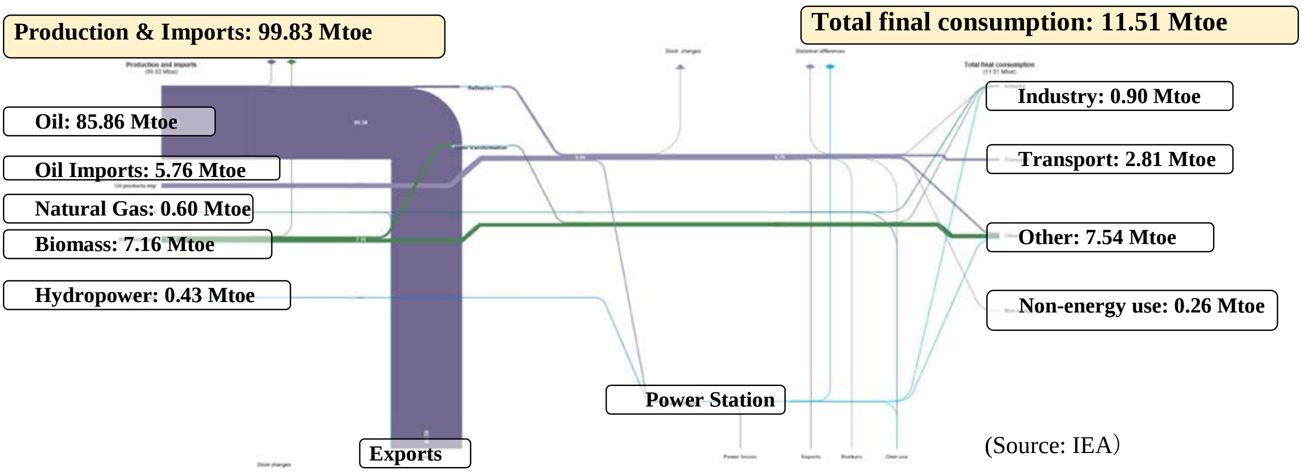
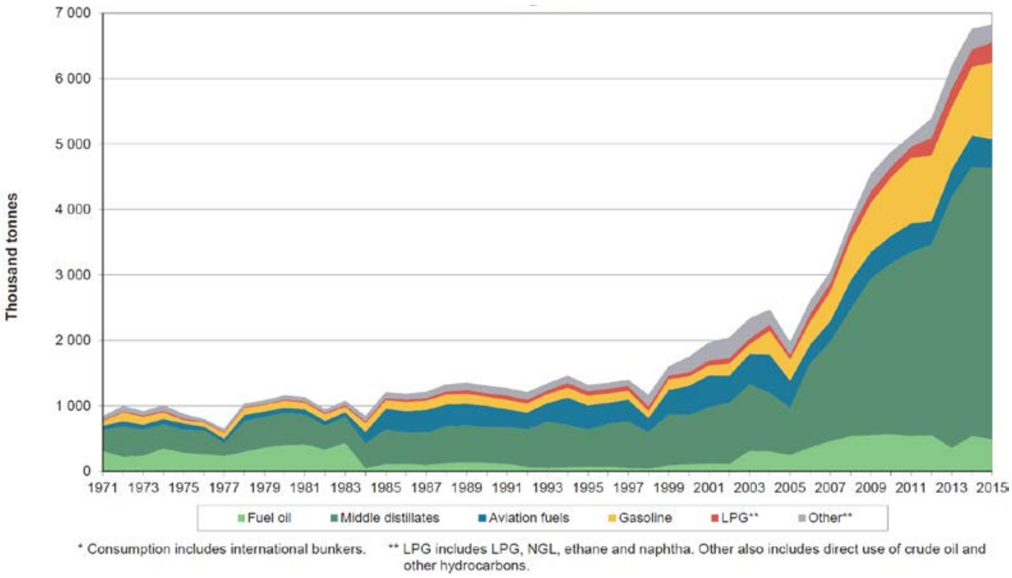


Figure 3-1 Primary energy flow in Angola

(1) **Consumption of oil products**

Figure 3-2 shows the transition in the consumption of oil products in Angola. Consumption has rapidly increased since 2003 after the end of the civil war. The increases in the consumption of middle distillates such as kerosene, jet fuel, and diesel have been especially rapid. This supports of the assumption that fuel consumption is increasing in transportation and commerce.



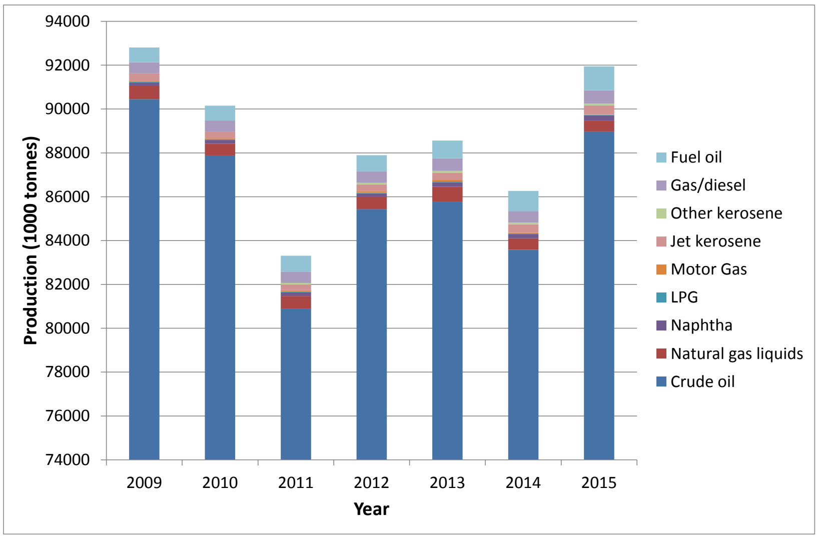
(Source : IEA)

Figure 3-2 Consumption of oil products in Angola (consumption includes international bunker)

(2) Production of oil products

Figure 3-3 shows the transition in the production of oil products in Angola. The most abundantly produced oil product is clearly crude oil.

Crude oil production dropped to its lowest level in 2011. Then, it climbed back up to about 89 million tonnes in 2015.



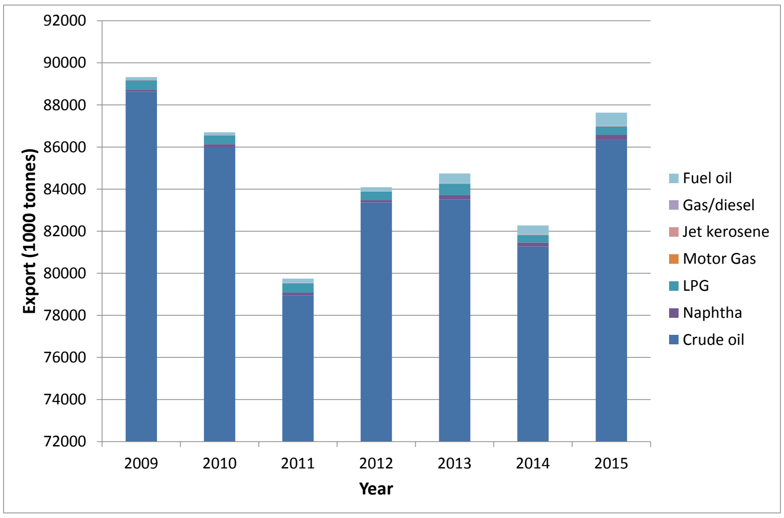
(Souce : IEA)

Figure 3-3 Oil production in Angola

(3) Import of oil products

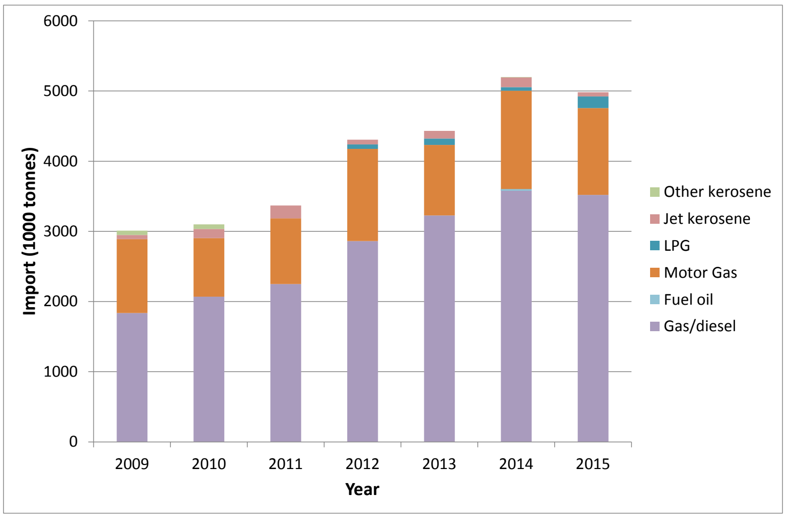
Figure 3-4 and 3-5 respectively show the transitions in the amounts of oil products imported and exported to and from Angola. Domestically produced crude oil makes up the most of the exports, leaving very little left over to send to Angola's domestic refineries.

On the other hand, diesel oil and gasoline make up more than 90% of the imports, and their import levels are increasing. These figures show the Angolan "distortion" wherein Angola, the leading oil producer of Africa, imports secondary oil products.



(Source：IEA)

Figure 3-4 Exported oil production from Angola

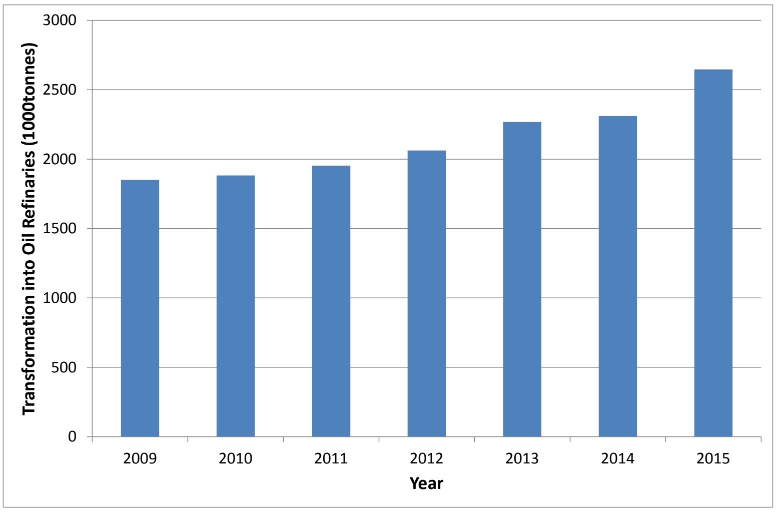


(Source：IEA)

Figure 3-5 Imported oil production into Angola

(4) **Refined oil products**

Figure 3-6 shows the transition in the amount of refined oil produced at domestic refineries. The amount is gradually increasing, but a failure of the domestic refineries in keeping up with domestic consumption has led to an increase in oil product imports.

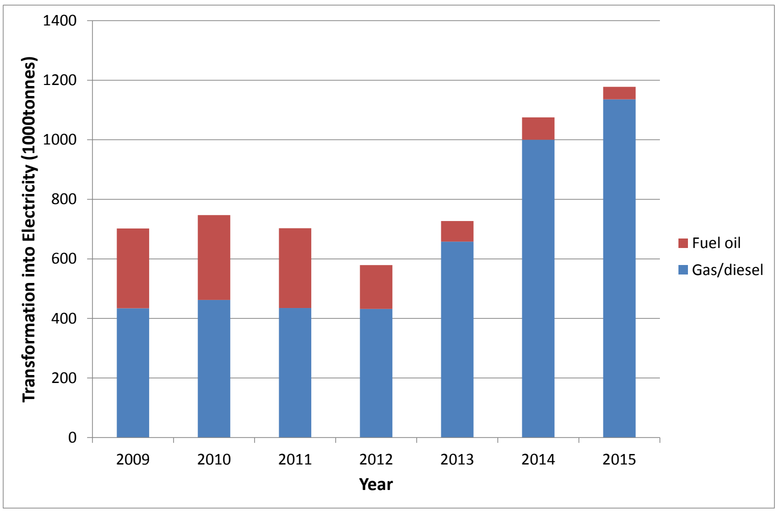


(Source：IEA)

Figure 3-6　Refined oil production in Angola

(5) **Converted oil products for power generation in Angola**

Figure 3-7 shows the transition in converted oil products for power generation in Angola. The conversion amount is dramatically increasing and the oil product used for fuel is shifting from heavy oil to lighter oil.



(Source：IEA)

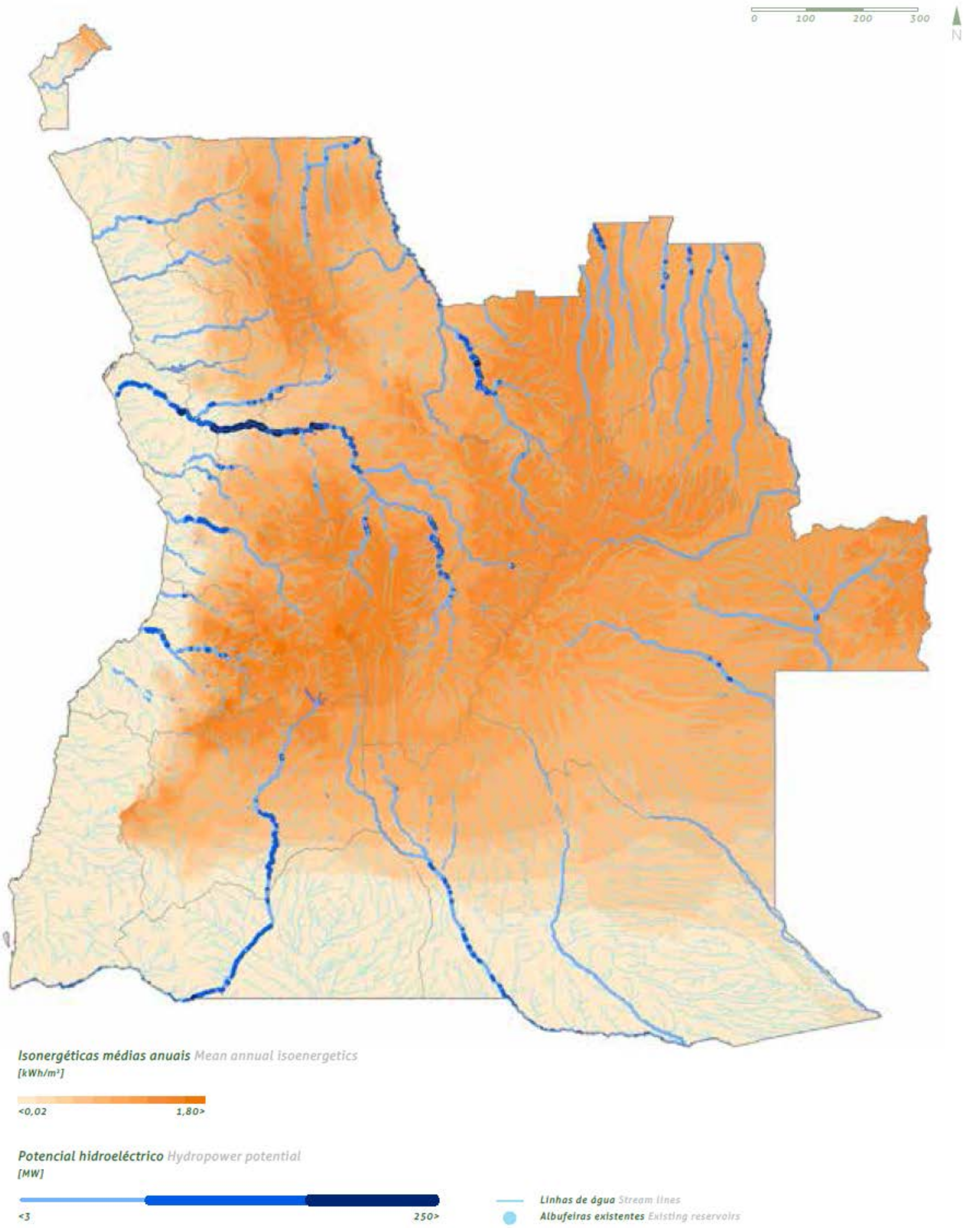
Figure 3-7　Converted oil products for power production in Angola

3.2 The potential of primary energy

For the analysis of the potential of primary energy in Angola, we confirmed the potentials of large hydro, oil, natural gas, and renewable energy.

3.2.1 Large hydropower

Angola has one of the highest potentials for hydropower among the countries of Africa. According to the Atlas and National Strategy for New Renewable Energies, the potential for hydropower is 18 GW, 86% of which is made up by the Kwanza River, Cunene River, Catumbela River, and Queve River Basin. Figure 3-8 shows the hydropower potential throughout Angola.



(Source：Atlas and National Strategy for the New Renewable Energies)

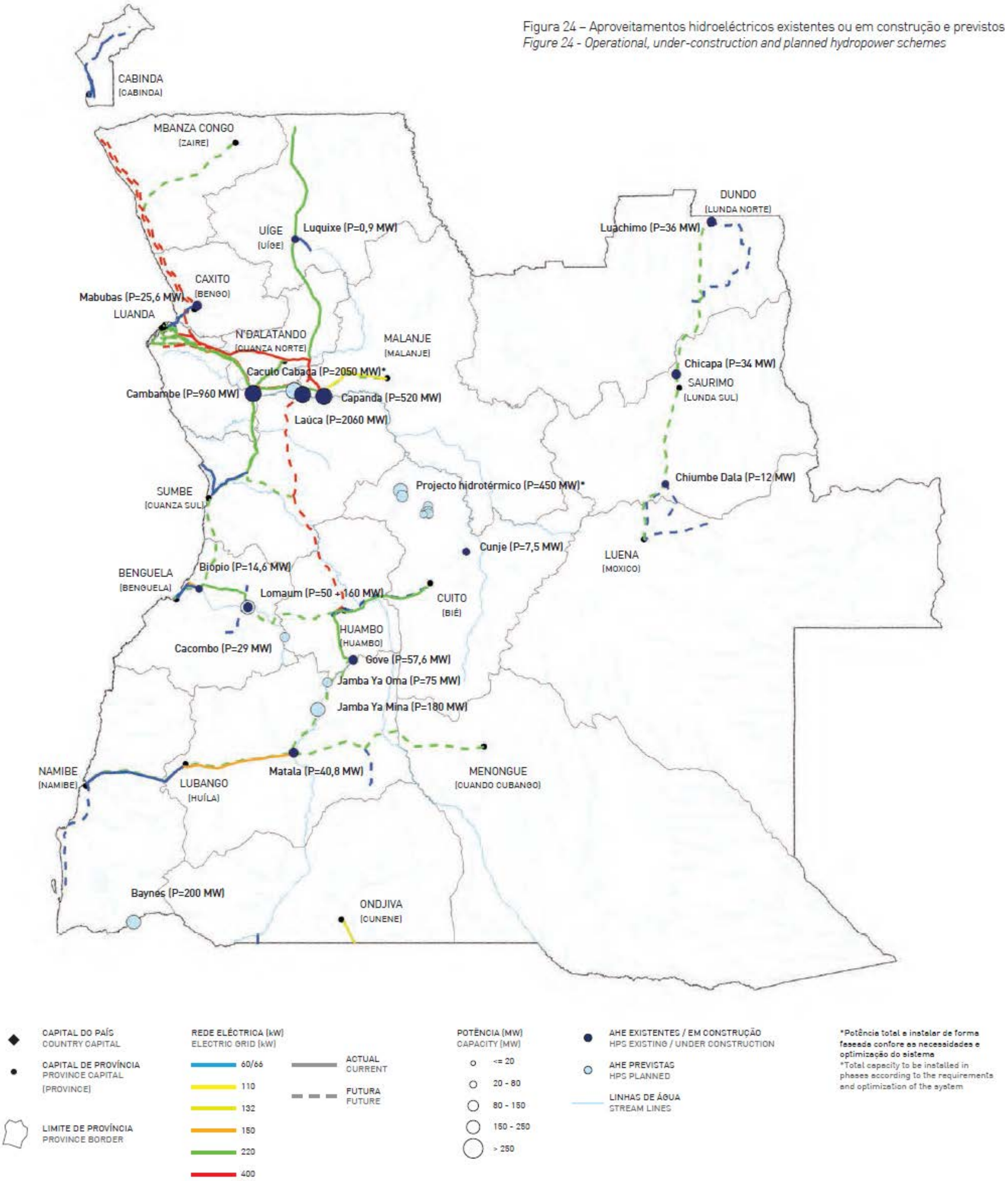
Figure 3-8 Hydropower potential throughout Angola

Table 3-1 lists Angola’s new large hydropower plants, and Figure 3-9 shows the locations of existing/planned hydroelectric power plants in Energia 2025. According to our team's interview survey, however, the planned projects on the list have been reviewed by MINEA and GAMEK. The latest information is shown in Chapter 6.

Table 3-1 List of new large hydropower plants

No.	Name	River Name	Capacity [MW]	Energy [GWh/year]	Project Cost Mil $
1	Carianga	CUANZA	381	1557	1295
2	Bembeze	CUANZA	260	1075	768
3	Zenzo 1	CUANZA	460	2680	1206
4	Zenzo 2	CUANZA	114	695	623
5	TÚMULO DO CAÇADOR	CUANZA	453	2759	1041
6	QUISSONDE	CUANZA	121	773	838
7	Salamba	CUANZA	48	194	324
8	QUISSUCA	LONGA	121	589	567
9	Cuteca	LONGA	203	873	734
10	CAFULA	QUEVE	403	1919	1121
11	UTIUNDUMBO	QUEVE	169	743	406
12	DALA	QUEVE	360	1686	1010
13	CAPUNDA	QUEVE	283	1200	741
14	BALALUNGA	QUEVE	217	1013	475
15	MUCUNDI	CUBANGO	74	368	538
16	CAPITONGO	CATUMBELA	41	249	239
17	CALENGUE	CATUMBELA	190	1136	471
18	CALINDO	CATUMBELA	58	340	187

（Source：Energia 2025）



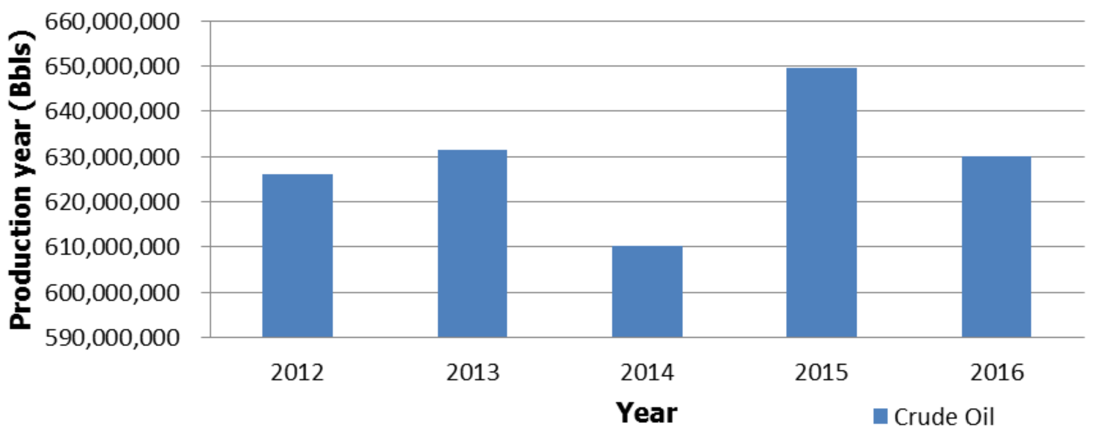
（Source : Angola Energia 2025）

Figure 3-9 Locations of existing/planned hydroelectric power plants

3.2.2 Oil

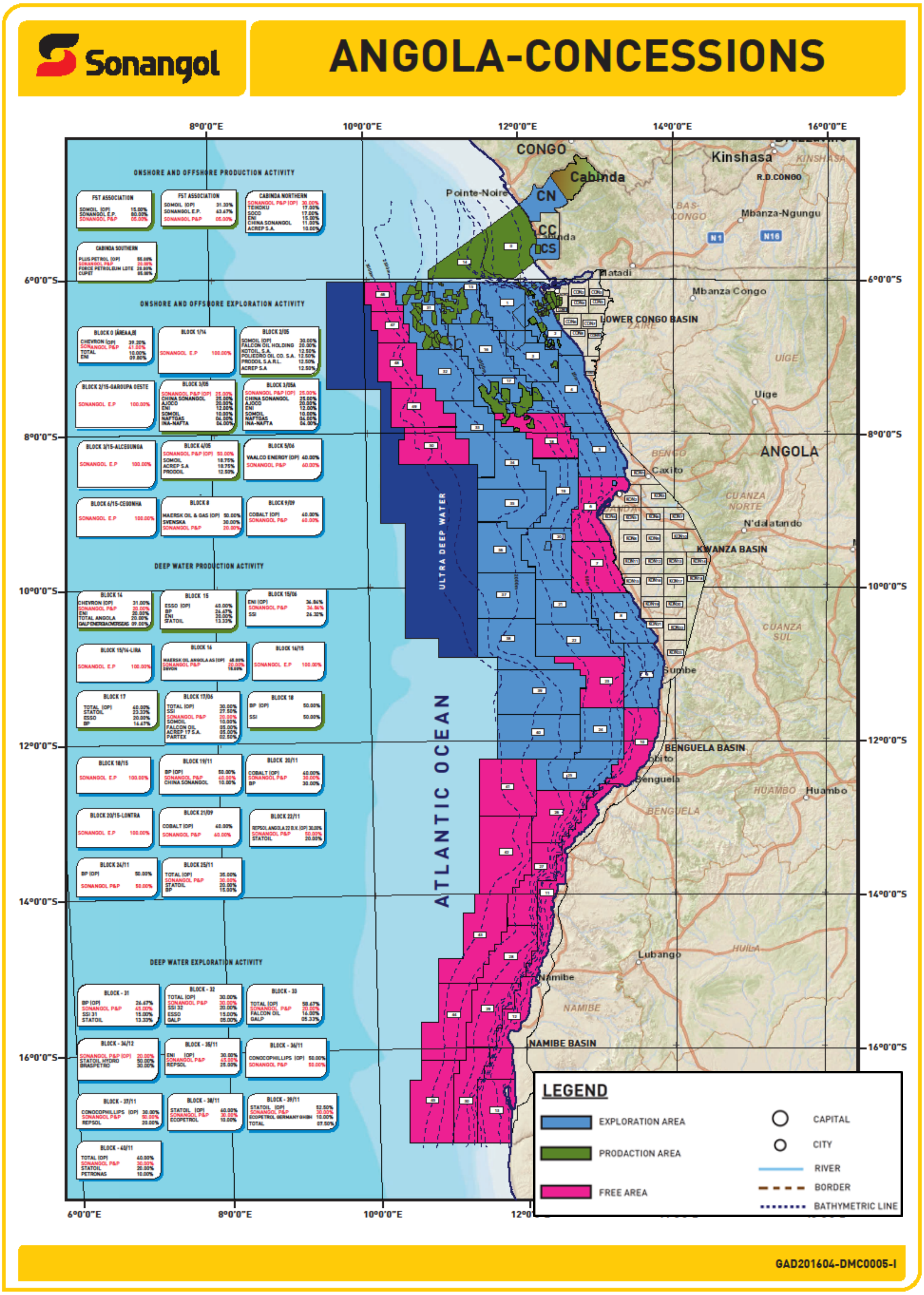
Oil resources in Angola are managed by the state-owned company Sonangol, and development is undertaken jointly with international oil companies (BP, Chevron, ENI, ExxonMobil, Petrobras, Statoil, Total, etc.). The Confirmed crude oil reserves in Angola total 12.7 billion barrels (BP statistics at the end of 2014) and production (January-November 2015 average) comes to 17,720,000 barrels/day (JOGMEC). The regions of oil production and development are located mainly in coastal areas from the northern to central part of the country, and only partially on land. Specific points include the coastal state of Cabinda and Zaire province.

Figure 3-10 plots the crude oil production results in Angola. The diagram in Figure 3-11 gives an overview of oil development in the country.



（Source : Sonangol Annual Report : 2012 - 2016）

Figure 3-10 Crude oil production results in Angola（2012～2016）



（Source：Sonangol web page）

Figure 3-11　Oil development in Angola

3.2.3 Natural gas

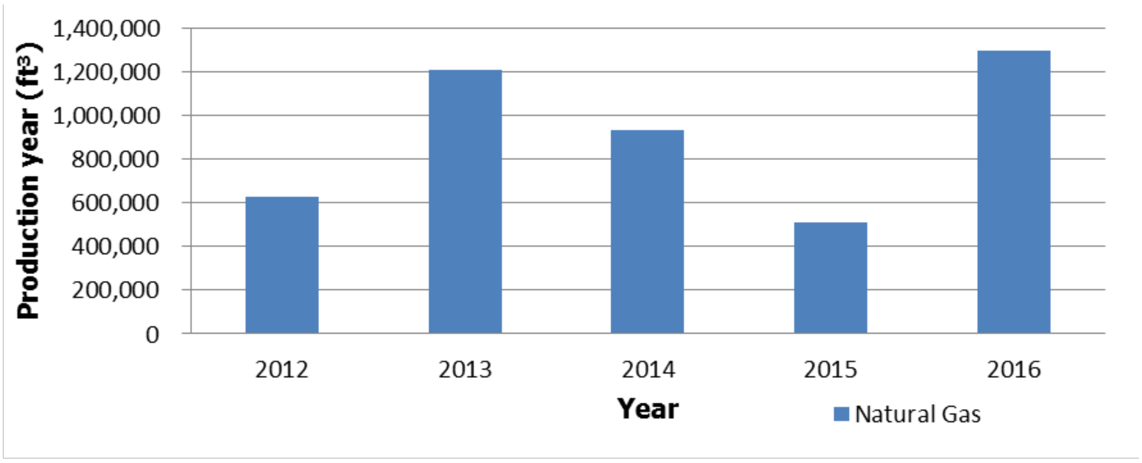
Confirmed natural gas reserves in Angola total 9.7 trillion cubic feet (2014, Cedigaz) and the commercial production volume comes to 29.7 billion cubic feet (2014, OECD / IEA). Most of the natural gas produced is accompanying gas produced through oil drilling and is treated as backfill or flare and left unused due to the high cost of use.

In recent years, however, the demand for natural gas has been increasing worldwide due to the lower greenhouse gas emissions of natural gas products compared to oil products and technological advances enabling more stable transportation of natural gas. The effective use of natural gas has been considered in Angola.

The state-owned company Sonangol E.P. manages natural gas production in Angola and is constructing a pipeline to transport accompanying natural gas generated from oil production facilities to the natural gas plant. As of 2017, existing pipeline connects Blocks 15, 17, and 18 and new pipelines connecting Blocks 0 and 14 are under construction. According to Angola LNG, the natural gas plant is designed to produce up to 1.1 billion ft^3/day or 5.2 million tons/year.

Angola has a plan to use natural gas as fuel for gas-fired thermal plants such as Soyo 1 CCGT (under construction as of 2017) and Soyo 2 CCGT (planned). Soyo 1 started operating in Unit 1 in July 2017 using diesel oil in a simple cycle. It will switch to gas generation once it is connected with the LNG plant in Soyo port Terminal via pipeline,

Figure 3-12 shows the amounts of natural gas produced in Angola.



（Source : Sonangol Annual Report 2012 - 2016）

Figure 3-12 Amounts of natural gas produced in Angola

3.2.4 Renewable energy

Figure 3-13 shows the total capacity of projects considered for each form of renewable energy (RE). As of 2017, high costs have curtailed any efforts to install RE plants. The total potential for RE, however, is about 20.0 GW. The Angolan government has set concrete targets for renewable energy installs by 2025 and selected a priority project in Angola Energia 2025.

The details on each form of RE are summarized in (1) to (4).

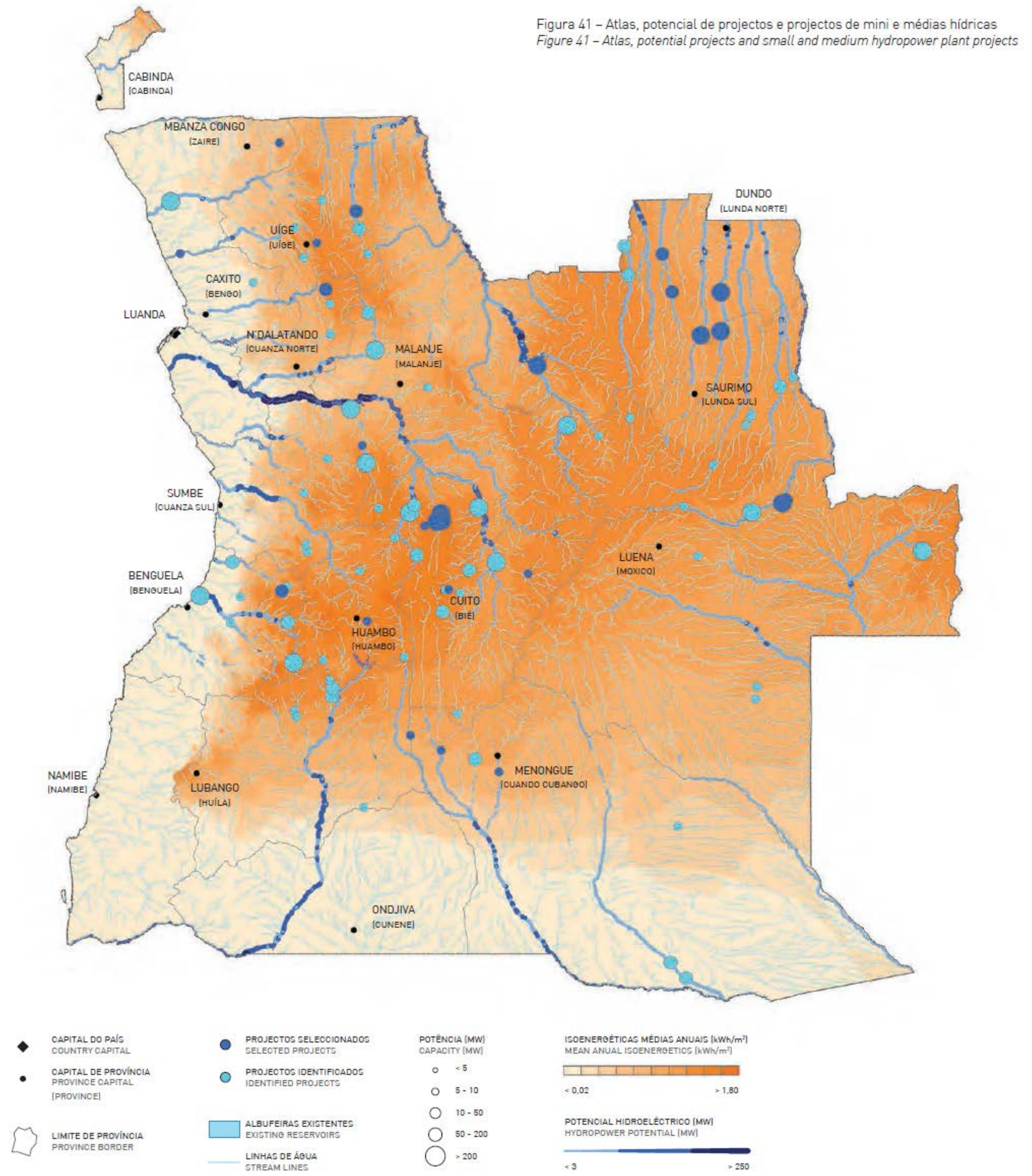
(Source : Atlas and National Strategy for New Renewable Energies, 2015)

Figure 3-13 The total capacity of projects considered for each RE

(1) Small and middle hydropower

Figure 3-14 shows the potential diagram of medium- and small-sized hydropower generation.

According to the Atlas and National Strategy for New Renewable Energies, the potential of small-middle size hydropower plat projects totals 600 MW and the currently installed capacity totals 60 MW. Future plans on Angola Energia 2025 call for the installation of 30 MW of off-grid small hydropower plants, 70 MW of on-grid small hydropower plants, and 270 MW of medium-sized hydropower plants, in total, by 2025.



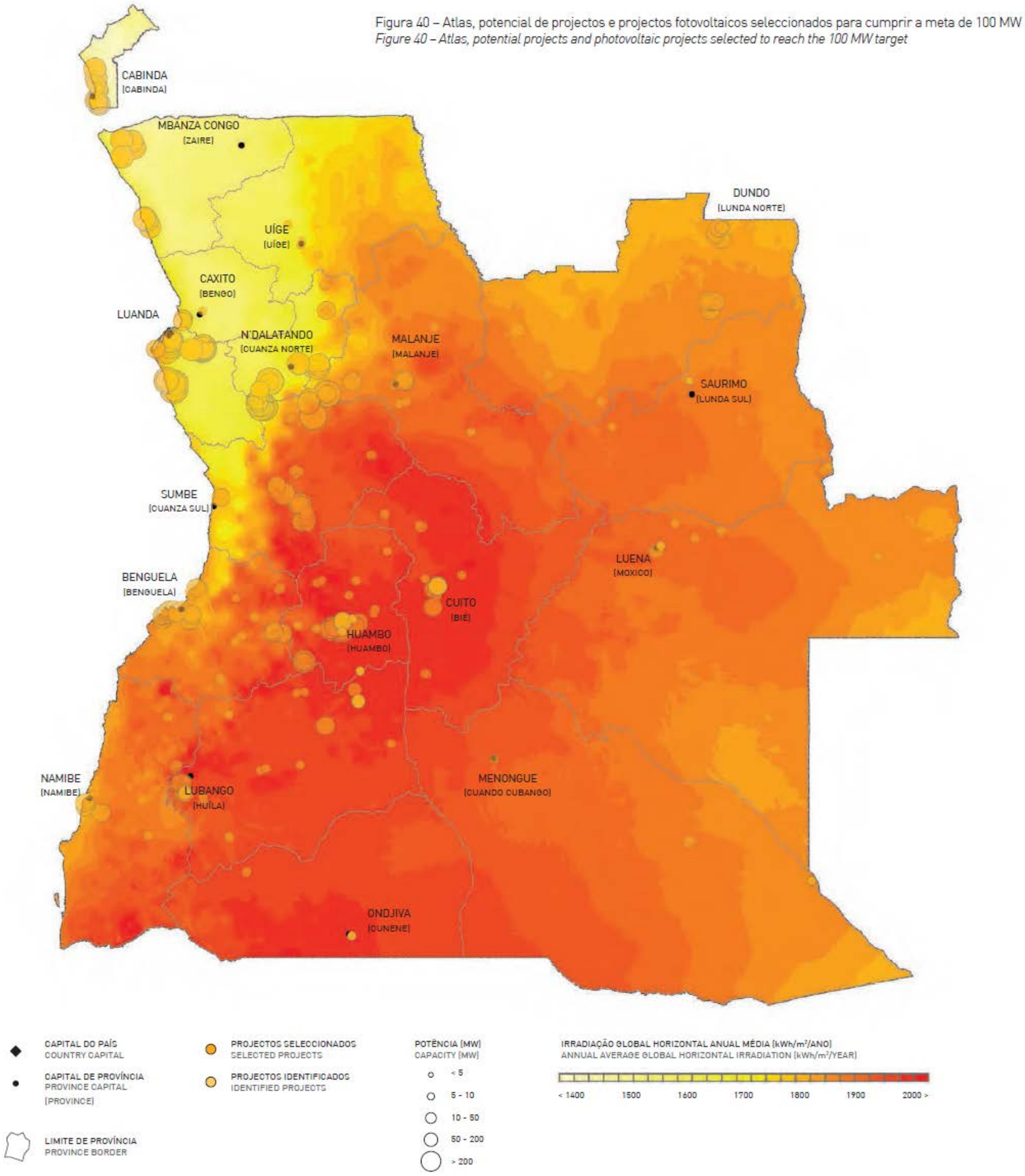
（Source： Angola Energia 2025）

Figure 3-14 the medium-small hydropower potential diagram in Angola

(2) **Solar energy**

The diagram in Figure 3-15 gives an overview of the RE potential in Angola. According to the Atlas and National Strategy for New Renewable Energies, Angola has a high solar resource potential, with an annual average global horizontal radiation ranging between 1.350 and 2.070 kWh/m^2/year and photovoltaic power (PV) potential totaling 17.3 GW, with PV projects already under study. PV constitutes the largest and most uniformly distributed renewable resource of the country.

When considering the installation of PV generation as an alternative to diesel power generation, however, the need to install batteries has pushed up costs to levels prohibitive enough to postpone installation. In the eastern (Huambo, Kuito, etc.) and southern regions, meanwhile, the installation of medium- and large-scale PV generation facilities has clear cost advantages over diesel power generation. The PV installation target is 100 MW by 2025.



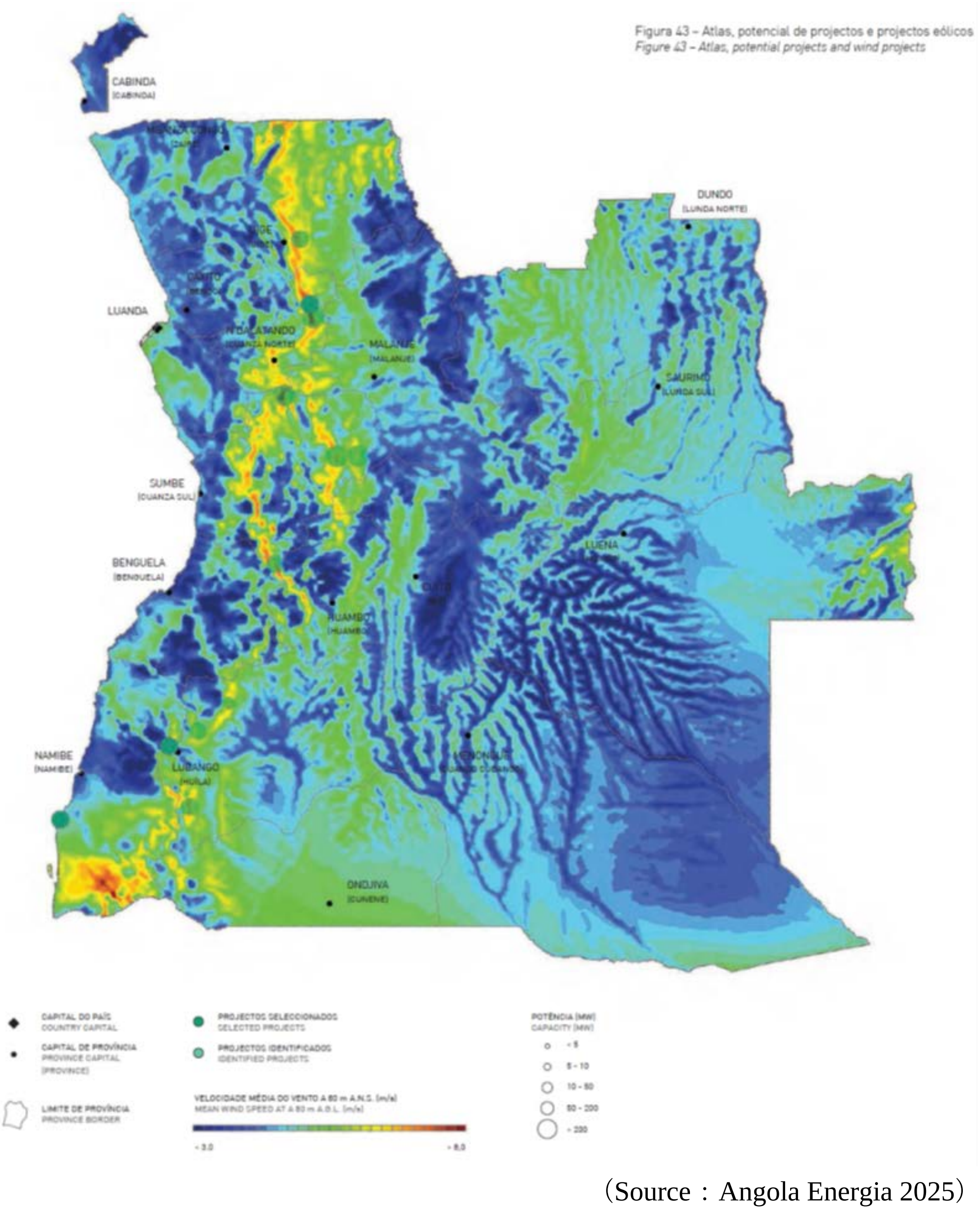
(Source：Angola Energia 2025)

Figure 3-15 Solar energy potential in Angola

(3) **Wind energy**

Figure 3-15 shows the Wind Energy potential diagram in Angola. According to Angola Energia 2025, locations with high potential for wind energy can be found at higher altitudes along a North-South axis of the country and in the southwest region, where the wind reaches high average speeds exceeding 6 meters per second at 80 meters above ground level. The wind resource in the rest of the country ranges between 3.5 and 5.5 meters per second, offering limited potential for electricity generation at competitive costs.

The 12 survey sites have a total capacity of 3.9 GW, and the capacity for wind generation with high economic efficiency at high-priority sites totals 0.6 GW. Looking ahead, plans are in place to introduce 100 MW of wind energy capacity by 2025. There are three main projects: the Tombwa wind project, a project in Cuanza Norte, and a project in Lubango.



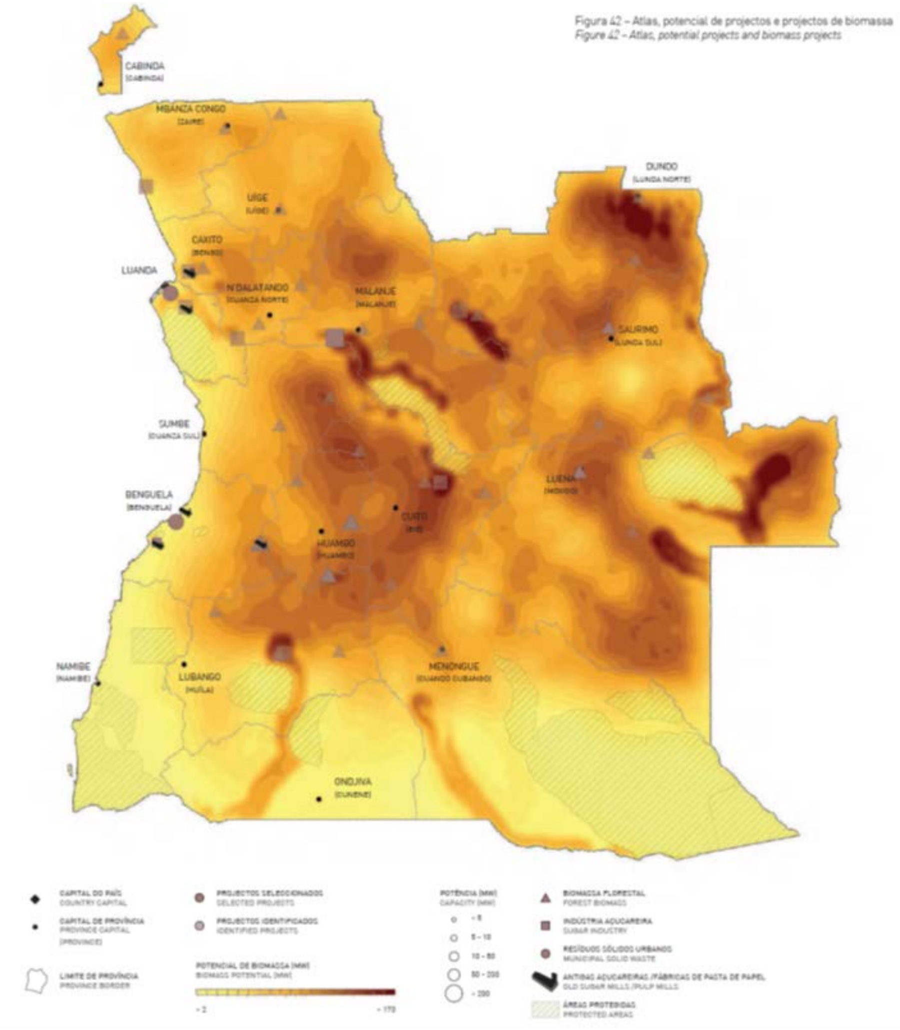
（Source：Angola Energia 2025）

Figure 3-16 Wind Energy potential in Angola

(4) **Biomass**

The diagram in Figure 3-17 gives an overview of the biomass generation potential in Angola. Biomass resources in the country include forest resources and agricultural residues (mainly sugarcane). The sites with the highest potential for these resources are located in the central region (Huambo, Bie, Benguela) and eastern region (Moxico, Luanda-Sul, Luanda - Norte). The total capacity of biomass energy potential in Angola is 4 GW, and the total capacity of studied projects is 1.5 GW.

According to Angola Energia 2025, plans are in place to install 500 MW of biomass power generation capacity by 2025. The main projects mentioned are to generate 300 MW from hydrothermal power (hydrothermal) using existing forest resources, 100 MW from Malange in the Biocom Project using sugarcane production, and 50 MW from the incineration of solid waste discharged from cities represented by Luanda City and Benguela City.



(Source：Angola Energia 2025)

Figure 3-17 Biomass generation potential in Angola

3.2.5 Coal

Coal reserves have not been investigated in Angola and the country has no experience in the use of coal.

Hence, there is no coal-related data as of 2017.

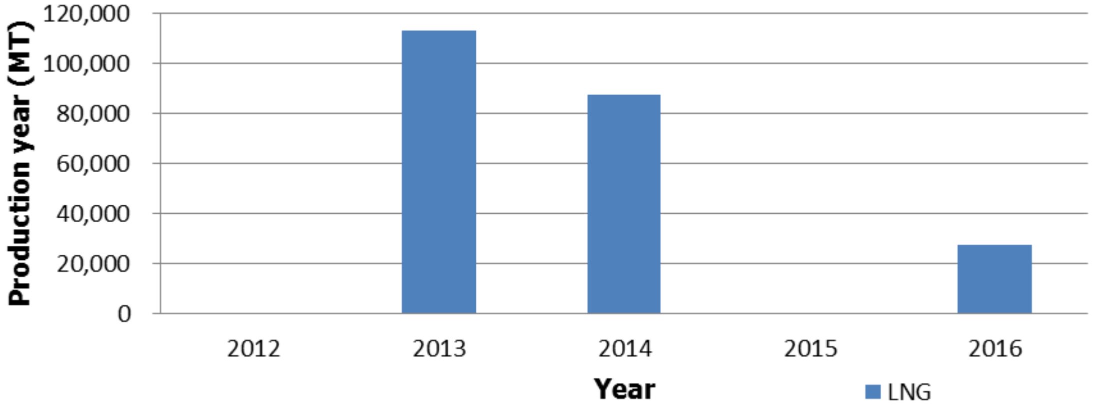
3.3 Condition of energy supply facilities

3.3.1 Liquefied natural gas (LNG) plant

Figure 3-18 shows the actual production of LNG from 2012 to 2016.

Angola LNG, the only LNG plant in Angola, is located in Soyo Province of Zair State.

The plant is connected with an oil production plant and sends the associated gas it produces to a refinery by pipeline. The Angola LNG production facility has a capacity of 34 MSm^3 / d.



(Source : Sonangol Annual Report 2012 - 2016)

Figure 3-18 Actual production of LNG from 2012 to 2016

The LNG now produced is primarily exported. The future LNG utilization scenario in Angola Energia 2025 has two components:

- Export the LNG to remote countries by large LNG carriers
- Transport the LNG to Lobito, Namibe, etc. and re-gasify it to produce fuel for a new type of large thermal power plant.

Incidentally, it is unclear whether the plan is commensurate with the cost generated by the regasification after the production of LNG using energy.

3.3.2 Oil refinery plant

Angola currently owns only one oil refining facility in the capital city of Luanda, but the refinery capacity is insufficient for oil production. So that, Angola, therefore relies on imports for more than 80% of its domestically consumption of oil products. To implove this situation, Sonangol has developed plans to build new refinery facility projects located in the central coastal city of Lobito, the State of Soyo in northern Zaire, and the coastal city of Namibe in the south.

Table 3-2 presents information on the existing/planned refinery facilities. The Lobito project was scheduled to start operation in 2018, but construction was halted in August 2016 due to a shortage of funds. The Soyo project, meanwhile, was launched, but the project never proceeded to the actual construction stage. Construction for the Namibe project was started in July 2017 and is now underway.

On February 2018, Sonangol announced new plans to develop oil refining facilities in central Lobito and northern Cabinda province, along with an expansion plan for the existing Luanda Rifinery. Proposals accepted from domestic and foreigin companies under these plans are now being evaluated.

Sonangol has reported that it is targeting completion of a Lobito facility with a capacity of 200,000 bpd/day, the same level set in the previous plan, by 2022. Completion of a Cabinda facility with a smaller capacity is targeted for 2020.

In addition, an agreement with Italy’s company ENI was already reached towards the end of last year for the execution of an expansion plan for the existing Luanda Rifinery. Production will be expanded from the present 57,000 bpd/day to 65,000 bpd/day by 2020 under that plan.

Table 3-2 Information on existing/planned refinery facilities

Refinery Name	Unit	Luanda	Lobito	Soyo	Namibe	Cabinda
Company		Sonarel	Sonaref →N/A	N/A	Sonaref	N/A
Operation Start	year	1958 →2020	2016(stop) →2022	N/A	N/A	2020
Cost	USD	N/A	8 billion →12 billion	N/A	12 billion	N/A
Capacity	bpd/day	57,000 →65,000	200,000	110,000	400,000	N/A

（Source：Sonangol Universo, and released information）

3.4 Price trends for each form of primary energy

In the study of the optimum power plan until 2040, the setting of the fuel cost is an important factor. When setting value from the perspective of a national economy, fuel costs are often based on international prices. Therefore, the team will investigate and consider costs based on prices in the international market.

The study refers to data from World Energy Outlook 2016 (WEO - 2016) published by the International Energy Agency (IEA) and World Bank (WB). Price fluctuations to the present and future forecasts up to 2040 are compared in three scenarios studied by the IEA.

The three scenarios in WEO-2016 are as follows:

· New Policies Scenario
· Current Policies Scenario
· 450 Scenario

In the New Policies Scenario, the country's adopted targets under the Paris Agreement adopted by the 2015 United Nations Climate Change Conference (COP 21), an agreement mandating greenhouse gas reductions by almost all countries, are fully or partially achieved. The use of fossil fuels is suppressed and the installation of renewable energy and other forms of clean energy is promoted.

In the current policy scenario, the Paris Agreement is not implemented or renegotiated, and the use of fossil fuels does not change from the present.

The 450 Scenario is a scenario for a decarbonized society proposed by the IEA's WEO. In this scenario, target of the average temperature is devised as an energy composition that can suppress a temperature rise of 2 °C from the Industrial Revolution era.

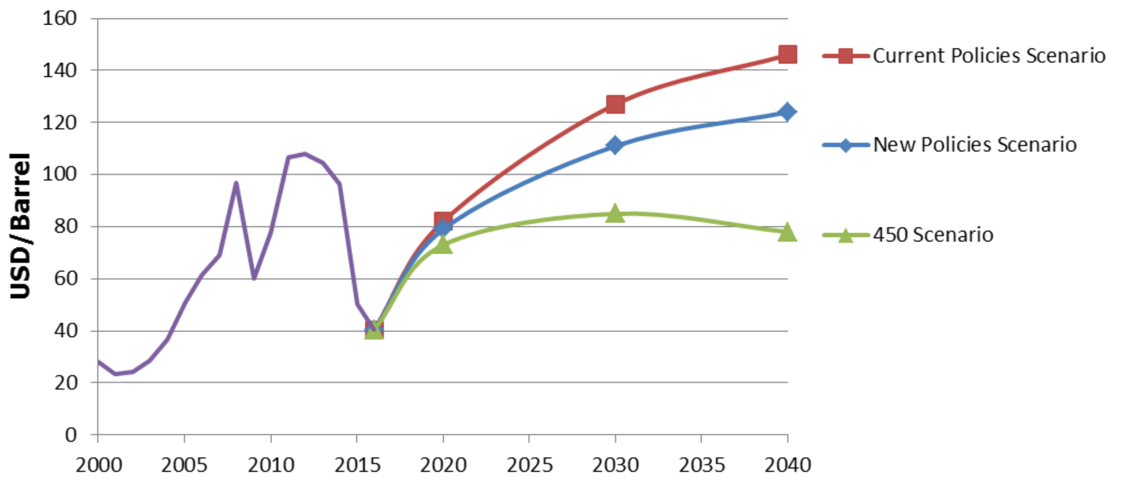
3.4.1 Crude oil

Figure 3-19 shows the changes in crude oil prices in the international market since 2000 and the future development in each scenario. The future oil price trend is expected to rise in every case. The current price is $ 40/Barrel due to the discount from 2012.

However, a strong demand for crude oil in emerging markets is expected to remain in the future in all three scenarios. Crude oil is currently being purchased at low prices from OPEC member countries, but purchases at high prices from non-OPEC countries will increase. Hence, oil prices continue to edge gradually higher and ultimately reach $ 80/Barrel in 2020 in every case.

In all three scenarios, the price fluctuation after 2020 will continue to rise with the ongoing development of oil resources and a decrease of inexpensive, high quality so-called "sweet spots" necessitating further moves into areas with expensive and low-quality oil.

Conversely, the 450 Scenario foresees lower prices accompanying reduced crude oil demand and price maintenance supported by a stronger push toward a decarbonized society, compared the other scenarios.



※WTI, tax excluded (Source: IEA World Energy Outlook 2016)

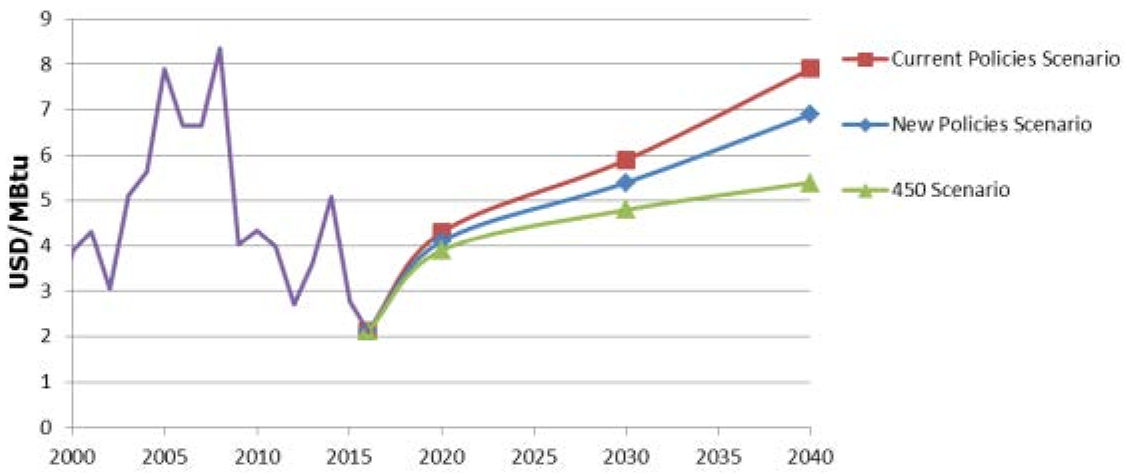
Figure 3-19 Changes in crude oil prices in the international market

3.4.2 Natural gas

Natural gas has no international common price like crude oil, but there is a fixed price for each region, i.e., (1) USA, (2) Europe, (3) China, and (4) Japan. The (1) US price is based on the cost to transport and sell domestically produced products by pipeline, the prices in (2) Europe and (3) China are based on the cost of importing raw gas in pipelines and processing it into LNG, and the price in (4) Japan is based on the import price for only LNG.

In the case of Angola, natural gas is produced domestically and will be connected to domestic consumption areas by pipeline in the future. The condition is similar in the (1) USA, so we refer to forecast fluctuation in both countries.

Figure 3-20 shows the forecast for price fluctuations of natural gas from 2000 up to 2040. Because the price of natural gas is correlated with the crude oil price, it is expected to rise to around $ 4/MBtu against strong demand up to 2020, as with crude oil price. In the case of natural gas, however, the demand for LNG will increase worldwide in the future as a cleaner fuel with lower rates of CO_2 emission. Hence, the price of natural gas will continue to rise for both domestic consumption and exports in each scenario.



※US price, tax excluded (Source: World Bank and IEA World Energy Outlook 2016)

Figure 3-20 Forecasted fluctuation of natural gas prices (2000 - 2040)

3.4.3 Selected fuel price for formulating the "Optimal Generation Mix"

Since Angola is also participating in the Paris Agreement, the team will adopt the New Policies Scenario base value as the fuel cost when considering the optimum power plan. Specific values for each fuel cost will be shown in the section on the power supply development plan.

3.5 Items to Prepare to Promote Power Development

When planning a power supply plan, especially a thermal power development plan, the fuel supply policy is important to consider. More specifically, the thermal power development plan must thoroughly consider the type of fuel to be used, the supplier of the fuel, the method for transporting it, and the equipment necessary for using it.

In this section we analyze and examine the options for thermal power plants in the optimum generation mix plan, the fuel(s) to be used in the plants, and the kinds of fuel supply facilities needed.

3.5.1 Options for Power Supply

In Chapter 6 we study power supply development plans in detail. As a result of examination, the following have been selected as available power supply options.

- Large hydropower plant
- CCGT
- GT
- Renewable energy power (small hydropower plant, wind power, solar power, biomass, etc.)

The thermal power options in the power supply plan in Angola are CCGT and GT.

3.5.2 Options for Fuel, and Fuel Characteristics

Natural gas, LNG, LPG and diesel oil are the assumed options for fuel. The characteristics of each fuel are summarized in Table 3-3.

Table 3-3 Fuel Characteristics

Fuel	Characteristics	2015 Price
Natural Gas	➢ In Angola, natural gas is produced as an associated gas from oil fields. ➢ Unless transportation costs are considered, the price per unit calorie is the cheapest. Therefore, application to mine-mouth power plants is economically advantageous. ➢ Gas supply facilities such as gas pipelines are necessary when locating power plants near demand areas. The cost for these facilities will increase the cost of electricity generation overall. ➢ The CO_2 emission factor of natural gas is about 20% lower than that of LPG. Hence, the use of natural gas is advantageous when considering CO_2 emissions.	Approx. 1 cent/Mcal
LNG	➢ LNG is liquefied natural gas by cooling. Angola has an LNG plant in Soyo. ➢ The price per unit calorie is almost the same as that for LPG. For application to thermal power plants, a large-scale LNG tank will be required near the power plants. The high cost for this type of facility will increase power generation cost overall.	Approx. 4 cents/Mcal

	➢ The CO_2 emission factor of LNG is about 20% lower than that of LPG. Therefore, the use of LNG is advantageous when considering CO_2 emissions.	
LPG	➢ Besides being produced from associated gas in oil and gas fields, it is produced in the crude oil refinery process. ➢ The price per unit calorie is similar to that of LNG. ➢ The fuel supply facilities are minimal, so the supply cost can be low. ➢ The thermal efficiency when applied to CCGT and GT is comparable to that of natural gas or LNG. ➢ The unit of CO_2 emissions is about 20% higher than natural gas and LNG	Approx. 4 cents/Mcal
Diesel oil	➢ It may be referred to as light oil in Japan. ➢ The price per unit calorie can be somewhat cheaper than or nearly equal to that of LNG. The thermal efficiency drops, however, so the cost of power generation rises. ➢ The fuel supply facilities are minimal, so the supply cost can be low. ➢ When applied to CCGT and GT, the thermal efficiency drops significantly compared to that of natural gas, LNG, or LPG. ➢ In addition, the CO_2 emission factor is about 40% higher than that of natural gas and LNG. In view of the thermal efficiency during power generation, CO_2 emissions will increase significantly.	Approx. 4 cents/Mcal

Diesel oil is used in most GT and diesel power plants in Angola. The extensive use of diesel oil is thought to be due to the government’s practice of providing diesel oil to power plants free of charge or at low cost. As you can see from the table above, the adoption of diesel oil would be disadvantageous both in terms of CO_2 emissions and the national economy. It will be important to switch to LPG, LNG, and natural gas in the future.

3.5.3 Setting of Thermal Power Generation Planning Scenarios and Selection of Fuel

In this section we will set scenarios for the thermal power development plans and assume which fuels can be used most realistically when the scenarios are realized.

(1) **Middle Demand Power Supply**

< Basic Policy on Power Supply Development> Mine-mouth power plants using natural gas are the most economical. => CCGT in Soyo is the most advantageous.
<Issues> ➢ A relatively large power supply established in Soyo will be affected by the unilateral power flow from Soyo to Benguela (Soyo => Luanda => Benguela) in the structure of Angola’s power system.

This point could partly impede system stability.

- This point also requires an excessive current flow leading to an increase in power transmission loss.
- The line between Soyo and Luanda has a current capacity of 400 kV 2200 MW (N - 1 criteria) and can transmit only to two power plants of the Soyo CCGT (750 MW) class. If we are to build a third power plant, one more transmission line circuit will be required.

<Other information about Construction Costs: based on investigation in Japan>

Cost to Construct the Transmission Line: Approx. 1 millUSD/km

Cost to Construct the Gas Pipeline: 4 – 13 millUSD

Cost to Construct the LNG Tank: 100 – 150 millUSD/unit (Capacity 125,000m3).

FSRU (Floating Storage Regasification Unit): 250 – 330 millUSD (Capacity 140,000m3)

Cost to Construct the LPG Tank: 10-30 millUSD/unit (Capacity 20,000 m3).

< Prerequisites for Making the CCGT Development Scenario>

- Development up to a second CCGT in Soyo is reasonable.
- Regarding development beyond a third CCGT, it would be necessary to add transmission lines to the demand areas Luanda and Benguela. The construction cost in that case would be likely to reach at least 300 mill USD/circuit.
- Therefore, it will be necessary to compare the power generation near the demand site as well.
- In this case we can consider the supply of natural gas by a gas pipeline and supply of LNG after installation of the LNG tank and vaporization facility, etc.
- The cost of constructing a gas line pipeline is estimated to be at least 1,000 millUSD. Use devoted solely to power generation would also be burdensome, so joint use with other industries is considered a prerequisite.
- Regarding LNG supply, the preparation of two LNG tanks would cost up to 200 to 300 millUSD, which would be relatively inexpensive.
- While the FSRU would be more costly than an LNG tank, it would have the advantage of a short installation period.
- With the use of LPG, on the other hand, supply facilities would be very inexpensive. This is an option, given that the current LPG price is close to the LNG price. CO_2 emissions, however, would increase by about 20%.

< CCGT Development Scenario>

- In Soyo, the development of CCGTs for two power stations takes top priority. Development surpassing three power plants depends on the transmission line extension cost. But in view of system stability, we recommend CCGT construction near the demand site.
- Considering the increase in demand, especially in Benguela and the rest of the central area, developing CCGT in Lobito port in Benguela has definite merits.
- Furthermore, with the growth of demand in the central and southern parts, it would be meaningful not only to construct a CCGT at Lobito Port additionally, but also to develop a CCGT at Namibe Port in the southern part. If CCGT development in the southern part progresses thus and international interconnection with Namibia is developed, it may be possible to sell power to the SAPP in the future.
- Considering the above points, after placing priority on building two 750 MW class power plants in

Soyo, there is a plan to develop the subsequent CCGT at Lobito Port and Namibe Port.

< Fuel supply scenario>

- We recommend setting the following fuel supply scenario according to the above CCGT development scenario.
- In Soyo, we continue to supply natural gas for the mine-mouth power plants.
- For the Lobito CCGT, we are preparing to supply LPG in the first step, and to supply LNG and switch from fuel to LNG in the second step, as soon as LNG supplying facilities are set up.

(2) **Peak Demand Power Supply**

< Basic Policy on Power Supply Development>

Mine-mouth power plants using natural gas are the most economical. => CCGT in Soyo is the most advantageous.

Better system stability can be expected, however, if the peak demand power supply is located near the demand site.

<Issues>

- With the installation of GT, the peak demand power supply, in Soyo, in addition to CCGT, the middle-demand power supply, the Angolan power system will generate an extremely unilateral current toward Soyo => Luanda => Benguela. This would be quite disadvantageous for the stability of the system.
- The dual installation above would also cause an excessive power flow leading to increased power transmission loss.
- The 400 kV line between Soyo and Luanda, however, has a current capacity of 2200 MW (N-1 criteria). If only two 750 MW class CCGTs are developed in Soyo, the margin of the transmission capacity would be about 700 MW. Given the sufficient room available, it would be possible to connect the GT of the output corresponding to the margin.

< GT Development Scenario>

- It would be rational from an economic viewpoint to develop GT capacity of about 700 MW as mine-mouth power plants in Soyo. As a prerequisite for development, however, control by a dispatching center to secure system stability would be necessary.
- For further development, it will be important to connect to backbone lines near demand areas such as Luanda and Benguela.
- Considering the above points, the development of several GTs as mine-mouth power plants in Soyo cannot be ruled out, though the scale of GT plant that can be developed would have to be limited.
- As peak demand power supply, it is assumed that many GTs are placed in the main substation near Luanda or Lobito port in Benguela. The GT placed at Lobito port is also thought to be combined into a CCGT, as this would be effective as a countermeasure in the event of rise in the middle demand above the peak demand level due to changes in the load factor, etc. in the near future.

< Fuel supply scenario>

- We recommend setting the following fuel supply scenario according to the above GT development scenario.

➢ In Soyo, we continue to supply natural gas for the GT. ➢ Regarding the GTs near the demand sites of Luanda and Benguela, it would be difficult to supply natural gas by gas pipeline. Hence, in both cases we are preparing to supply LPG. ➢ An LNG relay station will be installed in the future. If it becomes possible to supply vaporized gas in the pipeline from there, we will switch to LNG.

3.5.4 Facilities to Prepare for Power Development Promotion

Soyo CCGT, GT	➢ Soyo is located near the existing oil field, and mine-mouth power plants can use natural gas produced from associated gas. ➢ Construction of gas pipeline for the Soyo 1 power plant is already in progress. Operation is scheduled to start in 2018. ➢ It will be necessary to increase the current gas pipeline capacity. ➢ As the study focused beyond the fuel supply facilities themselves, it will be necessary to continue discussing the rationality of upgrading the transmission line to Luanda. It will also be necessary to consider the development of SCADA for power plant control.
Lobito CCGT, GT	➢ In the first step, it will be necessary to improve the LPG supply facilities. ➢ It will be necessary to examine whether to import LPG or obtain it from a domestic refinery. When selecting procurement from a domestic refinery, it will be necessary to jointly consider reinforcement of the refinery with the relevant organizations. ➢ In the second step, it will be necessary to develop supply facilities such as LNG tanks. ➢ It will be necessary to establish a supplier portfolio by examining the ratio of domestic LNG and imported LNG to be used.
Luanda GT	➢ Basically, assume the use of LPG and improve the LPG supply equipment accordingly. ➢ As a method for transportation to the LPG terminal, improved roads and railroads will also be required. ➢ Regarding the use of LNG, it will be necessary to raise the demand for an LNG relay station, including demand in other industries in the future.

All of the aforesaid matters relate to the Angolan energy master plan now being formulated, so we will keep track of the details of the plan as they evolve.

Chapter 4 Procedure for Formulating a Power Master Plan based on the Optimal Generation Mix ("The Best Mix")

4.1 Basic policy for an optimal generation mix

Before explaining the major components of the Power Development Master Plan such as the power demand forecast, generation development plan, and transmission development plan in the following chapters, we would like to confirm the procedure used to formulate the Master Plan in accordance with a policy for formulating a plan to obtain an optimal generation mix ("The Best Mix").

The policy for an optimal generation mix is the first to formulate an optimal generation development plan from the particular viewpoints of Angola and to establish the most effective transmission development plan based on the generation plan. As a precondition for planning, it goes without saying that a highly accurate power demand forecast must be obtained by analyzing the economic situation and future vision of the country.

What, then, are the "particular viewpoints" of Angola? The most important viewpoint for Angola is economic. For some countries, in contrast, it may be energy security. The prevention of global warming is another viewpoint of rising importance.

The following are important considerations for examining the optimum power plan:

- ✓ Economic matters (reduction of supply cost (generation cost + transmission cost))
- ✓ Supply reliability (annual LOLE, etc.)
- ✓ Energy security (stability of fuel supply, stability of fuel cost)
- ✓ Environmental and social considerations (environmental impact assessment, greenhouse gas emission, etc.)
- ✓ Feasibility (social environment, development lead time, funds, etc.)

4.2 Items to examine

4.2.1 Economic matters

In formulating an optimal power development master plan from the viewpoint of economic efficiency, we will generally consider the following.

- ✓ To study the composition ratio of a power supply with minimized power generation costs, including fixed costs such as capital costs and variable costs such as fuel costs. The study is generally carried out using an analysis method such as a screening method and demand-supply operation simulation software such as PDPAT.
- ✓ Once the optimal generation mix ratio is obtained, a more specific power generation project plan is prepared. The plan also specifies where power plants are to be located on the power grid.
- ✓ Based on the generation development plan, to formulate an additional transmission development plan for transferring electricity from power plants to demand sites as efficiently as possible. The additional plan is also implemented to examine the transmission construction and calculate the transmission costs.

When implementing such a study, it is the generation development plan that most affects the economics of the power plan. And this is the most important point. There are mainly two analysis methods, namely, the screening method and PDPAT.

(1) **Screening method**

Figure 4-1 shows an example of an analysis result by the screening method.

The screening method is <u>a method to obtain the required supply capacity of each power plant</u> and analyze the optimal generation mix based on the relationship between the annual facility utilization rate and annual generation expenditure, and the annual duration curve reflecting the utilization rate of each power source at different costs~~,~~.

The upper figure shows annual expenses of each power supply. The Y intercept of the linear function indicates annual expenditure corresponding to fixed costs. The inclination indicates variable cost, mainly fuel cost. The lower figure shows the annual duration curve. In this example we focus only on hydropower, coal-fired thermal, CCGT, and Oil GT for simplification.

In this case, since hydropower plants can be generated at the lowest cost in the range of a facility utilization rate of 20% or more, the total power generation cost can be reduced by operating the hydropower plants at a high load factor. It is important to generate electricity with priority over other power supplies to cover power demand. In other words, it is important to operate hydropower plants to meet power demand in preference to other power sources.

Next, looking at coal-fired thermal power, we can see that the expenditure becomes cheaper at a utilization rate of 60% or more. To ensure that the load factor is at least 60% in operating the plants, we can improve the economic efficiency by installing the coal-fired thermal plant capacity sufficient to meet the demand of 60% or more of the annual occurrence probability. Incidentally, the demand, the basic part of the duration curve, is called the base demand, and the power supply that covers this is called the base power supply.

We can see, from the projection of the facility utilization rate of the base power supply to the duration curve, that the required installed capacity of the base power supply is about 4,200 MW. If hydropower plants with 2,200 MW capacity can be installed, it would be appropriate to introduce 2000 MW as coal-fired thermal power plants.

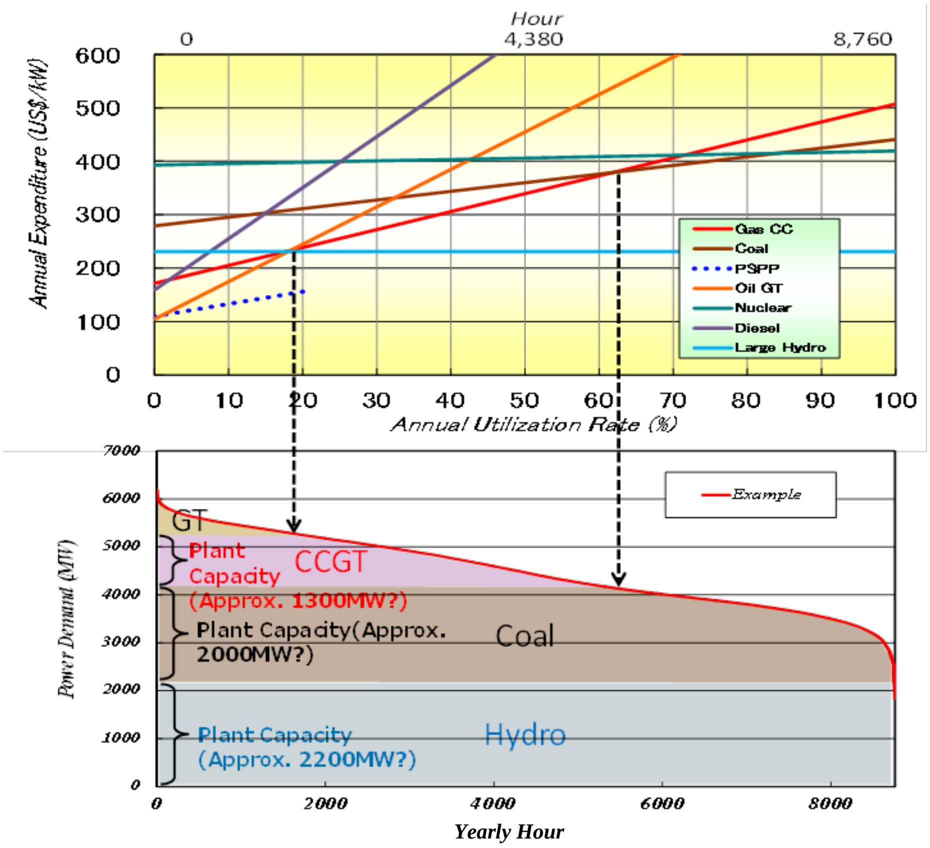
Considering the CCGT in the same way, it is economically advantageous to utilize a CCGT with a facility utilization rate of about 20% and 60%, so plants should meet the demand in an occurrence-probability range of between about 20% and 60% (middle demand). In this example, the installation of a CCGT with a capacity of about 1,300 MW is required.

In addition, it is advantageous for the Oil GT to meet the demand within an occurrence-probability range of about 20% or less (peak demand) because it is economically advantageous to use the Oil GT at a utilization rate of about 20% or less. In the example, the installation of plants with a capacity of only about 700 MW is required.

After the required installed capacity of each power source is obtained as described above, the optimal power supply ratio can be calculated based on the results. In the future generation development plan, the required installed capacity of each power supply will be examined with reference to the optimal power supply ratio.

The data necessary for these studies are shown below.

Item	Required data	Note
For power demand forecast	Duration curve of power demand forecast	Hourly data from 8,760 hours of demand forecast
For power supply	Construction cost of each power type (USD/kW)	
	Heat efficiency (%)	
	Annual expenditure rate (%)	Interest, Depreciation, O&M cost, etc.
	Fuel price (USD/kW)	



(Sources: JICA Survey Team)

Figure 4-1 Example of a screening method

(2) PDPAT

PDPAT (Power Development Planning Assist Tool) is a supply-and-demand operation simulation software application developed by Tokyo Electric Power Company (TEPCO). Supply-and-demand operation simulation software simulates how power plants should be dispatched to best meet the assumed daily demand.

Figure 4-2 shows an example of an analysis of the power supply situation.

PDPAT simulation analysis can determine how power plants can be dispatched to minimize the total costs of the fuel used by the plants. The analysis outputs the total fuel cost as well as the total annual expenditure of the power plants. Since the cost of the entire power system can be obtained in a given year, the software can examine the optimal generation mix by comparing the annual power generation cost for each development scenario.

As mentioned above, PDPAT analyzes the economics of power generation by simulating the dispatch of power plants in scenarios closer to reality. As such, the following data are required.

Item	Required data	Note
For power demand forecast	Duration curve of the power demand forecast	Hourly data from 8,760 hours of demand forecast
For power supply	Construction cost for each power plant (USD/kW)	
	Heat rate curve of each power type	
	Annual expenditure rate (%)	Interest, Depreciation, O&M cost, etc.
	Fuel price (USD/calorific value or volume)	
	Power plant specifications	Maximum output, Minimum output, etc.
	Hydropower plant operational data	Monthly power generation, etc.

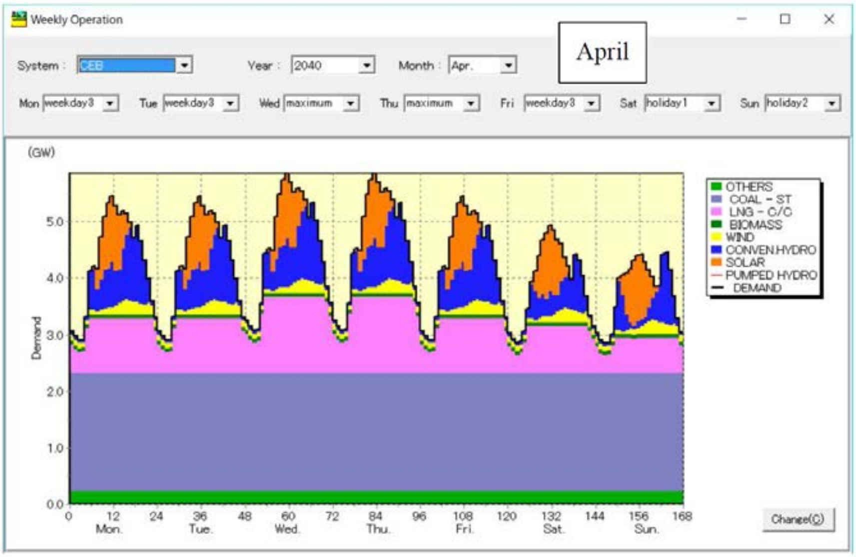


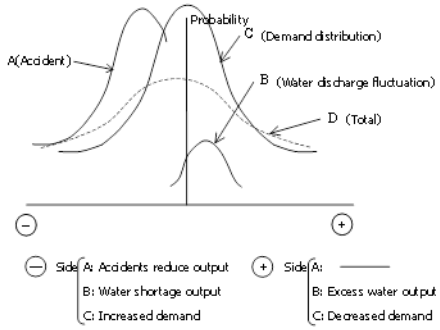
Figure 4-2　An example of output from PDPAT

When PDPAT conducts an economic analysis for the optimal generation mix, it obtains the approximate proper power supply ratio by the screening method and lists a power plant construction plan based on the results. PDPAT usually prepares the Best Mix Plan using the listed data.

4.2.2 Supply reliability

Supply reliability is often expressed by LOLP (loss of load probability) and LOLE (loss of load expectation). LOLP is the probability that the supply capacity will be insufficient against the demand within a given period or year. LOLE is the expectation of when the condition will occur. These two variables are basically synonymous.

The probability distribution of LOLP is mainly obtained by synthesizing the following probability distribution.



Probability distribution	Characteristic
Demand distribution	Normal distribution
Hydropower output fluctuation by water discharge fluctuation	When the hydropower supply capacity is evaluated by firm output, it is distributed on the plus side.
Output fluctuation due to forced power plant outages	Binomial distribution. The values are distributed on the minus side.

Figure 4-3 Probability distribution synthesized into LOLP

Since LOLE is the expectation of when the supply shortage will occur based on this probability distribution, it can be expressed by the formula shown in Figure 4-4.

Where,

Pi: Probability of supply shortage

Hi: Time at which demand occurs when the supply capacity is insufficient.

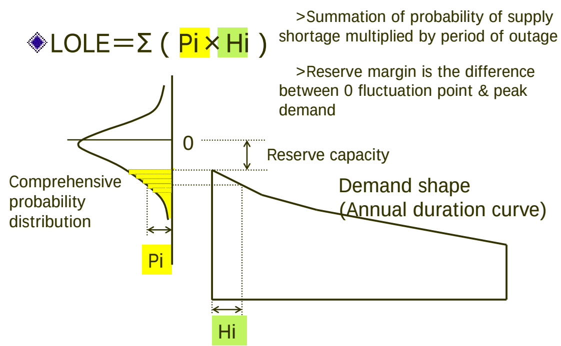


Figure 4-4 LOLE

From the experience of the Survey Team, we think it is appropriate to adopt a LOLE of 24 hours per year in emerging countries. That is to say, we aim for a power supply system that allows a total of one day of outage in a year.

Since the required supply capacity cannot be directly obtained from the supply reliability, we employ the concept of reserve margin rate. First, we obtain the relationship between LOLE and the supply reserve margin ratio. After determining the required reserve margin ratio based on the adopted supply reliability, we usually calculate the required total supply capacity from the reserve margin. We then formulate the power development master plan with the required supply capacity.

$$\text{Reserve margin rate} = \frac{\text{Supply Capacity} - \text{Demand}}{\text{Demand}}$$

Figure 4-5 shows the stops taken to create the relationship between LOLE and the reserve margin ratio. The calculated LOLE basically corresponds to the reserve margin, a changing parameter. And by summarizing these data sets, we can then obtain the correlation diagram. As you can see, a large reserve margin is needed to build a power supply system with high supply reliability, i.e., a low LOLE.

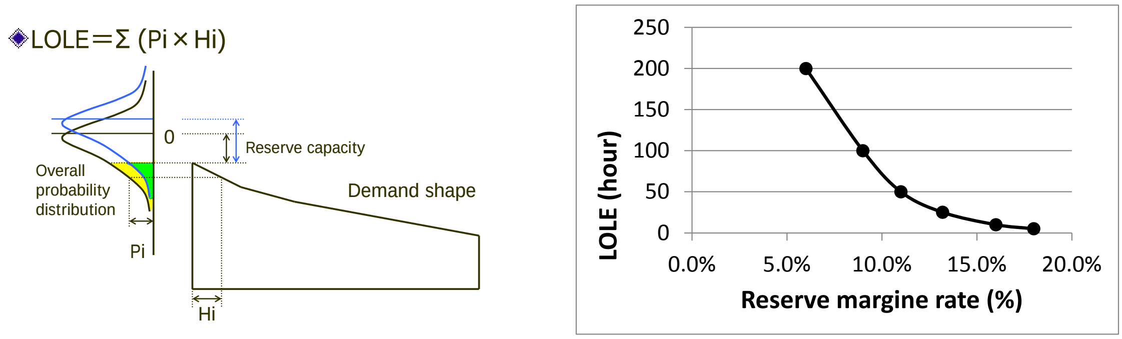


Figure 4-5 Relation between LOLE & the reserve margin rate

Since the required supply capacity can be calculated by the following equation, a power plan satisfying this capacity can be formulated.

$$\text{Supply capacity} = (1 + \text{Reserve margin rate}) \times \text{Demand}$$

Figure 4-6 shows an example of a formulated power supply plan. The blue line in this example plots the forecasted power demand. The power supply development plan, meanwhile, must satisfy the required supply capacity plotted by the red line, taking into account the reserve margin. This can be seen in the figure.

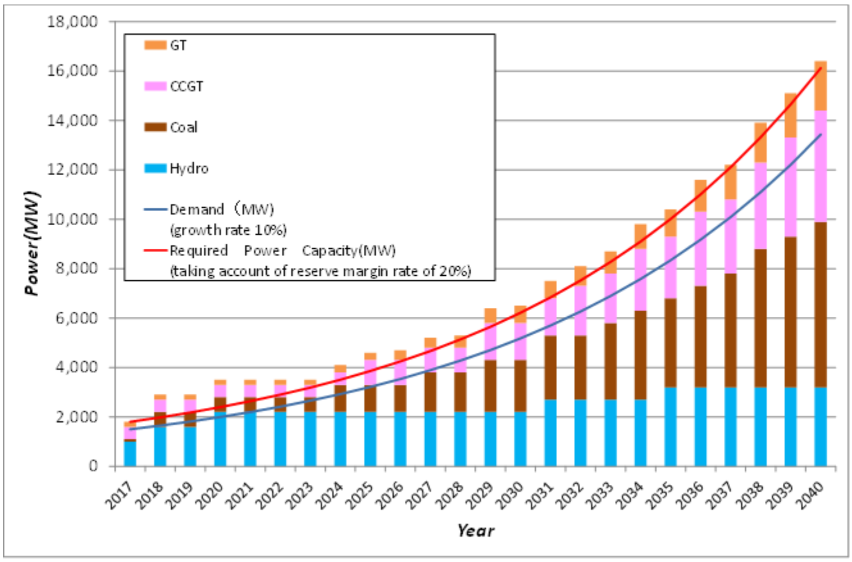


Figure 4-6 Required supply capacity and generation development plan (Example)

4.2.3 Energy security

When studying the plan for an optimal generation mix, considerations other than economy may sometimes be necessary. Energy security, for example, is an especially important consideration in countries not blessed with domestic resources, like Japan. The following points may be important to consider.

- ✓ Securing domestic energy
  - ➢ Development of domestic mineral resources (fossil fuel)
  - ➢ Nuclear power development as long-term usable energy

- ➢ Development of hydropower
- ➢ Development of solar power, wind power, geothermal power, biomass power, etc.

✓ Diversification of fossil fuel types; diversification of suppliers

In any case, many of the foregoing are ultimately decided by political judgments at high levels, so consistency with the national energy policies is important to ensure.

4.2.4 Environmental and social considerations

Environmental and social considerations are also important from viewpoints other than economic efficiency. Apart from the conventional EIA for each project, it has become increasingly important in recent years to evaluate the impact on global warming in each scenario in the overall power development master plan. This is why coal-fired thermal power plants, which are economically superior, are becoming difficult to introduce into master plans. Global environment issues take some degree of precedence.

In addition, many countries regard the use of renewable energies as important mitigations of global warming. The method by which these power supplies are to be incorporated into the power development master plan must be considered.

Consistency with national energy policies and INDC is important to ensure, as many of these problems are decided politically at very high levels.

4.3 Flow for formulating a power development master plan

Figure 4-7 shows a formulation procedure incorporating important items in the plan for an optimal generation mix described in the previous section. The power development master plan of Angola is also carried out according to this procedure.

The transmission development plan is greatly affected by the power generation scenario, especially the type of installed power plant and the location of the power plant in the national grid. Needless to say, optimization of the power transmission equipment must be studied for each scenario.

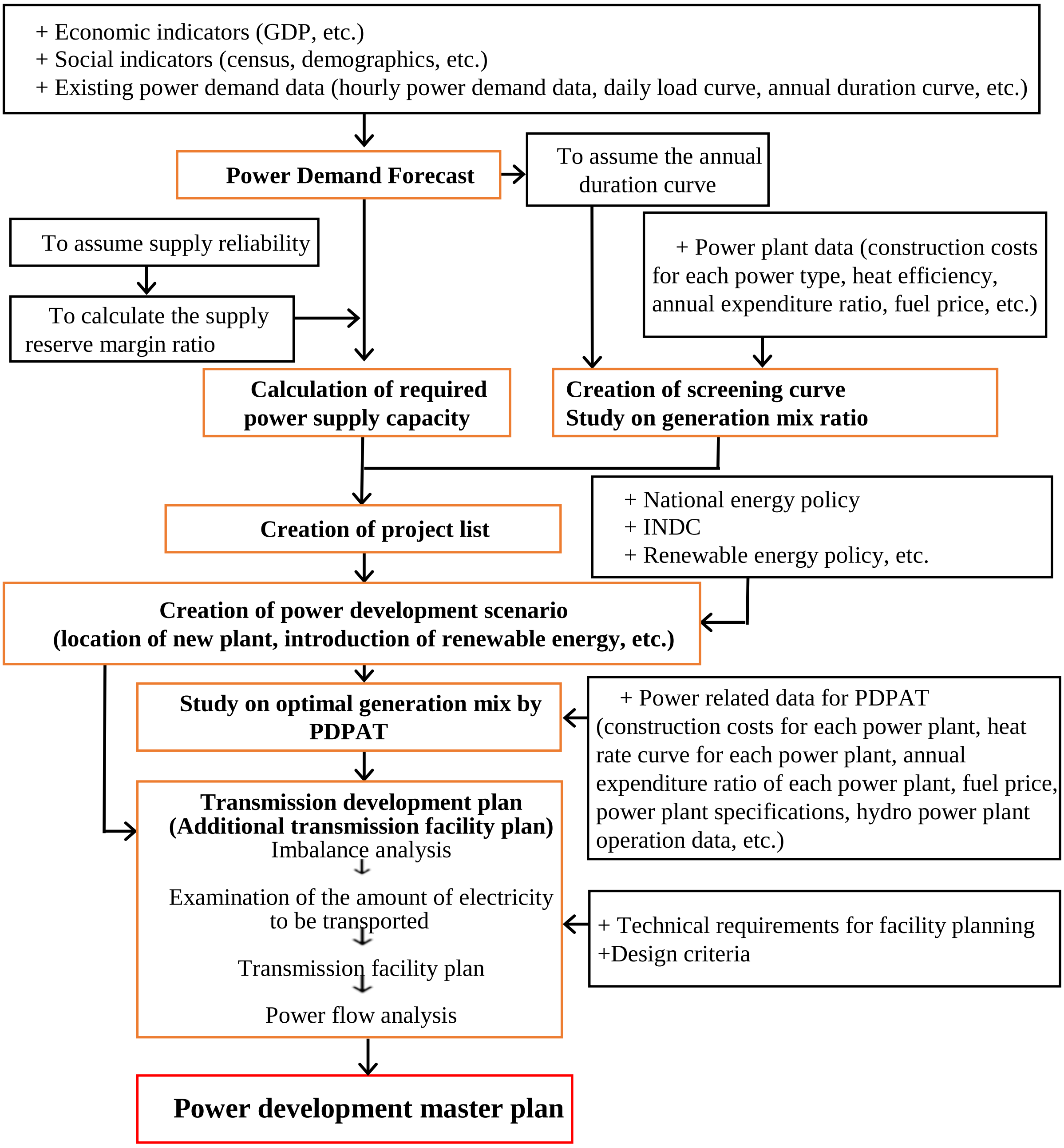


Figure 4-7 Flow for Formulating a Power Development Master Plan

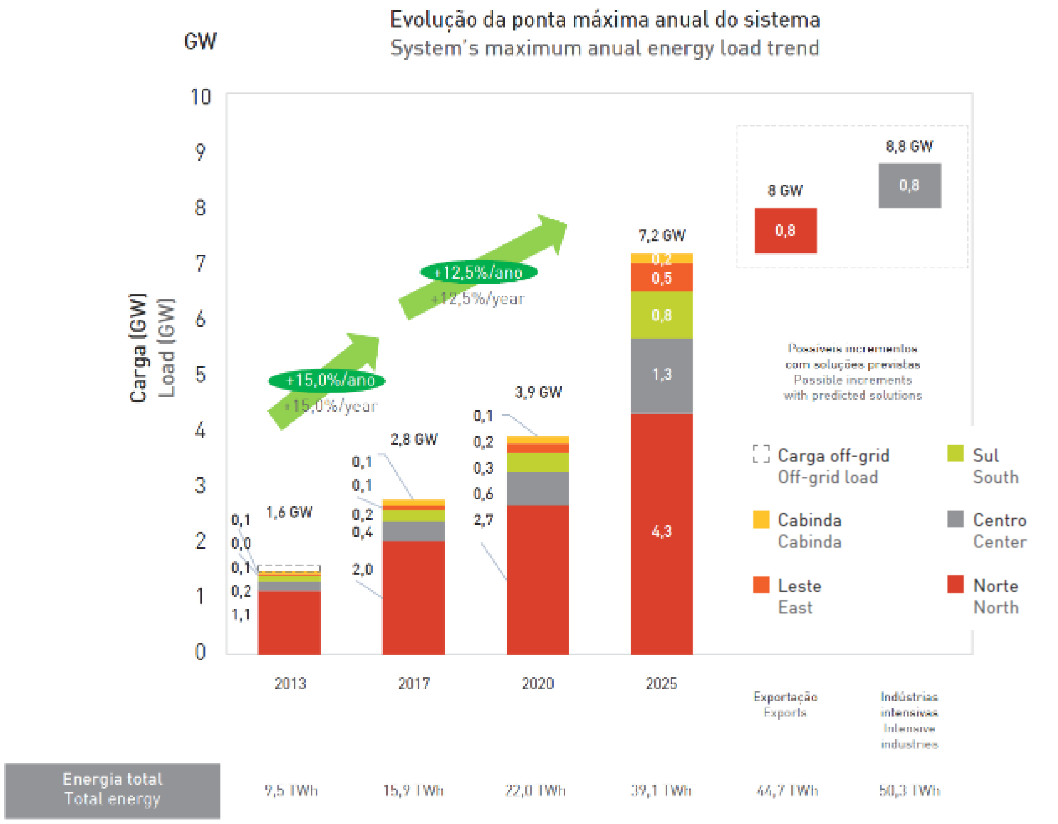
Chapter 5 Power Demand Forecast

5.1 Power demand forecast in current plan and related data

5.1.1 Current power demand forecast

"Angola Energia 2025" describes officially the electricity demand forecast as shown in Figure 5-1. This power demand forecast is implemented in 2014 and forecasted power demand up to 2025.

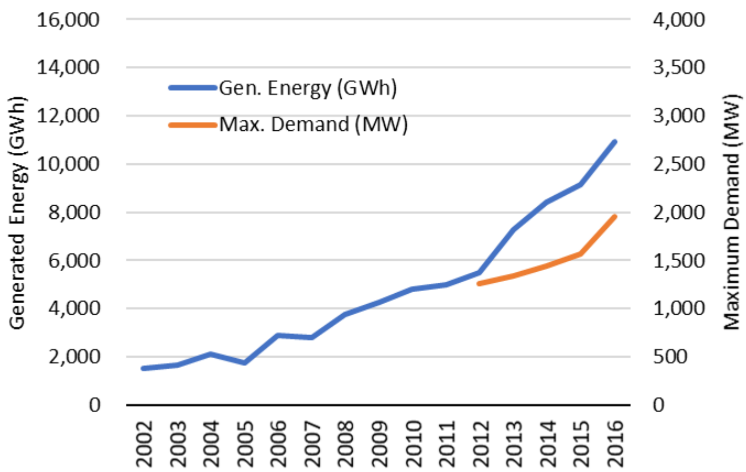
Figure 5-2 shows the actual power demand records up to 2016. While the forecast assumed the annual maximum demand growth rate of 15 % from 2013 to 2017, the actual power demand (incl. latent demand) grew at a rate of 7 % - 25 % (an average of 13.3 %) from 2013 to 2016. In the event that the assumed growth rate is nearly equal to the actual rate, however, the prospect of the maximum electric power in 2017 is about 2.3 GW, falling about 0.5 GW below the forecasted value.



(Source: Angola Energia 2025)

Figure 5-1 Current Power Demand Forecast (annual maximum demand)

The mean growth rate of the generated energy before 2012 was about 10 %. Since 2012, the generated energy has increased rapidly at a mean growth rate of about 19 %. The maximum power demand increased by 500 MW (25 %) in the year 2016 alone.



(Source: Prepared by the JICA Survey Team based on the WB Data-base and Data from RNT, ENDE)

Figure 5-2 Actual records of power demand

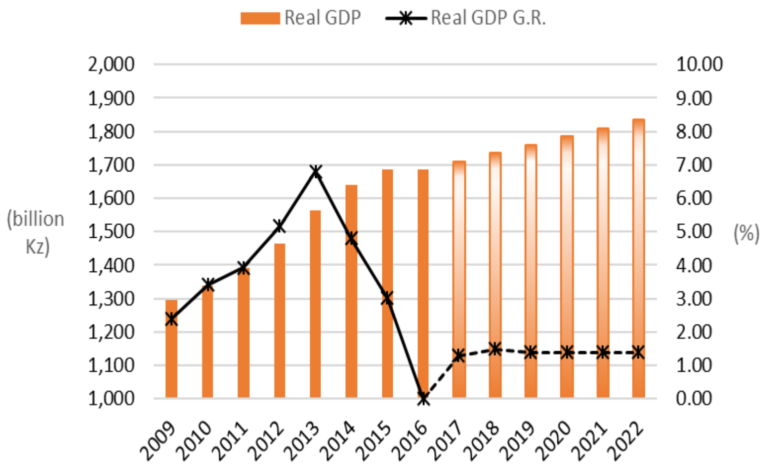
5.1.2 Forecast of GDP and population growth

(1) **Past records and forecast of GDP by IMF**

Past records of the GDP (2010 Constant Price, local currency unit) are shown in Figure 5-3, based on WB Data and GDP estimates in the 2017 version from the IMF.

The Angolan economic structure depends on the oil sector. The real GDP in 2013 was 96.3 billion dollars, of which the oil sector accounted for about 40%. From 2010 to 2013, macroeconomic stability was restored and economic growth accelerated. In 2014, however, maintenance and restoration works in several oil fields brought crude oil production down to 1.66 million barrels from 1.8 million barrels the year before. As a result, the real GDP growth rate fell to 4.2% (IMF estimate) from 6.8% in the previous year.

Furthermore, since the crude oil price plummeted from 100 US$/bbl. in 2014 to 50 US$/bbl. in 2015, the real GDP growth rate further decelerated to 3.0% in 2015 and 0.0% in 2016. According to estimates in the 2017 version from the IMF, the GDP is expected to grow at a rate of about 1.4% after 2017.



(Source: JICA Study Team prepared based on IMF Prospect)

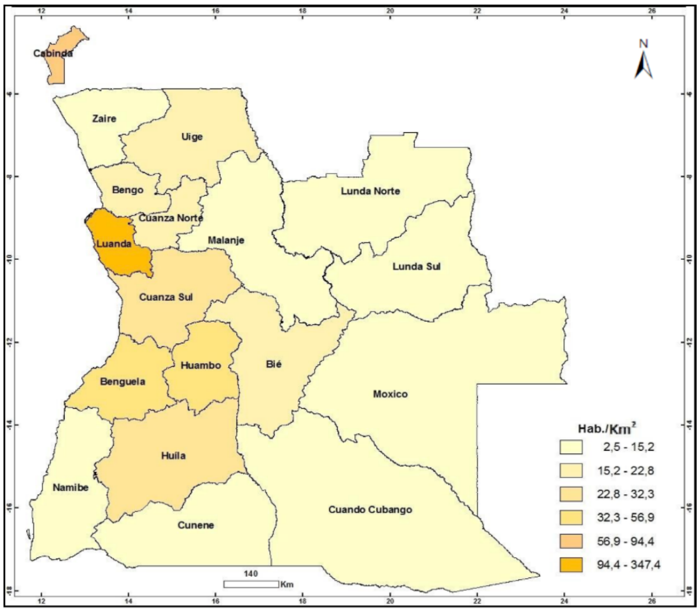
Figure 5-3 Past records and forecast of real GDP

(2) **Population forecast**

The total population in Angola is 25.9 million people (2014) according to population statistics from INE (Instituto Nacional de Estatística). Luanda has the highest population density within the country, at 100 heads/km^2 throughout the province.

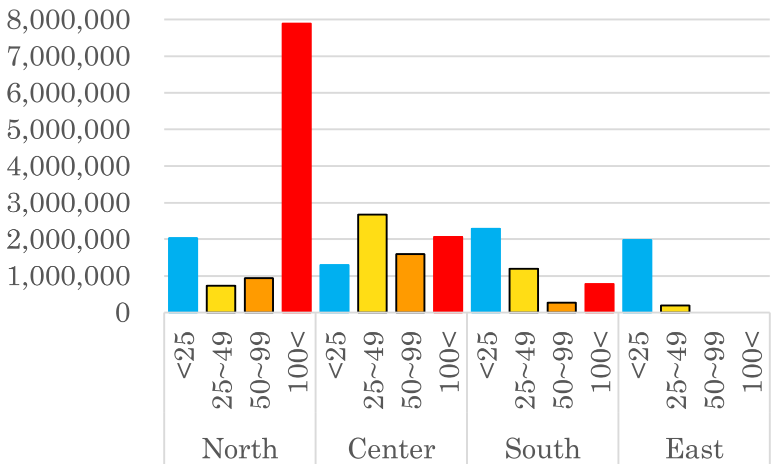
Six other provinces have municipal cities with population densities exceeding 100 heads/km^2: Uige and Malanje in the northern region, Cuanza Sul, Benguela, and Huambo in the central region, and Huila in the southern region. None of the provinces in the eastern region have population densities at comparable levels.

The population density by region is shown in Figure 5-5. The population of the north is about 1.6 million, accounting for about half (45%) of the Angolan population.



(Source: Population Statistics 2014 (INE))

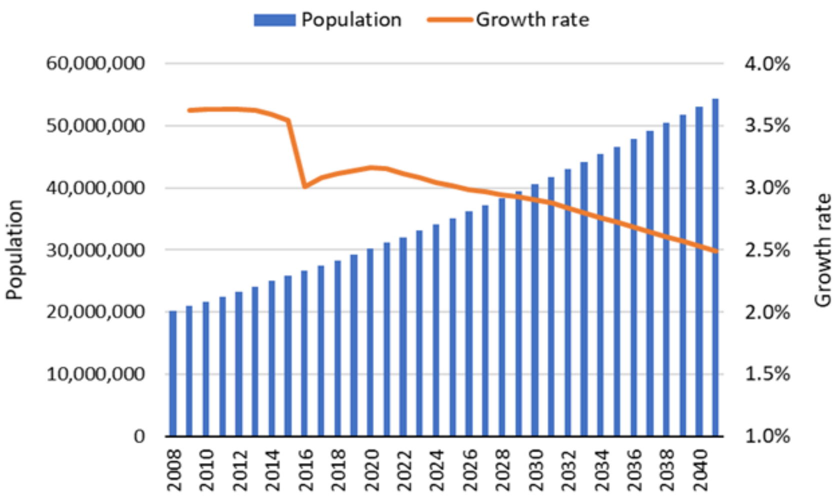
Figure 5-4 Population Density Map (2014)



(Source: Prepared by the JICA Survey Team based on population statistics 2014 (INE))

Figure 5-5 Population Density Distribution by Region (2014)

The population forecast (2014-2050) in Angola by INE is shown in Figure 5-6. The population nationwide in 2016 was estimated to be about 27.5 million people and to have grown at a rate of 3%. The total population in 2040 is forecasted to be about 54.3 million people and the growth rate will decrease up to 2.5%.

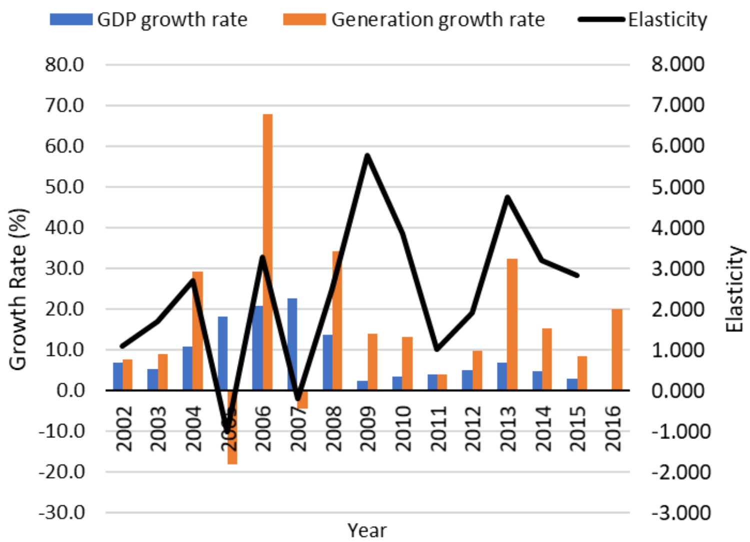


(Source: Population Projection 2014-2050 (INE))

Figure 5-6 Population Forecast in Angola

(3) Relationship between GDP growth rate and generated energy growth rate

The annual growth rates of the GDP and electricity demand after 2002, when the civil war ended, are shown in Figure 5-7. There is no correlation whatsoever between the annual GDP growth rate and generated energy growth rate. The elasticity (generated energy growth rate / GDP growth rate) varies from -1.0 to 6.0, showing considerably larger variation versus the general elasticity value of 1.0 to 2.0 in other developing countries. As such, it would be inappropriate to assume generated energy demand based on the GDP growth rate.



(Source: Prepared by the JICA Survey Team based on the WB Data-base)

Figure 5-7 Relationship between GDP Growth Rate and Generated Energy Growth Rate

(4) Changes in electrification rate

The changes in the electrification rate in Angola according to the WB data-base are shown in the table below. The development of large-scale generation facilities has not progressed since the civil war and the electrification rate has gradually decreased as the population grows.

The electrification rate is expected to begin to increase after 2016, however, as all units of Cambambe No. 2 (700 MW) were put into operation in 2016 and the transmission line network continues to expand. Angola Energia 2025 stipulates an electrification rate target of 60% by the end of 2025.

Table 5-1 Transition of Electrification Rate

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Electrification Rate (%)	38.4	37.7	37.5	36.4	35.8	35.1	34.6	33.9	33.3	32.0

(Source: WB Data-base)

5.1.3 Relevance and problems of the current power demand forecast

The current demand forecast by MINEA seems to be carried out based on an assumed power demand (supplied power plus load shedding power) calculated by summing up the annual maximum power demand for each economic sector – domestic, industrial, commercial, and others. As will be described later, the statistical data in the economic model (GDP) and electrification plan are also unclear. In particular, since any hourly power demand data including load shedding power (latent demand) have not been organized, it makes difficult to predict the amount of generated energy in every month.

For these reasons, the JICA Survey Team decided to forecast the nationwide maximum power demand up to 2040 by assuming power demand for the domestic sector (electrification plan), the industrial sector, and the commercial sector for each power system (North, Central, South, East) and then summing the values up.

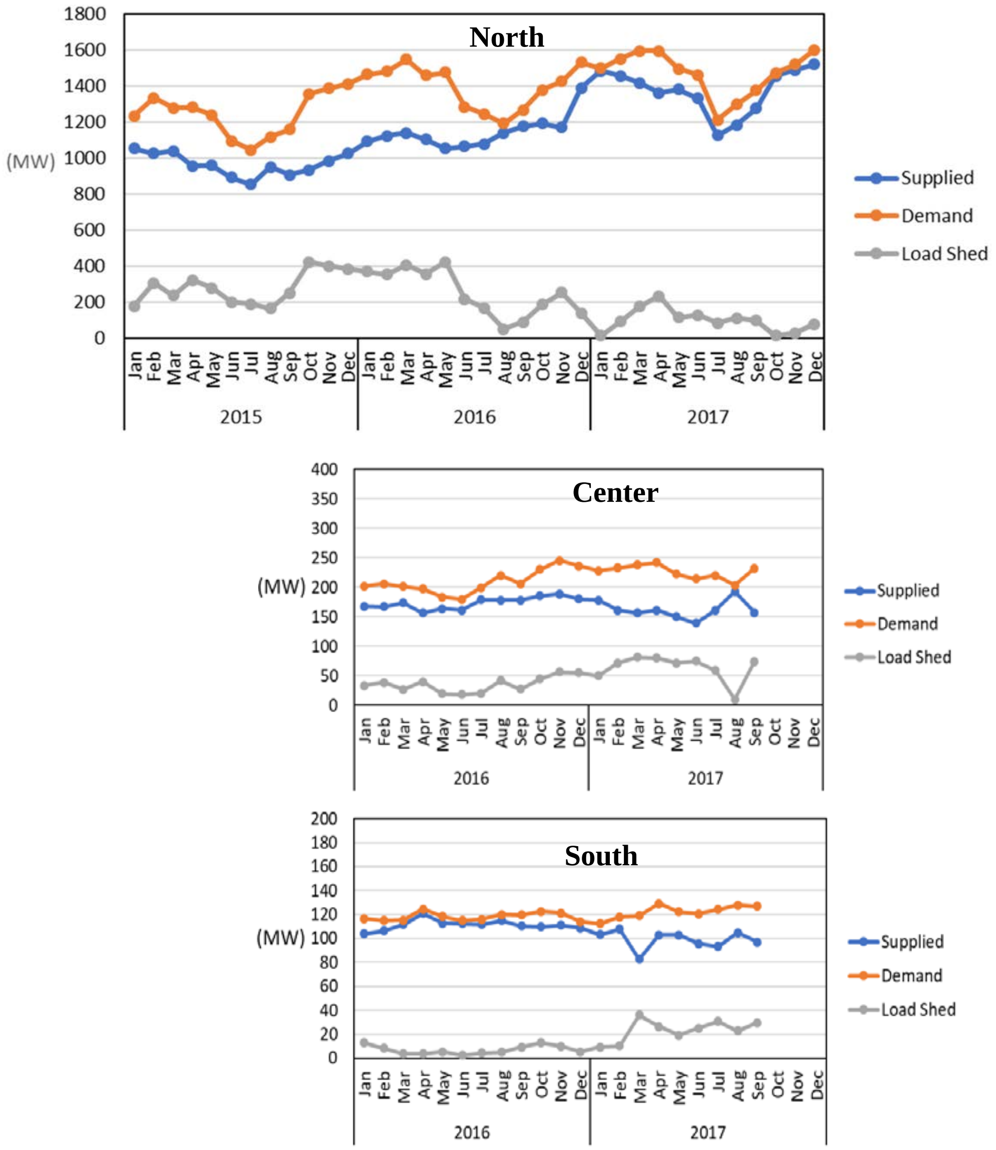
5.2 Power Demand Results and Regional Characteristics

5.2.1 Power Demand Results

(1) **Load shedding (Latent power demand)**

The supply and demand for electric power in Angola are imbalanced, which has resulted in supply power shortages for many years. Hourly records of load-shedding amounts (latent demand) have not been properly organized. As a consequence, it has only been possible to collect load-shedding data at the monthly maximum electric power in the North system after 2015 and in the Center and South system after 2016 (refer to Figure 5-8). Maximum load shedding of up to 400 MW took place from October 2015 to May 2016, but the level fell below 200 MW in 2017 due to the commissioning of the Cambambe No. 2 plant (700 MW) in 2016.

Load-shedding data for the East systems have not been unorganized and unknown.



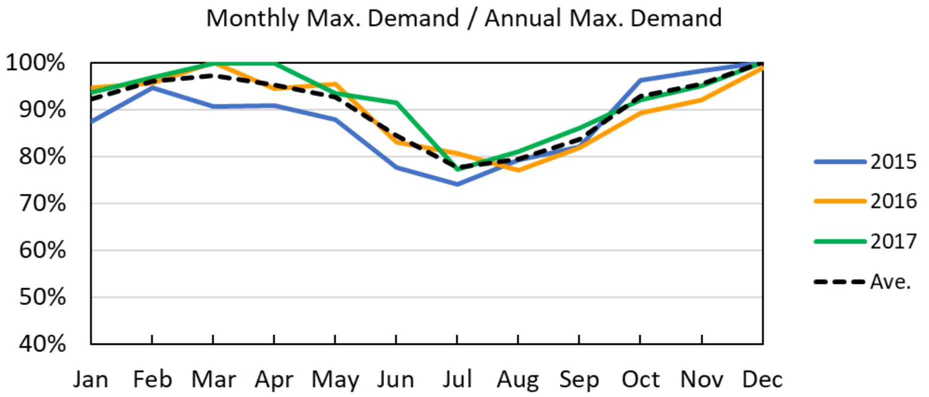
(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Figure 5-8 Monthly Maximum Demand and Load-shedding Results (North, Center and South System)

(2) Changes of monthly maximum demand in the whole country

The nationwide power demand results (incl. latent demand) in recent years are shown in the aforementioned Figure 5-8. The ratios of the monthly maximum power demand (incl. latent demand) to the annual maximum power demand in the North system are shown in Figure 5-9.

The fluctuation in power demand between seasons is relatively large. The annual maximum power demand occurred in December, and the monthly maximum demand fell to about 80% over the four months from June to September in winter.



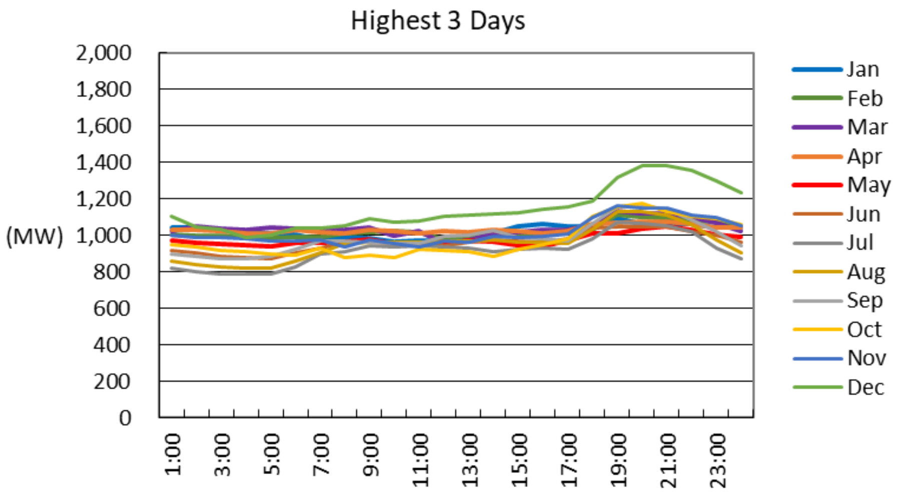
(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Figure 5-9 Comparison of Monthly Maximum Demand Results in

(3) Daily load curve results

Regarding the North system, digital data on the hourly power generation results since October 2015, when SCADA was introduced, were collected from RNT (NLDC). The daily load curve for the 3-day highest power demand month by month in 2016 is shown in Figure 5-10.

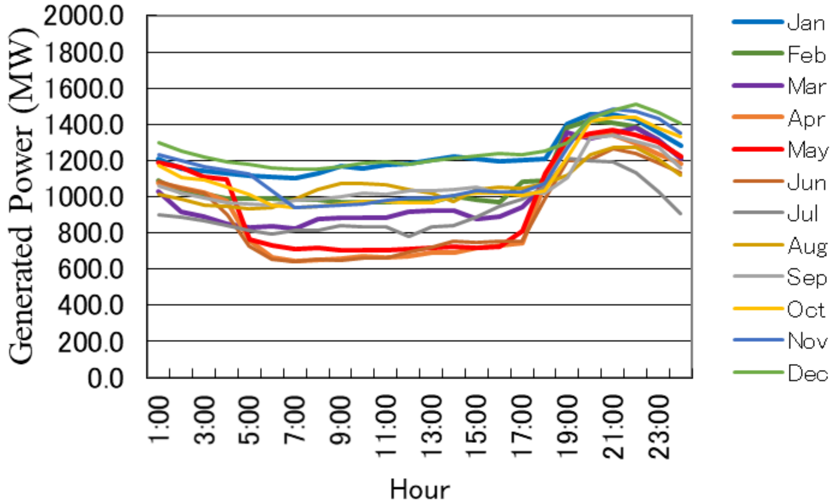
The daily load curve is an electric light peak type that peaks from 19:00 to 20:00, but it remains nearly flat in all months but December. This is clearly assumed to be due to the load shedding aforementioned in (1) according to the supply shortage at peak times.



(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Figure 5-10 Actual Daily Load Curves (North System: 2016)

Meanwhile, the daily load curve for the 3-day highest power demand by months in 2017 is shown in Figure 5-11. In order to impound water to the reservoir of Lauca HPP for commissioning, the Cambambe HPP in the lower stream had set limits to generation during daytime. Therefore, the curves cannot be referred.



(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Figure 5-11 Actual Daily Load Curves (North System: 2016)

Figure 5-12 Location of Lauca Hydropower Plant

5.2.2 Regional characteristics of power demand

Currently the national power system in Angola is divided into 5 regional power systems: North region, Central region, South region, East region, and Cabinda province. The table below shows the maximum power demand (incl. latent demand), number of customers, electrification rate, and maximum power demand per customer for each province in 2016.

The maximum power demand in the country, excluding Cabinda, is 1,989 MW, of which the North system accounts for approximately 80%. The electrification rate is considerably low, below 10 %, in both the South and East systems.

The maximum demand per consumer can be stratified into 2.0 kW for Luanda, Bengo, and Cuando-Cubango provinces, 1.5 kW for Zaire province, and 1.0 kW for the other provinces.

Table 5-2 Electrification Rate and Maximum Power Demand by Province (2016)

	Province	Real Maximum Demand (MW)	No. of Customers	Electrified Rate (%)	Demand/ Customer (kW)	Stratified Demand/ Customer
N	Luanda	1358.3	718,015		1.892	2.000
N	Bengo	27.7	14,784		1.874	2.000
N	Cuanza Norte	29.4	28,376		1.036	1.000
N	Malanje	37.3	35,430		1.053	1.000
N	Uíge	25.9	34,709		0.746	1.000
N	Zaire	21.0	14,025		1.517	1.500
N	Cabinda	46.4	49,048		0.946	1.000
Subtotal		**1546.3**		**50.8**		
C	Cuanza Sur	41.4	45,038		0.919	1.000
C	Benguela	160.0	100,685		1.589	1.500
C	Huambo	49.6	49,086		1.011	1.000
C	Bié	15.0	15,545		0.965	1.000
Subtotal		**266.0**		**26.7**		
S	Huíla	69.0	74,244		0.925	1.000
S	Cunene	15.4	16,545		0.931	1.000
S	Cuando-Cubango	19.2	7,832		2.451	2.000
S	Namibe	31.9	27,766		1.149	1.000
Subtotal		**135.1**		**7.3**		
E	Moxico	11.3	11,515		0.981	1.000
E	Lunda Norte	18.5	19,218		0.963	1.000
E	Lunda Sur	12.0	11,767		1.020	1.000
Subtotal		**41.8**		**5.4**		
TOTAL		**1989.0**	**1,273,628**	**32.3**	**1.562**	

(Source: Prepared by the JICA Survey Team based on Data from RNT and ENDE)

5.3 Power demand forecast up to 2040

5.3.1 Power demand forecasting methodology

As mentioned earlier, GDP growth and power demand growth are uncorrelated, and the power demand data, including that on latent demand, is poorly organized. Hence, the power demand in Angola is to be forecasted by another method according to the flow in the figure below.

First, the annual maximum power demand is forecasted based on INE's population growth forecast, electrification plan (government target), maximum power demand forecast for commercial and industrial sectors (assumption by ENDE), and the results for 2016 in Table 3-2. Second, daily load curves, including those for latent demand, are assumed for each month for each power system, and the annual load factors up to 2040 are estimated accordingly. Finally, the generated energy demand for each power system is forecasted for each ear based on the annual maximum power demand forecast and annual load factor forecast.

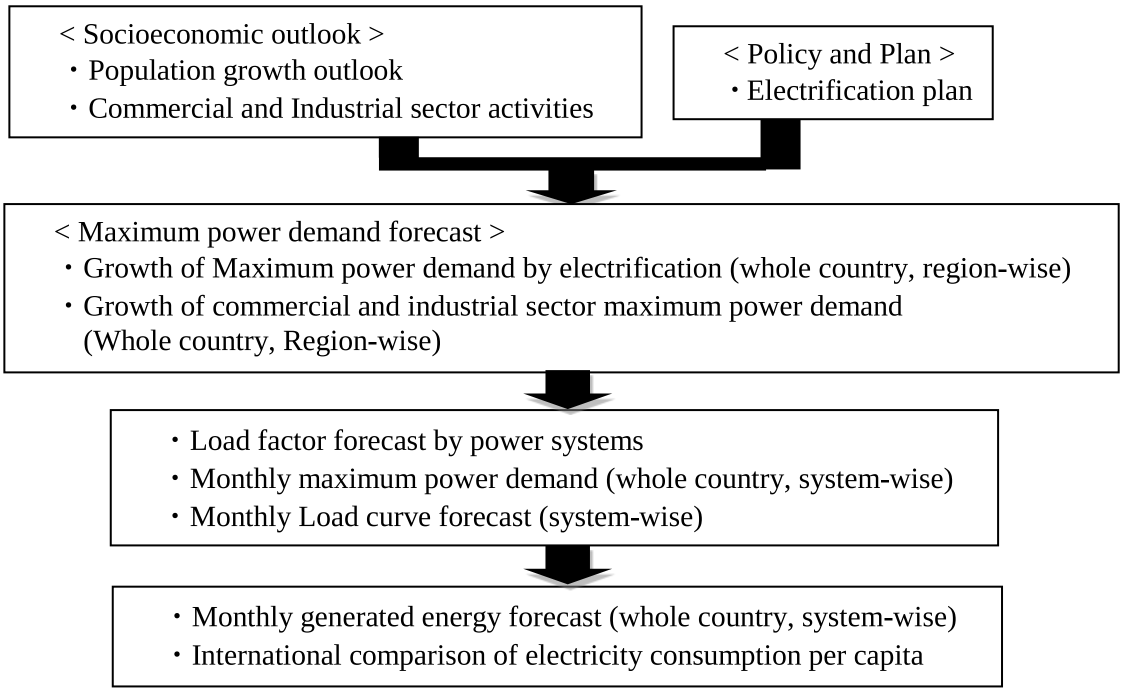
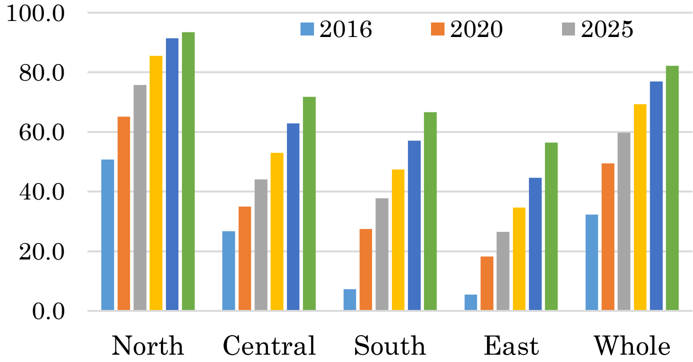


Figure 5-13 Power Demand Forecasting Flow in Angola

5.3.2 Annual maximum power demand forecast

(1) **Electrification plan**

The electrification plan was formulated based on the electrification rate (32.3% nationwide) as of 2016, as shown in Figure 5-14. The plan assumes that electrification proceeds from an area with high population density, such that the electrification rate in 2025 can reach 60%, the government target.



	2016	2020	2025	2030	3035	2040
North	50.8	65.1	75.8	85.5	91.4	93.5
Central	26.7	35.0	43.9	52.9	62.7	71.6
South	7.3	27.5	37.5	47.0	56.5	66.0
East	5.4	18.2	26.5	34.7	44.6	56.4
Whole	32.3	49.5	59.5	68.8	76.3	81.6

(Source: JICA Survey Team)

Figure 5-14 Electrification Plan

(2) Incremental power demand forecast for commercial and industrial sectors

Incremental power demand forecasts for the commercial and industrial sectors were assumed as shown in the table below, based on the incremental power demand (kW) up to 2025 estimated by ENDE, with the prerequisite that the incremental power demand for the commercial and industrial sectors can account for 20% of the maximum power demand in 2040.

Table 5-3 Incremental Power Demand Forecast for Commercial and Industrial Sectors

Province		2020	2025	2030	2035	2040
N	Luanda	66.7	92.5	192.5	292.5	392.5
N	Bengo	3.9	20.8	40.8	60.8	80.8
N	Cuanza Norte	20.8	88.6	138.6	188.6	238.6
N	Malanje	16.4	20.8	40.8	60.8	80.8
N	Uíge	20.8	65.5	115.5	165.5	215.5
N	Zaire	22.9	49.2	79.2	109.2	139.2
N	Cabinda	16.39	20.8	40.8	60.8	80.8
C	Cuanza Sul	2.3	20.8	40.8	60.8	80.8
C	Benguela	10.4	20.8	40.8	60.8	80.8
C	Huambo	22.2	32.1	62.1	92.1	122.1
C	Bié	1.9	20.8	40.8	60.8	80.8
S	Huíla	10.5	20.9	40.9	60.9	80.9
S	Cunene	3.4	20.8	40.8	60.8	80.8
S	Cuando-Cubango	3.8	20.8	40.8	60.8	80.8
S	Namibe	2.3	44.0	64.0	84.0	104.0
E	Moxico	7.4	44.0	64.0	84.0	104.0
E	Lunda Norte	7.4	44.0	64.0	84.0	104.0
E	Lunda Sur	6.4	20.8	40.8	60.8	80.8
Total		246.0	668.3	1,188.3	1,708.3	2,228.3

(Source: JICA Survey Team)

(3) Annual maximum power demand forecast

Annual Maximum Demand for the domestic sector in each province was calculated by the following formula based on the electrification plan aforementioned.

Max. Demand = Electrification rate x population / Mean population per customer x Maximum power demand per customer

Where,

Mean population per customer: 6.8 heads / number (2016 results)

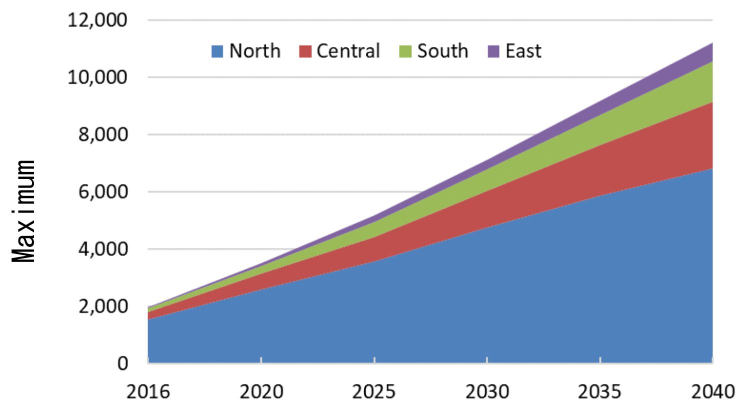
Maximum power demand per customer: Stratified maximum demand per customer in Table 5-2

In addition, by adding the annual maximum power demand for commercial and industrial sectors aforementioned, the region-wise (province-wise) annual maximum power demands up to 2040 were forecasted as shown inTable 5-4 and Figure 5-15.

Table 5-4 Annual Maximum Power Demand Forecast

		2020		2025		2030		2035		2040	
	Province	Population	Forecasted Demand (MW)	Population	Forecasted Demand (MW)	Population	Forecasted Demand (MW)	Population	Forecasted Demand (MW)	Population	Forecasted Demand (MW)
N	Luanda	8,523,574	2122.9	9,920,997	2751.9	11,332,670	3541.8	12,723,054	4220.5	14,120,025	4733.5
N	Bengo	462,598	58.6	553,863	119.1	656,180	176.6	766,679	242.2	882,618	315.7
N	Cuanza Norte	524,569	67.4	602,893	151.0	692,367	220.5	791,241	288.1	896,755	358.0
N	Malanje	1,175,886	103.3	1,362,964	151.8	1,581,477	216.2	1,827,369	290.5	2,090,620	359.0
N	Uíge	1,761,367	72.9	2,039,752	156.0	2,376,167	256.1	2,771,516	370.4	3,212,593	500.5
N	Zaire	720,902	54.8	836,664	104.9	960,805	164.4	1,092,530	230.3	1,232,419	303.2
N	Cabinda	847,377	104.1	965,555	135.0	1,088,094	177.6	1,213,169	222.3	1,342,068	269.3
	Subtotal		**2584.0**		**3569.8**		**4753.3**		**5864.2**		**6839.2**
C	Cuanza Sur	2,236,581	101.5	2,588,393	173.9	3,003,387	262.8	3,477,688	369.3	3,995,420	494.3
C	Benguela	2,611,074	299.9	2,965,850	415.5	3,361,497	562.6	3,793,794	733.9	4,250,235	882.0
C	Huambo	2,471,780	131.9	2,927,924	205.3	3,467,136	318.4	4,081,212	454.1	4,748,471	613.5
C	Bié	1,765,495	41.1	2,073,190	82.1	2,433,384	130.8	2,840,854	207.8	3,280,737	323.3
	Subtotal		**574.3**		**876.8**		**1274.7**		**1765.2**		**2313.2**
S	Huíla	2,997,267	121.2	3,486,668	201.3	4,054,938	310.6	4,705,412	443.5	5,418,796	601.6
S	Cunene	1,194,495	38.8	1,395,546	82.7	1,625,997	137.0	1,886,099	200.3	2,170,008	273.3
S	Cuando-Cubango	638,615	41.6	738,518	86.3	849,591	141.3	969,408	204.2	1,096,109	275.3
S	Namibe	608,649	65.3	716,595	128.7	835,795	169.0	964,302	212.3	1,100,773	258.6
	Subtotal		**266.8**		**499.1**		**757.9**		**1060.1**		**1408.8**
E	Moxico	907,681	27.6	1,056,030	75.2	1,228,578	109.4	1,420,377	157.5	1,623,913	224.0
E	Lunda Norte	1,030,631	37.9	1,185,039	96.5	1,357,513	144.2	1,549,313	198.5	1,757,670	259.9
E	Lunda Sur	649,133	25.6	754,520	77.4	871,618	92.4	996,379	134.5	1,124,767	180.6
	Subtotal		**91.1**		**249.2**		**346.0**		**490.5**		**664.5**
	TOTAL	**31,127,674**	**3516.3**	**36,170,961**	**5194.8**	**41,777,194**	**7131.9**	**47,870,396**	**9180.0**	**54,343,997**	**11225.7**

(Source: JICA Survey Team)



	2016	2020	2025	2030	2035	2040
North	1,546	2,584	3,570	4,753	5,864	6,839
Central	266	574	877	1,275	1,765	2,313
South	135	267	499	758	1,060	1,409
East	42	91	249	346	490	665
Total	1,989	3,516	5,195	7,132	9,180	11,226

(Source: JICA Survey Team)

Figure 5-15 Annual Maximum Power Demand Forecast

5.3.3 Daily load curve forecast

In order to predict the annual load factor, it is necessary to assume the daily load curve and maximum power in every month. This is problematic, however, as no organized hourly load-shedding data (latent demand data) are available in the North system. Furthermore, since SCADA has not yet been introduced in the other systems, no organized hourly load-shedding data (latent demand data) and also no hourly supplied power data are available.

(1) **North System**

The maximum power demand (including latent demand) for each month in the North system in the latest 3 years (shown in Figure 5-8) was normalized with annual maximum power demand, and the average was calculated as shown in Table 5-5. The annual maximum power occurs in December, the maximum power demand in July descends in the lowest level, about 77 % of the annual maximum power demand.

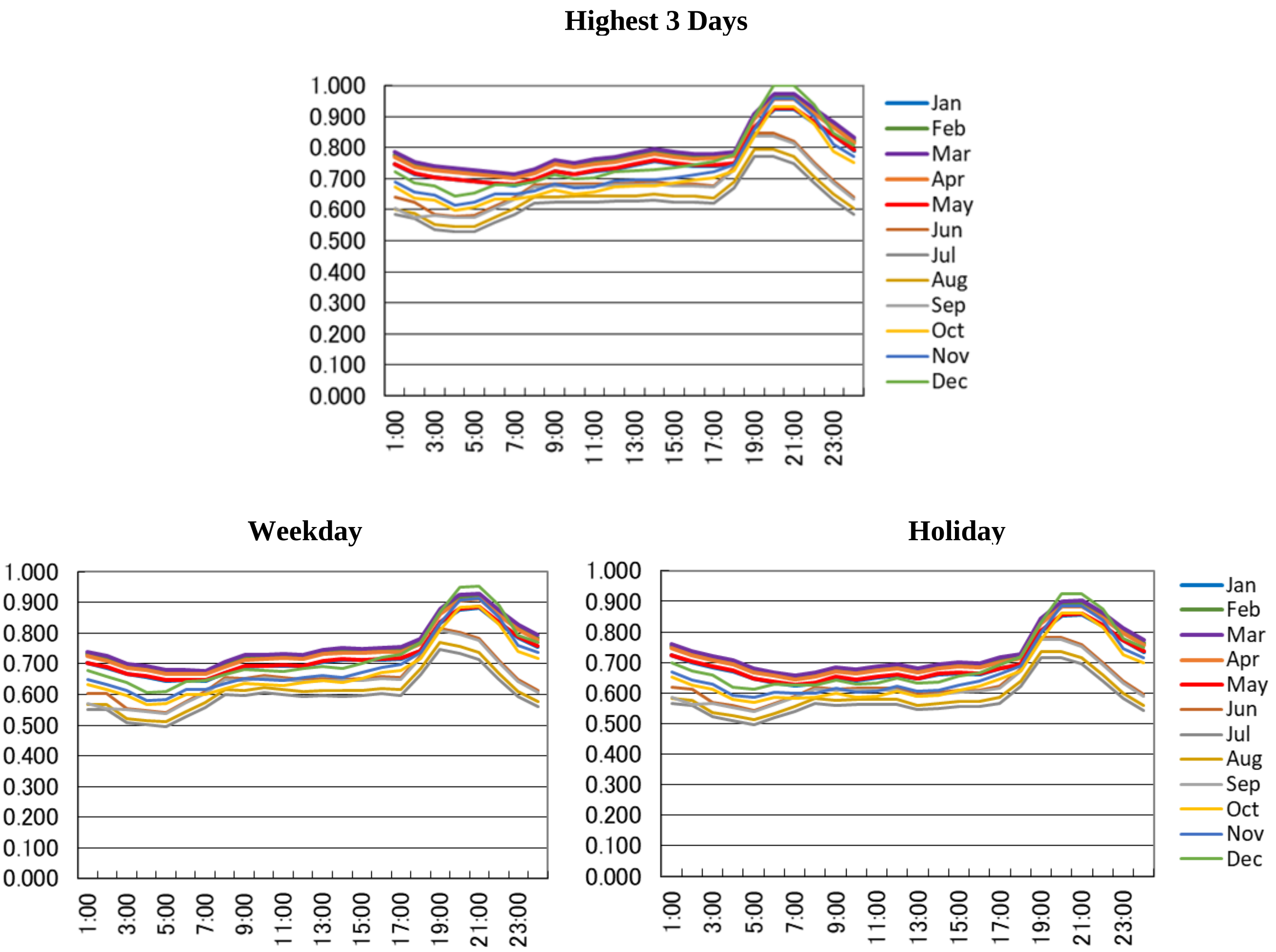
Table 5-5 Monthly Maximum Demand Fluctuation Normalized

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015	87%	95%	91%	91%	88%	78%	74%	79%	82%	96%	98%	100%
2016	95%	96%	100%	94%	95%	83%	81%	77%	82%	89%	92%	99%
2017	94%	97%	100%	100%	94%	84%	84%	84%	84%	—	—	—
Average	92%	96%	97%	96%	93%	85%	77%	80%	84%	93%	96%	100%

(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Next, the daily load curves (highest 3 days, weekdays, and holidays) every month as of 2016 were assumed by correcting the demand during the peak time (3 hours) based on the load curves in August and December 2016 and January 2017, when latent demand was relatively small (see Figure 5-8). The daily load curves on the highest 3 days, weekdays, and holidays assumed every month are shown in Figure 5-16 (normalized by the annual maximum power demand).

The annual load factor calculated from the above results is 70.3%.

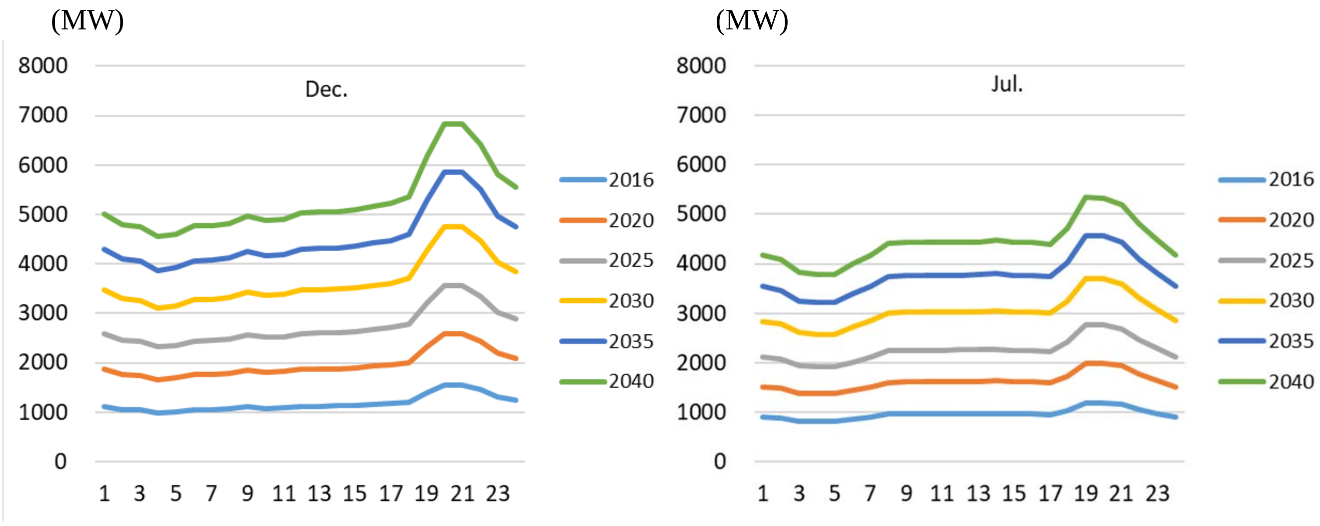


(Source: JICA Survey Team)

Figure 5-16 Daily Load Curves as of 2016 (North System)

Since the North system has a large city of Luanda, it seems likely that the power demand in the daytime will rise somewhat above the peak demand in the evening in the future. The annual load factor as of 2016 (70.3%) is expected to increase to about 72% in 2040, from the experience of other developing countries.

The daily load curves (highest 3 days, weekdays, holidays) every month up to 2040 were forecasted according to the aforementioned assumption. Figure 5-17 shows the daily load curves on the highest 3 days in December, when monthly maximum power demand is the highest, and in July when the monthly maximum power demand is the lowest in the year.



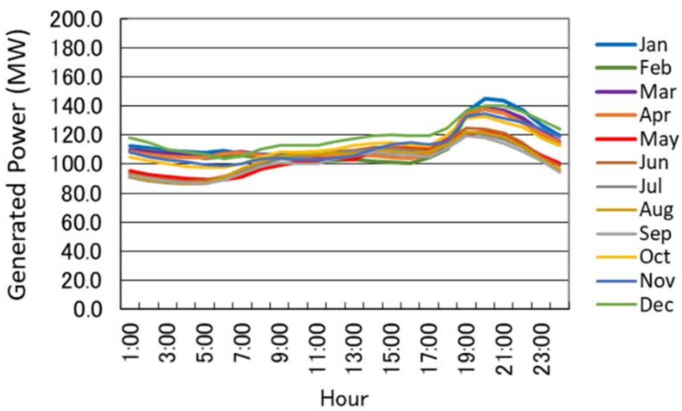
(Source: JICA Survey Team)

Figure 5-17 Daily Load Curve Forecast up to 2040 (North System; Highest 3 days)

(2) Central, South and East Systems

Since hourly generation data in the Center, South and East system have not been organized, the daily load curves in those systems are to be forecast based on the power supply records as of 2016 in the isolated subsystem in the North system.

The daily load curve for the highest 3 days by months as of 2016 in the isolated subsystem in the North system is shown in Figure 5-18.



(Source: JICA Survey Team)

Figure 5-18 Daily Load Curves of Isolated Subsystem in North System (2016)

The maximum power demand (including latent demand) for each month in the Center and South system in 2016 (see Figure 5-8) was normalized with annual maximum power demand, and the average was calculated as shown in Table 5-6. The annual maximum power occurs in December, the maximum power demand in June descends in the lowest level, about 77 % of the annual maximum power demand.

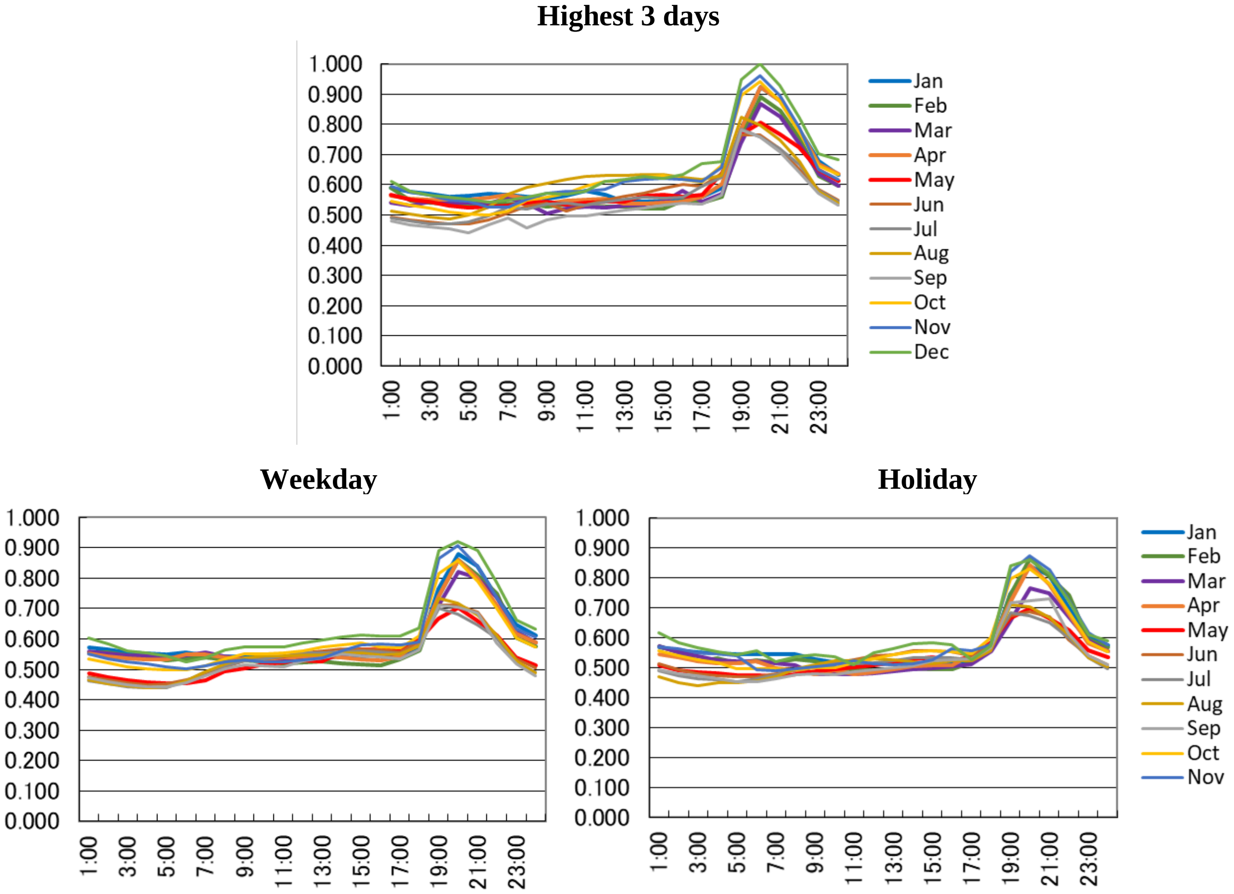
Table 5-6 Monthly Maximum Demand Fluctuation Normalized

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016	Center	82%	84%	82%	80%	75%	73%	81%	90%	84%	94%	100%	96%
	South	94%	92%	93%	100%	95%	92%	93%	96%	96%	99%	97%	91%
Applied		92%	89%	87%	92%	81%	77%	78%	82%	78%	94%	96%	100%

(Source: Prepared by the JICA Survey Team based on Data from RNT (NLDC))

Since the mean latent demand as of 2016 in the Center system, which has a second largest demand scale, was 30% of the monthly maximum power demand as shown in Figure 5-8, this ratio is applied to modify the hourly demand during the peak demand (3 hours) and the monthly daily load curves are forecasted. The daily load curves on the highest 3 days, weekdays, and holidays assumed every month are shown in Figure 5-19 (normalized by the annual maximum power demand). modified and normalized by monthly maximum are shown.

The annual load factor calculated from the above results is 56.8%.

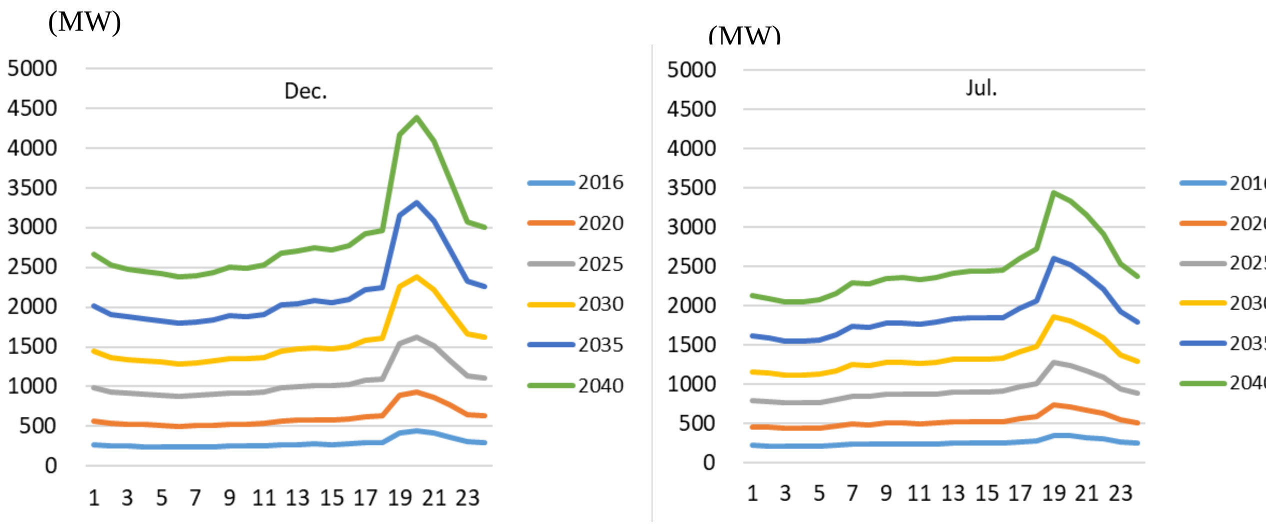


(Source: JICA Survey Team)

Figure 5-19 Daily Load Curves as of 2016 (Center+South+East System)

Since electrification will be promoted in the Center, the South and the East system until after 2040, It is expected that load curves for domestic demand will increase in the similar figure based on electrification and the ratio of demand for commerce, industry and commercial will not change. Accordingly, it seems likely that the annual load factor as of 2016 (56.8%) is no change up to 2040.

The total daily load curves in the Center, the South and the East System (highest 3 days, weekdays, holidays) every month up to 2040 were forecasted according to the aforementioned assumption. Figure 5-20 shows the daily load curves on the highest 3 days in December, when monthly maximum power demand is the highest, and in July when the monthly maximum power demand is the lowest in the North system in the year.



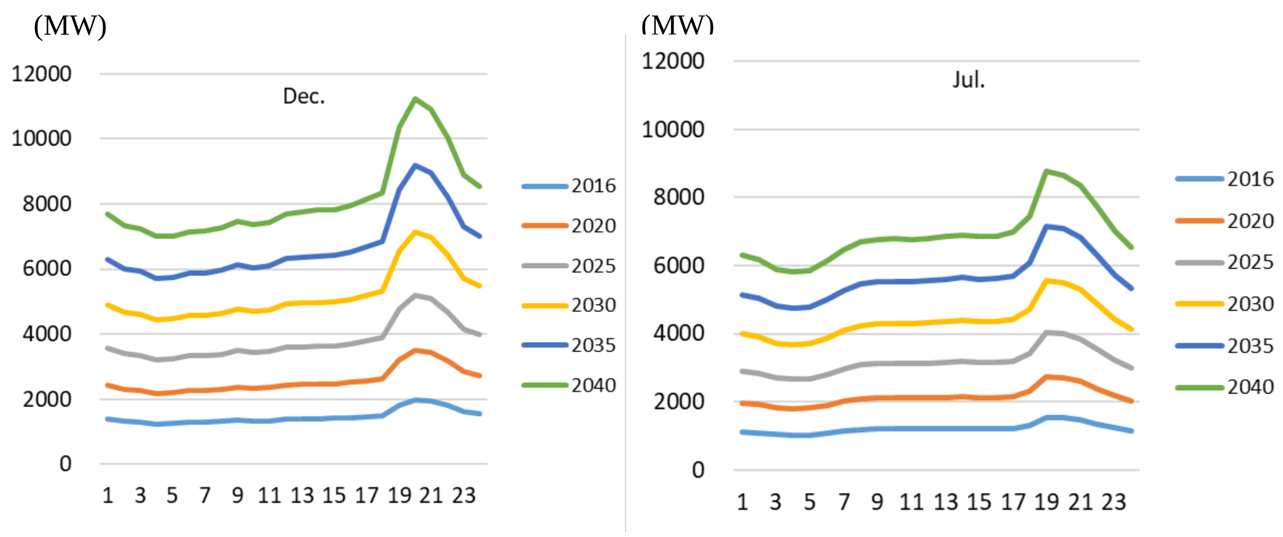
(Source: JICA Survey Team)

Figure 5-20 Daily Load Curve Forecast (Center+South+East System; Highest 3 days)

(3) **Whole country**

According to the aforementioned results, the annual load factor in the whole country (North, Center, South and East system) as of 2016 (67.3%) will descend up to 66.1% in 2040. The main reason is that the share of maximum power demand in the North system will decline from 77.7 % in 2016 to 61.0 % 2040 due to promotion of electrification in Center, South and East system.

Figure 5-21 shows the daily load curves on the highest 3 days in December, when monthly maximum power demand is the highest, and in July when the monthly maximum power demand is the lowest in the year.



(Source: JICA Survey Team)

Figure 5-21 Daily Load Curve Forecast (Whole County; Highest 3 days)

5.3.4 Annual generated energy demand forecast

Generation energy demand is calculated by the following formula.

Generated energy demand (kWh) = annual maximum power demand (kW) × 8,760 hours × annual load factor

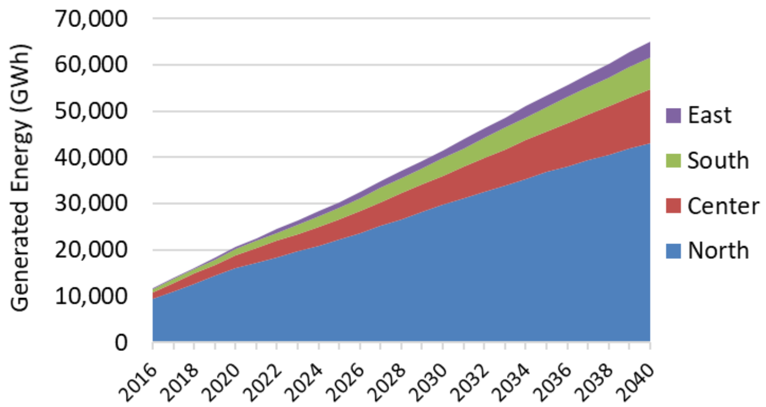
Based on the forecast of the annual maximum power demand and the annual load factor aforementioned, the results for the generated energy demand forecast are shown in Table 5-7 and in Figure 5-22.

Table 5-7 Annual Generated Energy Demand Forecast by System

(Unit: GWh)

	North	Center	South	East	Whole
2016	9,522	1,325	673	208	11,728
2017	11,131	1,708	837	269	13,946
2018	12,743	2,092	1,001	331	16,167
2019	14,359	2,476	1,165	392	18,392
2020	15,977	2,860	1,329	453	20,619
2021	17,214	3,161	1,560	611	22,546
2022	18,452	3,462	1,791	768	24,474
2023	19,693	3,763	2,023	926	26,405
2024	20,937	4,065	2,254	1,083	28,339
2025	22,183	4,366	2,485	1,241	30,275
2026	23,678	4,762	2,743	1,337	32,520
2027	25,175	5,158	3,001	1,434	34,768
2028	26,675	5,555	3,258	1,530	37,019
2029	28,179	5,951	3,516	1,626	39,272
2030	29,685	6,347	3,774	1,723	41,529
2031	31,103	6,836	4,075	1,867	43,881
2032	32,525	7,324	4,376	2,011	46,235
2033	33,949	7,813	4,677	2,154	48,593
2034	35,375	8,301	4,978	2,298	50,953
2035	36,805	8,790	5,279	2,442	53,316
2036	38,066	9,335	5,626	2,616	55,643
2037	39,330	9,881	5,973	2,789	57,974
2038	40,597	10,427	6,321	2,962	60,306
2039	41,865	10,973	6,668	3,136	62,641
2040	43,136	11,518	7,015	3,309	64,979

(Source: JICA Survey Team)



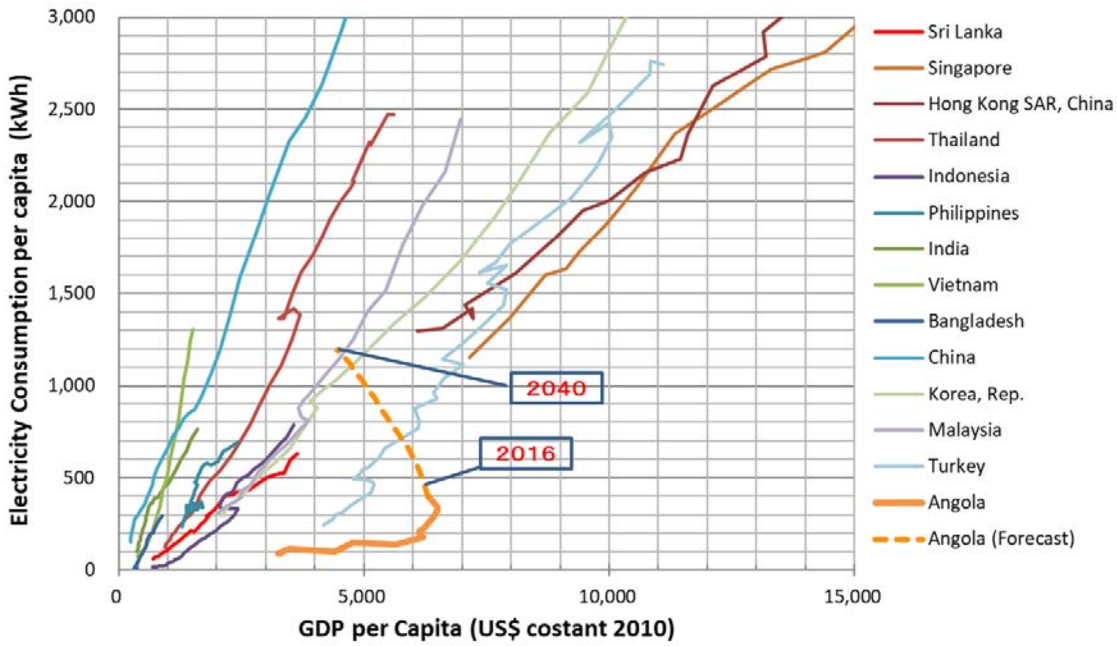
(Source: JICA Survey Team)

Figure 5-22 Generated Energy Demand Forecast

5.3.5 Macro-evaluation of power demand forecast

To confirm the validity of the power demand forecast results, they were compared with the results of other developing countries. The chart in Figure 5-23 plots the relationship between the results for GDP per capita and the electricity consumption per capita (1973 - 2013) in various developing countries, adding a prescript of Angola's results and the power demand forecast in Angola. The relationship between GDP and electricity consumption is gradually increasing in each country, although the gradient differs from one country to another, reflecting the differences in how electricity is used according to the countries' climatic conditions and industrial structures.

Since the growth rate of population is projected to decrease gradually from 3.0% in 2016 to 2.5% in 2040 whereas the growth rate of GDP is predicted to be constant after 2023 as 1.4% based on the IMF prediction until 2022, the GDP per capita will decline year by year. On the other hand, the electricity consumption per capita is forecasted to linearly increase as well as those of the other countries. Therefore, this demand forecast up to 2040 seems to be valid.



(Source: JICA Survey Team)

Figure 5-23 Relationship between GDP and Electricity Consumption per Capita

Chapter 6 Optimization of the Generation Development Plan

6.1 Current situation of power generation facilities

6.1.1 Existing power plants

(1) **Composition of Power Plants**

The installed capacity of the existing major power plants by type and by region is shown in Table 6-1. The composition of the generation types by region is shown in Figure 6-1.

Hydropower facilities have the largest share, accounting for more than half of the capacity in the whole country. The rest is supplied by thermal power, specifically, gas turbine and diesel plants. Meanwhile, most of the large hydropower plants are located in the north. The share of thermal power in the north is therefore higher than the shares in the central, south, and east regions.

Regarding the generation of the renewable energy, one biomass generation plant is in operation. Other large-scale development projects, including wind power and solar power plants, have yet to appear.

Table 6-1 Major power generation plants by region by type (MW)

Region	Total	Hydropower (except small)	Thermal Power		Renewable		
			GT	Diesel	Biomass	Wind	Solar PV
Whole Country	**4,339**	**2,365**	**1,181**	**743**	**50**	**0**	**0**
North Region	3,527	2,172	899	407	50	0	0
Central Region	492	125	254	113	0	0	0
South Region	221	41	28	152	0	0	0
East Region	99	28	0	71	0	0	0

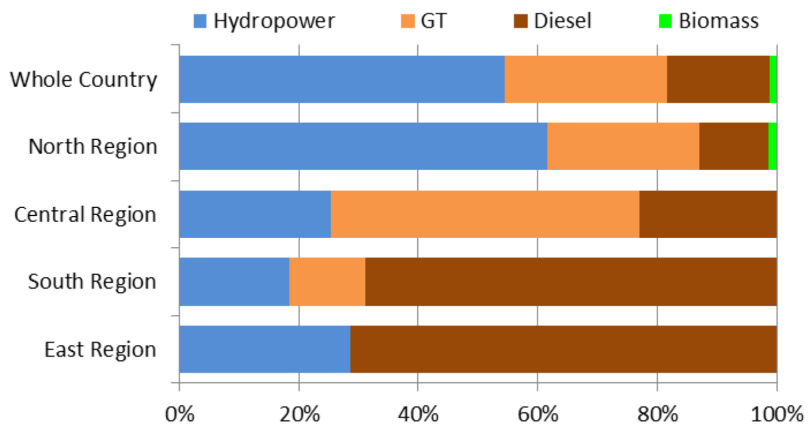


Figure 6-1 Composition of installed capacity

Meanwhile, aging of the power plants, in hydro/thermal/renewable power, have been progressed. There are many power plants that have stopped operation or are incapable of generating at the installed capacity. Particularly in the thermal power plants, the drop in the maximum available generation capacity is remarkable. The current available capacity of the thermal power plants is summarized in Table 6-2. Forty percent of the installed capacity of thermal power plants is restricted. Therefore, the current supply capacity should be evaluated based on the current available capacity.

Table 6-3 shows the available capacity by generation type and by region. Figure 6-2 shows the composition of available generation capacity by region. As the table and figure demonstrate, the share of hydropower generation exceeds 60%. Hence, power generation dominated by hydropower is more realistic than the ratio of installed capacity.

Table 6-2 Available capacity of thermal power (MW)

Region	Thermal Power		
	Installed capacity (1)	Available capacity (2)	Available ratio (2)/(1)
Whole Country	**1,924**	**1,145**	**60%**
North Region	1,306	751	58%
Central Region	367	226	61%
South Region	180	130	72%
East Region	71	38	53%

Table 6-3 Available capacity by type by region (MW)

Region	Total	Hydropower (except small)	Thermal Power		Renewable		
			GT	Diesel	Biomass	Wind	Solar PV
Whole Country	**3,441**	**2,286**	**739**	**406**	**10**	**0**	**0**
North Region	2,941	2,150	549	202	10	0	0
Central Region	311	85	162	64	0	0	0
South Region	157	27	28	102	0	0	0
East Region	62	24	0	38	0	0	0

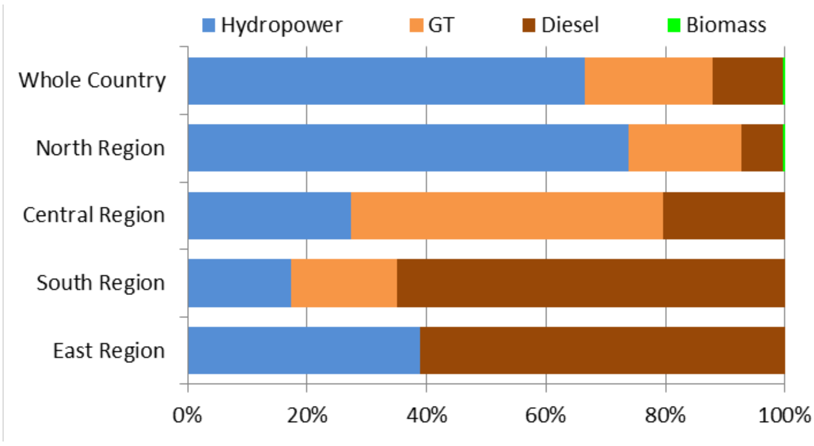


Figure 6-2 Composition of available generation capacity

(2) Ownership of power facilities

Table 6-4 shows the ownership of the existing power stations. Most of the O&M for existing power plants, including all of the large-scale hydropower stations with excellent capacity for adjustment of generation, has been conducted by PRODEL. Hence, PRODEL plays a significant role in providing a stable power supply.

Table 6-4 Ownership of power plants (MW)

Region	Total	Hydropower		Thermal Power		Biomass	
		PRODEL	Others	PRODEL	Others	PRODEL	Others
Whole Country	**4,339**	**2,274**	**92**	**1,373**	**552**	**0**	**50**
North Region	3,527	2,146	26	944	362	0	50
Central Region	492	75	50	337	30	0	0
South Region	221	41	0	28	152	0	0
East Region	99	12	16	63	7	0	0

(3) Hydropower stations

Basic information on the existing hydropower stations is shown in Table 6-5. The installed capacity of hydropower is 2,373 MW as of October 2017. Out of this capacity, 2,146 MW is provided by three (3) large-scale hydropower stations: Capanda, Cambambe, and Lauca hydropower. The Lauca power station is still under construction. Two (2) units have started commercial generation, and the others are to be completed in series, as described in the following section. The generation capacity of these three (3) hydropower stations has therefore been increasing.

All three (3) of these hydropower stations are located in Kwanza River. The Capanda hydropower station, which is located middle of the river, is the first developed hydropower plant in the river basin. The station has a large reservoir with 3,653 million m3 of effective storage and an installed capacity of 520 MW.

The Cambambe hydropower station is located downstream of the Capanda hydropower station. It began with an installed capacity of 180 MW. After completion, the dam was renovated to raise the height by 15m, and renovation of the existing plant for increasing the capacity to 260 MW, and also an additional power station of 700 MW was constructed. The renovation and expansion project are conducted by Odbrecht Angola, and Voith was in charge of power generation equipment and others.

The Lauca hydropower station is located midway between the above two hydropower stations. The Lauca hydropower station is a huge-scale plant with an installed capacity of 2,067 MW and reservoir capacity of 5,482 million m3. These three (3) hydropower stations currently play a very important role as major power sources in Angola.

(4) Thermal power stations

Basic information on the existing thermal power stations is shown in Table 6-6.

The Soyo thermal power station is the first combined cycle power plant introduced in Angola. Two (2) gas turbine generators with a total generation capacity of 250 MW have tentatively started generation at the plant using diesel oil for fuel. Completion of construction, with a natural gas supply for fuel, is slated for 2018.

The capacities of the other thermal plants are middle or small scale. There are about ten (10) gas turbine plants in the 20-to-40 MW class. The remaining plants are small-scale diesel power plants, some of which have not been connected to the main power grid.

Most of these gas turbine and diesel power plants are located in or near a substation of a local grid and used for stability of power voltage. Generation during peak time is reasonable, but the purpose of actual generation of these power plants seems to be for power shortage in a whole day. The generation cost therefore seems to be higher, which poses one of the important challenges to address in the Angolan power system.

Regarding the fuel type, Jet B is used for some gas turbines but the major fuel is diesel oil. Natural gas has not been used for generation so far. Plans for the utilization of natural gas for fuel cost reduction are under discussion with Sonangol but are not yet concluded.

Table 6-5 List of existing hydropower stations as of October 2017

Plant name	Grid connection	Owner	Location					Installed capacity (MW)	Number of units / unit capacity (MW)	Available capacity (MW)	Year commissioned	Note
			Area	Province	Municipality	Longitude	Latitude					
Lauca	on grid	PRODEL	North	Malanje	-	15° 7'32.38"E	9°44'30.58"S	666.0	6x333,1x67	666.0	2017-2018	#1,#2 completed, #3-#6 under construction, Total 2067MW
Capanda	on grid	PRODEL	North	Malanje	Cacuso	15°27'48.85"E	9°47'35.02"S	520.0	4x 130	480.0	2004/2007	-
Cambambe	on grid	PRODEL	North	Kwanza Norte	Dondo	14°28'44.76"E	9°45'4.40"S	260.0	4x 65	240.0	2012	-
Cambambe 2	on grid	PRODEL	North	Kwanza Norte	Dondo	14°29'1.08"E	9°44'47.27"	700.0	4x 175	640.0	2016	-
Mabubas	on grid	IPP	North	Bengo	Dande	13°42'0.57"E	8°32'6.77"S	25.6	4x 6.4	24.0	2012	-
Biópio	on grid	PRODEL	Central	Benguela	Lobito	13°43'36.24"E	12°28'4.58"S	14.58	4x 3.645	12.0	1955	-
Lomaúm	on grid	IPP	Central	Benguela	Cubal	14°23'8.39"E	12°43'31.27"S	50.0	2x10, 2x15	50.0	2015	-
Gove	on grid	PRODEL	Central	Huambo	Caála	15°52'12.72"E	13°27'7.41"S	60.0	3x 20	35.0	2012	-
Matala	on grid	PRODEL	South	Huíla	Matala	15° 2'30.93"E	14°44'39.96"S	40.8	3x 13.6	27.2	1959	-
							On grid Total=	**2,337.0**		**2,174.2**		
Luachimo	off grid	PRODEL	East	Lunda Norte	Dundo	20°50'35.45"E	7°21'48.94"S	8.4	4x 2.1	4.0	-	-
Chicapa	off grid	IPP	East	Lunda Sul	Saurimo	20°21'14.94"E	9°29'8.64"S	16.0	4x 4	14.0	-	-
Chiumbe Dala	off grid	PRODEL	East	Lunda Sul		20°12'14.75"E	11° 1'19.39"S	12.0	2x4, 2x2	10.0	2017	-
							Off grid Total=	**36.4**		**28.0**		
							Hydro Total=	**2,373.4**		**2,202.2**		

Table 6-6 List of existing thermal power stations as of October 2017

Plant name	Grid connec-tion	Owner	Location					Installed capacity (MW)	Number of units / unit capacity (MW)	Available capacity (MW)	Year commissioned	Type	Fuel	Note
			Area	Province	Municipalities	Longitude	Latitude							
Soyo	on grid	PRODEL	North	Zaire	Soyo	12°20'51.70"E	6°10'40.60"S	250.0	GT 4x125, ST 2x125	250.0	2017-2018	GT	Diesel/NG	#1,2 in operation, Total 750 MW(CCGT)
CD Benfica	on grid	PRODEL	North	Luanda	Belas	13° 9'54.40"E	8°57'14.73"S	40.0	10x 4	24.0	2013	Diesel	Diesel	
CT Cazenga #1	on grid	IPP	North	Luanda	Cazenga			24.4	1x 24.4	0.0	1979	GT	Diesel	N/A
CT Cazenga #2	on grid	IPP	North	Luanda	Cazenga			32.0	1x 32.8	32.0	1985	GT	Diesel	
CT Cazenga #3	on grid	IPP	North	Luanda	Cazenga			40.0	1x40	40.0	1993	GT	Diesel	
CT Cazenga #4	on grid	IPP	North	Luanda	Cazenga	13°18'23.38"E	8°48'53.54"S	22.4	1x 22.45	0.0	-	GT	Jet B	N/A
CT Cazenga #5	on grid	IPP	North	Luanda	Cazenga			22.4	1x 22.45	0.0	-	GT	Jet B	N/A
CT Cazenga #6	on grid	PRODEL	North	Luanda	Cazenga			22.0	1x 22	18.00	2010	GT	Jet B	
CT Cazenga #7	on grid	PRODEL	North	Luanda	Cazenga			22.0	1x 22	18.00	2010	GT	Jet B	
CT CFL	on grid	PRODEL	North	Luanda	Cazenga	13°16'36.78"E	8°49'41.66"S	125.0	5x 25	75.0	2012-2013	Diesel	Diesel	#1,#3 N/A
CD Viana Km9	on grid	PRODEL	North	Luanda	Viana	13°18'59.68"E	8°51'59.71"S	40.0	24x 1.66	25.0	2013	Diesel	Diesel	
CT Boa Vista I	on grid	PRODEL	North	Luanda	Luanda			45.0	1x 45	0.0	2011	GT	Diesel	N/A
CT Boa Vista II	on grid	PRODEL	North	Luanda	Luanda	13°13'19.10"E	8°49'20.40"S	45.0	1x 45	0.0	2011	GT	Diesel	N/A
CT Boa Vista III	on grid	PRODEL	North	Luanda	Luanda			41.2	1x 41.2	24.0	2011	GT	Diesel	
CT Refinaria	on grid	IPP	North	Luanda	Cazenga	13°18'28.20"E	8°46'56.37"S	25.5	-	0.0	-	GT	Diesel	
CT CIF Thermal	on grid	IPP	North	Luanda	Viana	13°34'0.35"E	9° 6'29.84"S	50.0	-	0.0	-	GT	Diesel	
CD Capopa 1	on grid	PRODEL	North	Malanje	Malanje	-	-	4.5	-	0.0	2013	Diesel	Diesel	
CD Capopa 2	on grid	PRODEL	North	Malanje	Malanje	-	-	19.6	5x3.9	15.7	2015	Diesel	Diesel	
CT Camama	on grid	PRODEL	North	Luanda	Belas	-	-	50.0	2x25	50.0	2017	GT	Diesel	
CT Biópio	on grid	PRODEL	Central	Benguela	Lobito	13°43'21.66"E	12°27'48.10"S	22.0	1x22.0	0.0	1977	GT	Diesel	
CT Quileva	on grid	PRODEL	Central	Benguela	Lobito	13°35'23.96"E	12°22'54.95"S	182.3	6x15,3x30.78	112.3	2010-2017	GT	Diesel	#2-5 N/A
CT Belem	on grid	PRODEL	Central	-	-	-	-	50.0	2x25	50.0	2017	GT	Diesel	
CD Quileva (Aggreko)	on grid	IPP	Central	Benguela	Lobito	13°35'20.90"E	12°22'58.58"S	30.0	39x0.79	26.4	-	Diesel	Diesel	
CD Lobito	on grid	PRODEL	Central	Benguela	Lobito	13°32'29.78"E	12°22'1.80"S	20.0	4x5.0	0.0	1986	Diesel	Diesel	N/A
CD Cavaco	on grid	PRODEL	Central	Benguela	Benguela	13°25'57.06"E	12°35'11.60"S	20.0	5x4.1	8.0	2013	Diesel	Diesel	#1,2,4,5 N/A
CD Benfica	on grid	PRODEL	Central	Huambo	Huambo	15°44'45.10"E	12°45'13.75"S	15.0	4x 3.75	11.3	2013	Diesel	Diesel	#3 N/A
CD Lubango	on grid	IPP	South	Huíla	Lubango	13°30'52.08"E	14°55'53.49"S	40.0	11x2.61	29.1	2013	Diesel	Diesel	
CD Arimba	on grid	IPP	South	Huíla	Lubango	13°34'48.45"E	14°57'7.87"S	40.0	28x1.43	31.4	2012	Diesel	Diesel	
							On grid Total=	**1,340.3**		**840.2**				
CD Morro Bento	off grid	IPP	North	Luanda	Belas	13°11'21.47"E	8°53'29.65"S	40.0	40x1.05	0.0	2017	Diesel	Diesel	N/A
CT Morro Bento 2	off grid	PRODEL	North	Luanda	Belas	13°11'21.47"E	8°53'29.65"S	50.0	2x 25	25.0	2017	GT	Diesel	#1 stopped
CT Rocha Pinto	off grid	IPP	North	Luanda	Belas	-	-	40.0	2x 20	-	-	GT	Diesel	N/A
CD Quartéis	off grid	PRODEL	North	Luanda	Cazenga	13°14'26.92"E	8°50'24.79"S	32.0	8x 3.75	16	2013-17	Diesel	Diesel	
CD Cassaque	off grid	PRODEL	North	Luanda	Viana	13°21'56.56"E	9° 6'58.12"S	20.0	18x 1.22	9.2	2013	Diesel	Diesel	
CD Morro da Luz	off grid	IPP	North	Luanda	Belas	13°11'50.09"E	8°52'13.68"S	20.0	29x1.38	0.0	-	Diesel	Diesel	
CT Viana	off grid	PRODEL	North	Luanda	Viana	13°18'59.68"E	8°51'59.71"S	22.0	1x22	22.0	2010	GT	Diesel	
CD Kianganga	off grid	PRODEL	North	Zaire	Zaire	-	-	19.7	-	11.13	2006-15	Diesel	Diesel	

Plant name	Grid connec-tion	Owner	Location					Installed capacity (MW)	Number of units / unit capacity (MW)	Available capacity (MW)	Year commissioned	Type	Fuel	Note
			Area	Province	Municipali ties	Longitude	Latitude							
CD Tomboco	off grid	PRODEL	North	Zaire	Zaire	-	-	1.0		1.016	-	Diesel	Diesel	
CD Kaluapanda	off grid	PRODEL	Central	Bié	Kuito	-	-	10.0	4x2.5	5.0	2011	Diesel	Diesel	#1,2 N/A
CD Caála	off grid	PRODEL	Central	Huambo	Caála	-	-	2.0	-	0.0	2004-09	Diesel	Diesel	
CD Bailundo	off grid	PRODEL	Central	Huambo	Bailundo	-	-	2.7	-	2.26	2013	Diesel	Diesel	
CD Camacupa	off grid	PRODEL	Central	Bié	Camacupa	-	-	3.2	-	1.2	2001	Diesel	Diesel	
CD Chinguar	off grid	PRODEL	Central	Bié	Chinguar	-	-	2.1	-	1.39	2008	Diesel	Diesel	
CD Lossambo	off grid	PRODEL	Central	-	-	-	-	8.0	-	8.0	-	Diesel	Diesel	
CD Xitoto I	off grid	IPP	South	Namibe	Namibe	12°10'14.86"E	15° 8'44.90"S	11.2	2x5.6	0.0	-	Diesel	Diesel	N/A
CD Xitoto II	off grid	IPP	South	Namibe	Namibe	12°10'14.85"E	15° 8'42.01"S	10.2	6x 1.66	6.8	2013	Diesel	Diesel	
CT Xitoto III	off grid	PRODEL	South	Namibe	Namibe	12°10'14.85"E	15° 8'42.01"S	28.0	1x28	28.0		GT	Diesel	
CD Airport	off grid	IPP	South	Namibe	Namibe	12° 7'26.88"E	15°14'20.56"S	11.7	3x3.89	7.8	2013	Diesel	Diesel	#2 N/A
CD Ondjiva	off grid	IPP	South	Cunene	Ondjiva	-	-	10.2	3x 3.33	6.8	2013	Diesel	Diesel	
CD Menongue	off grid	IPP	South	K. Kubango	Menongue	17°41'52.31"E	14°39'24.65"S	11.9	7x1.71	8.5	2013	Diesel	Diesel	
CD Tômbwa	off grid	IPP	South	Namibe	Tômbwa	11°51'0.70"E	15°48'17.30"S	9.6	5x1.4, 2x 1.2	4.32	2014-15	Diesel	Diesel	
CD Cuito Cuanavale	off grid	IPP	South	Kuando	Kubango	19° 8'44.30"E	15° 8'29.50"S	7.5	5x 1.7	7.5	2015	Diesel	Diesel	
							Off grid Total=	**372.9**		**171.9**				
CD Saurimo	off grid	PRODEL	East	Lunda Sul	Sumbe	20°24'5.16"E	9°38'32.58"S	14.1	5x 2.5	4.1	2011-14	Diesel	Diesel	
CD Dundo Nova	off grid	PRODEL	East	Lunda Norte	Dundo	20°48'20.98"E	7°22'55.82"S	30.0	8x 3.75	22.5	2013-14	Diesel	Diesel	
CD Luena (Hynday)	off grid	PRODEL	East	Moxico	Luena	19°56'44.40"E	11°45'39.72"S	7.5	5x 1.7	3.0	2012	Diesel	Diesel	
CD Luena (Catherpillar)	off grid	PRODEL	East	Moxico	Luena	19°54'40.62"E	11°47'30.00"S	6.5	2x1,64+2x1,6	1.6	2013	Diesel	Diesel	
CD Luau	off grid	PRODEL	East	-	-	-	-	5.4	-	3.6	2015	Diesel	Diesel	
CD Era	off grid	IPP	East	-	-	-	-	7.4	-	3.0	-	Diesel	Diesel	
							Off grid (East) Total=	**70.9**		**37.8**				
							Termal (main land) Total=	**1,784.0**		**1,050.0**				
CD Chibodo	off grid	IPP	Cabinda	Cabinda	-	-	-	30.6	18x1.67	15.3	2014	Diesel	Diesel	
CT Malembo I / II / III	off grid	PRODEL	Cabinda	Cabinda	-	-	-	95.0	2x35, 1x25	70	2012-15	GT	Diesel	
CD Santa Catarina	off grid	IPP	Cabinda	Cabinda	-	-	-	10.2	6x 1.7	6.8	2014	Diesel	Diesel	
CD Belize	off grid	IPP	Cabinda	Cabinda	-	-	-	2.2	2x 1.1	1.1	2014	Diesel	Diesel	
CD Buco Zau	off grid	IPP	Cabinda	Cabinda	-	-	-	2.2	2x 1.1	2.2	2014	Diesel	Diesel	
							Off grid (Cabinda) Total=	**140.2**		**95.4**				
							Thermal Total=	**1,924.2**		**1,145.4**				

6.1.2 Performance of large hydropower stations

As mentioned in the previous section 6.1.1(3), large-scale hydropower stations are developed in the Kwanza River. Two of the stations, the Capanda and Cambambe hydropower stations, operated as major power generation plants before the third station, Lauca, were constructed.

The Capanda power station is located in the middle of Kwanza River, upstream of the other two. The inflow record to the Capanda reservoir is shown in Figure 6-3. The inflow varies widely between the dry season and flood season, and also during the flood season year by year.

The generation record of the Capanda hydropower station is shown in Figure 6-4. The seasonal change in generation was regulated by use of the reservoir, but less power was generated during the dry season (September-October) than during the wet season. Inflow in 2011 and 2012, the driest years, was quite small, as was the generation during the dry season in those years. Inflow in the years 2016 to 2017 was also small, with similarly low generation in the dry season.

The available generation of hydropower depends on river discharge. Accordingly, a generation plan for reservoir usage to respond to shifting inflow during the flood season to dry season is important for a reservoir-type hydropower station. Given the large inflow gap between the flood and dry seasons in Angola, it will be necessary to estimate the available discharge of each month and reflect the estimates in the long-term development plan.

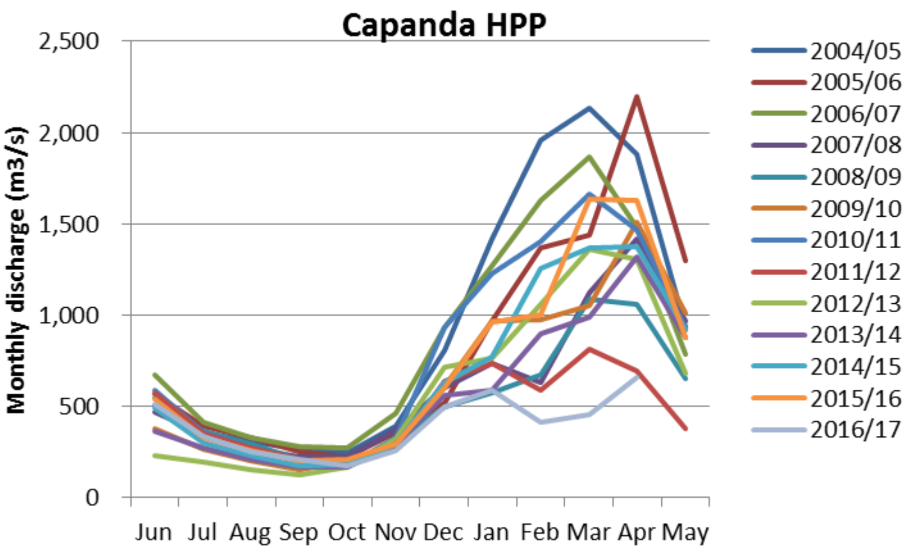


Figure 6-3 Inflow record of Capanda Hydropower Station

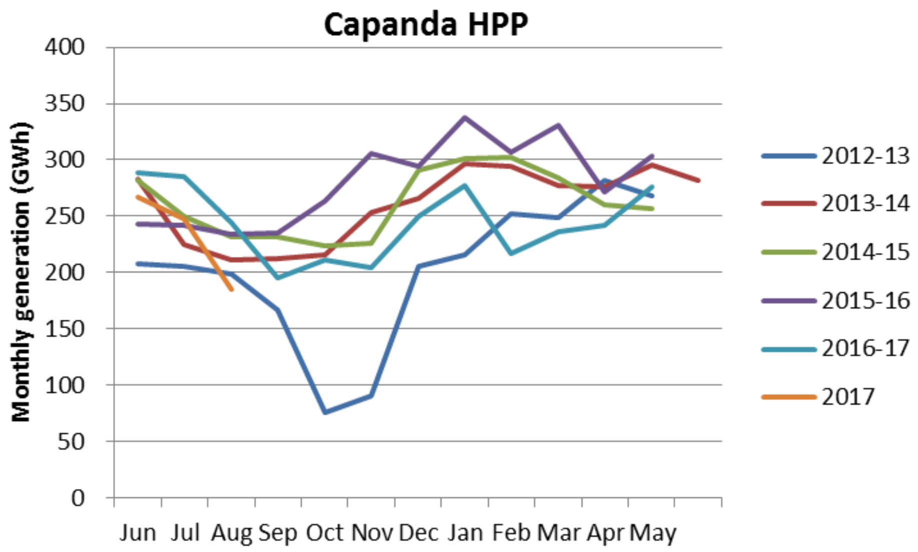


Figure 6-4 Generation record of Capanda Hydropower Station

6.1.3 Power stations under construction

(1) **Hydropower stations**

Two (2) large-scale hydropower stations are under construction: the Lauca hydropower station (2,167 MW) and Caculo Cabaca hydropower station (2,170 MW). Both stations are large reservoir types located in the Kwanza River between the Capanda and Cambambe hydropower stations.

<Lauca hydropower station>

As described in the previous section, The Lauca hydropower station is located downstream of Capanda hydropower station. One (1) turbine/generator utilizing maintenance flow and six (6) 333.3 MW Francis type turbine/generators are planned. The construction cost was financed from Brazil. The construction was carried out by ODLBRECHT, and ANDRIZ HYDRO took a role for hydro turbines/ generators. The first generator was completed in July 2017 and the second started generating power from October 2017. The following units are scheduled to be completed one at a time at two-month intervals going forward.

<Caculo Cabaca hydropower station>

The Caculo Cabaca hydropower station is located downstream of the Lauca power station and consists of four (4) 530 MW Francis type hydro turbine/generators and one (1) turbine/generator using maintenance flow. The construction cost was prepared by the loan of the Chinese Industrial and Commercial Bank of China (ICBC), and the joint venture of CGGC (China Gezhouba Group Co., Ltd.), BOREAL INVESTMENTS LIMITED, CGGC & NIARA - HOLDING LDA was selected for the contractor. Preparations for construction have started and diversion works have been ongoing from August 2017. Construction for the main works is scheduled to take place over a period of 80 months.

(2) **Thermal power stations**

Construction of the Soyo 1 thermal power station, the first combined cycle thermal power plant in Angola, is progressing. The plants in this power station have higher capacity and efficiency than the previous thermal power plants.

<Soyo 1 Combined Cycle Power Plant >

The Soyo 1 CCGT is being constructed in Zaire province in the north-west of Angola (see Figure 6-5). One gas turbine is already commissioned. The plant has a capacity of 750 MW and runs on gas and diesel oil.

The Soyo 1 CCGT consists of 2 blocks of multi-shaft-type CCGTs. Each block has a capacity of 375 MW and consists of two (2) sets of gas turbine generators, two (2) sets of heat recovery steam generators (HRSGs), and one (1) set of steam turbine.

A gas pipeline running from Angola LNG terminal at the Congo River to the Soyo 1 CCGT will supply natural gas to the CCGT from November, 2017.

Figure 6-5 Location of Soyo 1 CCGT

Figure 6-6 Bird's-eye View of Soyo 1 CCGT

(Source) Energia 2025 and Soyo 1 CCPP construction office

The main specifications for Soyo 1 CCPP are shown in the table below.

(a) Specifications for the Main Equipment

Equipment	Capacity and Number	Type	Manufacturer
Gas Turbine	125 MW x 4 sets	MS9001E	GE
Steam Turbine	125 MW x 2 sets	TCDF	GE
Generator (GT)	125 MVA x 4 sets	Hydrogen Cooling Synchronous	GE
Generator (ST)	125 MVA x 2 sets		
HRSG	HP= 145.27 t/h and LP=181.08 t/h x 4 sets	Horizontal Natural Circulation	Hangzhou

(b) Performance

Items	Gurantee Value
Plant Efficiency (LHV,%)	49.6 % at 15℃, 60%RH, 1,013mbar
Output (MW)	750 MW
Auxiliary Power (kW)	21.100 kw at 15℃, 60%RH, 1,013mbar
NOx (ppm)	41 ppm at 15% of O_2

(c) Notices

i) The gas turbine in the Soyo 1 CCGT can fire either gas or diesel oil. The generation started using diesel oil and then after completion of the pipeline, the fuel was changed to gas. As of January 2018, completion inspection for 3 of 4 gas turbines has been completed. Construction work is carried out by GAMEC and transferred to PRODEL after completion.

ii) Sonogas, the constructor of the gas pipeline, completed the construction in October 2017. The pipeline has a 20 inch diameter and runs a distance of 8 km from LNG terminal to Soyo 1 CCGT. The gas supply volume is 114 MMscfd, a little more than one-tenth of the 1,000 MMscfd production capacity of the LNG terminal.

iii) As for the gas price, the supplier (Sonagas) requires \$5 / MMBtu, while the operation side (PRODEL) requires \$3 / MMBtu. Finally the gas price was agreed as \$3 / MMBtu after negotiations.

iv) The price of diesel oil is the same as that used in other areas of Angola.

v) The National Bank of China is financing the Soyo 1 CCPP project.

vi) Land for extension of the thermal power plant has already been prepared. Since the land Soyo 1 CCGT occupies is designated as an industrial zone by the government, the plants in the area (excluding a thermal power plant) will be continuously developed and the land occupied by the industrial zone will be expanded in the future.

vii) The Soyo 2 CCGT is the only thermal power plant that construction is decided. Development of Soyo 2 is planned by IPP, and concession was given to an Angolan domestic capital (AE Energia). However, issues such as law improvement and PPA for IPP development are still remained, and the specific development schedule has not been determined.

viii) At present, Sonangol is developing a Gas Master Plan. The plan calls for the development of a gas pipeline from Soyo LNG Terminal to a number of Angola’s big port cities such as Luanda, Benguela, and Namibe, gas transportation by railway, and conversion from diesel oil to natural gas at the existing diesel power plants.

ix) Some 570 persons are working on the construction of Soyo 1 CCPP, of whom 55% are locals.

(d) Photographs

View of Soyo 1 CCGT from the access road

No. 4 gas turbine

Steam turbine building

400 kV GIS

6.2 Current power development plan

There is no power development plan issued at present, and the year of development for each candidate generation plant necessary to meet the demand increase is undetermined.

A study on candidate generation plants has been conducted (listed in “Energia 2025”). Meanwhile, GAMEK is carrying out the design of the candidate power plants and revising the initial plans in the study. Therefore, GAMEK’s design is currently the latest plan.

(1) Candidate projects for hydropower

Candidate hydropower projects are listed in Table 6-7. Among these projects, large-scale projects above 2,000 MW, that is, the Lauca and Caculo Cabaca hydropower stations, have already reached the construction stage. The progress of the other alternatives ranges from the project-finding stage to feasibility study stage. Therefore candidate projects of the 1,000 MW class still remain in the list. Meanwhile, the number of large-scale projects is limited. The total installed capacity of the candidate projects, including medium- to small-scale projects, is only about 10 GW.

Table 6-7 Candidate hydropower projects

Type	Plant name	Owner	Location		Installed capacity (MW)	Project cost (Mill. USD)	Note
			Area	Province			
Hydropower	Lauca	PRODEL	North	Malanje	2,067	4,300	
	Caculo Cabaça	PRODEL	North	Kwanza Norte	2,100	4,500	
	Zenzo	PRODEL	North	Kwanza Norte	950	N/A	
	Tumulo do Cacador	PRODEL	North	Kwanza Norte	453	1,041	
	Cafula	PRODEL	North	Kwanza Sul	403	1,121	
	Genga	PRODEL	North	Kwanza Sul		N/A	
	Benga	PRODEL	North	Kwanza Sul	987	N/A	
	Sanga		North	Kwanza Sul		N/A	
	Quilengue	PRODEL	North	Kwanza Sul	217	N/A	
	Cachoeira		North	Kwanza Sul		N/A	
	Carianga		North	Kwanza Norte	381	1,295	
	Bembeze		North	Kwanza Norte	260	768	
	Quissonde		North	Kwanza Sul	121	838	
	Cuteca		North	Kwanza Sul	203	734	
	Lomaúm (extension)	IPP	Central	Benguela	160	385	
	Cacombo	IPP	Central	Benguela	29	319	
	Calangue	IPP	Central	Benguela	190	471	
	Salamba		Central	Bie	48	324	
	Cunje		Central	Bie	8		
	Quissuca	IPP	Central	Kwanza Sul	121	567	
	Capitongo		Central	Benguela	41	239	
	Calindo		Central	Benguela	58	187	
	Baynes	PRODEL (50%)	South	Namibe	300	660	300 of 600 MW is Namibia
	Mucundi		South	Cuando Cubango	74	538	
	Jamb Ya Oma	IPP	South	Huila	75	500	
	Jamb Ya Mina	IPP	South	Huila	180	710	
	HPP Chiumbe Dala		East	Lunda Sul	8	30	
	Chicapa II (extension)	IPP	East	Lunda Sul	100	N/A	
	Luachimo (extension)		East	Lunda Norte	34	N/A	
	Cuango	IPP	East	Lunda Norte	30	158	
	Luapasso (H.S.Luapasso)	IPP	East	Lunda Norte	25	206	
	Camanengue (H.S.Luapasso)	IPP	East	Lunda Norte	29	173	
	Samuela (H.S.Luapasso)	IPP	East	Lunda Norte	15	93	
				Total =	9,666		

(2) Candidate projects for thermal power

Most of the candidate thermal power projects are planned as expansions or replacements of the existing small- to medium-scale thermal power stations running small diesel or gas turbines. Development for only one large-scale candidate project, the Soyo 2 thermal power station, has been decided. There are no other particular projects planned so far.

(3) Development plan for renewable energy plants

Currently only one biomass thermal plant and several small hydropower plants exist as renewable generation plants.

Small hydropower plants are mainly constructed and used for electricity supply to un-electrified areas. A further development by an IPP is planned, but the total capacity of the plan is only about 60 MW.

Regarding biomass generation, one 50 MW power station is in operation. “Energia 2025” describes a new 500 MW development, but the development plan at present is only 100 MW in total, including waste generation.

Regarding solar power and wind power generation, there are no power plants developed so far. Planning for a development based on a potential study has ongoing, however. Table 6-8 and Table 6-9 show the expected candidate projects listed by MINEA. “Energia 2025” describes the development of a 100 MW of solar power project and 100 MW wind power project. Several other plans for candidate projects have been progressed, but these are not included in the abovementioned list. It thus seems that development will be larger scale than the plans stated in “Energia 2025” overall.

Table 6-8 Candidate wind power generation projects

No.	Name of Project	Capacity (MW)	Note
1	BENIAMIN	52	Benguela
2	CACULA	88	Huila
3	CHIBIA	78	Huila
4	CALENGA	84	Huambo
5	GASTAO	30	Kwanza Norte
6	KIWABA NZOJI I	62	Malanje
7	KIWABA NZOJI II	42	Malanje
8	MUSSEDE I	36	Kwanza Sul
9	MUSSEDE II	44	Kwanza Sul
10	NHAREA	36	Bie
11	TOMBWA	100	Namibe
	Total	652	

Table 6-9 Candidate solar power projects

No.	Name of Project	Capacity (MW)	Note
1	BENGUELA	10	Benguela
2	CAMBONGUE	10	Namibe
3	CARACULO	10	Namibe
4	CATUMBERA	10	Benguela
5	LOBITO/CATUMBERA	10	Benguela
6	LUBANGO	10	Huila
7	MATALA	10	Huila
8	QUIPUNGO	10	Huila
9	TECHAMUTETE	10	Huila
10	NAMACUNDE	10	Cunene
	Total	100	

6.3 Preparation for a long-term power development plan by 2040

6.3.1 Setting conditions for an economic evaluations study using PDPAT

(1) **Supply reliability**

LOLP (Loss of Load Probability) and LOLE (Loss of Load Expectation) are both commonly used as indicators of the supply reliability of a power system. The latter LOLE has been popularly adopted around the world. Considering the sample LOLE values for foreign countries shown below, the target LOLE for the Angola power system is set at 24 hrs/year, that is a value used for many emerging countries.

- France, UK: 3 hours/year
- Developing country: 5 days/year
- Emerging country: 24 hours/year

(2) **Construction cost of power stations**

The construction cost of a new power station varies widely in accordance with the conditions of the development location. In some cases in present-day Angola, development studies have not been completed for the power stations to be considered in long-term development plans. Accordingly, a standard construction cost for each type of power station is assumed and used for the further study.

Standard construction costs have not been set, however, for wind power and solar power stations. In those cases, therefore, constant power price for all of the generated energy, a price equivalent to the power purchase cost for IPP developers, is adopted.

Table 6-10 Construction unit cost for each type of power

Type		unit capital cost ($/kW)	Note
Hydropower	Large scale	2,700	Average in Angola
	Medium/Small	5,400	ditto
Thermal power	Combined Cycle	1,200	Construction cost of SoyoTPP
	Gas Turbine	650	International price
	Diesel	900	International price
Renewable	Wind	-	Considered in generation cost
	Solar	-	Considered in generation cost

(3) **Fuel types and efficiencies of thermal power plants**

The fuel types and heat efficiencies of the different candidate types of thermal power plant are set as shown in Table 6-11.

Table 6-11 Fuel types and efficiencies of thermal power plants

Type of generation		Fuel type	Heat efficiency (%)
Thermal power	Combined Cycle	NG, LPG, LNG	56%
	Gas Turbine	NG, LPG	38%
		LFO	36%
	Diesel	LFO	42%
	Biomass	Bio fuel	30%

(4) Conditions for economic evaluation

There are no fixed ways to evaluate the finances of the power stations in Angola. Therefore, general calculation method and conditions for the calculations are adopted as shown in Table 6-12.

Table 6-12 Conditions for financial evaluation

Type of generation		Lifetime (years)	Depreci-ation	Interest (%)	Salvage (%)	O&M others (%)	Annual Expenditure Rate (%)
Hydropower		40	Straight line method	10	0	1	11.2
Thermal power	Combined Cycle	25				3	14.0
	Gas Turbine	20				5	16.8
	Diesel	20				5	16.8
	Biomass	20				2	13.8
Renewable	Wind	20				1	12.8
	Solar	20				1	12.8

(5) Forced outage rate

Recent records of the forced outage rates of the existing power stations, that is the rates of stoppage hours per year (excluding scheduled maintenance), are shown in Figure 6-7. The forced outage rates for both hydropower and thermal power have been on downward trends. As of 2017, the rates for thermal power and hydropower stood at about 8% and 2%, respectively. It seems feasible to maintain the current level in the future. These current records are adopted for the development planning.

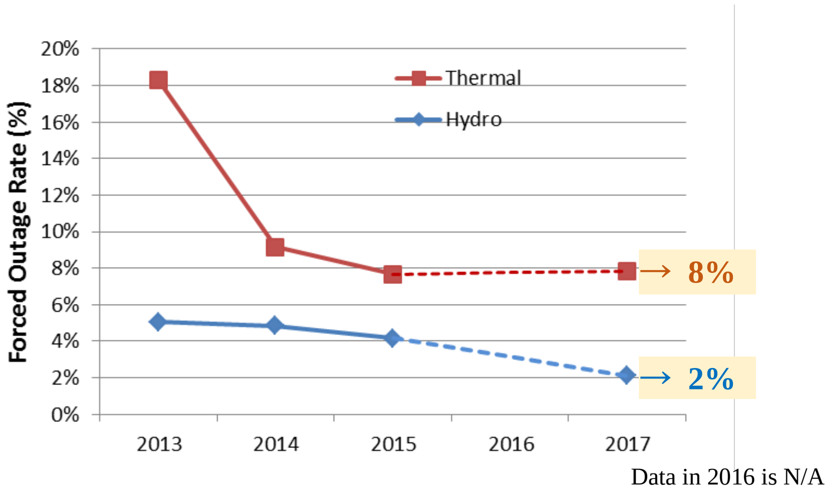


Figure 6-7 Actual records of the forced outage rates of power stations

(6) Calorific values and greenhouse gas emissions of thermal power

The calorific values and greenhouse gas emissions of the different fuels used for thermal power generation are assumed to be the general values shown in Table 6-13 below.

Table 6-13 Calorific values and greenhouse gas emissions per unit for different fuels

Fuel	Calorific value (kcal/kg)	CO_2 emission (kg-C/1000kcal)
LNG	13,000 kcal/kg	0.05735
NG	9,800 kcal/m^3	0.05735
LPG	12,000 kcal/kg	0.06857
HFO	9,200 kcal/L	0.08087
LFO	9,100 kcal/L	0.07865
Biomass	1,200 kcal/m^3	-

(7) **Fuel cost**

Future fuel prices for thermal power for the long-term power development planning in this study are set based on the current international price and the IEA's long-term forecast for the New Policy Scenario, as shown in Table 6-14 below.

Table 6-14 Fuel price for development planning

unit: UScent/Mcal

Year	Crude Oil	LFO	HFO	LPG	NG	LNG
2015	3.281	3.948	3.919	4.041	1.036	4.087
2016	3.641	4.382	4.349	4.485	1.155	4.032
2017	4.001	4.815	4.780	4.928	1.275	3.976
2018	4.361	5.249	5.210	5.372	1.394	3.921
2019	4.722	5.682	5.640	5.816	1.514	3.865
2020	5.082	6.116	6.071	6.259	1.633	3.810
2021	5.288	6.363	6.316	6.513	1.685	3.901
2022	5.494	6.611	6.562	6.766	1.737	3.992
2023	5.699	6.859	6.808	7.020	1.789	4.083
2024	5.905	7.107	7.054	7.274	1.840	4.175
2025	6.111	7.354	7.300	7.527	1.892	4.266
2026	6.317	7.602	7.546	7.781	1.944	4.357
2027	6.523	7.850	7.792	8.034	1.996	4.448
2028	6.729	8.097	8.038	8.288	2.048	4.540
2029	6.934	8.345	8.284	8.541	2.099	4.631
2030	7.140	8.593	8.529	8.795	2.151	4.722
2031	7.224	8.694	8.629	8.898	2.211	4.742
2032	7.308	8.794	8.729	9.001	2.271	4.762
2033	7.391	8.895	8.829	9.104	2.330	4.782
2034	7.475	8.995	8.929	9.207	2.390	4.802
2035	7.558	9.096	9.029	9.310	2.450	4.822
2036	7.642	9.197	9.129	9.413	2.510	4.841
2037	7.726	9.297	9.229	9.516	2.569	4.861
2038	7.809	9.398	9.329	9.619	2.629	4.881
2039	7.893	9.499	9.428	9.722	2.689	4.901
2040	7.977	9.599	9.528	9.825	2.749	4.921

6.3.2 Selection of the generation type for use in development planning

Hydropower development has so far played the main role in development plans. As the potential of large hydropower remains and the generation costs are lower, constant development in the future is preferable. Meanwhile, even if priority is given to the development of large-scale hydropower, the supply capacity seems to be insufficient over the medium to long term. Hence, the development of power sources in addition to hydropower projects will be needed. The optimization of an economically superior power source composition will therefore have to be considered. When selecting the candidate power types using the screening method described in Chapter 4, the conditions set in section 6.3.1 are used. The annual expenditure of each type of generation in the years 2018 and 2040 are shown in Figure 6-8 to Figure 6-11.

As a result of the examination discussed below, gas turbine (LPG), combined cycle (natural gas), and large hydropower are selected as the major types of candidate generation facility to be used in this master plan.

(1) **Peak supply**

Since the fuel cost of natural gas is somewhat lower, thermal power facilities using natural gas have an advantage for peak suppliers. Meanwhile, natural gas supply is currently available only at Soyo which is far from the demand center, and huge cost and time would be required for the development of gas supply facilities such as a new pipeline or new gas field. For the development of a peak supplier at a location other than Soyo, it will therefore be necessary to consider another type of fuel (LPG, Diesel oil etc.) that can be more easily transported as a realistic option.

Diesel and gas turbine (GT) are available as candidates for peak supply power using these gases as fuel, and GT is economical. Also, the difference between the use of diesel and LPG as fuel for GT is small (see Figure 6-10). Therefore, GT is selected as the peak supplier, and LPG is selected as fuel by virtue of the easier transport and facility maintenance associated with LPG.

Pumped-storage power plants (PSPP) are generally regarded as candidates for peaking power supply. At present, however, the effect of introducing PSPPs cannot be evaluated, as no low-cost or surplus electricity is available for pumping up water. It will be preferable, therefore, to evaluate the needs for PSPP in accordance with changes such as the generation cost reductions for solar/wind power and the introduction of large-scale development policies to combat global warming.

(2) **Middle supply**

Combined cycle gas turbine (CCGT) using natural gas for fuel is the most advantageous from an economic view point. Given the aforementioned supply restriction of natural gas, however, it will be necessary to consider the use of LPG/LNG as fuel for CCGT. In consideration of the choice of fuel, therefore, CCGT is taken as a promising candidate for the middle supply.

(3) **Base supply**

Large-hydropower is adopted as the base supplier.

The project cost and generated energy of a hydropower station vary widely in accordance with the site conditions. The light blue lines in the figures show the average of large hydropower based on Angola’s development plans.

The average of medium/small-scale hydropower is also shown in the figures. As the annual expenditure of medium/small-scale hydropower is higher than that for other power sources, the preferred approach is to first evaluate economic characteristics of the particular plans individually and then decide on development when the project is found to be economically advantageous or when other factors such as remote locations would make it difficult to supply electricity by other mean. Therefore, medium/small scale hydropower is excluded from consideration in this master plan.

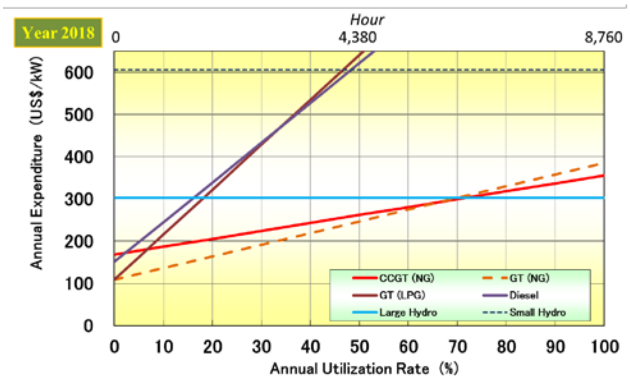


Figure 6-8 Annual expenditure by generation type (2018)

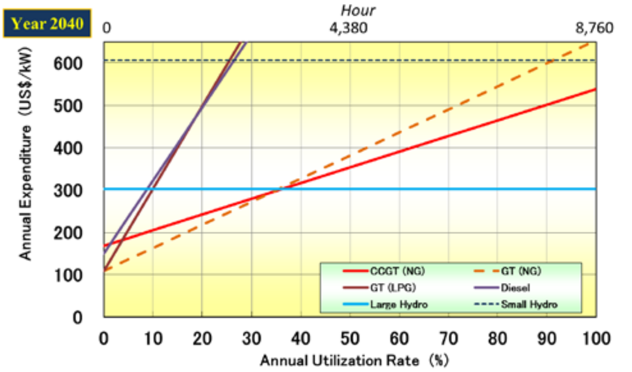


Figure 6-9 Annual expenditure by generation type (2040)

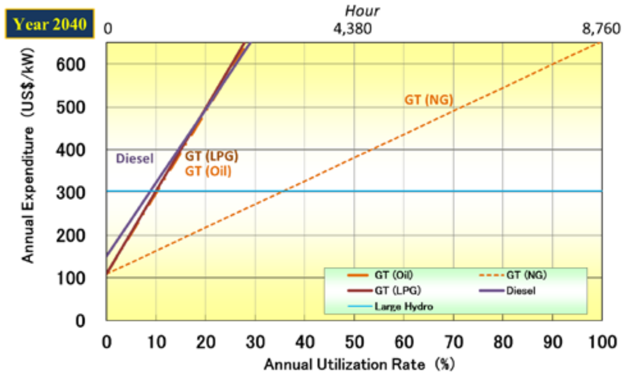


Figure 6-10 Character of peak facilities (2040)

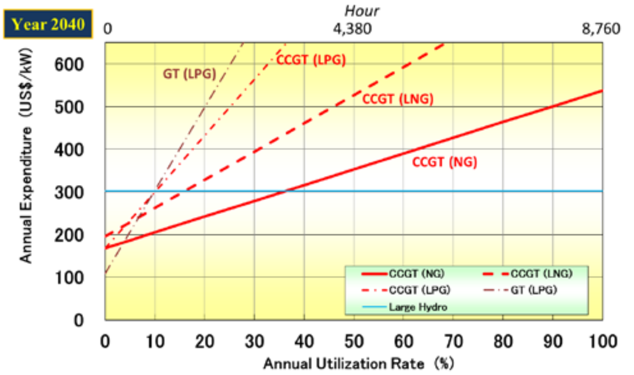


Figure 6-11 Character of middle facilities (2040)

6.3.3 Basic conditions for optimization of development plan

The optimization study on the development plan will be conducted by applying PDPAT. The specifics of development planning and optimization will be studied under the following conditions.

(1) **Candidate projects**

The existing candidate projects listed in the development plan basically take priority, though there are few thermal power candidates with large-scale and high-efficiency. In the event of any shortage of candidate projects, a dummy project will be introduced.

(2) **Monthly hydropower generation**

Monthly generation data should be prepared for each hydropower station as a necessary step for the optimization studies using PDPAT.

Since river discharge in Angola changes widely in a year as described in section 6.1.2, it is necessary for a study of supply demand balance to prepare expected monthly generation of each hydropower station considering regulation effect of the reservoir. The following factors, however, make it difficult to prepare all of the necessary monthly inflow and generation data for each hydropower station under a uniform condition.

- Actual records on parameters such as the inflow discharge and generation of existing power stations have not yet to be organized and in some cases are missing.
- The monthly generation has not yet been planned for many of the candidate projects, especially the projects not yet extensively studied.

In consideration of the current situations, the expected monthly generation of each existing and candidate hydropower project is estimated by simple simulation study based on the available project features and typical river discharge data of the hydropower station as assumption.

6.4 The most economical power supply configuration in 2040

A study on the most economical power supply in the year 2040, the final year and achievement point set under the long-term power development plan, has been conducted using PDPAT based on the currently existing power supply facilities. Necessary power supply will be developed to meet the demand increase in consideration of the retirement of aged power facilities. The power sources to be newly developed in the study are (1) gas turbine (LPG fired), (2) combined cycle (natural gas fired), and (3) large-scaled hydropower, (the sources selected in the previous section).

6.4.1 Hydropower development plan

As described in section 6.3.2, since the potential of large hydropower remains and the generation cost is lower, constant development in the future will be preferable.

There are however, important issues to address in the development of large-scaled hydropower.

- Fund procurement is a challenge since project cost is enormous.
- Natural and social EIAs are essential. Mitigation measures according to local conditions are required even if development is evaluated as appropriate.

As both of the aforementioned issues require time-consuming steps in the procedures required to have project implementation improved, there are limits in reality to the number of simultaneous developments possible.

Therefore the largest/earliest hydropower development plan, thought to be feasible for development in this master plan, is set based on the following assumptions.

- The interval between new developments is set as 3 years in consideration of approval procedures etc.
- In order to avoid risks such as delays due to congestion of construction work, the construction of simultaneous projects at one river is avoided as much as possible. (If one power plant is constructed at each of the four major rivers where hydropower plants are planned, a maximum of four construction works will be conducted in parallel).
- The duration of construction is 8 years, including 1 year for EIA approval procedures.

Figure 6-12 shows the development pattern for hydropower up to 2040 (prepared in consideration of past development plans).

Year			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Annual Peak Demand (MW)			2,371	2,753	3,135	3,516	3,852	4,188	4,523	4,859	5,195	5,582	5,970	6,357	6,744	7,132	7,542	7,951	8,361	8,770	9,180	9,589	9,998	10,407	10,817	11,226
River	Name of HPP	Capacity																								
Kwanza	Lauca	2,070		2,070																						
	Caculo Cabaça	2,172								2,172																
	Zenzo	950																950								
	Túmulo Caçador	453																						453		
	Quissonde	121																								
Quive	Cafula	100																								
	Genga	900																			900					
	Benga	1,000																								
	Sanga	85																								
	Quilengue	210											210													
	Cachoeiras	135																								
	Caiovole	60																								
Catumbela	Lomaum Extension	65		65																						
	Lomaum 2	150																								
	Calengue	190																								
	Cacombo	29																								
Cunene	Jamba Ya Oma	79																								
	Jamba Ya Mina	205																								
	Baynes(50% Angola)	300										300														
(East)	Luachimo (extention)	34				34																				
Total			0	2,135	0	34	0	0	0	2,172	0	300	0	210	0	0	0	950	0	0	900	0	0	453	0	0

Legend ● : Start of EIA Approval ■ : Construction of approved project ■ : Development plan

Figure 6-12 Development pattern for large hydropower by 2040

6.4.2 Relationship between LOLE and Reserve Capacity

LOLE, an indicator of the reliability of a power system, is not directly related to the power supply capacity (MW). For that reason, LOLE cannot be used to easily grasp how much power supply capacity needs to be developed in a power development plan to secure reliability. In Japan, the reserve margin rate is generally used instead of LOLE. The common practice is to obtain the relationship between the reserve margin rate and LOLE in advance, convert LOLE to the reserve margin rate, find the required supply capacity, and use it for the power development planning.

The reserve margin rate corresponding to the 24-hour of LOLE is formulated by PDPAT and RETICS. For the power development plan, the plan shown in Figure 6-12 is adopted for the hydropower development. Thermal power, which consists of CCGT and GT, will be developed to fill up the insufficient supply capacity. The composition ratio between CCGT and GT was set to the optimum ratio described in the next section. The relationship between LOLE and the reserve margin rate is calculated based on the above-mentioned development plan.

The calculation results are shown in Figure 6-13 and Figure 6-14. While the required reserve margin rate generally increases as the target LOLE gets smaller, this relationship varies in accordance with the power supply configuration, demand profile, etc. Figure 6-14 shows the necessary reserve margin rate for each year up to 2040. The required reserve margin gradually decreases, reaching about 11% after 2030. This value, 11%, is therefore set as the target.

The decrease in the required reserve margin rate year by year is mainly attributable to the yearly increases in the share of thermal power supply capacity and gradually decreasing influence of hydroelectric power generation with large variations due to river discharge fluctuations.

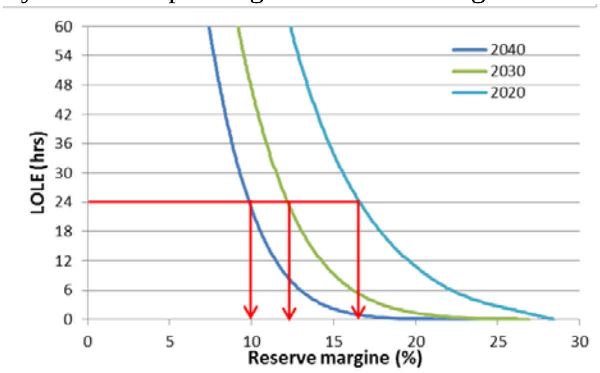


Figure 6-13 Relationship between LOLE and reserve margin rate

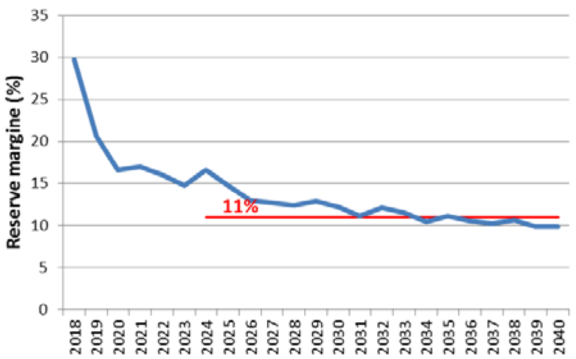


Figure 6-14 Necessary reserve margin rate equivalent to LOLE of 24 hrs

6.4.3 Most economical power supply composition ratio by using PDPAT

In this section, the power supply composition that minimizes the total cost in the year 2040, the final year of the power master plan, is considered.

As described in Chapter 5, peak demand in 2040 is forecasted to reach 11.2GW, or 2.7 times the actual peak demand recorded in 2017. Moreover, renovation of the existing power facilities is also required. Hence, the requirement of supply capacity appears to increase 13 GW. In this section, the most economical configuration in 2040 among large hydropower, combined cycle (CCGT), and gas turbine (GT) is examined.

The following assumptions are adopted for the calculation using PDPAT

- The target year is 2040
- The hydropower development pattern shown in 6.4.1, a realistic equivalent to the maximum, is adopted.
- The reserve margin rate is set at 11%, is the value selected in 6.4.2. GT shares the capacity for the reserve margin, as it has a lower fixed cost.
- The supply configuration ratio is calculated in the month with the lowest reserve margin in the year and defined as the ratio of the available supply (excluding the capacity corresponding to the reserve margin) of each power source to the peak demand of the month.

(1) Optimum share of GT

Figure 6-15 shows the relation between the total cost per year and the configuration ratio of GT, calculated using PDPAT. The annual cost is lowest when the configuration ratio of GT is 12%. When the ratio exceeds 12%, the cost sharply rises because the increased generation using the lower-efficiency GT pushes up the fuel cost. It seems therefore reasonable to set the configuration ratio of GT at 12%, and not to exceed that level in the development plans.

It is economical for GT, the power source with the lowest fixed cost, to share the supply capacity for the reserve margin, so the combined amount capacity of GT makes up 23% of the demand.

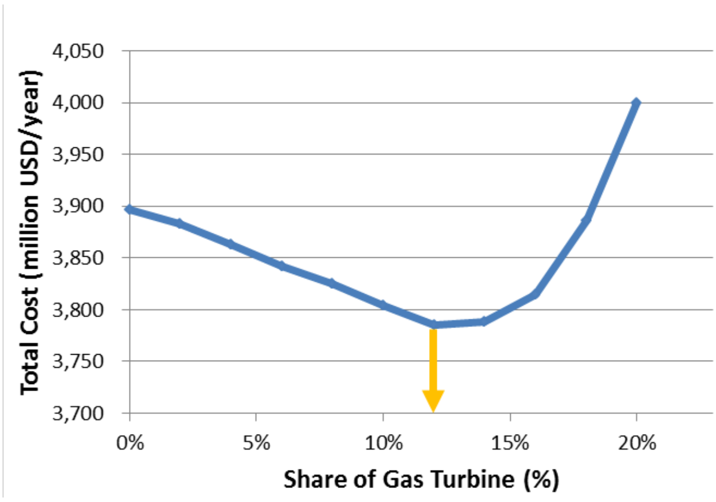


Figure 6-15 Configuration ratio of GT and total annual cost (year 2040)

(2) Minimum-cost configuration of power supply in the year 2040

Peak demand in the year 2040 appears in December. Meanwhile the supply-demand balance is the most severe in November in a year, since the supply capacity of hydropower declines during the drought period. Figure 6-16 shows the power configuration ratio when the ratio of GT is set to 12% in the November 2040 section. This configuration ratio corresponds to the future target value, and the final power development plan formulated for each year up to 2040 needs to approach this power configuration ratio.

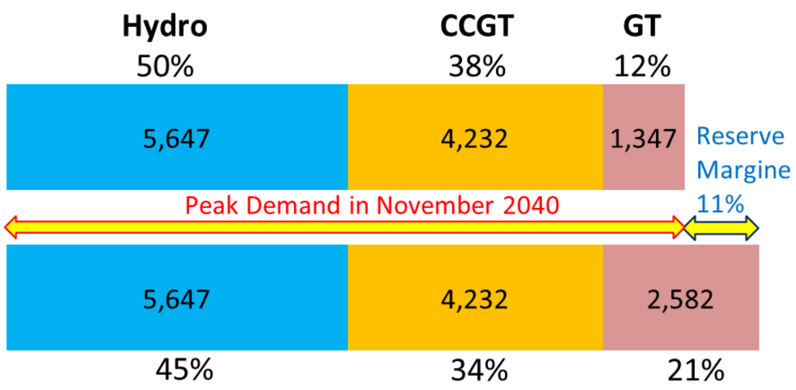


Figure 6-16 Cost minimum configuration of power supply in the year 2040 (November balance)

6.5 Formulation of the power development plan

6.5.1 Power development plan (Draft) by 2040

The power development plan (draft) for each year up to 2040 is formulated based on the following conditions. Figure 6-17 shows the proposed draft plan.

- The types of power plant newly developed are large hydropower, combined cycle (CCGT), and gas turbine (GT).
- The Reserve margin rate is set as 11% in November, when the supply-demand balance is strict. The supply shortage is acceptable, however, since new development will not be available in time by 2018.
- The retirement of power facilities at the end of their service lives is taken into account to the power supply capacity.
- Available supply capacity of hydropower calculated by PDPAT is used for evaluation of supply-demand balance every month.
- The development pattern shown in Figure 6-12 is adopted for hydropower development. If the supply capacity is still insufficient, a thermal power plant (GT, CCGT) will be developed.
- The configuration ratio of GT is set close to 12%, within a range not exceeding 12% of demand. The shortfall capacity is filled by CCGT.

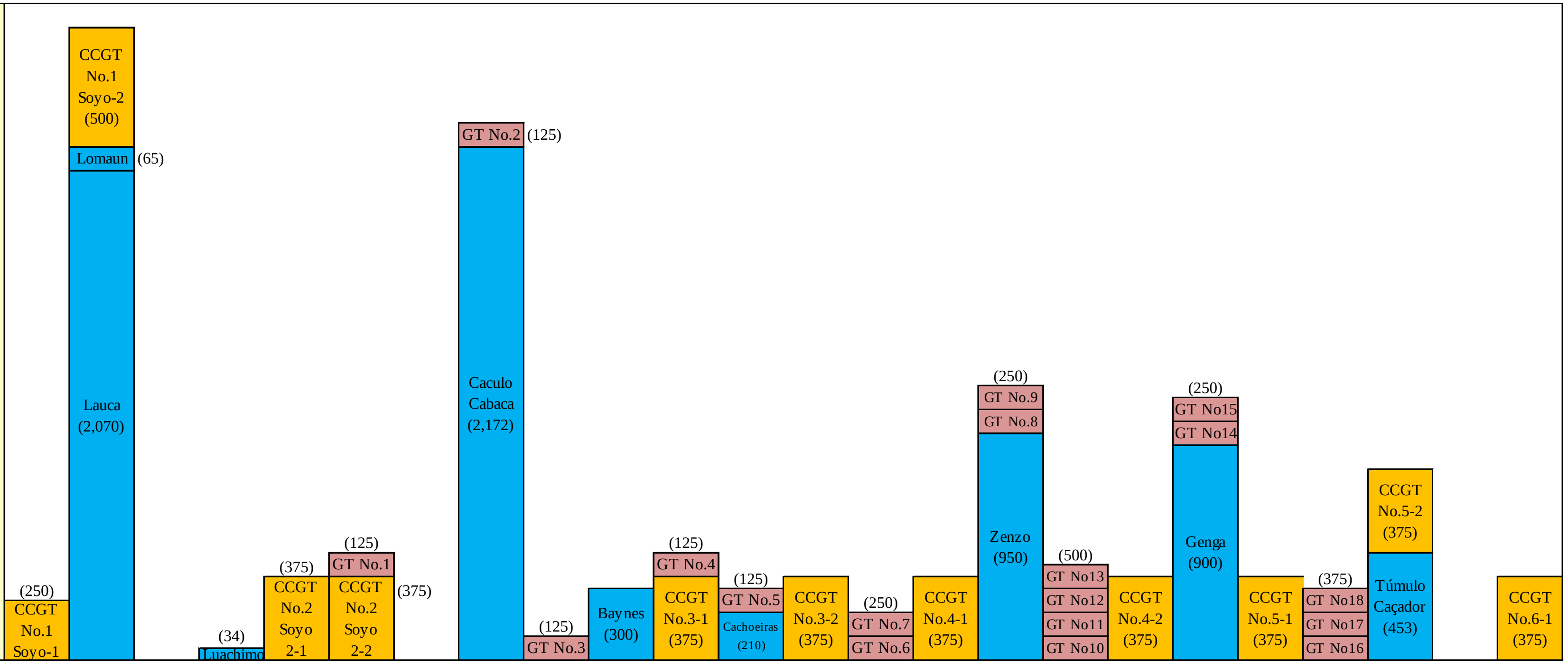
As a result of the trial, the following developments of power facilities are required by 2040.

Hydropower: 7,150 MW, including the Lauca HPP now under construction

CCGT: 4,125 MW (750 MW class, 5.5 sets), including Soyo and Soyo2 TPP

GT: 2,250 MW (125 MW class, 18 sets)

Development Plan
(Installed capacity, MW)



Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Annual Peak demand (MW)		2,371	2,753	3,135	3,516	3,852	4,188	4,523	4,859	5,195	5,582	5,970	6,357	6,744	7,132	7,542	7,951	8,361	8,770	9,180	9,589	9,998	10,407	10,817	11,226
Peak demand (Nov., MW)		2,273	2,638	3,005	3,370	3,692	4,014	4,336	4,658	4,981	5,352	5,723	6,094	6,466	6,838	7,231	7,623	8,017	8,409	8,803	9,196	9,588	9,980	10,373	10,766
Supply (Nov., MW)		2,376	2,974	3,685	3,789	4,252	4,731	4,819	5,676	5,890	5,989	6,589	6,866	7,341	7,621	8,075	8,678	8,896	9,347	9,874	10,358	10,716	11,426	11,534	12,017
Reserve margin (%)		4.6%	12.7%	22.6%	12.4%	15.2%	17.9%	11.1%	21.8%	18.2%	11.9%	15.1%	12.7%	13.5%	11.5%	11.7%	13.8%	11.0%	11.2%	12.2%	12.6%	11.8%	14.5%	11.2%	11.6%
Share of supply capacity (Nov.%)	Hydro	54%	50.0%	67.6%	63.3%	60.2%	57.5%	55.3%	67.2%	64.6%	62.0%	59.7%	58.6%	56.8%	55.1%	53.6%	57.0%	55.5%	54.2%	55.4%	54.2%	53.1%	54.4%	53.4%	52.4%
	CCGT	11%	28.4%	25.0%	22.3%	30.5%	37.4%	34.6%	32.2%	30.1%	28.0%	32.8%	30.8%	34.8%	32.9%	36.3%	34.4%	32.7%	35.7%	34.1%	36.7%	35.2%	37.6%	36.2%	38.3%
	GT	25%	21.4%	18.8%	16.7%	15.3%	15.4%	14.2%	15.9%	17.4%	16.2%	17.3%	18.3%	17.3%	19.1%	17.8%	19.2%	21.8%	20.8%	22.7%	21.7%	23.5%	22.5%	21.7%	20.9%
	Diesel	15%	12.5%	11.0%	9.8%	9.0%	7.3%	6.8%	6.3%	5.9%	5.5%	5.1%	4.8%	4.5%	4.1%	3.8%	3.1%	0.7%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Renewable	0%	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Share of installed capacity (%)	Hydro	42%	53.4%	53.4%	53.6%	48.5%	43.8%	43.8%	53.9%	52.7%	53.9%	49.6%	49.5%	46.8%	45.6%	43.5%	46.1%	45.4%	43.6%	45.3%	43.6%	42.4%	42.2%	42.2%	40.7%
	CCGT	6%	10.6%	10.6%	10.5%	14.3%	17.4%	17.4%	13.6%	13.3%	13.0%	14.9%	14.4%	16.3%	15.9%	17.7%	16.4%	16.1%	17.7%	16.4%	17.7%	17.3%	18.1%	18.1%	19.2%
	GT	14%	8.0%	8.0%	7.9%	7.2%	7.2%	7.2%	6.7%	7.7%	7.5%	7.9%	8.6%	8.1%	9.3%	8.7%	9.1%	10.8%	10.3%	10.9%	10.5%	11.5%	10.8%	10.8%	10.5%
	Diesel	8%	4.7%	4.7%	4.6%	4.2%	3.4%	3.4%	2.7%	2.6%	2.5%	2.3%	2.2%	2.1%	2.0%	1.9%	1.5%	0.4%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Renewable	0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 6-17 Power development plan (Draft)

6.5.2 Impact of introducing renewable energy

As stated in Section 6.2(3), Angola is aiming at introducing wind power and solar power generation. At present, eleven (11) wind power projects (652 MW) and ten (10) solar power projects (100 MW) are nominated as priority candidates.

These project plans, however, have only reached preliminary phases. Because of this, the specifications of each project necessary for evaluating the supply-demand balance, such as expected monthly generation etc., have yet to be made public. Since the output of wind/solar power generation fluctuates with changes in natural conditions, a detailed evaluation based on measured data will be required for an accurate determination of the capacity is available to be counted towards the available peak supply capacity. It will be indispensable to evaluate feasibility and establish specific generation plan for each project in the future.

In this section, assuming supply capacity based on the proposed installed capacity and average plant factor, and then impact of introducing wind/solar power to the greenhouse gas reduction and the influence on the annual total cost increase of the development plan (Draft) described in the previous section are examined. (Comparison was made in the year 2040).

As a result, the introduction of wind/solar power is effective for greenhouse reduction as shown by the orange broken line/right axis in Figure 6-18 and Figure 6-19, since CO_2 emission decreases in step with increases in the wind/solar power capacity.

In this examination, generation cost is indicated by parameters centered on current cost (wind power, 14 UScents/kWh; solar power, 6 UScents/kWh) as assumption. The impact on the annual total cost depends on the generation cost for both wind and solar power. When 1000 MW is installed with the central cost, the increase of the annual total cost is slight for solar power, and stand at 5% for wind power.

Meanwhile, the reduction of greenhouse gas emissions by introducing renewable energy is an important policy in Angola. Further, the small capacity of the prioritized projects translates into a small influence on the development plan overall. Therefore, a power development plan including the prioritized wind/solar project is prepared and set as the basic plan.

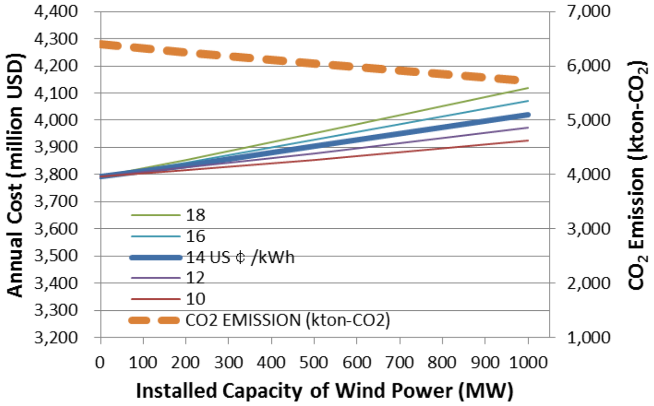


Figure 6-18 Impact of introducing wind power (year 2040)

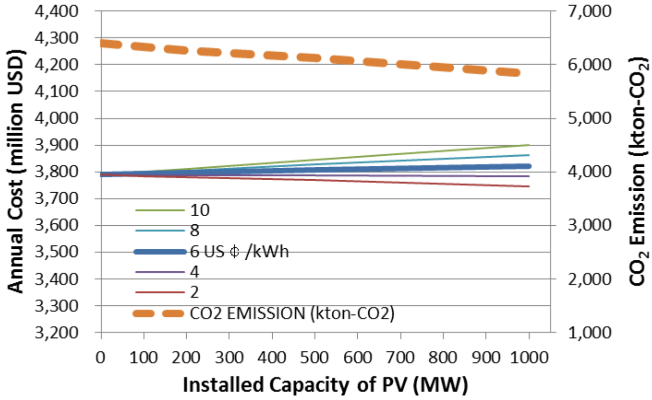


Figure 6-19 Impact of introducing solar power (year 2040)

Regarding biomass, project concepts have been conceived but no specific power generation plans have been determined. Hence, biomass will not be evaluated until a plan is concretized in the future. Biomass will thus be left out of the current development plan, as in the case with small and medium hydropower.

6.5.3 Power development plan with renewable energy (base plan)

(1) **Power development plan**

Power generation plan including wind/solar power has been established based on the draft plan described in the previous section.

Since the plan for wind/solar power is still in the preliminary stage, the nominated projects are assumed to develop during 10 years from 2028 after a planning period of ten years. The examination indicated no change in the development plan for thermal power and simply adding the wind/solar power projects to the draft plan becomes the optimum. This development plan is set as the basic plan.

The generation outputs of wind/solar power projects fluctuate widely since wind speed and solar radiation change under changing natural conditions. Output adjustments according to the requirements are therefore unavailable, and the available capacity necessary to secure the supply-demand balance is expected to be far smaller than the installed capacity. Also, the peak of electricity demand occurs at night, when solar power cannot generate. If on the other hand, the dispatching conditions are met, hydropower generation can be increased during the peak period as follows: (1) Store the water in the reservoir by reducing the generation of hydropower in accordance with the wind/solar generation, then (2) increase hydropower generation during peak periods using the stored water. Introducing wind/solar power projects into the power development plan is a complicated task. It will therefore be necessary to estimate the expected available monthly generation and hourly output for each candidate wind/solar power project. For the purpose, investigation and evaluation of the characteristics of hourly fluctuation of each month based on statistical review of the exact data of each planned location are desirable.

As of this time, however, none of the data necessary for evaluation is available. For this reason, the expected output in each hour of each month is assumed based on the installed capacity and average plant factor, making reference to the general characteristic values. Based on these assumed values, examination using PDPAT is conducted to grasp the influence. It will therefore be necessary to revise the power development plan when the design of each candidate project advances and specific generation plans are studied.

(2) **Output of supply-demand simulation using PDPAD (base case)**

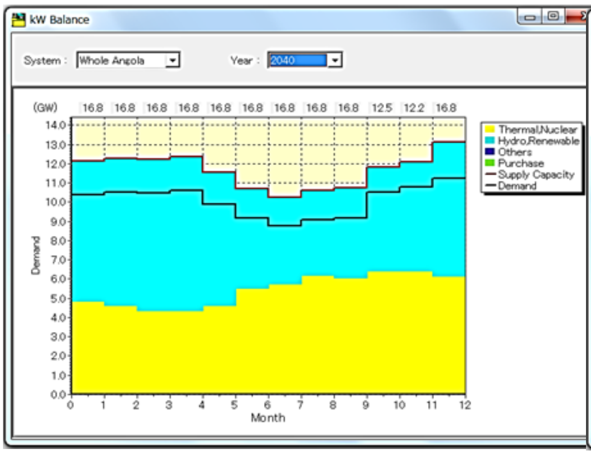
Figure 6-20 to Figure 6-25 show the supply-demand balance in each month in 2040, the final year of the master plan, and an example of the load dispatching for one day.

(3) **Power development of each year by 2040**

The recommended power development plan, the base plan, is shown in Figure 6-26. The supply-demand balance of the most severe month in each year by 2040 is shown in Figure 6-27. The share of hydropower in the peak supply configuration decreases year by year, and hydropower and thermal power are about the same size in 2040.

Figure 6-28 shows the relationship between the maximum demand in a year and the installed capacity of the power stations, for reference. As the available supply capacity of hydropower is restricted by season, the amount of installed capacity exceeds the demand in the figure. In fact, however, the available supply capacity is sometimes lower than installed capacity by season. The evaluation of the supply-demand balance will therefore have to be based on the most severe month of the year, as shown in Figure 6-27.

The power generation cost for each year and the unit cost per kWh are shown in Figure 6-29 and Figure 6-30, respectively. The annual power generation cost increases year by year as the supply capacity increases in step with demand increases. The fuel cost will also gradually rise. On the other hand, the unit price remains stable over the long term.



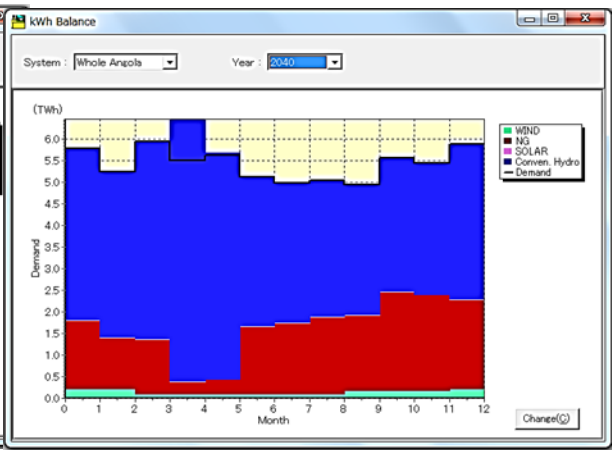
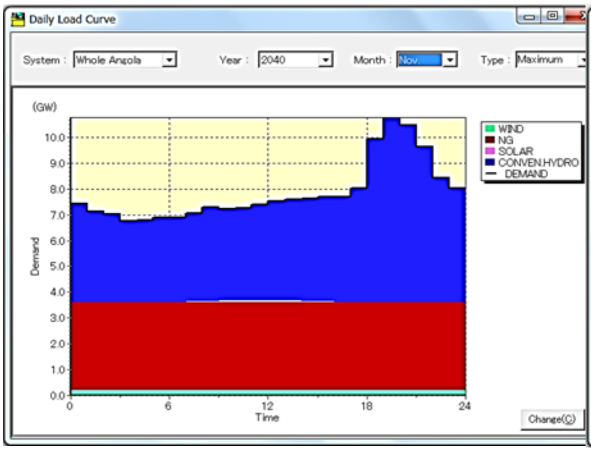


Figure 6-20 kW balance of each month in 2040

Figure 6-21 kWh balance of each month in 2040



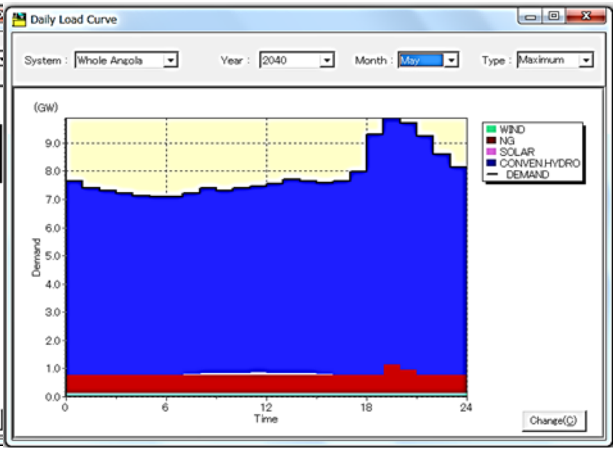
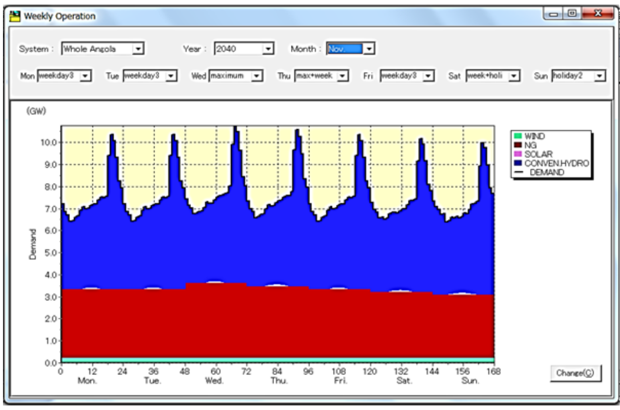


Figure 6-22 Example of load dispatch for one day <dry season, November 2040>

Figure 6-23 Example of load dispatch for one day <flood season, May 2040>



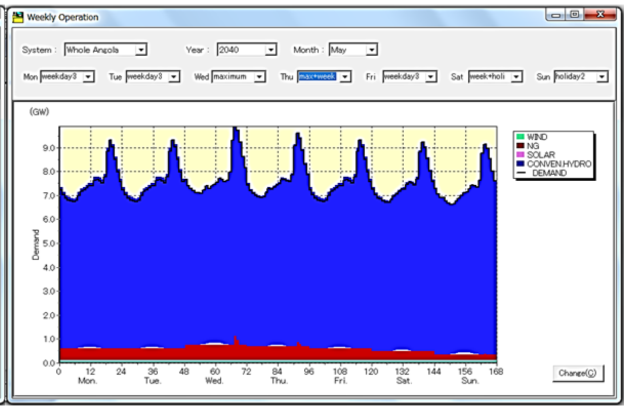
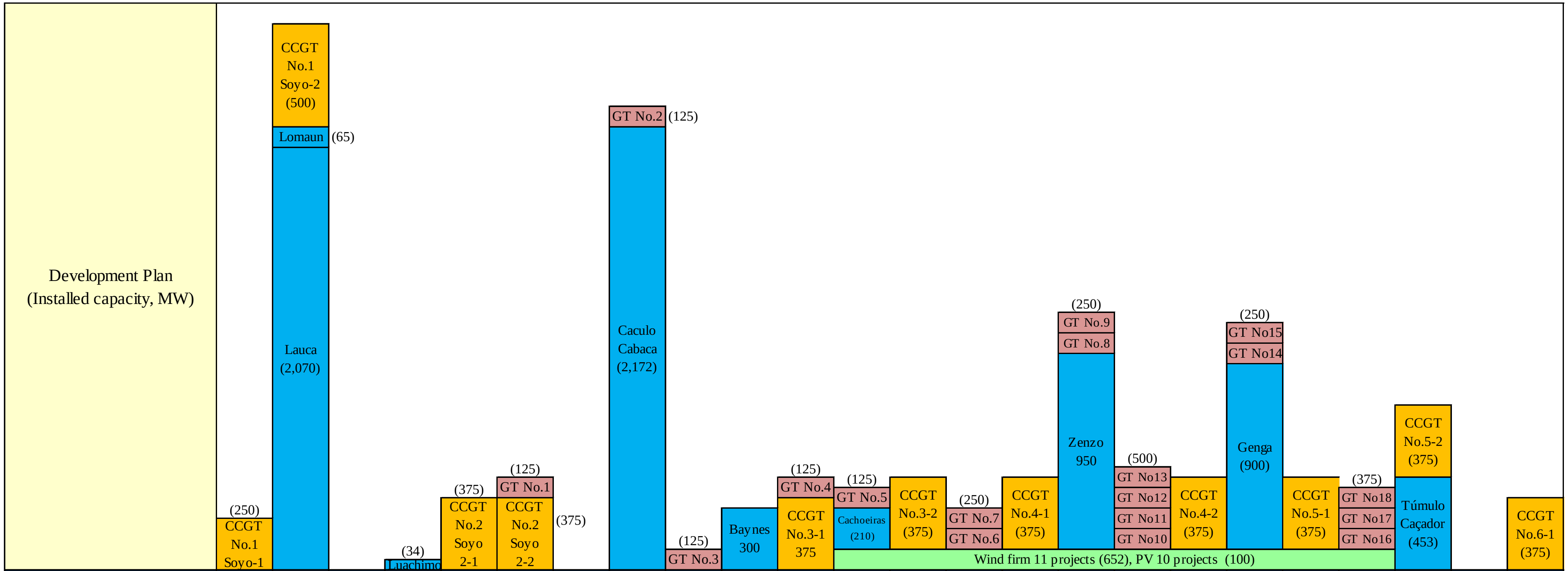


Figure 6-24 Example of weekly load dispatch <dry season, November 2040>

Figure 6-25 Example of weekly load dispatch <flood season, May 2040>



Year		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Annual Peak demand (MW)		2,371	2,753	3,135	3,516	3,852	4,188	4,523	4,859	5,195	5,582	5,970	6,357	6,744	7,132	7,542	7,951	8,361	8,770	9,180	9,589	9,998	10,407	10,817	11,226
Peak demand (Nov., MW)		2,273	2,638	3,005	3,370	3,692	4,014	4,336	4,658	4,981	5,352	5,723	6,094	6,466	6,838	7,231	7,623	8,017	8,409	8,803	9,196	9,588	9,980	10,373	10,766
Supply (Nov., MW)		2,376	2,974	3,685	3,789	4,252	4,731	4,819	5,676	5,890	5,989	6,589	6,872	7,353	7,639	8,098	8,708	8,932	9,389	9,922	10,412	10,775	11,485	11,593	12,076
Reserve margin (%)		4.6%	12.7%	22.6%	12.4%	15.2%	17.9%	11.1%	21.8%	18.2%	11.9%	15.1%	12.8%	13.7%	11.7%	12.0%	14.2%	11.4%	11.7%	12.7%	13.2%	12.4%	15.1%	11.8%	12.2%
Share of supply capacity (Nov.%)	Hydro	54%	50.0%	67.6%	63.3%	60.2%	57.5%	55.3%	67.2%	64.6%	62.0%	59.7%	58.6%	56.8%	55.2%	53.6%	57.0%	55.6%	54.2%	55.4%	54.2%	53.1%	54.4%	53.4%	52.5%
	CCGT	11%	28.4%	25.0%	22.3%	30.5%	37.4%	34.6%	32.2%	30.1%	28.0%	32.8%	30.8%	34.8%	32.9%	36.3%	34.4%	32.7%	35.7%	34.1%	36.7%	35.2%	37.6%	36.2%	38.3%
	GT	25%	21.4%	18.8%	16.7%	15.3%	15.4%	14.2%	15.9%	17.4%	16.2%	17.3%	18.3%	17.3%	19.1%	17.8%	19.2%	21.8%	20.8%	22.7%	21.7%	23.5%	22.5%	21.7%	20.9%
	Diesel	15%	12.5%	11.0%	9.8%	9.0%	7.3%	6.8%	6.3%	5.9%	5.5%	5.1%	4.8%	4.5%	4.1%	3.8%	3.1%	0.7%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Renewable	0%	0.4%	0.3%	0.3%	0.3%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.3%	0.3%	0.4%	0.4%	0.5%	0.5%	0.6%	0.5%	0.5%	0.6%	0.5%	0.5%	0.5%
Share of installed capacity (%)	Hydro	42%	53.4%	53.4%	53.6%	48.5%	43.8%	43.8%	53.9%	52.7%	53.9%	49.6%	49.2%	46.3%	44.9%	42.6%	45.0%	44.2%	42.3%	43.9%	42.1%	40.9%	40.7%	40.7%	39.3%
	CCGT	6%	10.6%	10.6%	10.5%	14.3%	17.4%	17.4%	13.6%	13.3%	13.0%	14.9%	14.3%	16.2%	15.7%	17.3%	16.0%	15.7%	17.2%	15.9%	17.1%	16.6%	17.4%	17.4%	18.5%
	GT	14%	8.0%	8.0%	7.9%	7.2%	7.2%	7.2%	6.7%	7.7%	7.5%	7.9%	8.5%	8.0%	9.1%	8.5%	8.9%	10.5%	10.0%	10.6%	10.1%	11.1%	10.5%	10.5%	10.1%
	Diesel	8%	4.7%	4.7%	4.6%	4.2%	3.4%	3.4%	2.7%	2.6%	2.5%	2.3%	2.2%	2.1%	2.0%	1.8%	1.5%	0.4%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Renewable	0%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.7%	1.2%	1.6%	2.1%	2.3%	2.8%	3.1%	3.2%	3.4%	3.7%	3.5%	3.5%	3.4%

Figure 6-26 Power development plan (base case)

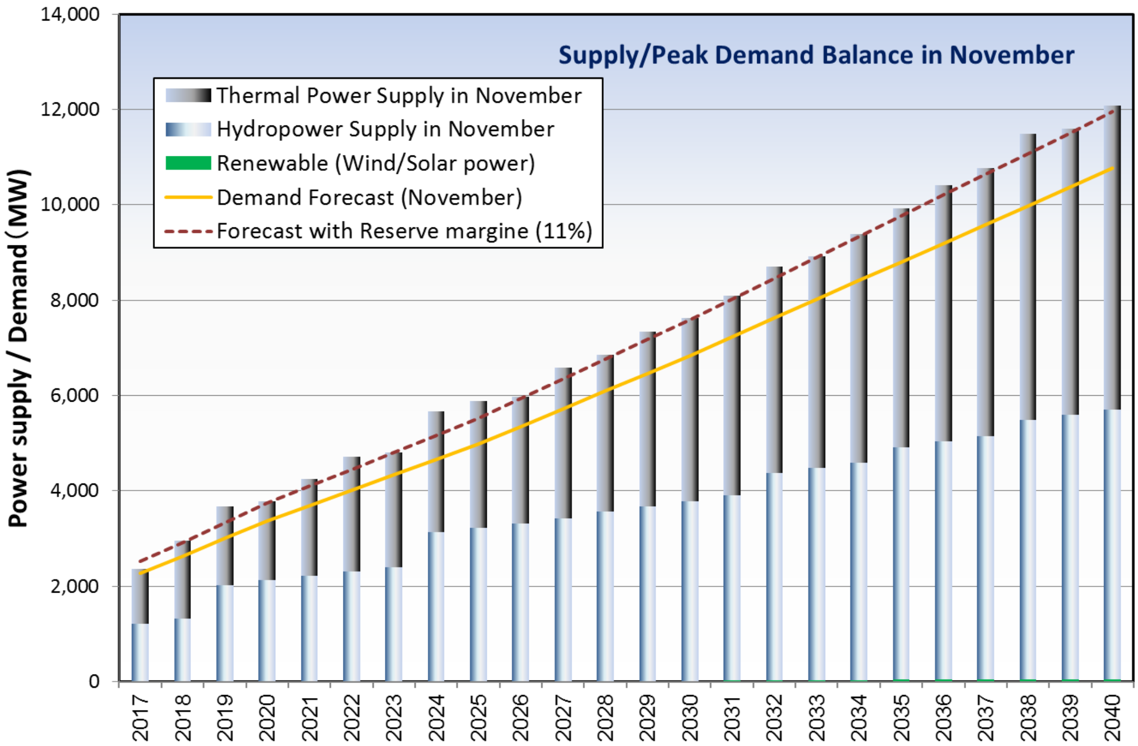


Figure 6-27 Supply–demand balance (base case, peak balance in November)

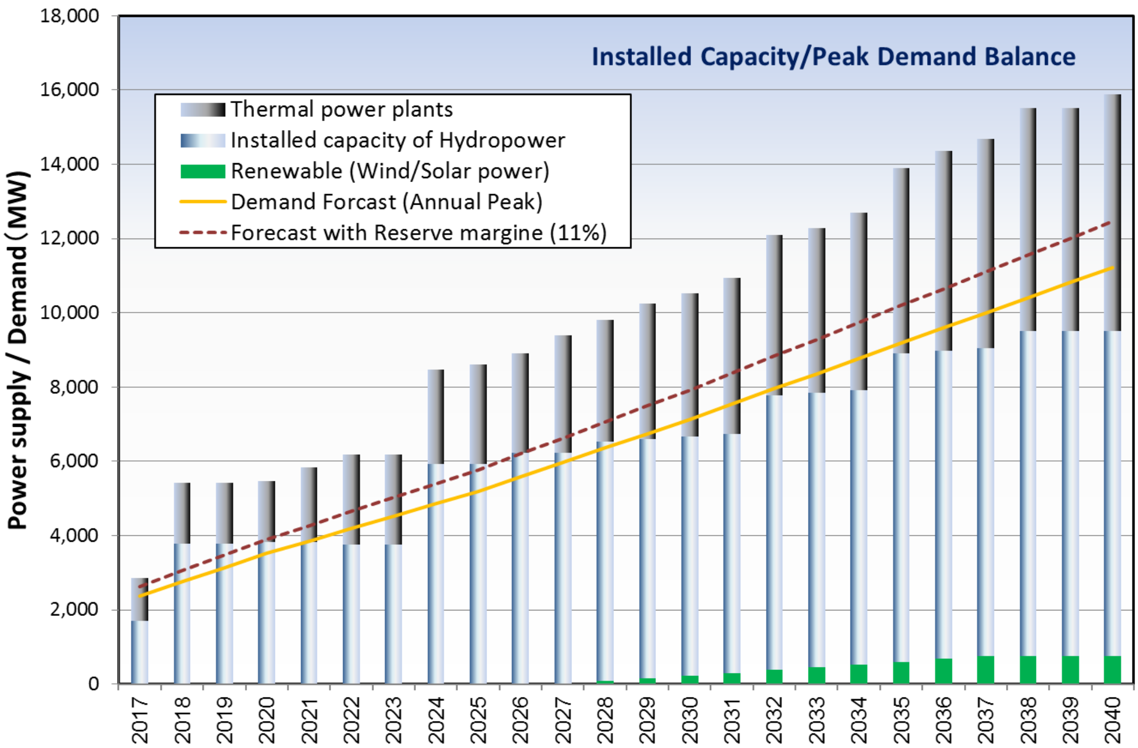
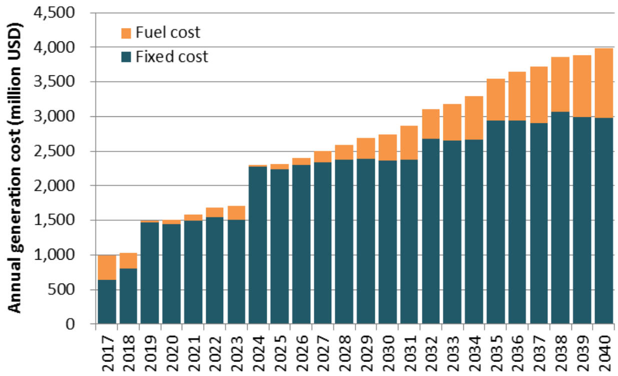


Figure 6-28 Supply–demand balance (base case, installed capacity-annual peak balance)



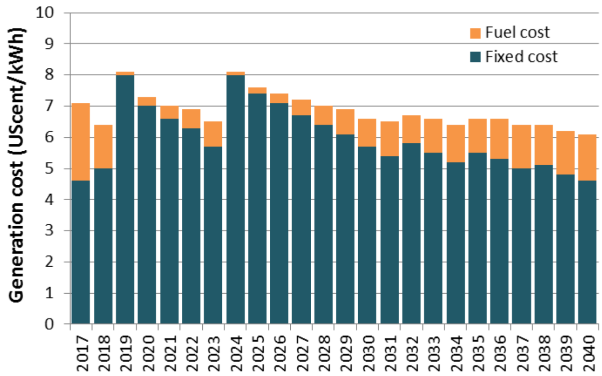


Figure 6-29 Annual generation cost (base case) **Figure 6-30 Unit cost of generation (base case)**

6.5.4 Greenhouse gas emission in the base case

The annual amount of greenhouse gas emissions produced each year by power generation type is shown in Figure 6-31. As the figure illustrates, annual emissions are greatly reduced by the new development of large hydropower, while on the whole greenhouse gas emissions are on an increasing trend due to the increases in thermal power generation and electric power demand.

The figure also shows the impact of the introduction of wind/solar power (capacity: 752 MW in total) to the total emission. The amount of reduction in 2040 resulting from introduction of wind/solar power is about 600 kt-CO_2 (about 10%). The introduction mitigates the rise in emissions, but not enough to reverse the trend of overall increase. To suppress the increase in emissions, a larger scale of development will be required for renewable energy (wind /solar power) or hydropower.

Figure 6-32 and Table 6-15 show greenhouse gas emission from Angola's Intended Nationally Determined Contribution (DRAFT INDC) and that from power generation. The share of greenhouse gas emissions from power generation is low, totaling only about 3% (in 2030) of the assumed value of the "Conditional scenario" (target value) of INDC.

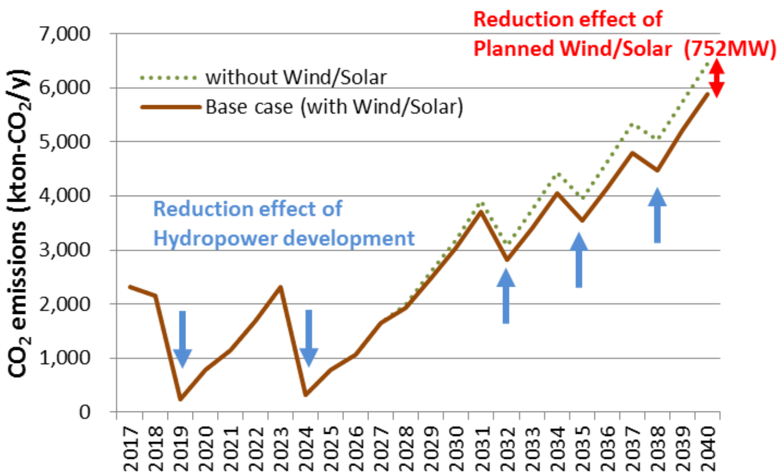


Figure 6-31 Greenhouse gas emission (base case)

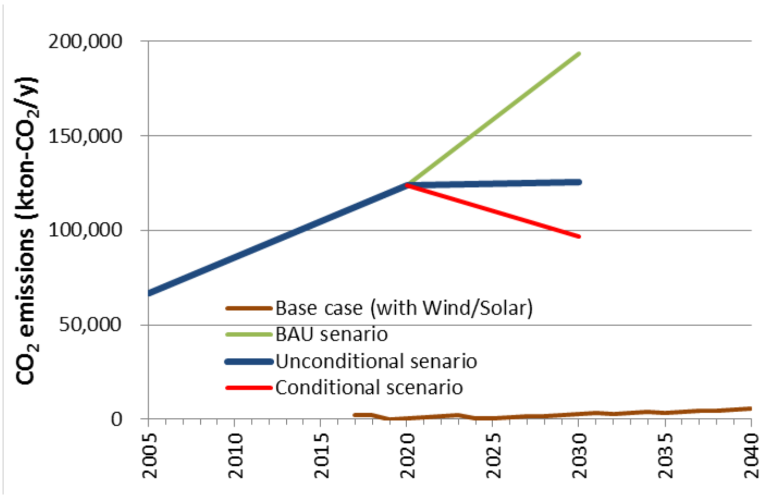


Figure 6-32 Angolan reduction plan (DRAFT INDC) and base case emission

Table 6-15 Expected emission from power generation (base case) and DRAFT INDC

(kton-CO_2/year)

		2005	(2017)	2020	2030
Draft INDC	BAU scenario	66,812	(112,400)	125,778	193,250
	Unconditional scenario				125,612
	Conditional scenario				96,625
Expected emission from power generation (base case)		-	2,300	800	3,000

Remark: INDC value in 2017 is interpolated between 2005 and 2020

6.6 Scenario case studies

6.6.1 Setting the scenario

A number of case studies have been conducted based on the proposed power development plan discussed in the previous section as a base case scenario (base case). The background and focal points of these studies are as follows.

- Delays in the development schedules for the power stations
  - Process delays in power development have a great influence on the optimum power supply configuration. In the case of Angola, since the development scales of hydropower projects are large, the delay in hydropower development compounds the negative impacts on the reliability of the power system.
  - Development of hydropower projects are often subject to delays all over the world. This risk is never small.
  - Another power source such as CCGT can conceivably be developed as an additional mitigation measure, but doing so would increase greenhouse gas emissions. The degree of influence is therefore considered in the study.
- Development location of CCGT
  - The fuel price of natural gas for CCGT is relatively low. At present, 400 kV transmission lines with a capacity of 2,000 MW (N-1 criteria) have already connected Soyo and Luanda. Soyo, the fuel supply point, is therefore the most economical location for development of CCGT.
  - The third and subsequent developments, however, require additional 400 kV transmission lines, which is costly. The transmission loss also increases when electric power is transmitted from Soyo to Luanda, and even to Benguela, a demand center in the central area. Taking these points into consideration, the promotion of development at Soyo after the third project does not always seem to offer economic advantages. In addition, the

power flow of the power transmission system becomes a one-sided flow from north to south, which is unfavorable for system stability.

- ✧ As a countermeasure against these issues, CCGT could conceivably be developed near a demand center, especially Lobito port which is near Benguela, and/or Namibe port, which is near the south demand center. In that case, however, as mentioned in Chapter 3, it would be desirable to adopt LPG for the fuel for CCGT until a supply system for natural gas / LNG is established (first step). In such a scenario, greenhouse gas emissions would increase by an estimated 20% compared with LNG. This emission increase must be considered as a factor.

➢ Additional development of renewable energy

- ✧ As stated in Section 6.5.4, greenhouse gas emissions in the base case are greatly increased by the development of power sources due to increased demand. Though the emissions from power generation are relatively small compared to the Draft INDC, a case with reduced emission is examined.
- ✧ The development of large hydropower effectively reduces, but large hydropower is hampered by the various restrictions as stated in Section 6.4.1 and is practically difficult to develop in a short period.
- ✧ Accordingly, a scenario to develop additional wind /solar power generation is examined in this section.

6.6.2 Delays in the development of the power stations

(1) **Risk of delays in hydropower development**

When the start of operation of a hydropower station is delayed, the supply power is reduced. Figure 6-33 shows the supply reserve ratio when hydropower development is delayed by 1, 2, and 3 years. Year when supply reserve cannot be secured are shown in orange in the figure, and years when the supply power is below demand are shown in red.

This examination reveals that the supply capacity decreases with development delay, and that the influence of delays is substantially larger in the nearest years. This conspicuous impact of delay seems to stem from the large scale of the hydropower relative to the demand scale. As the delay increases, the influence increases. Measures should therefore be promptly taken as soon as a delay is foreseen.

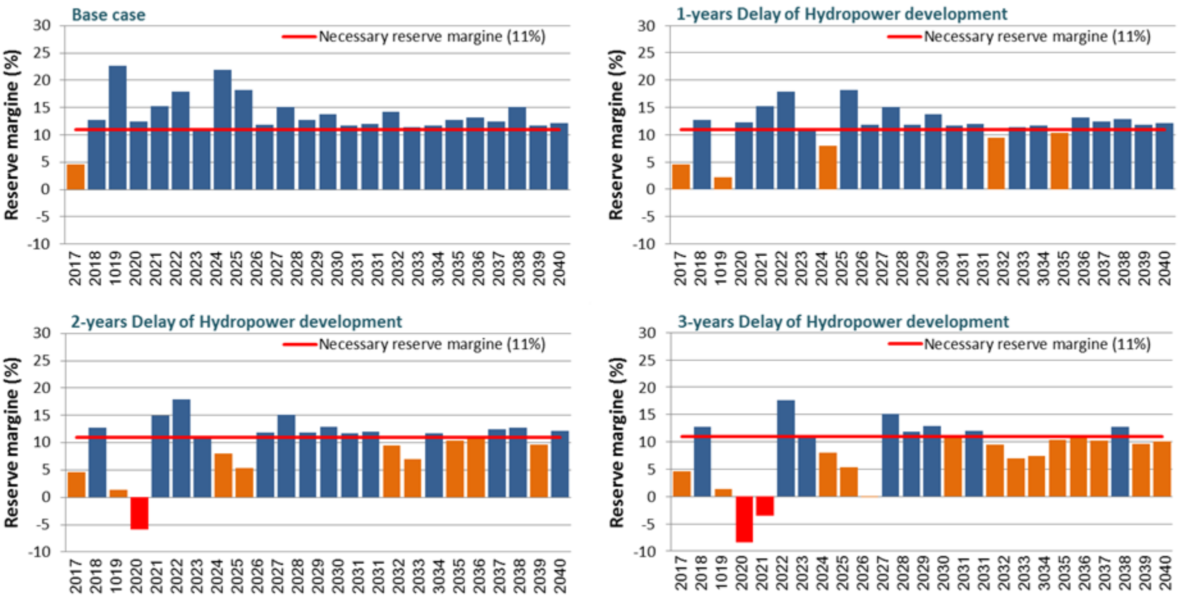


Figure 6-33 Influence of delays in hydropower development

(2) Risk of demand rises (equivalent to delay of hydro/thermal power development)

As in the preceding section, the effect in the case where the electric power demand exceeds the assumed value was examined. This is equivalent to the case where there are delays in the development of not only hydropower but in all the power sources including thermal power plants.

- Demand rise one year forward (= one-year delay of new power station development)
- Demand rise two years forward (= two-year delay of new power station development
  =one-year development delay+ one-year demand rise)
- Demand rise three years forward (=three-year delay of new power station development
  =two-year development delay+ one-year demand rise
  = one-year development delay+ two-year demand rise)

The reserve margin ratio for each case is shown in Figure 6-34. The supply reserve is reduced to about half of the required amount in almost all the subsequent years when the demand rise is forwarded by more than two years (power development is delayed by two years), which makes stable supply impossible. Moreover, a remarkable supply shortage continues when the demand rise is forwarded by three years. When the actual demand exceeds the assumed demand, therefore, the development plan must be revised from the next year to secure supply capacity.

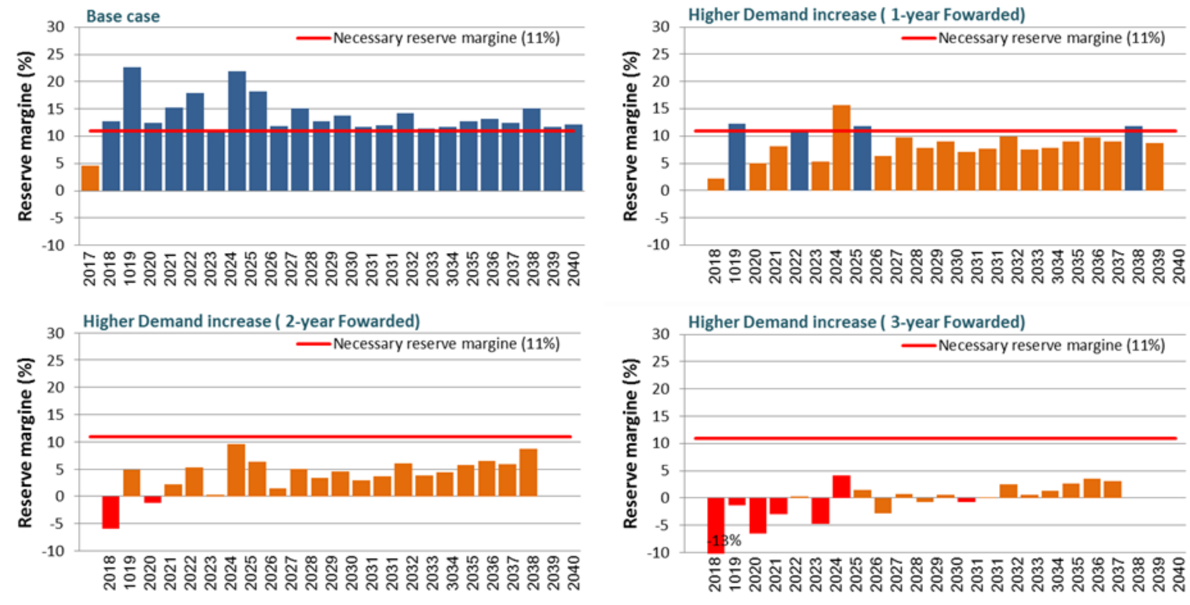


Figure 6-34 Influence of demand rise (=delay in the development of all power station types)

(3) Mitigation measures and its influence

If the electric power demand fluctuates more than one year (or the start of the power plant operation is delayed for one year), measures such as the introduction emergency power supply should be implemented as soon as possible. In this section, additional cost and increase of CO_2 emission, in the case additional GT generated by LPG for fuel is introduced as an emergency measure, are examined.

As a result, the influence continues for longer than a single year. As shown in Figure 6-35 and Figure 6-36, expenses rise and greenhouse gas emissions increase. These increases appear continuously until the supply capacity is secured. Countermeasures must therefore be taken as soon as such an event is foreseen, including revision of demand forecasts and the power development plan itself.

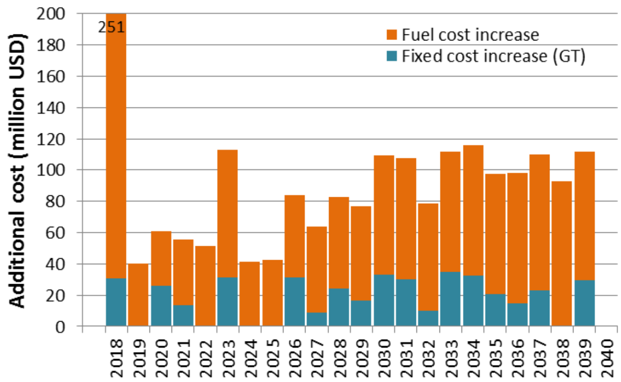


Figure 6-35 Cost increase for introducing emergency power supply

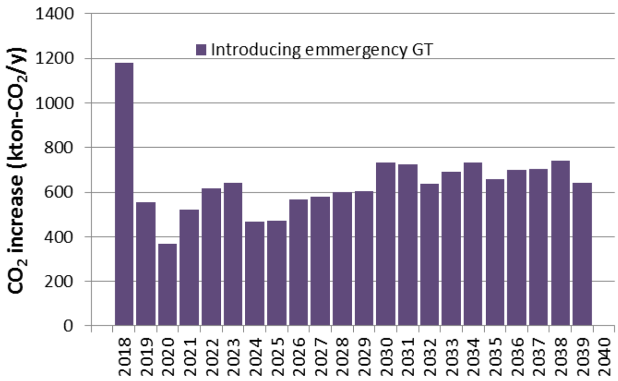


Figure 6-36 Increase of CO_2 emission by introducing emergency power supply

6.6.3 Development location of CCGT

(1) **Conditions and issues**

Regarding the development plan for thermal power, the Soyo 2 TPP is posted after complesion of the Soyo TPP currently under construction, but no specific plans follow. Specific plans have also yet to be formulated for the fuel supply, an issue with an important bearing on the siting of the CCGT thermal power plant.

As described in Section 6.6.1, the capacities of the existing 400 kV transmission line between Soyo and Luanda are 2,000 MW (N-1 criteria) in total, which is sufficient to transmit power from up to two of 750 MW-class plants. From the third plant onward, however, additional transmission lines will have to be constructed. Moreover, an uneven distribution of power generation equipment only in Soyo would be disadvantageous from the viewpoints of system stability and transmission loss.

Regarding fuel, Soyo is currently the only location available source of gas supply. It will therefore be necessary to consider the procurement plans for fuel when development of a TPP in another area. When plans call for the development of CCGT thermal power plants in the central/south areas, in particular, it will be necessary to consider a scheme for gradual fuel switching (see Section 3.5.4).

Table 6-15 shows general pros and cons in the case where the locations of future thermal power plants are concentrated in the northern part (Soyo) and when decentralized layout is taken.

Table 6-16 Pros and cons of the locations set for thermal power

	Concentrated layout in North (Soyo)	Decentralized layout (Soyo, Benguela....)
Fuel	○ : Efficiency improvement is available since the location is near existing gas supply facilities. × : A larger area will be needed. ? : The availability of natural gas supply must be confirmed.	○ : Location selection will be easier if the use of more easily transportable fuels such as diesel oil is acceptable up to completion of the natural gas supply facilities. × : Newly developed fuel supply facilities are needed. ? : Availability of fuels (oil, gas…).
Power grid	○ : Temporary use of existing transmission lines will be possible. × : As large power plants are located only in the north, there appears to be a need for strengthened transmission lines.	○ : The power flow is relatively smaller since power sources are located nearby both to the north and south of the demand center × : Transmission lines will have to be developed to connect the new power stations to the power grid.
Environment	— : Depends on the location.	— : Depends on the location.
Economy	○ : Cost reduction is expected since the generation/fuel supply facilities are located nearby. × : The transmission loss and cost for additional transmission lines are higher.	○ : Rescheduling of works to reinforce the transmission lines is expected. × : The cost of fuel supply facilities appears to be higher. ? : The need for integration of a port needs to be confirmed.
Energy Security	× : The concentrated layout heightens the risks to fuel procurement and reduces the power supply reliability.	○ : A risk diversification effect can be expected compared to the concentrated layout
Early realization	○ : Early development can be expected if the neighboring area is available for the new power plants. ? : Early utilization will be restricted if there are limits to the natural gas supply for generation fuel.	○ : Early development is expected if heavy oil is used as the primary fuel (because a suitable location for the power plants would be easier to find). If the location of the power plants is near an oil refinery facility, the use of light fuel, etc. will be an available option. × : Any delay in the development of the refinery facilities would lead to further delays in TPP commencement. .

○ : Advantages × : Disadvantages ? : Uncertain issues

(2) Candidate locations

If a new gas pipeline is laid, this location is advantageous because it will be possible to use cheap natural gas for fuel. On the other hand, a long time and huge cost would be required for the construction of a new gas pipeline. It would therefore be inappropriate to set pipeline as a condition for selection of site location at the present. Here, Lobito and Namibe are recommended as candidate locations that satisfy the following conditions. Both locations have construction plans for refinery facilities nearby, which is advantageous for the procurement of fuels such as LPG.

- ➢ Available space for construction of a power station close to the port used for fuel transportation
- ➢ Close to the main line and demand center
- ➢ Available site for construction of a LNG receiving facility, if necessary

(3) **Influence of fuel cost differences**

LPG or LNG is a candidate fuel for the CCGT plants in Lobito and Namibe, since providing natural gas is impossible. Both of these fuels, however, are more expensive than natural gas. In this section, the increment of fuel cost when using LPG and LNG as the fuel for the CCGT developed after the two CCGT power stations (Soyo and Soyo 2) that already are located in Soyo, is estimated using PDPAT.

The estimated annual cost is shown in Figure 6-37. At the beginning of introduction in 2029, the cost of LPG and LNG is higher than that of natural gas, but not by a big margin. Also, the difference between LPG and LNG is very small. However, the cost differences among the fuel types increase with the increase in the amount of thermal power generation and higher LPG costs. The annual cost using LPG surpasses that using natural gas by as much as 930 million USD in 2040, while that using LNG surpasses it by 310 million USD.

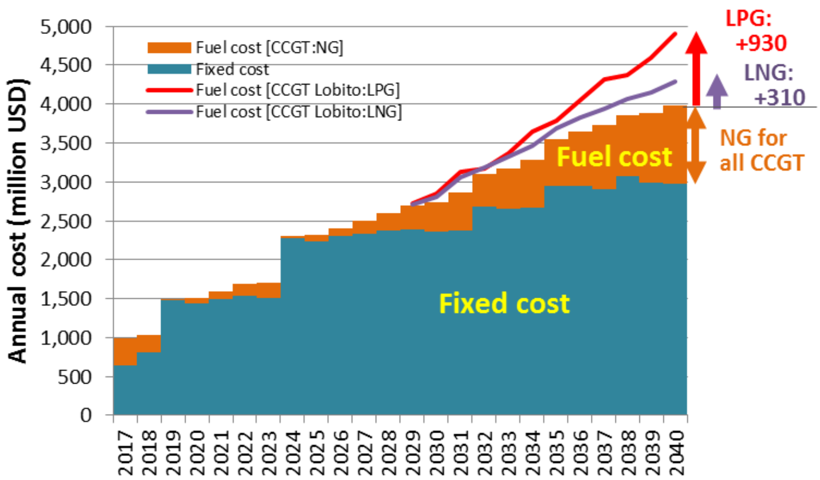


Figure 6-37 Cost increase when using LPG/LNG as fuel for CCGT
(Influence when the fuel for CCGT No. 3 or later is changed from NG to LPG/LNG)

(4) **Comparison of candidate locations**

Table 6-17 and Table 6-18 show the cost characteristics of the candidate sites for CCGT, including Soyo, and the development plan for a list of candidate locations narrowed down in consideration of the cost characteristics, respectively.

As a result of the comparison, the fuel cost difference has a greater influence than the transmission line and fuel tank construction cost, and Soyo site where natural gas can be used is advantageous from the cost aspect. This advantage premised on a low natural gas cost, which is an assumption formed based on international cost forecast. However, the cost of equipment such as fuel tanks may be reduced due to sharing with projects other than electric power, etc., so the cost differences does not necessarily mean larger as shown here.

On the other hand, decentralized layout has preferable properties as described in section (1). Especially energy security and risk diversification is an important factor for decision-making. Therefore, taking into account of this point, development of CCGT considering decentralized layout is the recommended option to consider, as shown in Table 6-18.

In addition, Soyo 2 is planned to be constructed by IPP, and it is decided to prepare necessary preparations including development of relevant laws etc. for the start of operation in 2021. To realize early development, however, it would be helpful to set up procedures for IPP development and establish a supporting scheme.

Table 6-17 Cost characteristics of candidate sites for CCGT

Items	Soyo site	Lobito site	Namibe site
① Construction cost for new transmission line for connecting to a main grid [Annual cost] (difference)	between SoyoTPP and Luanda (400 kV) 400 km,392 millionUSD [40 million USD/year] (Base)	between LobitoTPP and Nova Biopio SS (400 kV) 23 km, 23 million USD [2.3 million USD/year] (-38 million USD/year)	between Namibe TPP and Namibe SS (220 kV) 17 km, 7 million USD [0.7 million USD/year] (-39 million USD/year)
② Construction cost of fuel tank	-	LNG：150 million USD (+15 million USD/year)	
③ Additional fuel cost （in 2040, with assumed CCGT generation of 17,900GWh/y）	NG: 4.2 UScl/kWh (Base)	LPG: 15.1 USc/kWh (+ 930 million USD/year) LNG: 7.6 USc/kWh（＋310 million USD/year）	
④ Transmission loss	(Base)	Low（Slight）	Low（Slight）
①＋②＋③	(Base)	LPG: +907 million USD/year LNG: +287 million USD/year	LPG: +906 million USD/year LNG: +286 million USD/year

Note: Fuel cost and annual generation: assumed values for 2040.
Service life of transmission lines and tanks: 40 years. Interest rate: 10%.

Table 6-18 Narrowing down and selection of CCGT location

Power station	Deve lop-ment	Items	Soyo site	Lobito/Namibe site
No.1 750 MW class (375x2)	2017 /2018	Evaluation	◎ Soyo	×
		Construction in time Fuel supply Fuel cost Transmission cost Risk diversification	○ Under construction (partially completed) ○ NG available by 2018 ○Low (use of NG available) ○ 400 kV TL completed ○ First introduction of CCGT	× Construction cannot be completed in time × No fuel supply facility so far △ Limited to trafficable fossil fuel △ New construction required ○ First introduction of CCGT
No.2 750 MW class (375x2)	2021 /2022	Evaluation	◎ Soyo	×
		Construction in time Fuel supply Fuel cost Transmission cost Risk diversification	△ Possible (Support to IPP is required) ○ NG available by 2018 ○ Low (use of NG available) ○ 400kV TL completed × Concentrated layout	× Lead time is too short × Short lead time for fuel facilities △ Limited to trafficable fossil fuel △ New construction required ○ Diversification effect expected
No.3 750 MW class (375x2)	2024 /2029	Evaluation	△	○ Lobito, △ Namibe
		Construction in time Fuel supply Fuel cost Transmission cost Risk diversification	○ Possible ○ NG available by 2018 ○ Low (use of NG available) △ TL construction cost higher × Concentrated layout	○ Possible ○ Available by construction of fuel facility △ LPG/LNG cost is higher ○TL construction cost lower ○Diversification effect expected
No.4 750 MW class (375x2)	2031 /2034	Evaluation	△	○ Lobito, △ Namibe
		Construction in time Fuel supply Fuel cost Transmission cost Risk diversification	○ (same as No.3) ○ (same as No.3) ○ (same as No.3) △ (same as No.3) △ High concentration	○ (same as No.3) ○ (same as No.3) △ (same as No.3) ○ Use of TL available for No.3 ○ Diversification effect expected
No.5 750 MW class (375x2)	2036 /2038	Evaluation	△	○ Lobito, ○ Namibe
		Construction in time Fuel supply Fuel cost Transmission cost Risk diversification	○ (same as No.3) ○ (same as No.3) ○ (same as No.3) △ (same as No.3) △ Long-distance transmission risk remains	○ (same as No.3) ○ (same as No.3) △ (same as No.3) ○ New construction required ○ Lower long-distance transmission risk Diversification effect expected
No.6 750 MW class (375x1)	2040	Evaluation	○ Soyo	○ Lobito, ○ Namibe
		Construction in time Fuel supply Fuel cost Transmission cost Risk diversification	○ (same as No.3) ○ (same as No.3) ○ (same as No.3) △ (same as No.3) △ (same as No.4)	○ (same as No.3) ○ (same as No.3) △ (same as No.3) △ Available to use TL for No.3 ○ Lower long-distance transmission risk

NG: Natural Gas, TL: Transmission Line

6.6.4 Additional development of renewable energy

The amount of greenhouse gas emissions reduced through the development of the wind/solar power (752 MW in total) currently planned is about 600 kt-CO_2, or about 10% of the total emission (see section 6.5.4).

As mentioned earlier, the accuracy of this calculation is low because conditions of generation are assumed as the generation plans of the projects are at the initial stage. It seems likely however, that the further installation of wind/solar power will be necessary to realize reduced (or avoid increased) greenhouse gas emissions. In this section, therefore, a case of adding wind/solar power generation is examined as a reference.

(1) Greenhouse gas reduction effect

The greenhouse gas emission is examined in the case where wind/solar power is developed under the following conditions. We find that when both 300 MW of wind power and 300 MW of solar power are developed and installed every year from 2028, 10 years from now, onward, the expected greenhouse gas emission can be reduced to the same level as the current level in 2018 (see Figure 6-38).

There is a possibility, however, that the reduction effect may be overestimated, as this calculation is based on assumptions of the characteristics of the wind/solar power generation. The capacity of the development, meanwhile, is rather large compared with the potential of renewable energy, which is 20 GW in total (3.9 GW of wind power (of which 0.6 GW is prioritized in economy) and 17.3 GW of solar power), as described in section 3.2.4.

< Assumptions >

Wind power:	Development at 300 MW/year pace from 2028 to 2040, 3,900 MW in total
Solar power:	ditto
Reserve margin:	CCGT/GT development postponed within 11% of securing the reserve margin
Generations:	The expected hourly generation of wind/solar power is assumed based on the average of the current plans.

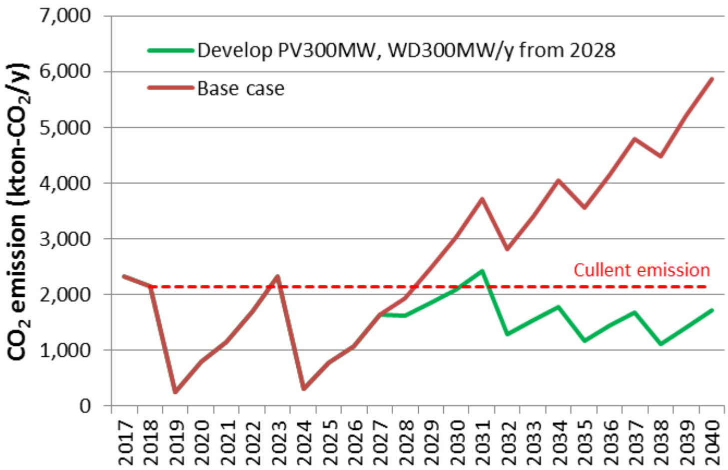


Figure 6-38 CO_2 reduction effect of large-scale introduction of wind/solar power

(2) Influence of additional wind/solar power development

In accordance with the additional development of wind/solar power examined in section (1) above, the generation cost increases. As shown in Figure 6-39, the total generation cost in a year increases with the introduction of wind /solar power. Compared with the base case, the amount of increase reaches 900 million USD/year in 2040.

Figure 6-40 shows the generation cost, which are about 1.4 UScents/ kWh higher in 2040 than in the base case.

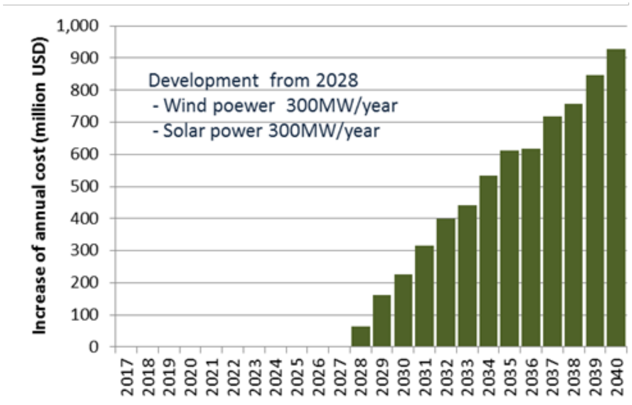


Figure 6-39 Increase of generation cost by introducing wind/solar power

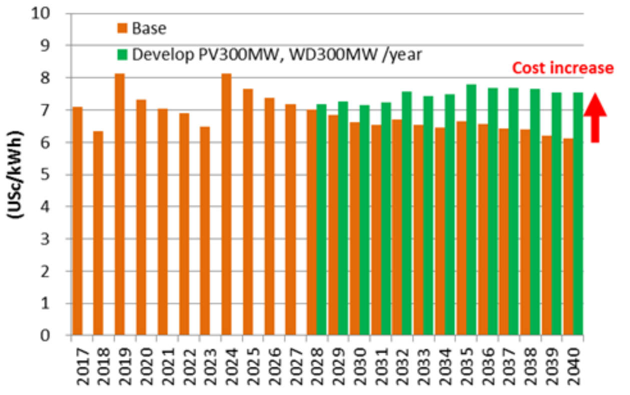


Figure 6-40 Increase of unit cost by introducing wind/solar power

6.7 Recommended project list

The recommended long-term power development plan is summarized in the table below.

Table 6-19 Long-term power development plan

Year	Long-term Power Development Plan				
	Hydropower	CCGT	GT	Wind power	Solar power
2017		Soyo1-1 (250)			
2018	Lauca (2070) Lomaun ext.(65)	Soyo1-2 (500)			
2019					
2020	Luachimo ext.(34)				
2021		Soyo2-1 (375)			
2022		Soyo2-2 (375)	Cacuaco No.1 (125)		
2023					
2024	Caculo Cabaça(2172)		Cacuaco No.2 (125)		
2025			Sambizanga No.1 (125)		
2026	Baynes (300)				
2027		Lobito1-1 (375)	Quileva No.1 (125)		
2028	Quilengue (210)		Quileva No.2 (125)	Beniamin (52)	Benguela (10)
2029		Lobito1-2 (375)		Cacula (88)	Cambongue (10)
2030			Quileva No.3 (125) Soyo-SS No.1 (125)	Chibia (78)	Caraculo (10)
2031		Lobito2-1 (375)		Calenga (84)	Catumbera (10)
2032	Zenzo (950)		Cacuaco No.3 (125) Cacuaco No.4 (125)	Gasto (30)	Lobito (10)
2033			Sambizanga No.2 (125) Quileva No.4 (125) Quileva No.5 (125) Quileva No.6 (125)	Kiwaba Nzoji I (62)	Lubango (10)
2034		Lobito2-2 (375)		Kiwaba Nzoji II (42)	Matala (10)
2035	Genga (900)		Soyo-SS No.2 (125) Cacuaco No.5 (125)	Mussede I (36)	Quipungo (10)
2036		Namibe1-1 (375)		Mussede II (44) Nharea (36)	Techamutete (10)
2037			Cacuaco No.6 (125) Sambizanga No.3 (125) Soyo-SS No.3 (125)	Tombwa (100)	Namacunde (10)
2038	Túmulo Caçador(453)	Namibe1-2 (375)			
2039					
2040	Jamba Ya Oma (79) Jamba Ya Mina (205)	Lobito3-1 (375)			
Total	7,438 MW	4,125 MW	2,250 MW	652 MW	100 MW